Virginia State Capitol

Virginia Energy Plan

Prepared by Virginia Energy, the Office of the Chief Energy Officer, and the Secretariat of Commerce & Trade

October 2026

Table of Contents

Introduction **5**

1A. Development of the 2026 VEP 5

The Current Energy Landscape **9**

2A. Virginia's Energy Profile 9
2B. Policy Landscape 14
2C. Energy Supply and Delivery 16
2D. Energy Needs for Data Centers and Other Large Load Customers 38
2E. End Use Electrification 41
2F. Energy Efficiency 45
2G. Energy Affordability 55
2H. Emissions and Health Implications 67
2I. Economic Opportunity and Energy Security 74

Outlook for Virginia's Power Sector **80**

3A. Power Sector Modeling Overview 80
3B. Load Growth and Policy Scenarios 82
3C. Capacity Expansion Modeling Results 87
3D. Key Modeling Takeaways & Implications 99
3E. The Decade Ahead 100

The Path Forward for Virginia **102**

4A. Vision for Virginia's Energy Future 103
4B. Energy Strategies 103
4C. Priority Actions 105
Virginia's Data Center Accountability Framework 113
4D. An Energy Future that Works for Every Virginian 122

Appendix **124**

Recent Energy Legislation 124
Stakeholder Input Summary 126
Modeling Assumptions and Inputs 130

Acronyms

ACEB: Accelerated Clean Energy Buyers
ACEEE: American Council for an Energy-Efficient Economy
ADMS: advanced distribution management systems
AEP: American Electric Power
AI: artificial intelligence
AMI: advanced metering infrastructure
AMLER: Abandoned Mine Land Economic Revitalization
APCo: Appalachian Power Company
APS: Allegheny Power
AREB: Accelerated Renewable Energy Buyers
ASNH: Affordable and Special Needs Housing
ATB: Annual Technology Baseline
ATT: advanced transmission technology
BESS: battery energy storage systems
BEV: battery electric vehicle
BTM: behind-the-meter
C-PACE: Commercial Property Assessed Clean Energy
CAFE: Corporate Average Fuel Economy
CAGR: Compound Annual Growth Rate
CAPEX: Capital Expenditure Cost
CC: combined cycle
CCAP: Comprehensive Climate Action Plan
CCR: Cost Containment Reserve
CEAB: Clean Energy Advisory Board
CETA: Clean Energy Transformation Act
CFPF: Community Flood Preparedness Fund
CFS: Commonwealth Fusion Systems
CHP: combined heat and power
CLOA: construction letter of authorization
CMM: coal mine methane
CNG: compressed natural gas
COD: commercial operation date
CORE: Community-Oriented Resilient Energy
CP: Coincident Peak
CPRG: Climate Pollution Reduction Grants
CREZ: Competitive Renewable Energy Zone
bcombustion turbine
CVOW: Coastal Virginia Offshore Wind
DCFC: direct-current fast charging
DELTa: Database of Emerging Large load Tariffs
DEPTH: Drivers of Electricity Pricing Trends & History
DEQ: Department of Environmental Quality
DER: distributed energy resource
DGS: Department of General Services
DHCD: Department of Housing and Community Development
DMV: Department of Motor Vehicles
DOE: U.S. Department of Energy
DOM: Dominion transmission zone
DPL: Delmarva Power
DR: demand response
DSS: Department of Social Services
DTT: direct-transfer-trip
EE: energy efficiency
EERS: Energy Efficiency Resource Standard
EHARP: Essential Home and Accessibility Repair Program
EIA: U.S. Energy Information Administration
EJ: environmental justice
ELCC: effective load carrying capability
EPA: U.S. Environmental Protection Agency
ERIS: Energy Resource Interconnection Service
ESA: electric service agreement
ESPC: Energy Savings Performance Contracting
EV: electric vehicle
FERC: Federal Energy Regulatory Commission
GDP: gross domestic product
GEM: Geospatial Energy Mapper
GET: grid-enhancing technology
GHG: greenhouse gas
GT: gas turbine
GTSA: Grid Transformation & Security Act
HB: House Bill
HEDC: Historically Economically Disadvantaged Community
HEV: hybrid electric vehicle
HGL: hydrocarbon gas liquid
HVAC: heating, ventilation, and air conditioning
HVDC: high-voltage direct current
IC: internal combustion
ICE: internal combustion engine
IMM: Independent Market Monitor
IOU: investor-owned utility
IPP: independent power producer
IRP: integrated resource plan
ITCS: Interregional Transfer Capability Study
JLARC: Joint Legislative Audit and Review Commission
JST: Jurisdiction-Specific Test
LBNL: Lawrence Berkeley National Laboratory
LCOE: levelized cost of energy
LDC: local distribution company
LDES: long-duration energy storage
LDV: light-duty vehicle
LEAD: Low-Income Energy Affordability Data

LLWR: large light-water reactor
LMI: low- and moderate-income
LPG: liquefied petroleum gas
MATS: Mercury and Air Toxics Standards
MSRP: manufacturer's suggested retail price
NEM: net energy metering
NERC: North American Electric Reliability Corporation
NEVI: National Electric Vehicle Infrastructure
NLR: National Laboratory of the Rockies
NNG: No New Gas
NOVEC: Northern Virginia Electric Cooperative
NRC: Nuclear Regulatory Commission
NREL: National Renewable Energy Laboratory
NYSERDA: New York State Energy Research and Development Authority
OBBBA: One Big Beautiful Bill Act
ODEC: Old Dominion Electric Cooperative
PAYS: Pay As You Save
PHEV: plug-in hybrid electric vehicle
PHMSA: Pipeline and Hazardous Materials Safety Administration
PIPP: Percentage of Income Payment Program
PJM: PJM Interconnection
PPA: power purchase agreement
PV: photovoltaic
R&D: research and development
RAC: rate adjustment clause
REC: renewable energy certificate
REZ: Renewable Energy Zone
RFP: request for proposals
RGGI: Regional Greenhouse Gas Initiative
ROE: return on equity
ROW: right-of-way
RPM: Reliability Pricing Model
RPS: renewable portfolio standard
RTEP: Regional Transmission Expansion Plan
RTO: regional transmission organization
SAF: sustainable aviation fuel
SB: Senate Bill
SCC: State Corporation Commission
SEDS: State Energy Data System
SELOA: substation engineering letter of authorization
SMR: small modular reactor
ST: steam turbine
TOD: transit-oriented development
TOTEX: total expenditure
T**OU:** time of use
USDA: U.S. Department of Agriculture
USGS: U.S. Geological Survey
VBAF: Virginia Brownfields Restoration and Economic Redevelopment Assistance Fund
VBRSP: Virginia Business Ready Sites Program
VCEA: Virginia Clean Economy Act
VCEIB: Virginia Clean Energy Innovation Bank
VCHEC: Virginia City Hybrid Energy Center
VEDP: Virginia Economic Development Partnership
VEP: Virginia Energy Plan
VEWAR: Virginia Energy Workforce Assessment Report
VGRIP: Virginia Grid Reliability Improvement Program
VIPC: Virginia Innovation Partnership Corporation
VMT: vehicle miles traveled
VNECA: Virginia Nuclear Energy Consortium Authority
VPIP: Virginia Power Innovation Fund and Program
VPP: virtual power plant
WAP: Weatherization Assistance Program
WDR: Weatherization Deferral Repair

Introduction

Introduction

A Virginia Energy Plan (VEP) is required to be developed every four years. The VEP provides a roadmap of Virginia's energy future and outlines recommendations for how this future can be realized collectively for residents and businesses. Each VEP considers trends and potential solutions using the data and information available at the time of publication. The VEP is not a regulatory or ratemaking document.

The 2026 energy planning cycle for Virginia is especially important because Virginia's power sector is expected to grow at rates not seen since World War II. There is significant uncertainty in forecasted electricity demand, which creates both immense challenges and opportunities for the Commonwealth at this moment. The VEP recognizes these challenges and provides a blueprint for how Virginia manages growth while maintaining reliable energy service, allocating costs equitably, considering environmental impacts, public health, and natural resources, and improving outcomes for residents and businesses.

This report provides the full 2026 VEP, including the Commonwealth's current energy landscape, electricity demand outlook, modeling analysis, key findings, and strategies for meeting future energy needs. A shorter overview of the Plan's principal findings and recommendations is available in the separate 2026 VEP Executive Brief.

1A. Development of the 2026 VEP

Legislative Framework

The VEP is governed primarily by statutes in Title 45.2 of the Code of Virginia. Together, these statutes establish the Commonwealth's energy policy, the purpose and content of the Plan, and the process for developing and updating it.

The overarching policy basis for the 2026 VEP is the "Commonwealth Clean Energy Policy," in §45.2-1706.1. This statute sets goals such as achieving economy wide net zero greenhouse gas (GHG) emissions by 2045. It also directs state agencies and political subdivisions to recognize and, where appropriate, act in accordance with these objectives.

Article 4 of Chapter 17 ("Virginia Energy Plan"), principally §45.2-1710, supplies the statutory objectives of and requirements for the VEP. Section 45.2-1710 requires the Virginia Department of Energy (Virginia Energy) to prepare a comprehensive 10-year VEP in consultation with the State Corporation Commission (SCC), the Virginia Department of Environmental Quality (DEQ), the Clean Energy Advisory Board (CEAB), and a broad stakeholder group representing consumers, environmental organizations, manufacturing, forestry, agriculture, and natural gas and electric utilities. These provisions also tie the Plan explicitly to the objectives listed in the Commonwealth Clean Energy Policy.

In addition to requiring recommendations, §45.2-1710 requires the VEP to include an analysis of the Commonwealth's energy infrastructure, energy consumption, energy efficiency (EE), air emissions, and disproportionate adverse impacts on economically disadvantaged or minority communities.

Section 45.2-1710 specifies that the Plan must include, among other elements, projections of energy consumption and fuel costs, analyses of the adequacy of generation, transmission, and distribution infrastructure, assessments of siting requirements and impediments to distributed resources, and evaluations of fuel diversity and efficiency opportunities. The VEP sections that follow provide an analysis of these topics.[1]

Article 4 further requires periodic updates and progress reporting, creating a recurring planning cycle aligned with gubernatorial terms.

Public Input Process

Virginia Energy prioritized strong public input and stakeholder engagement to better understand a wide array of perspectives and priorities. Virginia Energy gathered input from residents, businesses, community organizations, local governments, utilities, state agencies, and other stakeholders so the Plan would reflect Virginia's diverse energy needs, priorities, and opportunities. Virginia Energy used stakeholder input to validate planning assumptions, identify challenges and opportunities, understand regional and community perspectives, and strengthen the practicality and credibility of VEP recommendations. The engagement process also increased transparency, built awareness of the planning effort, and created meaningful opportunities for Virginians to help shape the Commonwealth's energy future.

Virginia Energy implemented a comprehensive engagement strategy that combined digital and in-person methods to reach statewide, regional, and sector-specific audiences. The engagement strategy paired broad public outreach with targeted stakeholder discussions to capture both community perspectives and technical expertise. Virginia Energy hosted an online public survey to collect broad input from residents and organizations across the Commonwealth, and convened six in-person regional meetings—in Abingdon, Danville, Petersburg, Arlington, Richmond, and Hampton Roads—that allowed participants to discuss local energy priorities, challenges, and opportunities while highlighting differences across Virginia's regions. Additionally, the team conducted twenty thematic virtual stakeholder meetings and focused consultations with state agencies, local governments, utilities, industry representatives, academic institutions, community organizations, and advocacy groups. Through these efforts, Virginia Energy and members of the Administration met with more than 500 individuals and received more than 3,000 survey responses.

The engagement process generated substantial input that revealed several consistent themes across stakeholder groups and geographic regions. Participants and survey responses emphasized the need to maintain affordable energy for households and businesses while ensuring a reliable and resilient energy system that supports economic growth, as well as barriers related to infrastructure constraints, implementation costs, workforce capacity, permitting requirements, and access to programs and funding. Stakeholders identified opportunities to expand EE, modernize the electric grid, strengthen workforce development programs, deploy distributed energy resources (DERs), and advance innovative energy technologies. Across many discussions, stakeholders encouraged Virginia Energy to consider equity, community impacts, and access to benefits when developing recommendations, particularly for rural, low-income, and historically underserved communities. Stakeholders also provided valuable insights on energy demand, grid reliability, infrastructure planning, and program implementation. The Administration and Virginia Energy used these findings to refine assumptions, prioritize recommendations, and develop a more informed, actionable, and responsive VEP.

Across the engagement process, stakeholders broadly agreed on the need for affordable, reliable, and resilient energy and infrastructure that supports economic competitiveness. They differed, however, on how to plan for uncertain data center growth, the future role of dispatchable resources, cost allocation, and the balance between faster development and local authority and environmental, cultural-resource, and community protections. The VEP uses this input to identify shared needs without implying consensus on every solution. Appendix: Stakeholder Input Summary provides additional regional and stakeholder-specific findings.

Figure 1. *Key results and top themes of stakeholder engagement efforts*

3,000+ Survey Responses
To the online public survey

6 Regional Meetings
In Abingdon, Danville, Petersburg, Arlington, Richmond, and Hampton Roads

20 Targeted Meetings
With state agencies, local governments, utilities, nonprofits, academia, & businesses

500+ Participants
In regional and targeted meetings

Meeting growing electricity demand while maintaining affordability and reliability

Emerged as the central challenge facing Virginia's energy system over the next decade

Accelerate energy infrastructure development while improving coordination

Particularly for permitting, siting, interconnection, and transmission planning

EE, demand management, energy storage, and grid modernization

Identified as important near-term strategies for improving system performance and reducing costs

Workforce shortages, supply chain constraints, financing challenges, and implementation

Noted as significant barriers to achieving Virginia's energy goals

Economic growth, community impacts, environmental considerations, and long-term energy resilience

Must be balanced when evaluating future energy investments and policies

Ensure energy investments deliver benefits to communities across Virginia

Accounting for local needs, land-use considerations, and potential impacts on residents and businesses

Modeling Analysis

The 2026 VEP used capacity expansion modeling to understand the least-cost mix of generation and storage resources that are needed to meet Virginia's electricity demand growth and clean energy goals.

This is the first VEP to include capacity expansion modeling. As further discussed in Section 3A: Power Sector Modeling Overview, the analysis provides a data-informed framework for evaluating alternative energy-system pathways and the tradeoffs among cost, reliability, health impacts, resource development, and policy objectives.

The Current Energy Landscape

The Current Energy Landscape

Virginia's energy landscape is diverse, interconnected, and changing rapidly. Electricity, natural gas, petroleum, and other fuels and energy sources are central to homes, businesses, transportation, public services, and Virginia's broader economy. The Commonwealth's energy system also extends beyond state lines: Virginia participates in regional electricity markets and relies on interstate networks for electricity, natural gas, and fuel supplies.

This chapter describes Virginia's current energy landscape, setting the foundation for forward-looking strategies. It summarizes how Virginians use energy; the resources, infrastructure, and institutions that deliver it; and the trends shaping near- and long-term needs. It also reviews the roles of electric utilities, competitive suppliers, local governments, regional market organizations, and state and federal agencies in energy planning and regulation.

Understanding these conditions is essential to evaluating Virginia's energy future. Demand is growing and changing, particularly as large load customers, including data centers, connect to the grid; households and businesses adopt new technologies; and weather, fuel markets, and supply-chain conditions affect energy systems. To meet this demand, Virginia is adding and retiring resources, expanding transmission and distribution infrastructure, and pursuing statutory and policy goals related to affordability, reliability, economic development, public health, and emissions reduction.

The sections that follow provide the factual foundation for the Plan's analysis of future energy needs, opportunities, tradeoffs, and policy choices.

2A. Virginia's Energy Profile

Like most states, Virginia relies on a variety of fuels to meet end-use consumption, including the direct consumption of fuels and energy sources converted into electricity. The sources that Virginia has come to rely on have shifted over time as new fuel sources have become commercially available and affordable. The largest single primary source of energy in Virginia in 2024 was petroleum, followed by natural gas, nuclear, and then other resources (see Figure 2).

The largest use of energy in Virginia is electricity generation to power homes, businesses, and industry. Petroleum for transportation is the second largest end-use of energy.

Figure 2. *Sankey diagram for Virginia's Energy Consumption in 2024*[2]

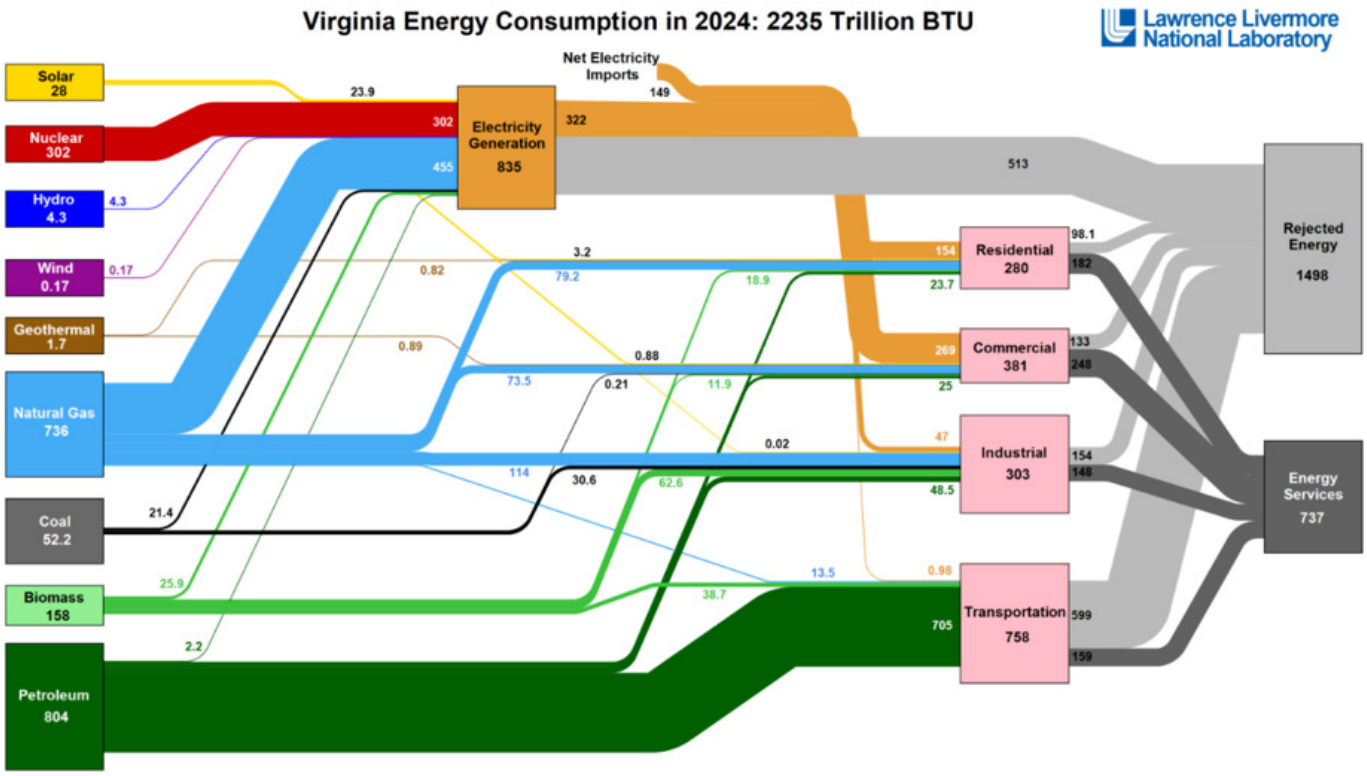
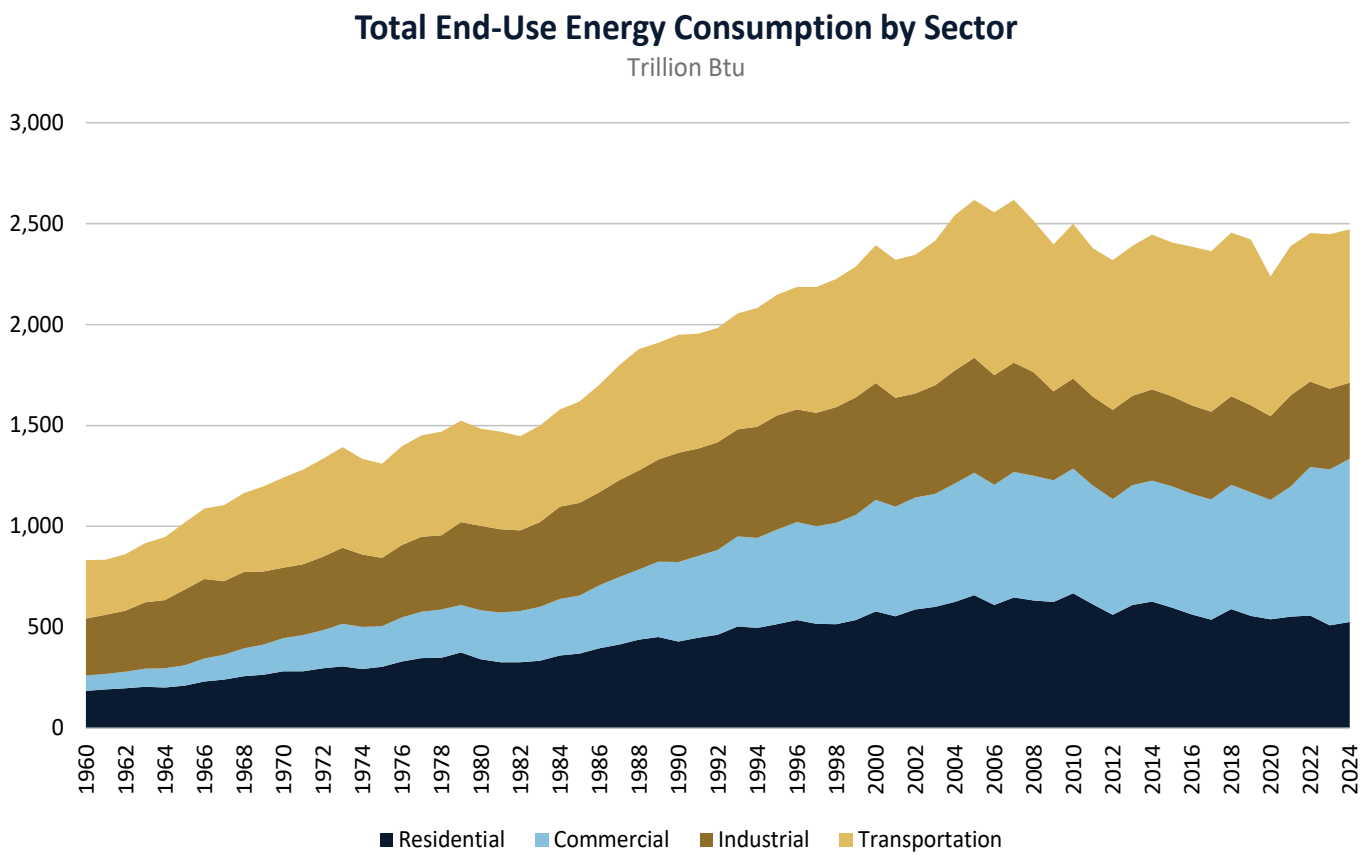


Figure 2 shows a Sankey diagram of Virginia's economy-wide energy consumption; read from left to right, one can see the primary sources of energy that Virginia relies on, what end-use consumption sectors they go to, and ultimately the amount of useful and rejected energy those sectors use. A primary source of energy is energy that is available as a resource from nature, such as natural gas, solar, nuclear, petroleum, etc. Traditional thermal primary sources of energy such as coal, oil, and natural gas, when being used to make secondary forms of energy (e.g., electricity) or directly consumed experience thermal losses, known as rejected or wasted energy. When talking about replacing energy sources, often through electrification, it is important to note that only useful energy must be replaced; the system needs to replace the energy consumed as energy services, not the rejected energy. Energy services, or useful energy, were only ~33% of total energy use in 2024.

After growing significantly from 1960 to the early 2000s, Virginia's total end-use energy consumption remained relatively flat from 2000 to 2024, increasing by only 3.29% over that twenty-four-year period. Improved efficiency gains helped manage overall energy consumption even as Virginia's economy has increased significantly: between 2010 and 2025, Virginia's inflation-adjusted gross domestic product (GDP) increased by 31% (from $476 billion to $624 billion)[3] and population has increased by 11%.[4]

Figure 3. *Total End-Use Energy Consumption by Sector*[5]



Consumption has been decreasing in the residential and industrial sectors and increasing in the commercial and transportation sectors. In 2024, Virginia's residential sector was responsible for 21.3% of all energy consumption, commercial was responsible for 32.7%, industrial 15.3%, and transportation 30.7%.

Table 1. *Comparison of the Portion of Total End-Use Energy Consumption by Sector, including losses*[6]

End Use	2020	2021	2022	2023	2024
Residential	24.1%	23.2%	22.8%	20.8%	21.3%
Commercial	26.5%	27.0%	30.0%	31.6%	32.7%
Industrial	18.5%	18.9%	17.2%	16.3%	15.3%
Transportation	30.9%	31.0%	30.0%	31.3%	30.7%

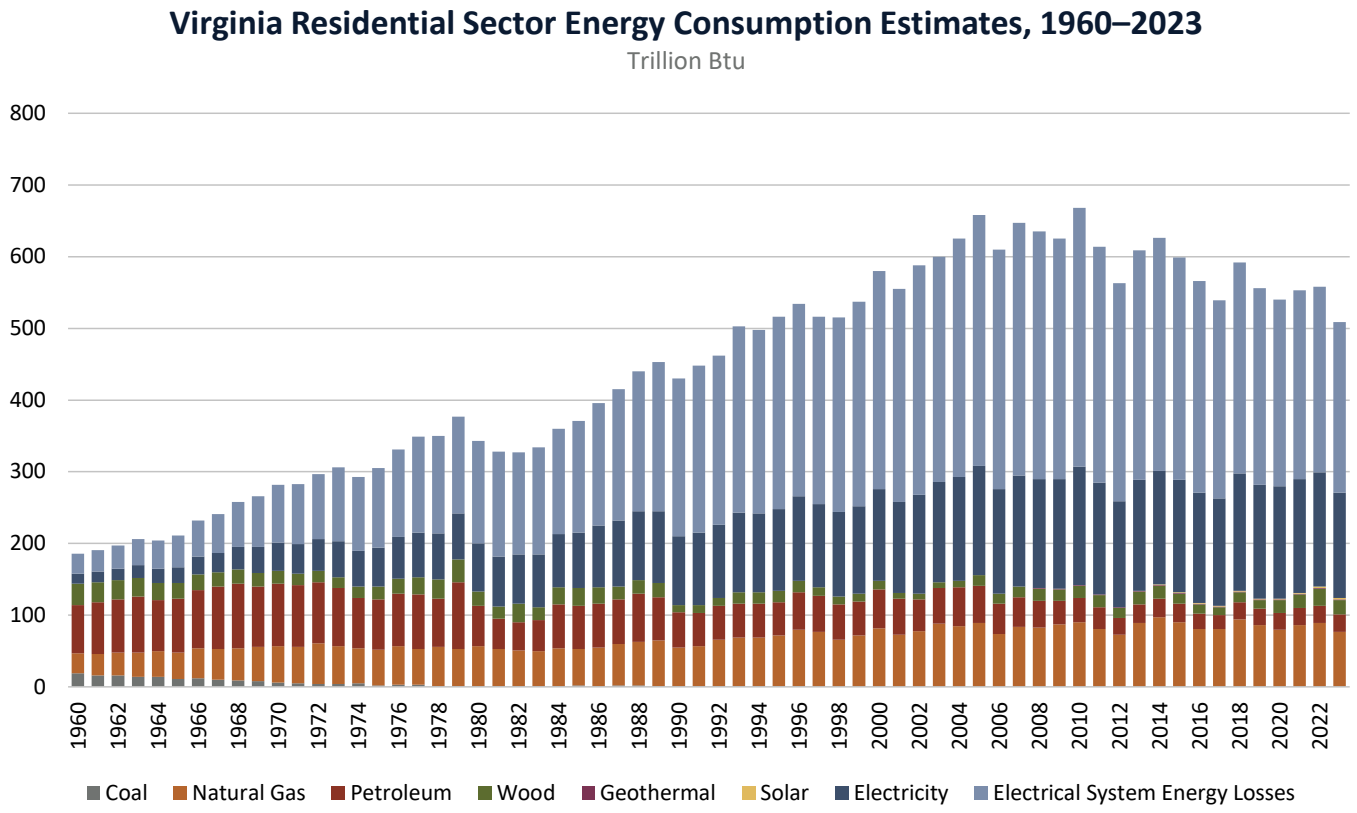
Virginia's energy resources, infrastructure, and technology opportunities vary by region. Southwest Virginia combines legacy energy assets, mine lands, coalbed methane, pumped storage, and long rural distribution circuits. Hampton Roads combines ports, military and shipbuilding facilities, offshore-wind and nuclear expertise, and coastal resilience needs. Southside and Central Virginia include manufacturing, municipal utilities, working lands, biomass, and opportunities on brownfields. Northern Virginia's concentrated load growth and transmission constraints increase the potential value of grid optimization, storage, distributed resources, and demand flexibility. These examples are illustrative: suitability depends on cost, grid location, community priorities, and site-specific land, water, environmental, and cultural-resource conditions.

Consumption Profile by End Use Sector

Residential

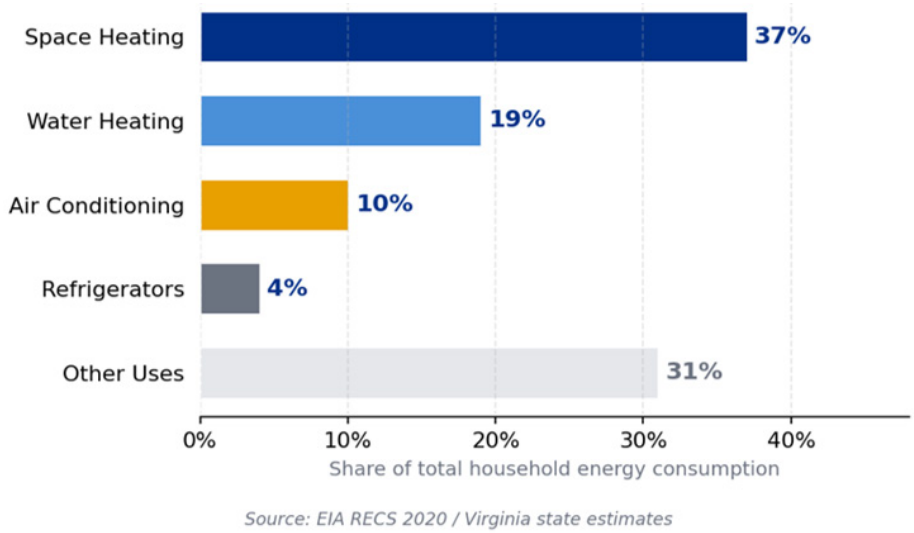
Virginia households have varied fuel profiles. Nearly all use electricity, but roughly 64% also rely on at least one onsite combustion fuel: natural gas (44% of households), propane (14%), or fuel oil/kerosene (6%). The remaining 36% of households are fully electrified.[7]

Figure 4. *Virginia Residential Sector Energy Consumption Estimates, 1960-2023*



Space heating is the single largest end use in Virginia homes, accounting for approximately 37% of household energy consumption, followed by water heating (19%), air conditioning (10%), refrigerators (4%), and other uses (31%). For homes relying on natural gas, consumption is concentrated in these thermal end uses. For all-electric homes, electricity serves the full range of end uses (heating, cooling, water heating, refrigeration, and appliances).

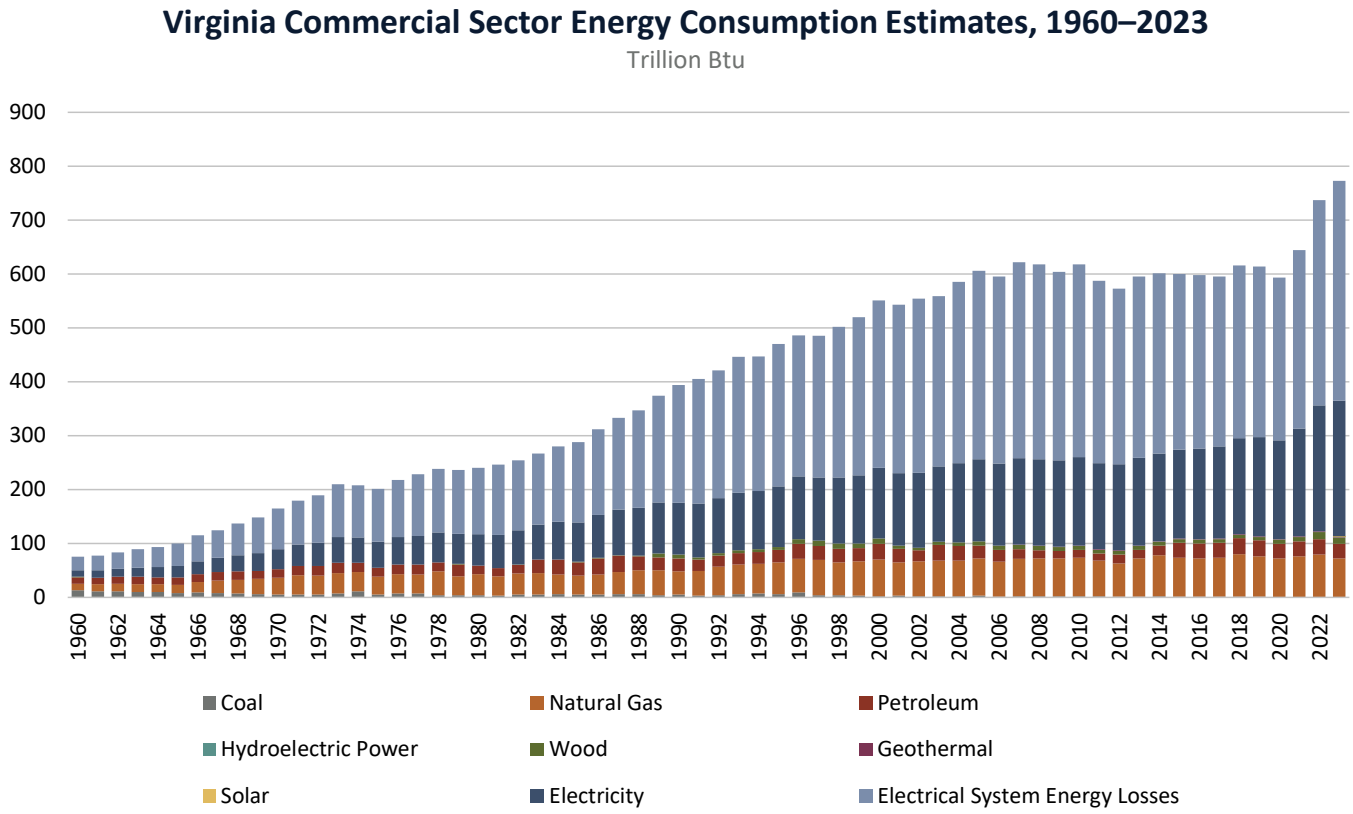
Figure 5. *Virginia Residential Energy End-Uses*



Commercial

Virginia's commercial sector relies predominantly on electricity and natural gas to meet its energy needs. The sector includes data centers, whose rapidly growing electricity consumption far exceeds new consumption from the electrification of homes and vehicles.

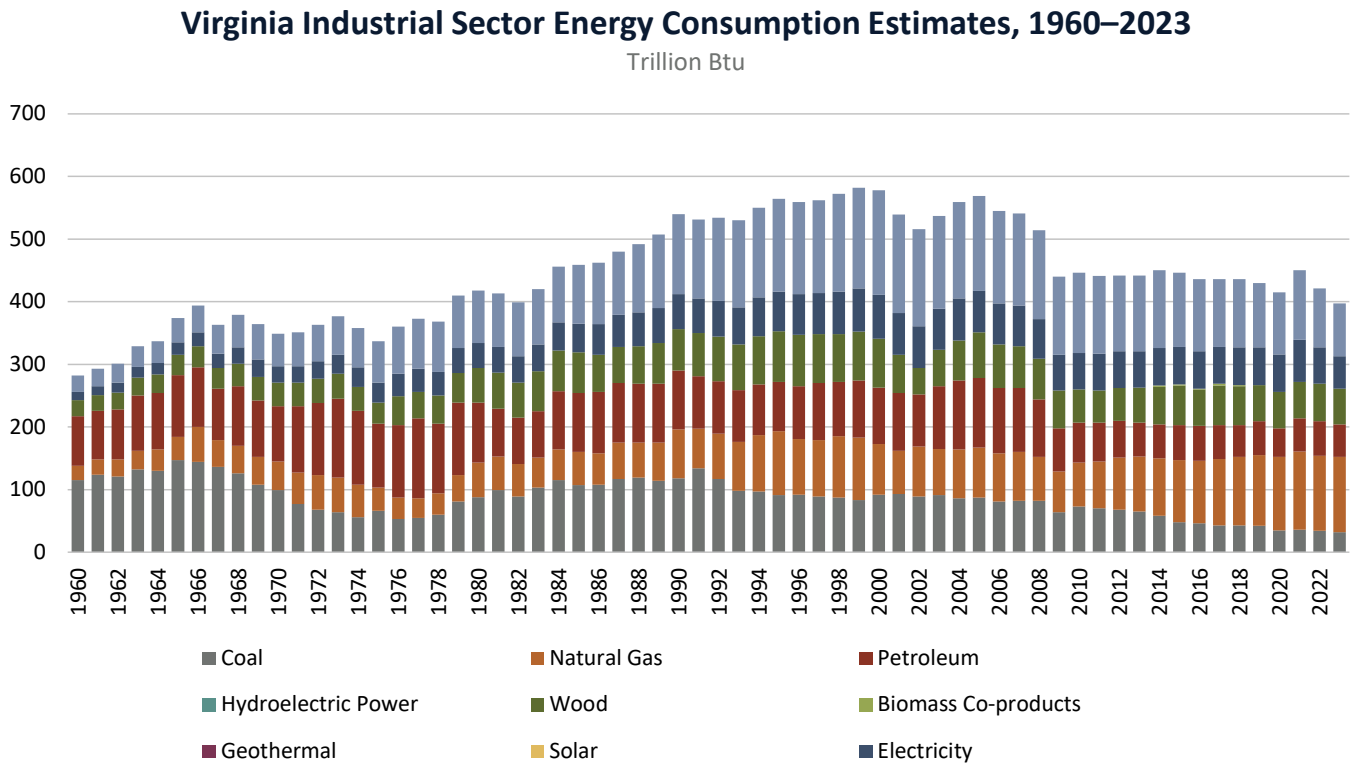
Figure 6. *Virginia Commercial Sector Energy Consumption Estimates, 1960–2023*[8]



Industrial

Virginia's industrial customers use a variety of energy sources, including coal, natural gas, wood, petroleum, and electricity. Petroleum and coal use in the sector has declined since the late 2000s and 2010, respectively, with natural gas meeting a larger share of industrial energy needs. The industrial sector is the second-largest consumer of natural gas for energy use.

Figure 7. *Virginia Industrial Sector Energy Consumption Estimates, 1960-2023*[9]



Natural gas consumption within the industrial sector does not include industrial consumption of natural gas as a feedstock for manufacturing or industrial processes.

2B. Policy Landscape

Virginia's electricity sector is regulated through several frameworks. The SCC reviews the rates and services of investor-owned electric utilities and member-owned electric cooperatives, which are subject to distinct statutory requirements. Municipal electric utilities generally set retail rates through local governing bodies or public authorities, although the SCC retains authority over specified facilities and service-territory matters. The SCC also reviews specified generation and transmission projects and determines whether regulated utilities may recover proposed costs from customers under applicable law.[10]

Over the last twenty years, Virginia has enacted a number of critical policies that shape the energy landscape and dictate the schedule on which utilities build clean energy and reduce emissions.[11] For the purposes of the VEP, the Virginia Clean Economy Act (VCEA) and Regional Greenhouse Gas Initiative (RGGI) are the most important policies that were incorporated into the capacity expansion model.

Table 2. *Key Virginia Power Sector Related Laws*

Key Policies	Description
2007 Virginia Electric Utility Regulation Act	Returned Virginia to a regulated electric market with some exceptions for large customers and renewable tariffs.
2018 Grid Transformation & Security Act (GTSA)	Required the two major investor-owned utilities (IOUs) to pursue grid modernization and resilience. Included: • Cost recovery mechanism for advanced grid infrastructure • 5,000 MW of solar and wind in the public interest, including 50 MW of rooftop solar • $1.1 billion in EE spending over 10 years
2020 VCEA	Establishes a mandatory renewable portfolio standard (RPS) that reaches 100% of covered retail electricity sales by 2045 for Dominion Energy Virginia (Dominion) and by 2050 for Appalachian Power Company (APCo), within the VCEA's statutory framework for renewable and zero-carbon resources.[12] This includes: • 16,700 MW of solar and wind in the public interest • 5,200 MW of offshore wind in the public interest • 3,100 MW of storage in the public interest • Mandatory retirement of all fossil generation by 2045 • Mandatory EE targets • Increased net metering cap from 1% to 6% of peak load • Created Percentage of Income Payment Program (PIPP) that caps bills against income for certain customers
2023 Affordable Energy Act	Changed the amount the investor-owned electric utility can over-earn in their base rates before rebating those costs to customers
2023 Virginia Electric Utility Regulation Act	Established financials for Virginia's IOUs: • Granted Dominion a 9.7% return on equity (ROE) for their 2023 biennial review • Set debt to equity at 52%/48% • Allowed for securitization of 2022 fuel costs
RGGI 2026	States that the Commonwealth shall participate in the RGGI cap and trade program to reduce power sector emissions.

The 2026 General Assembly passed several bills that expanded the requirements of VCEA and address the evolving energy context within Virginia and regionally. Key 2026 energy legislation expanded clean-energy procurement options, allowing qualifying large customers to procure zero-carbon resources in PJM Interconnection (PJM) to help offset certain VCEA-related costs. Storage legislation established new short- and long-duration storage categories

and substantially raised utility targets: Dominion Energy must petition for 4 GW of short-duration storage by 2030 and 16 GW by 2045, and procure or construct 4 GW of long-duration storage by 2045. APCo must petition for 780 MW of short-duration storage and procure or construct 520 MW of long-duration storage by 2045.

Other legislation in 2026 increased the distributed-generation RPS carveout from 1% to 4.5% through 2030 and 5% through 2045, raised the previously developed-site development requirement from 200 MW to 1 GW, and required utilities to begin procuring geothermal heating and cooling Renewable Energy Certificates (RECs) as part of their RPS requirements—0.5% in 2027, rising to 1% in 2029 and thereafter. PIPP was also amended in 2026 by reducing bill limits for participating customers from 10% and 6% to 5% and 3% of annual household income, respectively, and expanding eligibility by increasing the income threshold from 150% to 200% of the federal poverty guidelines.

See *Appendix: Recent Energy Legislation* for additional energy legislation that was passed and for additional detail.

2C. Energy Supply and Delivery

Virginia's energy system depends on both the resources that produce energy and the infrastructure that moves it to customers. Electricity is generated from a mix of resources and delivered through regional transmission and local distribution networks. Natural gas moves through interstate and local pipelines. Petroleum fuels, propane, coal, biomass, and other fuels are transported by pipeline, rail, truck, barge, or other means and may be stored before use.

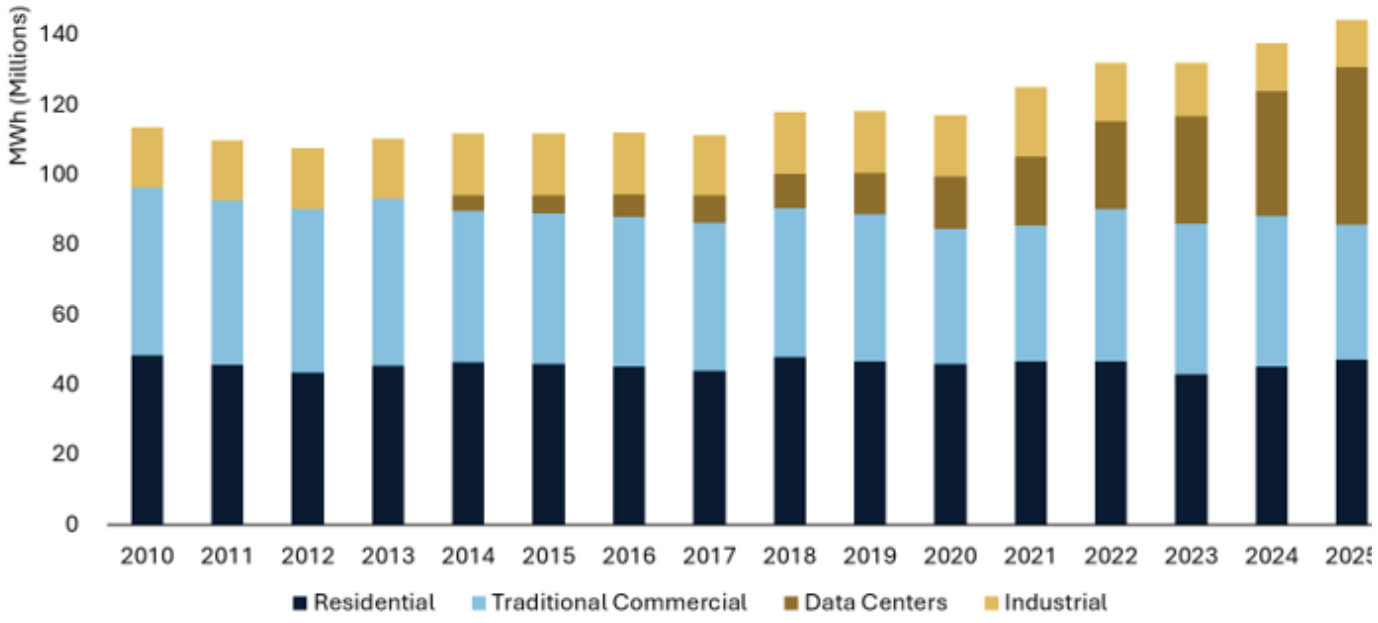
These systems operate at different geographic scales. Some resources and facilities are located in Virginia, while others are part of regional or national supply chains and markets. Virginia's electricity system is connected to the broader PJM region, and its natural-gas and petroleum supplies depend in part on interstate infrastructure and markets. As a result, conditions outside the Commonwealth—including weather events, fuel prices, infrastructure constraints, and changes in regional demand—can affect energy availability, reliability, and costs for Virginia customers.

This section describes the major systems that supply and deliver energy to Virginia's homes, businesses, industries, institutions, and transportation sector. It summarizes the electric power system; natural-gas, petroleum, and other fuel supply chains; and the infrastructure that supports the movement, storage, and delivery of energy. It also identifies key trends and considerations that shape the system's ability to serve customers safely, reliably, and affordably as Virginia's energy needs evolve.

Electricity

After years of relatively flat demand, electricity use is rising rapidly, driven largely by data centers. Data centers now account for approximately 31% of Virginia's annual electricity consumption as of 2025, while residential use has remained comparatively flat as efficiency gains offset population growth. Transportation electrification has started contributing to electricity demand but remains a relatively small portion today.

Figure 8. *Virginia electricity consumption (MWh) by end-use sector*[13]



Virginia Electricity Market Overview

The Commonwealth operates a primarily regulated, vertically integrated electric utility model under the Virginia Electric Utility Regulation Act.[14] Utilities own and operate generation, transmission, and distribution assets to serve retail customers within designated service territories.

The SCC regulates Virginia's two main IOUs, Dominion Energy Virginia (Dominion) and APCo,[15] and is authorized to have quasi-oversight of the electric cooperatives. The SCC oversees and approves IOUs' retail electricity rates, audits capital expenditures and riders, and approves long-term integrated resource plans (IRPs) to ensure utility investments are just and reasonable.

Electric Service Providers

There are four main types of electric service providers in Virginia:

1. **IOUs:** Serve the vast majority of Virginia's retail electricity customers under regulated rate-of-return frameworks. These include:
   - Dominion Energy Virginia (Dominion; Phase II utility): Serves ~2.8 million customers across central, eastern, and northern Virginia.
   - APCo (Phase I utility): Serves ~500,000 customers across southwestern Virginia.
   - Kentucky Utilities (Old Dominion Power): Serves a small customer footprint in far southwestern Virginia.

2. **Member-Owned Electric Cooperatives:** Thirteen non-profit, member-owned distribution cooperatives serving ~2 million customers, primarily in rural and suburban regions, purchasing bulk generation primarily through Old Dominion Electric Cooperative (ODEC) or wholesale market contracts.[16]

3. **Municipal Utilities:** Publicly owned municipal systems operating independent local distribution networks in specific cities and towns (e.g., Danville, Harrisonburg, Martinsville).

4. **Independent Power Producers (IPPs):** Merchant generation owners that construct and operate wholesale generation assets, selling energy and capacity into the PJM regional market or directly to utilities (such as Dominion, APCo, and ODEC) through power purchase agreements (PPAs).[17]

Figure 9. *Virginia Electric Service Territories*

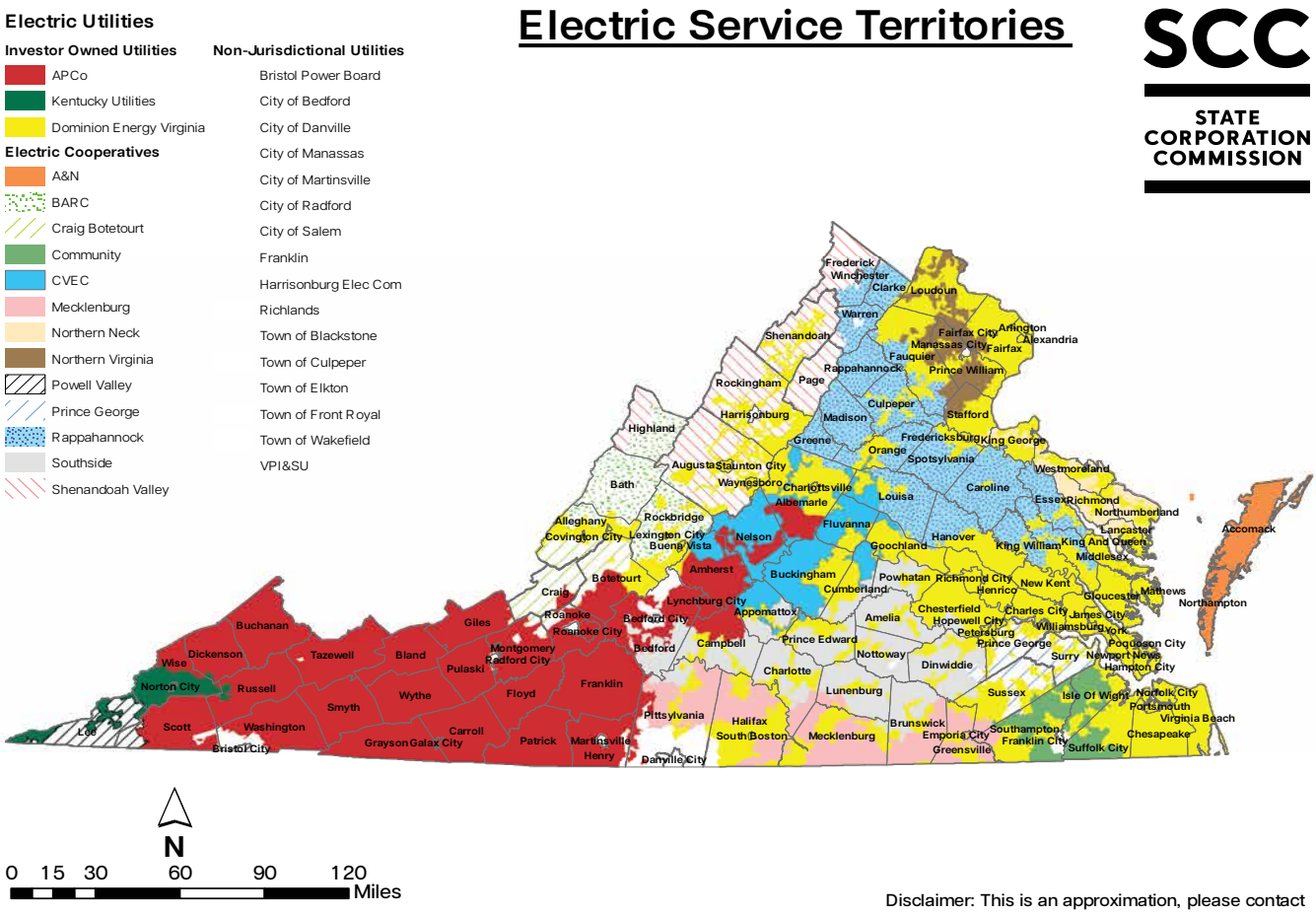


Table 3. *2024 Utility Bundled Retail Sales—Total*[18]

Entity	State	Ownership	Customers (Count)	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/ kWh)
Virginia Electric & Power Co	VA	Investor Owned	2,654,875	89,037,178	9,357,477.8	10.51
Appalachian Power Co	VA	Investor Owned	549,218	14,004,268	1,961,416.0	14.01
Northern Virginia Elec Coop	VA	Cooperative	182,074	12,234,081	883,338.0	7.22
Rappahannock Electric Coop	VA	Cooperative	180,962	4,069,232	514,124.0	12.63
Shenandoah Valley Elec Coop	VA	Cooperative	100,827	2,397,259	291,136.8	12.14

Entity	State	Ownership	Customers (Count)	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/ kWh)
Mecklenburg Electric Cooperative	VA	Cooperative	31,934	1,851,386	136,253.4	7.36
City of Danville - (VA)	VA	Municipal	42,984	970,181	115,356.8	11.89
Southside Electric Coop, Inc	VA	Cooperative	59,338	939,880	137,205.7	14.60
Central Virginia Electric Coop	VA	Cooperative	39,573	714,870	106,097.0	14.84
A & N Electric Coop	VA	Cooperative	37,341	705,648	84,042.9	11.91
City of Harrisonburg - (VA)	VA	Municipal	21,705	688,739	69,351.0	10.07
Kentucky Utilities Co	VA	Investor Owned	27,495	627,122	84,044.6	13.40
Bristol Virginia Utilities	VA	Municipal	16,485	446,318	46,907.0	10.51
City of Manassas - (VA)	VA	Municipal	16,624	394,352	42,034.0	10.66
Prince George Electric Coop	VA	Cooperative	12,489	362,124	42,573.0	11.76
City of Salem - (VA)	VA	Municipal	13,519	342,911	49,003.8	14.29
Virginia Tech Electric Service	VA	State	6,849	329,025	47,687.0	14.49
Northern Neck Elec Coop, Inc	VA	Cooperative	20,658	283,877	45,471.0	16.02
Community Electric Coop	VA	Cooperative	11,967	204,949	27,851.5	13.59
Town of Front Royal	VA	Municipal	7,837	171,970	17,564.0	10.21
BARC Electric Coop Inc	VA	Cooperative	13,097	171,827	28,458.0	16.56
City of Radford - (VA)	VA	Municipal	7,564	168,139	24,113.0	14.34
Town of Bedford - (VA)	VA	Municipal	6,939	166,575	20,023.9	12.02
City of Martinsville - (VA)	VA	Municipal	7,737	154,555	22,225.0	14.38
Powell Valley Electric Coop	VA	Cooperative	8,407	135,133	15,169.0	11.23
City of Franklin - (VA)	VA	Municipal	5,722	134,197	13,884.0	10.35
Town of Culpeper - (VA)	VA	Municipal	5,855	108,014	15,050.8	13.93
Craig-Botetourt Electric Coop	VA	Cooperative	6,954	79,878	15,729.9	19.69
Town of Richlands - (VA)	VA	Municipal	2,985	53,729	6,373.0	11.86
Town of Blackstone - (VA)	VA	Municipal	2,035	37,685	5,212.0	13.83
Town of Elkton	VA	Municipal	1,129	24,188	1,939.0	8.02
Town of Wakefield - (VA)	VA	Municipal	542	11,035	1,460.0	13.23
Tesla Inc.	VA	Behind the Meter	68	518	36.0	6.95

Entity	State	Ownership	Customers (Count)	Sales (Megawatthours)	Revenues (Thousands Dollars)	Average Price (cents/ kWh)
Sunnova	VA	Behind the Meter	2	4	0.4	10.00
Total			**4,103,790**	**132,017,857**	**14,228,609.0**	**12.31**

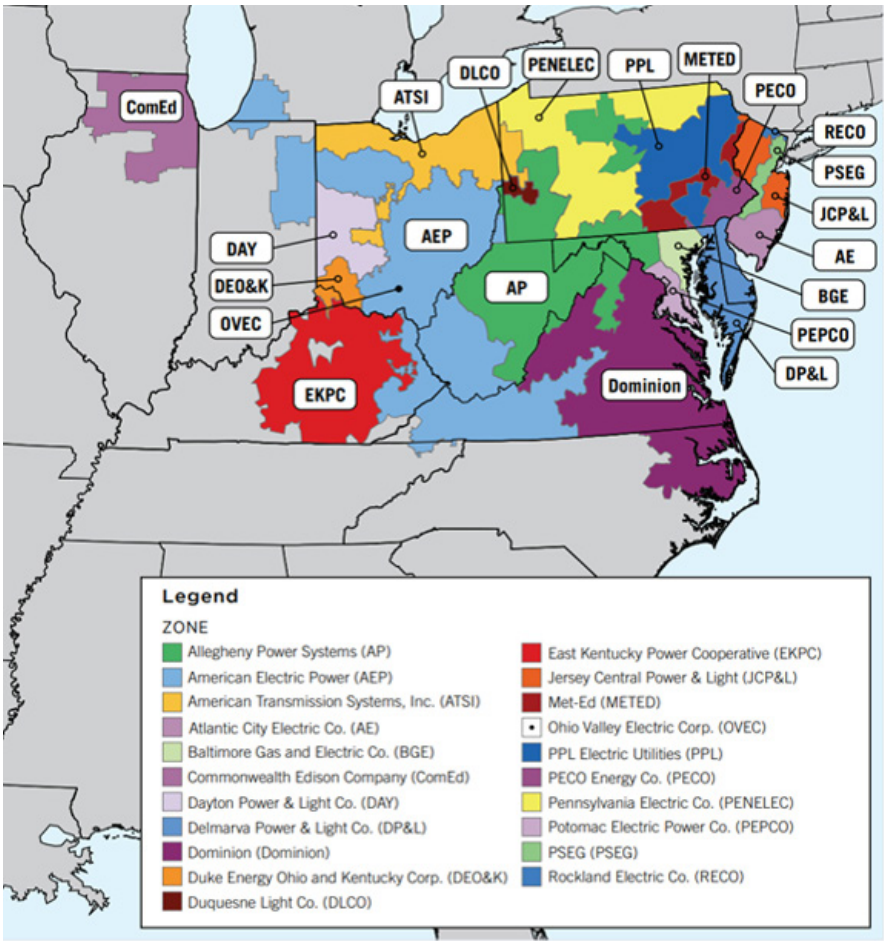
Wholesale Market Integration

Virginia's IOUs and electric cooperatives participate in PJM, the regional transmission organization (RTO) that operates competitive wholesale electricity markets and coordinates the high-voltage transmission system across 13 states and the District of Columbia. For operational, market-settlement, and planning purposes, PJM divides the regional grid into transmission zones that generally align with major utility service territories, including the Dominion (DOM), American Electric Power (AEP), Allegheny Power (APS), and Delmarva Power (DPL) zones in Virginia (see Figure 10).

Participation in PJM provides Virginia with access to a large, diverse regional resource pool rather than requiring each utility to meet all of its energy, capacity, and operating-reserve needs independently. Regional coordination supports reliability by enabling utilities to share reserves, dispatch available generation across state lines, plan transmission jointly, and purchase energy and capacity through competitive markets. It can also reduce costs when lower-cost regional resources are available and provide support during local outages or periods of unusually high demand.

These benefits come with tradeoffs. Virginia customers are exposed to regional market prices, transmission costs, resource constraints, and planning decisions that may originate outside the Commonwealth. PJM's recent challenges—including interconnection delays, rising capacity prices, transmission constraints, and uncertainty associated with rapid load growth—therefore have direct implications for Virginia. The Commonwealth's interest is not whether to participate in regional coordination, which provides substantial reliability and economic benefits, but how to improve PJM's planning and market processes and ensure that regional decisions appropriately reflect Virginia customers' needs.

Figure 10. *PJM Footprint*

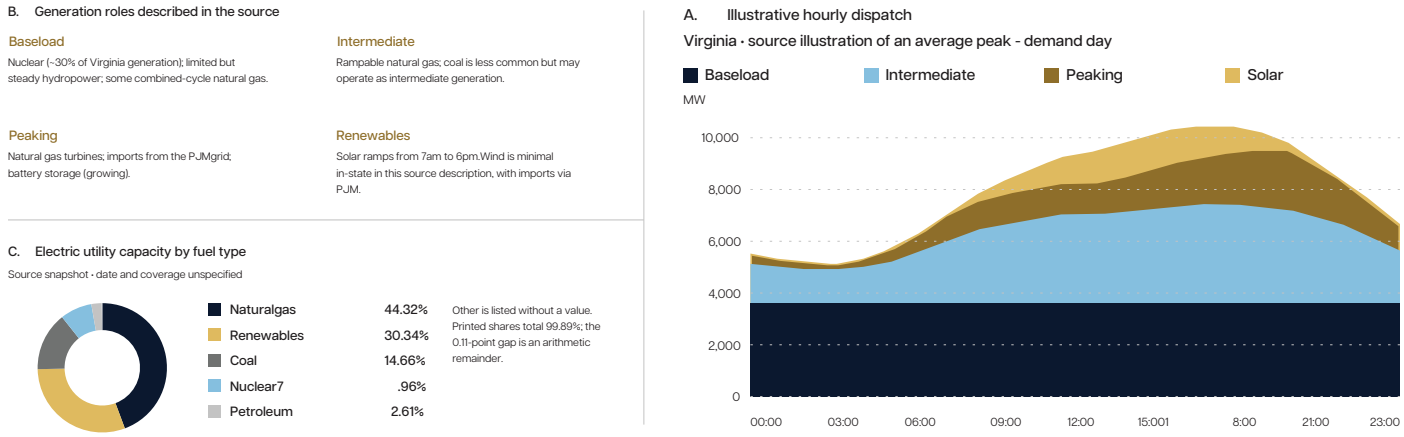


To ensure long-term resource adequacy—the availability of sufficient supply- and demand-side resources to meet projected demand and required reserves—and real-time operational balance, PJM administers centralized competitive wholesale markets.[19] These include:

- **Capacity market,** which procures commitments from resources to be available when needed three years in advance;
- **Energy market,** which manages the day-ahead and real-time dispatch of power plants; and
- **Ancillary services market,** which helps keep electricity supply and demand in balance.

PJM's energy market has two main components: the day-ahead market and the real-time market. The day-ahead market schedules resources and sets wholesale energy prices for the following day, while the real-time market adjusts the dispatch of resources as conditions change. Generating resources and demand-response resources—which provide time-specific changes in electricity demand to help meet system needs—offer into the market, and PJM selects enough resources to meet demand, generally in order from lowest to highest offer price. Resources selected in this process are said to clear the market.

Figure 11. *Illustrative example of Generator Dispatch*



PJM also directs regional grid expansion through its Regional Transmission Expansion Plan (RTEP) process, identifying transmission line projects needed to support reliability across member states and allocating multi-billion-dollar bulk transmission project costs across regional zones.

Historically, PJM governance has been dominated by its members—transmission owners, generation owners, electric distributors, end-use customers, and other suppliers—with minimal formal authority granted to states. However, because PJM's market rules, capacity auction structures, and transmission cost allocations directly drive customer bill increases and shape clean energy deployment, there has been increasing action from states to engage with PJM more directly, particularly after spiking capacity prices in recent years highlighted significant affordability concerns (See Section 2G: Energy Affordability). Starting in 2025 and continuing in 2026,20 the Commonwealth has been engaging in ongoing policy efforts focusing on reforming PJM capacity market rules, improving governance transparency, and ensuring regional transmission cost allocation models protect Virginia ratepayers from unreasonable cost-shifting.

Generation Supply

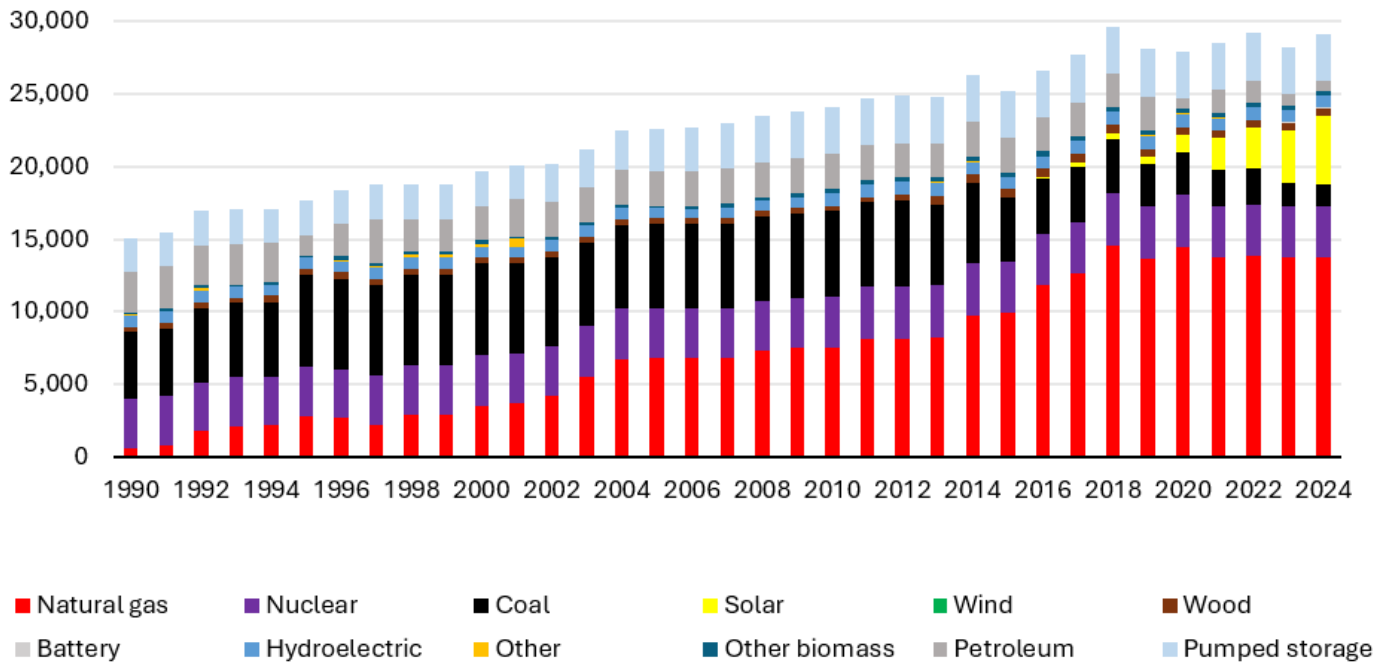
Capacity is the maximum amount of electric power a resource can provide at a given time and is measured here in megawatts (MW). As of June 2026, generating resources physically located in Virginia or off its coast had about 31,569.8 MW of nameplate capacity—their rated maximum output under defined conditions.[21] Different generation resources have different operating parameters, leading to different amounts of generation they put onto the grid. The amount of generation a resource actually puts onto the grid compared to its theoretical maximum amount is known as a resource's capacity factor. Similarly, storage resources have a usage factor that measures how much a battery is discharging over the course of a year. For example, if a battery is assumed to be a four-hour system that discharges completely once a day, that means that the system would run for a total of 1,460 hours out of the 8,760 hours in the year, or a 16.7% usage factor. Some resources that have low-capacity factors are maintained strictly as capacity resources and only operate during the highest system demand hours to maintain system reliability. Virginia's coal resources, which historically operated as high-capacity factor resources, are now reserved for summer peaking events when the grid is under stress due to the passage of VCEA and advancements in other technologies. On the other hand, the coal resources that Virginia's utilities own in West Virginia operate at much higher capacity factors.

Table 4. Virginia Total Electric Power Industry Capacity by Primary Energy Source, 2024[22]

Resource Type	Nameplate Capacity (MW)	2024 Capacity Factor (%)
Nuclear	3,568.0	92.4
Natural Gas – Combined Cycle (CC)	8,910.1	71.5
Wood	489.7	67.0
Other, Biomass	223.6	59.8
Wind – Offshore	12.0	47.7
Solar – Photovoltaic (PV)	4,678.4	20.2
Hydroelectric	866.6	16.5
Coal	1,530.1	16.1
Natural Gas – Gas Turbine (GT)	4,212.0	11.2
Natural Gas – Steam Turbine (ST)	587.8	10.6
Natural Gas – Internal Combustion (IC)	1.5	2.0
Petroleum – GT	607.4	0.8
Petroleum – IC	135.0	0.8
		2024 Usage Factors (%)
Pumped Storage	3,253.1	15.6
Battery	70.5	6.8

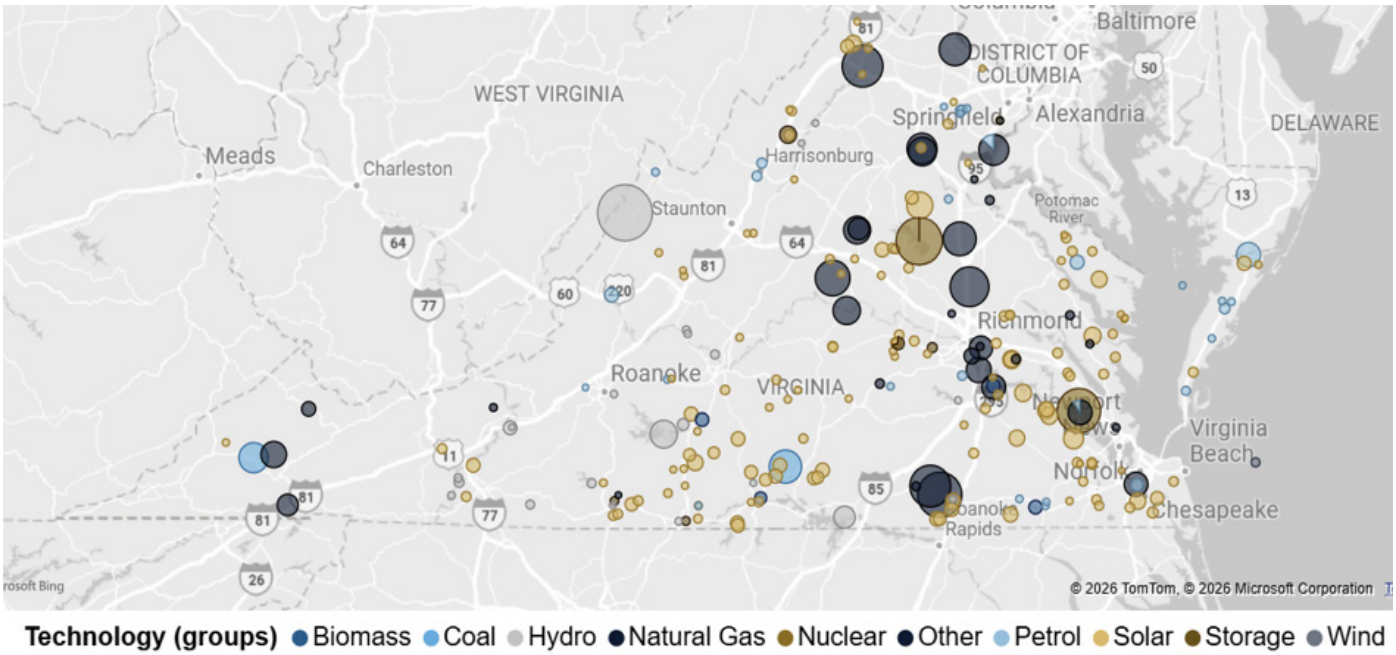
Virginia's power sector fuel mix has changed significantly over the past two decades, seeing a significant increase in the amount of natural gas-fired capacity and a marked decrease in coal capacity in the late 2010s and 2023. Solar capacity has been growing since 2017 and has become the largest source of annual capacity additions since 2019. Since 2015, Virginia's installed nameplate capacity increased from 25,181.6 MW to 29,146.5 MW.

Figure 12. *Total electric power sector capacity by primary energy source (MW), 1990 through 2024*



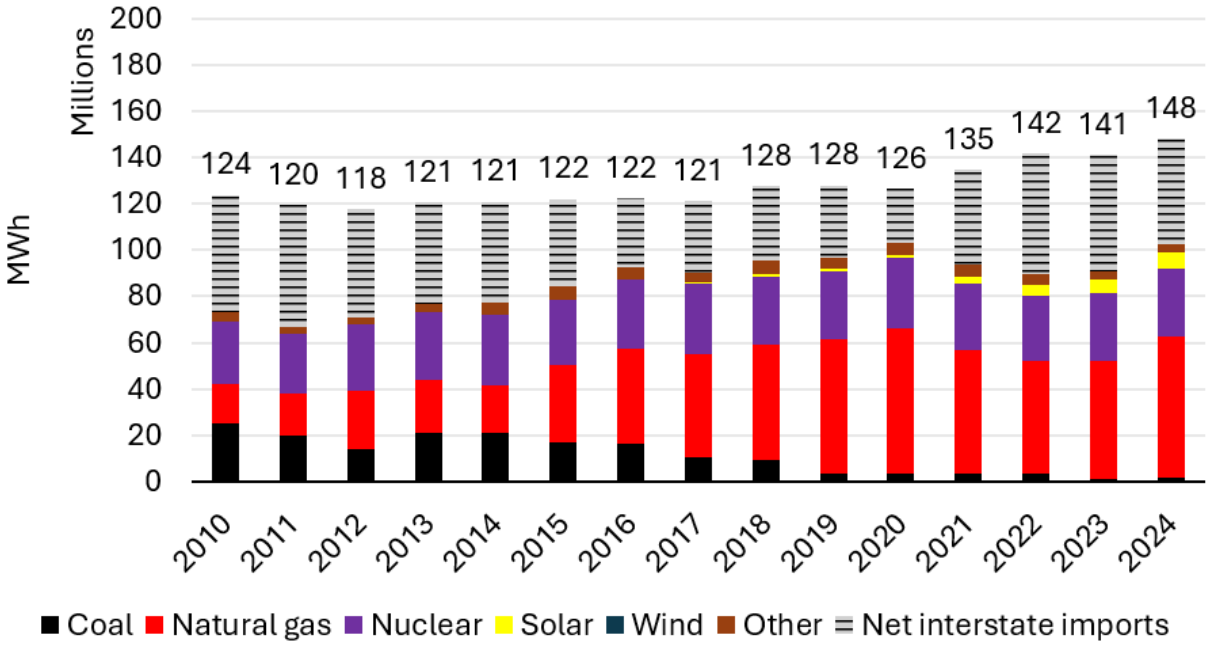
Virginia's power supply is spread across Virginia with the largest power plants fueled by natural gas or nuclear power.

Figure 13. *Map of Virginia's Operating Generators* [23]



In 2024, 41.2% of electricity provided to Virginia residents and businesses was delivered via natural gas, 30.6% from electricity imports, 19.6% from nuclear, 4.7% from solar, and 3.9% from other in-state sources.

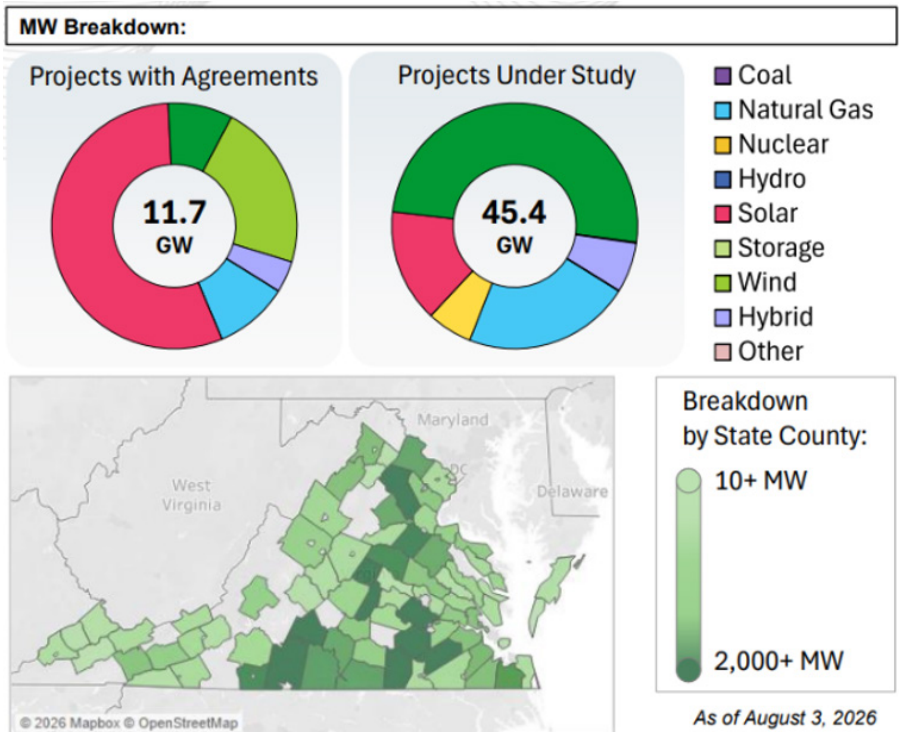
Figure 14. *Virginia Total Electricity Generation by Source (MWh), Including imports*



Virginia has always imported a significant share of the electricity it uses annually, though this amount declined in the late 2010s as in-state natural gas-fired generation grew, coming to an all-time low in 2020, when Virginia imported only 18.4% of total annual electricity. Since 2020, imports have started to grow again to meet rising electricity demand growth while adhering to new legislative mandates and replacing generation from high-cost coal capacity. By 2024, the share of electricity supplied by imports nearly doubled from its 2020 level to 30.6% of Virginia's total annual electricity consumption. This volume of imports puts Virginia among the top states relying on electricity imports; for example, in 2023, Virginia imported the most electricity of any state in the United States.[24] Virginia's electricity imports are largely powered by coal in West Virginia and legacy fossil-fuel facilities across PJM, largely in Pennsylvania and Ohio. Importantly, both Dominion and APCo own significant coal resources in West Virginia that provide electricity to their Virginia customers, whose generation is counted as imports.

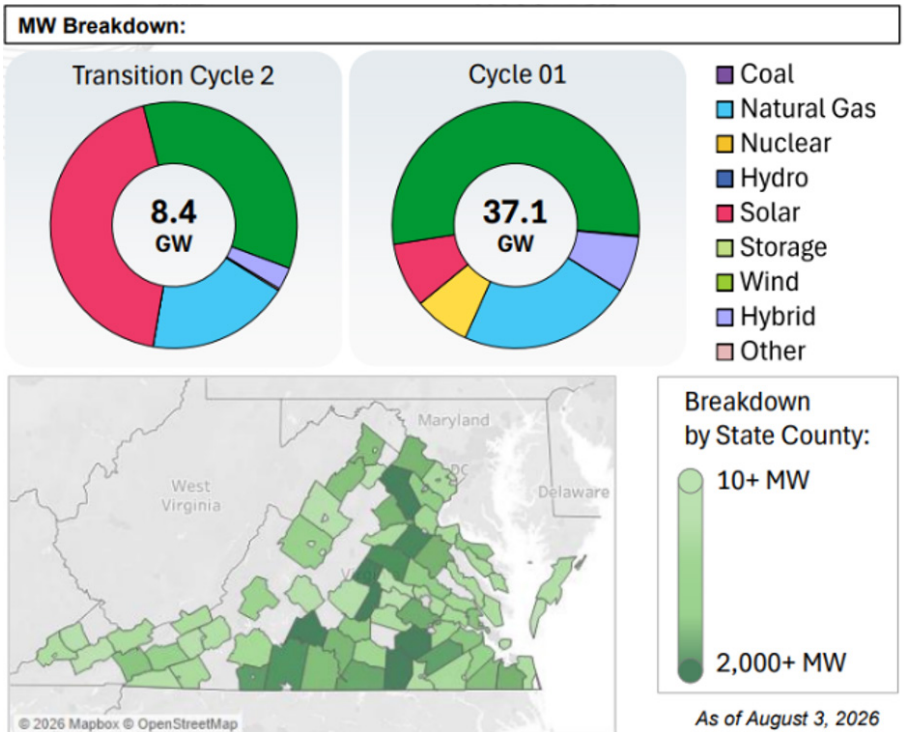
PJM operates an interconnection queue for generating resources that want to interconnect into the transmission network as a capacity resource. PJM identifies the necessary upgrades to the grid in order for the interconnecting resource to generate electricity to the grid without curtailment. Virginia currently has ~57,100 MW of capacity in PJM's queue, approximately 11,700 MW of nameplate capacity with generation interconnection agreements, meaning that these projects have entered into contracts to eventually enter service after upgrades are made. Not all of these projects have local approval and so not all of this capacity will enter service. The majority of projects with agreements are renewable projects, specifically solar, storage, and offshore wind. Historically, projects in the PJM Interconnection queue have a low success rate of reaching commercial operation.

Figure 15. Virginia's PJM Queued Capacity with Generator Interconnection Agreements and Under Study (MW, 2025)[25]



Recently, PJM completed its initial application review for Cycle 01; Virginia had approximately 37,100 MW of nameplate capacity entered in the study process, the majority of which was storage and natural gas.

Figure 16. *Breakdown of Virginia's PJM Queued Capacity Under Study (MW_{Energy}, 2025)*[26]



Virginia Clean Energy Targets and Current Deployment

As of June 2026, Virginia has 6,573 MW of renewable nameplate capacity, consisting of 5,300 MW of solar PV, ~460 MW of offshore wind from the Coastal Virginia Offshore Wind (CVOW) pilot turbines and CVOW-Commercial project, and 823 MW of conventional hydroelectric.[27] Virginia also has 230.6 MW of battery storage.[28]

The VCEA and subsequent legislation establish renewable and storage procurement targets that require Virginia's two IOUs, Dominion Energy and APCo, to petition for the approval to construct or acquire a certain amount of solar, onshore wind, and energy storage capacity by certain dates, as shown in Table 5. These storage targets were significantly increased in 2026 from prior requirements, demonstrating the increasing importance of storage as a critical resource to support cost efficiency and meet clean energy goals.

Table 5. Clean Energy and Storage Procurement Targets for Dominion and APCo

State	Dominion	APCo
Solar and Onshore Wind	16,100 MW	600 MW
Short-Duration Storage <=10 hrs	16,000 MW	780 MW
Long-Duration Storage >10 hrs, <= 24 hrs	2,000 MW	260 MW
Long-Duration Storage > 24 hrs	2,000 MW	260 MW

Additionally, Virginia law declares that up to 5,200 MW nameplate capacity of offshore wind by 2032 is in the public interest.[29] As of 2026, Virginia had ~450 MW of Offshore Wind capacity installed through the CVOW-Commercial project, developed by Dominion Energy.[30] Once fully installed, CVOW-Commercial will have 2,600 MW of capacity. Beyond this project, Dominion has the potential to bring online 4,800 MW of additional offshore wind capacity in the form of 800 MW in the CVOW-South Project, and 4,000 MW in the CVOW-East Project.[31] Additionally, the Kitty Hawk South lease area has the potential for 2,400 MW that could be delivered to Virginia. Including the currently under development CVOW-Commercial project, Virginia could have up to 9,800 MW of offshore wind capacity.

In addition to setting clean energy deployment goals, the VCEA also requires the retirement of fossil assets by 2045, unless doing so would threaten energy reliability. As part of the VCEA, Dominion retired Chesterfield Units 5 and 6 in 2023, the last of its wholly owned traditional coal-fired fleet located in the Commonwealth. The Clover coal-fired power plant and the Virginia City Hybrid Energy Center (VCHEC) were exempt from retiring in 2023 because they are co-owned by an electric cooperative and co-fire with biomass, respectively. Dominion also retired Yorktown 3, a heavy fuel oil facility, in 2023.

What we heard

Surveyed Virginians support solar, but they care about where it goes.

Rooftops, parking canopies, brownfields, landfills, and former mine land are welcome. Farmland and forest conversion is the sticking point. The objection is to losing land, not to the technology, which points toward putting already-disturbed land first.

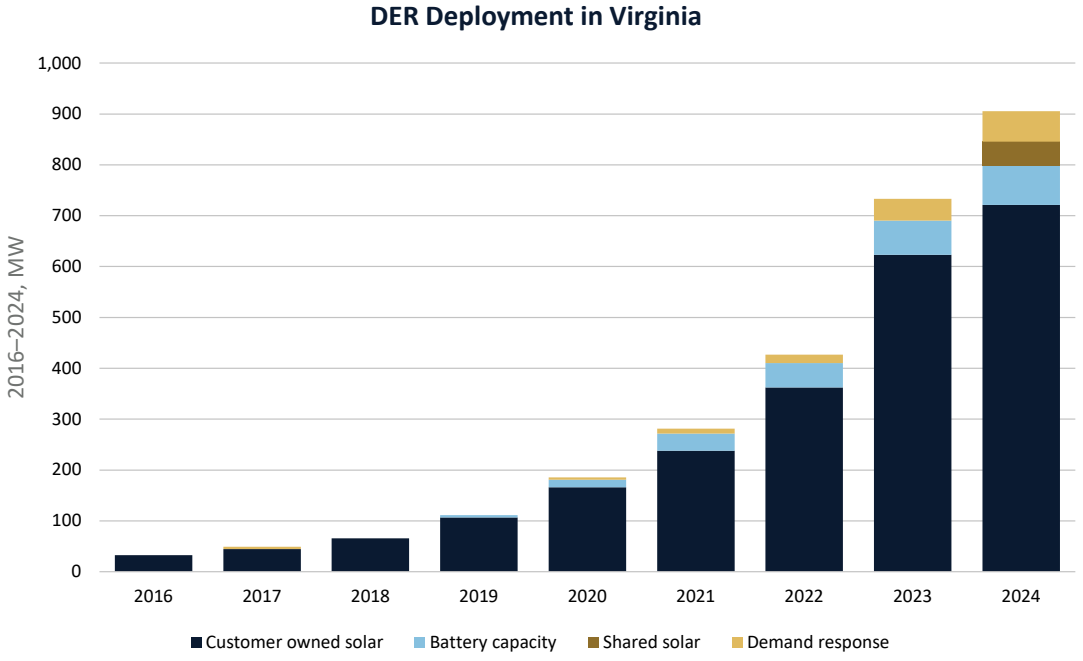
Distributed Energy Resources

Virginia law defines a DER as "a resource of up to five megawatts that is located on the customer's premises or is interconnected with the distribution system and produces or stores electricity or modifies the timing or amount of a customer's electricity consumption."[32] DERs include distributed solar (including home solar and small shared solar resources), battery storage, smart appliances such as thermostats and water heaters, and managed electric vehicle (EV) charging.

Virginia's DER portfolio has expanded rapidly. Between 2016 and 2024, the combined capacity of behind-the-meter (BTM) solar PV, battery storage and other DERs grew approximately 25-fold to about 858 MW, of which BTM solar and battery storage contributed 798 MW and other DERs 60 MW.[33, 34]

Beyond these technologies, demand response (DR)—programs that reduce or shift electricity demand at specific times—is another key component of the DER ecosystem. DR programs range from direct load control, where utilities remotely manage devices like smart thermostats and water heaters during peak periods, to price-based programs such as time-of-use rates that encourage customers to shift usage in response to price signals. Virginia has several ongoing programs and pilots in place to incentivize DR. Those with quantified peak-demand reductions are included in the graph below as DR capacity (*see* Figure 17). Programs include smart-thermostat offerings—Dominion's Smart Thermostat Rewards program (52.3 MW of peak-demand reduction in 2024) and APCo's Bring Your Own Thermostat program (7.3 MW)—as well as EV managed-charging pilots, including Dominion's EV Charger Rewards (460 kW) and EV Telematics Pilot (120 kW); additional programs include Dominion's Water Energy Savings DR, Peak Time Rebates and Off-Peak Plan, ODEC's Smart Thermostat Program, and Northern Virginia Electric Cooperative (NOVEC)'s Load Management Program.

Figure 17. *Estimated Virginia DER Deployment of BTM Solar PV, Battery Storage, Shared Solar and DR resources (2016-2024, MW)*[35,36]



DERs can operate individually or in aggregate to provide value to individual customers and an energy system on the distribution and transmission levels, particularly when aggregated into a virtual power plant (VPP) or DR programs. DERs can lower energy bills for customers by reducing or shifting energy consumption, an opportunity that is amplified

by the availability of dynamic electric rates. DERs can provide grid services, including generating capacity, distribution capacity, voltage and frequency regulation, load following, balancing, and reserves. DERs differ in which grid services they are best suited to provide. Deployed widely and strategically to meet identified grid needs spatially and temporally, DERs can defer or eliminate the need for grid infrastructure investments.

As these advantages have become clearer, Virginia has steadily expanded the policies that enable DER adoption. The foundation was laid in 1999 with the establishment of net energy metering (NEM) for customer-sited solar energy systems. Virginia's NEM policy has evolved over time. The existing NEM policy provides a one-to-one retail rate for electricity exported to the grid, subject to system size caps and a utility-wide enrollment cap of 6% of peak load, with 1% reserved for low-income customers. These caps limit how much net-metered capacity each utility territory can absorb. Currently, penetration in Dominion territory equals roughly 3% while penetration in APCo territory is less than 1%.

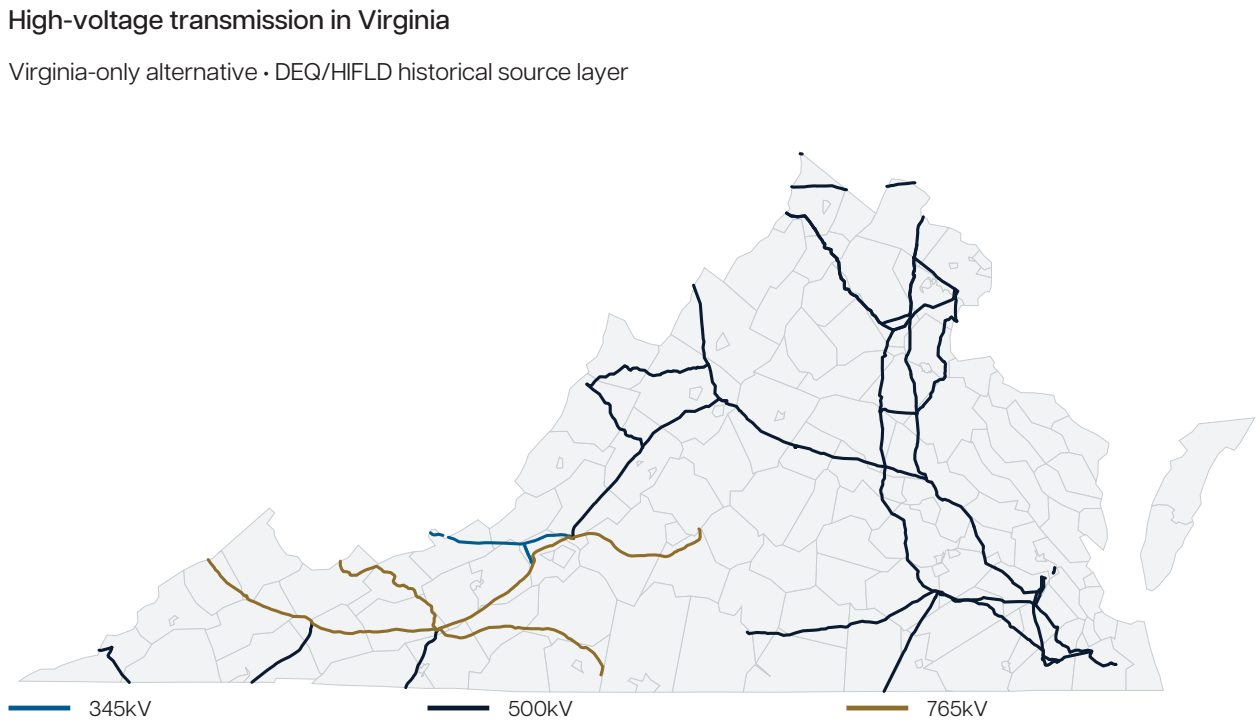
In 2013, the Commonwealth expanded access to distributed solar PPA pilot programs. The latest VCEA requirements have further advanced DER support, setting a 4.5%–5% distributed generation carve-out in the RPS requirements for Dominion and establishing shared solar programs for Dominion and APCo.

Growing DER deployment has pushed Virginia to explore aggregation and VPP programs that further capture grid-level value from these resources. VPPs allow DERs to be coordinated to balance supply and demand, with participants compensated through various methods, such as bill credits. In 2025, the General Assembly directed Dominion to establish a VPP pilot program capped at 450 MW by 2028, at which point the SCC will establish a permanent VPP program with procurement targets. In 2026, the General Assembly established the same structure for APCo, with the VPP pilot program capped at 150 MW by 2029. Program specifics and results for these new programs will emerge over the coming years and inform the procurement targets established by the SCC.

Transmission

High-voltage transmission infrastructure serves as the bulk delivery backbone of the Commonwealth's electric grid, moving power from large-scale generation facilities to local distribution networks. Virginia's transmission system is primarily comprised of 500 kV lines that move electricity across Virginia, anchored by interstate connections in Northern Virginia to PJM and in Western Virginia by two 765-kV lines operated by APCo that connect to AEP's regional multi-state network.

Figure 18. *Virginia Service Area Electric Transmission System by High Voltage Class*[37]
(Note: Not shown on this map are Virginia's 100 kV and 230 kV transmission lines)



Virginia's bulk grid is physically interconnected with neighboring states, allowing utilities to import wholesale electricity from the broader PJM market. Historically, this transfer capacity allowed the Commonwealth to import lower-cost regional generation during periods of peak local demand.

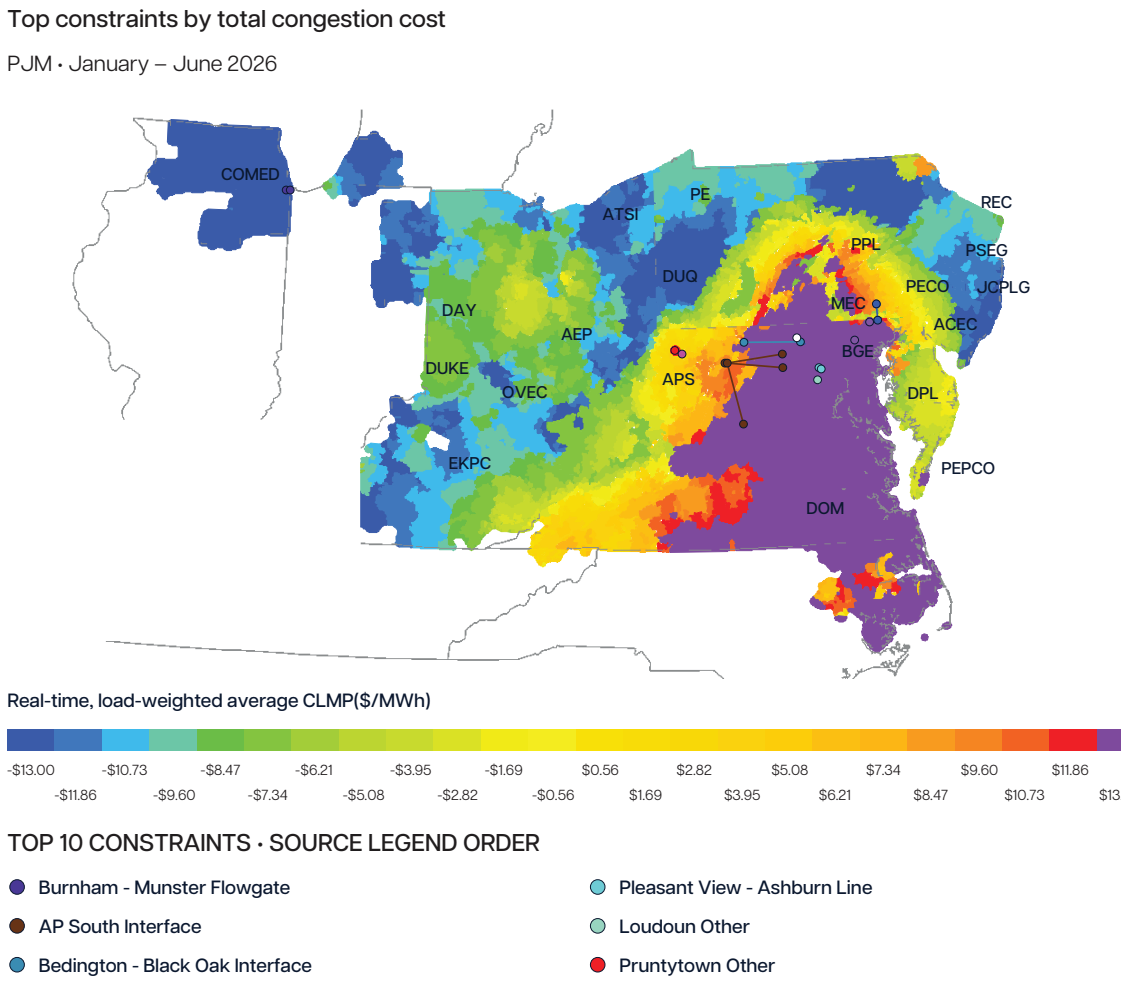
In recent years, however, rapid load growth in Northern Virginia combined with permitting and construction delays on major regional transmission projects has significantly constrained interstate import capacity. PJM's latest reliability modeling indicates that Virginia's import demand will exceed its physical transmission capacity by 2028.

Congestion costs from constrained transmission lines have recently increased in Virginia. When regional import limits are reached, transmission lines become congested. Congestion prevents lower-cost electricity generated elsewhere in PJM and Virginia from flowing into Northern Virginia, where congestion is highest in the Commonwealth. To maintain real-time grid stability, grid operators are forced to commit more expensive local generation or dispatch higher-cost regional resources. The difference in these costs creates substantial annual congestion costs, which are ultimately passed through to Virginia retail ratepayers in the form of higher overall power costs. Transmission congestion is indicative of two things: the need to develop additional interstate/regional transmission infrastructure to successfully move electricity from lower cost to higher cost areas and the need to more locally develop cheaper forms of electricity so that prices are not as high. Congestion costs alone do not mean that these solutions should be pursued, but that planners must consider their capital costs against the operational cost savings that customers would experience. In 2021, the DOM Zone had an estimated $144.6M in congestion costs, which increased dramatically in 2022 when Northern Virginia was constrained to get their power needs. In the first half of 2026, the DOM Zone transmission congestion costs of $643.9M are more than quadruple the entire 2021 value.

Table 6. *Total Congestion Costs, Dominion Transmission Zone ($ Million)*

	Internal to Zone	External to Zone	Grand Total
2021[38]	$38.7	$105.9	$144.6
2022[39]	$206.4	$234.1	$440.6
2023[40]	$25.8	$129.7	$155.5
2024[41]	$66.0	$180.4	$264.4
2025[42]	$283.2	$301.8	$585.1
22026H1[43]	$128.1	$515.8	$643.9

Figure 19. *Location of the top 10 constraints by total congestion cost: January through June 2026*[44]



Increasing interstate transmission capacity could reduce congestion costs and give ratepayers greater access to lower-cost electricity. Studies by the U.S. Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), and the University of Michigan have found that expanding interstate and interregional transmission could reduce customer costs.[45]

In response to this need for additional capacity, transmission investments in the Commonwealth have increased

significantly. In PJM's regional transmission planning process,[46] transmission investments across the PJM region surged from $1.35 billion in 2022 to $7.16 billion in 2025.[47]

Table 7. *Virginia Transmission Project Costs, by project approval year*

	Baseline Projects	Network Projects	Supplemental Projects
2022[48]	$879.55 Million	$115.6 Million	$358.94 Million
2023[49]	$3.562 Billion	$90.23 Million	$200.46 Million
2024[50]	$3.639 Billion	$1.236 Billion	$2.304 Billion
2025[51]	$5.439 Billion	$177.61 Million	$1.541 Billion

Within Virginia's in-state transmission projects, load growth driven by data centers in Northern Virginia has been a key driver of recent transmission projects. In its 2024 IRP, Dominion identified 203 transmission projects that would cost $7.6 billion over the 2024-2031 period in Virginia alone. Dominion attributed at least ~33% directly to data center growth, though Commission Staff also noted that the four most expensive projects were multi-factor projects, worth a total of $2.66 billion, and located in Northern Virginia, so were also likely driven in large part due to data center growth.

Table 8. *Dominion 2024 IRP, Supplemental Company Testimony, List of Planned Transmission Projects (2024–2031)*

	# of Projects	% of Projects	Project Cost Estimates ($M)	% of Total Cost
Data Center Driven	89	44%	2,435.3	32%
Mixed Load	36	18%	3,306.3	44%
Non-data center driven	78	38%	1,853.5	24%
Total	**203**		**7,595.1**	

Several major high-voltage transmission projects are approved or under development to strengthen Virginia's transmission system, increase transfer capability, and address reliability needs associated with rapid load growth and changing regional power flows. Project routes, costs, and in-service dates remain subject to engineering, permitting, regulatory review, and further PJM revisions.

Resolving Virginia's transmission constraints without imposing unsustainable rate burdens requires a combination of traditional new high-capacity transmission additions alongside advanced, lower-cost grid strategies (e.g., advanced transmission technologies (ATTs), adding transmission along existing rights-of-way, and offsetting transmission needs through local generation, storage, and demand flexibility).

Resolving Virginia's transmission constraints without imposing unsustainable rate burdens requires a combination of traditional new high-capacity transmission additions alongside advanced, lower-cost grid strategies (e.g., advanced transmission technologies (ATTs), adding transmission along existing rights-of-way, and offsetting transmission needs through local generation, storage, and demand flexibility).

Without additional transmission expansion, the Dom Zone may lack sufficient import capacity to meet rising electricity demand.

Distribution

The electric distribution network is the "last mile" of electricity delivery, carrying power from high-voltage transmission substations through overhead and underground medium-voltage feeders to residential, commercial, and industrial customers. Managed by Virginia's IOUs, member-owned electric cooperatives, and municipal utilities, the distribution grid is shifting from one-way delivery toward bidirectional operation to accommodate DERs such as distributed solar, storage, EVs, and smart appliances.

As highlighted in the ***Virginia Energy Security Plan***, this critical distribution infrastructure faces mounting physical risks from severe weather events, flooding, and cybersecurity threats.[52] Targeted investments in grid hardening alongside deployment of modern protection, control, and situational awareness systems can help maintain service under more frequent and intense disruptions.

Beyond weather resilience, rapid transportation electrification and commercial expansion—particularly data center growth along suburban corridors—require significant distribution capacity additions. Utilities are deploying high-capacity distribution substations, advanced voltage control systems, and localized circuit upgrades to maintain power quality—the voltage, frequency, and waveform conditions customer equipment needs—and service reliability across high-density commercial corridors.

Distribution system planning and operations must also account for the rapid growth of DERs,[53] such as rooftop solar, customer-sited storage, and controllable loads (see Section 2C: Energy Supply and Delivery for further discussion on DERs). As discussed in Section 4C: Priority Actions, there is a significant opportunity to better leverage distribution systems—including using advanced distribution management systems (ADMS), dynamic voltage optimization, and VPPs—to defer or avoid capital-intensive physical substation buildouts to help reduce costs and make better use of the existing grid. Recent reforms, including updates to IRP mandates and landmark grid utilization legislation, formally elevate the role of DERs, VPPs, and non-wires alternatives in long-term utility planning, directing regulators and utilities to optimize current grid capacity before committing to new capital-intensive distribution infrastructure.[54]

Natural Gas

Today, natural gas is a primary fuel used largely for electricity generation as well as industrial, commercial, and residential applications. Transitioning to a carbon-free future in line with the VCEA and Commonwealth Clean Energy Policy framework will require a managed transition from natural gas to cleaner resources.

Natural Gas Market and Governance Overview

Virginia natural gas infrastructure primarily consists of midstream and downstream which is regulated as follows:

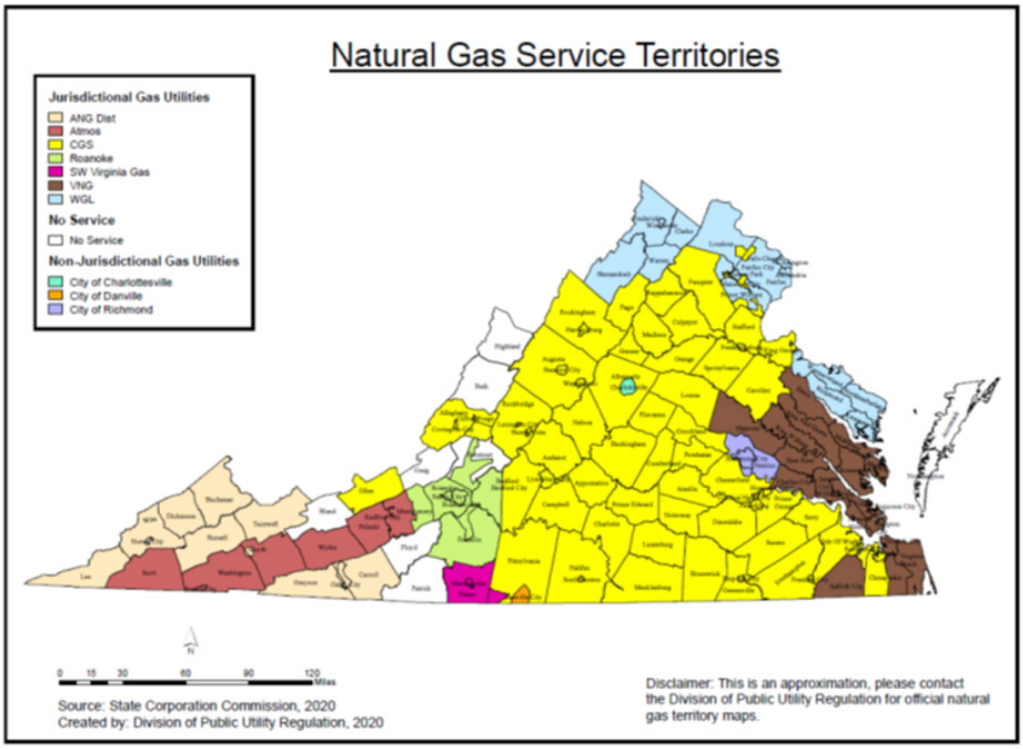
1. **Midstream interstate pipelines and supporting infrastructure**: Interstate transmission pipelines and underground storage facilities are regulated federally by the Federal Energy Regulatory Commission (FERC) for siting, rates, and capacity allocation, and by the Pipeline and Hazardous Materials Safety Administration (PHMSA) for safety standards.

2. **Downstream retail distribution through Local Distribution Companies (LDCs):** Natural gas retail distribution is managed by seven jurisdictional investor-owned gas utilities regulated by the SCC, the three largest of which are Virginia Natural Gas, Columbia Gas of Virginia, and Washington Gas. The SCC evaluates base rates, capital expenditure riders (such as SAVE Act infrastructure replacement programs), and safety compliance. Three non-jurisdictional municipal gas utilities (e.g., the cities of Charlottesville, Richmond, and Danville) operate independently.

See Figure 20 for the natural gas distribution service territories.

The Commonwealth, through Virginia Energy, permits all natural gas wells within Virginia and associated facilities to gather and transport that natural gas to the point of sale. The agency inspects all of these facilities to ensure safety and environmental protection.

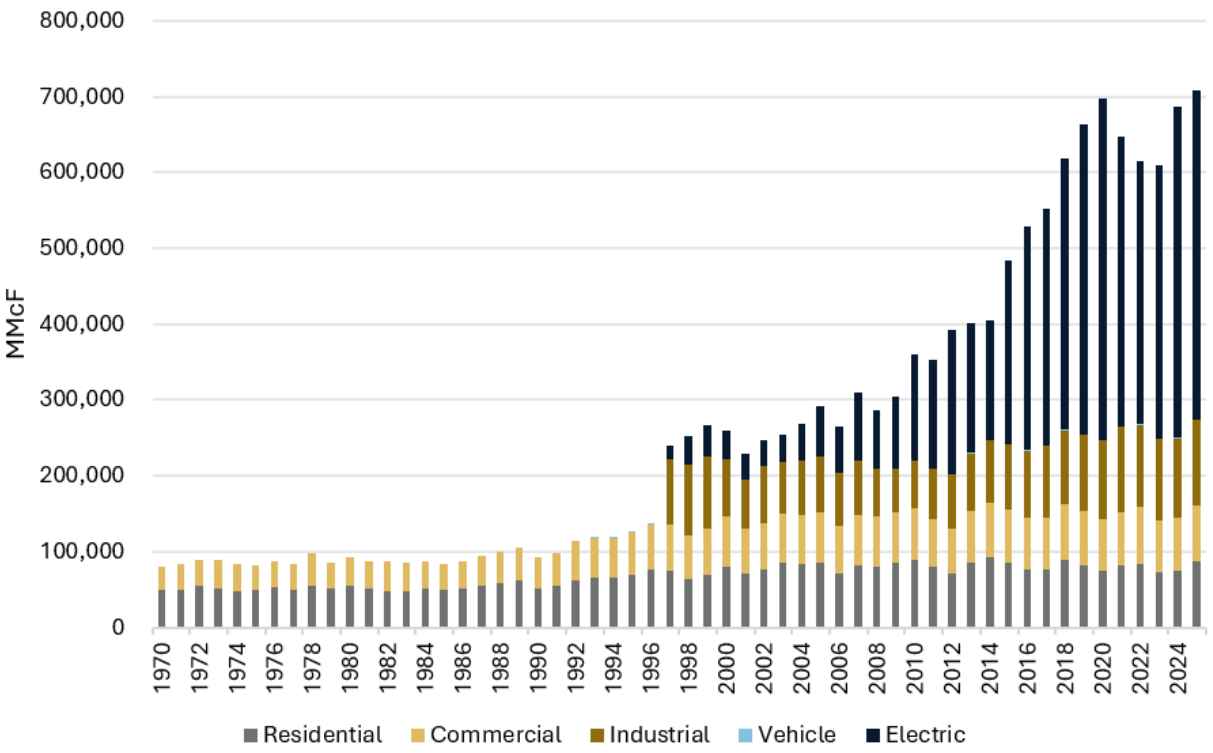
Figure 20. Map of Virginia Natural Gas Service Territories[55]



Natural Gas Demand Profile

Natural gas consumption in Virginia has increased by over 87% since 2010, primarily driven by increasing demand from the electric power sector and natural gas replacing coal as a dominant fuel for electricity generation. The electric power sector is Virginia's largest natural gas consumer, representing nearly two-thirds of total natural gas demand in Virginia in 2025. The industrial sector is the second-largest natural gas-consuming sector in Virginia and accounted for 15% of deliveries to customers in 2025. The commercial and residential sectors primarily use natural gas for space and water heating and cooking, and in some cases cooling, among other uses.[56]

Figure 21. *Virginia Natural Gas Consumption by End Use*[57]



Natural Gas Supply and Delivery

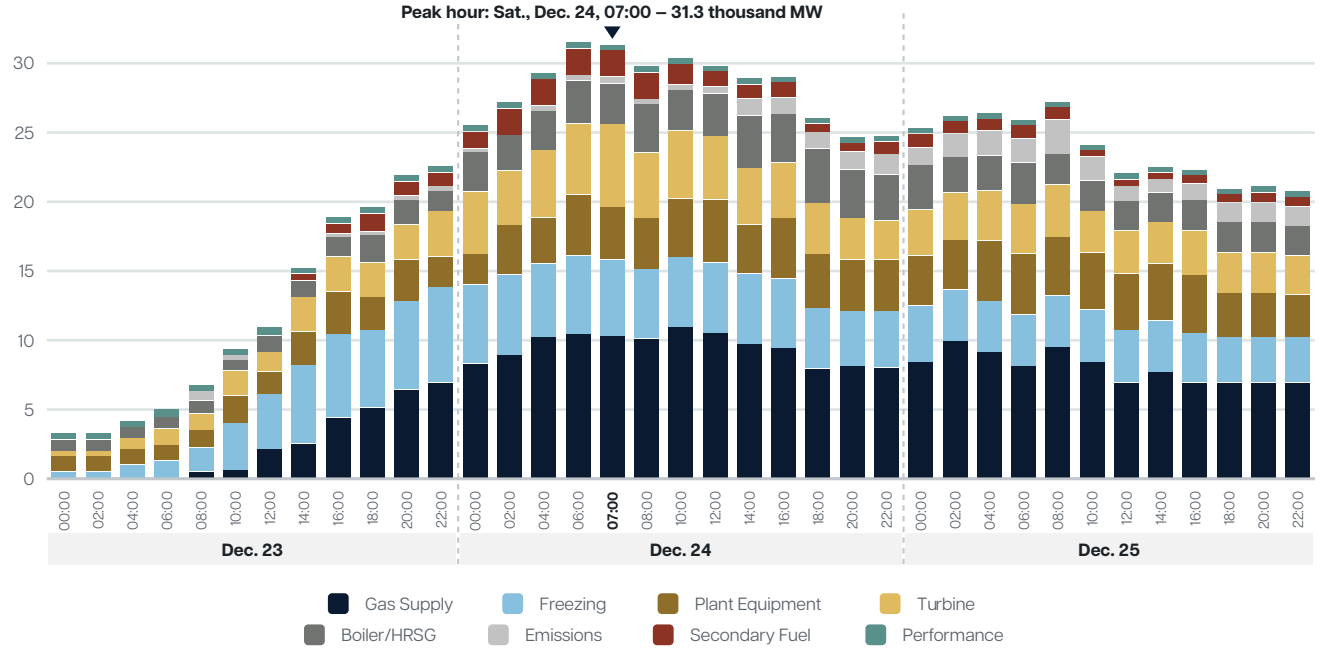
Virginia imports the majority of its natural gas via interstate and intrastate supply pipelines and facilities. Most of the natural gas supplied to customers in Virginia comes from the Gulf Coast and from the Appalachian region by interstate natural gas pipelines. There are two large sources of interstate supply: Transco (Williams) and the Columbia system (TC Energy). The Transco system delivers supply from the south from the Gulf of Mexico and from the north originating in Pennsylvania. The Columbia system delivers supply from the Appalachian Basin's Marcellus and Utica Shale deposits.

Although important economically, particularly to regions in Southwest Virginia, Virginia's natural gas production is a relatively small portion of the supply. Virginia accounts for less than 1% of the nation's total natural gas reserves and production. All of Virginia's producing natural gas fields are located in Southwest Virginia. Two of these natural gas fields are among the nation's top 100 as ranked by proven reserves, and both produce coal mine methane (CMM), which is natural gas derived from coal seams. In 2020, more than 80% of Virginia's natural gas production was CMM. Notably, there are important emissions benefits from capturing CMM that would otherwise escape as fugitive emissions and instead using the CMM for productive use, such as power generation. The state's annual natural gas production has steadily declined from its peak of more than 151 billion cubic feet in 2011 to about 81 billion cubic feet in 2024.

Risks to gas pipeline capacity exist, especially with extreme weather. Lack of natural gas fuel due to fuel production and distribution issues can prevent generation resources from operating. During Winter Storm Elliott, natural gas supply and natural gas power plant failures were significant, resulting in over 30 GW of natural gas plant outages across PJM during the storm.

Figure 22. *Gas Plant Forced Outages During Winter Storm Elliott in PJM*[58]

Forced outages and derates of gas-fired units by cause, Dec. 23–25, 2022 (thousand MW)



Source: PJM, Winter Storm Elliott: Event Analysis and Recommendation Report (July 17, 2023); GADS data as of March 1, 2023. Only even hours are shown, plus Dec. 24, 2022 07:00, the hour with the largest forced outages and derates. Wind and solar unit outages are not included.

Petroleum and Liquid Fuels:

Petroleum and refined liquid fuels power most of Virginia's transportation sector, provide fuel for backup generation, and meet important heating needs in rural communities. Because Virginia produces negligible crude oil, it relies on interstate supply chains for refined products from Gulf Coast and international refining hubs.

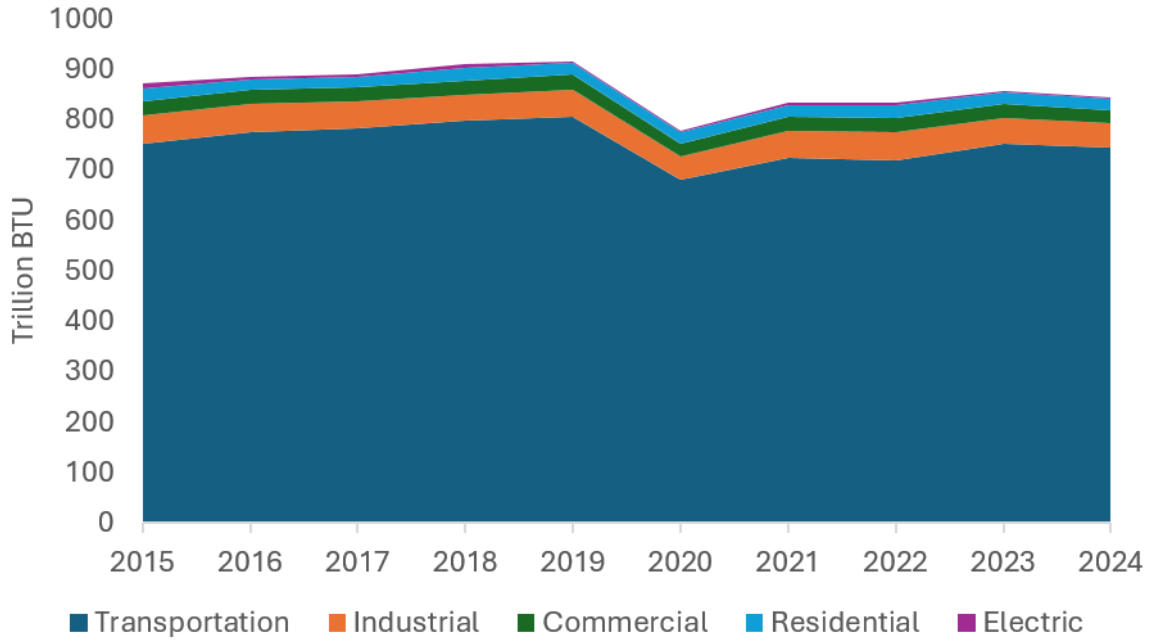
Petroleum Market and Governance Overview

Unlike electric and natural gas distribution utilities, petroleum supply operates in an open wholesale and retail market. Prices for crude and refined products are set in an international market. Prices may vary at different access points (for example, retail fueling stations) based on last-mile transportation costs to that point, longer-term fuel contracts, fuel blends, and market position.

Petroleum Demand Profile

Virginia consumes approximately 6.7 billion gallons of liquid fuels per year, equivalent to approximately 440,000 barrels per day. These fuels include motor gasoline, distillate fuel oil (diesel and heating oil), kerosene and jet fuel, propane, and residual fuel oil. Transportation accounts for approximately 88% of all petroleum products consumed in Virginia, and most of this consumption is in the form of gasoline, diesel fuel, and aviation fuel. Liquid fuels have not rebounded to pre-COVID pandemic levels. This is driven by a reduction in jet fuel, as the aviation industry did not rebound to the extent that day-to-day driving has (motor gasoline use is essentially flat between 2019 and 2024). Distillate fuel oil usage has also dropped since 2019, which may represent a softening of industrial use, as well as methodological changes by EIA in some residential and industrial oil use estimates.

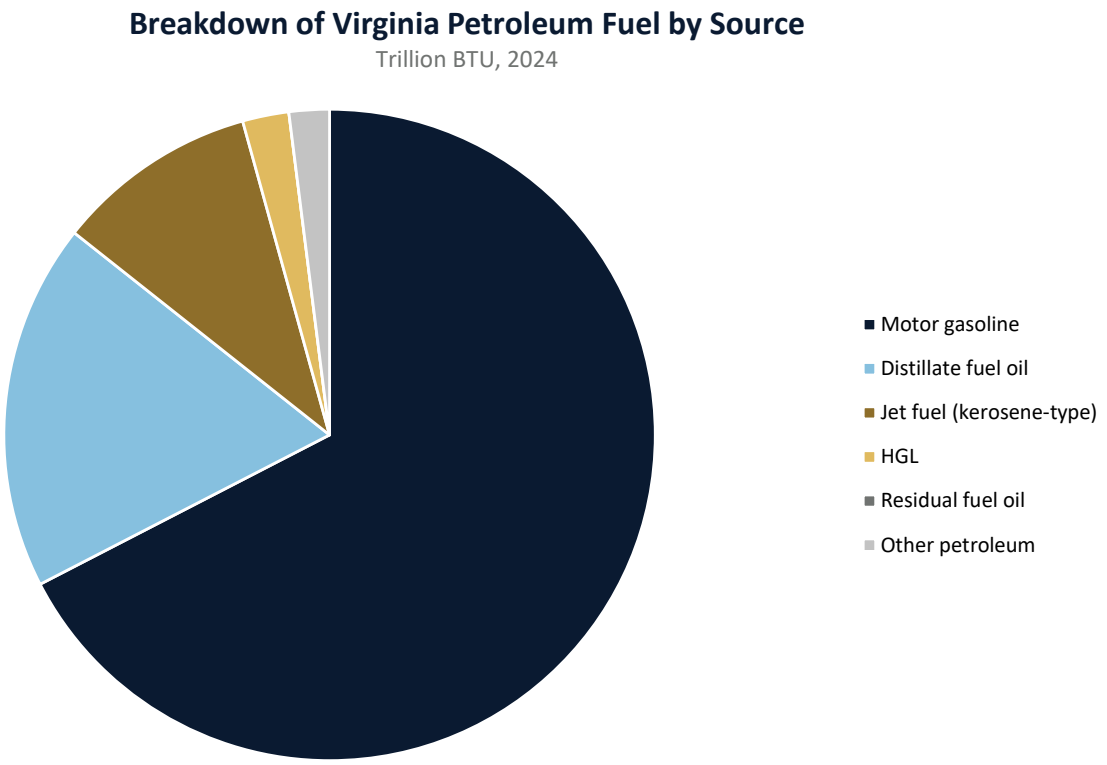
Figure 23. *Virginia Petroleum Consumption by End-Use Sector*[59]



Specific fuels used:

- Motor Gasoline: Motor gasoline is the most consumed petroleum product in Virginia. Transportation accounts for ~97% of gasoline consumption. Virginia maintains ~2.4 million barrels of gasoline storage at bulk terminals, which is roughly nine days of average supply.
- Distillate Fuel Oil: Distillate fuel oil includes diesel fuel and heating oil. More than 80% of distillate consumption supports transportation, while the remainder serves industrial, commercial, residential, and electric power applications. Average terminal inventories provide approximately eighteen days of supply.
- Kerosene and Jet Fuel: ~99% of Virginia's kerosene consumption is in the form of jet fuel. Aviation fuel supply is supported through direct pipeline connections and airport fuel storage facilities for military and civilian activities.
- Hydrocarbon Gas Liquids (HGLs) including Propane: Propane supports residential heating (over half of consumption), agricultural operations, and commercial applications.
- Residual Fuel Oil: Residual fuel oil represents a small but strategically important component of Virginia's fuel mix to support maritime bunkering and industrial operations.

Figure 24. *Breakdown of Virginia Petroleum Consumption by Fuel Type (Trillion BTU, 2024)*[60]



Petroleum Supply Infrastructure

In-state petroleum production supplies less than one-tenth of one percent of Virginia's petroleum use, so the Commonwealth relies on imports of refined products from refineries in other states and overseas, delivered primarily via interstate pipelines and marine terminals.

Virginia's petroleum supply chain is centered on two major interstate pipeline systems: Colonial Pipeline and the Products (SE) Pipeline. These systems transport refined petroleum products from Gulf Coast refining centers into Virginia and the broader Mid-Atlantic region. Colonial Pipeline delivers fuel to terminals serving Richmond, Hampton Roads, Northern Virginia, and Dulles International Airport. Products (SE) Pipeline provides additional supply to Northern Virginia, Richmond, Roanoke, Reagan National Airport, and Dulles International Airport.

Marine terminals in Hampton Roads supplement pipeline deliveries by receiving petroleum products through domestic and international maritime trade. These facilities provide an important alternative supply pathway during pipeline disruptions and support the Commonwealth's broader fuel distribution network. Petroleum products received through Virginia ports include gasoline, distillates, kerosene, residual fuel oil, and ethanol used in gasoline blending.

Fuel delivered by pipeline or marine vessel is stored at bulk terminals and distributed throughout the Commonwealth by truck. Major terminal clusters in Northern Virginia, Richmond, Hampton Roads, and Roanoke are critical distribution hubs.

Liquid Biofuels

Researchers are evaluating liquid biofuels as substitutes in nearly all fuel categories. These fuels can be produced in the United States and Virginia from sustainable sources such as agricultural and forestry products. For aviation in particular, liquid biofuels are among the limited options for reducing dependence on imported petroleum.

For nearly two decades, Virginia has pursued biofuels research for carbon, economic, and energy security reasons. Market growth has not met expectations for a variety of reasons including slow market demand, production costs, isolated emphasis on fuel subcategories, and volatility from federal administrative shifts in emphasis. One of the clearest outcomes of this work is the recommendation that biofuels policy and incentives should be developed collectively (as with petroleum refining, biofuel refining produces several co-products at once), not in isolation. Global demand for sustainable aviation fuel (SAF) is increasing, including in response to European Union mandates that took effect in 2025.[61]

Key Petroleum and Liquid Sector Considerations and Challenges

Virginia's petroleum sector is characterized by transportation-dominated demand, limited in-state production, and reliance on imported refined products delivered via interstate pipelines and terminal infrastructure that link the Commonwealth to regional, national, and international markets. From a resilience perspective, Virginia's status as a net consumer of petroleum products with minimal in-state production emphasizes the importance of reducing demand through efficiency and maintaining diverse supply sources and routes to maintain fuel availability.

Virginia Energy's sustainable transportation programs promote biodiesel, ethanol, propane/liquefied petroleum gas (LPG), compressed natural gas (CNG), and electricity. Virginia Clean Cities, a DOE-designated coalition based at James Madison University, advances air quality improvement, economic opportunity, and energy security through the deployment of alternative fuel vehicles and infrastructure, including EVs, natural gas vehicles, and biofuel use in fleets.

The challenges confronting alternative fuels deployment include: developing alternative distribution systems, such as electric charging stations for vehicles; higher cost of some alternate fuels themselves, and the vehicles that consume them; a long fleet turnover time – most vehicles stay in service 15+ years, making fleet replacement slow; and for liquid biofuels: low market demand, higher cost of production, volatile federal environment.

The challenges confronting improved efficiency in transportation include: consumer preference for vehicles that can be fuel-inefficient; a lack of availability of adequate transit, or viable walking or biking infrastructure in much of Virginia; as housing costs increase and availability remains constrained, families have fewer opportunities to live close to jobs and services, increasing the number of miles they must drive each day; and legacy infrastructure that requires heavy car usage to accomplish daily life in some parts of Virginia.

Residential and commercial petroleum use is relatively modest compared to transportation but remains important for space and water heating, cooking, and specific commercial and industrial processes, primarily through fuel oil and propane.

2D. Energy Needs for Data Centers and Other Large Load Customers

Data centers have become one of the most significant economic growth areas shaping Virginia and the nation's energy system. They support digital services used by businesses, hospitals, schools, financial institutions, government agencies, defense organizations, and people. They also generate local tax revenue and contribute to Virginia's role in the national and global digital economy.

At the same time, data centers use considerably more electricity than traditional commercial buildings and represent the largest source of projected growth in electricity demand based on the 2026 PJM Load Forecast Report. Data centers were also the most frequently raised issue in public survey comments.

Their growth also has implications for electricity supply, transmission and distribution infrastructure, cost allocation and customer bills, reliability, land and water use, air quality, and local decision-making.

Data Centers Differ from Other Large Load Customers

A large load customer is a customer whose facility or campus requires substantially more electricity at a given time than a typical home or business. Examples include data centers, manufacturing facilities, hospitals, military installations, ports, and other large or continuously operating facilities.

These customers are not interchangeable. A hospital, shipyard, manufacturing plant, military facility, and data center may have different operating patterns, power-quality requirements, economic roles, and abilities to reduce or shift electricity demand. Policies designed for one type of customer may not be appropriate for another.

Data centers themselves also vary. Some support government, defense, communications, financial, or other critical functions, while others serve commercial computing needs. Facilities can differ in size, cooling systems, water use, backup-power arrangements, efficiency, and ability to shift computing activity—factors that all impact energy consumption.

Changing When and How Virginia Uses Electricity

Most data centers operate around the clock and have a high load factor, meaning their electricity demand remains relatively close to peak demand—the highest electricity demand during a defined period—throughout the day and year. Homes and traditional businesses generally have more pronounced periods of high and low demand.

As data centers expand, Virginia is seeing not only higher demand during summer and winter peaks, but also greater electricity use overnight and during other hours when the grid was historically less heavily used. This can allow existing infrastructure to be used more fully where sufficient capacity is available. When the system is already constrained, however, rapid growth can require major investments in generating resources, transmission lines, substations, and local distribution systems.

Data center development has been concentrated in Northern Virginia, where it is a major driver of new electric infrastructure. New facilities are also being proposed elsewhere, including along the Interstate 95 corridor and in electric cooperative territories. Expansion into new regions may create economic opportunities, but it can also introduce major infrastructure and land-use decisions for communities with less experience evaluating these projects.

Forecasting Demand and Protecting Customers

One of the most difficult planning questions is determining how much proposed data center demand will materialize and when it will connect to the grid.

A request for electric service is not the same as a completed project. Developers may consider several sites before selecting one, request more service capacity than a facility ultimately requires, or change schedules as market conditions evolve. Counting every request as future demand could lead to infrastructure being built for projects that are delayed or never completed. Underestimating credible demand could leave Virginia without sufficient infrastructure to maintain reliability or support economic development.

The VEP therefore examines multiple demand scenarios. Its detailed forecast considers project status, contractual commitments, anticipated demand relative to requested capacity, and the time required for facilities to reach full operation (see Section 3B: Load Growth and Policy Scenarios and Appendix: Modeling Assumptions and Inputs).

Who pays for new infrastructure is equally important. Data centers can contribute significant utility revenue (see the "Costs and Who Pays" subsection) but serving them may require investments that would not otherwise be needed or would not be needed as quickly. During Energy Plan listening sessions, stakeholders consistently said that new data centers should bear an appropriate share of the costs and financial risks arising from their service requirements.

The SCC has created a separate large load rate class for Dominion Energy Virginia and related service terms for qualifying large load customers, including a 14-year contract term, minimum demand charges, collateral requirements, and exit-fee provisions, effective January 1, 2027.[62] In a separate, ongoing proceeding, the SCC directed revisions to Dominion's proposed large load connection queue process standards, including enhanced site-control and surety requirements, clearer study timelines, and public reporting.[63] These measures are intended to distinguish more certain projects from preliminary requests and reduce the risk that existing customers bear costs for load that does not materialize. Broader allocation of shared generation and transmission costs remains subject to future SCC proceedings.

Energy, Environmental, and Community Impacts

Data center impacts extend beyond electricity consumption. Many facilities rely on diesel generators for emergency backup power. During a widespread or extended outage, sustained generator operation could require substantial fuel deliveries, while operation of generators could affect local and regional air quality.[64] Depending on facility design, data centers may also affect water supplies, noise, land use, transportation infrastructure, and nearby natural or cultural resources.

Some facilities can reduce their system impacts through more efficient computing and cooling equipment, battery storage, clean energy resources, water-saving technologies, or demand flexibility that shifts computing activity away from periods when the grid is under stress. These opportunities vary by facility, and claims about efficiency, clean energy, flexibility, or water use should be supported by measurable commitments.

Local governments also weigh whether proposed facilities are compatible with surrounding land uses and whether anticipated tax revenue justifies public infrastructure costs and long-term fiscal exposure. Stakeholders called for accessible information and engagement early enough to influence project siting, design, mitigation, and community benefits.

Supporting Responsible Growth

The question facing Virginia is how growth among data centers and other large load customers can support the Commonwealth while protecting existing customers and communities. Relevant considerations include:

- Whether projected demand is supported by credible project commitments that will be scaled up within timelines initially promised by developers and/or operators;
- Whether customers whose service requirements create new infrastructure needs bear an appropriate share of the costs and risks;
- How projects will support reliability, power quality, and resilience;
- Whether energy and water are used efficiently and environmental effects are minimized;
- How land-use, public infrastructure, and local fiscal risks are addressed;

- Whether projects provide durable regional and community benefits; and
- Whether commitments are transparent, measurable, and enforceable.

These considerations frame the more detailed strategies for data centers and other large load customers presented in Chapters 3 and 4 below. They also highlight the need for coordination among the Commonwealth, regulators, utilities, PJM, local governments, developers, large customers, and affected communities.

2E. End Use Electrification

End-use electrification—the replacement of equipment that directly burns gasoline, diesel, natural gas, propane, or fuel oil with equipment powered by electricity—when paired with EE and an increasingly lower-emitting electricity supply, can reduce GHG emissions and other air pollutants. Many electric technologies, including EVs and heat pumps, are also more energy-efficient than comparable combustion technologies, offering strong potential return on investment, though their effects on customer bills depend on equipment costs, energy prices, usage patterns, and available incentives.

Transportation presents Virginia's largest electrification opportunity because it is the Commonwealth's largest source of GHG emissions. Electrification is also expanding in buildings through heat pumps, electric water heating, and other appliances, and may reduce emissions from some industrial processes and equipment. The pace and benefits of this transition will depend on affordability, customer choice, charging and grid infrastructure, workforce readiness, and the availability of sufficient reliable electricity supply. The following sections examine these trends and their implications across Virginia's end-use sectors.

Transportation Electrification

EV Adoption

The transportation sector relies significantly on petroleum and is the largest end-use consumer of energy in Virginia (see Figure 2). Electrification of vehicles is a significant opportunity to reduce petroleum use and GHG emissions from transportation.

Two types of vehicles use electricity from the grid: battery electric vehicles (BEVs), which use only electricity, and plug-in hybrid electric vehicles (PHEVs), which use both electricity and petroleum fuel. Together, these categories are referred to as EVs.

Hybrid electric vehicles (HEVs) use petroleum fuel but through regenerative braking capture some energy that would otherwise be lost and reuse it through a battery and electric motor. BEVs and PHEVs therefore represent transportation electrification, while HEVs are discussed later as a form of vehicle efficiency.

Transportation electrification also means that the transportation and electricity sectors are becoming more closely connected. Transportation is becoming a growing class of demand for the grid, and EVs can provide some of the storage and demand management opportunities discussed in the "Distributed Energy Resources " subsection.

Because of the fundamental efficiencies of electric motors compared to IC engines, this results in a reduction in energy use for a comparable vehicle. The average EV (in 2021) "can travel 4.4 times further on a given amount of energy than the average gasoline vehicle."[65] In terms of GHG emissions, as the electric grid's GHG emissions intensity declines, the emissions benefits of transportation electrification increase.

The majority of the approximately 8 million vehicles in Virginia are traditional internal-combustion engine (ICE) light-duty vehicles (LDVs). While BEVs and PHEVs represent less than 3% of all registrations by the end of 2025, these segments of electrified vehicles are growing quickly. As shown in Figure 27, EVs were only 0.4% of the fleet in 2020 but grew to 2.15% by the end of 2025. As of December 2025, there were approximately 170,000 EVs (BEVs and PHEVs) in Virginia.66 The commercialization of electrified medium- and heavy-duty vehicles lags LDVs as initial vehicles are just now entering marketplaces.

Figure 25. *EVs Registered in Virginia*[67]

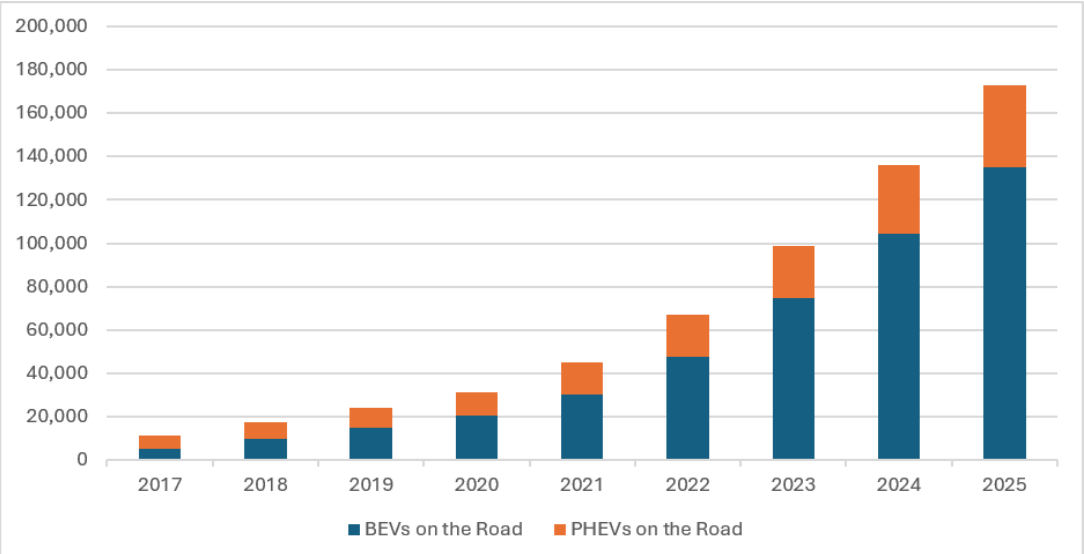


Figure 26. *EV original registrations by year in Virginia*[68]

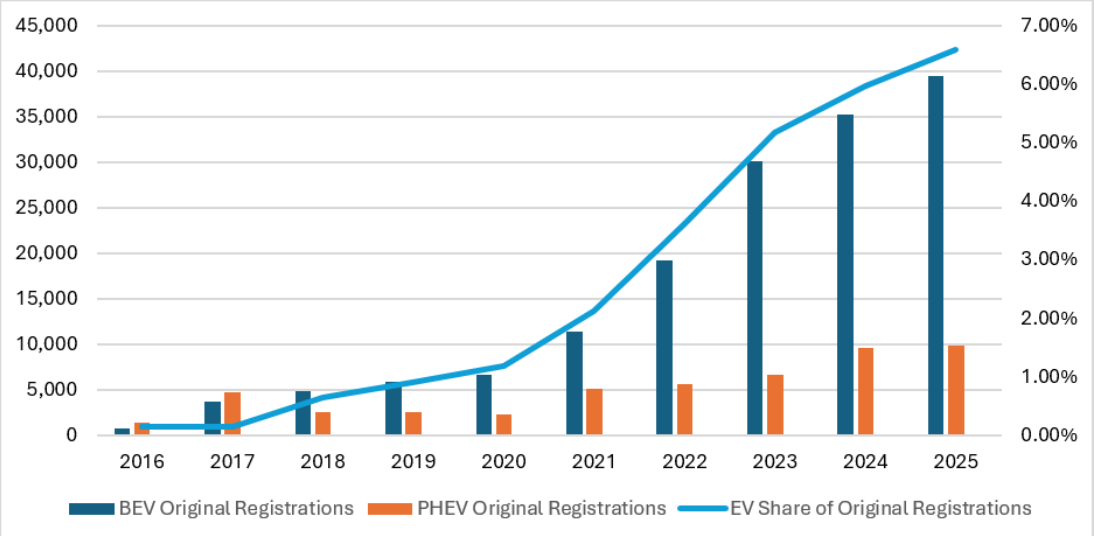
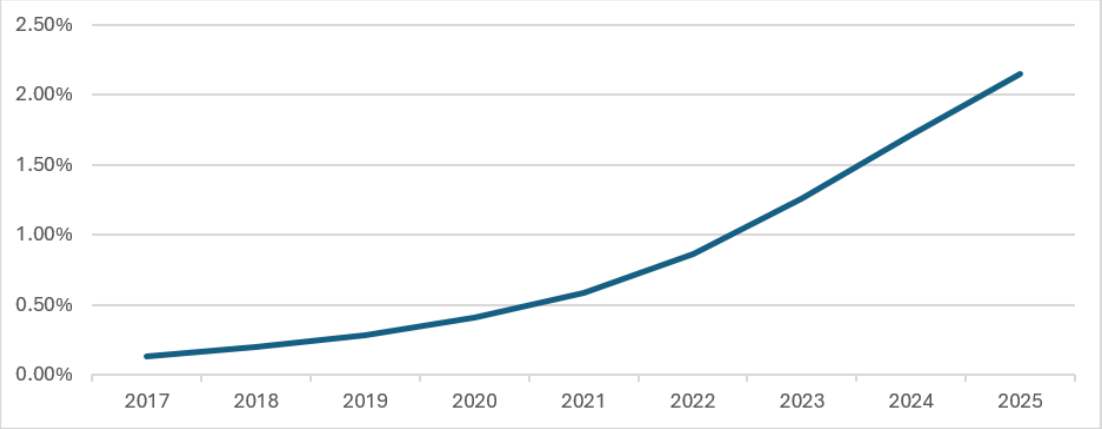


Figure 27. *Share of EVs on the road in Virginia* [69]



EV Charging Infrastructure

As of mid-2026, Virginia has approximately 5,434 public electric charging ports plus 1,018 private ports in limited access locations (such as shared chargers in workplace parking decks accessible only to employees). The number of private charging ports at individual homes is unknown but far greater than the values in Table 9.

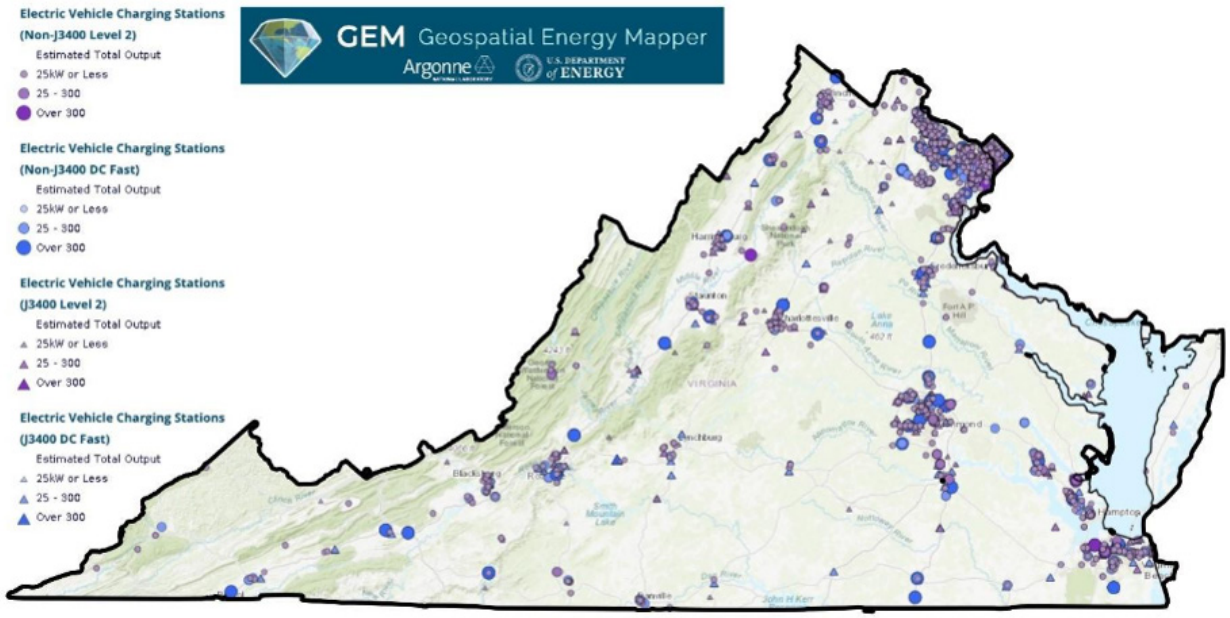
Table 9. *EV Charging Stations by type in Virginia*[70]

	Level 1		Level 2		DCFC		Total	
Type	**Ports**	**Stations**	**Ports**	**Stations**	**Ports**	**Stations**	**Ports**	**Stations**
Public	29	10	3815	1536	1588	361	5432	1907
Limited Access	206	29	779	158	33	12	1018	199
Totals	**235**	**39**	**4,594**	**1,694**	**1,621**	**373**	**6,450**	**2,106**

Virginia's public EV charging infrastructure has expanded rapidly in recent years, particularly along major interstate corridors such as I-95, I-64, and I-81 and within urban centers like Northern Virginia, Richmond, and Hampton Roads. Virginia has used federal and state funding to deploy DC fast chargers that support long-distance travel and reduce concerns about running out of charge. However, coverage remains uneven. Rural regions and parts of Southwest and Southside Virginia have fewer public charging options. While the backbone network is improving, redundancy at key locations remains limited, increasing the operational impacts of outages or inoperable stations.

While public EV infrastructure is critical for large scale adoption, most analyses of EV charging patterns emphasize that most charging will take place at home. For example, a study by National Renewable Energy Laboratory (NREL) found that 64% of charging (by energy) and 92%+ of chargers in 2030 will be at home, with <1% of chargers needing to be DC Fast Chargers (accounting for ~20% of energy).[71] Support for Level 1 and Level 2 at-home charging, in particular in multi-family dwellings, is an important lever to promote adoption.

Figure 28. *EV Charging Stations by Type in Virginia*[72]



Virginia's EV charging ecosystem shows strong momentum but faces challenges related to equity, consistency, and long-term scalability. Public charging is improving in visibility and coverage but must expand more deliberately into underserved and rural regions, while private charging needs stronger policy support to ensure access for renters, apartment and condo owners, and lower-income households. Coordination among state agencies, utilities, local governments, and private operators will be essential to align infrastructure growth with grid capacity and transportation demand. If these gaps are addressed, Virginia is well positioned to support broader EV adoption.

Medium- and heavy-duty vehicle electrification requires different charging investments, often at fleet depots and other locations where these vehicles concentrate, such as truck stops, warehouses, ports, and intermodal facilities.

Building Electrification

Building electrification replaces natural gas and delivered-fuel equipment with electric heat pumps, water heaters, and cooking equipment. Where electrification replaces indoor fuel-combustion equipment, it reduces occupants' exposure to combustion pollutants. For example, the U.S. Environmental Protection Agency (EPA) identifies gas stoves as an indoor source of nitrogen dioxide and carbon monoxide; children and people with asthma or other respiratory conditions may be more sensitive to nitrogen dioxide exposure.[73]

Virginia is already more electrified than most states: for example, 27% of households use a central heat pump as their primary heating equipment, more than double the national rate of 13%, aided by a mixed climate suited to heat pumps.[74] This existing level of building electrification has been driven by cost savings potential and building codes. High-efficiency electric equipment was incentivized by federal tax credits that expired December 31, 2025, following passage of the One Big Beautiful Bill Act (OBBBA). The 2021 Virginia Energy Conservation Code (effective January 2024) now requires heat pumps, rather than electric resistance, as the primary heat source in new construction if a ducted or ductless heat pump can be installed.[75]

There remains significant opportunity to reduce energy bills for Virginia households through conversion to heat pumps. Specifically, an RMI analysis finds meaningful cost-saving opportunities for two household segments in Virginia: homes with electric resistance heating and homes relying on delivered fuels (propane or fuel oil). Approximately 2.1 million Virginia homes use electric resistance for space or water heating. Upgrading to heat pumps could save these households an estimated $2,054 per year on average.[76]

Further, over 333,000 Virginia homes use oil or propane for heating (~191,000 propane; ~142,000 oil). Homes using delivered fuels are disproportionately single-family, rural, and older. Upgrading to air-source heat pumps and heat pump water heaters could save these households an estimated $1,620 per year on average.[77] Unlike delivered fuels, which emit combustion pollutants such as fine particulate matter ($PM_{2.5}$), nitrogen dioxide (NO_2), and carbon monoxide, electric heat pumps produce no direct on-site combustion emissions.

In addition to bill savings, heat pump upgrades could provide meaningful grid benefits by reducing peak electricity demand. RMI estimates that Virginia could realize ~1,840 MW of electric grid peak savings from upgrading all single-family electric resistance homes to heat pumps (including space and water heating).[78]

2F. Energy Efficiency

EE measures reduce the energy required to perform a given task. Reducing overall energy consumption through improved EE is often among the most cost-effective ways to reduce customer costs while also supporting climate goals.

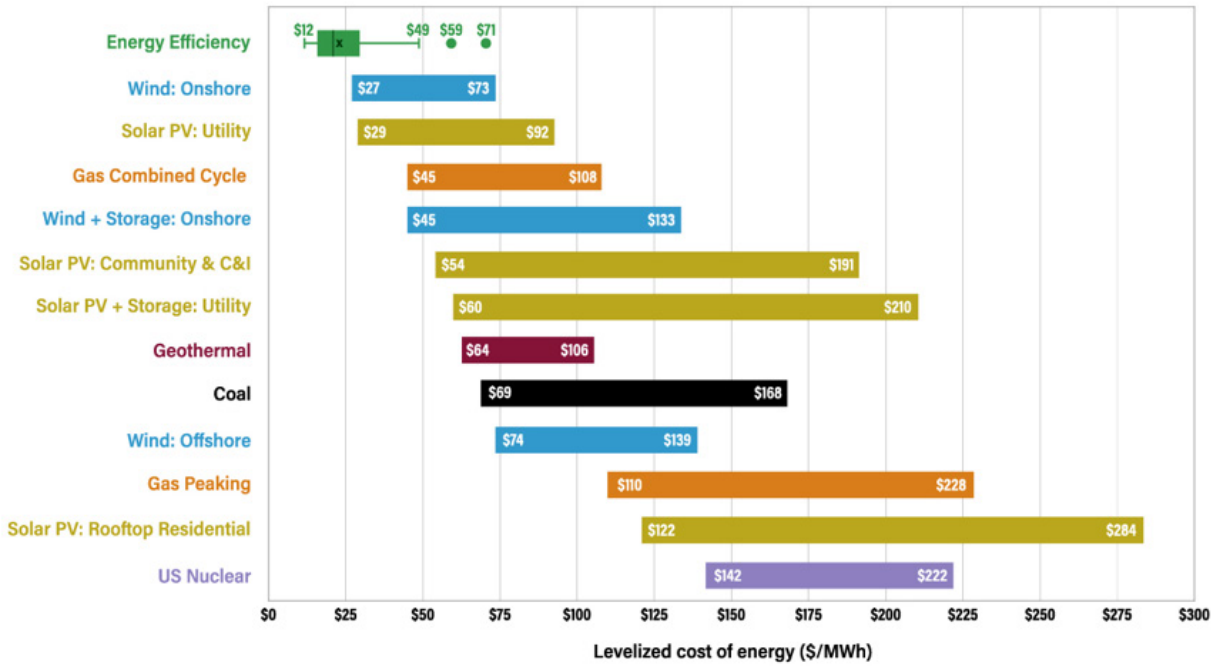
EE opportunities are applicable across all segments of the energy production, delivery and end-use consumption value chain. Three particularly important sectors with opportunities to improve efficiency include:

1. **Electric system efficiency:** across supply (e.g., improving efficiency of power plants, solar generation or battery performance) and delivery (e.g., reducing transmission and distribution line losses);
2. **Building efficiency:** high-performance new construction and retrofitting existing buildings; and
3. **Transportation efficiency:** improving vehicle fuel efficiency (including improving ICE and hybrid performance as well as EVs); putting more people/goods in each vehicle through use of transit, rail, and carpooling; and reducing overall miles driven per capita (or per unit of economic productivity) through better planning and design.

EE benefits for Virginians are significant. A 2017 NREL/DOE ResStock analysis estimates that cost-effective improvements could reduce energy use in single-family homes by 28%, saving 9.6 billion kWh of electricity and 30.1 trillion Btu of gas, propane, and fuel oil annually, and reducing household utility bills by $1.5 billion per year.[79] Ensuring that EE measures in new single-family homes are installed correctly in compliance with building code could generate over $2.9 million in annual energy savings to residents (2017-2018 study).[80] In 2023, the DOE estimated that adoption of the latest model of energy codes at that time could yield $4 billion in cumulative energy cost savings over 30 years and up to $11 billion in cumulative energy cost savings by moving closer to net zero-energy code standards.[81]

Many EE measures have lower levelized costs than new supply-side resources, meaning that reducing demand can cost less than building new energy generation resources to serve it.[82] Additionally, because efficiency retrofits can be deployed within months, expanding demand-side efficiency offers some of the best near-term opportunities to curb rising bills.

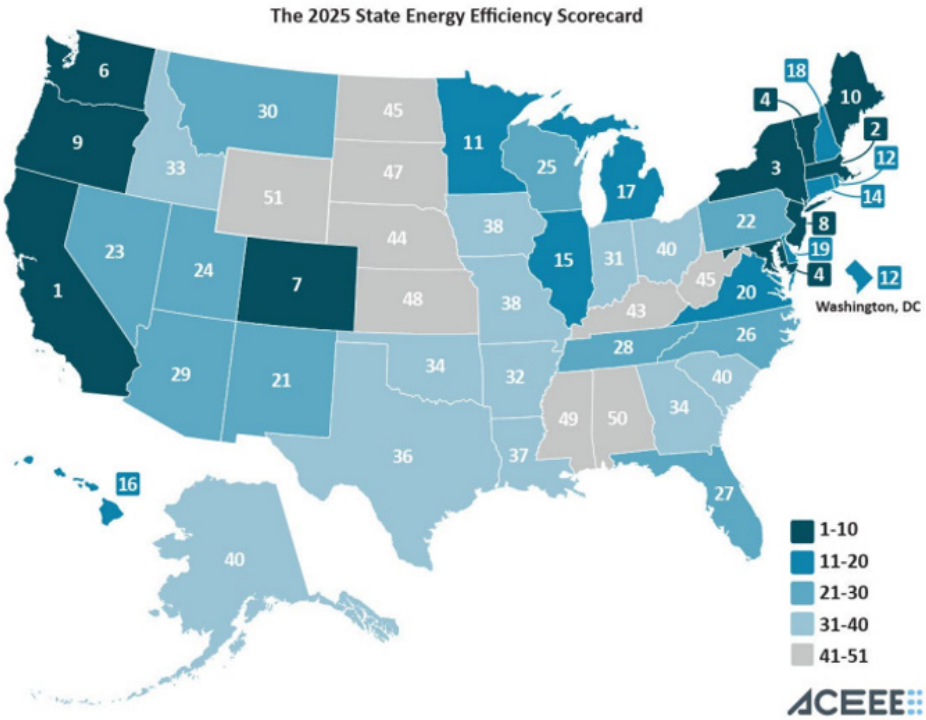
Figure 29. *A comparison of the levelized cost of EE and supply-side resources. Vertical line and "X" represent the median and mean costs of EE, respectively.*[83]



While EE potential is conceptually significant, Virginia decisionmakers are limited in their ability to plan for maximizing EE due to the lack of statewide EE potential data. Virginia law requires the SCC to retain a qualified independent expert to conduct an EE potential study for Dominion and APCo to inform the Energy Efficiency Resource Standard (EERS) savings targets the Commission sets every three years. While these independent, utility-specific reviews are useful, a statewide study would provide greater insights. For example, Pennsylvania's Public Utility Commission directly retains an independent Statewide Evaluator to produce a single Energy Efficiency and Peak Demand Reduction Market Potential Study covering all major electric distribution companies on a recurring multi-year cycle, most recently incorporating the effects of federal rebates and delivered-fuel-to-heat-pump switching.

This context can be seen in American Council for an Energy-Efficient Economy (ACEEE)'s *2025 State Energy Efficiency Scorecard*,[84] where Virginia ranked 20th, earning 45.5 out of 100 potential total points. Virginia scored well on state government initiatives, receiving 8.5 out of 9 points. Virginia received approximately 50% of available points in other categories (transportation policies: 16 of 26 points, building EE policies: 11 of 24 points, and industrial policies: 3 of 6 points) except for utility and public benefits (7 of 29 points) and appliance efficiency standards (0 of 6 points).

Figure 30. *2025 State Scorecard rankings by ACEEE*



Electric System Efficiency

While the primary focus of utility efficiency programs is empowering end-use customers to reduce consumption (demand-side efficiency), a critical and complementary opportunity lies in improving the efficiency of the grid itself (supply- and delivery-side efficiency). Supply-side efficiency opportunities vary by resource. At fuel-burning power plants, improved operations and maintenance, upgraded controls and equipment, and more efficient generating units can reduce a plant's heat rate—the amount of fuel required to produce a unit of electricity. A lower heat rate reduces fuel consumption, operating costs, and emissions for the same electricity output.[85]

Energy storage efficiency can likewise be improved by selecting appropriate technologies, reducing conversion and auxiliary-system losses, and managing charging and discharging to limit degradation. These measures increase round-trip efficiency, or the share of electricity used to charge a storage system that is later returned to the grid.[86] Together, improvements in generation, storage, and grid delivery can provide more usable electricity from existing and new infrastructure.

Additionally, there are significant opportunities to improve the efficiency of transmission and distribution systems. Nationally, approximately 5% of electricity is lost in transmission and distribution.[87] Virginia experiences a similar level of transmission and distribution loss.[88] Distribution-system losses are generally greater than transmission-system losses because electricity travels through more extensive, lower-voltage infrastructure before reaching customers.[89] Modernizing transmission infrastructure through reconductoring—replacing existing wires with advanced conductors—can reduce losses on upgraded lines and, in some applications, approximately double their power-carrying capacity while using existing transmission structures and rights-of-way.[90] The loss reduction depends on the conductor selected, line loading, and system conditions; one DOE-sponsored assessment found that advanced conductor designs with lower electrical resistance could reduce losses on the affected line by approximately 30%.[91] Replacing aging

distribution transformers with higher-efficiency units can also reduce both no-load core losses, which occur whenever a transformer is energized, and load losses, which increase as electricity flows through it. Although the savings from an individual transformer may be modest, they can become significant across a utility's large transformer fleet.[92]

Building Energy Efficiency

Building EE refers to construction practices, technologies, and operational practices that reduce the total energy required to perform a given task or activity in a building. As the Commonwealth faces affordability challenges and growing demand, EE in buildings can reduce the energy needed to provide heating, cooling, lighting, and other services. It can complement DERs, DR, and VPPs by reducing ongoing electricity and fuel use; its effect on peak demand depends on the measure, building characteristics, and when customers use energy. Historically, improvements in building efficiency have helped keep Virginia's retail electricity demand relatively flat despite strong population and economic growth.

The primary policy driver for utility-administered EE programs in Virginia is the EERS established under the VCEA. The EERS requires Dominion and APCo to achieve escalating annual energy savings relative to their 2019 retail electricity sales. The VCEA set targets through 2025, and the SCC must establish targets for every successive three-year period thereafter.[93]

As shown in Table 10, while APCo has consistently met or exceeded its statutory goals, Dominion has regularly fallen short of its annual EERS targets. Dominion attributes these shortfalls to customer adoption barriers and program enrollment friction, while consumer advocates point to program design and outreach shortfalls.[94]

Table 10. *Comparison of IOU Energy Savings Goals and Actual Energy Savings Achieved*

	Dominion		APCO	
Year	**EE Goal**	**EE Achieved**	**EE Goal**	**EE Achieved**
2022	1.25%	1.23%	0.50%	1.52%
2023	2.50%	1.42%	1.00%	2.05%
2024	3.75%	1.6%	1.50%	2.58%
2025	5.00%	2.0%	2.00%	3.16%
2026	3.00%	-	3.00%	-
2027	4.00%	-	3.50%	-
2028	5.00%	-	4.00%	-

The law restricts the SCC from approving new IOU fossil-fuel generation if the IOU has not met its EERS targets, unless the generation is needed to resolve a threat to grid reliability. In years in which a utility meets its EERS target, the SCC awards a margin on EE program operating expenses in that year, to be recovered through a rate adjustment clause (RAC), which margin shall be equal to the general rate of return on common equity.[95]

To meet EERS targets, IOUs must demonstrate to the SCC that proposed EE and DR programs are cost-effective. Through 2028, utilities must analyze proposed programs using, at minimum, the Participant Test, the Utility Cost Test, the Ratepayer Impact Measure Test, and the Total Resource Cost Test. Following 2024 legislation directing the SCC to establish a single, consistent cost-effectiveness test, the Commission has adopted regulations creating a Virginia Jurisdiction-Specific Test (JST). The JST broadens the analysis to capture additional utility system impacts such as

market-based avoided capacity value using PJM auction clearing prices as well as non-utility impacts such as GHG emissions and other environmental effects. Utilities will begin using the JST in 2029.

Virginia has numerous programs promoting EE in new construction as well as retrofits and rehabilitation of existing buildings. The set of programs can be broadly categorized into income-qualified programs, market rate utility programs, and other state-sponsored programs.

1. **Income-Qualified Programs:** There are a range of programs available to serve income-qualified households in both single-family and multi-family buildings. HB 3/SB 5 created an Income-Qualified Energy Efficiency and Weatherization Task Force, led by the Virginia Department of Housing and Community Development (DHCD), and tasked it with delivering a comprehensive plan by 2027 to reach all eligible households with weatherization and efficiency retrofits by 2034. Existing programs include:

    - **Weatherization Assistance Program (WAP):** Providing eligible households with no-cost weatherization upgrades, Virginia's federally funded WAP is administered by DHCD in partnership with a network of regional providers. From July 2025 through September 2026, DHCD worked with 14 local providers to complete weatherization upgrades in 228 units and weatherization readiness upgrades in 36 units across the state.[96]

    - **Home Repair Programs:** Virginia's re-entry into RGGI in July 2026 restored a major funding stream supporting income-qualified EE. Using RGGI auction proceeds, DHCD administers the Weatherization Deferral Repair (WDR) Program, which funds repairs for specific conditions that prevent homes from receiving federal weatherization services. Eligible uses for WDR funding include roof, framing, wall, ceiling, floor, or other structural repairs when necessary; health and safety repairs required for safe weatherization; compliance with applicable building codes and weatherization standards; and follow-on federal WAP weatherization once the home is made weatherization ready. Additionally, DHCD's Essential Home and Accessibility Repair Program (EHARP) offers support for home health and safety upgrades. Programs that offer home repair support, such as WDR and EHARP, are crucial to ensure that the homes most in need of energy savings can get repairs needed to unlock more narrowly prescribed efficiency funding. Since 2021, WDR has served over 2,500 homes with the highest number of homes in a single year, 766, served in 2023.[97] Figure 31 shows WDR project locations between 2021-2025.

    - **Utility Programs:** Dominion and APCo each offer income-qualified EE programs. Looking ahead, HB 2/SB 72 requires utilities to serve at least 30% of eligible low-income households by 2031 (allowing fuel switching from delivered and stored fuel sources to high-efficiency heat pumps starting in 2028).

    - **Multifamily Affordable Housing:** In addition to the WDR program, DHCD uses RGGI auction proceeds to provide supplemental funding for high-efficiency housing through its Affordable and Special Needs Housing (ASNH) program. ASNH incorporates EE into affordable housing development and preservation, supporting projects involving new construction, substantial rehabilitation, and adaptive reuse. This includes high-performance/green-building standards, HERS energy-performance requirements, and energy-efficient building envelopes and mechanical systems. Since ASNH program inception, 10,965 units across 152 development projects have received EE improvements, and $274 million has been obligated to incentivize high performance and green building standards.[98] See Figure 32 for levels of RGGI funding awarded by jurisdiction and ASNH project sites in fiscal years 2020-2026. Also, Virginia Housing administers the state's Low-Income Housing Tax Credit program, which incentivizes EE in affordable housing.

Figure 31. *Map of WDR Projects between 2021-2025 by Number and Zip Code in Virginia. Source: Virginia Department of Housing and Community Development (WDR Data, 2021-2025), US Census Bureau, The Nature Conservancy, ESRI, June 2026.*

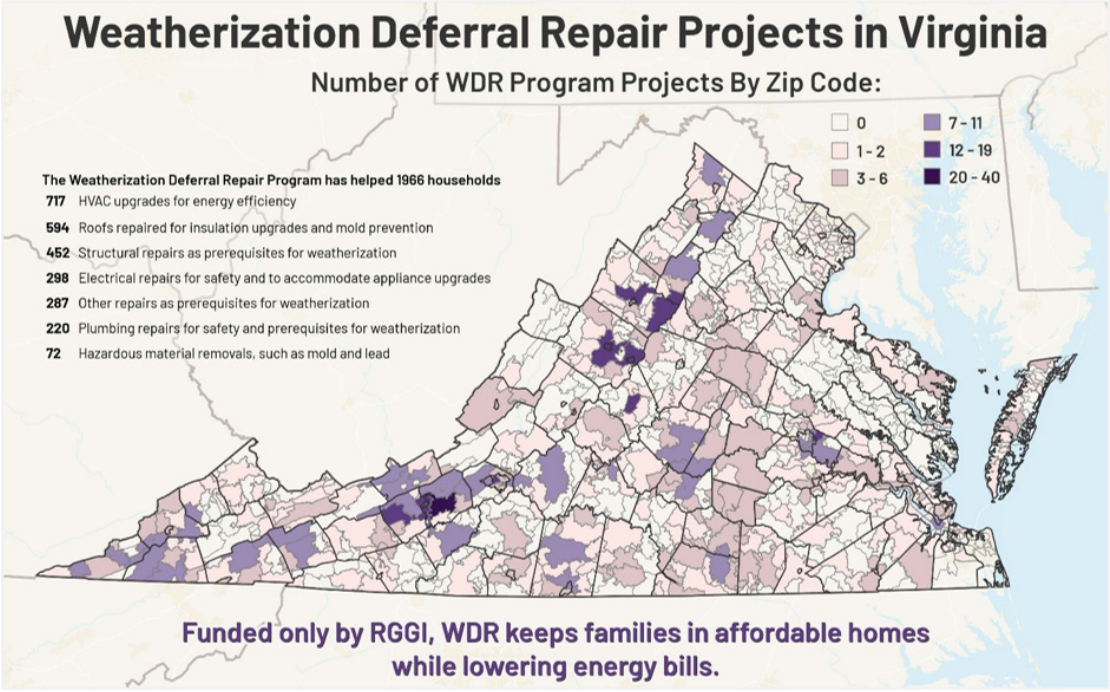
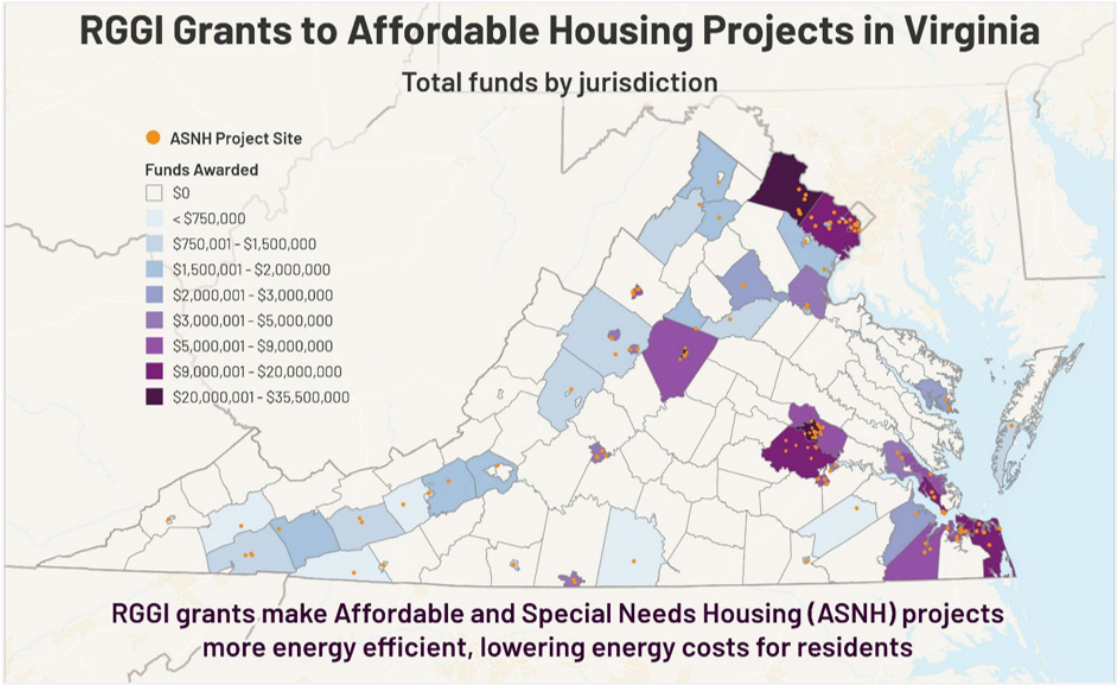


Figure 32. *Map of ASNH Project Sites across Virginia and Total Amount of RGGI Funds Awarded by Jurisdiction in Fiscal Years 2020-2026. Source: Virginia Department of Housing and Community Development (HIEE Data, 2020-2026), US Census Bureau, The Nature Conservancy, ESRI, June 2026*



2. **Market-Rate Utility Programs:** To meet their EERS goals, Dominion and APCo have each established a growing a set of EE programs for their customer classes, including single-family residential, multi-family residential, and small to large businesses. [99] Dominion also has specialized programs for hospitality, healthcare, agricultural, and data center customers. While not subject to the EERS, many electric cooperatives and municipal utilities also offer customer-facing EE programs.

3. **Other State-sponsored Programs:** Virginia Energy sponsors statewide EE programs for commercial buildings, such as Commercial Property Assessed Clean Energy (C-PACE) financing, as well as for publicly owned buildings, such as Energy Savings Performance Contracting (ESPC). Both programs support EE as well as a range of other projects. Additionally, Virginia Energy has secured federal funding through the Home Energy Rebate programs, which will offer EE rebates to eligible single-family households and multi-family properties.

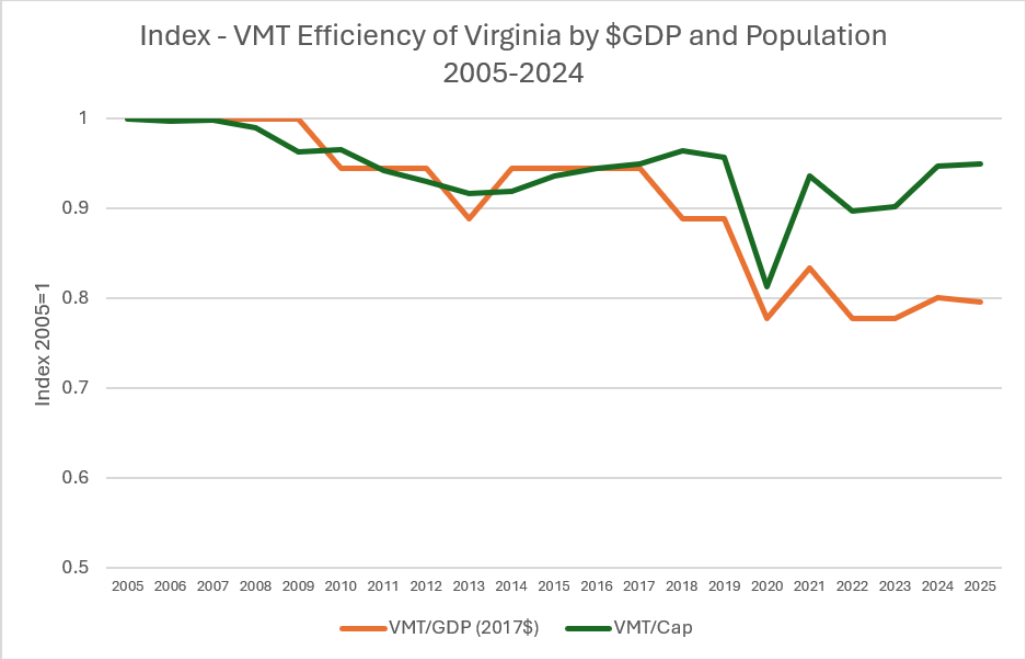
Despite this robust policy framework and set of programs promoting building EE, barriers remain. They include misaligned incentives to invest in bill-lowering measures, insufficiency of incentives or financing to cover upfront costs, customer and contractor awareness and confusion of various incentive options and eligibilities, customer and contractor awareness and trust of technologies, information asymmetry in the real estate market (e.g., lack of energy information in listings), and workforce constraints.

Transportation Efficiency

EE in transportation can take several forms, such as putting more people or goods in each vehicle, improving the efficiency of the vehicle's propulsion system, and reducing the need to travel as much to meet daily needs.

EE investments in transportation include all investments in transit through the state's Commonwealth Mass Transit Fund and the Virginia Passenger Rail Authority. Virginia has promoted carpooling through the significant expansion of Express Lanes, which allows free access to carpoolers and transit. In addition, legislation as well as guidelines have encouraged mileage-efficient transportation planning in some circumstances. Lastly, population growth in the Commonwealth has been concentrated in denser-than-average areas, which tend to require less transportation energy per capita. The total number of vehicle miles traveled (VMT) in Virginia grew about 10% between 2005 and 2024 (with a reduction during the pandemic). But Figure 33 shows that VMT per capita, a critical measure of transportation efficiency, has declined, which indicates a more VMT-efficient commonwealth than in past decades. The ratio of VMT per dollar of GDP (in fixed year dollars) has gone down even more sharply, showing that the decoupling of economic growth and driving is possible. This trend must continue and accelerate to hit energy reduction goals.

Figure 33. *Indexed measure of VMT-efficiency, a critical measure of transportation efficiency, per dollar GDP and per capita since 2005*



Challenges to providing more energy-efficient transportation include: consumer preference for lower efficiency vehicles, and for driving single-occupancy vehicles; a lack of availability of transit/freight rail in many areas of the Commonwealth; and legacy guidelines at various agencies that favor conventional vehicles agnostic of efficiency benefits.

Unlike an energy-efficiency investment whose savings are recouped directly by the purchaser over time, such as an efficient water heater, transit provides systemwide efficiency and community benefits while its costs are borne largely by public agencies.

Transportation efficiency requires a two-pronged approach:

1. **Reducing VMT:** Reducing total VMT acts as the transportation equivalent of "weatherizing" a building—designing communities and transportation systems so that less energy is required to achieve the same daily economic and social activities. VMT reduction is achieved through two primary pathways:

    - **Shortening Trip Distances via Land-Use Planning**: Updating local planning standards and expanding transit-oriented development (TOD) concentrates homes, jobs, and retail uses. By reducing the physical distance between homes and daily destinations, communities naturally lower vehicle trip generation and the length of each trip generated.

    - **Shifting Modes to Higher Person-per-Vehicle Transportation:** Expanding public transit funding, increasing carpooling, and investing in intercity passenger rail, freight rail, and safe, connected bicycle and pedestrian infrastructure allow Virginians to shift single-occupancy vehicle trips to higher-efficiency, multi-modal options. As shown in the figures below, shifting trips to carpooling, transit, and freight rail can produce substantial efficiency gains.[100],[101],[102]

Figure 34. *Compares the Energy Intensity for Various Modes of Personal Transportation*

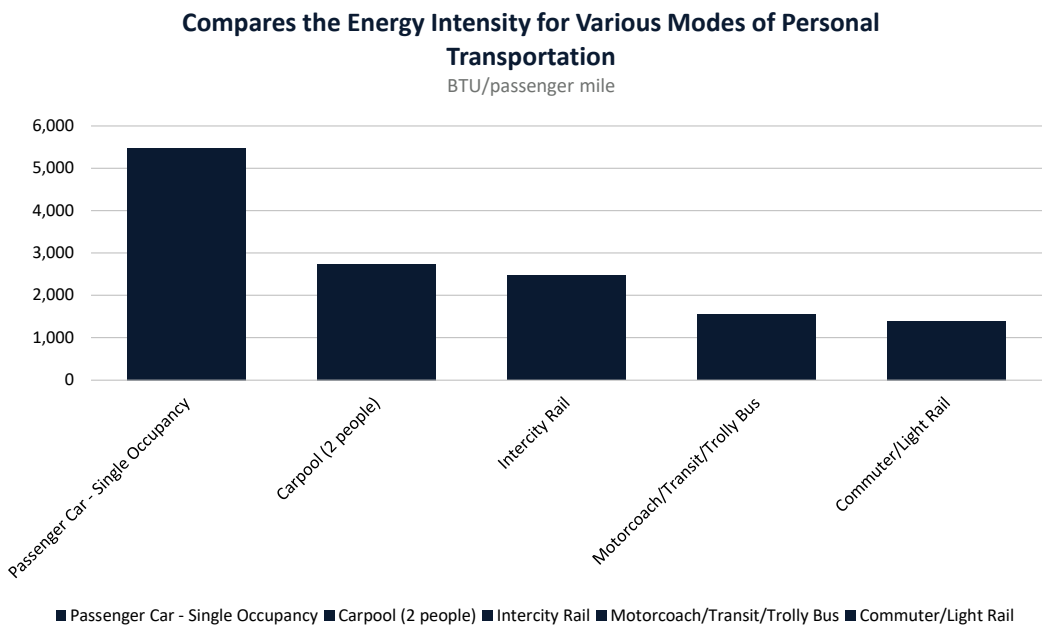
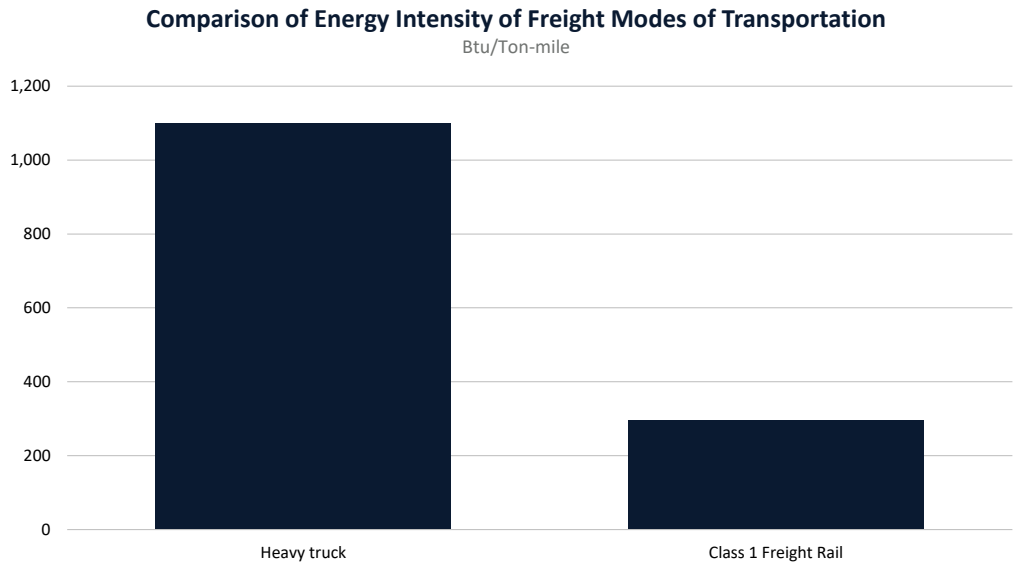


Figure 35. *Comparison of Energy Intensity of Freight Modes of Transportation*

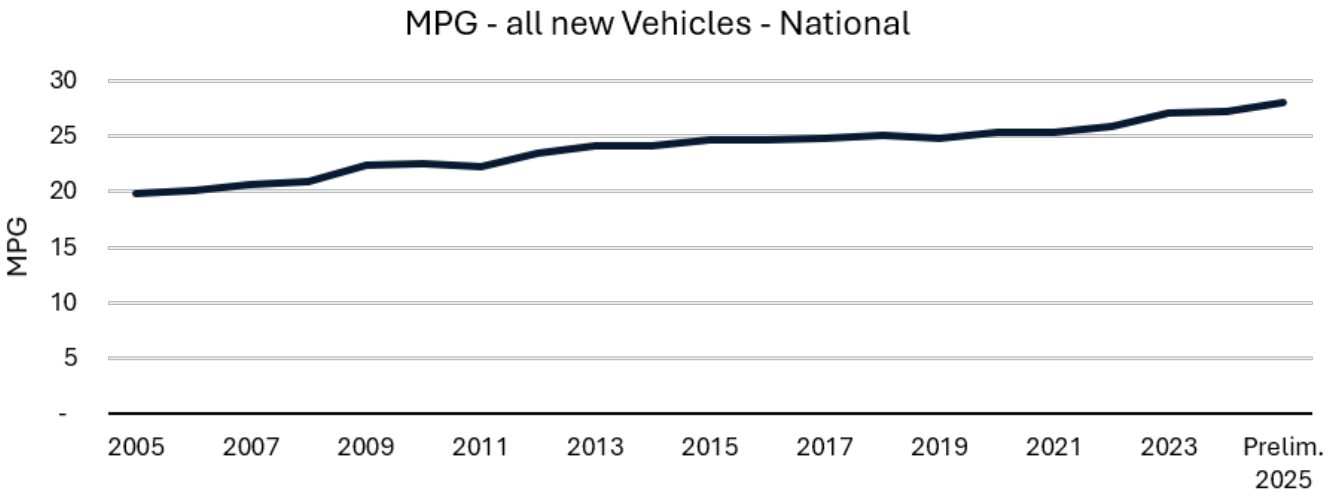


2. **Improving vehicle fuel efficiency:** EVs use less energy per mile than internal-combustion-engine vehicles, making them both an efficiency improvement and a shift in fuel source. While EV deployment continues to grow, accelerating fuel efficiency improvements across petroleum-powered vehicle fleets represents a significant, near-term energy saving opportunity.

The average efficiency of LDVs has historically been driven by federal law, in particular the Corporate Average Fuel Economy (CAFE) standards. As shown in Figure 36, the fuel economy of the new cars entering the national fleet has increased ~40% since 2005.[103] In Virginia, as in the nation, improvements in the fuel economy of individual classes of LDVs have been offset by a shift to larger vehicles, which tend to be less fuel efficient as a class.

In 2021, the State Air Pollution Control Board adopted Virginia's Clean Cars Regulation (9 VAC 5-95), effective March 2024, which had requirements for low-emission and zero-emission vehicles for the 2025 model year and that pushed beyond Federal standards. However, in 2024, the Virginia Secretary of Natural and Historic Resources announced that Virginia would instead default to the Federal targets for fuel economy. There is federal litigation ongoing regarding whether California (and thus other states) have the right to a Clean Air Act waiver to enforce vehicle standards beyond the Federal standards.

Figure 36. *Combined average fuel economy for all new passenger vehicles by model year – US*[104]



Key opportunities to improve vehicle efficiency include:

- **Technology-Neutral Efficiency Policy for Vehicles Registered in Virginia:** To maximize near-term energy security and consumer affordability, state transportation policies can actively promote sales of higher efficiency vehicles across all vehicle classes and powertrain technologies—incentivizing hybrids, ultra-efficient ICE platforms, and alternative fuels alongside BEVs.

  Vehicle mix and consumer choice among existing vehicles is the most powerful lever to quickly improve overall fleet efficiency. There are six vehicles that average over 50 MPG for sale in 2026 in Virginia that have gasoline as the sole source of energy. A 50 MPG vehicle cuts petroleum consumption (thus gasoline expenses) in half compared to the average Virginian, who drives a 25 MPG car. These six models are ~40% cheaper in upfront purchase price than the average 2026 model car, and far cheaper to operate.[105]

  Beyond vehicles on the market today, systemic application of advanced ICE technology could yield up to 10% efficiency improvements, and adding hybridization to all petroleum vehicles systemically could add another ~30% efficiency improvements (40% total) to a vehicle, without any electric fuel needed.[106] Only full electrification can completely eliminate petroleum use.

- **After-market efficiency adjustments for heavy- and medium-duty vehicles:** Research indicates that after-market activities, from driver training and logistics to aerodynamic add-ons to chassis and low-rolling

resistance tires, can offer significant per-ton-miles savings.[107]

- **Programs to educate consumers about maximizing efficient driving for LDVs:** Drivers can take steps to significantly improve their existing cars' efficiency – keeping tires fully inflated and wheels aligned can improve fuel economy 0.5%-6%.[108]

While electrification and other alternative fuels are required to fully eliminate petroleum use, significant efficiency opportunities remain for petroleum-using vehicles through vehicle purchasing behavior and ongoing maintenance. Barriers include consumer preference for inefficient characteristics (such as large size, weight, and acceleration), and lack of policy incentive. Cost is not a barrier, as fuel-efficient petroleum-powered cars are cheaper than typical cars (in part because they tend to be sedans or small SUVs).

2G. Energy Affordability

Energy affordability—the ability of a customer or household to obtain essential energy without financial hardship—is a defining challenge of Virginia's current energy landscape. Historically, Virginia's real average retail electricity prices declined when adjusted for inflation (though overall nominal average retail prices increased). Over the past year, however, that trend has started to reverse as compounding market pressures—increased PJM capacity costs driven by surging data center electricity demand, post-Covid-19 inflation increasing underlying energy costs, and volatile fossil fuel prices—have placed upward pressures on retail bills. To date, residential customers have felt these cost pressures most directly. To ensure costs are affordable for all ratepayers moving forward, a combination of increased utilization of existing grid infrastructure, strategic energy system expansion, and appropriate cost allocation will be necessary.

Affordability also differs by customer. For households, it includes energy burden, bill volatility, shutoffs, and access to efficiency and assistance. For manufacturers and small businesses, it includes total delivered energy cost, power quality, and predictability. For local governments and public institutions, it includes operating costs and infrastructure-related fiscal effects. The VEP therefore considers electricity prices, rates, and customer bills, as well as how costs, risks, and benefits are distributed.

Electricity Prices

Nationally, real inflation-adjusted electricity prices fell 3% from 2015 to 2025, supported by low natural gas prices, coal retirements, declining renewable costs, and overall flat demand growth.[109] Similarly, from 2015 to 2025, Virginia's real inflation-adjusted average retail electricity prices decreased by ~9.5% (while nominal average retail prices rose by ~22% with inflation). During this time, expanding commercial load growth—particularly from data centers—helped absorb fixed utility system costs and kept average retail prices down in Virginia, as the regional grid maintained sufficient surplus capacity to accommodate this new demand. Relative to other peer southeastern states, Virginia's average electricity prices were competitive across customer classes (see Figure 37 below).

However, recent data reveals a clear shift. While Virginia's inflation-adjusted prices declined by ~1% annually from 2015 to 2025, in the last year between 2024 and 2025, average retail prices grew by 4.6%--outpacing general inflation. As shown in Figure 38, this trend held across all customer classes in Virginia as well as in many other states, including Virginia's southeastern peers, signaling escalating cost pressures across the power sector.[110]

Figure 37. *Inflation-Adjusted Real Average Retail Electricity Prices in Virginia vs. Peer States for All Customer Classes (2015–2025)*[111]

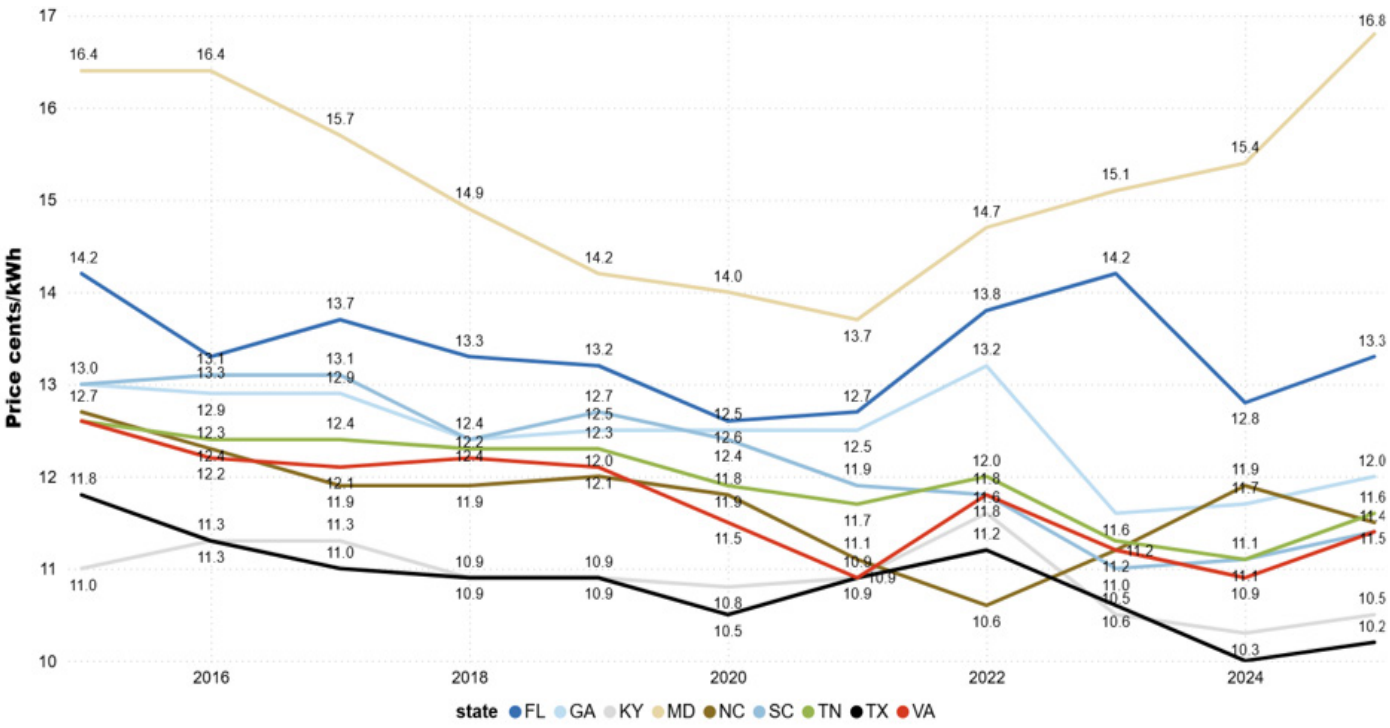
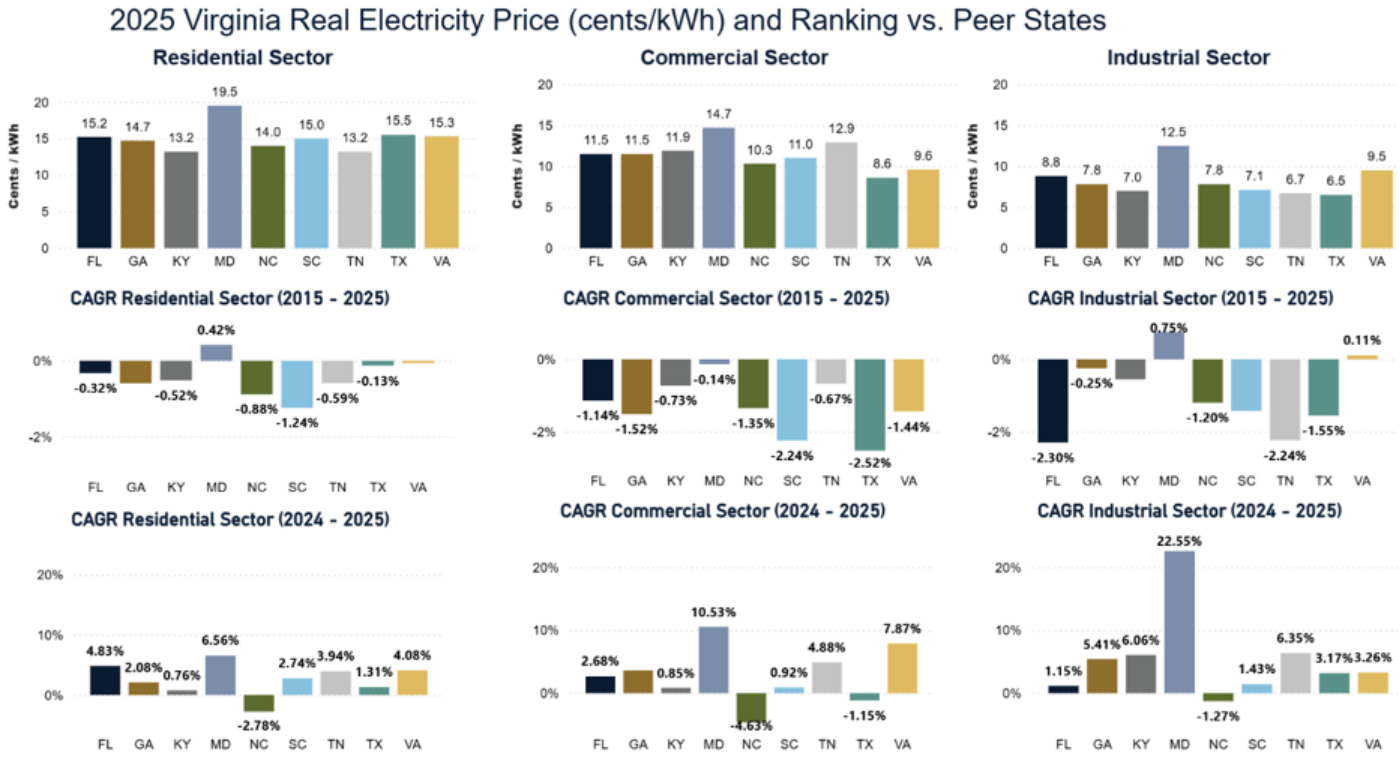


Figure 38. *Average retail electricity prices (¢/kWh) and Compound Annual Growth Rate (CAGR) for inflation-adjusted electricity prices by customer segment from 2020-2025 and 2024-2025, Virginia vs. southeastern peer states*[112]



Despite recent increases, Virginia's overall average retail electricity prices remain regionally competitive and are below the national average. In 2025, Virginia's average residential price was in line with regional peers, while commercial prices remained below most southeastern peer states.

Trends and Current Outlook of Electric Rates and Bill Composition

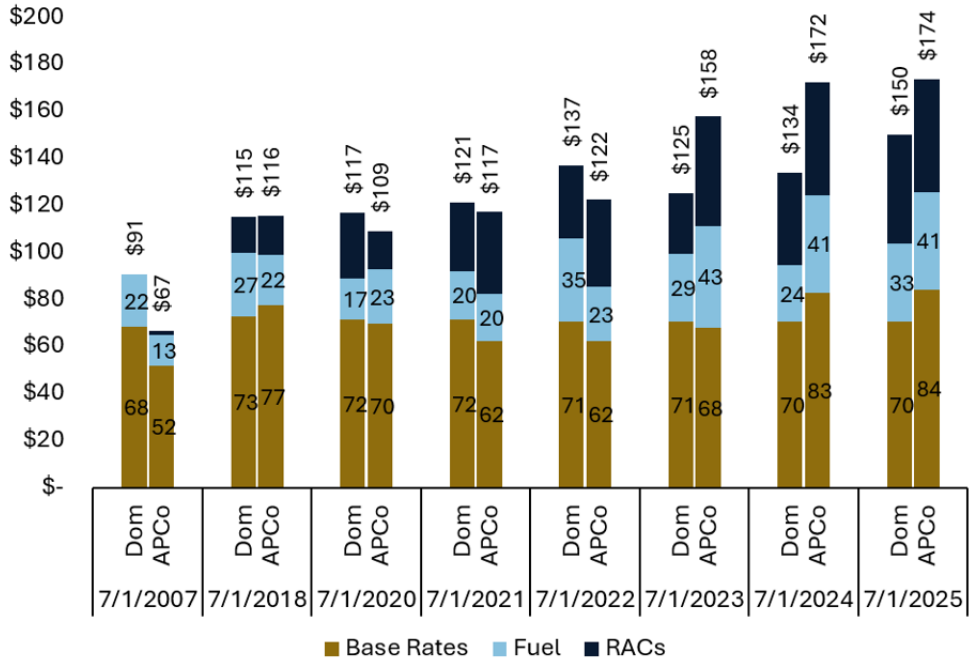
An electric bill is the total amount charged to a customer for a billing period after applicable rates, fixed charges, riders, taxes, fees, and credits are applied. A typical Virginia electric bill has three main utility-charge components:

- **Base rates:** recover the utility's authorized ROE and core operating expenses as approved in rate cases;
- **Fuel factor**: recovers fuel and purchased power costs, which are a straight pass through to customers; and
- **Rate adjustment clauses (RACs) or riders**: recover specific cost categories, such as legacy generation, transmission, environmental compliance costs, VCEA/renewables procurement costs, or grid modernization projects, plus the utility's authorized ROE.

Unlike base rates, which are set through a formal rate case process and remain fixed until the next biennial review, the utility recovers costs (plus rate of return) of RACs from customers dollar-for-dollar annually, with a true-up to correct for any over- or under-recovery. This cost-recovery structure generally creates little regulatory lag or earnings risk for approved rider costs.

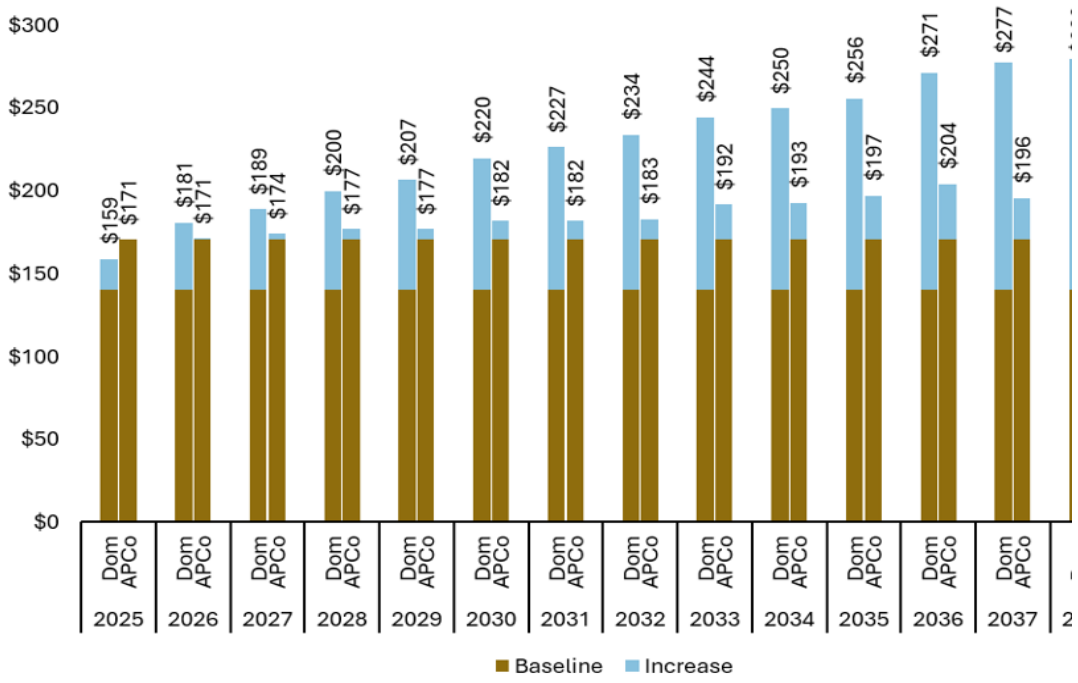
Over time, the base-rate share of the bill has declined, while fuel and RAC charges have taken a larger share.

Figure 39. *Virginia Utility Residential Bill Comparison (1,000 kWh/month), Dominion and APCo, 2007 to 2025*[113]



Dominion reported that it expects 74% of its $54.8 billion capital plan for 2026–2030 to be recovered through riders, reinforcing the trend toward rider-driven bill growth.[114] Looking ahead, Dominion customers are expected to see the largest bill increases, with average monthly bills projected by the utility to reach about $274 by 2039, compared with about $189 for APCo customers.

Figure 40. *Forecasted average residential customer monthly bill, by IOU*[115]



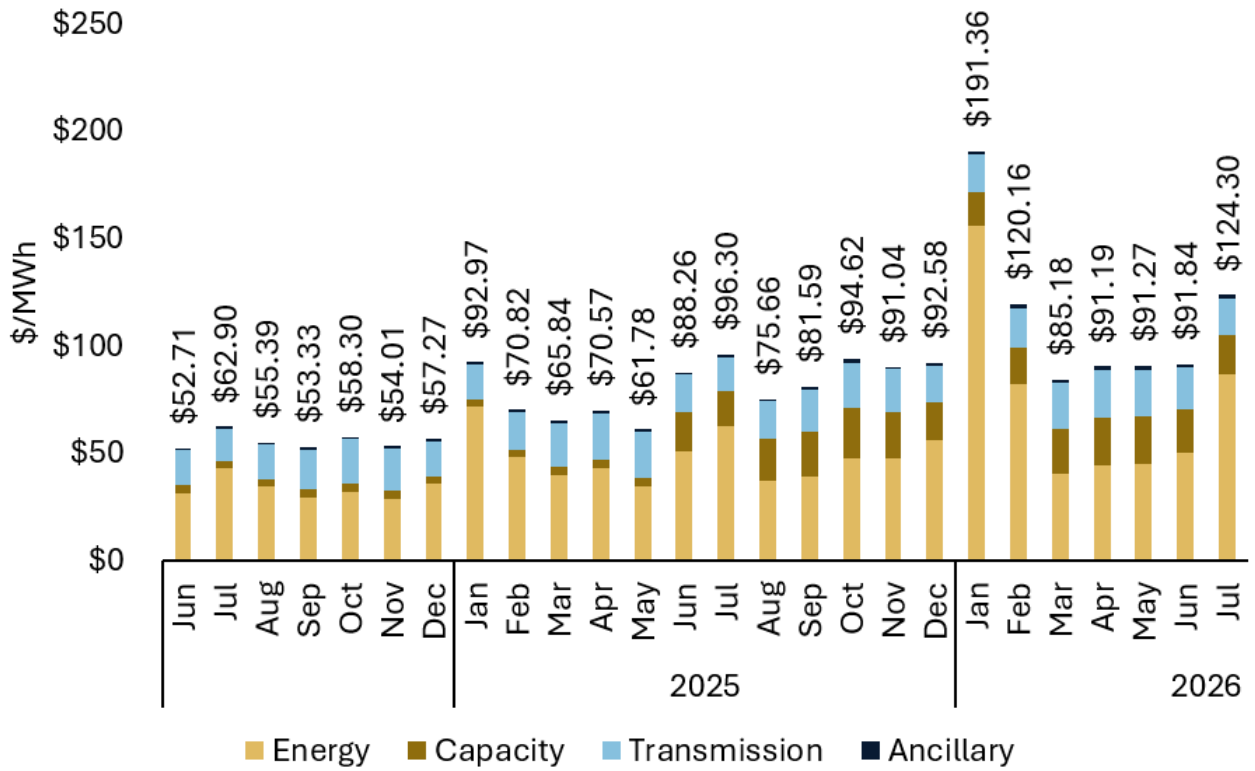
Factors Affecting Electricity Bills and Rates Today

Key drivers of upward pressure on electricity prices, particularly in Virginia and the PJM area, include:

1. **PJM capacity costs**: High PJM capacity prices have recently been a key driver of 2025 price increases in Virginia and neighboring states.[116] Wholesale capacity costs historically represented a modest component of utility rates. However, recent PJM capacity auctions experienced an explosive increase in auction clearing prices, surging from approximately $29/MW-day in June 2024 to $444/MW-day by June 2025.

   Following the capacity-price increase for the 2025/2026 delivery year, capacity's share of total wholesale electricity costs increased beginning in June 2025.

Figure 41. *Total cost of wholesale power ($/MWh) by component, Energy, Capacity, Transmission, and Ancillary, June 2024 through July 2026*[117]



This increase in capacity auction prices is primarily driven by data center growth in the forecast but has also been affected to a lesser extent due to resource retirements, the slow addition of new resources, and changes to capacity accreditation. According to PJM's Independent Market Monitor (IMM), accelerated load forecasts tightened regional reserve margins and triggered significant capacity market revenue increases. In June 2025, the IMM reported that total capacity market revenues rose to $14.7 billion (up from $2.2 billion in 2024/2025), with forecasted data center load accounting for $9.4 billion of the total revenue requirement, or 63%. This trend continued in the following two delivery year cycles, with total forecasted data center demand accounting for over $23 billion in capacity market costs, representing roughly half of the total clearing costs passed through to regional load-serving entities across the three delivery years.

Table 11. *Increase in capacity market revenues due to the inclusion of data center load*[118]

	Native Load	All Data Center Load	Total Auction Cost
2025/2026 Delivery Year	$5,354,943,499	$9,332,103,858	$14,687,047,358
2026/2027 Delivery Year	$8,853,172,918	$7,271,197,971	$16,124,370,889
2027/2028 Delivery Year	$9,913,924,713	$6,497,653,512	$16,411,578,225
2028/2029 Delivery Year	$10,140,129,902	$6,267,819,123	$16,407,949,025
Total	$34,262,171,032	$29,368,774,465	$63,630,945,497

2. **Fossil fuel costs**: Natural-gas prices remain an important driver of electricity costs in regions with substantial gas-fired generation, including PJM. Higher gas prices can increase generation and wholesale-power costs and, depending on utility fuel-cost recovery mechanisms, hedging practices, and regulatory timing, can affect customer bills. Nationally, the price of natural gas delivered to electric generators increased 36% in 2025 from its 2024 low; PJM wholesale electricity prices increased by 1.6 cents per kilowatt-hour, closely tracking regional gas-price increases.[119] In Virginia, geopolitical shocks and extreme weather events in 2021–2022 caused sharp spikes in natural gas prices, creating significant price shocks for Virginia utilities.

   For APCo, between 2007 and 2024, the average APCo residential monthly bill rose from $66 to approximately $174, a 164% increase far outpacing inflation.[120] APCo customers experienced a large increase due to higher-than-expected natural gas prices in 2022. This fuel cost rolled off customers' bills in November 2025, providing some relief.[121]

   For Dominion, the 2021 to 2022 price spike caused a $1 billion fuel under-recovery. A portion was securitized under legislation passed by the General Assembly and is being recovered from customers over approximately seven years.

3. **Utility capital spending and business model trends:** Virginia's electric system is served primarily by vertically integrated IOUs, electric cooperatives, and municipal utilities. IOUs generally provide or procure generation, maintain transmission and distribution facilities, and provide retail service within their territories. Their approved rates are designed to recover prudent costs of service and provide an opportunity to earn a return on eligible capital investment. This differs from a fully restructured retail-choice model, in which customers routinely select a separate competitive supplier for generation service. Virginia permits limited retail-access options, but regulated utility service remains the primary model for most customers. Electric cooperatives are member-owned, and municipal utilities are locally owned; their rates are generally established through their own governing structures, subject to the SCC's authority over specified facilities, service-territory, and other matters.[122]

   For IOUs, the main components of the business model affect customer rates and bills in different ways:

   - **Fuel, purchased power, and operating costs:** Utilities recover reasonable costs to operate and maintain the system, including fuel, purchased electricity, labor, maintenance, and customer service. Fuel and purchased-power costs can change substantially over time and are often recovered through separate rate-adjustment mechanisms. These costs are distinct from capital investment: they affect utility revenue requirements and customer bills, but they do not become long-lived assets in rate base.

   - **Capital investment in generation and the grid:** Utilities invest in long-lived assets, including generation facilities, transmission lines, substations, distribution circuits, undergrounding, grid-automation technologies, cybersecurity, and equipment needed to connect new customers and DERs. Customers generally pay for these investments over time through depreciation and the authorized return on the portion of the investment included in rate base.

   - **ROE:** ROE is one component of the authorized return that IOUs may earn on eligible capital investment. Together with debt costs, it is part of the utility's overall cost of capital. Because an IOU earns a return on approved capital investment, both the authorized ROE and the amount of capital included in rate base can materially affect customer revenue requirements.

   Transmission and distribution infrastructure investment is likely to remain an important affordability consideration

as Virginia serves growing demand, replaces aging equipment, improves resilience, and accommodates new technologies. Nationally, Lawrence Berkeley National Laboratory (LBNL) identifies transmission and distribution costs as one of several contributors to recent retail-electricity-price changes, alongside fuel and wholesale-power costs, new generation, capacity costs, and storm recovery.[123] In Virginia and the PJM region, the effect of delivery-system investment on customer bills will depend on the scale, timing, financing, cost allocation, and SCC-approved recovery of individual projects.

Recent SCC proceedings illustrate both the scale and variety of these investments. Dominion's grid-transformation and strategic-undergrounding programs include substantial physical distribution-system investments, including main feeder hardening and the undergrounding of outage-prone tap lines. For the June 2026–May 2027 rate year, Dominion proposed approximately $333 million in Rider DIST revenue requirements, including about $179 million for the Strategic Undergrounding Program, $120 million for grid-transformation projects, and $35 million for rural-broadband projects.[124]

The mix of investments within a capital program also matters. In Dominion's 2025 grid-transformation proceeding, the largest proposed component was approximately $235 million for main feeder hardening, compared with approximately $19 million for outage-management-system enhancements and $24 million for a remote-sensing and asset-analytics program. The SCC approved the plan with additional requirements for performance reporting and more specific cost-benefit analysis, including analysis of actual approved investments and the incremental costs and benefits of proposed projects.[125]

APCo's grid-transformation plan provides a second example. Its first phase proposed approximately $135 million of grid investments over three years, including distribution automation, smart reclosers, circuit ties, voltage-support equipment, reconductoring, substations, and transformer upgrades. APCo proposed to seek recovery of approximately $122 million through a future RAC.[126]

As utility capital programs expand, the cost-effectiveness and customer value of individual investments—not only the total size of the program—become increasingly important.

4. **Elevated capital costs for new generation:** The cost of developing new generating capacity has risen across technologies. Higher material and equipment prices, sustained interest rates, tariffs, supply-chain repricing, labor constraints, and longer development timelines increase project costs before a facility begins operating. These pressures affect solar, wind, storage, natural gas, nuclear, and the transmission and interconnection equipment needed to connect them to the grid.

   Lazard's 2026 analysis found year-over-year increases in the levelized cost of energy (LCOE)—the estimated average cost of producing electricity over a facility's operating life—across the technologies for which it presents historical comparisons. Lazard estimates the current unsubsidized LCOE at $40–$98 per megawatt-hour for utility-scale solar, $37–$99 for onshore wind, $61–$156 for utility-scale solar paired with storage, $51–$129 for combined-cycle natural gas, and $144–$276 for natural gas peaking generation. Although wind and solar costs have increased from their 2021 lows, Lazard finds that they generally retain a cost advantage over new conventional generation on an unsubsidized LCOE basis.[127]

By the numbers

When asked about affordability, four out of five survey respondents named the electric bill. Gas and propane, transportation fuel, and EV charging costs each drew less than a third as much concern.

Cost increases are particularly significant for technologies that depend on specialized equipment or globally concentrated supply chains. Lazard reports that combined-cycle gas turbine supply is constrained, extending project-development timelines beyond historical norms. Its analysis uses a high-end capital-cost assumption of $2,400–$2,600 per kilowatt for projects in early development with commercial operation after 2028 and cautions that current LCOE estimates may not yet fully reflect recent market quotations. Storage costs have also increased: Lazard estimates an LCOS of $215–$414 per megawatt-hour for a two-hour utility-scale battery and $210–$292 for a four-hour battery, attributing the recent increase partly to tariffs on imported lithium-ion batteries and supply-chain diversification.

Generation projects also depend on transformers and other grid equipment. The DOE reported average lead times ranging from approximately 51 weeks for distribution transformers to 137 weeks for power transformers, with prices increasing by 37% to 80%, respectively. DOE identified limited manufacturing capacity, labor shortages, and constraints on electrical steel and copper as contributing factors.[128] Long equipment lead times can delay project completion, increase financing and interconnection costs, and make near-term cost estimates less certain.

LCOE provides a useful comparison of generation costs, but it does not represent the full cost to Virginia customers. Actual system and bill impacts also depend on financing and ownership, federal tax treatment, capacity value, fuel-price exposure, transmission and interconnection costs, and resource timing and location.

Understanding the Impact of Data Center Customer Growth on Rates

Rapid growth in electricity demand, especially from data centers, is reshaping Virginia's affordability challenge. Experience with large loads nationally shows that the effect of demand growth on existing customers' bills is not predetermined. Its direction and magnitude depend on tariff design, cost allocation, available generation and grid infrastructure, and exposure to market volatility, as well as the scale and timing of the new demand.[129]

While large commercial load growth historically helped suppress customer rates in Virginia by spreading fixed infrastructure costs across a larger volume of sales, modern grid constraints have inverted this dynamic.[130] Today, the surge in data center demand (further discussed in Section 2D) has exceeded available grid capacity, creating upward pressure on rates due to additional generation, transmission, and distribution capacity that needs to be built out to serve this load.

One of the most important governing principles in Virginia's regulated utility ratemaking is cost causation: costs should be borne by the customers whose service requirements caused them to be incurred.

The choice of cost allocation methodology is one of the most consequential decisions in utility rate design because it directly determines what share of system costs residential customers bear relative to commercial and industrial customers. Dominion's 2025 biennial rate case presented the SCC with a comparison of eight different allocation methodologies, producing materially different results.[131] As shown in Figure 42, the residential share of system costs ranges from 37.2% under an energy-based (Factor 3) methodology to 51.3% under a Single Coincident Peak (Single CP) demand methodology. The methodology the SCC selects effectively determines how much of the grid's fixed infrastructure costs households absorb versus large commercial and industrial customers.[132]

Table 12. *Comparison of Class Cost Allocation Methodology Results, Allocation Methodologies Presented in Dominion's 2025 Triennial Rate Case, Based on 2024 Allocation Factor Determinants.*[133]

Methodology	Total	Residential	GS-1	GS-2	GS-3	GS-4	Churches
Factor 3 (Energy)	100.0%	37.2%	4.9%	13.3%	14.4%	29.9%	0.3%
Probability of Dispatch (Watkins)	100.0%	37.4%	5.0%	13.2%	14.1%	29.9%	0.3%
Probability of Dispatch (Nelson)	100.0%	38.3%	5.0%	13.1%	13.9%	29.3%	0.3%
BiP (Using SWPA)	100.0%	42.4%	5.1%	12.9%	13.3%	26.0%	0.3%
Summer Winter Peak & Average	100.0%	43.1%	5.1%	12.8%	13.1%	25.5%	0.3%
12 CP	100.0%	48.5%	5.2%	12.6%	11.8%	21.6%	0.3%
Average and Excess	100.0%	49.8%	5.6%	13.2%	11.3%	19.5%	0.4%
6 CP	100.0%	51.1%	5.4%	12.5%	11.3%	19.3%	0.4%
Single CP (System Peak Demand)	100.0%	51.3%	5.3%	12.8%	11.1%	19.0%	0.4%

The 2024 Joint Legislative Audit and Review Commission (JLARC) study found that data centers were likely to drive up costs for all customers through future infrastructure buildout and recommended establishing a separate data center customer class.[134] While the SCC did not act on the cost allocation challenge in November 2025 and continued the use of the Average and Excess methodology for Dominion, it did approve Dominion's request to create a new GS-5 rate class for customers using more than 25 MW and with a utilization rate of greater than 75%, effective January 2027.[135] In 2026, the General Assembly created an option for large customers that maintain a workforce of at least 200 individuals engaged in activities other than data storage to elect to remain on their existing rate schedule.[136] APCo has established a comparable large load tariff with a 100 MW threshold, and several electric cooperatives have also established large load tariffs.[137]

The minimum demand obligation structure, requiring GS-5 customers to pay minimums of 85% of contracted distribution and transmission demand and 60% of generation demand, is intended to ensure that large load customers bear the fixed infrastructure costs of their service requirements, rather than shifting stranded costs to residential and small commercial ratepayers if data center load does not materialize.

Beyond the energy costs covered under GS-5, in August 2026, the SCC ruled that costs for transmission developments built exclusively to serve large load customers must be allocated directly to those customers, further helping to shield households and other businesses from bearing the costs of this infrastructure.[138]

Virginia's growing electricity demand creates both opportunities and challenges for affordability. Near-term tools such as strategic siting, grid-enhancing technologies (GETs), and demand flexibility may help capture the benefits of load growth while limiting added system costs, although their effectiveness will depend in part on utility planning and investment incentives. Cost allocation will also continue to shape how infrastructure costs are distributed between large load customers and other ratepayers. The GS-5 rate class and APCo's large load tariff are important steps in that direction, but further action is needed to move toward a more equitable cost-allocation methodology that imposes less of a burden on residential and small business customers.

Energy Burden of Virginia's Households

In-home Electricity Expenses and Assistance

Although Virginia's average energy prices have historically been relatively competitive, many Virginia households face unaffordable electricity and natural gas bills. These pressures contribute to utility disconnections, and many households report making difficult tradeoffs among energy, food, and medicine.

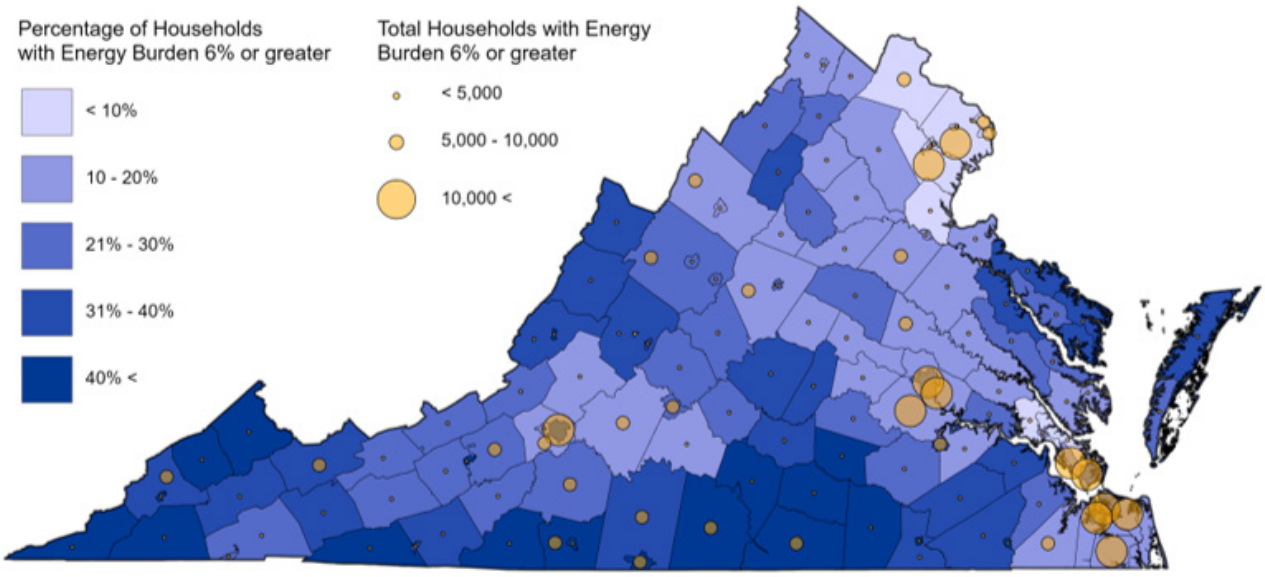
Averaged statistics on rates and bills mask deep disparities in the lived experience of energy affordability across Virginia households. Energy burden—the share of gross household income spent on home energy costs, generally calculated as annual home energy costs divided by annual gross household income—provides a more complete measure of affordability because it accounts for both the cost of energy and a household's capacity to pay.

According to the DOE's Low-Income Energy Affordability Data (LEAD) tool, approximately 17% of Virginia households, or more than 550,000 households, carry an energy burden above the 6% threshold that characterizes households as facing a high energy burden.[139] On average, Virginia households with high energy burdens have an estimated annual energy-affordability gap of about $1,014 per household, compared with a national average affordability gap of $921.[140]

A 2023 Virginia Department of Social Services (DSS) survey found that 65% of low-income households reported having to choose between paying their utility bills and paying for groceries or medicine, 77% said they were not as warm in winter as they needed to be, and 75% were not as cool in summer because they could not afford it.[141]

Energy affordability challenges occur across Virginia, but their geographic patterns vary. As shown in Figure 43, the share of households with high energy burdens appears greater in parts of Southwest, West Central, Valley, Southside, and Eastern Virginia. The total number of affected households is greater in major population centers, particularly Northern Virginia, greater Richmond, and Hampton Roads.

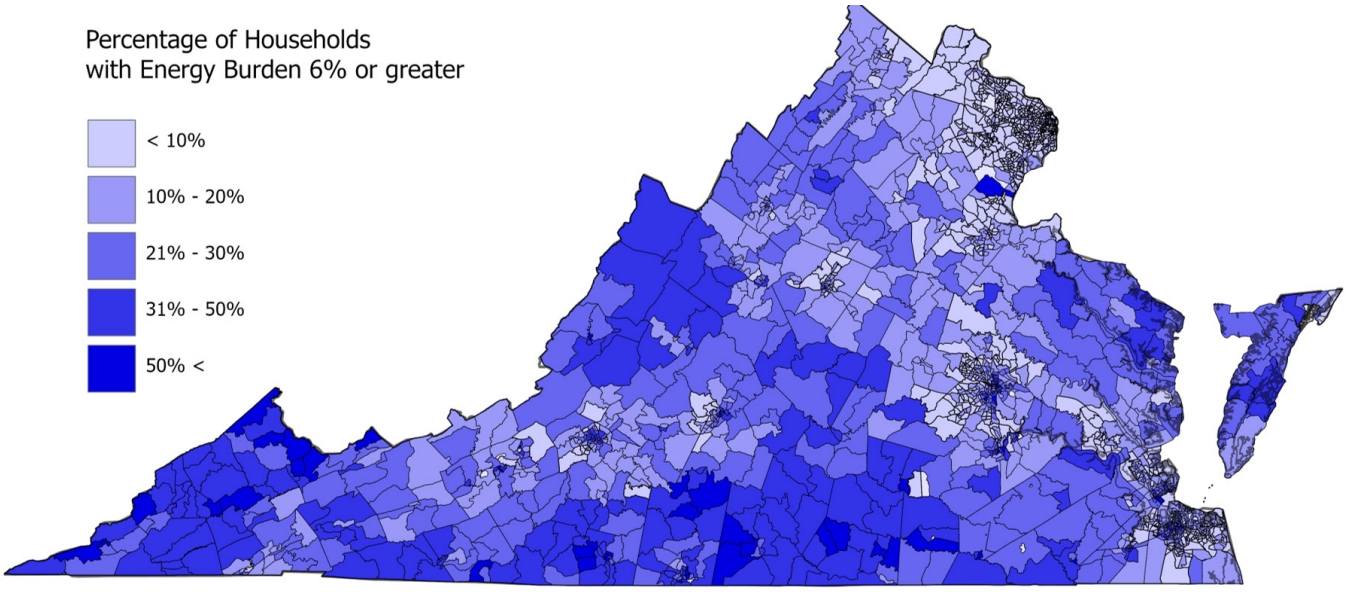
Figure 43. *High Energy Burden by Locality: Share and Number of Households*



Source: Virginia Energy analysis of U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool; 2022 underlying data, tool updated 2024.

Important variation is also revealed below the locality level. As shown in Figure 44, concentrations of high energy burden can occur within individual localities at the census-tract level and may not be fully visible in locality-wide measures. Conversely, localities with relatively high overall concentrations of energy burden can also contain communities where high energy burden is considerably less prevalent.

Figure 44. *High Energy Burden by Census Tract*



Source: Virginia Energy analysis of U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool; 2022 underlying data, tool updated 2024.

As shown in Table 13, energy burden is more common in older housing. Across housing constructed before 1980, roughly 2 to 3 in every 10 households have energy burdens of 6% or higher, compared with 6.6% of households in buildings constructed in 2020 or later. While these relationships reflect associations in the data, they do not, by themselves, establish causation; household energy burden is a multifactorial challenge.

Table 13. *Household Energy Burden and Average Home Energy Costs by Building Age, Virginia*[142]

Building Age	Households	Households with a High Energy Burden	Share of Households with a High Energy Burden	Avg. Electricity Cost ($)	Avg. Natural Gas Cost ($)
Before 1940	208,579	60,824	29.2%	1,698	611
1940–1959	403,345	108,040	26.8%	1,748	427
1960–1979	824,763	171,499	20.8%	1,767	478
1980–1999	1,049,822	144,530	13.8%	1,750	660
2000–2019	789,035	72,753	9.2%	1,441	636
2020 or later	14,232	938	6.6%	1,805	700
Total	**3,289,776**	**558,584**	**17.0%**	**1,751**	**540**

Higher average energy burden also overlaps substantially with broader patterns of economic and historical

disadvantage. Many localities with higher average energy burdens are also wholly or partly eligible as Historically Economically Disadvantaged Communities (HEDCs). While this overlap does not establish causation, it is consistent with the multifactorial nature of energy burden and the broader socioeconomic conditions reflected in HEDC eligibility.

Disconnections are a lagging but powerful indicator of energy unaffordability. From November 2023 to October 2024, approximately 14% of Dominion's residential customers, 13% of Old Dominion Power's residential customers, and 9% of APCo's residential customers experienced a disconnection.[143] Virginia's average disconnection rate ranked third among the 24 states reporting disconnection data in 2023, with 230,131 homes disconnected and IOU customers in Virginia 87% more likely to experience a disconnection compared with the U.S. overall.[144] In 2024, Virginia recorded 461,587 electric shutoffs, a 12.7% electric shutoff rate, ranking 10th among the 50 states and the District of Columbia, versus a 9.4% national average.[145] The average account balance at disconnection in the first nine months of 2024 was $463 for Dominion customers and $362 for APCo customers.[146] These figures represent only a partial picture of statewide disconnections. Beginning July 1, 2027, Virginia law will provide a more complete picture by explicitly requiring both investor-owned electric utilities and electric cooperatives to submit monthly residential-disconnection data to the SCC.[147]

Federal, state, and utility assistance programs provide critical support but reach only a portion of households that may qualify. In fiscal year 2023, Virginia's energy assistance programs provided approximately $134 million in energy subsidies to 231,642 low-income households, about 21% of potentially eligible households. The Energy Assistance Program served households with heating, cooling, and crisis needs, while separate programs supported home weatherization and EE improvements.[148],[149]

Virginia's PIPP provides additional bill relief to eligible Dominion and APCo customers.[150] By early 2026, nearly 35,000 households were participating, receiving an average annual benefit of approximately $883. Recent program spending averaged approximately $17.8 million annually, including benefits and utility administrative costs.[151] Legislation enacted in 2026 (HB 884) expands eligibility and reduces participants' required payments beginning January 1, 2027, potentially increasing both program participation and total benefit.[152] Separate legislation strengthens notice, payment-assistance, and disconnection protections for customers experiencing difficulty paying their bills.[153]

These participation levels show that assistance programs provide meaningful relief but remain smaller than the overall population experiencing high energy burdens. Improving affordability therefore requires both effective enrollment in available programs and attention to the underlying factors that determine bills, including household income, energy prices, housing condition, energy use, and access to efficiency improvements.

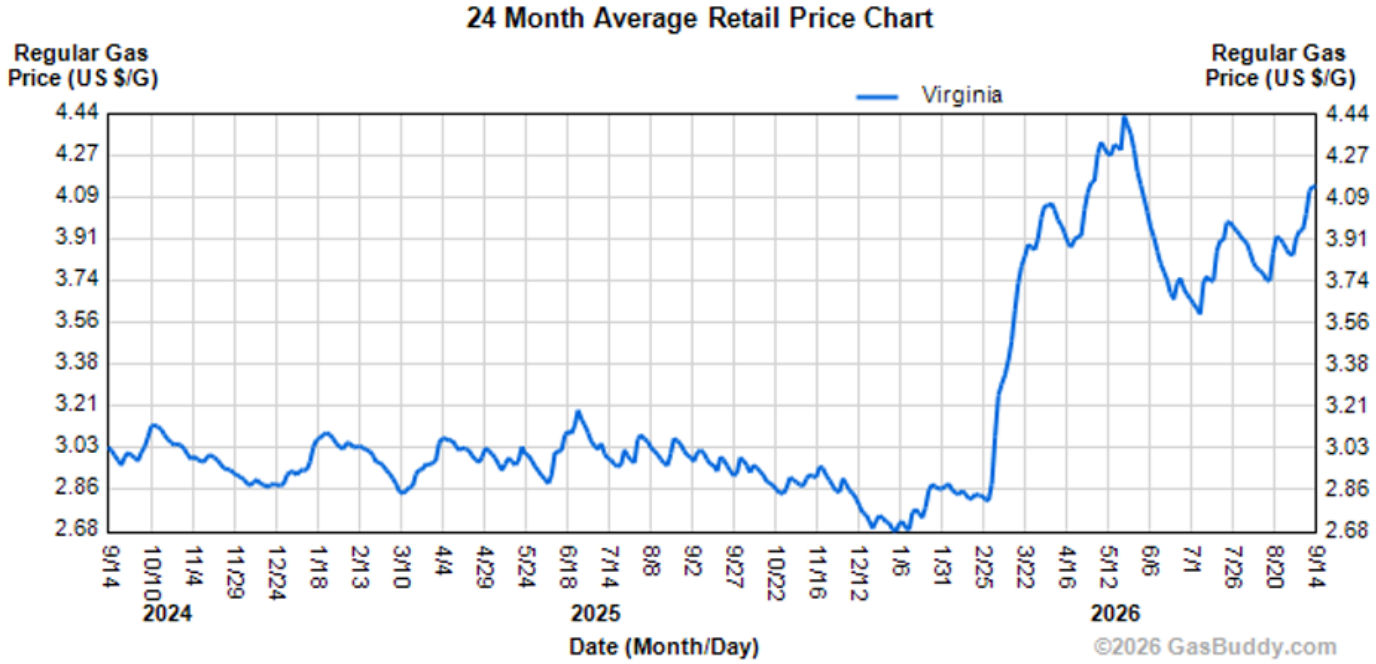
Overall, energy burden remains substantial and unevenly distributed across Virginia. Lower-income households, residents of older housing, and HEDCs face the greatest pressures, while disconnection data demonstrate the consequences when bills become unaffordable. Assistance programs provide important relief, but current participation reaches only a portion of the households that may qualify.

Transportation Energy Costs

Virginia policymakers have more tools to influence regulated electricity rates than market prices for gasoline and diesel. However, transportation fuels—particularly gasoline and diesel—represent a major share of Virginia household energy budgets.

Between 2000 and 2025, average inflation-adjusted retail gasoline prices in Virginia rose 7%.[154] In 2026, gasoline prices have increased significantly—jumping by 40% since February 2026 when the U.S. and Iran conflict started.[155]

Figure 45. *24 Month Average Retail Gas Price ($/gallon)*



Vehicle fuel efficiency gains have helped mitigate these cost increases for consumers (alongside reducing emissions), but fuel price volatility remains an ongoing affordability challenge. For example, at a retail price of $4.00 per gallon, a typical two-vehicle Virginia household spends approximately $3,700 annually on gasoline (compared with approximately $2,700 annually at $3.00 per gallon). For the average household, annual transportation fuel expenditures exceed their average annual residential electric bill (~$2,000/year), making transportation efficiency and fuel choice critical components of the Commonwealth's overall energy affordability agenda.[156]

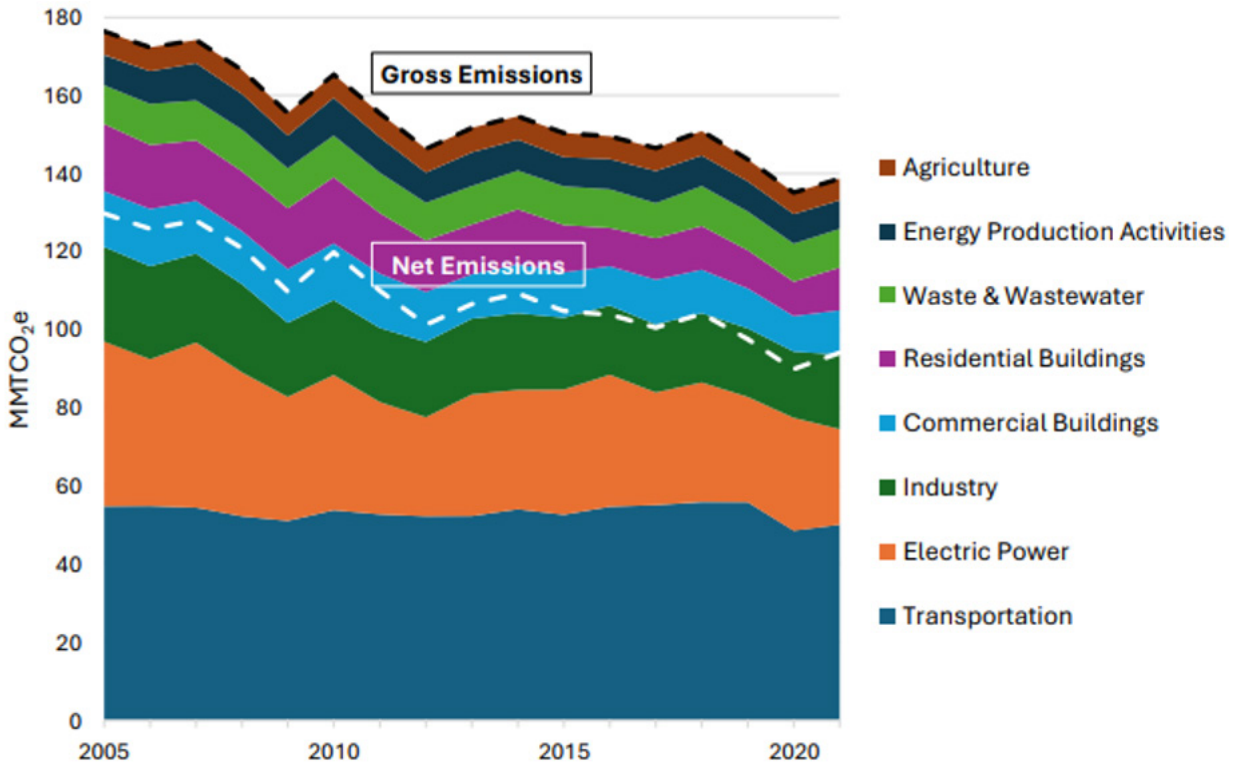
2H. Emissions and Health Implications

Statewide GHG Inventory

Between 2005 and 2021, Virginia's net GHG emissions decreased by approximately 21%**.** Key drivers of this overall decline include structural fuel switching from coal to natural gas in the electric power sector as well as EE improvements across commercial and residential buildings, and industrial modernization. However, progress across individual economic sectors has varied significantly, driven by population growth, urbanization, and changing end-use energy demands.

A brief summary of Virginia's GHG emissions is included here by sector with additional detail to follow, focused specifically on the power and transportation sectors and localized health and environmental justice (EJ) impacts of emissions. A comprehensive, multi-sectoral breakdown of historical emission trends, modeling methodologies, and targeted reduction strategies is detailed in the Virginia DEQ's *2026 Comprehensive Climate Action Plan* (CCAP).[157]

Figure 46. *Virginia 2005-2021 GHG Emissions Trends*



Key trends by sector:

- **Transportation Sector (36% of Total Emissions):** Transportation remains the Commonwealth's largest emitting sector. Vehicle emissions experienced a sharp, temporary contraction in 2020 due to pandemic-related travel reductions but have steadily rebounded toward pre-2020 levels. While vehicle fuel efficiency improvements and expanding EV adoption have helped moderate per-mile emissions, sustained population growth, sprawl, and increased freight demand have driven total VMT upward.
    - **CCAP Priority GHG Reduction Measures:** 1) Reduce GHG emissions from the on-road and off-road transportation sectors through vehicle electrification, EV infrastructure, and zero- and low-carbon fuels and 2) Invest in public and alternative modes of transportation statewide to reduce VMT.[158]
- **Electric Power Sector (17% of Total Emissions):** The power sector achieved the largest emissions reduction of any economic sector, dropping approximately 42% between 2005 and 2021. This decline was driven primarily by the rapid transition from coal-fired generation to natural gas-fired[159] and solar PV generation, alongside utility participation in regional carbon markets.
    - **CCAP Priority GHG Reduction Measures:** 1) Deploy on-site renewable energy generation at residential, commercial, industrial, agricultural, and forestry facilities, 2) Expand large-scale clean power generation to reduce GHG emissions from nonrenewable resources, and 3) Improve electric grid reliability and security.[160]
- **Building Sectors (Residential: 8% | Commercial: 8% | Combined: 16% of Total Emissions):** Emissions from residential and commercial buildings have declined steadily since 2005 (by ~36%), supported by building energy code updates, utility EE programs, and initial space/water heating electrification. However, direct on-site fossil fuel

combustion (natural gas, fuel oil, and propane) for space and water heating remains a persistent baseline source of building emissions.

    - **CCAP Priority GHG Reduction Measures:** 1) Increase residential, commercial, and industrial building EE and implement GHG emission reduction solutions and 2) Reduce GHG emissions from data centers.[161]

- **Industrial Sector (14% of Total Emissions):** Industrial emissions dropped 21% between 2005 and 2021, primarily due to process efficiency gains and fuel-switching from coal/oil to natural gas for direct combustion. While direct combustion and electricity emissions declined, non-combustion industrial process emissions (e.g., substitutes for ozone-depleting substances, cement, and chemical manufacturing) have increased. Continuing to pursue solutions that can help reduce emissions from the industrial sector (e.g., green hydrogen, biogas, electrification of industry, etc.) will be critical.

    - **CCAP Priority GHG Reduction Measures:** Identify and implement strategies to reduce GHG emissions in manufacturing and industrial processes, materials, and products.[162]

- **Agriculture, Waste, and Energy Production Activities (Smallest Emitting Sectors):** These three sectors collectively represent the smallest emitting categories in Virginia's inventory—Agriculture (4%), Energy Production Activities (5%), and Waste & Wastewater (7%). Each has achieved minor net reductions since 2005 through landfill gas capture, agricultural soil management, and the gradual phase-out of active fossil fuel extraction.

    - **CCAP Priority GHG Reduction Measures:**

        - **Agriculture:** Incentivize and implement climate-smart agricultural practices, including investing in existing Virginia Agricultural Cost Share practices with GHG reduction benefits.[163]

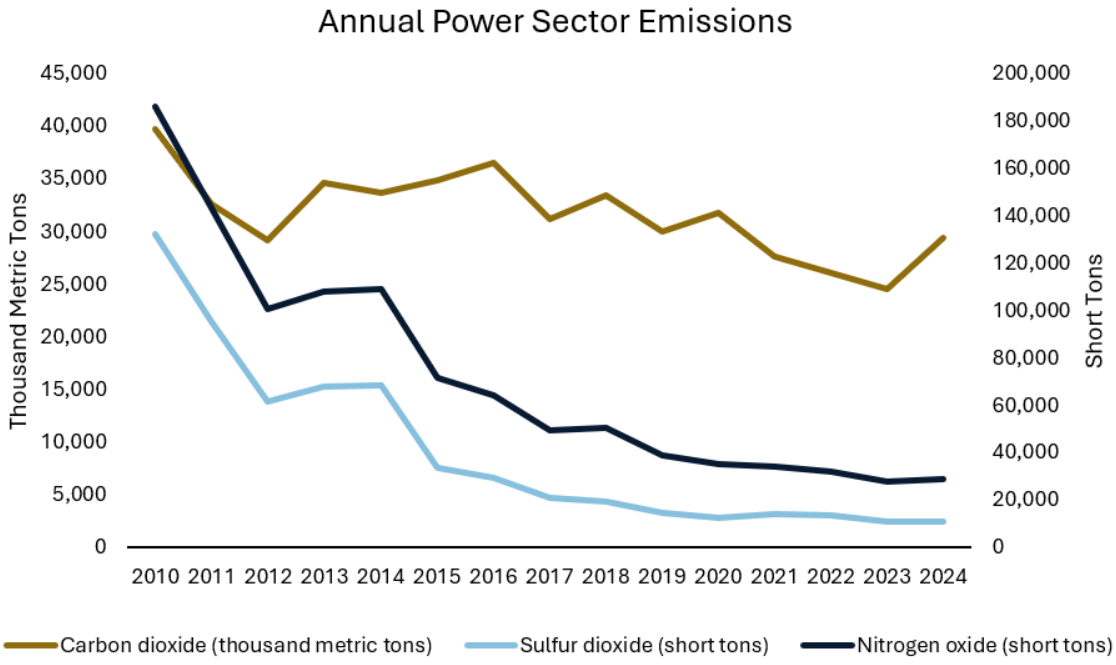
        - **Waste:** Identify and implement strategies to reduce high-potency GHG emissions from waste and wastewater treatment.[164]

        - **Energy Production:** Identify and implement strategies to reduce high-potency GHG emissions from fossil fuel energy production.[165]

Power Sector Emissions

Annual power-sector carbon dioxide (CO_2) emissions have decreased by approximately 42% between 2005 and 2021. Virginia's power sector emissions decreased from 2020 to 2023, but increased in 2024, with the removal of Virginia from RGGI and increased power sector end-use consumption. Power sector CO_2 emissions intensity has decreased by 54.4% since 2000. This is largely attributed to the conversion of Virginia's power fleet from coal-based resources to natural gas-fired units as well as to retirements of coal and heavy oil plants.[166] Today, the majority of power sector emissions are associated with natural gas-fired generation and midstream infrastructure.

Figure 47. *Virginia's annual power sector emissions (2010–2024)*[167]



Concurrently, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) declined significantly due to three main factors: widespread fuel switching from coal to natural gas, environmental compliance under federal Mercury and Air Toxics Standards (MATS), and the retirement of legacy coal and heavy fuel oil plants.

Despite these historical gains, continued reliance on and the proposed expansion of fossil natural gas presents critical climate, environmental, public health, and regulatory risks that conflict with the Commonwealth's statutory clean energy targets under the VCEA.

Expanded natural gas-fired generation capacity inherently increases long-term dependence on upstream extraction and transmission systems associated with methane emissions, land disturbance, forest fragmentation, and additional environmental impacts. Scientific literature further suggests that continued expansion of long-lived natural gas infrastructure may create "carbon lock-in" risks that complicate long-term decarbonization objectives. Combined-cycle power plants, combustion turbines, and associated pipeline systems are generally designed to operate for a minimum of 30 to 40 years. Significant expansion of these assets during the 2020s and 2030s could result in continued fossil fuel dependence extending well beyond the VCEA's targeted carbon-free electricity timelines.

The climate profile of natural gas-fired generation extends beyond power plant combustion emissions alone. Methane, the primary component of natural gas, is a highly potent, short-lived climate pollutant with a global warming potential 81–83 times that of CO_2 over 20 years.[168] Methane leakage occurs throughout the supply chain, including production fields, pipeline compressor stations, transmission pipelines, storage systems, and local distribution infrastructure.

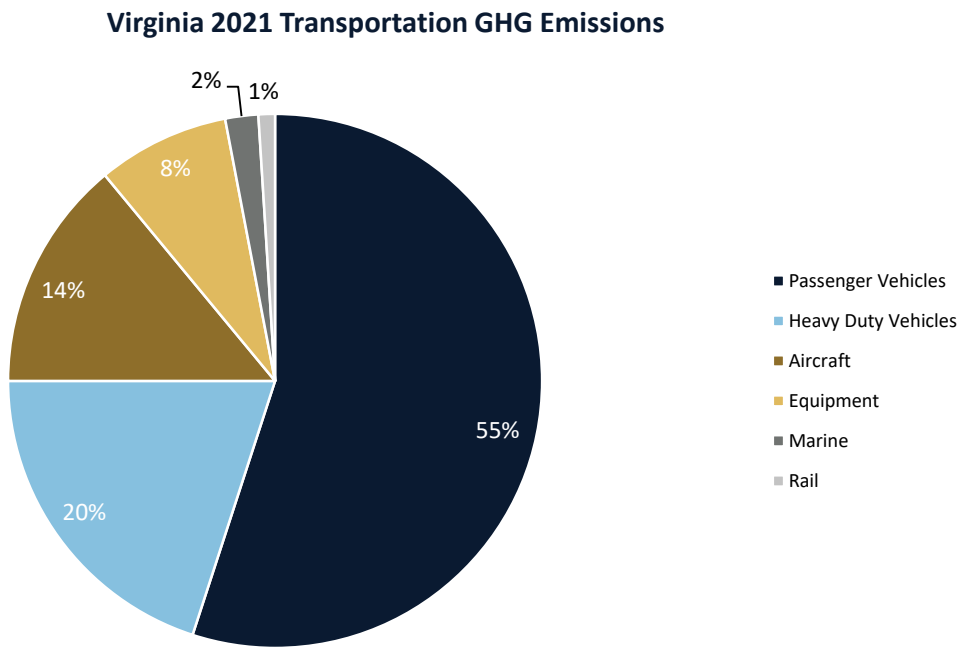
When accounted for, fugitive methane emissions materially inflate the net GHG footprint of natural gas-fired generation.[169] Research indicates that methane leakage rates as low as 2-5% can make natural gas worse from a climate perspective than coal.[170]

The implications of methane leakage are particularly important for Virginia because the Commonwealth increasingly relies on interstate pipeline infrastructure transporting shale gas from the Appalachian Basin.

Transportation Sector Emissions

Transportation is the Commonwealth's largest source of GHG emissions, accounting for 36% of total emissions in 2021. While personal passenger vehicles comprise the majority of the sector's total footprint, heavy-duty freight imposes a disproportionate environmental and public health burden.

Figure 48. *Virginia Transportation GHG Emissions.*[171]



Transportation emissions are broken out into different categories including particulate matter ($PM_{2.5}$), nitrogen oxide (NO_x), and GHGs. Despite representing only 8% of the 7.6 million vehicles registered in Virginia, heavy-duty trucks and buses are responsible for a disproportionate share of emissions, representing 30% of NO_x, 43% of $PM_{2.5}$, and 20% of GHG emissions. This disproportionate impact reflects how these vehicles operate: with frequent stops, low speeds, and heavy loads forcing diesel engines to work harder at reduced efficiency.[172]

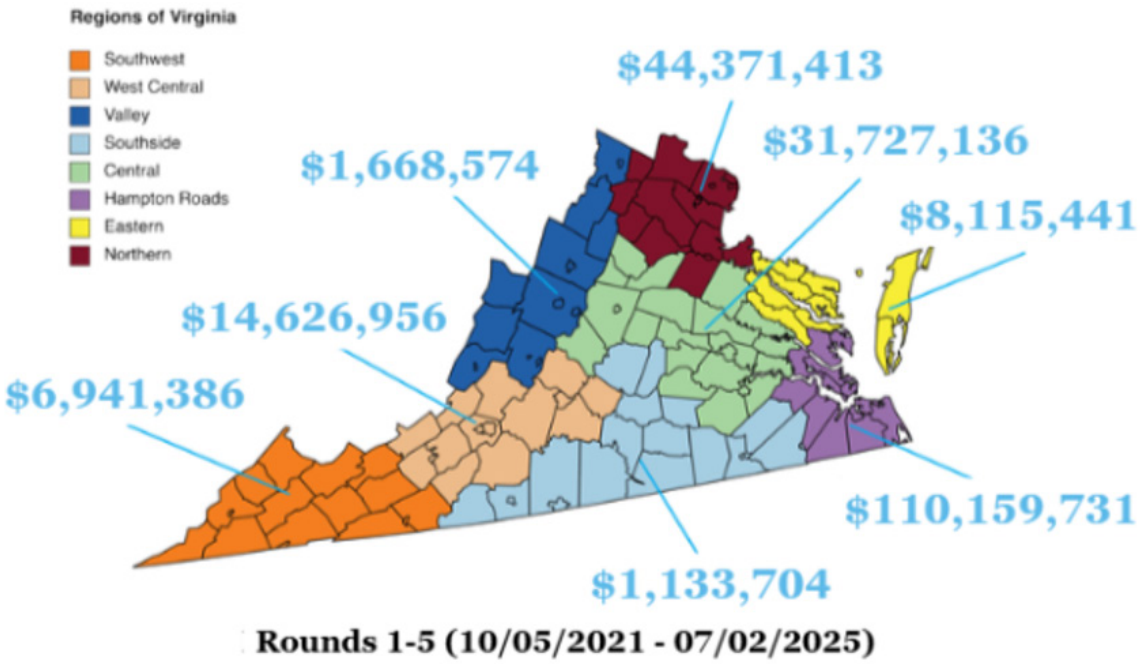
RGGI Overview

As a result of legislation passed during the 2020 General Assembly, Virginia started participating in RGGI in 2021. During Virginia's three years of participation (2021–2023), in-state carbon emissions dropped by 22%[173] and the Commonwealth collected $827.7 million from generators for 68 million short tons of CO_2 allowances. When Virginia was pulled out of RGGI, emissions and costs increased.

Of these funds, $413.9 million supported low-income EE programs and $372.5 million supported the Community Flood Preparedness Fund (CFPF); 5% was used for administrative purposes, in line with the statutory percentages.[174] This revenue provided measurable benefits to Virginians. An analysis of RGGI proceeds found that every $1 invested in EE programs brings a lifetime bill savings return of about $4.[175] For flood mitigation, every $1 invested saves about $6 down the road.[176]

See Section 2F: Energy Efficiency for additional charts on RGGI-funded energy efficiency and low-income housing projects across Virginia.

Figure 49. *Distribution of RGGI funding for CFPF Projects (2021-2025)*[177]



When Dominion's Rider RGGI was removed in June 2024 following Virginia's exit from RGGI, it was $4.43/month. Following Virginia rejoining RGGI in 2026, Dominion has filed to reinstate the rider at an estimated $10 to $13/month beginning March 2027, reflecting higher allowance prices and the scarcity of allowances required.[178] The 2026 Virginia State Biennial Budget directs 45% of RGGI revenues to be returned as a bill credit to residential customers, small businesses, and churches, estimated to fully offset and possibly reduce monthly bills. For Dominion customers, these customer classes were assigned 41% of the costs related to RGGI compliance, meaning that these customer classes should expect a net credit on their bill related to Rider RGGI.

The remaining 55% of RGGI revenues will be allocated to Virginia's existing RGGI-related programs. This is expected to result in $649 million in RGGI revenue allocated from Dominion's participation alone by February 2028, in line with previous levels of funding and well above initial expected values of funding when Virginia first started participating in RGGI in 2021.

Health and Environmental Justice Impacts

Air pollution and environmental degradation are not experienced equally across the Commonwealth. EJ communities bear a disproportionate share of cumulative environmental burdens, as stationary fossil-fuel power plants, major interstate freight corridors, industrial facilities, and logistics hubs are frequently concentrated within or adjacent to lower-income and minority census tracts. Addressing the public health and EJ implications of energy generation, transportation, and industrial activities is central to Virginia's clean energy transition.

Health Burdens of Power Generation

While the retirement of coal facilities has substantially reduced statewide sulfur dioxide and mercury emissions, natural gas-fired electricity generation continues to emit significant volumes of pollutants that are adverse to human health.

NO_x emissions from combustion turbines and combined-cycle facilities contribute to the formation of ozone and secondary $PM_{2.5}$ pollution. Secondary $PM_{2.5}$ pollution occurs when particulate matter forms in the atmosphere through chemical reactions of gases, rather than being directly emitted. Extensive peer-reviewed research has linked $PM_{2.5}$ exposure to asthma, chronic respiratory disease, cardiovascular illness, stroke, lung cancer, and premature mortality. Research has found that emissions from electricity generation contribute to unequal $PM_{2.5}$ exposure patterns affecting minority and lower-income populations at higher rates.[179] Moreover, additional research indicates that emissions from the oil and natural gas supply chain contribute significantly to premature mortality and respiratory disease burdens in the United States.[180]

These findings are particularly relevant as Virginia's IOUs continue to propose fossil fuel resources to meet electric demand growth associated with data centers and electrification. Proposed expansion of combustion turbine (CT) facilities in EJ communities will increase localized NO_x emissions during peak demand periods, worsening ozone formation during high-temperature summer conditions when air quality impacts are most severe.

As data center capacity expands, the thousands of permitted diesel backup generators—particularly in Northern Virginia—represent a growing, localized air quality challenge. While intended for emergency use, the simultaneous operation of these units during peak grid stress events or local outages creates sharp, concentrated spikes in emissions, worsening localized air quality and ozone formation during high-temperature periods.

Health Burdens of Transportation

Transportation is Virginia's largest source of GHG emissions and a significant source of pollutants that affect human health, including fine particulate matter ($PM_{2.5}$), nitrogen oxides (NO_x), volatile organic compounds, and pollutants that contribute to ground-level ozone. $PM_{2.5}$ includes very small particles emitted directly by engines, brakes, and tires or formed in the atmosphere from other emissions. Short- and long-term exposure to transportation-related pollution is associated with asthma, respiratory and cardiovascular disease, adverse birth outcomes, hospitalizations, and premature death.[181]

Exposure is greatest near heavily traveled roads, freight corridors, ports, industrial areas, and logistics hubs. On-road diesel vehicles contribute to particulate-matter pollution throughout Virginia, with concentrations along major corridors such as I-81, I-95, I-64, and freight routes in Hampton Roads. DEQ's EJScreen+ indicates that many communities near these transportation corridors also experience economic or environmental disadvantages. National research similarly finds that low-income populations and communities of color are more likely to live near major roadways and experience elevated exposure to transportation-related air pollution.[182]

Reducing vehicle emissions can therefore produce substantial health benefits, particularly in highly exposed communities. Although Virginia's CCAP does not assign a monetary value to the Commonwealth's transportation-related health damages, an analysis of Virginia's Advanced Clean Cars II standards estimated that the modeled transition to cleaner vehicles could avoid approximately 115 premature deaths, 1,780 asthma attacks, and 8,190 lost workdays annually by 2050, representing more than $1.3 billion in avoided annual health costs.[183] These estimates are scenario-specific rather than a comprehensive valuation of current health damages, but they illustrate the potential scale of the public-health benefits associated with reducing transportation emissions.

2I. Economic Opportunity and Energy Security

Energy Workforce

Virginia's energy workforce functions as an interconnected ecosystem rather than a single industry, supporting roughly 196,015 energy-related jobs across Virginia in 2024, nearly 5% of the Commonwealth's workforce.[184] Energy employment extends beyond utilities and generation, with construction accounting for the largest share (around 66,425 jobs, or 34%), followed by professional and business services (20%), manufacturing (11%), and other sectors, including trade, transportation, and mining. Management and supply-chain roles constitute the largest occupational cluster at 39%, followed by construction and energy-efficiency jobs at 24%. This highlights that workforce planning should consider both energy-specific trades and wider logistics, administrative, and technical roles critical to the energy industry.

Geographically, energy employment is concentrated in Virginia's largest labor markets delineated approximately by GO Virginia regions: Northern Virginia (GO VA Region 7) alone accounts for 31% of statewide energy jobs, with Richmond, Hampton Roads, and the Roanoke–New River Valley areas (Regions 4, 5, and 2) also serving as major centers. Meanwhile, Southwest Virginia (Region 1) has a disproportionately high concentration of energy employment, with nearly 1 in every 8 workers employed in the sector (**Table 14**). Currently, workforce pressures are concentrated on a core set of technical, skilled-trades, and digital occupations, including electricians, heating, ventilation, and air-conditioning (HVAC) technicians, line workers, and selected information technology roles. Stakeholders largely described workforce constraints as a lack of alignment among training capacity, employer engagement, and regional access.

Table 14. *Energy Employment by GO Virginia Region, 2024*[185]

GO VA Region	Energy Jobs	Percent of Total Energy Jobs in VA	Total Jobs (all sectors)	Percent Energy of Total Jobs
1	14,628	7.5%	123,405	11.9%
2	27,694	14.1%	328,995	8.4%
3	5,612	2.9%	135,549	4.1%
4	30,625	15.6%	807,296	3.8%
5	29,162	14.9%	755,828	3.9%
6	7,046	3.6%	166,151	4.2%
7	60,893	31.1%	1,302,900	4.7%
8	9,147	4.7%	234,297	3.9%
9	11,087	5.7%	178,886	6.2%
TOTAL	**196,015**	**100%**	**4,033,307**	**4.9%**

Energy Driven Economic Development

Economic Development Considerations

Virginia has been a reliable environment and partner for economic development for decades. The Commonwealth succeeds when industry has confidence that its needs can be met in areas including but not limited to workforce,

housing, site readiness, infrastructure and energy availability, reliability, and affordability. The increased pressures on Virginia's energy supply—and across the region—from rapidly increasing energy demand have extended timelines for interconnection broadly and driven upward pressure on prices. As discussed in Section 2G: Energy Affordability, Virginia's commercial electricity rates are highly competitive across the region—even after accounting for recent price increases since 2024 after a decade of declining inflation-adjusted prices. As Virginia continues to invest in expanding energy supply and enhancing efficiency, economic growth will follow.

While any one of the aforementioned factors companies consider when making siting decisions can cause one state to win a project over another, energy should not be the reason Virginia loses projects or its standing as a national business leader. Energy has risen to the top of the priority list for the business community when considering new siting decisions, and Virginia must position itself to be energy ready to ensure economic competitiveness.

A key theme resulting from the VEP stakeholder engagement process from economic development partners is the importance of not just energy availability, in the form of more molecules and electrons, but long-term coordinated planning. This will ensure that the energy needs of all Virginians are met for the years ahead and that the investments made in Virginia today can be served for generations to come with the opportunity to expand and grow. Virginia's energy and economic development planning efforts must be aligned and complementary to provide a comprehensive approach to both economic development and energy infrastructure planning.

An additional theme that emerged from the stakeholder process is that energy demands must be met, but not at the expense of environmental stewardship or quality of life. Virginia has struck a balance in these areas by advancing thoughtful and considerate economic development goals alongside protective climate and environmental laws. As this Plan demonstrates, Virginia can and will continue to strike that balance even as it works to meet emergent demand pressures.

A final theme that arose is the desire for the Commonwealth to support and implement policies that provide businesses and communities with greater transparency and predictability regarding infrastructure availability, planning, and project implementation. The phrase "economic development is a team sport" is often repeated in industry gatherings, and it is also applicable to energy development. It is imperative that state agencies, utilities, regional organizations, and local organizations are coordinated in understanding and making the energy investments needed for the Commonwealth to succeed.

Energy Supply Chains

Virginia has positioned itself to be a highly competitive place for economic development broadly, including within the energy supply chain. The Commonwealth is home to manufacturers of key energy components including but not limited to semiconductors, solar components, offshore wind power transmission cables, transformers, substations, and other products to support the digital infrastructure supply chain, grid connectivity, and power transmission infrastructure.

Additionally, Virginia is home to a robust nuclear and nuclear support industry with manufacturers of nuclear fuel, reactor components, equipment and more. As energy and supply chain security become ever-present and increasing priorities, it is critical that Virginia continues to be known as a great place to do business for energy supply chain opportunities across energy technologies.

Virginia continues its strong climate for entrepreneurs with energy-focused business incubators that are supporting a diverse set of early-stage companies developing innovative energy technologies. Examples include technology developers that are supporting critical infrastructure security, circular supply chain opportunity identification, and more.

Virginia has a rich mining history and remains an important source of high-quality metallurgical coal within the domestic and global steelmaking supply chain. Most coal produced in the Commonwealth is metallurgical grade, valued for its high carbon content and relatively low impurities, and used primarily in the production of coke for steelmaking. With blast-furnace steel production continuing to depend on metallurgical coal and coke, particularly in international markets, Virginia's metallurgical coal remains a strategically important component of the steelmaking supply chain, which in turn is critical for a broad spectrum of energy infrastructure components.

Virginia is also home to the largest mineral separation plant of its kind in North America and has a growing critical minerals and rare earth elements processing industry. Key industrial entities have partnered with Virginia's higher education institutions to develop innovative technologies. Those same universities are national leaders in responsible mineral mining, extraction, and processing workforce development efforts, which is critical to continued success and growth of the industry. The diversity of Virginia's energy supply chain presents the opportunity to continue an emphasis on achieving economic development goals while expanding the energy product manufacturing industry.

Energy Readiness for Economic Development Sites

The Commonwealth has robust real estate development opportunities through current programs such as investment through GO Virginia, the Virginia Business Ready Sites Program (VBRSP), Abandoned Mine Land Economic Revitalization (AMLER) Program, Virginia Brownfields Restoration and Economic Redevelopment Assistance Fund (VBAF), and others to support site development and revitalization. Additionally, the Virginia Economic Development Partnership (VEDP) has a database that contains over 1,800 sites available for economic development prospects. These properties vary in size and readiness for development. Some of these sites are featured as part of VEDP's VBRSP, which ranks properties on a tiered scale of 1 (lowest level of readiness) to 5 (considered "shovel ready"). As of September 2026, 378 sites are ranked, with 48 ranking in tiers 4-5, 27 in tier 3, and 303 in tier 2 or below. This data exhibits that while Virginia has a robust number of sites with economic development potential, achieving complete site and energy readiness to reach "shovel ready" status requires additional investment and preparation.

Site readiness is needed for the Commonwealth to remain competitive for future economic development projects. With growing energy demands, these current site readiness programs need a comprehensive energy approach to ensure energy generation projects exist to power future projects in a timely manner. This will require a proactive approach to the necessary long-term energy infrastructure mapping and investments for holistic site readiness. While there are many factors that contribute to the site selection process, Virginia should never lose a project due to a lack of adequate energy infrastructure or lack of certainty by a company that its energy needs can be met.

Efforts to support energy generation on key economic development sites that cannot be met by the utility at peak demand times will be critical to support future economic growth in the Commonwealth. Considerations for energy storage systems that could be pre-designed for a project site's peak capacity needs while a prospect is identified could help demonstrate that Virginia is meeting the moment for energy needs. Virginia should be leading the nation in setting the highest standards for industrial development and driving innovation across all sectors. The Virginia Clean Energy Innovation Bank (VCEIB) offers financial products that can be leveraged to deploy clean and innovative energy solutions to meet needs of companies seeking to locate or expand in Virginia.

There is further opportunity to ensure resources are maximized by prioritizing brownfield site clean-up as another mechanism to support site readiness. VEDP's database of 1,800+ economic development prospect sites currently includes 17 sites classified as brownfields. However, this is not a comprehensive list; many of the properties in the database have a history of development and likely meet the statutory definition of brownfield. This approach can be especially impactful in Southwest Virginia due to the concentrated presence of former mine land. This region can actively incorporate mined land repurposing efforts that support economic development site readiness goals, prime the area for business attraction, and lead to increased tax revenue and job creation.

Leadership in advanced nuclear and fusion

Nuclear energy remains important to a reliable, affordable, and carbon-free electric system in Virginia. The Commonwealth's current fleet provides continuous generation that supports fuel diversity and grid reliability, and its contribution is material to progress toward the VCEA objective for carbon-free electricity by mid-century.[186] At the same time, Virginia's strategic approach has been expanded to include support for advanced reactors, SMRs, fusion energy, supply chain development, manufacturing, workforce training, and commercialization.

Virginia enters this planning period with a strong nuclear foundation and a clear statutory framework for continued leadership in nuclear energy and nuclear innovation.[187] The Commonwealth's existing nuclear fleet provides more than 95 percent of Virginia's carbon-free electricity, and state policy recognizes nuclear energy as a clean energy source while directing long-term planning for its continued role in the Commonwealth's energy future.[188] The Virginia Nuclear Energy Consortium Authority (VNECA) was established in 2013 for the purposes of making the Commonwealth a national and global leader in nuclear energy. VNECA's 2025 strategic plan is intended to leverage nuclear energy's economic, technical, and environmental strengths to address grid reliability, clean energy goals, economic expansion, and national priorities in defense, research, and medical innovation.[189]

The Commonwealth also has policy tools that support new nuclear development. Section 45.2-1734 of the Code of Virginia authorizes the Virginia Power Innovation Fund and Program (VPIP) for research and development (R&D) of innovative energy technologies, including nuclear, and budget language establishing the fund included support for Virginia Nuclear Innovation Hub, SMR research at institutions of higher education, nuclear workforce development, and site selection assistance for future SMR projects. VPIP's initial appropriation has been fully allocated to nuclear and other innovative projects, but it remains a viable vehicle for continued efforts to advance technologies and supply chains.

Consistent with these authorities, Virginia can support predevelopment activities for potential reactor projects through site readiness, technical review and improved coordination among state agencies, utilities, localities, and federal partners. The Commonwealth already has identifiable opportunities at existing and emerging locations. The Nuclear Regulatory Commission (NRC) states that the proposed North Anna Unit 3 site is within the existing North Anna site boundary and the NRC is also engaged in pre-application activities with APCo regarding a future early site permit for an SMR at the Joshua Falls property in Campbell County.

Virginia's nuclear innovation strategy also includes fusion energy. Commonwealth Fusion Systems (CFS) announced that it will locate its planned grid-scale ARC Fusion power plant in Chesterfield County at the James River Industrial Center on a Dominion Energy site and the company has stated that the project is intended to provide approximately 400 MW of firm, carbon-free electricity by the early 2030s.[190] In April 2026, CFS announced that it had become the first fusion company to apply to PJM, moving the Virginia project further into the grid connection process for a commercial generating facility.[191] In hosting the world's first fusion power plant, Virginia stands at the forefront of the fusion energy industry.

Defense-related nuclear capabilities are also part of Virginia's broader strategic advantage. The Commonwealth's nuclear planning documents describe defense applications and national security as integral to Virginia's nuclear mission, and the 2025 to 2029 strategic plan highlights the role of Virginia companies in sustaining the existing fleet and supporting developments in defense propulsion and related technologies.[192] These connections, together with the Commonwealth's commercial fleet, innovation activity, research base, and federal relationships, support a diversified nuclear portfolio that spans power generation, advanced technology development, and national security.

Energy Security and Resilience

Secure, reliable energy infrastructure that delivers safe and affordable energy is vital to the Commonwealth's strong economic growth, public health, and quality of life, as well as the readiness of community lifelines and critical defense missions that depend on the grid and petroleum products.[193] The Commonwealth's *Energy Security Plan* is the organizing framework for this work, providing statewide guidance on how Virginia assesses its energy risk profile, prepares for and mitigates disruptions, and coordinates with partner agencies, utilities, federal partners, local governments, and tribal nations.[194] Mounting severe weather threats, evolving physical and cyber threats, rapidly growing demand from data centers, industrial facilities, and defense-related operations, and aging bulk power and transmission infrastructure heighten the urgency of keeping this plan current and actionable, and aligning it with programs that harden the grid and build community-scale resilience.

Resilience needs differ by place. From VEP stakeholder input, communities in Southwest highlighted long circuits, mountainous terrain, and prolonged storm outages; Hampton Roads communities emphasized flooding, fuel availability, ports, military installations, and coastal grid constraints; Northern Virginia residents emphasized cyber risks and continuity for concentrated critical loads; and Tribal representatives emphasized backup power, microgrids, cultural-resource protection, and limited administrative capacity.

To operationalize the Commonwealth's *Energy Security Plan*, Virginia is advancing programs that strengthen grid resilience at both the bulk power and community levels. The Virginia Grid Reliability Improvement Program (VGRIP) deploys federal grid-resilience funding to harden vulnerable transmission and distribution infrastructure against disruptive events, modernize equipment, and reduce the frequency and duration of outages that affect homes, businesses, critical facilities, and defense installations.[195] Complementing these grid hardening efforts, the Community-Oriented Resilient Energy (CORE) program supports local governments and community-based organizations in developing energy resilience hubs powered by DERs including solar-plus storage, mobile resilience solutions, and backup generation. Together, these efforts create a pipeline of model projects that can maintain critical services when the grid is stressed.[196]

The VCEIB further accelerates this work by mobilizing public and private capital for clean energy and resilience infrastructure, including battery energy storage projects that serve as community resilience hubs. VCEIB's targeted awards, including $3 million in financing for a 4-MW, 4-hour battery energy storage system deployed by Rappahannock Electric Cooperative in Caroline County, demonstrate how the bank can support storage projects that provide new capacity, strengthen local grid reliability as demand grows, and generate long-term net savings for customers.[197]

Energy disruptions disproportionately affect EJ communities, underscoring the need to target resilience hubs, microgrids, and grid-modernization and hardening investments in ways that advance equity and EJ while improving reliability and resilience for all Virginians.[198]

Energy security and resilience are also critical to powering the digital infrastructure that supports Virginia's expansive military and federal government base as well as hospitals and other critical operations—including data centers serving these sectors. Disruptions to grid reliability, backup fuel supply, or related interdependencies (telecommunications, cooling, cybersecurity) can affect commerce, public services, national security, and emergency response. Continuity planning for these facilities should be coordinated among utilities, fuel suppliers, local governments, and state and federal emergency managers.

Outlook for Virginia's Power Sector

Outlook for Virginia's Power Sector

The Energy Plan provides additional analysis on the long-term outlook for the Commonwealth's power sector through 2050. The analysis examines how electricity demand, generation, resources, fuel use, infrastructure needs, technology development, market conditions, and policy requirements may shape Virginia's future energy system. It evaluates a range of potential pathways and their implications for reliability, affordability, resource development, and broader economic and environmental outcomes. While the analysis includes the fuels used for electricity generation and compares projected power-sector fuel consumption with current levels, it does not provide a comprehensive forecast of total energy or fuel consumption across all sectors of Virginia's economy, including transportation and other non-electric uses.

3A. Power Sector Modeling Overview

Approach

The 2026 Energy Plan's outlook is based on a long-term planning framework that uses established industry modeling methods and tools. The framework integrates electricity demand forecasting, capacity expansion modeling, and broader impact analysis to evaluate resource needs and system outcomes through 2050.

Capacity expansion modeling is a standard resource-planning method used by electric utilities, system operators, regulators, and energy planners. It evaluates combinations of existing and new generation, energy storage, demand-side resources, and electricity imports to identify portfolios that meet projected electricity demand, reliability requirements, and policy constraints at the lowest modeled system cost.

This is the first VEP to incorporate capacity expansion modeling, reflecting the Virginia Department of Energy's investment in developing modeling and forecasting capabilities—making it one of the few state energy offices with these capabilities in-house. The analysis provides a data-informed framework for evaluating alternative energy-system pathways and the tradeoffs among cost, reliability, health impacts, resource development, and policy objectives.

In summary, the analysis has three key components:

- Electricity demand forecasting: estimates future electricity requirements under multiple load-growth scenarios;
- Capacity expansion modeling: identifies the lowest-cost portfolio of generation, storage, demand-side resources, and electricity imports capable of meeting modeled electricity demand, reliability requirements, and applicable policy constraints; and
- Societal and Environmental impact analysis: evaluates the broader implications of each modeled pathway. This includes estimated carbon-related impacts using the social cost of carbon, public-health impacts associated with changes in power-sector air emissions, workforce requirements associated with new energy infrastructure, and land requirements associated with resource development.

Together, these analyses provide a broader view of the potential implications of different power-sector pathways.

Key assumptions & inputs

Modeling incorporates assumptions related to electricity demand, technology costs and performance, fuel, wholesale-market prices, resource development constraints, reliability requirements, and applicable energy policies. Key current policies represented are the VCEA, which requires increasing clean energy procurement by Dominion and APCo, and RGGI-related carbon constraints, which place a declining limit and cost on carbon emissions.[199],[200]

Key inputs and assumptions include:

- **Electricity demand:** Multiple load-growth scenarios are evaluated (as discussed below) to reflect uncertainty regarding the amount of data center development in Virginia. The demand forecasts also incorporate assumed reduction in electricity consumption resulting from EE improvements in line with existing policy requirements.
- **Electricity imports**: Import prices are based on modeled wholesale prices from a PJM-wide capacity expansion analysis, using zones surrounding the DOM Zone as the relevant import markets. Import volumes are limited to reflect transmission constraints.
- **Natural-gas prices**: Gas price assumptions are based primarily on utility planning inputs, supplemented where appropriate by regional market and long-term fuel-price forecasts.
- **Resource costs and performance:** Capital-cost, operating-cost, performance, and commercial-availability assumptions for generation and storage resources are based primarily on National Laboratory of the Rockies (NLR) Annual Technology Baseline (ATB) technology-cost projections, supplemented by utility planning filings, PJM planning information, and other publicly available industry sources where appropriate.
- **Build limits** (maximum capacity of resources allowed to be built in a year): These limits are intended to reflect practical development constraints, including siting and local land-use approvals, PJM Interconnection timelines, transmission availability, supply-chain capability, workforce availability, construction lead times, and financing considerations.
- **Broader impact assumptions:** Modeled portfolios are also evaluated for their potential carbon, health, workforce, and land-use implications. These analyses translate changes in generation, emissions, and resource development into additional indicators that help illustrate impacts beyond direct power-system costs.
- **Selected baseline assumptions:** Additional assumptions include retirement of existing IOUs' fossil generation by 2045; RGGI allowances decline to zero by 2050; treatment of certain VCEA procurement requirements as minimum build requirements for solar, offshore wind, and storage; continued growth in DERs of 10% annually; and inclusion of specified new nuclear and fusion resources where consistent with identified development plans and scenario assumptions. Resource adequacy assumptions are designed to remain consistent with PJM planning requirements and methods, including a 20% planning reserve margin, PJM-based effective load carrying capability (ELCC) values for variable and storage resources, and limits on external energy and firm-capacity purchases.

Interpretating Results and Limitation

The modeling results should be interpreted as scenario-based planning outcomes that illustrate a range of potential system pathways. Results are sensitive to underlying input assumptions, especially related to the cost of fuel and technology.

The current analysis represents Virginia as a single planning area and does not explicitly model the geographic location of new load, generation, or transmission and distribution constraints within the commonwealth. Similarly, the results do

not fully capture regional congestion, localized infrastructure needs or differences in system conditions across Virginia.

More location-specific modeling helps better identify more realistic operations constraints that might impact infrastructure buildout and the investments needed in specific regions. The SCC directed Dominion, in its 2024 IRP proceeding, to include four regional nodes in subsequent modeling—an approach that can better account for regional demand growth, generation location, and transmission constraints.[201] Virginia Energy aims to expand its modeling capabilities to better account for location-specific impacts in future Energy Plan modeling.

Additionally, capacity accreditation inputs for resources reflect current PJM ELCC values—including only ~9% for solar—which directly impact how much new capacity is needed to be built. Any changes to these ELCC values—or broader ongoing PJM market reforms—could adjust these accreditations over time and impact capacity build out requirements. For this modeling analysis, Current PJM rules serve as the modeling baseline.

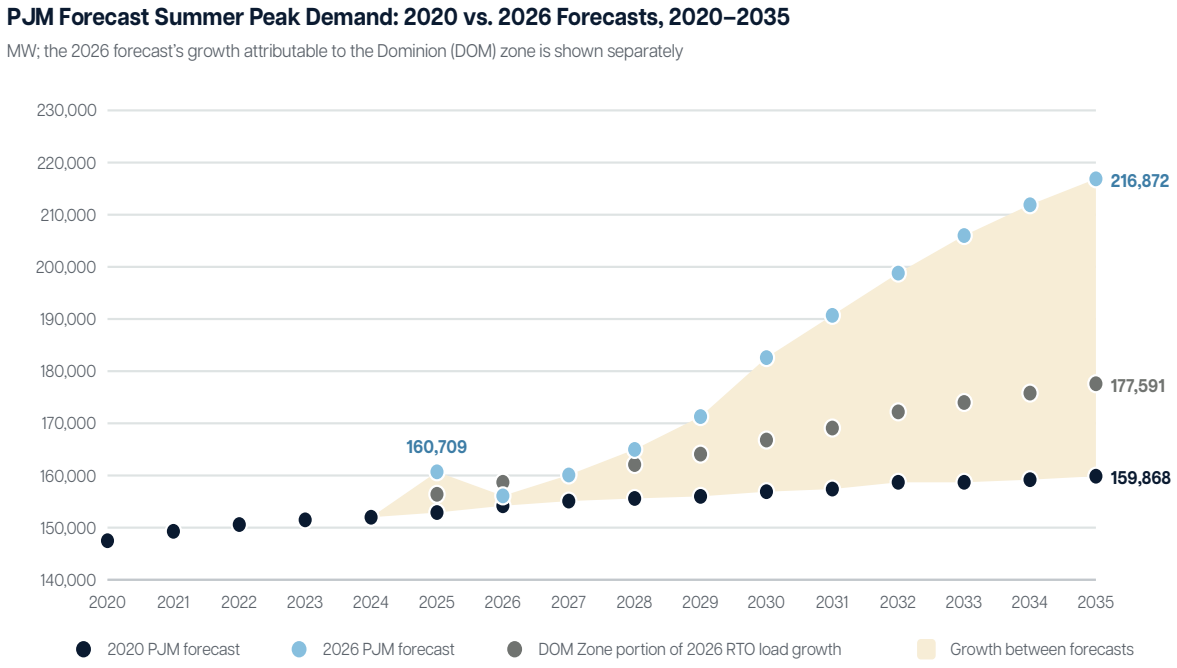
See Appendix: Modeling Assumptions and Inputs for additional information about key assumptions, inputs, and interpreting results.

3B. Load Growth and Policy Scenarios

A New Era of Load Growth

After nearly two decades of relatively flat electricity demand, electricity demand is rising rapidly across the country, driven primarily by data centers, advanced manufacturing, and electrification.[202] PJM's 2026 forecast projects more than 55 GW of peak-demand growth through 2035—driven primarily by data centers—compared with less than 10 GW of growth in its 2020 outlook. Virginia is at the center of this regional trend with the DOM Zone accounting for more than 30% of PJM's projected growth.

Figure 50. *PJM Projected peak-demand growth – 2020 vs 2026 PJM forecasts, with 2026 DOM Zone broken out, 2020–2035*[203]



As this growth is driven primarily by data centers, which operate at high and relatively steady utilization rates, it is changing the shape of system electricity demand and has important implications for resource planning. In both the PJM and Virginia's DOM Zone load forecast, total annual energy consumption (MWh) is growing significantly faster than peak demand (MW). While Virginia's DOM Zone summer and winter peak demand is projected to grow annually at a rate of 5.4% and 5.1% respectively, total electricity consumption is forecast to grow at a rate of 7.2% through 2035. Consequently, this means a system serving more continuous load needs not only resources that can meet short periods of peak demand, but also sufficient energy supply and transmission delivery capacity to serve customers reliably across all hours.

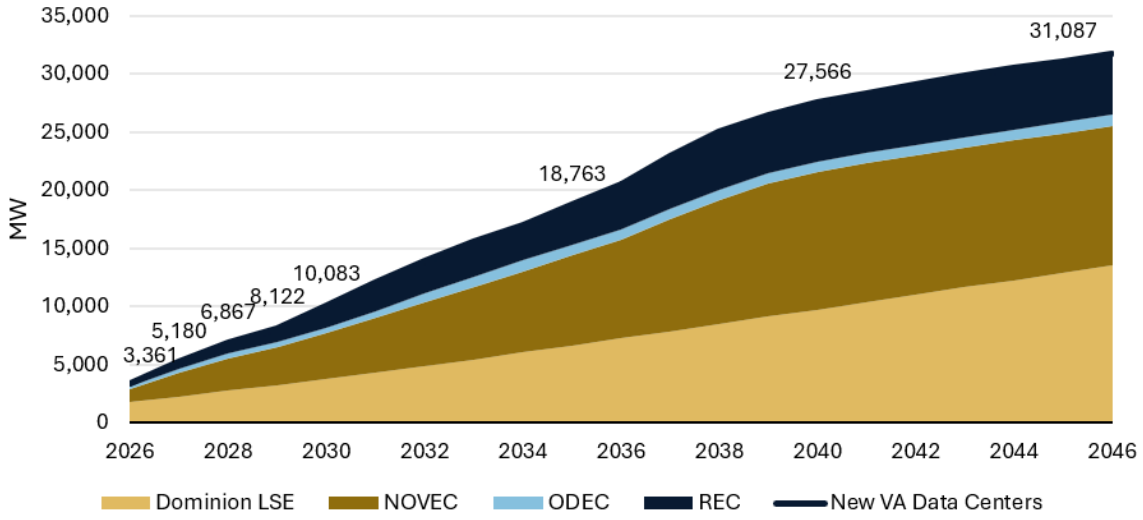
Table 15. *Comparison of 10-year summer and winter peak and annual net energy growth rates, 2026 PJM annual load forecast*[204]

	PJM Forecasts	DOM Zone Forecasts
Summer Peak	3.6%	5.4%
Winter Peak	4.0%	5.1%
Annual Net Energy	5.3%	7.2%

Projected load growth is concentrated in Northern Virginia but is expanding into cooperative service territories and other parts of the Commonwealth. This geographic concentration has important implications for transmission and distribution planning. NOVEC and Rappahannock Electric Cooperative (REC) are projected to experience faster percentage growth in data-center load than Dominion. Because electric cooperatives generally rely more heavily on wholesale-market purchases than IOUs with larger owned-generation portfolios, rapid load growth can increase their exposure to PJM power supply and capacity market purchases unless adequate supply, contracts, and infrastructure are secured.

Growth is also beginning to emerge in Southwest Virginia. After experiencing declining load historically, APCo reported 540 MW of contracted data-center demand in its 2026 rate case and approximately 25,000 MW of potential demand under inquiry or negotiation, noting that this additional growth "will be transformative and has begun to manifest in the Company's prospective rates, providing a measure of relief for current customers."[205] APCo's 2026 RPS filing forecasts annual energy-requirement growth of 1.1% and peak-demand growth of 0.5 percent through 2040.[206]

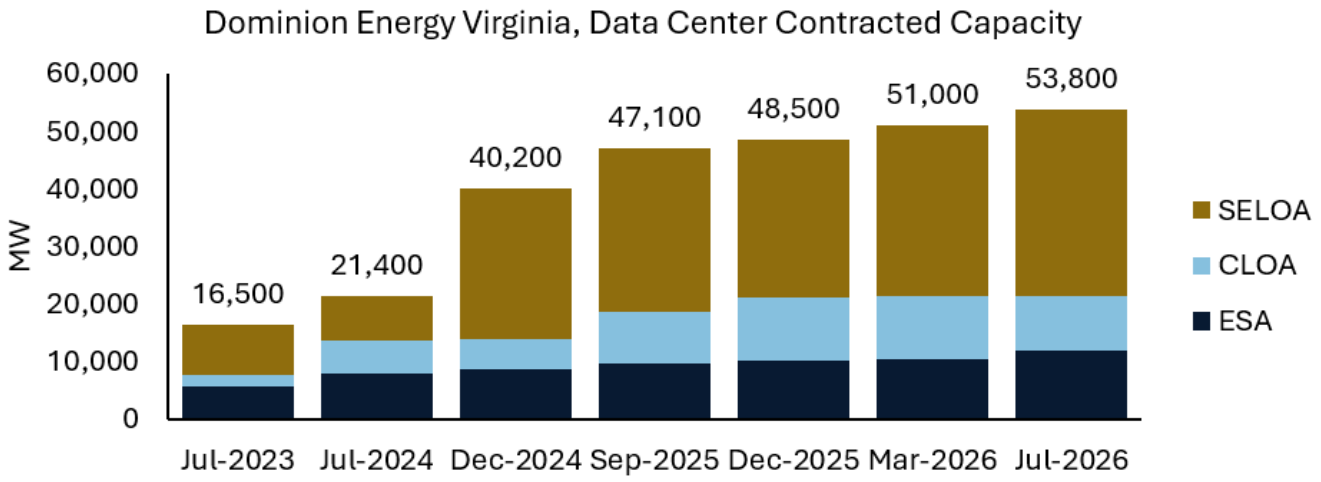
Figure 51. *Virginia New Data Center Load Forecast by Load Serving Entity*[207]



There is significant uncertainty associated with how much currently requested data center demand will ultimately materialize. A large load request for electric service is not necessarily a completed project or an operating load: developers may evaluate multiple sites, revise facility size or construction schedules, or ultimately decide not to proceed. National analysis by Wood Mackenzie estimates that only 28% of requested U.S. data-center load is likely to materialize, and other states have recently seen a drop in data center demand after imposing more robust financial commitments.[208] In September 2025, AEP Ohio established a large-load tariff that required specified financial commitments from prospective data-center customers; following implementation, AEP Ohio reduced its projected 2030 data-center load forecast from approximately 30 GW to 13 GW. [209] This underscores the difference between early-stage inquiries and commercially committed demand.

For example, Dominion Energy's total requested data center contracts have reached 53,800 MW as of July 2026. However, most of this pipeline remains in preliminary utility engineering and study stages, rather than representing customers with final commitments to take electric service. Only 22% was supported by a binding electric-service agreement (ESA), under which the customer commits to take service and meet minimum payment obligations. Another 18% was supported by an active construction letter of authorization (CLOA), under which the utility may begin to do some engineering and infrastructure work, but the project retains greater uncertainty. The remaining 60% was in preliminary engineering or earlier stages (under substation engineering letter of authorization, or SELOA) and therefore carries substantially greater uncertainty about whether, when, and at what scale the requested load will materialize.

Figure 52. *Comparison of Dominion Contracted Data Center Capacity Over Time*



As of September 2026, Virginia is strengthening its approach to large-load forecasting, interconnection, and collateral requirements. Virginia's ongoing reforms include:

- Dominion Energy Virginia's Schedule GS-5 large-load class, effective January 1, 2027, which establishes contract, minimum-demand, and collateral requirements for qualifying customers;[210]
- HB 892 (2026), directing the SCC to investigate large-load forecasting methods, including potential duplication across forecasts and steps utilities take to minimize forecast risk;[211] and
- An SCC proceeding concerning large-load interconnection-queue management, including potential changes to study processes, site-control requirements, financial security, and transparency.[212]

These changes are underway and their ultimate effect on future forecasts is not yet known, but stronger financial commitments, improved queue management, and more rigorous forecast review can help distinguish credible projects from preliminary requests and reduce risks to existing customers. VEP modeling outlooks will therefore be updated as projects advance and as utilities, regulators, and data centers provide more reliable evidence of need.

Power sector resource planning must manage both underbuilding and overbuilding risk. Underbuilding generation, transmission, and distribution infrastructure can constrain economic growth, delay electrification, increase congestion, and make it difficult to achieve Virginia's clean energy and net-zero goals. Conversely, overbuilding infrastructure for speculative demand can raise costs for households and small businesses if that expected load does not materialize to pay for those costs. The planning challenge is to build the flexible, no-regrets resources and infrastructure needed to support economic growth and net zero goals, while phasing larger commitments as demand becomes more certain and ensuring that data center customers contribute appropriately to the costs and risks of the system expansion they require. These uncertainties are reflected in the alternative load scenarios evaluated in the following section.

Electricity Demand Growth Scenarios

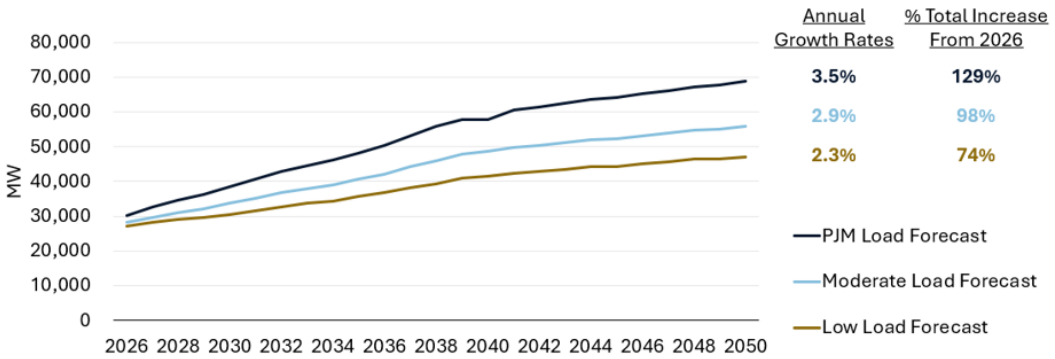
To reflect the uncertainty in demand growth due to unknown data center demands, the Energy Plan evaluates three demand scenarios based on different levels of data center load realization:

- **High PJM Forecast:** All forecasted data-center demand in PJM's outlook materializes, including projects at both early and more advanced stages of utility review.
- **Moderate Forecast**: Includes customers with binding service commitments—executed electric service agreements (ESAs)—and approximately 70% of projects authorized to proceed with early utility planning and construction. It excludes any data centers with only preliminary engineering requests.
- **Low Forecast:** Includes only customers with binding commitments to take on electric service and fund required infrastructure to serve their load.

The Moderate Load Scenario is considered as the VEP's central planning case, while the high and low cases show the range of resource needs if more or less proposed data center demand materializes.

The PJM Load Forecast combines PJM's forecast for the DOM with APCo's Virginia load forecast.[213] Under the high, moderate, and low scenarios, Virginia's coincident peak demand reaches approximately 68,850 MW, 55,823 MW, and 47,138 MW, respectively, by 2050. The scenarios are not predictions; they provide a range for evaluating resource, transmission, and cost implications under different levels of demand realization.

Figure 53. *Virginia Coincident Peak-Demand Outlook Under Three Load Scenarios used in Energy Plan Modeling (MW, 2025–2050)*



All three load growth scenarios use a common outlook for residential, non-data center commercial, and other industrial load based, including EE improvements and EV-related adoption modeled. EE improvements reduce the electricity demand the model must serve before it selects new generation, storage, or transmission resources; the model assumes achievement of statutory baselines to reduce demand by 9% by 2050 relative to 2019 utility retail sales. These reductions lower both annual electricity consumption and peak demand.

Policy Scenarios

The Energy Plan modeling considers three primary policy cases and two other alternative scenarios. These policy cases show how Virginia's resource needs, costs, emissions, and infrastructure requirements change under various policies and targeted adjustments designed to improve affordability, flexibility, and reliability. The two alternative scenario cases test additional key tradeoffs. The policy cases and sensitivities are:

- **No Policy Goals:** Removes VCEA and RGGI requirements. This case provides a reference point for evaluating system cost, emissions, health impacts, and infrastructure needs in the absence of Virginia's current clean energy policy requirements.
- **Current Policies (as of October 2026):** Reflects compliance with current Virginia law. This case serves as the baseline for assessing whether Virginia's existing policy framework can meet growing demand while maintaining reliability and achieving statutory clean energy and net zero goals.
- **Distributed Flexibility Scenario:** Builds on current law with a 10 GW DER target, 10% data-center demand flexibility, and up to 5 GW of non-combustion gas resources. This tests whether more distributed, flexible resources can reduce system costs, congestion, and local air-pollution impacts while maintaining reliability.
- **Distributed Flexibility Scenario with Moderate Solar/In-State Priority:** Applies the Distributed Flexibility policies while limiting annual solar deployment and out-of-state capacity purchases. This alternative scenario evaluates the cost and resource tradeoffs of placing greater emphasis on in-state supply while reducing the pace of solar development.
- **Distributed Flexibility Scenario with No New Gas (NNG):** Applies the Distributed Flexibility policies but does not allow new Virginia natural gas generation of any type—neither combustion nor non-combustion. This alternative scenario evaluates the cost, reliability, emissions, and infrastructure implications of meeting future electricity demand without new gas-fired generation.

Figure 54. *2026 VEP Policy Key Adjustments across Scenarios*

Scenario	Key Assumptions					
	DER adoption	Demand flexibility	Non-combustion gas	Solar build limit	New VA gas	Capacity import cap
No Policy	10% annual growth	–	–	1,800 MW/year	Allowed	20 GW by 2035
Current Policies (as of October 2026)	10% annual growth	–	–	1,800 MW/year	Allowed	20 GW by 2035
Distributed Flexibility Scenario	5 GW by 2040; 10 GW by 2045	10%	Up to 5 GW by 2035	1,800 MW/year	Allowed	20 GW by 2035
Distributed Flexibility with Moderate Solar & In-State Priority	5 GW by 2040; 10 GW by 2045	10%	Up to 5 GW by 2035	1,200 MW/year	Allowed	10 GW by 2035
Distributed Flexibility with No New Gas	5 GW by 2040; 10 GW by 2045	10%	–	1,800 MW/year	Not allowed	20 GW by 2035

See Appendix: Modeling Assumptions and Inputs for additional detail on inputs, assumptions, and how to interpret results.

3C. Capacity Expansion Modeling Results

The capacity expansion analysis identifies multiple resource pathways capable of meeting Virginia's projected electricity demand while satisfying modeled reliability requirements and maintaining a path to net-zero by 2050. Across the scenarios, rapid load growth requires substantial additions of new generation, energy storage, demand-side resources, and supporting grid infrastructure. Virginia also continues to rely on regional energy and capacity markets, making transmission capability, PJM market conditions, and resource development elsewhere in the region important components of the Commonwealth's long-term outlook. Across the scenarios depending on the direction the Commonwealth takes will also impact workforce needs and energy supply chain pipeline.

The results also highlight the value of system flexibility. Expanding demand flexibility and DERs can reduce peak demand, infrastructure needs, and modeled system costs. Limited deployment of shorter-lived non-combustion gas resources may provide additional near-term capacity while reducing local air-pollution and health impacts and avoiding the long-lived infrastructure impacts associated with large, centralized gas generation. The following results compare the modeled pathways and their principal tradeoffs.

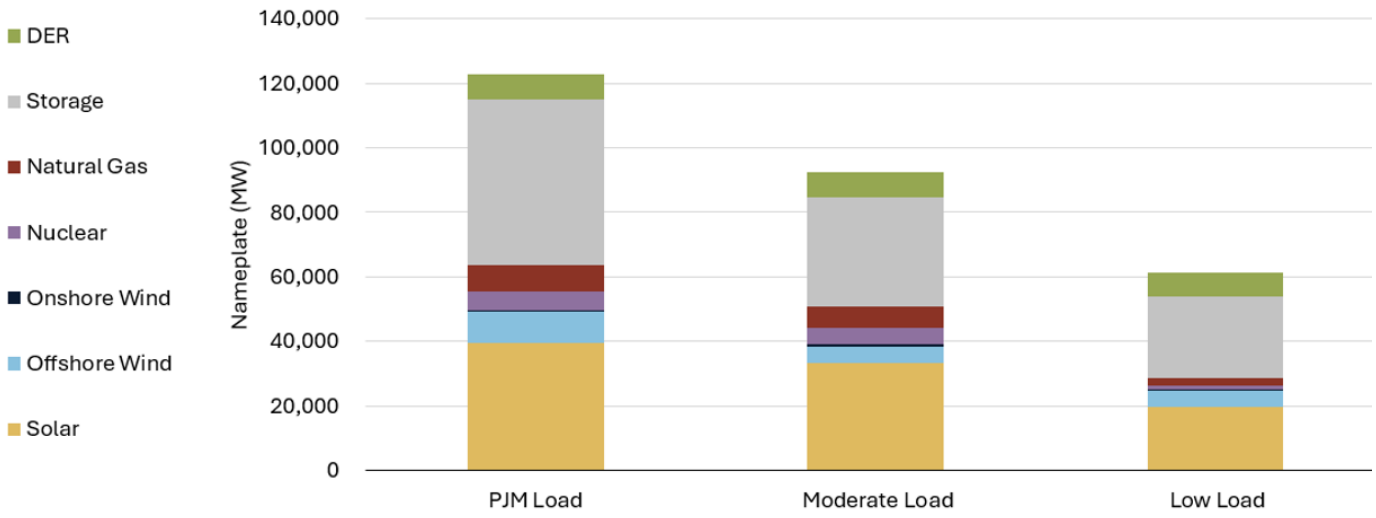
The VCEA made Virginia the first southern state to create a net-zero goal by mid-century. Despite current Virginia utility plans that are not on track to meet the VCEA's net-zero goal, the Energy Plan modeling demonstrates that there are multiple paths forward to achieve that goal even amidst Virginia's growth. Deliberate policy choices can further reduce costs and improve health outcomes for Virginians on that path.

Current Policies Scenario Across Load Forecasts

The Current Policies case reflects compliance with current Virginia law, including VCEA and RGGI, without additional significant legislative or regulatory changes. It serves as the current-policy benchmark for evaluating how Virginia's resource needs change under different levels of electricity-demand growth.

Across all three load forecasts, the Current Policies scenario requires Virginia to deploy a significant amount of new nameplate capacity of all fuel types to successfully meet growing demand. The system also continues to rely on regional electricity imports for both energy and capacity, underscoring the importance of PJM market conditions, transmission availability, and regional resource development (see the "Imports" subsection for further discussion).

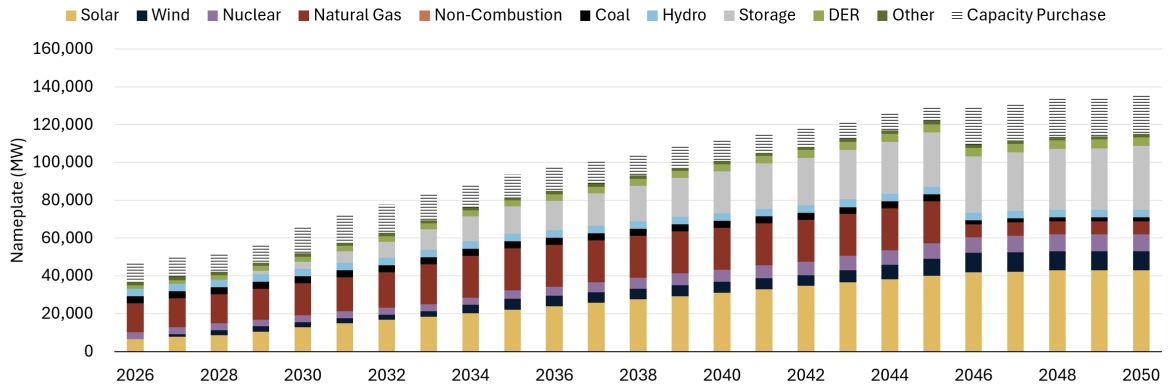
Figure 55. *Current Policies Scenario for all load forecasts – Total Capacity Additions 2026 – 2050, Nameplate MW*



Note: Chart only represents capacity additions (MW) through the planning period. It does not include Virginia's existing installed capacity and does not represent energy generation (MWh) from existing or new resources.

Today, Virginia has ~30,000 MW of installed nameplate capacity, with an additional ~10,000 MW purchased through external capacity purchases elsewhere in PJM. Even under the Low Load Forecast, Virginia would need to add capacity approaching twice its current installed nameplate capacity by 2050. The Moderate and PJM Load Forecasts require still larger additions, including clean firm resources such as nuclear. In a Moderate Load Forecast, this would imply reaching ~100,000 MW of total installed capacity by 2050. Meeting this scale of demand growth will require coordinated action on project siting, permitting, interconnection, grid infrastructure, workforce, and supply chains to support economic development, protect Virginia's national security interests, and meet the state's clean energy goals.

Figure 56 Total Virginia Installed Nameplate Capacity in a Current Policies Moderate Load Forecast 2026 – 2050, Nameplate MW



Annual Capacity Additions (MW)

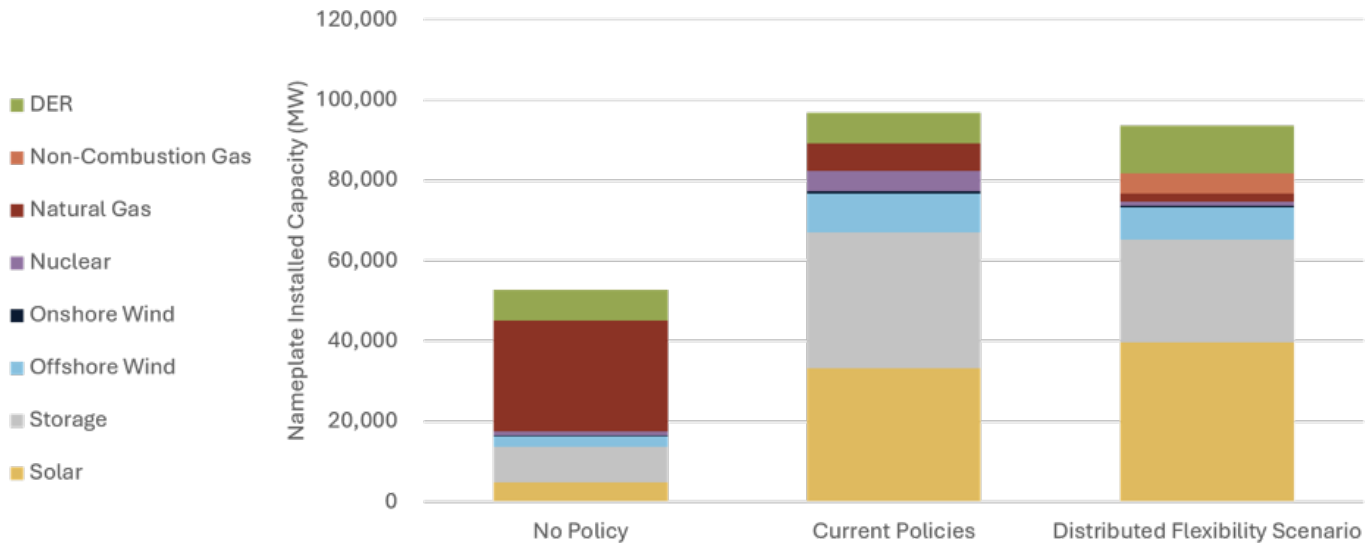
Solar	0	0	0	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	300	600	0	0
Wind	0	1,373	1,293	0	0	0	0	200	1,500	1,300	14	0	0	0	0	0	0	640	1,300	1,300	1,300	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	1,000	0	600	600	600	0	600	0	600	0	600	0	600	0	0	0
Natural Gas	0	0	0	948	630	948	948	2,166	1,083	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	1,800	1,800	2,400	2,400	2,400	2,400	1,200	1,200	1,477	1,700	1,700	1,700	1,700	1,200	1,200	1,200	1,200	1,200	1,200	300	1,171

Virginia's investor-owned utilities resource additions are not on track to meet the VCEA's net zero goals. As of its 2025 Integrated Resource Plan, Dominion's preferred plan is to build roughly 8 GW of new natural gas generation; the preferred plan does not include any retirements of existing or planned fossil fuel generation and notes the intention to use the VCEA's reliability exception to exempt new and existing fossil generation from retirement.[214] APCo's fossil fuel generation is primarily located in West Virginia; APCo plans to retire its only Virginia gas plant and to convert its West Virginia plants from coal to gas by 2040. While the VCEA does not apply to APCo's West Virginia assets, continued use is not aligned with VCEA's net zero goals.[215]

Policy Scenarios in a Moderate Load Growth Forecast

The Moderate Load Forecast is used for the primary policy comparison because it represents a central planning case in which data-center demand grows substantially but not all proposed data center projects materialize. The comparison illustrates the tradeoffs among direct system costs, emissions, health impacts, and resource needs under alternative policy choices.

Figure 57. *Comparison of No Policy, Current Policies, and Distributed Flexibility Scenario for Moderate Load Forecasts – Total Capacity Additions 2026 – 2050, Nameplate MW*



Note: Chart only represents capacity additions (MW) through the planning period. It does not include Virginia's existing installed capacity and does not represent energy generation (MWh) from existing or new resources.

Table 16. *Key cost results for No Policy, Current Policies, and Distributed Flexibility scenario under moderate load forecast*

	No Policy	VCEA/RGGI	Distributed Flexibility Scenario
System Cost ($B)	$295	$422	$385
Social Cost of Carbon ($B)	$285	$53	$71
Cost of Health Impacts ($B)	$145	$35	$19
Total Cost ($B)	$725	$510	$475

No Policy Goals Scenario

The No Policy case removes all policy constraints (VCEA, RGGI, etc.) and allows the model to select resources based primarily on total system cost. There is no consideration for climate costs or health-related costs. Social costs associated with carbon emissions and health impacts are calculated separately and are not included in the model's resource-selection objective.

While the No Policy scenario is the lowest system cost pathway, the overall carbon emissions are significantly higher than the Current Policies case. Emissions nearly double over the next 20 years through the addition of ~27 GW of new gas capacity—with annual emissions climbing even higher by 2050 than they were in 2005, at the height of Virginia's reliance on coal. That level of new fossil fuel development, added on top of Virginia's fossil fleet, would impose roughly $145 billion of health-related costs on Virginia communities. To fuel such a massive buildout of gas resources, Virginia would need to construct several new large-scale pipelines projects.

Decarbonizing this new natural gas capacity through carbon capture or hydrogen would not be economically viable in Virginia. Carbon capture at this scale is also not feasible in Virgina due to geologic limitations in the Atlantic Coastal Plain.[216] As a result, the new and existing gas capacity in the No Policy case could not realistically be decarbonized in time to meet Virginia's net- zero goals.

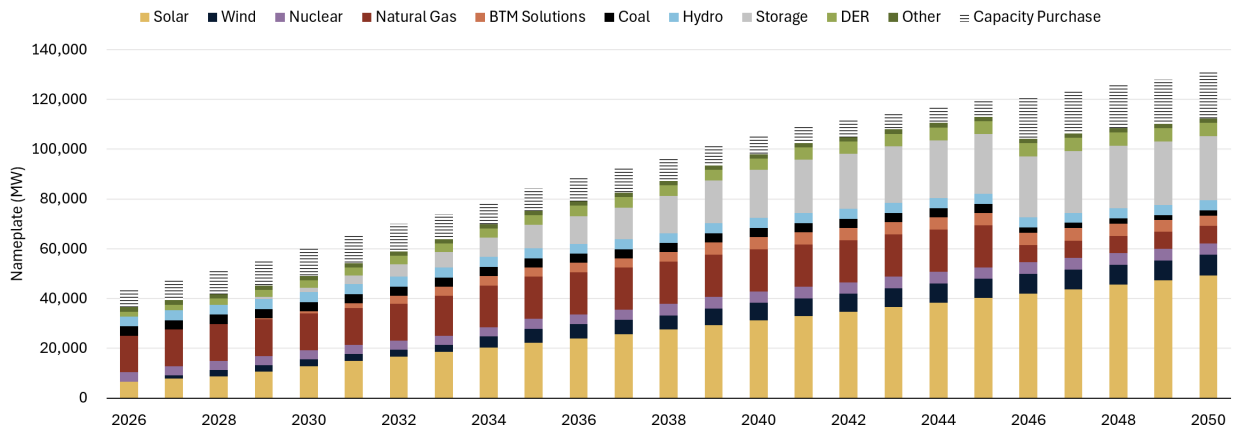
Distributed Flexibility Scenario

The Distributed Flexibility Scenario builds on the Current Policies case by testing three targeted changes designed to manage rapid load growth with a more distributed, flexible, and lower-impact resource mix: a statewide 10 GW DER target, 10% data center demand flexibility during peak periods,[217] and up to 5 GW of optional non-combustion gas capacity. This tests how targeted adjustments could impact costs, local air pollution and health impacts, emissions, and generation buildout.

In the moderate load forecast, the Distributed Flexibility Scenario produces lower direct system costs than Current Policies while remaining on a pathway consistent with the VCEA's 2045 and 2050 targets. The cost reduction is driven primarily by lower peak demand and reduced need for larger centralized resources. The Distributed Flexibility Scenario reduces direct system cost by ~10% from $422 billion to $385 billion due to greater system flexibility. The use of non-combustion gas resources drives a reduction in estimated health damages by ~40% from $35 billion to $19 billion, providing an option to meet near-term capacity needs without committing to large, long-lived centralized gas infrastructure and reducing health impacts. The Distributed Flexibility Scenario case has higher modeled carbon emissions than Current Policies because the non-combustion resources are available beyond 2045 and are not subject to the same RGGI or retirement treatment as other carbon-emitting generation—highlighting a tradeoff between reducing health impacts near-term and managing carbon emissions.

In the Distributed Flexibility Scenario, Virginia reaches ~110,000 MW of total installed nameplate capacity with 20,000 MW secured through external capacity purchases in PJM.

Figure 58. *Total Virginia Installed Nameplate Capacity in the Distributed Flexibility Scenario, Moderate Load Forecast 2026 – 2050, Nameplate MW*



Annual Capacity Additions (MW)

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Solar	0	0	0	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Wind	0	1,373	1,293	0	0	0	0	200	1,500	1,300	0	0	0	995	393	0	0	649	0	0	255	0	0	0	419
Nuclear	0	0	0	0	0	0	0	0	0	400	0	0	600	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	1,083	919	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Combustion Gas	0	0	0	420	396	1,200	1,200	548	0	0	0	0	88	1,148	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	777	1,000	1,550	1,521	1,300	1,650	1,650	1,700	1,600	2,200	2,200	2,200	2,200	600	600	600	600	600	300	300	300	300

Distributed Flexibility Alternatives Scenarios

The VEP evaluated two additional alternatives to the Distributed Flexibility Scenario.

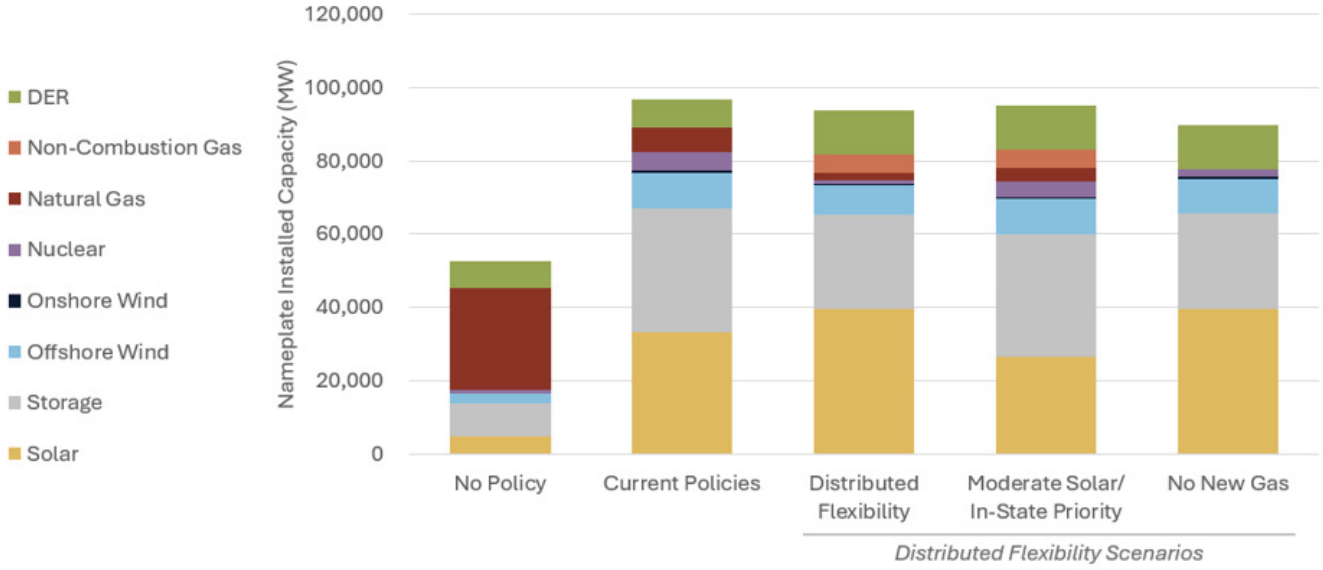
The Moderate Solar/In-State Priority has the same policy adjustments as the Distributed Flexibility Scenario but limits the amount of annual solar build from 1,800 MW to 1,200 MW and reduces the amount of external capacity the state can purchase to today's levels. With less solar development and fewer external capacity purchases available, the model selects additional nuclear and offshore wind capacity versus the Distributed Flexibility Scenario to meet demand and reliability requirements. These additional investments result in higher modeled costs across all cost categories compared with the Distributed Flexibility Scenario.

The second alternative, the No New Gas, is the same as the Distributed Flexibility Scenario but the model does not build any new gas generation in Virginia. Notably, the No New Gas sensitivity is the only scenario in which Virginia would not need to expand gas infrastructure. While the No New Gas sensitivity results in lower system costs than the Current Policies approach, it is overall costlier with higher carbon emissions (due to similar trends seen in the Distributed Flexibility Scenario above with greater demand flexibility reducing buildout of nuclear and offshore wind). The No New Gas case also produces greater local health impacts than the Distributed Flexibility Scenario, though still substantially lower than Current Policies, because it relies more on existing fossil-fuel units, which tend to be older and less efficient. The No New Gas case suggests this pathway could cause greater adverse health impacts in communities near those existing facilities.

In addition to the alternative policies modeled above, another analysis was conducted to test biomass potential, under the Distributed Flexibility Scenario case. This sensitivity restricted new utility-scale natural gas and instead allowed up to 3,500 MW of biomass starting in 2033; restricting gas was necessary since the model otherwise always chooses it. Under these constraints, the model builds the full 3,500 MW of biomass—but not until 2041, and only as resource-adequacy capacity that is never dispatched, adding roughly $47 billion in system costs without generating any electricity under normal operations. This reflects biomass' relatively high startup costs, short-run marginal costs, and ramp limitations, which make it more expensive to operate than the gas capacity it is displacing; the model is effectively building biomass only because it has no cheaper alternative available to meet reliability needs. These results suggest that alternative uses for forestry residuals—such as sustainable aviation fuel—may offer a more cost-effective and productive pathway than biomass power generation.

Summary of All Policy Cases Results

Figure 59. *Comparison of Policy Scenarios for Moderate Load Forecasts – Total Capacity Additions 2026 – 2050, Nameplate MW*



Note: Chart only represents capacity additions (MW) through the planning period. It does not include Virginia's existing installed capacity and does not represent energy generation (MWh) from existing or new resources.

Table 17. *Costs for Policy Scenarios Under Moderate Load Forecasts*

	No Policy	Current Policies	Distributed Flexibility	Moderate Solar/ In-State Priority	No New Gas
System Cost ($B)	$295	$422	$385	$405	$398
Social Cost of Carbon ($B)	$285	$53	$71	$75	$64
Cost of Health Impacts ($B)	$145	$35	$19	$20	$22
Total Cost ($B)	**$725**	**$510**	**$475**	**$500**	**$484**

Table 18. *Emissions for Policy Scenarios Under Moderate Load Forecasts*

Emissions type	No Policy	Current Policies	Distributed Flexibility	Moderate Solar/ In-State Priority	No New Gas
Total CO2 Emissions (MMT)	998	209	283	299	252
Total PM2.5 (MT)	46,202	20,397	14,045	15,206	16,776
Total NOx (MT)	374,035	152,608	92,223	99,979	109,523
Total SOx (MT)	269,190	52,077	22,942	25,195	25,622

Overview of the Policy Adjustments

DERs: DERs can include customer-sited solar and storage, community solar, smart thermostats, smart heat pumps, managed EV charging, geothermal heating and cooling solutions, and other customer-owned or customer-connected resources. Aggregated through VPPs, they can provide energy, capacity, and demand-response services at scale—reducing reliance on centralized generation and grid investments. DERs reduce demand during constrained periods, improve use of existing infrastructure, and can defer or avoid high-cost peaking generation, transmission, and distribution upgrades. Although they may cost more than utility-scale solar, DERs mobilize private capital and compensate participating customers, supporting customer affordability. The Distributed Flexibility Scenario targets 10 GW of DER deployment by 2045, including 5 GW by 2040. For modeling purposes, DERs are modeled as solar+storage systems; additional value may be available from other flexible technologies and VPP-enabled resources.

Data center demand flexibility: Data-center demand flexibility is the ability of large customers to reduce, shift, or manage electricity use when the grid is most constrained. It can be delivered on site through load shifting, on-site storage, or curtailing operations, or through verified off-site resources and contracts—including VPPs, distributed solar and storage, and DR—that reduce system peak elsewhere on the grid. Reducing load during the highest-demand hours lowers the amount of new capacity and grid infrastructure the system must build, while improving utilization of existing infrastructure. The Distributed Flexibility Scenario assumes all data centers provide the equivalent of a 10% reduction in peak demand.

Non-combustion gas resources: Non-combustion gas resources—including fuel cells and linear generators—can provide firm, dispatchable capacity without conventional combustion. Compared with conventional gas generation, they produce substantially lower local emissions of pollutants such as nitrogen oxides, sulfur dioxide, and fine particulate matter, reducing health impacts in nearby communities, particularly communities that have been disproportionately affected by energy infrastructure. These resources can generally be deployed within 18–24 months, have shorter useful lives of roughly 5–20 years, and connect to distribution infrastructure, which could reduce the need for major new pipeline investments. They can therefore serve as limited-duration bridge resources for near-term reliability needs without committing to long-lived centralized gas infrastructure and while staying aligned with a pathway to net zero by 2050. The Distributed Flexibility Scenario makes up to 5 GW available for the model to select beginning in 2029 and continuing through 2050; if selected, the resources are modeled as peakers with capacity factors capped at 20%.

Table 19. *Total Capacity Additions by Resource Type for Policy Scenarios Under Moderate Load Forecasts (2026-2050, MW, Rounded)*

Resource type	No Policy	Current Policies	Distributed Flexibility	Moderate Solar/ In-State Priority	No New Gas
Solar	4,800	33,300	39,600	26,400	39,463
Storage	9,000	33,748	25,748	33,477	26,077
Offshore Wind	2,586	9,740	7,894	9,736	9,560
Onshore Wind	80	480	480	480	480
Nuclear	1,000	5,200	1,000	4,362	2,200
Natural Gas	27,618	6,723	2,002	3,649	0
Non-Combustion Gas	0	0	5,000	5000	0
Distributed Energy (DERs)	7,616	7,616	11,948	11,948	11,948
Total Capacity Additions	**52,700**	**96,807**	**93,672**	**95,052**	**89,728**

Comparing all policy scenarios under a moderate load growth outlook illustrates the importance and value of the VCEA, RGGI, and other policy adjustments in reducing emissions and managing carbon and health costs versus the No Policy case. The Distributed Flexibility Scenario can provide a better pathway from Current Policies trajectories in terms of total system cost and reduced health impacts, despite a marginal tradeoff in carbon emissions.

The results of the Current Policies case demonstrate that continuing to prioritize offshore wind and nuclear deployment could help reduce carbon emissions and reduce existing fossil fuel emissions to mitigate local health impacts; and while this adds to system costs in relation to the Distributed Flexibility Scenario, the additional costs of that development could be primarily or entirely covered by data centers to reduce impacts to other households and small businesses.

Cross-Cutting Findings

Costs and Who Pays

In the Current Policies moderate demand growth scenario, total system costs are ~$422B. This includes capital investment for new energy generation and fuel and other operating costs for all system assets from 2026-2050. However, these modeled system costs should not be interpreted as costs borne by existing customers.

Without context, these cost figures may appear significant. However, they should be viewed in light of the extraordinary scale of projected load growth. In Dominion's GS-5 rate class, a 1 GW data center pays roughly $700 million per year for electricity under current cost allocation frameworks.[218] This represents just 5-8% of the data center's total annual cost of ownership. When applying this to the 20 GW of data center load that comes to fruition in Virginia in the moderate load outlook, that suggests those new data centers alone would contribute roughly ~$265 billion in total revenue to utilities through 2050. This is baseline electricity revenue from new data center load, with no consideration of revenue from the legacy customer base or adjustments to cost allocation.

These payments could conceivably help cover the incremental cost of building out the energy infrastructure needed to serve their demand while keeping Virginia on track for a clean energy future. A "no new data center load case" was run as a comparative analysis against these baseline outlooks, which found that the costs of serving new data center load represented ~50% of the total cost of new energy additions in a Current Policies, moderate load outlook (or ~$200B in incremental cost). While illustrative, this demonstrates how much new revenue will be generated for the system from new data centers coming online.

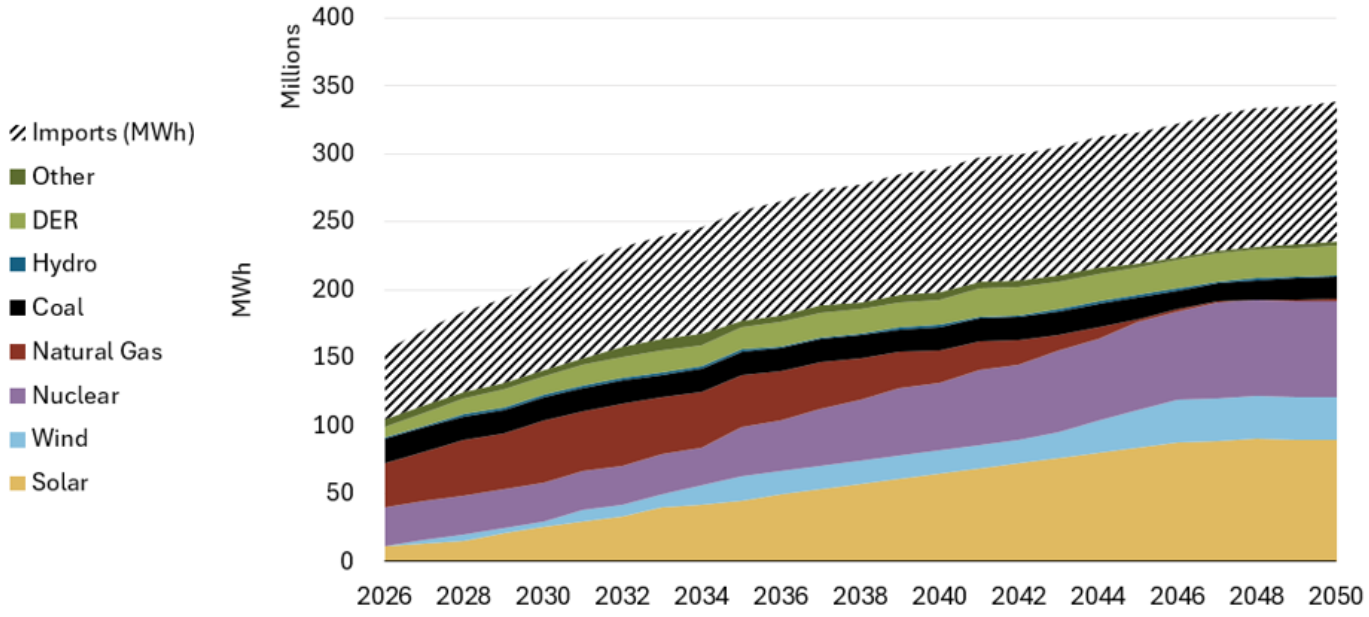
Importantly, Dominion and APCo projected roughly $180B in collective spending in 2019 and 2020, before any of the current data center load was in the forecast.[219],[220] After adding in spending that would be required for cooperatives, the outlook has not materially changed for existing Virginia customers.

Put plainly, these costs appear high because the scale of growth Virginia faces is enormous, but the modeling shows that the problem is solvable. Further, these results suggest that with proper cost allocation, Virginia can serve new data center growth with clean energy solutions, while also improving the situations of Virginia families and small businesses.

Imports

Across all demand growth and policy scenarios, Virginia continues to import roughly 30% of its electricity needs. This underscores the importance of continued regional engagement, because Virginia's affordability, reliability, and emissions outcomes are shaped not only by in-state choices but also by the broader PJM system and neighboring states' generation mix.

Figure 60. Annual generation for Current Policies in the moderate load forecast (2026-2050, MWh) (reflective of similar trends across other scenarios)



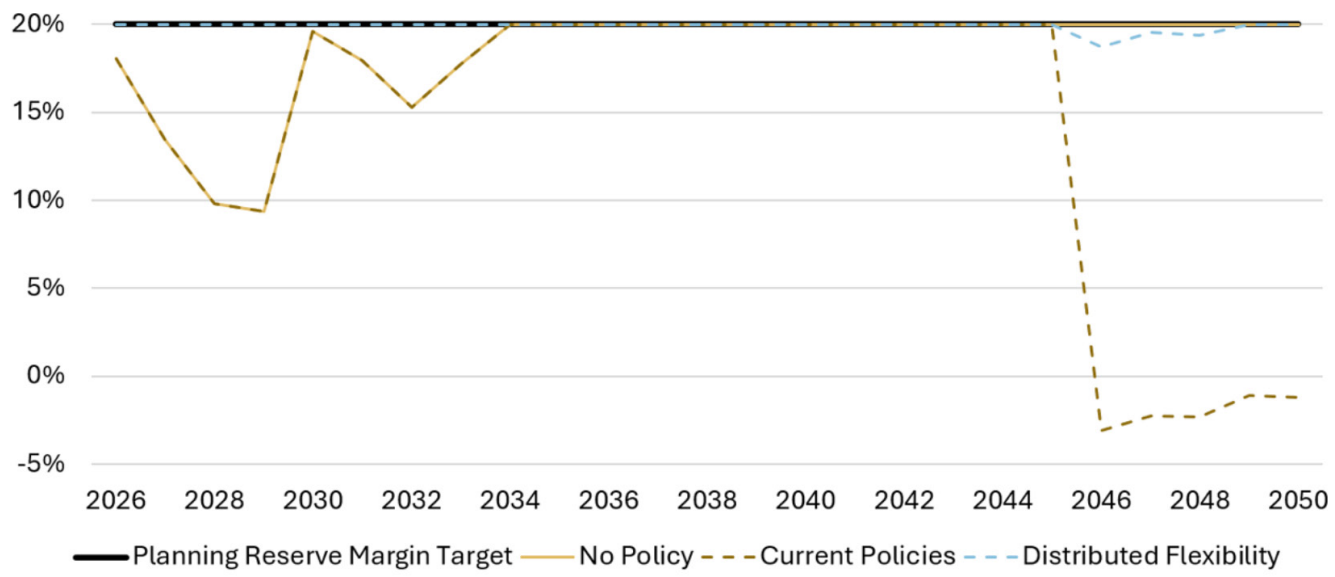
Resource Adequacy

Across all policy scenarios in the moderate load growth discussed above, the system achieves its target 20% planning

reserve margin, preserving a significant amount of excess system capacity to maintain resource adequacy and protect reliability.

However, if all PJM load materializes, meeting this scale of growth and maintaining target reserve margins becomes challenging without policy adjustments. In the No Policy scenario, new gas alone cannot come online quickly enough to meet near-term resource adequacy needs. This remains true in the Current Policies trajectory, with resource adequacy a challenge in the near-term and long-term. Flexible resources such as DERs, storage, DR, and other quick-to-deploy solutions are therefore essential to meeting Virginia's energy needs today while also providing long-term system reliability and flexibility.

Figure 61. Planning Reserve Margins across select policy scenarios for PJM high load growth forecast (%)



Implementation Considerations

Land Use Impacts

The scale of solar deployment in modeled pathways has important land-use implications. The Energy Plan is sensitive to managing the impacts to Virginia's land resources to support the necessary solar buildout to achieve lowest system costs.

Figure 62 below shows the amount of land that would need to be developed for solar if all new solar projects were developed on greenfield sites and that buildout was consistent with the historical displacement of forest and farmland. According to reports from Virginia Farm Bureau and the Virginia Department of Forestry, Virginia has 7.3 million acres of farmland and as of 2018 Virginia had 16 million acres of forestland.[221] Historical solar deployment has been on a mix of forest and farmland, with 50% of utility scale solar to date being developed on forested land and 40% on farmland.[222] The In-State Priority sensitivity uses 27% less land for solar use than the Distributed Flexibility Scenario, but costs $20 billion more in system costs.

Figure 62. *Solar Land Use Results for New Solar Capacity Expansion Additions, Assuming Historical Land Use Percentage Rates, Across Select Policy Cases in Moderate Load Growth Forecast*

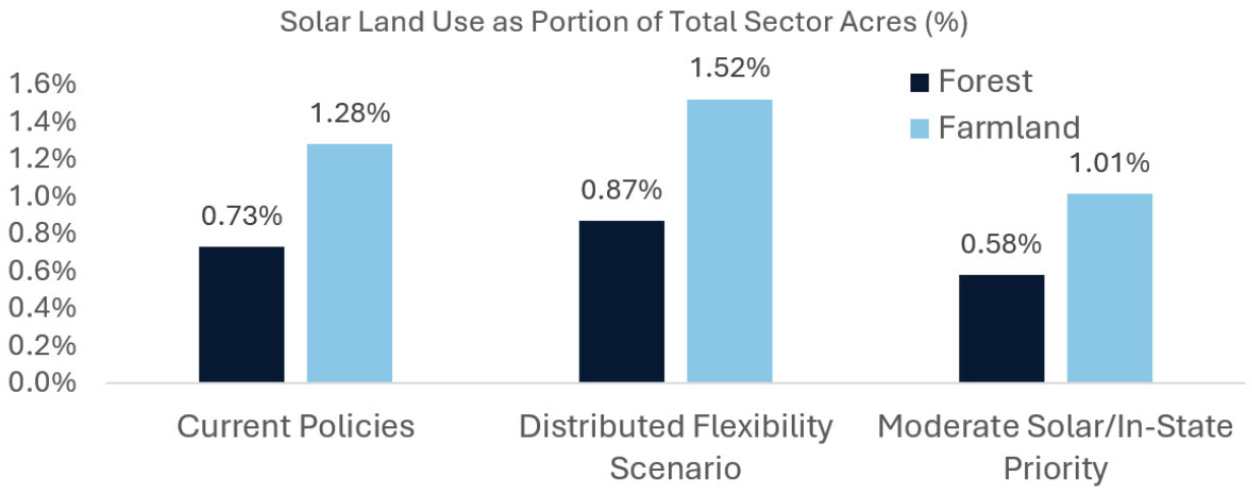


Table 20: *Solar Land Use Results in Acres for New Solar Capacity Expansion Additions and System Costs Across Select Policy Cases in Moderate Load Growth Forecast*

	Current Policies	Distributed Flexibility Scenario	Moderate Solar/In State Priority
Solar Land Impact (Acres)	233,000	277,000	185,000
System Cost ($B)	$422	$385	$405

Prioritizing solar and storage on brownfields, former mine lands, rooftops, parking canopies, and other previously disturbed or dual-use sites can reduce pressure on farmland and forestland while putting underused property back into productive use. Virginia has substantial potential: estimates identify more than 100,000 acres of former mine land and additional brownfield sites that may be suitable for renewable-energy development, although suitability depends on site conditions, grid access, remediation needs, and local approval. These projects will often be smaller and more costly than greenfield development, so there is some tradeoff in total cost.

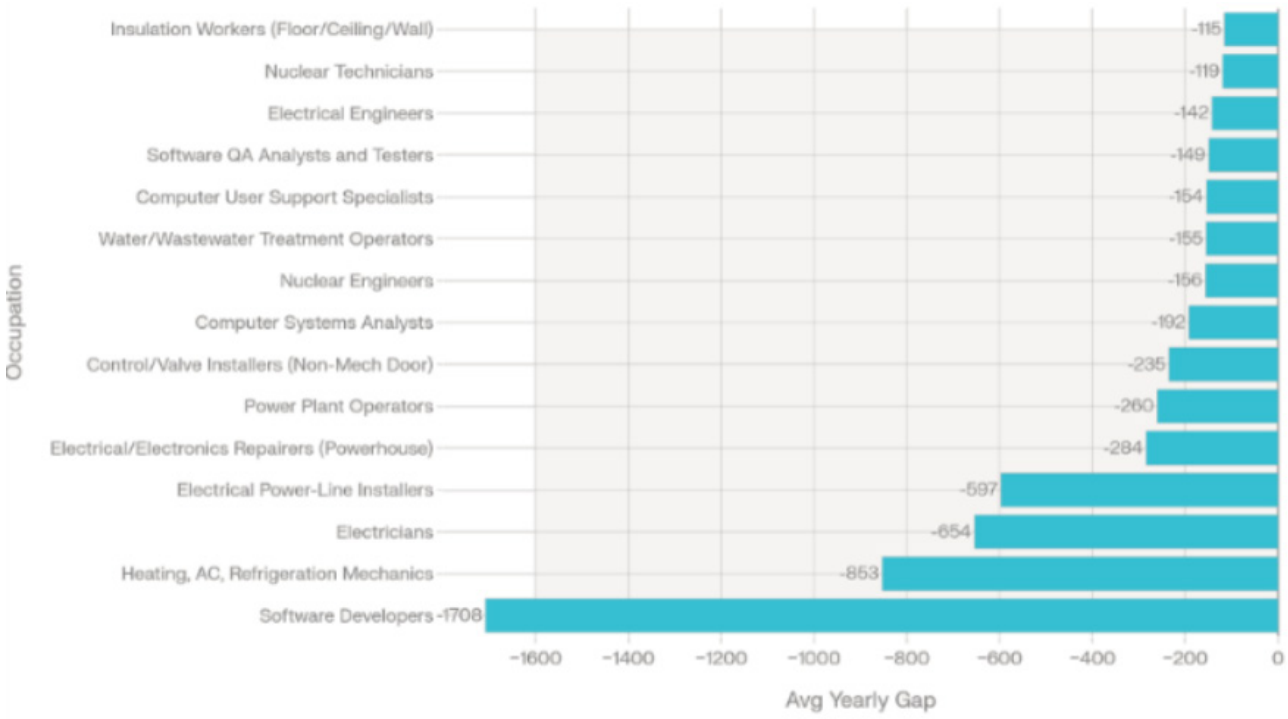
The Commonwealth's Solar Permit by Rule (PBR) mitigation program, which requires developers of small utility-scale solar projects to offset significant impacts to prime agricultural soils and contiguous forest lands—generally by conserving an equivalent amount of comparable farmland or forest off-site—can further help to protect Virginia's working lands as solar development continues to expand.[223]

Workforce

Delivering any modeled pathway will require a larger and more specialized workforce. Across VEP modeled scenarios, an estimated ~5,000 – 20,000 construction jobs are needed every year over the next two decades, and a total of ~20,000 permanent operational jobs are created. This includes general roles—such as in construction, electrical work, and home contracting—as well as specialized roles—such as in nuclear, offshore wind, and advanced grid planning and operations.

In the near-term through 2030, projections from Virginia Energy Workforce Assessment Report (VEWAR) based on the 2026 Virginia's CCAP found the most significant projected workforce shortages are in Digital Technology roles and key technical fields such as software developers, HVAC mechanics and installers, electricians, and electrical power-line installers and repairers (see Figure 63).[224,1] These constraints could affect project cost and timing, reinforcing the need for workforce development, apprenticeships, education pathways, and supply-chain investment.

Figure 63. Largest Projected Annual Worker Shortfall by Occupation through 2030, 2026–2030[225]



Economic Impacts

If projected data center growth materializes, it will translate into hundreds of billions in private capital investment to Virginia alongside hundreds of billions in energy investment in generation, storage, and grid infrastructure needed to support this growth and meet Virginia's clean energy goals. There is significant additional opportunity to attract the supply chains needed to build and operate this expanded energy system, serving both the Virginia market and the rapid growth happening across the United States. Taken together, these outlooks demonstrate the scale of the economic opportunity at stake: supporting construction and long-term jobs, growing advanced manufacturing and energy industries, and extending the benefits of growth across the Commonwealth.

3D. Key Modeling Takeaways & Implications

The modeling shows that regardless of the load that materializes, there are multiple pathways where Virginia can meet demand and remain on a path to net-zero by 2050. Across all scenarios, the least-cost pathways require a deliberate and expansive buildout of solar, storage, wind, and nuclear—and will require accompanying transmission and distribution delivery infrastructure. Virginia must move quickly to add generation—including roughly up to 1.8 GW

[1] Data includes only Construction and Energy Efficiency, Energy and Natural Resources, and Digital Technology occupations.

of solar and 1-2.2 GW of storage annually over the next two decades—by accelerating permitting, interconnection, workforce, supply-chain, and siting efforts. Other similarly sized states have already shown that solar additions at this scale are possible, such as Ohio, which added 1.5 GW in 2025 and 2.7 GW in 2024.[226] Illinois added nearly 3 GW in 2024 and 2.2 GW in 2025.[227]

Given the uncertainty in load growth, Virginia should prioritize resources that are flexible, fast to deploy, and cost-effective. That means focusing on EE, flexible storage, low-cost solar, and better use of the existing grid through DERs and VPPs. The modeling shows that non-combustion gas is a better interim option than large, centralized gas infrastructure to reduce health impacts and avoid locking in long-lived assets. Virginia should also maintain future optionality by continuing to invest in a portfolio of clean firm resources, including nuclear, fusion, and long-duration energy storage (LDES), to meet long-term needs while deploying near-term solutions today.

The scale of new energy development demonstrated in the modeling reinforces the importance of minimizing land impacts and protecting Virginia's natural and working lands. Prioritizing solar and storage on brownfields, former mine lands, rooftops, parking canopies, and agrivoltaic or other dual-use sites can reduce pressure on farmland and forests. Continued conservation, restoration, and sustainable management of forests, wetlands, agricultural lands, and other natural carbon sinks—consistent with the 2026 CCAP—can further reduce net emissions while supporting resilience, water quality, habitat, and community health.

Virginia should use this moment to strengthen its approach to system planning and cost allocation. The modeling reinforces that the state can serve growing demand while staying on a path to net zero, but only if it moves faster on the least-cost clean resources and ensures that new load bears the costs it creates. That includes planning for flexible demand, especially from data centers and accelerating deployment of DERs, and making sure that households and small businesses are not left to subsidize the infrastructure needed to serve large new loads.

3E. The Decade Ahead

Despite the load growth facing Virginia, these results show a path forward without veering off track of the Commonwealth's clean energy goals. Virginia's clean energy ambitions are attainable. This analysis demonstrates how Virginia can meet this moment in a way that protects the wallets of Virginia families and small businesses while transitioning to a net-zero system that is more distributed, more flexible, and more resilient.

The Path Forward for Virginia

The Path Forward for Virginia

Virginia is at a pivotal moment. Rapid growth in electricity demand is creating new opportunities for jobs, investment, and innovation, but it is also putting pressure on household bills, electric grid reliability, and the communities that host new infrastructure. The choices Virginia makes today will determine whether Virginia becomes a state for energy innovation and will shape whether families can afford their bills, whether businesses can grow with confidence, and whether communities share equitably in the benefits of growth.

The priorities laid out in this VEP are about delivering real benefits for Virginians—supporting families, powering businesses, and strengthening communities.

For families, that means lower and more predictable energy costs, more comfortable and efficient homes, cleaner air, dependable service, stronger communities, and shared economic opportunity.

For businesses, it means affordable, readily available, and reliable power that supports investment, job creation, and long-term competitiveness. Getting energy right is central to Virginia's economic future. As competition intensifies for infrastructure, advanced manufacturing, and major corporate investment, Virginia's energy system must be reliable, scalable, and cost-effective—enabling businesses to expand with confidence while supporting long-term growth across the Commonwealth. Data centers can help drive investment in clean energy, grid modernization, and demand flexibility, and this growth should pay for the infrastructure it requires rather than shifting costs to Virginia's households and other businesses.

The VEP modeling informed the choices in this Plan, balancing health and pollution impacts, lower energy burdens, and improved outcomes for households and communities facing disproportionate energy costs or infrastructure impacts, while delivering on Virginia's clean energy goals. The modeling shows that Virginia has multiple pathways towards a net-zero power sector by 2050, consistent with the Commonwealth's clean energy goals and with additional policies that can help further reduce costs and harmful health impacts. The vision and strategies laid out below are intended to keep Virginia on track towards a cleaner, healthier, and lower cost energy future.

Virginia can meet this challenge through a Clean-First, Least-Cost energy strategy: deploying proven, readily available, and cost-effective solutions now—including EE, solar, storage, DERs, demand flexibility, and better use of the existing grid—while expanding grid capacity and advancing clean firm resources for the future, such as advanced nuclear, offshore wind, and LDES.

Where near-term capacity needs cannot be met with cleaner options, shorter-lived non-combustion resources can provide a lower-pollution bridge without committing the Commonwealth to large, long-lived natural gas infrastructure. Virginia can reduce land impacts by prioritizing solar and storage on rooftops, brownfields, agrivoltaics, parking canopies, and other dual-use sites. These investments can strengthen local economies, modernize infrastructure, and create significant jobs in every region of the Commonwealth.

This Plan positions Virginia to be a leader in driving energy innovation and responsible growth that delivers a cleaner, more affordable, reliable, and competitive energy system. The strategies and actions in this section provide a practical path forward: lowering costs for families and businesses; ensuring reliable power for a growing economy; building the workforce and infrastructure needed for the future; and delivering tangible, lasting benefits to communities across the Commonwealth.

4A. Vision for Virginia's Energy Future

The VEP advances a long-term vision for an affordable, reliable, clean, and resilient energy system that delivers practical benefits to households, businesses, and communities in every region of the Commonwealth.

VIRGINIA'S ENERGY VISION

Deliver affordable, reliable, and locally beneficial clean energy that works for every community in Virginia and powers a thriving economy—today and for generations to come.

Achieving this vision will require Virginia to advance three interdependent pillars at the same time. These pillars provide the framework for the strategies and actions in this section.

Pillar 1: Affordable Energy for Every Virginian

Reduce total energy burdens for households and businesses today while creating durable, systemwide solutions—including lower-cost energy resources, efficient use of existing infrastructure, and reduced exposure to volatile fuel costs—that keep energy affordable over the long term.

Pillar 2: Clean Firm Resources to Power Virginia's Growth

Position Virginia's generation mix, supply chains, and innovation pipeline to support Virginia's growth and clean energy goals now and in the future. Meet today's growing demand from data centers and development with proactive planning and infrastructure deployment.

Pillar 3: Local and Sustainable Energy that Benefits Every Community

Ensure that every region of the Commonwealth can participate in and benefit from Virginia's energy transition through clean energy investments that strengthen local economies, improve resilience, and deliver community benefits, while building the workforce, infrastructure, and capacity needed to sustain shared economic and environmental gains over the long term.

4B. Energy Strategies

The Commonwealth will pursue seven mutually reinforcing strategies to advance this vision and deliver on the opportunity to improve outcomes for households, businesses, and communities. Informed by stakeholder input, power-sector modeling, and analysis of Virginia's energy system, they provide a durable but adaptable path forward as demand, technologies, markets, and costs evolve.

Table 21. *Virginia's Seven Energy Strategies*

Energy Strategies	Pillar 1: Affordable Energy	Pillar 2: Clean Firm Resources	Pillar 3: Local and Sustainable
1. Accelerate the deployment of the lowest cost, fastest, and cleanest energy solutions	✓	✓	✓
a. Deploy utility-scale storage and solar	✓		✓
b. Accelerate adoption of energy efficiency and consumer affordability programs	✓		✓

Energy Strategies	Pillar 1: Affordable Energy	Pillar 2: Clean Firm Resources	Pillar 3: Local and Sustainable
c. Unlock distributed energy resource deployment, aggregation, and market integration	✓		✓
d. Improve utilization of the existing grid	✓		✓
2. Ensure data center growth advances Virginia's energy goals	✓	✓	✓
3. Align utility incentives with affordable energy outcomes	✓	✓	✓
4. Advance development of clean baseload resources in Virginia	✓	✓	
5. Reduce emissions from and better leverage gas infrastructure		✓	✓
6. Drive affordable, clean transportation across the Commonwealth	✓		✓
7. Build a homegrown workforce and supply chain to power Virginia's energy economy	✓	✓	✓

✓ Primary Impact ✓ Secondary Impact

Other Virginia Plans and Strategies

This Energy Plan complements other related statewide strategic plans, including:

- The Virginia Data Center Accountability Framework (Sept 2026) which outlines strategies and expectations for data center developers in the Commonwealth
- The Virginia Comprehensive Climate Action Plan (June 2026) which highlights pathways and strategies to reduce emissions and pollutants across sectors
- The Virginia Comprehensive Economic Development Policy (forthcoming late 2026) which will discuss the state's economic development strategies, including implications for energy supply chains and generation and energy workforce and talent pipeline

The Energy Plan also builds on several ongoing working groups, whose findings will further help shape and inform Virginia's energy strategy. These groups are noted below as relevant.

4C. Priority Actions

This section identifies priority actions and supporting actions that translate the Commonwealth's energy strategies into an actionable roadmap. Priority actions are high-impact opportunities that guide the Administration's primary energy agenda. Supporting actions are complementary measures that could be pursued by the Administration, other state entities, utilities, local governments, or other stakeholders.

The actions are not intended to represent every potentially useful energy policy. Rather, they identify the measures most directly aligned with stakeholder input, power-sector modeling, and the Commonwealth's near-term energy needs.

Governor Spanberger signed a record number of substantive energy bills in 2026 in support of these strategies (See Appendix: Recent Energy Legislation). The Administration continues to work relentlessly to implement those reforms. The following actions build on that progress.

Delivering these strategies will require cross-cutting investments to build and expand institutional capacity, regulatory expertise, and public engagement. State entities—like Virginia Energy, the SCC, and other state authorities and agencies—along with local governments, utilities, and external partners will need the staff, technical resources, and clear processes necessary to proactively support and manage increasingly complex energy issues.

Accelerate the Deployment of the Lowest Cost, Fastest, and Cleanest Energy Solutions

Advance competitive deployment of utility-scale storage and solar

Context: Delivering the energy deployments needed to meet Virginia's clean energy goals requires getting solar, storage, transmission, and other energy assets planned more strategically and deployed more quickly and cost-effectively.

Recent utility-proposed clean energy procurements have been higher cost than national and regional averages. Dominion's 2026 RPS Development Plan proposed costs of $2,932/kW for utility-scale solar, $5,265/kW for distributed solar, and $2,705/kW for utility-scale storage, compared to DOE national average costs of $1,800/kW and $3,000/kW for utility-scale and distributed solar, respectively, and NREL national average costs of $1,336/kW for utility-scale storage.[228] National lab analysis of Virginia's RPS compliance costs identifies utility ownership as a contributing factor to these elevated prices.[229] Reducing costs of generation development to bring Virginia in line with competitive deployments in other states can help reduce overall energy costs for Virginians. Other states have addressed this dynamic by separating clean energy procurement from utility control; for example, New York State Energy Research and Development Authority (NYSERDA) conducts competitive solicitations for long-term renewable energy contracts in New York.[230] The Illinois Power Agency develops state procurement plans and runs renewable procurements and statewide solar programs.[231] Washington requires utilities to run competitive, all-source requests for proposals (RFPs) open to third-party owners when acquiring new generation.[232] Shifting toward more competitive, state-run or state-informed all-source clean procurement can lower long-term costs for customers, while still allowing utility-owned projects to participate and win when they are the most economic option.

Today, most of the Commonwealth's solar, storage, and transmission buildout still advances through utility IRPs, developer proposals, and PJM Interconnection processes on a project-by-project basis, which can make it harder to enable least-cost and locationally optimal siting and deployment. Pursuing a more proactive, coordinated statewide and regional planning strategy could also help deliver system-optimal deployments that reflect the Commonwealth's and communities' energy and economic development priorities. Other jurisdictions show what this can look like.

Texas's Competitive Renewable Energy Zone (CREZ) program and similar Renewable Energy Zone (REZ) approaches abroad pair high-quality resource areas with planned transmission corridors to major load centers, enabling large-scale clean energy development while reducing congestion and curtailment.[233] New York's Build-Ready program identifies underused land like brownfields, landfills, or existing commercial sites to make them ready for private renewable energy development.[234] Virginia has a strong foundation to build on, including recent planning reforms, existing statewide site-development models, and proactive site identification by localities that can support a more proactive approach.

Priority Actions:

- **Develop a state-led renewables marketplace to support competitive project developments:** Explore moving VCEA renewables compliance procurement to a state-led process that issues RFPs and evaluates utility-owned and third-party resources side by side on least-cost, least-risk criteria, rather than presuming utility ownership shares. Procurements could be designed to include utility-scale renewables, storage, clean firm resources, and demand-side options, and would not cap utility participation if utility projects win on economics. This could be modeled after other states that use more state-engaged procurement models (e.g., NY, IL).
- **Develop a proactive statewide energy planning and site readiness identification strategy:** Identify high-value areas and corridors for utility-scale solar, storage, and transmission; assess grid access, environmental and community impacts, land-use compatibility, and economic-development opportunities; and use the results to guide early site readiness, transmission planning, and local engagement. This builds on the Energy Plan statute's existing direction to score parcels for solar and wind suitability, while retaining local input and appropriate project-specific review. Virginia Energy—in close collaboration with localities, planning district commissions, VEDP, SCC, utilities, landowners, and other relevant stakeholders—can expand and build on existing modeling and site outreach work to develop and update statewide energy plans and support businesses with their energy generation needs as they consider Virginia for economic development projects.
- **Support greater use of unused interconnection capacity:** Identify projects with PJM interconnection agreements that have not yet been built to remove barriers to deployment to unlock near-term additions. Implement surplus interconnection and by-right storage approaches that allow generation and storage to be added at existing substations and interconnection points that add capacity while minimizing land and grid interconnection impacts.
- **Scale up proactive local energy education and development support**: Provide technical assistance, model ordinances and revenue sharing agreements, and flexible funding that help localities adopt safe, predictable solar and storage permitting frameworks, while also supporting equitable local development through statewide coordination, education, and

What we heard

Stakeholders called for a more coordinated, statewide approach to energy planning, education, and project delivery—one that helps communities, utilities, business partners, and developers plan ahead rather than respond project by project. Siting, land use, and mitigation was the second most important energy priority identified by survey respondents (49% ranked as "most important").

"We should have [a] comprehensive plan for energy development, which could be done by working with localities."

"Energy availability, site readiness, substation and equipment constraints, and limited coordination" are causing regions to lose economic opportunities.

additional assistance for planning boards, local governments, and fire departments.

- **Advance PJM energy-only and other market reforms**: Advocate regionally for reforms to improve the affordability and effectiveness of PJM's markets, including Energy Resource Interconnection Service (ERIS) processes to make this a more useful and effective option for project developers and advocating for integration of battery storage—including appropriate capacity values—into PJM markets. In PJM, ERIS was created as a lower-cost-, energy-only- interconnection path—allowing generators to inject power on an as-available- basis without full capacity deliverability. PJM's current study practices treat ERIS much like capacity-grade- NRIS, limiting its potential to speed low-cost- resource additions and relieve energy demand pressures. By changing overly restrictive study assumptions and reforming operational practices, PJM could transform ERIS into an option that significantly reduces interconnection timelines to add more clean energy to meet near-term needs.

Other supportive actions:

- **Review statutory utility ownership requirements where they drive up costs:** Evaluate whether current utility-ownership splits under VCEA are still consistent with least-cost procurement and whether adjustments could reduce ratepayer costs and foster innovation and healthy competition while preserving utility reliability and investment signals.
- **Standardize and strengthen revenue-sharing for local benefits:** Enhance and encourage adoption of model revenue-sharing ordinances that create predictable, transparent payments for local host communities. Develop strategies that support enhanced local impacts, such as using a portion of this for bill credits for local households and small businesses or other local benefits.
- **Support continued development of cost-effective and high-value transmission** (e.g., HVDC projects, high voltage, transmission on existing right-of-way, interregional transmission).

Accelerate Adoption of EE and Consumer Affordability Programs

Context: Many Virginia households still live in homes with high energy burdens, poor insulation, and aging heating equipment, which limits the impact of bill assistance alone. About 17% of households—more than 550,000—face electricity burdens above 6% of income (see Section 2G: Energy Affordability). For these households, the most durable bill relief often can come from improving EE and strategic electrification upgrades.

Virginia has a robust suite of EE and bill assistance programs and high penetration of advanced metering infrastructure (AMI) to build on, but there is significant opportunity to expand and strengthen their impact, particularly for utility customers given participation rates that fall short of utility EE goals in recent years (see Section 2F: Energy Efficiency). Concerted action to maximize effectiveness of utility programs and uptake of all consumer affordability programs can help ensure that high-burden

What we heard

Stakeholders consistently described energy efficiency, weatherization, and customer-affordability programs as essential long-term tools to lower household bills. Energy efficiency and weatherization was the third top energy priority identified by survey respondents (38% ranked as "most important"). Complex program navigation, split incentives between utilities and residents, lack of awareness, upfront costs, and contractor trust were noted as key challenges.

"Energy efficiency is the first fuel—it's the cheapest, fastest way to cut demand, bills, and the need for new generation."

households, including renters, fully benefit from available utility, state, and federal resources.

See forthcoming Income-Qualified Energy Efficiency and Weatherization Task Force for additional and more detailed recommendations on expanding EE and weatherization opportunities (final report due September 30, 2027).

Priority actions:

- **Increase adoption and improve the effectiveness of ratepayer-funded EE programs**: Develop and pursue strategies to ensure each dollar of utility investment in EE is having maximum impact, such as: fully leverage AMI data for targeted marketing and metered savings verification, align utility incentives with EE delivery (e.g., performance incentives and penalties, shared savings), commission a statewide utility EE potential study, convene a utility program evaluation advisory group, and evaluate viability of third-party run EE utility models. Maximize the impact of utility programs by formally supporting the SCC in program monitoring, promoting accessible and affordable financing options (including in partnership with VCEIB and other community finance organizations), supporting a high-quality contractor network statewide, and leading engagement with housing stakeholders for EE considerations into multi-family and single-family housing.

Maximize adoption of available programs that provide both immediate and lasting bill relief: Expand Virginia Energy Connect to increase awareness and adoption of customer programs and incentives available across the state, with a focus on reaching households with high energy burdens and high opportunities for energy savings. Coordinate and amplify outreach across DSS, DHCD, Virginia Energy, utility and external partnerships to max out customer enrollment in bill relief programs like PIPP, DSS energy crisis assistance, and the forthcoming income and age qualified solar/storage/EE programs.

Virginia Energy Connect

Virginia Energy Connect helps residents and businesses navigate the maze of federal, state, local, and utility incentives through a single easy-to-use platform. In about 30 seconds, Virginians can discover the programs they may qualify for and gain the knowledge needed to move forward confidently with their applications.

Learn more: **https://energy.virginia.gov/connect/**

- **Promote strategic electrification strategies:** Conduct analysis and identify opportunities to implement programs that incentivize cost-effective electrification at local scale, reduce local pollution, reduce costs of upgrading aging pipeline infrastructure, and free up existing gas capacity for industrial and hard-to-decarbonize uses. Assess opportunities that ensure access to and benefits for low-to-moderate income households.
- **Advance Pay As You Save (PAYS) to expand access to EE:** Support SCC technical conferences and utility programs that use PAYS to install energy solutions at no upfront cost to customers, with repayments tied to the meter and limited to a portion of verified bill savings so participants see immediate net benefits and broader uptake is possible across income levels and for renters.

Other supportive actions:

- **Reduce energy costs and strengthen resilience at public facilities:** Prioritize efficiency upgrades paired

with cost-effective solar, storage, geothermal and thermal-energy-network projects[235] where appropriate at public facilities—such as state agencies, schools, colleges, local government buildings, libraries—to reduce costs and save taxpayer dollars. Expand and increase adoption of Virginia Energy's energy-savings performance contracting and demand-response programs.[236] Provide targeted technical assistance and financing support to help public entities reduce utility and maintenance costs, improve resilience, and capture available federal incentives before they expire.

- **Support enhanced data collection and analysis to better understand program reach and outcomes:** Where feasible, use available geographic, income, and demographic data, including information related to environmental justice communities to better understand participation in affordability and energy-efficiency programs and identify opportunities to reach households and communities experiencing high energy burdens.
- **Promote adoption of cost-effective commercial and industrial efficiency.** Increase awareness and broader adoption to help businesses reduce energy costs and climate impacts. Identify and promote opportunities for industrial efficiency and decarbonization opportunities to further reduce Virginia's climate impacts. Virginia can build on existing C-PACE financing and the Commonwealth's combined heat and power and waste-heat-to-power roadmap.
- **Support the weatherization network to respond to shifts in federal funding, optimize current funding streams and increase production to weatherize more homes:** Consider state support for weatherization optimization programs that leverage the current programs.
- **Promote greater availability and adoption of time of use (TOU) rates:** Through the SCC, evaluate and implement opportunities to expand dynamic TOU rate adoption, including increasing awareness, and pairing with other VPP or DER programs that enable customers to benefit from existing AMI. Any TOU efforts should be carefully designed to ensure customers that are most exposed and unable to shift their consumption during high-price periods are not adversely impacted.
- **Promote shift to high-efficiency equipment availability for replacements:** Explore and implement opportunities to provide low-cost financing or other incentives to HVAC and water heater product distributors to ensure the best-quality, high-efficiency products are readily available to customers during replacement cycles. Work with distributors to ensure the installer workforce is trained to communicate about high-efficiency options and conduct high-quality installs.

Unlock DER Deployment, Aggregation, and Market Participation

Context: DERs can help Virginia meet rising electricity demand by accelerating adoption of and aggregating distributed solar and storage, smart thermostats and heat pumps, managed EV charging, and other flexible customer resources into dispatchable grid capacity. The Energy Plan modeling targets deployment of 10 GW of aggregated DER participation by 2045 as a key strategy to most effectively meet demand growth while reducing overall system costs. This will require significantly more customer-scale DER deployment and enrollment in VPP programs. These resources can support reliability and affordability by reducing peak demand and compensating participating households and small businesses for grid services.

Virginia is building this foundation through Dominion Energy's 450 MW VPP pilot, a forthcoming APCo VPP pilot, and 2026 legislation authorizing electric cooperatives to establish VPPs alongside other supportive initiatives, including expanding agrivoltaics and a pilot program to increase access for low-moderate income households to solar, storage, and EE (see Appendix: Recent Energy Legislation). However, Virginia remains behind leading states in DER deployment[237] and must address program caps, interconnection barriers, enabling regulations, utility planning, and customer compensation structures to scale these resources effectively.

Note: See forthcoming DER Task Force report for additional and more detailed recommendations on expanding DER deployment and market integration (released November 2026).

Priority actions:

- **Address DER deployment barriers to accelerate broad DER adoption:** Implement solutions that increase access to and reduce the costs and time for deployment of all types of DERs (e.g., addressing upfront cost barriers; expanding low-cost financing; enhancing customer awareness), including supporting implementation of Virginia Energy's Residential Smart Solar Permitting platform and the Solar Interconnection Grant Fund. Modernize Virginia's DER interconnection code (including right-sizing direct-transfer-trip (DTT) interconnection requirements for commercial & industrial applications) to reduce barriers and costs for smaller DER projects while ensuring safety, reliability, and consumer protection.
- **Enhance statewide policies and programs that enable DER aggregation and market participation at scale:** Develop necessary programs and rules for permanent DER aggregations to participate fully in Virginia's retail and PJM's wholesale markets. Establish standardized statewide policies and regulations for key VPP-enabling policies (e.g., data access, dual-participation rules, transaction settlement, cybersecurity requirements) and expanded compensation models that pay DERs and VPPs for the grid services they provide.[238] Expand clear and simple customer education, simplify VPP enrollment, ensure sufficient customer protections and value to support adoption and empower customers to effectively participate. Efforts should build on existing and forthcoming utility VPP programs and align with FERC 2222 and other PJM market policies for DER and demand-side resources.
- **Prioritize low-conflict, dual-use sites for DER deployment:** Expand support for site-redevelopment tools that reduce costs and encourage use of previously disturbed land, agrivoltaics, and other dual-use projects through existing siting frameworks and disturbed-land carve-outs. Support streamlined approval pathways for solar and storage on brownfields, closed landfills, abandoned mines, industrial sites, parking lots, and warehouse roofs so projects can move faster and with fewer land-use impacts (e.g., greater use of existing permit-by-rule standards for small-scale projects, providing additional funding and incentives for dual-use and brownfield projects).

Other supportive actions:

- **Deploy DERs at public facilities:** Prioritize deployment of solar, storage, and other DERs—paired with EE programs—at schools, municipal buildings, and other public facilities to reduce costs, save taxpayer money, and enhance community resilience. Expand education resources (e.g., model solar and storage PPAs for public facilities, tailored outreach), remove deployment barriers, and support with low-cost financing to support adoption.
- **Eliminate the net metering cap:** Proactively remove or significantly raise the current net metering cap when the current 6% cap is met so customer-sited solar can reach a larger share of Virginia's load, in alignment with additional compensation models to support VPPs more broadly (as noted above) and with appropriate modifications in compensation as needed to manage against cost-shifts to other customers as adoption expands. NEM adjustments should be designed and coordinated with other compensation reforms to enable VPP/DER market participation (as noted above).
- **Expand agricultural net metering threshold:** Expand agricultural net metering thresholds to align with other commercial projects (from 500 kW to 3 MW) so agricultural customer-generators can host larger distributed systems without losing net metering eligibility.
- **Support continued shared solar development:** Continue expanding access to shared solar projects, which could include eliminating or increasing shared solar program caps (725 MW for Dominion, 150 MW for APCo);

the minimum bill structure designed to minimize cost shifting can allow more households and businesses—especially low- and moderate-income (LMI) customers—to access shared solar options.

- **Support plug-in solar and storage adoption:** Implement and expand support for safe plug-in/balcony solar and modular storage solutions, building on recent legislation to provide renters and households without traditional rooftop options a pathway to participate in DER adoption and reduce bills.

Improve utilization of the existing grid

Context: Nationally, the power grid has historically been built to serve a small number of peak-demand hours, leaving average year-round utilization in the range of roughly ~50%.[239] As Virginia's electric systems absorb unprecedented new demand, the fastest and lowest-cost path to additional capacity is often getting more value out of infrastructure the Commonwealth has already built, rather than defaulting first to new greenfield construction. Improving grid utilization—including improved use of existing transmission rights-of-way—can be completed more quickly than new lines, helps meet near-term demand, and reduces costs by both lowering the amount of new infrastructure required and curbing rapidly rising transmission congestion costs (see "Tranmission" subsection).

Multiple proven solutions are available to increase the capacity and flexibility of Virginia's existing electric grid, including VPPs and ATTs such as advanced conductors and GETs. Other options include storage as a transmission asset and siting transmission infrastructure in existing rights-of-way. Many utilities across the country now use these tools to add capacity and reduce costs, demonstrating that they are commercially ready rather than experimental.[240] To date, most of these technologies have not been widely deployed in Virginia.

Virginia's recent legislation requiring development of grid utilization metrics—and paving the way for additional action once metrics and data are available—provides a strong foundation for continued actions to support optimal use of the existing grid.[241]

Priority actions:

- **Promote adoption of ATTs:** Align utility incentives with ATT deployment (e.g., shared-savings mechanisms), support privately-funded deployments, and require transparent data-driven consideration of ATTs and GETs before new supplemental transmission projects are approved**.**

- **Integrate DERs and VPPs into utility planning and operations to capture their full grid value:** Continuing to integrate DERs and VPPs into core utility forecasting, resource planning, distribution planning, and system operations can ensure these resources are evaluated alongside traditional generation and wires investments—building on Virginia's recent IRP reforms that call for more holistic consideration of DERs and ongoing grid utilization and performance-based regulation proceedings.[242] Move towards more advanced orchestration of customer-sited resources—including shared data, interoperable controls, appropriate compensation, and performance

What we heard

Many stakeholders supported distributed energy—including dual use options like parking canopies and agrivoltaics—as a way to meet near-term needs. 42% of survey respondents noted DERs as a "most important" energy priority.

"Focus on solar on parking-facility roofs, shared solar on farmland, plug-in solar... and maybe AI firms can pay for some of it."

"If more homes and businesses had battery storage, we could help address current grid limitations while we upgrade."

measurement—to deliver reliable capacity, reduce peak demand, and defer or avoid higher-cost infrastructure.

- **Promote effective implementation of grid utilization metrics to support cost-effective system improvements:** Support effective implementation of grid utilization metrics—through ongoing SCC processes and utility engagement—to develop clear and scalable approaches that result in safe and efficient use of existing infrastructure to improve affordability and mitigate impacts of grid infrastructure development.

Other supportive actions:

- **Implement ongoing IRP reforms across utilities, iterating as needed to achieve intended impacts:** Support robust implementation to deliver integrated planning across generation, transmission, distribution, and DERs; a more proactive and forward-looking assessment of load growth, congestion, and reliability needs; and improved transparency around least-cost alternatives. Consider integrated electric and gas planning strategies. Continue integration of DERs, VPPs, ATTs and other advanced technologies in integrated grid planning approaches (as noted above).

Ensure data center growth advances Virginia's energy goals

Context: Virginia is the world's largest data-center market, and VEP modeling projects that data centers could account for more than 90% of the Commonwealth's electricity-demand growth over the next two decades. Rapid data center load growth is driving grid infrastructure constraints and higher costs, including at the PJM wholesale-market level, as discussed in Section 2G: Energy Affordability. Continuing to implement robust protections and cost allocation practices will be essential to protect residential, small businesses, and other ratepayers from the infrastructure costs caused by data centers.

Data center investment can help accelerate deployment of clean generation, storage, grid infrastructure, and other emerging technologies—supporting innovation, bringing technologies down the cost curve, and creating broader affordability and reliability benefits for Virginians.[243] Data center development can also support jobs, local tax revenue, and private investment.

However, achieving these outcomes requires appropriate regulatory structures, state policies, and programs to manage responsible and strategic growth. It will require data centers—and utility and industry partners—to step up and help meet Virginia's energy priorities. When done right, continued data center growth can align with Virginia's energy, economic-development, and community priorities.

Priority actions:

- **Ensure data centers pay for the incremental costs they drive:** Evaluate and establish mechanisms—across generation, transmission, and distribution—to allocate costs to data centers and other large power users in line with cost causation, such as supporting implementation of GS-5–type tariffs and other customer-funded construction and ownership-transfer models, and exploring other approaches (e.g., subsidiary models) to allocate incremental costs to GS-5 customers, while ensuring systemwide benefits are equitably shared.
- **Require demand flexibility for new interconnections.** Require large data centers to demonstrate onsite and offsite demand-flexibility capability, including the ability to reduce load (on-site or off-site) during grid emergencies, through battery storage, flexible computing, backup arrangements, or contracted demand-response resources. Build on Virginia's 2026 large-load demand-flexibility legislation and align program design with PJM's proposed large-load curtailment and capacity framework.

Virginia's Data Center Accountability Framework

Governor Spanberger established a *Data Center Accountability Framework* to set clear expectations for data center development in the Commonwealth. This framework includes five key principles:

Engage Transparently with Communities: Communities must have meaningful, timely information and a genuine role in decisions about proposed data center development. Data center development and existing operations should be transparent, without unnecessary secrecy or limitations on disclosure. Developers should engage early, openly, and in good faith; disclose material impacts; and work with local partners to provide benefits that address community priorities.

Protect Our Environment: Economic growth must not come at the expense of public health and every Virginian's right to clean air and water. Data center projects should meet high standards for air quality, water and land conservation, and noise control as well as account for cumulative impacts on nearby communities.

Improve Affordability for Virginians: Data centers must pay their fair share of the generation, transmission, distribution, and other public investments their operations require. Virginia's data center growth and market position should lower—not raise—energy costs for households and other customers.

Advance Clean Energy and Grid Reliability: Data centers must be active partners in meeting Virginia's clean energy goals, including by supporting new clean generation, EE, and flexible demand. Their development should strengthen—not weaken—grid optimization, resilience, and reliability.

Deliver a Better Deal for Our Workforce: Responsible data center growth requires durable, broadly shared value for Virginians, including creating and sustaining good jobs that ensure communities can thrive. Data center development should support quality jobs, workforce training, local procurement, infrastructure improvements, and long-term community economic growth.

Learn more: https://www.governor.virginia.gov/media/governorvirginiagov/governor-of-virginia/pdf/Data-Center-Accountability-Framework.pdf

- **Remove barriers and create pathways to support clean energy deployment:** Adjust policies that discourage data center customers from bringing their own clean capacity—such as adjusting minimum demand generation charges—so that verified clean energy procurement is not penalized, and establish channels for private capital from data centers to fund high-value DER and VPP deployments that lower bills for households, businesses, and public facilities, in line with recent legislation.[244]
- **Limit new BTM fossil generation, prioritizing non-combustion bridge power solutions where critical to meet near-term needs:** Limit reliance on new BTM natural-gas generation for data centers. Where needed for near-term reliability and no feasible lower-emission alternative exists, prioritize non-combustion or zero-carbon alternatives—such as battery storage, linear generators or fuel cells using low-carbon fuels where available, and other qualifying technologies. Ensure that small-scale BTM combustion gas facilities (e.g., units <25 MW) are compliant with RGGI if aggregated together with other units <25 MW.
- **Promote responsible development and community benefits through the Data Center Accountability Framework:** Continued data center development must align with all of Virginia's requirements for responsible development, beyond energy. This includes transparent disclosure of power, water, emissions, backup generation, and community impacts; meaningful community engagement; environmental safeguards; local workforce development; and equitable local economic benefits. *See Virginia's Data Center Accountability Framework for additional detail.*

Other supportive actions:

- **Continue to improve transparency on data center cost allocation and infrastructure impacts:** Enhance public visibility into how transmission, generation, and distribution costs driven by large loads are allocated—through regular reporting, clear dashboards, and accessible data—so regulators, communities, and customers can see who is paying for what and adjust frameworks as needed.
- **Accelerate cleaner backup-power replacements:** Build on recent legislation[245] by supporting replacement of retiring diesel backup generators with zero-carbon or lower-emissions alternatives (e.g., battery storage, linear generators) or Tier 4-equivalent generators.
- **Protect grid reliability through aligning voltage and ride-through standards for data centers with national best practice:** Ensure Virginia interconnection requirements are closely aligned with emerging NERC and FERC best practices for large computational loads.[246]
- **Enable reuse of data center waste heat:** Use forthcoming studies on data center waste heat potential to identify pilot projects and develop policies that enable reuse in district heating, industrial processes, or other applications, turning waste heat into a local resource instead of a lost byproduct.

Align Utility Incentives with Affordable Energy Outcomes

Context: Today, Virginia's IOUs operate under a cost-of-service model, in which their authorized ROE is tied to their capital expenditure—rather than specific performance outcomes—with operational expenditures (e.g., fuel costs, maintenance) directly passed through to customers. This structure was initially designed in earlier eras when steady, predictable infrastructure buildout was the primary system need. However, as the scale of infrastructure investment accelerates to meet rising demand, improve system resilience, and replace aging infrastructure and with the broad availability of modern technologies and grid operating practices, there is a need to modernize incentive structures so they reward the most cost-effective path to reliability, not simply the largest capital outlay (alternatives include: performance-based regulation, TOTEX ratemaking,[247] ROE adjustments, debt-to-equity adjustments).

In Virginia, Dominion earns an ROE of 9.8% with a 52/48 equity-to-debt structure and APCo earns a 9.75% ROE with a 50/50 equity-to-debt structure. APCo is currently requesting an increase in its ROE to 10.5%. Both utilities also currently receive a 0.5% transmission ROE adder for participating in the PJM RTO.

Priority actions:

- **Promote cost-allocation and fuel-cost-sharing models that enhance affordability:** Prioritize cost-allocation reforms that more fully reflect cost-causation principles, including consideration of methods such as probability of dispatch where appropriate; the SCC would retain discretion to select the methodology best supported by the record for a particular case. Authorize the SCC to establish fuel-cost sharing mechanisms under which utilities bear a portion of fuel and purchased-power costs that exceed approved forecasts, rather than placing the full burden on customers. The framework could use escalating tiers, similar to Virginia's CVOW cost-containment approach.[248]
- **Pursue ROE reforms to lower utility costs for ratepayers**: Remove the voluntary 0.5% PJM RTO transmission ROE adder—aligning with similar recent actions by Maryland and New Jersey—while requiring continued participation in the PJM RTO.[249,250] Evaluate alternatives to the current utility ROE methodology, such as tying a default authorized ROE to the 10-year U.S. Treasury yield plus a fixed adder and establishing a competitive equity auction process, such as Pennsylvania recently proposed.[251] Tying ROE to a clear benchmark makes utility profits more predictable and better aligned with the utility's low-risk monopoly status, which can materially lower the financing costs passed through to ratepayers while still supporting needed investment. The SCC has the authority to pursue these options, which could support improved affordability outcomes and align incentives.
- **Pursue debt-to-equity ratio reforms that reduce costs for customers:** Review whether Virginia's current IOU capital structure (using an effective equity split of 50-52% for state IOUs' capital) appropriately balances customer costs and financing needs. Using more low-cost debt and less high-cost equity reduces the average return utilities earn on customer-funded investments, which lowers the cost that must be recovered in rates while still keeping utilities financeable.

What we heard

Virginians expressed significant concern that rapid data-center growth was driving cost increases and shifting financial, water, and community impacts onto existing customers and host localities. Data-center and other large-load participants pointed to customer-funded infrastructure, flexible operations, storage, on-site resources, and grid services as tools they can bring to the table.

Other supportive actions:

- **Advance performance-based regulation:** Support strategies that align utility incentives with priority grid outcomes (e.g., affordability, peak reduction, EE, grid utilization), building on the ongoing PBR working group efforts led by the SCC. This could include shared savings models for reducing utility operating expenses, increasing EE adoption, or optimizing grid utilization (pending the outcomes of the forthcoming grid utilization metrics proceeding).
- **Encourage utilities to pursue lower cost public and federal capital and debt where available:** Encourage or require Virginia's IOUs to proactively seek lower cost financing from federal programs and state vehicles

where it reduces customer costs, including DOE loan programs or U.S. Department of Agriculture programs available to cooperatives. Recent DOE loan packages for utilities[252] have been estimated to cut hundreds of millions of dollars per year from interest expenses, lowering the cost ultimately recovered from ratepayers, and DOE guidance now calls for assurance that loan benefits are passed through to customers.

Advance Development of Clean Firm Resources in Virginia

Context: Energy Plan modeling indicates that meeting Virginia's long-term reliability and clean energy objectives will require substantial deployment of offshore wind, advanced nuclear, and LDES. Building the workforce, supply chains, sites, transmission, financing structures, and regulatory pathways needed for these resources must begin now to support deployment at the scale and pace anticipated.

As further discussed in Section 2I: Economic Opportunity and Energy Security, Virginia is well positioned to advance these clean firm resources: Dominion and APCo are evaluating SMR options, while the Commonwealth has a federally permitted offshore-wind lease area supporting the 2.6-GW CVOW project and a statutory 5.2-GW offshore-wind target. While recent federal actions and tariffs have adversely impacted the offshore wind industry, preserving Virginia's offshore wind development readiness (including strengthening domestic supply chains and workforce) will be critical to ensure the state is ready when there is a favorable federal environment.

National momentum is rapidly building for nuclear deployment. For example, in 2026, DOE issued a conditional $17.5 billion loan commitment for long-lead components for up to 10 AP1000 reactors and closed a $1.52 billion loan for the Palisades nuclear-plant restart. New York is pursuing an 8.4-GW nuclear reliability backbone, including at least 1 GW of new advanced nuclear and a pathway for another 4 GW. Duke's 2026 Carolinas Plan includes approximately 4.5 GW of new nuclear; and Kentucky has provided $10 million in nuclear-development grants to spur in-state development. In PJM, Constellation is pursuing the restart of the 835-MW former Three Mile Island Unit 1 in Pennsylvania—renamed the Crane Clean Energy Center—with a target return to service date of 2027.[253]

This national momentum creates an opportunity for Virginia to participate in regional collaboration and benefit from shared learning, supply chains, and financing. Leveraging this national momentum, Virginia should pursue its own clean-firm resource strategy while using disciplined procurement, federal risk-sharing, and cost-containment mechanisms to protect consumers from overruns and achieve cost reductions through scaled deployment.

Priority actions:

- **Update VCEA RPS requirements for new zero-carbon technologies:** Work with the General Assembly to revise VCEA and related statutes so that new dispatchable zero-carbon generation—such as fusion, fission, and geothermal technologies—is explicitly included within the RPS framework, placing these resources on a level playing field with wind and solar and incentivizing more third-party development.
- **Require SCC and utilities to evaluate zero-carbon generation before committing to long-lived fossil generation assets:** Require the SCC and utilities to evaluate opportunities to meet Virginia's growing electricity demand with dispatchable zero-carbon generation before committing to long-lived fossil generation assets that may become stranded or require retirement prior to the end of their economic life.
- **Accelerate responsible nuclear deployment, including with appropriate cost protections:** Pursue strategies that accelerate nuclear deployment at scale across the Commonwealth. This should include supporting nuclear financing structures that protect residential ratepayers from cost overruns; this could include promoting large load offtake models, large multi-unit orderbooks, ring-fenced subsidiary investment

structures, and greater use of federal DOE financing and risk-sharing tools. Virginia Energy could also serve as a lead state office to conduct strategic siting assessments, support pre-development work, coordinate permitting and regulatory actions across local, state, and federal agencies, and partner with local communities on education and outreach.

- **Expand catalytic financing via VCEIB to support clean firm resources and energy innovation:** Continue and expand VCEIB funding as a core tool for accelerating commercialization and deployment of innovative technologies—especially clean firm resources, long-duration storage, and grid-enhancing solutions—by bridging financing gaps for projects that advance affordability, reliability, resilience, energy security, and economic competitiveness and by leveraging state funds to attract significantly greater private or federal capital.

Other supportive actions:

- **Strengthen Virginia's offshore-wind industry and deployment readiness:** Implement the Commonwealth's new offshore-wind workforce-development law and sustain port, vessel, supply-chain, and operations-and-maintenance readiness. Maintain clear policy, permitting, transmission, and stakeholder-coordination pathways so Virginia is prepared to advance future offshore-wind development efficiently and responsibly as market and federal conditions permit.
- **Conduct a statewide nuclear siting and technical potential study:** As part of Virginia's proactive statewide energy planning evaluations (noted in the "Deploy Utility Scale Storage and Solar" subsection above), Virginia can identify optimal sites and technical potential for advanced nuclear (SMRs and LLWRs) across Virginia, including opportunities on brownfields, at or near military bases as appropriate, existing industrial sites, and conversion of fossil-to-nuclear opportunities to inform state deployment strategies and long-term resource planning.

What we heard

Stakeholders supported offshore wind and nuclear as clean, reliable power and potential engines for Virginia job growth, supply chains, and energy security—especially in Hampton Roads. Nuclear was the survey's most broadly supported generation source with support outweighing concern by roughly four to one. For both technologies, participants had significant concerns about high costs, delivery timelines, and ratepayer impacts.

- **Support continued nuclear industry and R&D development:** Expand support for nuclear R&D, including reactor technology, fuel development and recycling, and supply-chain investments, building on previous funding support for the Virginia Innovative Nuclear Hub and other efforts. Continue to support and expand Virginia's existing nuclear innovation ecosystem, universities, and existing industry to build the talent and capabilities needed for long-term deployment.
- **Explore a regional nuclear compact:** Work with PJM and neighboring states to evaluate a regional nuclear compact or similar cooperative framework focused on advanced nuclear and SMRs, aiming to share costs and risks, coordinate siting and transmission needs, and support continued decarbonization of the regional power system.
- **Continue supporting cutting-edge fusion development, building on Virginia's existing leadership:** Advance fusion as a potential new generation resource and economic opportunity by supporting research, demonstration, and commercialization efforts that position Virginia to capture supply chain benefits and

integrate fusion as an important long-term clean energy resource.

- **Support research, development, and deployment of LDES:** Pursue strategies that drive LDES technology development; market reforms and resource planning and valuation methodologies that appropriately compensate LDES for their broader system value; and other strategies to develop a mature and cost-effective LDES industry.

Reduce Emissions from and Better Leverage Gas Infrastructure

Context: Natural gas is expected to remain part of Virginia's near-term energy mix, primarily to serve Virginia's existing natural gas power plants and industrial uses, with some minor additions of natural gas generation possibly needed (as illustrated in the Energy Plan's modeling). Meeting this demand may require targeted additions to pipeline or distribution capacity; however, before building costly new infrastructure, prioritizing improved utilization of available capacity in existing infrastructure is critical to reduce costs, land disturbance, and permitting needs and to avoid locking in high-cost fossil fuel infrastructure assets. Multiple tools exist that could support improved utilization of pipeline infrastructure—modern compressor stations and turboexpanders on existing pipelines can increase throughput and flexibility—in addition to other operational practices.

Reducing methane emissions across the gas supply chain is essential to limit its climate and air-pollution impacts. Opportunities include capturing and beneficially using biogas from agricultural anaerobic digestion, wastewater, food waste, and landfills; expanding Virginia's CMM capture work; and supporting verified upstream and midstream methane reductions associated with gas consumed in the Commonwealth.

Priority actions:

- **Prioritize improved use of existing gas infrastructure before building greenfield:** Assess technical potential and strategies to maximize value from existing pipeline and facility assets through measures such as compressor upgrades, turboexpanders, targeted reinforcements, operational optimizations, and optimizing offtake contract structures. New greenfield gas pipelines should only be considered where existing assets cannot reliably and cost-effectively meet verified needs.
- **Encourage programs and markets that enable durable reductions in methane emissions from gas infrastructure:** Explore creation of a methane reduction market or regulatory/incentive frameworks that support verified emission cuts—such as compressor electrification, leak detection and repair, and high-efficiency digesters. Data center customers could stimulate demand for lower-emissions gas, with procurement and contracting models that fund upstream methane-reduction projects (e.g., targeted pipeline upgrades, electrified compressors, biogas production, and CMM capture) while providing transparent accounting of emission impacts.[254]
- **Support capture of fugitive methane emissions from existing resources for productive use** (e.g., landfills, CMM, etc.): Continue and expand programs like the CMM Capture & Utilization Program run by Virginia Energy and DEQ. Explore establishing dedicated funding for the existing Mine Gas Remediation Fund.[255]

Other supportive actions:

- **Support targeted biogas expansion tied to methane reduction:** Prioritize development of biogas projects (e.g., anaerobic digesters) that directly reduce methane emissions from agriculture, forestry, food processing, landfills, and wastewater while creating additional value streams for local industries and facilities.
- **Identify high-potential biogas opportunities:** Virginia Energy, the Department of Agriculture and Consumer

Services, and DEQ could map and assess high-potential biogas sites across the Commonwealth—such as major livestock operations, food-industry facilities, and municipal waste systems—and develop a pipeline of projects that can serve as models.

Drive Affordable, Clean Transportation Across the Commonwealth

Context: Rising gasoline and diesel prices are increasing household and business transportation costs, with over $1,000 in annual costs added to average Virginia households from recent price spikes in 2026 (see Section 2G: Energy Affordability) for more context. Transportation also remains Virginia's largest source of greenhouse-gas emissions, accounting for approximately 36% of statewide emissions. To reduce costs and emissions, there is significant need for a broad affordability strategy that expands access to efficient vehicles, electric and hybrid options, reliable transit and rail, convenient charging, and land-use and transportation choices that reduce VMT.

Priority actions:

- **Promote Higher Efficiency Vehicles, including EVs, hybrids, and ICE vehicles:** Virginia should pursue opportunities to promote a more efficient fleet drawing from vehicles already on the market - through incentives, education, and influence over specific fleets. This includes education and support for vehicle maintenance practices that improve vehicle efficiency of any car or truck.
- **Expand Transportation Demand Management through adoption of more VMT-efficient transportation/ land-use planning and prioritization approaches**: Adjust planning practices to prioritize VMT-efficient development, being friendlier to pedestrian and transit modes, and mixing types of activities. Relevant state agencies will begin to study and then deploy planning guidelines to promote VMT-efficient outcomes. This can include promoting increased walking/biking through land-use planning and improving the safety of these modes, in line with recommendations from the Virginia State Highway Safety Plan (forthcoming in December 2026) and related programming. Accelerating Transit-Oriented Development (building housing and jobs near transit) can also create a win-win: residents and workers have lower-cost, higher efficiency transportation options and developers have a faster approach to build. This can include completing and implementing the recommendations from the in-process Transit-Oriented Development opportunities study.
- **Expand state and private funding in transit and rail to reduce VMT**: Direct additional funding to transit from existing state funding sources and make sure existing state funding is leveraged as effectively as possible through improvements to grant management. Continue to maximize opportunities for federal funding for transit and rail. Make sure transit expansion is felt in all parts of the state – rural, suburban, and urban. Consider expanding ability of localities to raise money for transit. Partner with private entities where appropriate to expand transit funding. This could

What we heard

Stakeholders differed on natural-gas infrastructure: some emphasized reliable service, modernization, and capacity to support heating, industry, and grid reliability, while others warned that new gas power plants and pipelines increase emissions, methane leaks, ratepayer costs, and stranded-asset risk.

"Virginia's energy security depends on not being overly reliant on any single fuel source or delivery pathway... [it] means natural gas as a reliable bridge fuel while aggressively building out nuclear, utility-scale solar, and storage."

include incentivizing carpooling and transit by offering reliability benefits through express lanes and directing a portion of toll revenues to support transit expansion in-corridor.

Other supportive actions:

- **Complete implementation of the National Electric Vehicle Infrastructure (NEVI) EV charging infrastructure program:** Phase 1 of Virginia's NEVI initiative focused on key Alternative Fuel Corridors and funded 35 DC-fast Charging Projects. Virginia was certified as "fully built out" on these corridors. Phase 2 will expand support for fast charging across the state, including focus on rural areas with no existing fast charging. Depending on federal action, additional funding may be required to adequately support fast charging across the state.
- **Expand public charging at state-owned properties:** Virginia owns many parking lots that are accessible to the public, from DMV customer centers to Amtrak parking lots to parks. Placing Level 1 or Level 2 charging at these locations can meaningfully expand the supply of public charging throughout the Commonwealth.
- **Expand Comprehensive Community Charging Initiative:** Directly fund, or work with utilities to guarantee, rebates for home and business charger installation. Expand and extend EV-Charging Access Programs, particularly for rural and low-income communities and multi-family dwellings.
- **Promote more adoption of EVs:** Supporting consumer charging incentives, including point-of-sale EV rebates for LMI buyers with possible MSRP limits; offering higher incentives for first-time EV or high-efficiency HEV buyers who trade in older, inefficient cars; and ensuring utilities provide competitive EV charging rates while allowing EVs to participate in revenue-generating DR programs can help expand access to and reduce upfront costs of EV ownership.
- **Develop a smart strategy for low-carbon transportation fuels for appropriate sectors (biofuels, hydrogen, SAF):** Collaborate with Agriculture and Forestry, Transportation, and Energy stakeholders to compare all bio-energy options for the Commonwealth's best return, prioritize goals such as energy diversity, sustainability, carbon neutrality, and local economic benefits. Initial focus should be on Sustainable Aviation Fuels (leveraging residual forest products from Virginia's forestry industry), while recognizing that biofuel production is integrated across sectors and supportive policies should be likewise integrated. Virginia's agriculture and forestry sectors generate substantial biowaste feedstock that remains underutilized due to unfavorable economics relative to fossil fuels, representing an untapped opportunity for energy security and rural economic development. Review current biofuels incentives to assess fiscal impacts and evaluate opportunities to cover a broader range of feedstocks and applications—beyond aviation to medium- and heavy-duty transportation and other hard-to-abate sectors—to help monetize this feedstock while advancing carbon, methane, and GHG reduction goals.
- **Lead by example with supporting electrification of state fleets:** Review Department of General Services' (DGS) current total cost of ownership vehicle evaluation and procurement processes to understand alignment with existing regulations to support cost-effective purchasing of fuel-efficient ICEs, Hybrids, and EVs. DGS is required to implement a total cost of ownership calculator "to encourage and promote the use of cost-effective vehicles by considering the total cost of ownership by agencies of the Commonwealth." In the three years of reporting available, DGS and other agencies have purchased 2 EVs and 15 Hybrids (out of 3,050 vehicles purchased) and reported a total savings of <$20,000, suggesting an opportunity to enhance this process.[256] In addition to electrification, the state could pursue biofuels as an option for the state fleet where electrification is not possible or feasible.

Note: See the forthcoming Virginia Economic Development Policy (expected November 2026) for additional context on strategies to support energy supply chain and workforce development as part of broader state economic development strategies.

Build a Homegrown Workforce and Energy Supply Chain to Power Virginia's Energy Economy

Context: Meeting Virginia's growing energy needs will require thousands of additional construction, skilled-trades, operations, and maintenance workers each year, with VEP modeling suggesting roughly 5,000-20,000 in annual construction jobs across sectors and 20,000 new operating jobs by 2050 (see Section 3C: Capacity Expansion Modeling Results). This creates strong career opportunities for good-paying jobs but also a risk of labor shortages without scalable training and work-based learning pipelines. Meeting these future energy workforce needs will require sustained investment in employer-aligned training and work-based learning pathways into foundational energy occupations—such as electricians, lineworkers, HVAC technicians, welders, and controls technicians. At the same time, supply-chain constraints for grid equipment and emerging technologies are increasing project costs and timelines. Coordinated workforce, manufacturing, commercialization, and financing strategies can help Virginia capture more of the economic value associated with its energy buildout. Economic development and energy technical expertise must be coordinated to increase value and benefit of Virginia's sites for future economic development and drive responsible growth in our communities.

Note: See the Governor's forthcoming Comprehensive Economic Development Policy (expected November 2026) for additional context on strategies to support energy supply chain and workforce development as part of broader state economic development strategies.

Priority actions:

- **Scale employer-led energy training, registered apprenticeships, credentials, and work-based learning:** Expand registered apprenticeships, community-college pathways, industry credentials, and paid work-based learning for priority occupations, with attention to expanding access for underutilized talent pools and addressing barriers to participation and employment. Workforce efforts should be informed and supported by investments from energy employers to align training programs with job requirements, with public support tied to employer training and hiring commitments.
- **Target energy supply chains as a priority sector for economic development:** Coordinate the work of VEDP, VCEIB, and VIPC to support early growth stage energy companies, energy supply chain, and energy generation to support economic development and energy generation in the Commonwealth.
- **Enhance coordination across energy planning and economic development capabilities across state agencies:** Energy and economic development professionals must coordinate to identify strategic energy siting and generation opportunities that can reduce grid stress and congestion and support cost reduction for ratepayers. Make key economic development sites "energy ready," ensuring a proactive approach to the necessary long-term energy infrastructure mapping and investments for holistic site readiness.

What we heard

Stakeholders saw Virginia's energy buildout as an opportunity to grow Virginia-based manufacturing, skilled-trades careers, technology development, and supply chains—especially by building on regional strengths in ports, shipbuilding, nuclear, and advanced energy.

"Virginia can become a leader in workforce development for the energy sector by expanding training pipelines."

- **Leverage the full suite of state tools to support emerging and mature energy industries:** Coordinate and enhance state programs, using VCEIB and other financing tools for emerging businesses and projects, VIPC for commercialization and early-stage innovation, and VEDP for site development, company attraction, expansion, and workforce incentives. This can help ensure end-to-end support for a variety of industries, including presenting a coherent state strategy.

Supportive actions:

- **Promote local hiring strategies in state-funded programs:** Where feasible, incorporate local hiring, workforce-development, and in-state supply-chain considerations into state-supported energy procurements, financing, grants, and infrastructure investments.
- **Improve contractor training and consumer protections:** Expand training, credentialing, and verification for consumer-facing providers, including weatherization, HVAC, solar, and EV-charging contractors, building on existing Virginia Energy Connect workforce programs.
- **Continue evaluating critical minerals opportunities:** Continue assessing commercially viable opportunities for responsible critical minerals extraction, processing, recycling, and related manufacturing in Virginia.

4D. An Energy Future that Works for Every Virginian

Virginia's energy future will be defined not simply by how much power the Commonwealth builds, but by whether that progress improves life for the people who depend on it. Success means a family can keep the lights on without sacrificing other necessities; a manufacturer, farm, hospital, school, or small business can count on dependable energy; and every community can see a fair share of the jobs, investment, resilience, and costs that new infrastructure creates without unduly bearing the health costs of heavy, localized pollution.

Virginia can meet this moment with continued ambition and innovation to achieve the Commonwealth's clean energy and climate goals. By making strategic, data-driven choices, requiring responsible and sustainable growth, and investing in the people and places that will power its future, Virginia can build an energy system that is more affordable today and over the long term, clean, homegrown, reliable and resilient. That system can benefit communities and create opportunities in every region of the Commonwealth.

Appendix

Appendix

Recent Energy Legislation

A record number of energy related bills were passed in the 2026 General Assembly session, key efforts that will continue to be implemented over the coming years. Relevant legislation is noted below.

Solar & Storage Expansion

- **SB 448 / HB 895 (Energy Storage Expansion):** Substantially ramps up Dominion's long-term energy storage mandates, increasing short-duration storage targets from 2.6 GW to 16 GW by 2045 and increasing APCo's targets from 400 MW to 780 MW. Creates 4 GW long-duration storage target for Dominion and a 520 MW long-duration storage target for APCo by 2045.

- **SB 175 / HB 628 (Distributed Generation Expansion Act):** Quintuples Dominion's annual distributed generation build requirements, mandates 1 gigawatt of solar be built on previously developed sites (brownfields, landfills, parking lots), allows PPAs for all, and increases the amount of third-party development.

- **SB 327 / HB 1062 (Virginia Energy Savers Act):** Creates 8-year program for IOUs to fund EE, residential solar, and residential storage for income- and age-qualified customers. Total investment over 8 years could exceed $300 million if utility growth rates continue.

- **SB 254 / HB 807 (Shared Solar Expansion):** Adds 525 megawatts of new community solar capacity across Dominion's territory, maintaining a low-income carve-out.

- **SB 255 / HB 809 (Shared Solar Net Crediting):** Simplifies the shared solar process for APCo customers by transitioning utilities to a unified, consolidated billing model. Adds 50 megawatts of capacity to APCo's program.

- **HB 891 / SB 443 (Storage (w/ Solar) By Right):** Allows storage facilities to be co-located on existing solar sites. Governor's amendments limit storage facility to size of solar facility and require siting agreement negotiations.

- **HB 711 / SB 347 (Siting Standards):** Does not require localities to approve any solar projects but does require localities to adopt ordinances with standards within a certain range. Also requires written decision explaining any project denials.

- **SB 382 / HB 590 (Smart Solar Permitting):** Directs the creation of a statewide, automated permitting platform to standardize and fast-track residential rooftop solar approvals.

- **SB 250 / HB 395 (Balcony / Plug-in Solar):** Eliminates local red tape and sets safety standards allowing renters and condo owners to adopt portable, small-scale solar systems.

- **SB 26 / HB 1234 (Parking Lot Solar Canopies):** Empowers local governments to require solar canopies on new, nonresidential parking lots with 100 or more spaces.

- **SB 340 / HB 508 (Agrivoltaics Definition):** Establishes the legal framework for agrivoltaics, allowing solar development to coexist with active farming and preserving agricultural land.

Large Energy Users

- **SB 253 (Data Center Infrastructure Cost Allocation):** Ratepayer protection bill requiring the SCC to prevent cost shifting from data centers in Dominion's next rate case, authorizes securitization for increased fuel costs to reduce impacts to ratepayers, and provides guardrails around undergrounding program.

- **HB 1191 / SB 377 (Large Load Infrastructure Funding):** Establishes a framework allowing large load customers to fund their own infrastructure upgrades in electric cooperative territory while insulating residential utility customers from the cost.

- **HB 507 (Backup Generator Requirements):** Requires new backup diesel generators to be Tier 4 or better. Tier 4 generators emit significantly less pollution than Tier 2 or Tier 3 generators, which are most common among current data centers.

- **SB 267 (Comprehensive Energy Infrastructure Analysis):** Requires a state review of utility infrastructure for opportunities to uprate zero-carbon generating resources, energy storage resources, and transmission upgrades, including GETs and high-performance technologies. Also requires an analysis of whether large load customers could finance such upgrades as a condition of accelerated interconnection.

- **HB 284 / SB 371 (Demand Flexibility):** Requires utilities to launch voluntary demand flexibility programs for large load customers to reduce demand during peak periods.

- **HB 892 (Utility Load Forecast Audit):** Requires a state review of utility load-forecasting practices and the assumptions used to justify infrastructure investments.

- **SB 598 / HB 369 (Accelerated Clean Energy Buyers):** Renames and broadens state corporate purchasing rules, allowing major commercial or industrial buyers to count investments in advanced nuclear (like the AP1000) and fusion energy toward their clean energy compliance metrics.

Utility Reform, Efficiency, & Emerging Tech

- **HB 429 / SB 249 (IRP Reform):** Makes significant changes to the IRP process including transmission planning integration and more holistic consideration of DERs within the planning process.

- **HB 1360 (Uneconomic Dispatch):** Requires utilities to show that their dispatch decisions for coal and oil units were prudent in relevant cost recovery dockets.

- **SB 505 / HB 1256 (Fuel-Price Spike Mitigation Study):** Directs the Commonwealth to review strategies to protect retail utility ratepayers from severe monthly bill spikes triggered by global fossil fuel market volatility.

- **HB 2 / SB 72 (Low-Income EE Targets):** Mandates that Dominion and APCo hit explicit targets to provide prescriptive EE upgrades to at least 30% of eligible low-income households by 2031. Eligible low-income households are defined as those that rely on delivered fuel (heating oil and propane), not natural gas.

- **HB 884 (PIPP Expansion):** Beginning January 1, 2027, reduces bill amounts from 6% and 10% of annual income to 3% and 5% of annual income, respectively. Increases eligibility threshold from 150% of the federal poverty level to 200% of the federal poverty level.

- **HB 434 / SB 621 (Grid Utilization Mandate):** Directs the SCC to establish grid utilization metrics and requires increased utilization over time, which can be accomplished by technologies including DERs and Grid Enhancing Technologies (GETs) and advanced transmission software to maximize existing lines before proposing new infrastructure corridors.

- **HB 1065 / SB 508 (Surplus Interconnection):** Instructs electric utilities to identify and reuse underutilized grid interconnection points in their IRPs to safely bring new generation online faster.

- **HB 562 / SB 487 (Electric Co-op VPPs):** Authorizes electric cooperatives to aggregate residential battery storage and smart thermostats to function as VPPs that balance grid load.

- **HB 1467 (APCo VPPs):** Requires APCo to aggregate residential battery storage and smart thermostats to function as VPPs that balance grid load.

- **HB 889 / SB 497 (Transmission Lines in Existing ROW):** Establishes a policy of the Commonwealth that existing corridors, utility corridors, and highway corridors shall be prioritized over new corridors for new transmission facilities.

Stakeholder Input Summary

Purpose and Approach

Virginia Energy implemented a comprehensive engagement strategy that combined digital and in-person methods to reach statewide, regional, and sector-specific audiences. Virginia Energy gathered input from residents, businesses, community organizations, local governments, utilities, state agencies, and other stakeholders to ensure that the Energy Plan reflected the Commonwealth's diverse energy needs, priorities, and opportunities. The engagement strategy paired broad public outreach with targeted stakeholder discussions to capture both community perspectives and technical expertise.

Through these efforts, Virginia Energy met with more than 500 individuals and received 3,003 survey responses over seven weeks. Virginia Energy used stakeholder input to validate planning assumptions, identify challenges and opportunities, understand regional and community perspectives, and strengthen the practicality and credibility of Plan recommendations. The engagement process also increased transparency, built awareness of the planning effort, and created meaningful opportunities for Virginians to shape the Commonwealth's energy future.

Summary of Engagement Activities

Public survey

Virginia Energy conducted a statewide online survey to gather broad public input on Virginia's energy future. The 3,003 responses addressed energy priorities, affordability, reliability, infrastructure, emerging technologies, implementation barriers, and populations that may require particular attention. Open-ended questions also generated substantial qualitative feedback. Approximately 88% of respondents identified themselves as residents; the remainder represented

advocacy and community organizations, government, and technical experts.

Respondents ranked electric generating resources as the highest priority among eleven candidate focus areas, followed by siting, land use, and mitigation; EE and weatherization; advanced and emerging technologies; and transmission and distribution. Respondents selected public acceptance or trust as the top implementation barrier, followed by capital cost or financing, permitting or regulatory requirements, unclear roles across levels of government, and local land-use or zoning issues. Electricity bills dominated affordability concerns, while low-income households and rural communities emerged as the most frequently identified groups needing particular attention.

The open-text responses added important context. Data centers emerged as the most frequently discussed issue, even though the survey did not ask a specific question about them. Approximately 64% of respondents raised data centers in written comments, most often in relation to electricity demand growth, infrastructure costs, ratepayer protection, cost allocation, and impacts on land, water, and communities. Other frequently raised topics included solar development, affordability, grid reliability, transmission, clean energy, environmental impacts, nuclear energy, siting, natural gas, EE, and utility accountability.

Regional in-person meetings

Virginia Energy convened six in-person regional listening sessions in Abingdon, Hampton Roads, Danville, Arlington, Petersburg, and Richmond. The regional meetings brought together approximately 200 participants and used live polling, facilitated small-group discussions, and report-outs to gather place-based input on current energy challenges, affected customer groups, implementation barriers, and possible solutions. The regional sessions helped Virginia Energy understand how statewide energy issues appear differently across rural, industrial, coastal, urban, and rapidly growing regions.

Across the six sessions, participants identified affordability, growing electricity demand, infrastructure constraints, and reliability as major challenges. Participants also highlighted permitting and siting barriers, cost and funding limitations, policy and market barriers, workforce shortages, and infrastructure limitations as obstacles to meeting Virginia's energy needs over the next decade. Regional polling showed that participants often viewed low-income customers, households, rural communities, industry and manufacturing, and large energy users as groups facing significant energy-related challenges.

Regional input added important local context

Virginia Energy intentionally held sessions in different geographies to capture regional differences in context, challenges, and priorities. Table 22 summarizes the different local contexts from each session.

Table 22. *Regional Input from Stakeholder Meetings*

Region	Distinctive input from meeting discussions
Abingdon / Southwest Virginia	Participants emphasized rural affordability, long outages, fragmented utility service territories, older housing, legacy energy assets, abandoned mine lands, and opportunities to convert regional resources into durable local economic benefits.
Hampton Roads / Southeast Virginia	Participants connected energy planning to military readiness, port and maritime operations, offshore wind, nuclear expertise, coastal resilience, policy durability, and energy-ready economic development sites.
Danville / Southside Virginia	Participants linked energy availability to industrial recruitment and retention, power quality, municipal utility leadership, supply-chain constraints, skilled-trade shortages, and the need to protect existing employers and residents from cost and reliability impacts.
Arlington / Northern Virginia	Participants focused on load growth driven by data centers, distributed resources, storage, district energy, waste-heat reuse, GETs, cybersecurity, large load customer cost allocation, and local authority.
Petersburg / Central Virginia	Participants emphasized long-term infrastructure readiness, policy durability, demand uncertainty, supply chains, workforce needs, natural gas and industrial needs, and trusted information about costs, benefits, and tradeoffs.
Richmond / Central Virginia	Participants emphasized affordability, community solar, rooftop solar, batteries, DR, EE, resilience hubs, public trust, interconnection delays, workforce gaps, financing constraints, and equitable access to energy investments.

Virtual stakeholder meetings and targeted consultations

Virginia Energy also conducted over twenty thematic virtual stakeholder meetings and focused consultations with state agencies, local governments, utilities, industry representatives, academic institutions, community organizations, advocacy groups, tribal representatives, regulators, manufacturers, and other key stakeholders. These meetings added detail on customer, technology, land-use, regulatory, and implementation issues to the engagement record.

Thematic sessions highlighted the importance of EE and weatherization as system resources and housing-quality strategies; environmental and consumer advocates emphasized affordability, clean energy, public health, EJ, utility accountability, and ratepayer protection; large load stakeholders stressed the need to differentiate data centers, manufacturers, defense facilities, hospitals, ports, and other major users; solar and storage participants focused on interconnection, local permitting, fair valuation of distributed resources, shared solar, battery safety, and customer education; transportation stakeholders broadened the discussion beyond charging to include land use, freight, transit, managed charging, and workforce readiness; agriculture and forestry stakeholders raised working-land protection and bioenergy opportunities; and tribal representatives elevated outage resilience, microgrids, technical assistance, and cultural-resource protection.

Targeted consultations added institutional, regulatory, utility, and industry perspectives. State agencies connected energy demand to water availability, air quality, housing, infrastructure finance, technology, workforce, natural resources, and local fiscal risk. Utilities and regulators emphasized rapid load growth, generation and transmission timelines, interconnection, cost allocation, supply-chain delays, fuel and weather risks, and the need for clear and durable planning assumptions. Manufacturers, cooperatives, natural gas stakeholders, and defense-related industrial

stakeholders emphasized affordability, power quality, fuel diversity, reliability, service territory differences, national security, and the role of energy availability in economic competitiveness.

Major Themes and Findings

Affordability, Reliability, and Growing Demand

Participants consistently identified the need to maintain affordable, reliable, and resilient energy service while preparing for significant growth in electricity demand. Stakeholders linked energy availability and supply to economic development, business retention, defense readiness, manufacturing growth, and affordability. Survey respondents reinforced this theme by identifying electric generation as the top statewide priority and electricity bills as the dominant affordability concern.

Infrastructure Development, Planning, and Coordination

Stakeholders repeatedly identified generation, transmission, distribution, interconnection, permitting, siting, and long-term planning as critical issues. Participants called for transparent demand forecasts, clearer decision criteria, more realistic planning assumptions, stronger coordination among utilities and public agencies, and approaches that distinguish likely load growth from speculative proposals. Many participants also emphasized cost allocation and the need to ensure that new large load customers pay their fair share of growth-driven infrastructure costs.

Efficiency, Demand Management, Distributed Resources, and Grid Modernization

Stakeholders identified EE, weatherization, DR, distributed solar, storage, VPPs, microgrids, GETs, and other practices as tools that can reduce costs, strengthen reliability, and improve existing infrastructure. Meeting participants emphasized that these resources need clearer valuation, easier customer access, and improved coordination among energy system actors and government.

Workforce, Supply Chains, Financing, and Implementation Capacity

Stakeholders emphasized that workforce shortages, equipment lead times, supply-chain constraints, financing barriers, policy uncertainty, and implementation capacity could slow Virginia's ability to meet energy goals and rising energy demand. Participants called for workforce pipelines, technical training, apprenticeship programs, domestic manufacturing, stronger coordination between education and industry, and financing mechanisms that help households, businesses, local governments, utilities, and community organizations implement needed projects.

Community Impacts, Equity, Public Trust, and Meaningful Engagement

Participants repeatedly emphasized that successful implementation will require trusted information, transparent decision-making, and engagement early enough to shape project siting, design, and community benefits. Survey respondents selected public acceptance or trust as the top implementation barrier, and meeting participants called for accessible data, credible messengers, plain-language communications, and strategies that ensure energy investments deliver benefits equitably. Improved education and outreach efforts to explain energy technologies, the energy system, and best practices for personal energy use were frequently cited as a solution to multiple barriers.

How Virginia Energy Considered and Incorporated Input

Virginia Energy used stakeholder and public input throughout development of the VEP. Engagement findings helped refine planning assumptions, identify emerging issues and risks, prioritize areas requiring additional analysis, and

shape the VEP's recommendations. Stakeholder input reinforced the importance of addressing affordability, reliability, resilience, infrastructure development, workforce capacity, implementation barriers, public trust, and long-term planning certainty.

The Plan incorporates engagement findings by elevating several cross-cutting issues that stakeholders raised repeatedly: rapid electricity demand growth; fair and transparent cost allocation; the need for generation, transmission, distribution, and interconnection solutions; the role of efficiency, demand-side resources, storage, and grid modernization; workforce and supply-chain constraints; and the importance of meaningful public engagement and trusted information. The Plan also reflects regional and institutional differences by recognizing that rural communities, coastal regions, military and industrial centers, large load corridors, cooperative and municipal utility territories, and local governments face different conditions and implementation barriers.

Virginia Energy did not treat engagement as an opportunity to affirm perspectives or to seek unanimous agreement. Participants often agreed on the challenges but differed on the appropriate solution, the preferred technology mix, the desired pace of implementation, the role of state versus local authority, and the allocation of costs and risks, among other aspects. Virginia Energy used these differing perspectives to determine tradeoffs and identify areas where the VEP could provide transparent criteria and processes, realistic assumptions, and clear implementation pathways. The engagement process ultimately gave Virginia Energy a stronger foundation for developing a practical, informed, and responsive VEP that reflects both statewide priorities and the diverse perspectives of Virginians.

Modeling Assumptions and Inputs

The Virginia Department of Energy modeling team used ITRON's MetrixND, an electricity Load and Consumption forecasting software, and Energy Exemplar's PLEXOS, a capacity expansion modeling software, for this modeling exercise. Key inputs and assumptions that informed this analysis are below.

How to Interpret Key Results

Capacity additions are new nameplate megawatts (MWs) required to meet modeled demand and planning-reserve requirements; they do not include Virginia's existing installed capacity and should not be confused with annual electricity generation (MWh), which depends on how often resources operate and affects fuel costs, emissions, and health impacts.

System costs include modeled capital, operating, fuel, and compliance costs for new and existing generation, but exclude added costs of utility ROE (9.7% for APCo and 9.8% for Dominion), available federal tax credits, and the full cost of transmission needed to serve new load and deliver generation.

Social cost of carbon estimates climate damages using $262 per metric ton of CO_2. Health damages were calculated for $PM_{2.5}$, SO_2, and NO_x based on mortality estimates previously used by the EPA.[257] Total CO_2 emissions are in-state CO_2 emissions from modeled operation of existing and new fossil-fuel resources and exclude emissions associated with imports; emissions from APCo-owned gas units in West Virginia are excluded (though the fuel costs associated with these units are included, given they would be allocated to Virginia ratepayers).

Core Input Assumptions

The modeling framework evaluates a broad suite of commercially available and emerging generation, storage, and firm capacity technologies. Table 23 details the cost parameters, commercial availability dates, and technology performance assumptions utilized in the capacity expansion model.

Table 23. *Capital Expenditure Cost (CAPEX), Capacity Accreditation and Commercial Availability Assumptions for Selectable Capacity Expansion Model Resources* [258,259, 260, 261, 262]

Technology Type	2025 CAPEX Cost ($/kW)	PJM ELCC Value	Earliest COD
Battery Storage 1 hr	$862.51	N/A	2029
Battery Storage 2 hr	$1,500.92	N/A	2029
Battery Storage 4 hr	$2,334.94	50%	2029
Battery Storage >= 10 hr	$4,836.99	72%	2031
Simple Cycle CT	$1,884.39	60%	2029
CC CT	$2,575.00	74%	2033
Solar PV	$1,740.62	9%	2029
Hybrid Solar + Storage	$2,794.45	50%	2029
Offshore Wind	$7997.68	69%	2034
Onshore Wind	$1,832.639	41%	2033
Biomass	$5,105.77	60%	2033
Nuclear AP1000	$12,756.00	95%	2035
Nuclear Gen III+ SMR	$18,655.00	95%	2035
Fusion	$22,200.00	95%	2035
Non-Combustion Natural Gas	$3,100	95%	2029

Note: PJM does not assign an ELCC value to battery storage of 1 and 2 hour durations.

CAPEX assumptions also include estimated transmission costs, new gas-pipeline infrastructure, and firm natural gas supply contract costs. To prevent unrealistic market deployment rates, the model enforces explicit real-world physical, regulatory, and market constraints:

Table 24. *Key VEP Model Constraints*

Constraint	Modeling Limit / Cap	Notes
Solar Build Cap	1,800 MW / year	Aligns with ambitious pace of deployment seen in other states
Offshore Wind Cap	5,180 MW total by 2035	Aligns with statutory VCEA target (2.58 GW CVOW Commercial + 2.6 GW supplemental)
Import Reliance Cap	30% Annual Consumption	Enforces in-state resource adequacy and protects Virginia from regional import curtailments during PJM-wide winter emergencies; aligned with recent past import rates

Constraint	Modeling Limit / Cap	Notes
Transmission Expansion	10,000 MW existing transmission capacity in 2025; 10,000 MW of interstate transmission added by 2035	Reflects execution timeline for approved PJM Regional Transmission Expansion Plan (RTEP) market efficiency and reliability projects
Distillate Fuel Oil Cap	Limits runtime of distillate fuel oil units to historical capacity factors	Prevents an unrealistic amount of utilization from these units that would exceed real-world permit limits

Other assumptions:

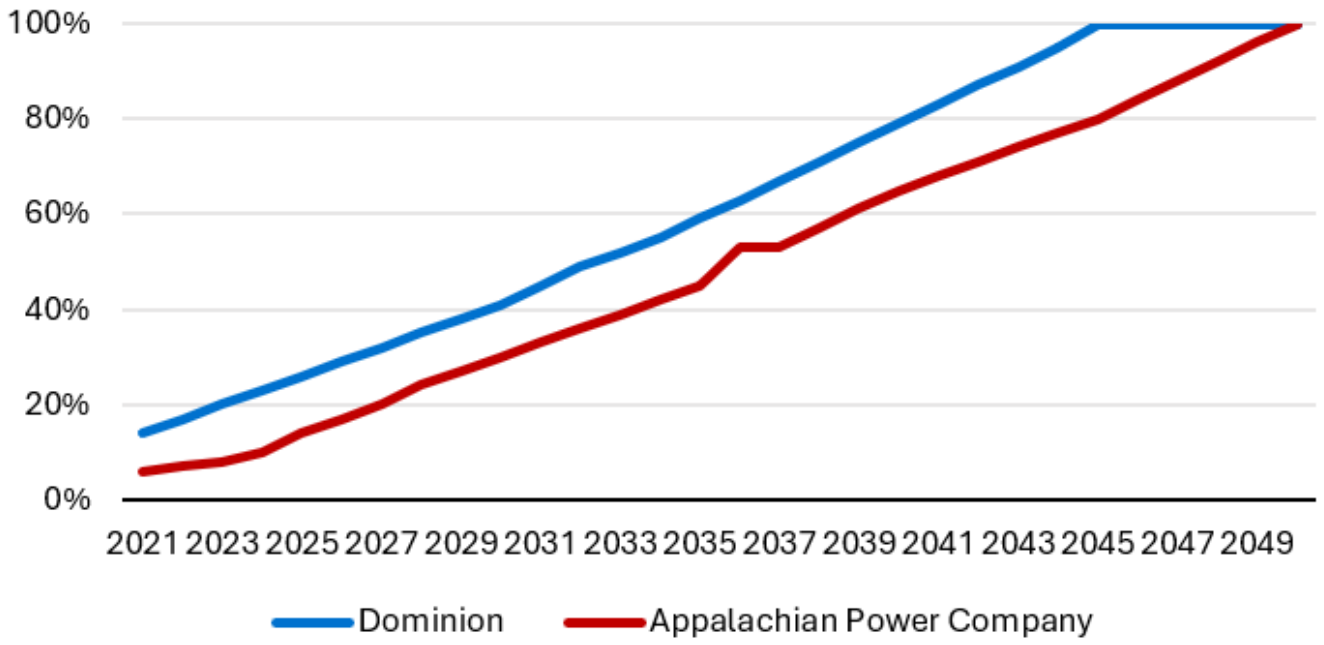
New nuclear capacity can start to be constructed in 2035, with up to two 300-MW units every other year and 4,800 MW total by 2050; requires a 400-MW fusion facility in 2035 and 600 MW of SMR capacity in APCo territory in 2038, consistent with identified development plans; the model does not include new large nuclear facilities because of siting constraints in Virginia (if sufficient space could be identified, e.g., brownfields, military land, this could reduce the costs of nuclear). Up to 1,083 MW of new combined-cycle gas capacity and 237 MW of new combustion-turbine capacity are allowed to be built in West Virginia, consistent with APCo's 2026 RPS plan; emissions from these units are not included in reported Virginia emissions, but their fuel costs are included in system costs.

EV charging accounts for about 3% of total demand growth, under a moderate adoption outlook where EVs make up 31% of Light Duty Vehicles (LDV) by 2050; even if EV adoption accelerates to 100% of all light duty vehicles by 2050, EVs would represent only around ~9% of total load growth, an amount the grid can expand to serve as it simultaneously scales to meet other large new loads.

RPS Compliance

Virginia's two large investor-owned electric utilities are required to participate in an RPS that requires the utilities to retire an increasing number of renewable energy credits (RECs) equal to a percentage of the previous year's sales. By 2045 for Dominion and 2050 for APCo, both are required to retire RECs equivalent to 100% of their previous year's sales.

Figure 64. *Virginia IOU RPS Goals*



To effectively capture RPS compliance, the capacity expansion model considers the Commonwealth's annual consumption and the respective utility's portion of that consumption to determine the RPS requirement. Specifically, Dominion represents approximately 67.96% of sales, APCo represents approximately 14.02%, and the electric cooperatives and municipal electric utilities represent approximately 18.03%. For Dominion, this consumption is decreased by the amount of generation supplied by nuclear and sales to participants in the Accelerated Clean Energy Buyers (ACEB) program[2] to determine the amount of generation that is necessary to be RPS compliant.

Dominion is required in any compliance year to retire DER RECs from solar, wind, or anaerobic digestion resources of 1 MW or less as a percentage of its total RPS Program requirements. For 2026-2030, Dominion must retire a number of DER RECs equivalent to 4.5% of its total RPS Program requirement, increasing to 5% after 2030. Because the capacity expansion model is discretely expanding DER resources, the VEP retires DER RECs equivalent to their generation output equivalent to the codified requirement and for any shortfall pays the DER REC deficiency payment. The DER REC deficiency payment started at $75/MWh of deficiency in 2021 and has increased by 1% annually.

RGGI

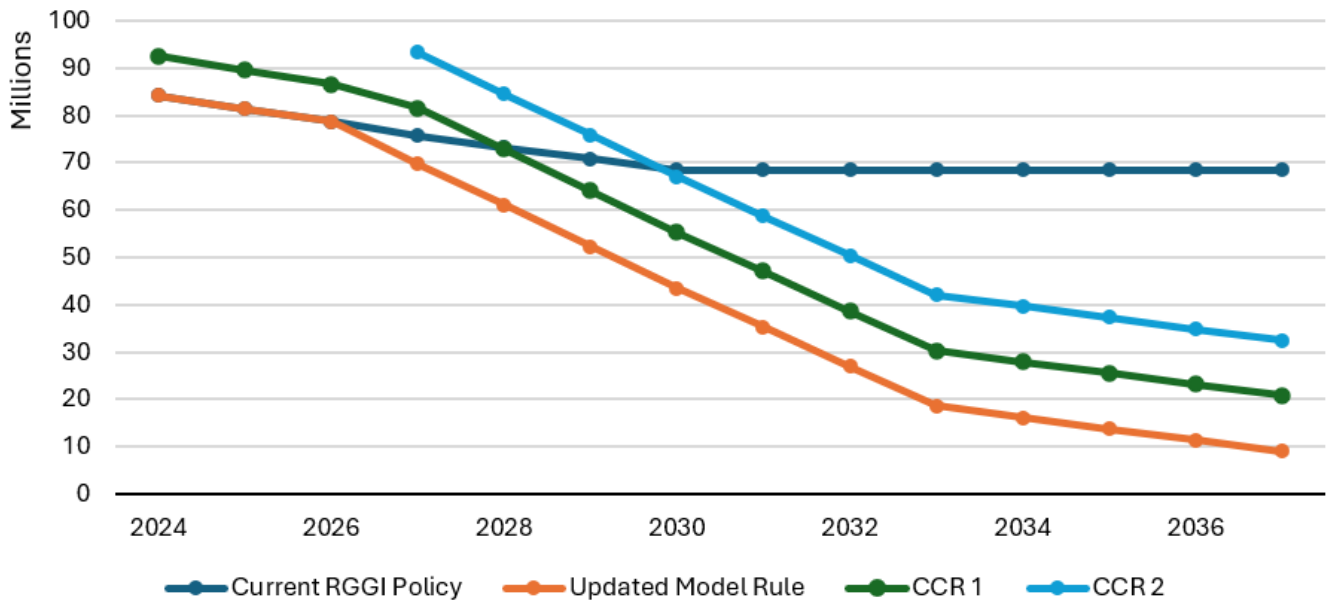
In July 2026, Virginia rejoined the RGGI, a CO_2 cap and trade program designed to help participating states reduce their GHG emissions. The program requires operators in participating states with generators equal to or greater than 25 MW in capacity that emit CO_2 from fossil fuel usage to purchase allowances equivalent to their short tons of CO_2 emissions on a three-year compliance basis. To sell these allowances, RGGI holds quarterly auctions open to both compliance and non-compliance entities. Non-compliance entities typically sell allowances on the secondary market for a higher

[2] The Accelerated Clean Energy Buyers program (ACEB), formerly the Accelerated Renewable Energy Buyers program (AREB), allows for a commercial or industrial customer of Dominion Energy or Appalachian Power Company with an aggregated load over 25 MW to enter into contracts certified by the SCC, Dominion Energy, Appalachian Power Company, or another entity to purchase clean energy above the amount the utility is currently providing as part of its general service.

price. In scenarios that consider participation in the RGGI cap and trade program, RGGI acts as both a power-sector CO_2 emissions cap and a price on allowances for dispatching carbon-emitting units. The capacity expansion model is more restrictive than the actual operation of RGGI in the Commonwealth. In reality, Virginia entities could purchase allowances that are allocated to other states even if Virginia's allowances are set to zero.

In July 2025, RGGI completed its third program review, which would significantly decrease the availability of CO_2 allowances for participating states between 2027 and 2037.

Figure 65. *RGGI Cap Trajectory Update*



As can be seen in the Figure 65, the Updated Model Rule will significantly decrease the number of allowances available compared to the Current RGGI Policy.

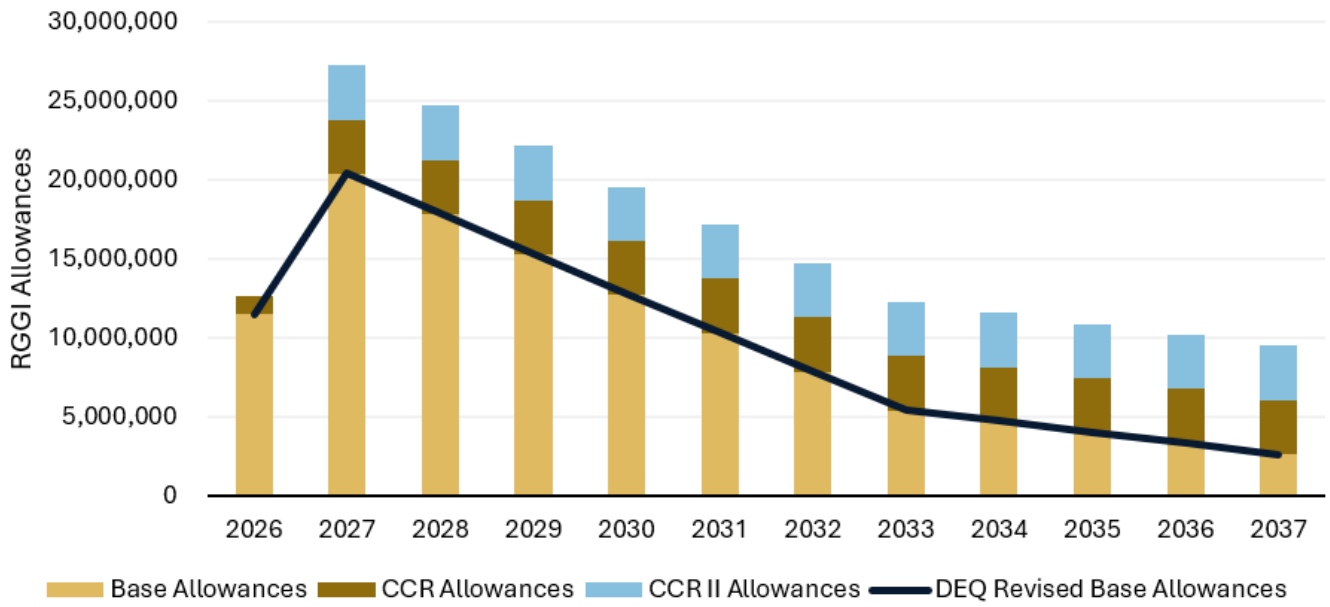
Table 25. *Summary of RGGI Regional Allowance Cap Updates, not including Virginia*

Year	Allowance Cap	Minimum Reserve Price	CCR Trigger Price		CCR Volume	
			Tier I	Tier II	Tier I	Tier II
2027	69,806,919	$9.00	$19.50	$29.25	11,746,358	11,746,358
2028	61,081,054	$9.63	$20.87	$31.30	11,746,358	11,746,358
2029	52,355,189	$10.30	$22.23	$33.49	11,746,358	11,746,358
2030	43,529,324	$11.03	$23.89	$35.83	11,746,358	11,746,358

Year	Allowance Cap	Minimum Reserve Price	CCR Trigger Price		CCR Volume	
			Tier I	Tier II	Tier I	Tier II
2031	35,277,611	$11.80	$25.56	$38.34	11,746,358	11,746,358
2032	26,925,899	$12.62	$27.35	$41.02	11,746,358	11,746,358
2033	18,574,187	$13.51	$29.26	$43.89	11,746,358	11,746,358
2034	16,187,983	$14.45	$31.31	$46.96	11,746,358	11,746,358
2035	13,801,780	$15.46	$33.50	$50.25	11,746,358	11,746,358
2036	11,415,578	$16.55	$35.85	$53.77	11,746,358	11,746,358
2037	9,029,374	$17.70	$38.36	$57.53	11,746,358	11,746,358

The CO_2 emissions cap is modeled due to the requirements of Va. Code § 10.1-1308 D, which requires that, "no allowances be issued for covered units in 2050 or any year beyond 2050." DEQ recently released its preliminary revised Virginia Annual Allowance trajectory, however this occurred after Virginia Energy had developed its own forecast and run the capacity expansion models. The VEP allowance forecast was 99.87% of DEQ's revised numbers, suggesting a high amount of certainty related to the RGGI portion of this modeling exercise.

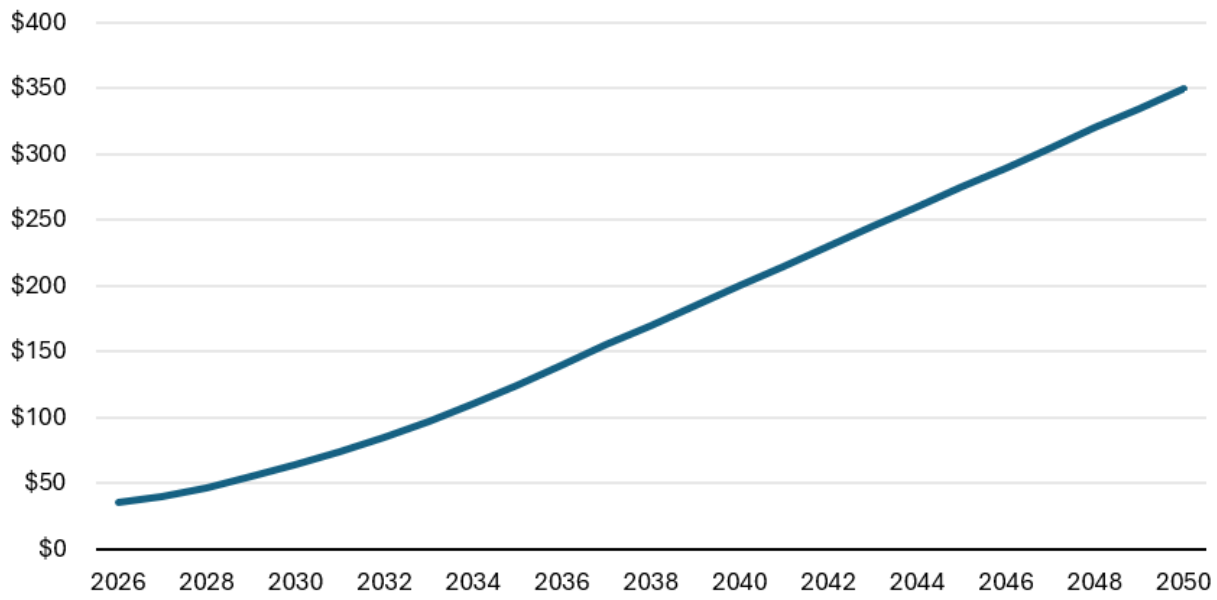
Figure 66. *Annual RGGI Allowances available for Virginia Compliance*



The RGGI forecast for Virginia relies on information provided by RGGI, which has allocated 11.48 million short tons worth of base allowances to Virginia for the half-year of 2026, as well as 1.148 million CCR allowances that are released if a certain allowance price threshold is cleared. If Virginia had participated in RGGI for the full year it would have been allocated 22.96 million base allowances and 2.296 million CCR allowances. The VEP uses the full year 2026 allowance as the baseline for forecasting future-year compliance. Virginia's base allowances are calculated by taking the average

reduction for the rest of RGGI states participating in the Third Program Review and reducing Virginia's full year 2026 base allowances by this percentage, resulting in a decrease of available base allowances to 2.64 million in 2037. During 2024, 2025, and 2026 all CCR allowances were sold during the first annual auction, and the model assumes that Virginia electric utilities will purchase and retire at least all the base and CCR allowances prorated for Virginia. RGGI recently completed their Third Program Review, which includes a second tier of CCR (CCR II) allowances starting in 2027 that are available at a significant premium to the other allowances. The amount of CCR and CCR II allowances available in each year remains fixed starting in 2027 at 3.430 million CCR allowances, which was calculated based on Virginia's 2026 percentage of CCR credits before Virginia re-entered RGGI. The total available number of allowances, inclusive of both CCR and CCR II in 2027 is 27.2 million and decreases to less than 9.5 million in 2037, with available allowances required to decrease to 0 by 2050.

Figure 67. *RGGI Allowance Price Forecasts*



Commodity Price Assumptions

The Virginia Energy pricing forecasts rely heavily on the assumptions of the 2025 Dominion IRP Update. These prices were also compared to the EIA *Short-Term Energy Outlook* and Enverus's commodity forecast analysis as part of the 2025 Dominion RPS Docket. While the 2025 Dominion IRP Update price forecasts only extend to 2039, the VEP extended the forecasts to 2050, using linear extrapolation.

Natural Gas Henry Hub and Delivered Fuel Price Forecasts

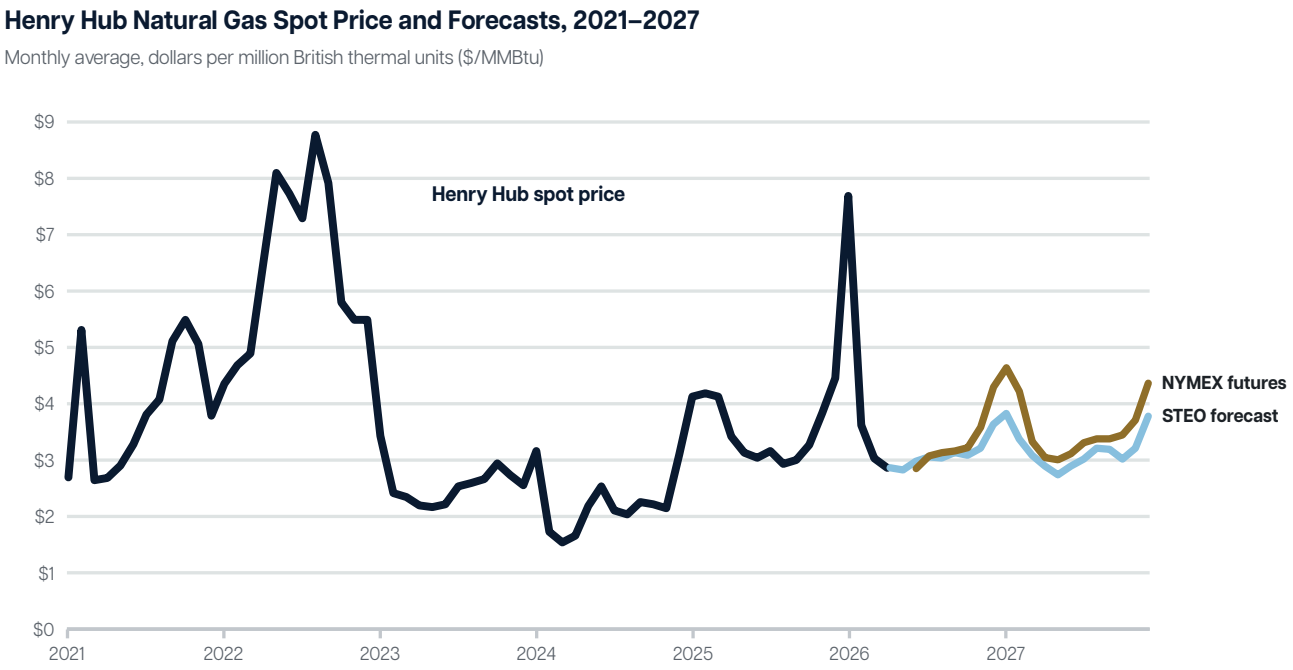
For the price of natural gas, the modeling team elected to use Dominion's commodity price for natural gas provided by ICF in the 2025 Dominion IRP Update, specifically a combination of their Least Cost VCEA Compliant Case for Henry Hub and Zone 5 Delivered natural gas.

Table 26. *Commodity Price Forecast Natural Gas, Dominion 2025 IRP Update*

$/MMBtu	Least Cost VCEA Compliant Case	
	Henry Hub	Zone 5
2025	3.76	3.78
2026	4.27	4.95
2027	4.08	4.40
2028	4.40	4.51
2029	4.67	4.58
2030	4.93	4.80
2031	5.15	5.10
2032	5.38	5.28
2033	5.50	5.46
2034	5.61	5.64
2035	5.73	5.78
2036	5.94	6.00
2037	6.15	6.24
2038	6.38	6.45
2039	6.61	6.68

EIA's Annual Short-Term Energy Outlook shows a relatively stable outlook for natural gas and to remain below $4 per MMBtu through the end of 2027.

Figure 68. *Gas Price Forecast*



Source: U.S. Energy Information Administration, Short-Term Energy Outlook, May 2026; Bloomberg L.P.; LSEG Data. Futures curve is the average settlement price for the five trading days ending May 7, 2026.

Electricity Market Price Forecasts

Electricity import prices were derived by running a PJM-wide capacity expansion model, using hourly market prices from zones surrounding the DOM Zone to represent the cost of imported energy in each hour. Capacity purchase prices are based on Dominion Energy Virginia's 2025 IRP Update, to represent the cost of capacity procured from outside Virginia through the regional transmission system.

Table 27. *Electricity Commodity Price Forecasts, 2025 Dominion IRP Update, Least Cost Compliant Case*

Year	Imports $/MWh	Capacity $/kW-yr		Capacity $/MW-day	
		PJM RTO	Dom Zone	PJM RTO	Dom Zone
2025		98.52	162.15	269.92	444.26
2026	37.02	111.14	137.15	304.49	377.13
2027	37.02	108.54	120.15	297.37	329.18
2028	36.39	105.73	144.28	289.66	395.30
2029	38.43	110.05	160.05	301.50	438.48
2030	36.55	108.30	144.57	296.71	396.08
2031	41.36	116.25	127.68	318.49	349.80

Year	Imports $/MWh	Capacity $/kW-yr		Capacity $/MW-day	
		PJM RTO	Dom Zone	PJM RTO	Dom Zone
2032	46.82	122.59	122.59	335.87	335.87
2033	45.74	130.20	130.20	356.73	659.73
2034	46.56	142.46	142..46	390.31	390.31
2035	51.42	154.11	154.11	422.23	422.23
2036	57.21	166.97	166.97	457.45	457.45
2037	55.49	180.60	180.60	494.80	494.80
2038	75.32	194.29	194.29	532.30	532.30
2039	63.31	208.24	208.24	570.53	570.53
2040	78.51			610.34	610.34
2041	71.82			634.49	63449
2042	74.56			647.06	647.06
2043	57.38			658.94	658.94
2044	71.47			666.24	666.24
2045	58.35			674.73	674.73
2046	59.63				
2047	59.63				
2048	60.19				
2049	60.46				
2050	60.46				

Note: Several forecasted values do not extend to 2050, so are left blank here.

Endnotes

Endnotes

1. Va. Code § 45.2-1706.1, https://law.lis.virginia.gov/vacodefull/title45.2/chapter17/article3/; Va. Code § 45.2-1710, https://law.lis.virginia.gov/vacodefull/title45.2/chapter17/article4/; Va. Code tit. 45.2, ch. 17, https://law.lis.virginia.gov/vacodefull/title45.2/chapter17/.

2. Lawrence Livermore National Laboratory, https://flowcharts.llnl.gov/commodities/energy.

3. State Annual Summary Statistics: Personal Income, GDP, Consumer Spending, Price Indexes, and Employment, Regional Economic Accounts, U.S. Department of Commerce Bureau of Economic Analysis (Sept. 20, 2026), https://apps.bea.gov/regional/downloadzip.htm?_gl=1*co1cd6*_ga*MTU3MzU0NTM4LjE3ODk3NTc5OTQ.*_ga_J4698JNNFT*czE3ODk5MTUwMDgkbzMkZzAkdDE3ODk5MTUwMDgkajYwJGwwJGgw.

4. State Population Totals and Components of Change, Annual Population Estimates: 2020 - 2025, Estimated Components of Resident Population Change, and Rates of the Components of Resident Population Change for the United States, States, District of Columbia, and Puerto Rico: April 1, 2020 to July 1, 2025 (NST-EST2025-ALLDATA). United States Census Bureau Population and Housing Unit Estimates (Sept. 20, 2026), https://www.census.gov/data/tables/time-series/demo/popest/2020s-state-total.html.

5. State Energy Data System (SEDS): 1960–2024 (Complete), U.S. Energy Information Administration, Virginia: Total Energy Consumption by End-Use Sector (June 26, 2026), https://www.eia.gov/state/seds/seds-data-complete.php?sid=VA#Consumption.

6. Id.

7. 2020 Residential Energy Consumption Survey, U.S. Energy Information Administration, https://www.eia.gov/consumption/residential/data/2020/index.php?view=state.

8. State Energy Data System (SEDS): 1960–2023, U.S. Energy Information Administration, Table CT5, https://www.eia.gov/state/seds/sep_use/com/pdf/use_com_US.pdf.

9. State Energy Data System (SEDS), U.S. Energy Information Administration, Table CT6, https://www.eia.gov/state/seds/sep_use/ind/pdf/use_ind_US.pdf.

10. Responsibilities, Virginia State Corporation Commission (accessed Sept. 1, 2026), https://www.scc.virginia.gov/regulated-industries/utility-regulation/pur-responsibilities/; Va. Code §§ 56-585.3 and 56-265.4:1, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.3/ and https://law.lis.virginia.gov/vacode/title56/chapter10.1/section56-265.4:1/; Va. Code § 15.2-5416, https://law.lis.virginia.gov/vacode/title15.2/chapter54/section15.2-5416/.

11. Va. Code § 56-585.5 defines which resources are 'zero-carbon' and which resources are 'RPS eligible.

12. Va. Code § 56-585.5 C, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.5/.

13. Virginia Electricity Profile 2024, U.S. Energy Information Administration (accessed July 2026), https://www.eia.gov/electricity/state/virginia/. Supplemented with response from PJM Interconnection to Virginia Energy data requests.

14. Va. Code § 56-576, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-576/.

15. Per § 56-585.1, a Phase I Utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a Phase II Utility is an investor-owned incumbent electric utility that was bound by such a settlement. In practice, Appalachian Power is the only utility in the Commonwealth that meets the definition of a Phase I Utility and Dominion Energy Virginia is the only utility in the Commonwealth that meets the definition of a Phase II Utility.

16. Virginia, Maryland and Delaware Association of Electric Cooperatives (accessed Sept. 2, 2026), https://www.vmdaec.com/.

17. PPAs are contracts under which a purchaser agrees to buy electricity, and in some cases, the associated renewable energy certificates, from a generating facility at agreed-upon terms and prices over a specified period.

18. Electricity Data, U.S. Energy Information Administration, https://www.eia.gov/electricity/data.php.

19. Understanding the Differences Among PJM's Markets, PJM (2026), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/understanding-the-difference-among-pjms-markets.pdf.

20. PJM Governors Collaborative Joint Statement of Intent, PJM (Sept. 25, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250925-pjm-governors-collaborative-joint-statement-of-intent.pdf.

21. Preliminary Monthly Electric Generator Inventory, U.S. Energy Information Administration (June 2026), https://www.eia.gov/electricity/data/eia860m/.

22. Virginia Electricity Profile 2024, U.S. Energy Information Administration (Nov. 10, 2025), https://www.eia.gov/electricity/state/virginia/.

23. 2025 Virginia State Infrastructure Report, PJM Interconnection LLC (Aug. 3, 2026) at 11, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2025/virginia.pdf

24. Virginia Was the Top Net Electricity Recipient of Any State in 2023, U.S. Energy Information Administration (Dec. 20, 2024), https://www.eia.gov/todayinenergy/detail.php?id=64104.

25. 2025 Virginia State Infrastructure Report, PJM Interconnection LLC (Aug. 3, 2026) at 11, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2025/virginia.pdf.

26. Id. at 12.

27. Preliminary Monthly Electric Generator Inventory, U.S. Energy Information Administration, https://www.eia.gov/electricity/data/eia860m/.

28. Id.

29. Va. Code § 56-585.1:11, https://law.lis.virginia.gov/vacode/title56/chapter10/section56-585.1:11/.

30. Brian Martucci, Dominion offshore wind project cost rises nearly $300M, Utility Dive (Aug. 3, 2026), https://www.utilitydive.com/news/dominion-offshore-wind-project-cost-rises-nearly-300m/826845/.

31. Charlie Paullin, Dominion wins second offshore wind lease area with lone bid, Virginia Mercury (Aug. 14, 2024), https://virginiamercury.com/2024/08/14/dominion-wins-second-offshore-wind-lease-area-with-lone-bid/.

32. Va. Code § 56-585.1:19 A, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1:19/.

33. Deloitte, Virginia DER Baseline — Solar PV + BESS, internal analysis (Aug. 21, 2026), based on U.S. Energy Information Administration, Form EIA-861, Net Metering file; proprietary BTM storage vendor data for Virginia; Lawrence Berkeley National Laboratory, Tracking the Sun (battery attachment rates); and US DOE Alternative Fuels Data Center.

34. Battery figures are a modeled estimate blending EIA-861 data with vendor and LBNL attachment-rate data, rather than a direct census.

35. Id.

36. Battery figures are a modeled estimate blending EIA-861 data with vendor and LBNL attachment-rate data, rather than a direct census.

37. 2025 Virginia State Infrastructure Report, PJM Interconnection LLC (Aug. 3, 2026) at 5, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2025/virginia.pdf.

38. 2021 State of the Market Report for PJM, Monitoring Analytics, Sec. 11, "Congestion and Marginal Losses," table 11-18, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec11.pdf.

39. 2022 State of the Market Report for PJM, Monitoring Analytics, Sec. 11, "Congestion and Marginal Losses," table 11-16, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec11.pdf.

40. 2023 State of the Market Report for PJM, Monitoring Analytics, Sec. 11, "Congestion and Marginal Losses," table 11-16, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec11.pdf.

41. 2024 State of the Market Report for PJM, Monitoring Analytics, Sec. 11, "Congestion and Marginal Losses," table 11-10, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec11.pdf.

42. 2025 State of the Market Report for PJM, Monitoring Analytics, Sec. 11, "Congestion and Marginal Losses," table 11-17, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-sec11.pdf.

43. 2026 Quarterly State of the Market Report for PJM: January through June, Monitoring Analytics, Sec. 11,

"Congestion and Marginal Losses," table 11-17, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q2-som-pjm-sec11.pdf.

44. 2026 Quarterly State of the Market Report, Monitoring Analytics, Sec. 11, fig. 11-7, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q2-som-pjm-sec11.pdf.

45. Ham et al., Transmission lowers US generation costs, but generator incentives are not aligned (Feb. 24, 2026), https://www.pnas.org/doi/abs/10.1073/pnas.2524463123?af=R; Interregional Transfer Capability Study (ITCS), NERC (Nov. 2024), https://www.nerc.com/globalassets/initiatives/itcs/itcs_final_report.pdf.

46. PJM uses its Regional Transmission Expansion Planning (RTEP) process to plan for grid expansion of the transmission network to ensure reliability, market efficiency, and compliance with state and federal policies for up to 15 years in the future.

47. 2025 Virginia State Infrastructure Report, PJM Interconnection, LLC (June 2026; updated Aug. 2026), slide 2, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2025/virginia.pdf.

48. 2022 Virginia State Infrastructure Report, PJM Interconnection, LLC, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2022/2022-virginia-state-infrastructure-report.pdf.

49. 2023 Virginia State Infrastructure Report, PJM Interconnection, LLC, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2023/virginia.pdf.

50. 2024 Virginia State Infrastructure Report, PJM Interconnection, LLC, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2024/virginia.pdf.

51. 2025 Virginia State Infrastructure Report, PJM Interconnection, LLC, https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2025/virginia.pdf.

52. Virginia Energy Security Plan (2024); https://energy.virginia.gov/public/documents/VASESP_2024_PublicVersion_Final.pdf.

53. 2026 Va. Acts Ch. 607, https://lis.virginia.gov/bill-details/20261/HB429.

54. 2026 Va. Acts Ch. 607, https://lis.virginia.gov/bill-details/20261/HB429; 2026 Va. Acts Ch. 612, https://lis.virginia.gov/bill-details/20261/SB621.

55. State Corporation Commission Regulated Companies & Service Map, https://www.scc.virginia.gov/media/sccvirginiagov-home/consumer-home/public-utilities/natural-gas/regulated-companies-amp-service-map/gas_map.pdf.

56. Natural Gas Consumption by End Use, U.S. Energy Information Administration (accessed Aug. 31, 2026), https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_sva_a.htm.

57. Natural Gas Consumption by End Use: Virginia, U.S. Energy Information Administration (accessed Sept. 1, 2026), https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SVA_A.htm.

58. Winter Storm Elliott: Event Analysis and Recommendation Report, PJM (July 17, 2023) at 49, 51, https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

59. State Energy Data System (SEDS), U.S. Energy Information Administration, Table CT1, https://www.eia.gov/state/seds/sep_use/total/pdf_a/use_tot_VAa.pdf.

60. State Energy Data System, U.S. Energy Information Administration, Table CT1, https://www.eia.gov/state/seds/sep_use/total/pdf_a/use_tot_VAa.pdf.

61. SAF Policy Actions, European Union Aviation Safety Agency (accessed Sept. 1, 2026), https://www.easa.europa.eu/en/domains/environment/eaer/sustainable-aviation-fuels/saf-policy-actions.

62. Final Order, Dominion 2025 Rate Case, Case No. PUR-2025-00058 (Nov. 25, 2025) at 22–25, https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

63. Interim Order Establishing Additional Proceedings, Dominion 2026 Transmission Case, Case No. PUR-2026-00011 (May 12, 2026) at 2–4, https://www.scc.virginia.gov/docketsearch/DOCS/8c5b01!.PDF.

64. Data Centers in Virginia, Virginia Joint Legislative Audit and Review Commission, Report 598 (Dec. 2024), https://jlarc.virginia.gov/pdfs/reports/Rpt598.pdf.

65. Singer et al., Electric Vehicle Efficiency Ratios for Light-Duty Vehicles Registered in the United States, National Renewable Energy Laboratory (2023), https://www.nrel.gov/docs/fy23osti/84631.pdf.

66. Atlas Public Policy, Evaluate Virginia Market Overview (accessed Sept. 23, 2026), https://atlaspolicy.com/evaluateva/.

67. Id.

68. Id.

69. Id.

70. Alternative Fuels Data Center, U.S. Department of Energy, Virginia Transportation Data for Alternative Fuels and Vehicles (accessed Sept. 1, 2026), https://afdc.energy.gov/states/VA.

71. Eric Wood et al., The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure, National Renewable Energy Laboratory (2023), https://docs.nlr.gov/docs/fy23osti/85654.pdf.

72. Geospatial Energy Mapper (GEM), Argonne National Laboratory (accessed Sept. 12, 2026), https://gem.anl.gov/.

73. Nitrogen Dioxide's Impact on Indoor Air Quality, U.S. Environmental Protection Agency (Apr. 29, 2026), https://www.epa.gov/indoor-air-quality-iaq/nitrogen-dioxides-impact-indoor-air-quality.

74. 2020 Residential Energy Consumption Survey Data, U.S. Energy Information Administration (accessed Sept. 1, 2026), https://www.eia.gov/consumption/residential/data/2020/.

75. Codes, Virginia Building and Code Officials Association, 2021 Virginia Energy Conservation Code (based on the 2021 International Energy Conservation Code with state amendments; effective Jan. 18, 2024) (accessed Sept. 1, 2026), https://vbcoa.org/resources/codes/.

76. Lower Bills, Better Grids: Heat Pump Benefits for Electric Resistance-Heated Homes, RMI (Apr. 2026), https://rmi.org/resources/lower-bills-better-grids-heat-pump-benefits-for-electric-resistance-heated-homes/.

77. Green Upgrade Calculator, RMI, Analysis Conducted 2025–2026, https://greenup.rmi.org/.

78. Id.

79. Virginia Residential Energy Efficiency Potential, U.S. Department of Energy, National Laboratory of the Rockies (Sept. 2017), https://resstock.nlr.gov/factsheets/VA.

80. Virginia Residential Energy Code Field Study: Baseline Report, Pacific Northwest National Laboratory, prepared for the U.S. Department of Energy (Oct. 2019), https://www.govinfo.gov/content/pkg/GOVPUB-E-PURL-gpo154573/pdf/GOVPUB-E-PURL-gpo154573.pdf.

81. Virginia Code Savings, U.S. Department of Energy, https://www.energy.gov/sites/default/files/2023-10/virginia-codes-savings.pdf.

82. Mike Specian & Alex Aquino, Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth, American Council for an Energy-Efficient Economy (Feb. 4, 2026), https://www.aceee.org/resource/u2601/.

83. Id.

84. 2025 State Energy Efficiency Scorecard Research Report, American Council for an Energy-Efficient Economy (Mar. 2025), https://www.aceee.org/wp-content/uploads/2026/05/the_2025_state_scorecard.pdf.

85. Average Tested Heat Rates by Prime Mover and Energy Source, 2014–2024, U.S. Energy Information Administration, Table 8.2 (Oct. 16, 2025), https://www.eia.gov/electricity/annual/html/epa_08_02.html.

86. Findings from Storage Innovations 2030: Lithium-Ion Batteries, U.S. Department of Energy (July 2023) at 3, https://www.energy.gov/sites/default/files/2023-09/2_Technology%20Strategy%20Assessment%20-%202%20Lithium-ion_508.pdf.

87. How Much Electricity Is Lost in Electricity Transmission and Distribution in the United States?, U.S. Energy Information Administration (Nov. 7, 2023), https://www.eia.gov/tools/faqs/faq.php?id=105&t=3.

88. Virginia Electricity Profile 2024, U.S. Energy Information Administration (Nov. 10, 2025), Table 10, "Supply and Disposition of Electricity," https://www.eia.gov/electricity/state/virginia/.

89. Roderick Jackson et al., Opportunities for Energy Efficiency Improvements in the U.S. Electricity

Transmission and Distribution System (Apr. 2015) at 12, 36, https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20Opportunities%20for%20Energy%20Efficiency%20Improvements%20in%20the%20US%20Electricity%20Transmission%20and%20Distribution%20System_0.pdf.

90. Advanced Conductor Scan Report, Idaho National Laboratory (2024), https://inl.gov/content/uploads/2024/10/23-50856_R12a_-AdvConductorsScanProjectReportCompressed.pdf.

91. Roderick Jackson et al., Opportunities for Energy Efficiency Improvements in the U.S. Electricity Transmission and Distribution System (Apr. 2015) at 4–5, https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20Opportunities%20for%20Energy%20Efficiency%20Improvements%20in%20the%20US%20Electricity%20Transmission%20and%20Distribution%20System_0.pdf.

92. Energy Conservation Program: Energy Conservation Standards for Distribution Transformers; Final Rule, U.S. Department of Energy, 89 Fed. Reg. 29834 (Apr. 22, 2024) at 30088–90, https://www.energy.gov/sites/default/files/2024-04/dt_ecs_fr.pdf.

93. 2020 Va. Acts Ch. 1193, https://legacylis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1526; Final Order, Dominion EERS Proceeding, Case No. PUR-2023-00227 (Feb. 27, 2025) at 9, https://www.scc.virginia.gov/docketsearch/DOCS/841401!.PDF; Final Order, APCo EERS Proceeding, Case No. PUR-2024-00134 (Feb. 28, 2025) at 10, https://www.scc.virginia.gov/docketsearch/DOCS/844501!.PDF.

94. Dominion Proposed Energy Efficiency Savings Targets Report, Dominion EERS Proceeding, Case No. PUR-2023-00227 (June 12, 2024), https://www.scc.virginia.gov/docketsearch/DOCS/7zpn01!.PDF; Comments of Sierra Club, Dominion EERS Proceeding, Case No. PUR-2023-00227 (Nov. 25, 2024), https://www.scc.virginia.gov/docketsearch/DOCS/82qy01!.PDF.

95. Va. Code § 56-585.1, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/.

96. Weatherization Network Monthly Meeting August 2026 slide deck, Virginia Department of Housing and Community Development.

97. Weatherization Network Monthly Meeting August 2026 slide deck, Virginia Department of Housing and Community Development.

98. RGGI Programs Presentation to the Virginia Energy Commission Regional Greenhouse Gas Initiative (RGGI) Subcommittee, Virginia Department of Housing and Community Development (Sept. 2026).

99. Va. Code § 56-576, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-576/.

100. Updated Comparison of Energy Use and Emissions from Different Transportation Modes Using the Latest Available Datasets, Texas A&M Transportation Institute, prepared for the American Bus Association Foundation (Dec. 2023), Tables 10, 22.

101. National Transportation Statistics, U.S. Department of Transportation, Bureau of Transportation Statistics, Table 4-25, "Energy Intensity of Class I Railroad Freight Service."

102. Average for heavy trucks calculated from Association of American Railroads/Federal Railroad Administration ton-miles-per-gallon data.

103. 2025 EPA Automotive Trends Report, U.S. Environmental Protection Agency (Feb. 2026), https://www.epa.gov/automotive-trends/explore-automotive-trends-data.

104. National Transportation Statistics, U.S. Department of Transportation, Bureau of Transportation Statistics, Table 4-23, "Average Fuel Efficiency of U.S. Light Duty Vehicles," Washington, DC.

105. New Cars With the Best Mileage in 2026, Carfax.com (March 6, 2026), https://www.carfax.com/rankings/best-mpg-cars

106. Assessment of Technologies for Improving Light-Duty Vehicle Fuel Economy—2025–2035, National Academies of Sciences, Engineering, and Medicine, Chap. 4, "Internal Combustion Engine-Based Powertrain Technologies" (2021), https://doi.org/10.17226/26092; Hybrid Vehicle Technology Developments and Opportunities in the 2025–2035 Time Frame, International Council on Clean Transportation (Feb. 13, 2025), https://theicct.org/wp-content/uploads/2025/02/ID-292-%E2%80%93-Hybrid-techology_paper_final.pdf.

107. Learn about SmartWay Verified Technologies, U.S. Environmental Protection Agency (accessed Sept. 1, 2026), https://www.epa.gov/smartway/learn-about-smartway-verified-technologies.

108. Gas-Saving Tips, U.S. Department of Energy, Alternative Fuels Data Center, https://afdc.energy.gov/files/u/publication/gas-saving_tips.pdf; Das et al., Effect of Wheel Alignment, Speed, and Road Condition on Fuel Efficiency of a Light-Duty Vehicle, Mechanical Engineering Research 12 (2022) at 1–7.

109. DEPTH Tool: Drivers of Electricity Pricing Trends & History, Lawrence Berkeley National Laboratory (accessed Sept. 1, 2026), https://emp.lbl.gov/depth-tool-drivers-electricity-pricing-trends-history; Donohoo-Vallett et al., Caught in the Current: Historical and Prospective Drivers of Changes in US Electricity Prices, Rhodium Group (Apr. 21, 2026), https://rhg.com/research/us-electricity-prices-drivers/.

110. Retail Electricity Price Trends and Drivers: Data Update—2026 Edition, July Update, Lawrence Berkeley National Laboratory (July 2026) at 13, https://emp.lbl.gov/sites/default/files/2026-07/Retail%20Price%20Trends_2026%20edition_JulyUpdate.pdf.

111. DEPTH Tool: Drivers of Electricity Pricing Trends & History, Lawrence Berkeley National Laboratory (accessed Sept. 1, 2026), https://emp.lbl.gov/depth-tool-drivers-electricity-pricing-trends-history.

112. DEPTH Tool: Drivers of Electricity Pricing Trends & History, Lawrence Berkeley National Laboratory (accessed Sept. 1, 2026), https://emp.lbl.gov/depth-tool-drivers-electricity-pricing-trends-history.

113. Annual Status Report: Implementation of the Virginia Electric Utility Regulation Act, Virginia State Corporation Commission, aggregated data from 2007–2025 editions.

114. Q4 2025 Earnings Call, Dominion Energy (Feb. 23, 2026), https://s2.q4cdn.com/510812146/files/doc_financials/2025/q4/2026-02-23-DE-IR-4Q-2025-earnings-call-slides-vTCl.pdf.

115. 2025 Integrated Resource Plan Update, Dominion Energy Virginia, https://www.scc.virginia.gov/docketsearch/DOCS/88_t01!.PDF; 2025 Renewable Portfolio Standard Application, Appalachian Power Company, https://www.scc.virginia.gov/docketsearch/DOCS/85lt01!.PDF.

116. Paul Donohoo-Vallett et al., Caught in the Current: Historical and Prospective Drivers of Changes in US Electricity Prices, Rhodium Group (Apr. 21, 2026), https://rhg.com/research/us-electricity-prices-drivers/.

117. Monitoring Analytics, PJM Independent Market Monitor, https://www.monitoringanalytics.com/.

118. Monitoring Analytics, Market Monitor Report (July 28, 2026). https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MC_Market_Monitor_Report_20260728.pdf

119. Wiser et al., Retail Electricity Price Trends and Drivers: Data Update—2026 Edition (Apr. 2026) at 19–20, https://emp.lbl.gov/sites/default/files/2026-03/Retail%20Price%20Trends_2026%20edition.pdf.

120. Matt Busse, 4 Va. lawmakers target rising Appalachian Power bills, Cardinal News (Jan. 21, 2026), https://cardinalnews.org/2026/01/21/4-va-lawmakers-target-rising-appalachian-power-bills/.

121. Matt Busse, Appalachian Power request would lower monthly bills, Cardinal News (Oct. 1, 2025), https://cardinalnews.org/2025/10/01/appalachian-power-request-would-lower-monthly-bills/.

122. Va. Code §§ 56-577, 56-585.1, 56-585.3, 15.2-5416; Responsibilities, Virginia State Corporation Commission (accessed Sept. 1, 2026), https://www.scc.virginia.gov/pages/Responsibilities.

123. Ryan Wiser et al., Retail Electricity Price Trends and Drivers: Data Update—2026 Edition, (Apr. 2026) at 18–24, https://emp.lbl.gov/sites/default/files/2026-03/Retail%20Price%20Trends_2026%20edition.pdf.

124. Order for Notice and Hearing, Petition of Virginia Electric and Power Company, For Revision of a Rate Adjustment Clause, Designated Rider DIST, and Consolidation of Riders DIST and RBB, Case No. PUR-2025-00136 (Sept. 19, 2025) at 3–7, https://www.scc.virginia.gov/docketsearch/DOCS/884k01!.PDF.

125. Final Order, 2025 Dominion GTSA Case, Case No. PUR-2025-00051 (Sept. 23, 2025) at 1–9, https://www.scc.virginia.gov/docketsearch/DOCS/887701!.PDF.

126. Order for Notice and Hearing, 2025 APCo GTSA Case, Case No. PUR-2025-00098 (Aug. 7, 2025) at 1–3, https://www.scc.virginia.gov/docketsearch/DOCS/876v01!.PDF.

127. Lazard's Levelized Cost of Energy+ Analysis—Version 19.0, Lazard (Aug. 2026) at 6, 12, https://www.lazard.com/media/lrecseyq/lazards-lcoeplus-v190_vf.pdf.

128. Identifying Risks in the Energy Industrial Base: Supply Chain Readiness Levels, U.S. Department of Energy (Jan. 2025) at 7–8, https://www.energy.gov/sites/default/files/2025-01/Identifying_Risks_in_the_Energy_Industrial_

Base-Supply_Chain_Readiness_Levels_vFinalPublication.pdf.

129. Millican et al., Electricity Affordability and Load Growth: Diagnosing and Fixing the Problem, Center on Global Energy Policy, Columbia University SIPA (June 2026), https://www.energypolicy.columbia.edu/wp-content/uploads/2026/06/LoadGrowth-CGEP_WhitePaper_061726-3-digital.pdf.

130. Ryan Hledik & Long Lam, Retail Electricity Price Trends and Drivers, Lawrence Berkeley National Laboratory & The Brattle Group (July 2026), https://emp.lbl.gov/sites/default/files/2026-07/Retail%20Price%20Trends_2026%20edition_JulyUpdate.pdf.

131. Ex. 128, Comparison of Allocation Methodology Results, Dominion 2025 Rate Case, Case No. PUR-2025-00058 (Sept. 11, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/88vj01!.PDF.

132. Under demand-based allocation methodologies (such as Coincident Peak approaches), customers who consume electricity during periods of highest system demand, typically hot summer afternoons, bear a larger share of infrastructure costs. Large data centers, which operate at high, relatively flat load factors around the clock, contribute to peak demand but are not uniquely responsible for it. Under energy-based methodologies, cost responsibility aligns more closely with total consumption.

133. Id.

134. Data Centers in Virginia, Virginia Joint Legislative Audit and Review Commission (2024), https://jlarc.virginia.gov/landing-2024-data-centers-in-virginia.asp.

135. Final Order, Dominion 2025 Rate Case, Case No. PUR-2025-00058 (Nov. 25, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

136. 2026 Va. Acts Ch. 1124.

137. DELTa: Database of Emerging Large load Tariffs, Smart Electric Power Alliance (accessed Sept. 1, 2026), https://sepapower.org/large-load-tariffs-database/.

138. Final Order, Rider T1 Tariff Rate Adjustment Clause, Case No. PUR-2026-00056 (July 31, 2026), https://www.scc.virginia.gov/docketsearch/DOCS/8dt001!.PDF

139. Virginia Energy analysis and calculations based on Low-Income Energy Affordability Data (LEAD) Tool, U.S. Department of Energy (2022 underlying data; tool updated 2024); Drehobl et al., How High Are Household Energy Burdens?, American Council for an Energy-Efficient Economy (2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf.

140. Energy Equity Factsheet: Virginia, Energy Equity Project (2025), https://drive.usercontent.google.com/download?id=1jxQL3CB83ZkzqD_NvcidpGJdGmYOOXMv&authuser=0&acrobatPromotionSource=gdrive_chrome-list.

141. Biennial Report on the Effectiveness of Low-Income Energy Assistance Programs, Virginia Department of Social Services (Oct. 2023), https://rga.lis.virginia.gov/Published/2024/RD201/PDF.

142. Virginia Energy analysis and calculations based on Low-Income Energy Affordability Data (LEAD) Tool, U.S. Department of Energy (2022 underlying data; tool updated 2024).

143. Matt Busse, Appalachian Power, Consumer Advocates Look to Reduce Customer Disconnections, Cardinal News (Feb. 13, 2025), https://cardinalnews.org/2025/02/13/appalachian-power-consumer-advocates-look-to-reduce-customer-disconnections/.

144. Energy Equity Factsheet: Virginia, Energy Equity Project (2024), https://drive.google.com/drive/folders/1JxpQXnalPYkxfk0M4c9VIYLZPKMFDsPL.

145. Tsunami of Shutoffs: Virginia Utility Shutoffs, Energy Equity Project (2024), using U.S. Energy Information Administration Form EIA-112 data for the 2024 reporting year, https://tsunami-of-shutoffs.org/explore/VA/?fuel=electric&metric=shutoffs&unit=rate.

146. Virginia Organizing Assessment Responses, Virginia Regulatory Assessment: Environmental Justice and Equity, Including Affordability for LMI Customers, Virginia Energy Performance-Based Ratemaking Stakeholder Process (2025), https://energy.virginia.gov/public/documents/Stakeholders/assessments/Virginia%20Organizing.EJ_VA_Regulatory%20Assessment.pdf.

147. Va. Code § 56-249.01, https://law.lis.virginia.gov/vacodeupdates/title56/section56-249.01/.

148. The Virginia Department of Social Services administers the Energy Assistance Program, including fuel, cooling, and crisis assistance. The Virginia Department of Housing and Community Development administers related weatherization assistance. In fiscal year 2023, the Fuel Assistance component served 113,592 households at a cost of approximately $45.6 million.

149. Biennial Report on Low-Income Energy Assistance Programs, Virginia Department of Social Services (Mar. 15, 2024), https://rga.lis.virginia.gov/Published/2024/RD201/PDF.

150. Va. Code § 56-585.6, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.6/.

151. State Fiscal Impact Statement: HB 884 ER—Electric Utilities; Percentage of Income Payment Program; Eligibility, Delayed Effective Date, Virginia Department of Planning and Budget (Mar. 31, 2026), https://lis.blob.core.windows.net/files/1215002.PDF.

152. 2026 Va. Acts Ch. 690, https://lis.blob.core.windows.net/files/1222142.PDF.

153. See Va. Code § 56-245.1:4 (requiring additional multilingual notices and generally prohibits disconnection for nonpayment until an account is at least 60 days in arrears and the utility has made reasonable efforts to offer payment assistance, a payment plan, or information about other assistance and efficiency programs), https://law.lis.virginia.gov/vacode/title56/chapter10/section56-245.1%3A4/.

154. State Energy Data System (SEDS), U.S. Energy Information Administration.

155. GasBuddy.com (accessed Sept. 15, 2026).

156. EPA Automotive Trends Report, Environmental Protection Agency (2025), https://www.epa.gov/system/files/documents/2026-02/420r26001.pdf; Virginia DMV (accessed August 2026), https://www.dmv.virginia.gov/vehicles/taxes-fees/mileage-choice.

157. Comprehensive Climate Action Plan, Commonwealth of Virginia (June 2026), https://www.deq.virginia.gov/home/showpublisheddocument/37491/639204798115700000.

158. Id. at 12, 26.

159. See Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, Science (June 21, 2018) Vol. 361, Issue 6398 (finding that supply chain emissions were ~60% higher than the U.S. EPA inventory estimate in 2015), https://www.science.org/doi/full/10.1126/science.aar7204.

160. Comprehensive Climate Action Plan, Commonwealth of Virginia (June 2026) at 12, 30, https://www.deq.virginia.gov/home/showpublisheddocument/37491/639204798115700000.

161. Id. at 12, 41.

162. Id. at 12, 37.

163. Id. at 12, 61.

164. Id. at 12, 51.

165. Id. at 12, 56.

166. Dominion Energy retired the last of its wholly owned traditional coal-fired fleet (Chesterfield 5 & 6) located in the Commonwealth as well as its heavy fuel oil facility (Yorktown) in 2023.

167. Virginia Electricity Profile 2024, U.S. Energy Information Administration (Nov. 10, 2025), https://www.eia.gov/electricity/state/virginia/.

168. Climate Change 2021: The Physical Science Basis, Intergovernmental Panel on Climate Change, Chap. 7, Table 7.15; see also Understanding Global Warming Potentials, U.S. Environmental Protection Agency (Dec. 29, 2025), https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.

169. Balcombe et al., The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions, ACS Sustainable Chem. Eng. (2017) 5(1):3-20, https://doi.org/10.1021/acssuschemeng.6b00144.

170. Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, Science (2018) Vol 361, Issue 6398, https://www.science.org/doi/full/10.1126/science.aar7204; Itziar Irakulis-Loitxate et al., Satellite-based survey of extreme methane emissions in the Permian basin, Science Advances (2021), https://www.science.org/doi/10.1126/sciadv.abf4507.

171. Comprehensive Climate Action Plan, Commonwealth of Virginia (June 2026) at 27, https://www.deq.virginia.gov/home/showpublisheddocument/37491/639204798115700000.

172. Kevin X. Shen, Exposure to Diesel Particulate Pollution in Virginia, Union of Concerned Scientists (Aug. 29, 2022), https://www.ucs.org/resources/diesel-pollution-va.

173. Data Preview, Clean Air Markets Program Data, Environmental Protection Agency (Aug. 20, 2026), https://campd.epa.gov/data/custom-data-download9.

174. Va. Code § 10.1-1330 C, https://law.lis.virginia.gov/vacode/title10.1/chapter13/section10.1-1330/.

175. The Investment of RGGI Proceeds in 2024, The Regional Greenhouse Gas Initiative (June 2026) at 7, https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2024.pdf.

176. Laura Lightbody & Matthew Fuchs, Every $1 Invested in Disaster Mitigation Saves $6, Pew (Jan. 11, 2018), https://www.pew.org/en/research-and-analysis/articles/2018/01/11/every-$1-invested-in-disaster-mitigation-saves-$6.

177. Nicole Vaughan, Community Flood Preparedness Fund Projects, Virginia Conservation Network (Jan. 10, 2022), https://vcnva.org/cfpf-projects-virginia/.

178. See Petition, Dominion Rider RGGI Proceeding, Case No. PUR-2026-00085 (June 08, 2026) at 11, https://www.scc.virginia.gov/docketsearch/DOCS/8cn%2401!.PDF.

179. Marshall et al., Tracing Environmental Equity and Air Pollution Research at ES&T, Environ. Sci. Technol. (2026) 60 (8): 5905–5909, https://doi.org/10.1021/acs.est.6c01725.

180. Vohra et al., The health burden and racial-ethnic disparities of air pollution from the major oil and gas lifecycle stages in the United States, Science Advances (2025) Vol. 11, Issue 34, https://www.science.org/doi/10.1126/sciadv.adu2241.

181. Overview of Air Pollution from Transportation, U.S. Environmental Protection Agency (May 28, 2025), https://www.epa.gov/transportation-air-pollution-and-climate-change/overview-air-pollution-transportation; State of the Air 2025, American Lung Association (2025) at 25–30, https://www.lung.org/getmedia/5d8035e5-4e86-4205-b408-865550860783/State-of-the-Air-2025.pdf.

182. Virginia EJScreen+ Platform, Virginia Department of Environmental Quality (accessed Sept. 1, 2026), https://www.deq.virginia.gov/news-info/get-involved/environmental-justice/ejscreen.

183. The Road to Clean Air: Benefits of a Nationwide Transition to Electric Vehicles, American Lung Association (Sept. 2020), https://www.lung.org/getmedia/99cc945c-47f2-4ba9-ba59-14c311ca332a/electric-vehicle-report.pdf; Transition to Electric Vehicles Would Save Virginia Lives, Avoid Economic Impacts, American Lung Association (Sept. 15, 2020), https://www.lung.org/media/press-releases/road-to-clean-air-va.

184. Virginia Energy Workforce Assessment Report, vol. 1, Emerging Technologies and Workforce Needs, Virginia Energy (July 2026).

185. 2026 Virginia Energy Workforce Assessment Report (VEWAR), Volume I, Exhibit 4 (p. 18).

186. Nuclear Energy: Virginia's Energy Safety Net, Virginia Energy (accessed Sept. 7, 2026), https://www.energy.virginia.gov/renewable-energy/Nuclear.shtml.

187. Va. Code § 45.2-1734, https://law.lis.virginia.gov/vacode/title45.2/part/section45.2-1734/; Va. Code tit. 45.2, ch. 21, https://law.lis.virginia.gov/vacode/title45.2/chapter21/.

188. Va. Code § 45.2-1709, https://law.lis.virginia.gov/vacode/title45.2/chapter17/section45.2-1709/.

189. Virginia is Nuclear 2025-2029 Strategic Plan, Virginia Nuclear Energy Consortium Authority (2025), https://www.commerce.virginia.gov/media/governorvirginiagov/secretary-of-commerce-and-trade/va-nuclear/va-nuclear-pdf/11-6-25-2025-2029_Virginia_Strategic_Plan_For_Nucleear_Energy.pdf.

190. We will bring clean fusion energy to the grid from our campus in Chesterfield County, Virginia, Commonwealth Fusion Systems (accessed Sept. 12, 2026), https://cfs.energy/chesterfield/overview/.

191. Commonwealth Fusion Systems Becomes First Fusion Company to Apply to PJM Interconnection, the Largest U.S. Wholesale Electricity Market, Commonwealth Fusion Systems (Apr. 28, 2026), https://cfs.energy/news-and-media/commonwealth-fusion-systems-becomes-first-fusion-company-to-apply-to-pjm-interconnection-the-largest-u.s.-wholesale-electricity-market.

192. Virginia is Nuclear 2025-2029 Strategic Plan, Virginia Nuclear Energy Consortium Authority (2025), https://www.commerce.virginia.gov/media/governorvirginiagov/secretary-of-commerce-and-trade/va-nuclear/va-nuclear-pdf/11-6-25-2025-2029_Virginia_Strategic_Plan_For_Nucleear_Energy.pdf.

193. Unleashing Virginia: Strengthening the Commonwealth's Transmission System for National Defense, Converge Strategies (2026), https://convergestrategies.com/wp-content/uploads/2026/07/Unleashing-Virginia_Converge-Strategies-and-Energy-Strategies-.pdf.

194. Commonwealth Energy Security Plan, Virginia Energy (2024), https://energy.virginia.gov/public/documents/VASESP_2024_PublicVersion_Final.pdf.

195. Virginia Grid Reliability Improvement Program (VGRIP), Virginia Energy (accessed Sept. 1, 2026), https://energy.virginia.gov/energy-efficiency/VGRIP.shtml.

196. Community-Oriented Resilient Energy Program, Virginia Energy (accessed Sept. 1, 2026), https://energy.virginia.gov/energy-efficiency/CORE.shtml.

197. Virginia Energy Awards $3 Million to Rappahannock Electric Cooperative for Battery Energy Storage Systems, Virginia Energy (accessed Sept. 1, 2026), https://www.energy.virginia.gov/public/documents/newsroom/2025/Virginia%20Energy%20Awards%20$3%20Million%20to%20Rappahannock%20Electric%20Cooperative%20for%20BESS%20fin.pdf.

198. Equity and Resilience: Implications at the Intersection of Climate Change and Community, Electric Power Research Institute (2022), https://www.epri.com/research/products/000000003002025062; Equitable Electric Grid: Defining, Measuring, and Integrating Equity into Electricity-Sector Policy and Planning, Pacific Northwest National Laboratory (2023), https://www.pnnl.gov/sites/default/files/media/file/MOD-Plan%20Equity%20Paper%20Final.pdf.

199. Dominion must retire renewable energy certificates equal to 100% of covered retail sales by 2045, and APCo must do so by 2050.

200. See Va. Code § 56-585.5, https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.5/.

201. Final Order, Dominion 2024 IRP, Case No. PUR-2024-00184 (July 15, 2025) at 6, https://www.scc.virginia.gov/docketsearch/DOCS/86qq01!.PDF.

202. Wilson et al., Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers, Grid Strategies (Nov. 2025), https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf.

203. 2026 PJM Load Forecast Report, PJM Interconnection LLC (Jan. 14, 2026), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.

204. 2026 PJM Load Forecast Report, PJM Interconnection LLC (Jan. 14, 2026), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.

205. Direct Testimony of William K. Castle, 2026 APCo Rate Case, Case No. PUR-2026-00044 (May 29, 2026) at 5:3-5, https://www.scc.virginia.gov/docketsearch/DOCS/8cjp01!.PDF.

206. Application, APCo 2026 RPS, Case No. PUR-2026-00065 (May 15, 2026) at 20, https://www.scc.virginia.gov/docketsearch/DOCS/8cgd01!.PDF.

207. Load Forecast Development Process, PJM Interconnection LLC, Long-Term Load Forecast, 2026 Tables (Feb. 2, 2026), https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

208. Gabriel Levin & Emily Forgash, Most Power Sought for U.S. Data Centers Will Never Materialize, Bloomberg (Aug. 12, 2026), https://www.bloomberg.com/news/articles/2026-08-12/most-electricity-sought-for-ai-data-centers-in-us-will-never-materialize.

209. Ethan Howland, Manufacturers say AEP Ohio still inflating data center demand after halving forecast, Utility Dive (Feb. 6, 2026), https://www.utilitydive.com/news/aep-ohio-data-center-load-tariff-oma-manufacturers/811583/.

210. Final Order, Dominion 2025 Rate Case, Case No. PUR-2025-00058 (Nov. 25, 2025) at 23–27, https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

211. 2026 Va. Acts Ch. 1077.

212. See Large Load Interconnection Case, Case No. PUR-2026-00011, https://www.scc.virginia.gov/docketsearch#caseDocs/146728.

213. Across all scenarios Appalachian Power Company's portion of the load and consumption forecasts remains the same per the company's 2025 RPS filing. As noted above, the 2026 RPS filing showed a forecast increase due to large load adjustments. This was filed after this analysis was conducted and will be incorporated into future modeling.

214. See Dominion 2025 IRP Update, Case No. PUR-2025-00184 (Oct. 15, 2025), at 52 (noting that the preferred portfolio "would require the Company to petition the Commission for a reliability exception outlined in the VCEA in order to preserve existing and planned fossil generation from retirement in 2045."), https://cdn-dominionenergy-prd-001.azureedge.net/-/media/content/about/our-company/irp/pdfs/2025-integrated-resource-plan-update.pdf?rev=c656e4bd80184dbc80d4531cb6e9e975.

215. See Application, APCo 2026 RPS, Case No. PUR-2026-00065 (May 15, 2026) at 51 (selecting new "CT and CC capacity, respectively, with those resources remaining in service through the end of the study period," and converting "Amos Units 1-3 and Mountaineer Plant to 100 percent natural gas beginning in 2040[.]"), https://www.scc.virginia.gov/docketsearch/DOCS/8cgd01!.PDF.

216. National Assessment of Geologic Carbon Dioxide Storage Resources – Results, USGS (Sept. 2013) at 14 (showing a total storage capacity of 14 Gt in the Atlantic Coastal Plain, compared with 1,800 Gt in the Gulf Coast), https://pubs.usgs.gov/circ/1386/pdf/circular1386.pdf.

217. See Xcel Energy to meet Minnesota's energy needs with first-in-the-nation distributed capacity procurement, Sparkfund (Oct. 6, 2025) (Google committing $50 million to Xcel Energy's Capacity*Connect program, which targets up to 200 MW of strategically located distributed battery storage), https://sparkfund.com/xcel-energy-sparkfund-press-release; Project Flex, Verrus (developing flexible data-center campus in Michigan to reduce peak grid needs, avoid or defer infrastructure and peaker-plant costs, and support lower rates for other customers), https://projectflexmi.com/; Virginia to Expand Energy Grid Reliability and Innovation through New U.S. Department of Energy GRIP Award, Virginia Dept. of Energy (Aug. 12, 2024) (deploying battery storage at an Iron Mountain data center for flexibility and reliability), https://energy.virginia.gov/public/documents/newsroom/2024/Press%20Release-VirginiaEnergy%20receives%20funding%20for%20energy%20innovation%20202400812.pdf.

218. Ex. 701, Large Load Tariff Revenue Comparison, Prepared for Colorado Utility Consumer Advocate by RMI, Co. PUC Proceeding 26AL-0137E (Aug. 19, 2026), https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=1072951&p_session_id=; calculations adjusted by Virginia Energy.

219. Dollar figures adjusted for inflation and extrapolated over a 25-year period as opposed to 15 years.

220. APCo 2019 IRP at 126, https://www.scc.virginia.gov/docketsearch/DOCS/4g7b01!.PDF; Dominion 2020 IRP at 5, https://www.scc.virginia.gov/docketsearch/DOCS/4m_I01!.PDF.

221. Virginia Farm Bureau Agriculture Facts, Virginia Farm Bureau, https://www.vafb.com/membership-at-work/agriculture/agriculture-facts; Forest Resource Information, Virginia Department of Forestry, https://www.dof.virginia.gov/forest-utilization-sustainability/forest-inventory/forest-resource-information.

222. Pitt et al., Re-Evaluating the Land Use Impacts of Utility-Scale Solar Energy Development in Virginia, Virginia Commonwealth University (Dec. 2024), https://scholarscompass.vcu.edu/wilder_pubs/58/.

223. 9 Va. Admin. Code 15-60-60.

224. Virginia Energy Workforce Assessment Report, vol. 1, Virginia Energy, Exhibits 28, 60.

225. Virginia Energy Workforce Assessment Report, vol. 1, Virginia Energy, Exhibits 28, 60.

226. OH Solar State Spotlight, SEIA (Sept. 2026), https://seia.org/media/17839/ohio.pdf/.

227. IL Solar State Spotlight, SEIA (Sept. 2026), https://seia.org/state-solar-policy/illinois-solar/

228. Solar Photovoltaic System Cost Benchmarks, U.S. Dept. of Energy, https://www.energy.gov/cmei/systems/solar-photovoltaic-system-cost-benchmarks; Cole et al., Cost Projections for Utility-Scale Battery Storage: 2025 Update, National Renewable Energy Laboratory (June 2025), https://docs.nlr.gov/docs/fy25osti/93281.pdf.

229. Wiser et al., Retail Electricity Price Trends and Drivers: Data Update – 2026 Edition, LBNL & Brattle (Apr. 2026), https://eta-publications.lbl.gov/sites/default/files/2026-03/retail_price_trends_2026_edition.pdf.

230. Solicitations for Large Scale Renewables, NYSERDA, https://www.nyserda.ny.gov/All-Programs/Large-

Scale-Renewables/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts.

231. Renewable Resources, Illinois Power Agency, https://ipa.illinois.gov/renewable-resources.html.

232. Clean Energy Transformation Act (CETA), Washington State Department of Commerce, https://www.commerce.wa.gov/energy-policy/electricity-policy/ceta/.

233. Prateek Joshi & Jal Desai, Transmission Planning with Renewable Energy Zones (REZ): Overview, Select Case Studies, and Key Enablers, National Renewable Energy Laboratory (Mar. 2023), https://docs.nlr.gov/docs/fy23osti/85346.pdf.

234. Build-Ready Program, NYSERDA, https://www.nyserda.ny.gov/All-Programs/Build-Ready-Program.

235. See Geothermal Energy, William & Mary (detailing how 531 geothermal wells help efficiently and sustainably cool residence halls and dining facilities), https://www.wm.edu/offices/sustainability/plans-progress/progress/geothermal/.

236. Demand Response, Virginia Energy, https://www.energy.virginia.gov/energy-efficiency/demand-response.shtml; Energy Savings Performance Contracting, Virginia Energy, https://energy.virginia.gov/energy-efficiency/performancecontracting.shtml.

237. Ingrid Behrsin, The State(s) of Distributed Solar – 2025 Update, Institute for Local Self-Reliance (Apr. 14, 2026), https://ilsr.org/article/energy-democracy/the-states-of-distributed-solar-2025-update/.

238. See The Value Stack, NYSERDA (describing NY's mechanism to compensate energy created by DERs), https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources.

239. Hledik et al., The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability, Brattle (Mar. 2026), https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf.

240. White et al., Pathways to Commercial Liftoff: Innovative Grid Deployment, U.S. Department of Energy (Apr. 2024), https://static1.squarespace.com/static/67f555826ee1df58205ff806/t/6827af76cb588c0ccb63581b/1747431307855/Liftoff_DOE_Innovative+Grid+Deployment_Apr+2024.pdf.

241. 2026 Va. Acts Ch. 612, https://lis.virginia.gov/bill-details/20261/SB621.

242. 2026 Va. Acts Ch. 608, https://lis.blob.core.windows.net/files/1218860.PDF; 2026 Va. Acts Ch. 701, https://lis.blob.core.windows.net/files/1222266.PDF.

243. See Diana DiGangi, Fervo-Google geothermal deal underscores baseload power scarcity, analysts say, Utility Dive (Sept. 2, 2026), https://www.utilitydive.com/news/analysts-say-fervo-google-geothermal-deal-underscores-baseload-power-scarci/829419/.

244. 2026 Va. Acts Ch. 378, https://lis.blob.core.windows.net/files/1217721.PDF.

245. 2026 Va. Acts Ch. 397, https://lis.blob.core.windows.net/files/1217630.PDF.

246. FERC Sets Year-End Deadline for NERC to Finalize Registry Criteria and Standards for Computational Loads, NERC (July 16, 2026), https://www.nerc.com/newsroom/ferc-sets-year-end-deadline-for-nerc-to-finalize-registry-criteria-and-standards-for-computational-loads.

247. Goldenberg et al., Totex Ratemaking Could Help Keep Rates Affordable Through the Clean Energy Transition, RMI (July 13, 2022), https://rmi.org/resources/totex-ratemaking/.

248. Second Proposed Stipulation and Motion to Receive and Consider, CVOW CPCN Case, Case No. PUR-2021-001412 (Oct. 28, 2022), https://www.scc.virginia.gov/docketsearch/DOCS/7p3y01!.PDF.

249. Governor Sherrill Announces Ratepayer Relief, Signs Major Legislation on Energy, Saving New Jerseyans $1B Annually, State of New Jersey (July 7, 2026), https://www.nj.gov/governor/news/2026/20260707a.shtml.

250. Governor Moore Calls for End to Unfair Monthly Utility Fees, The Office of Governor Wes More (July 2, 2026), https://governor.maryland.gov/news/press-releases/governor-moore-calls-end-unfair-monthly-utility-fees.

251. See Fiscal Note, HB 2224 (PA), PA House Committee on Appropriations (setting a default ROE at the 10-year U.S. Treasury bond yield plus two percentage points and allowing a competitive equity auction process as an alternative if a utility seeks a higher return), https://www.legis.state.pa.us/WU01/LI/BI/FN/2025/0/HB2224P3646.pdf.

252. See Energy Department Announces Largest Loan in Department History, Delivering Over $7 Billion in Electricity Cost Savings for Georgia and Alabama Customers, U.S. Dept. of Energy (Feb. 25, 2026), https://www.energy.gov/articles/energy-department-announces-largest-loan-department-history-delivering-over-7-billion.

253. Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid, Constellation (Sept. 20, 2024), https://www.constellationenergy.com/news/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html.

254. Requests for Proposals: Addressing Upstream Natural Gas Emissions, Meta (May 19, 2026), https://sustainability.atmeta.com/blog/2026/05/19/request-for-proposals-addressing-upstream-natural-gas-emissions/.

255. CPRG Project Implementation Grants, Virginia Department of Environmental Quality, https://www.deq.virginia.gov/air-energy/climate-pollution-reduction-grant/project-implementation-grants.

256. Va. Code § 2.2-1176.2, https://law.lis.virginia.gov/vacode/title2.2/partC/section2.2-1176.2/; Triennial Report - Electric Vehicle (EV) Procurement Cost Savings & Avoid Emissions, Department of General Services (Jan. 1, 2026), https://rga.lis.virginia.gov/Published/2026/RD18/PDF.

257. Krewski et al., Extended Follow-Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality, Health Effects Institute (2009), https://www.healtheffects.org/publication/extended-follow-and-spatial-analysis-american-cancer-society-study-linking-particulate; Marc Hafstead, Carbon Pricing 105: Effects on Human Health, Resources for the Future (May 11, 2020), https://www.rff.org/publications/explainers/carbon-pricing-105-effects-human-health/.

258. National Laboratory of the Rockies, 2024 Annual Technology Baseline, https://atb.nlr.gov/.

259. Layla S. Araiinejad & Koroush Shirvan, Techno-economic analysis of deuterium-tritium magnetic confinement fusion power plants, Applied Energy (Dec. 15, 2025), https://www.sciencedirect.com/science/article/abs/pii/S0306261925012978.

260. Kelsey Roarty, NYSERDA Completes Zero by 40 Technoeconomic Assessment, National Association of State Energy Officials (Nov. 6, 2025), https://www.naseo.org/news/article?NewsID=4195.

261. Cycle Service Request Status, PJM Interconnection, https://www.pjm.com/planning/m/cycle-service-request-status.

262. Direct Testimony of Devi Glick on Behalf of Sierra Club & NRDC, Dominion 2024 IRP, Case No. PUR-2024-00184 (Feb 28, 2025), https://www.scc.virginia.gov/docketsearch/DOCS/843I01!.PDF.