Policy Interventions to Address Rising Electricity Costs in Virginia

Clean Energy Deployment, Beneficial Electrification, and Electric Utility Reforms can Reduce Energy Costs for Consumers

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CONTENTS

EXECUTIVE SUMMARY

Consumers across the United States are facing major affordability challenges due to increases in electricity bills, along with the rising costs of other essential goods.[1] Low- and middle-income households spend a higher percentage of their income on electricity compared to higher-income households, making electric bills highly regressive. These expenditures on energy as a percentage of income are often referred to as a customer's "energy burden" because they are not discretionary. As discussed by the U.S. Department of Energy:

> High energy burdens can threaten a household's ability to pay for energy, and force tough choices between paying energy bills and buying food, medicine, or other essentials.[2]

This report discusses some of the drivers behind these recent bill increases and the policy levers that states can use to address electric rate affordability for their residents and businesses. We focus on quantifying the impacts of four important policy levers that can significantly improve energy affordability. These consist of 1) requiring data centers to bring their own clean energy generation; 2) alleviating capacity constraints by increasing the pace and scale of clean energy deployment; 3) right sizing utility profits to better reflect risk and 4) accelerating beneficial electrification technologies like electric vehicles and building electrification.

As shown in Table 1, by 2030, **these four levers could save a typical Virginia household $712 per year and a moderately sized commercial customer $2,073 per year. In total, they could reduce statewide energy costs by $16.6 billion**.

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[1] For example, studies have shown a strong correlation between increasing housing and energy burdens, compounding affordability challenges for low-income households. See, for example, Hatch, Graff, "Housing costs are not a monolith: The association between neighborhood energy burdens and eviction filing rates." Available at: https://www.sciencedirect.com/science/article/pii/S0264275124002099.

[2] U.S. Department of Energy, *Low-income Household Energy Burden Varies Among States – Efficiency can Help in All of Them,* Available at: https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf.

Table 1. Virginia estimated savings from implementing all policy levers

	2026	2027	2028	2029	2030
Residential average annual bill savings per customer (nominal $/year)	$142	$135	$140	$346	$712
Commercial average annual bill savings per customer (nominal $/year)	$456	$408	$415	$1,028	$2,073
Total statewide savings (nominal $, billions)	$1.5	$1.4	$1.5	$3.9	$8.3

- ***Data centers to "bring their own clean energy generation."*** Due primarily to the current drive to develop artificial intelligence (AI) platforms among several technology companies, the electric system is starting to see massive loads from data centers for processing and storing data, which are expected to increase in coming years. Synapse quantifies the impact of requiring data centers to "self-supply" or "bring their own generation" for incremental power and capacity needs. To implement this recommendation, PJM (the entity responsible for grid planning in VA and surrounding areas) can support implementation of this policy, and/or states could work together to support this policy across the region.

- ***Alleviating capacity constraints in PJM.*** Demand is rapidly rising in the PJM region and new supply is not keeping up, resulting in large spikes in market prices. Many new power plants, primarily renewable energy resources and storage facilities, are waiting to come online to meet rising demand but are hindered by broken interconnection processes or unfavorable local siting regulations. Faster connection of this clean energy is necessary to meet demand and reduce cost burdens. PJM, state legislatures, and public utility commissions (PUC) can implement a host of measures to increase supply or reduce peak demand. These include clearing the interconnection queue, removing siting barriers, and implementing demand-side measures to address this issue.

- ***Rightsizing utility return on equity (ROE).*** ROE compensates utility shareholders for their investment, which is paid for by ratepayers as a percentage of all prudent utility capital expenditures. A proper assessment of ROE accounts for the actual risk of the utility. When ROE is set higher than necessary to compensate for this risk, it creates perverse incentives for the utility to "goldplate" and over-invest in capital expenditures beyond what is necessary for safe, reliable, and affordable service. Studies indicate that in some instances ROEs have been authorized at higher levels than warranted based on the risk of these investments, and a reduction in ROE can be a viable option for reducing costs and better aligning the interests of ratepayers and utilities. PUCs can establish more appropriate ROEs to reflect the actual risk of regulated utilities, and state legislatures could direct commissions to use specific methodologies for calculating ROE or impose a cap on the allowed ROE.

- ***Accelerating beneficial electrification of vehicles and buildings to reduce rates and bills:*** As states decarbonize the transportation and building sectors, increased load from electric vehicles (EV) and building electrification measures can be managed to use electricity during off-peak periods, which saves all ratepayers on their electric bills if the revenues from this additional load exceed the costs incurred. States and PUCs can play a role in encouraging beneficial electrification through rate design and incentives.

We note that these measures are just some of the policies that can address this important issue. Beyond the policies modeled in this report, there are numerous additional measures that can address affordability challenges for consumers. For example:

- ***Additional measures to increase supply or reduce peak demand*:** The modeling includes only a subset of policies to accelerate the buildout of new supply. Additional measures, like state financial incentives, portfolio standards, and state procurement, can help bring on additional capacity. Other measures, including energy efficiency, distributed energy resources, and demand response, can reduce peak demand and, therefore, decrease capacity requirements and related market prices. Adopting these measures has the potential to result in additional savings for customers.

- ***Additional financial tools to reduce long-term utility borrowing costs*:** Financing options such as securitization and third-party financing can help lower long-term costs.

- ***Targeted relief for low-income customers*:** Several measures not explored in this analysis can reduce costs for certain customers. Expanding low-income affordability programs can reduce bills for vulnerable customers, and legislative funding of ratepayer programs can shift cost burdens onto a more progressive tax structure than utility bills.

- ***Leveraging non-ratepayer funds.*** Costs that benefit society as a whole are often incorporated into utility programs, disproportionately burdening low-income households. State or federal tax revenues can shift the cost burden from ratepayers to other stakeholders, often on a more progressive basis than utility bills.

BACKGROUND

Electric rates and bills have not increased dramatically for Virginia ratepayers over the past few years, but the ongoing data center boom is causing substantial consternation regarding the likely bill impacts this will cause in the near future. Northern Virginia is considered the largest data center market in the world, with around 655 completed data center facilities located in the Commonwealth.[3] Another source estimates that this represents 50 percent of all data center facilities in the United States.[4] The rise of artificial intelligence, coupled with Virginia's continued favorable tax treatment for data centers, means that the Commonwealth will likely continue to accept new data center customers.[5] PJM's 2025 load forecast highlights data center load as one of the top drivers of the region's increasing load forecast.[6] In 2025, Dominion announced a request to the State Corporation Commission to raise the average customer's monthly bill by approximate $21, citing the need to build more infrastructure to meet demand from data centers.[7]

In this section, we share data on recent rate trends in Dominion Virginia's service territory to put these recent announcements and discussion in context.

PJM market issues are a key reason for increasing electric bills

Serving 67 million customers, PJM Interconnection is the regional transmission organization operating the transmission grid in all or parts of 13 Mid-Atlantic and Midwest states and the District of Columbia. PJM market electricity costs, which are passed on to customer bills, are on the rise and are projected to continue increasing over the next few years due to several intersecting issues.

First, the PJM interconnection queue has numerous generators which have requested interconnection to the PJM system but have been delayed in doing so. By the end of 2023, PJM had the longest queue backlog of any grid operator in the United States with some projects in the queue for five years.[8] PJM is reforming its interconnection process to shorten the review process for each project to one-to-two years.[9] However, as part of its interconnection reform process, PJM has closed its queue and will not

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[3] Baxtel, *Virginia Data Center Market.* Accessed on October 21, 2025. Available at: https://baxtel.com/data-center/virginia?lat=37.793614455800544&lng=-79.2668442999998&distance=286472.080006893.

[4] "Existing and Proposed Data Centers – A Web Map." Piedmont Environmental Council. Available at: https://www.pecva.org/work/energy-work/data-centers/existing-and-proposed-data-centers-a-web-map/.

[5] Poon, Linda. "The World's Data Center Capital Has Residents Surrounded." *Bloomberg*. July 29, 2025. Available at: https://www.bloomberg.com/news/features/2025-07-29/loudon-county-data-center-growth-strains-residents-seeking-ai-regulation.

[6] "2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand." *PJM Inside Lines*. January 30, 2025. Available at: https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[7] Hafner, Katherine. "Here's how – and why – Dominion Energy plans to raise your electric bill." WHRO. August 20, 2025. Available at: https://www.whro.org/environment/2025-08-20/heres-how-and-why-dominion-energy-plans-to-raise-your-electric-bill.

[8] Rand et al. "Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023." Lawrence Berkeley National Laboratory. April 2024. Available at: https://emp.lbl.gov/publications/queued-2024-edition-characteristics.

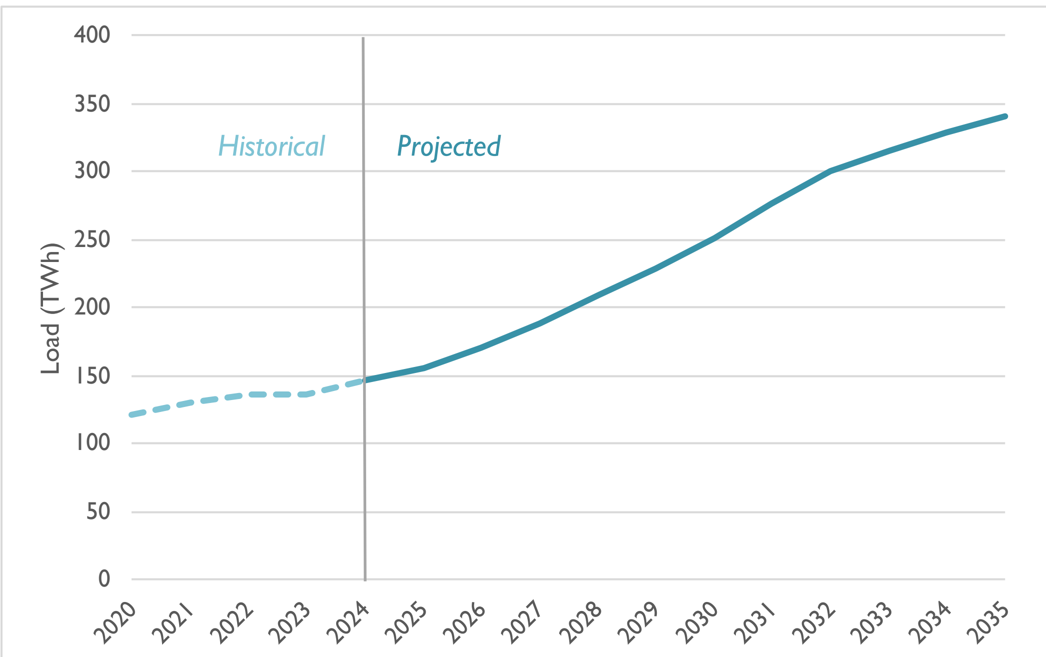
[9] Howland, Ethan. "PJM CEO Asthana responds to criticism, says states must address supply challenges." Utility Dive. September 24, 2025. Available at: https://www.utilitydive.com/news/pjm-asthana-resource-adequacy/760920/.

reopen it until 2026.[10] A congested queue leads to slower deployment timelines for new generation, which drives up energy and capacity prices because supply is low relative to demand.

As supply resources are constrained, PJM is also experiencing unprecedented load growth, both in terms of peak and annual energy demand. The 2025 PJM load report estimates that summer peak load will increase by 56 GW, or 36 percent, over the next 10 years. Similarly, PJM estimates that annual energy demand will increase by 495,264 GWh or 59 percent between 2025 and 2035. Without reform of status quo processes, high prices and reliability challenges will severely impair the functioning of this market.

Figure 1 illustrates that Virginia's annual demand is projected to increase by 119 percent between 2025 and 2035.[11]

Figure 1. Forecasted annual demand for Virginia



PJM has cited expected load from data centers as the primary driver behind the overall load growth projections for the region.[12] While PJM's 2022 load forecast projected a 5,700 MW increase by 2037 in

[10] Howland, Ethan. "FERC orders changes to PJM's grid interconnection process, plus 3 other open meeting takeaways." Utility Dive. July 25, 2025. Available at: https://www.utilitydive.com/news/ferc-pjm-grid-interconnection-queue-christie/754050/.

[11] PJM Resource Adequacy Planning Department. "PJM 2025 Long-Term Load Forecast Report. January 24, 2025. Page 6. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.

[12] "2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand." PJM Inside Lines. January 30, 2025. Available at: https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

the Dominion Zone, known as “data center alley,” the 2025 forecast projected a 20,000 MW increase from data centers alone over the same period.[13] The high data center load growth projections and slow pace of new project deployment have raised grid reliability concerns, prompting PJM to begin pushing for reforms to its interconnection processes.[14]

Related issues have already affected the wholesale capacity market. In July 2024, capacity prices for the 2025–2026 delivery year hit record highs of $269.92/MW-day up from $28.92/MW-day in 2023, a nearly 10-fold increase. In response to these high prices, PJM implemented a price cap ahead of the auctions for the 2026–2027 and 2027–2028 delivery years. This cap protects customers from even higher price spikes. In July 2025, capacity prices in hit the $329.17/MW-day price cap across the region, up another 22 percent from the prior year. PJM estimates that this could lead to 1.5–5 percent bill increases for some ratepayers, with some variability by state. PJM estimates that the capacity price would have been 18 percent higher were it not for the price cap.[15]

Recent electric rate trends in Virginia

Rates for residential customers of Dominion increased by 9 percent between 2024 and 2025, from 17 cents per kWh to 19 cents per kWh.

The primary driver of recent increases in rates for Dominion is the fuel charge rider—a rate component related to electricity supply. This rider flows through costs related to the natural gas, oil, and other fuels Dominion purchases as the fuel for its generation plants. The fuel charge rider accounted for 16 percent of the total rate in 2025, increasing by 43 percent between 2024 and 2025 from 2.1 cents per kWh to 3 cents per kWh. The increase in the fuel change rider from 2024 to 2025 accounted for 46 percent of the overall increase in rates. In general, generation-related rate increases in Dominion territory are mitigated by the fact that Dominion is a vertically integrated utility and therefore owns most of its own capacity to serve load. This allows it to purchase less from the PJM market, which has recently experienced huge price spikes. However, as load increases, Dominion is likely to have to procure an increasing amount of capacity from the market, in which case Dominion customers will face larger price increases for this component of the bill.

Transmission riders are another rate component somewhat affected by increasing loads, as higher demand can require more or additional transmission infrastructure. Dominion’s transmission riders increased 24 percent between 2024 and 2025, from 1.6 cents per kWh to 1.9 cents per kWh. This

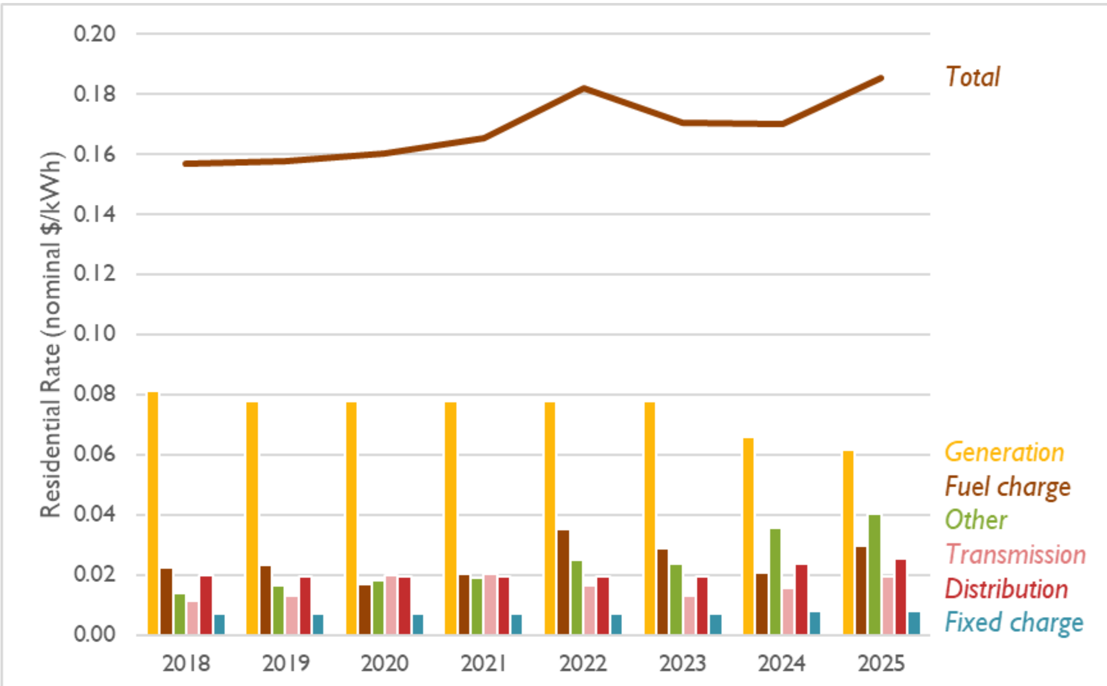
[13] Kunkel, Cathy. “Projected data center growth spurs PJM capacity prices by factor of 10.” Institute for Energy Economics and Financial Analysis. July 30, 2025. Available at: https://ieefa.org/resources/projected-data-center-growth-spurs-pjm-capacity-prices-factor-10.

[14] Howland, Ethan. “PJM launches fast-track push to set rules for adding data centers.” Utility Dive. August 12, 2025. Available at: https://www.utilitydive.com/news/pjm-cifp-fast-track-data-center-large-load/757399/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202025-08-12%20Utility%20Dive%20Newsletter%20%5Bissue:75840%5D&utm_term=Utility%20Dive.

[15] Howland, Ethan. “PJM capacity prices set another record with 22% jump.” Utility Dive. July 23, 2025. Available at: https://www.utilitydive.com/news/pjm-interconnection-capacity-auction-prices/753798/.

increase accounted for 20 percent of the increase in rates overall. The “Other” category consists of over 20 small rate components. The “fixed” category is the customer or fixed charge paid by a customer converted to a $/kWh rate for purposes of illustration in the figure.

Figure 2. Dominion residential rate by rate component, 2018–2025 (nominal dollars)



1. Summary of Results

By 2030, policy measures to address cost drivers discussed in this report can reduce costs significantly compared with the status quo. However, we note that since this report leverages modeling from previous Synapse projects, these policies were not studied together to determine and segregate out any overlapping effects. For example, requiring data centers to bring their own generation and increasing capacity in PJM have overlapping benefits. For simplification purposes and to understand the cumulative impact of multiple policies that address affordability, this section presents the results of our analyses separately and in combination. This is helpful for understanding the magnitude of these policy levers relative to various options.

In years where both the datacenter bring-your-own-generation (BYOG) and alleviating capacity constraint measures create savings (2029 and 2030), there may be some overlap between the estimated impacts. In the datacenter BYOG measure, savings accrue from avoiding additional load, which leads to lower energy and capacity prices incurred by non-datacenter customers. For the improved interconnection queue measure, additional resources come online and help to depress energy prices and capacity prices, leading to savings for all customers. We have not performed an analysis that identifies the compound effect of both reducing demand *and* increasing supply. In such a scenario, lower demand may not lead to as much new supply coming online (relative to what comes online in the improved queue scenario). In this scenario, the overall change in capacity and energy prices may not be as large as aggregate effect of the two scenarios were added together. For this reason, in 2029 and 2030, rather than adding the savings of the two measures together in the total line, we report out just the larger of the two savings, with the idea that aggregate savings are unlikely to be lower than this value, and would very likely be higher. Total bill impact estimates include our estimate of generation and distribution bills, which comprises the vast majority of customer bills.

Table 2 and Table 3, below, provide annual impacts of each policy lever individually and in total.

Table 2. Summary of Virginia residential bill impacts on annual bills

	Virginia Residential Bill Impact, Nominal $				
	2026	2027	2028	2029	2030
Data Center BYOG	-$92	-$82	-$65	-$87	-$177
Alleviating Capacity Constraints	$0	$0	-$18	-$286	-$649
Dist. And Gen. ROE Reduction	-$42	-$43	-$45	-$46	-$48
Managed Charging	-$8	-$10	-$12	-$13	-$15
Total - All Levers*	**-$142**	**-$135**	**-$140**	**-$346**	**-$712**

**The total savings in 2029 and 2030 do not include savings from the Data Centers Self-Supply scenario to account for potential double-counting of benefits between these policy cases. Therefore, the sum of all individual measures in 2029 and 2030 does not equal the total shown above.*

Table 3. Summary of Virginia commercial bill impacts on annual bills

	Virginia Commercial Bill Impact, Nominal $				
	2026	2027	2028	2029	2030
Data Center BYOG	-$266	-$211	-$160	-$223	-$430
Alleviating Capacity Constraints	$0	$0	-$52	-$818	-$1,856
Dist. And Gen. ROE Reduction	-$190	-$197	-$203	-$210	-$217
Managed Charging	$0	$0	$0	$0	$0
Total - All Levers*	**-$456**	**-$408**	**-$415**	**-$1,028**	**-$2,073**

**The total savings in 2029 and 2030 do not include savings from the Data Centers Self-Supply scenario to account for potential double-counting of benefits between these policy cases. Therefore, the sum of all individual measures in 2029 and 2030 does not equal the total shown above.*

Table 4 provides a summary of the baseline residential bills absent any policy interventions, and the bills experienced by customers if the policy intervention took place.

Table 4. Summary of Virginia residential bills

	Virginia Residential Bill, Nominal $				
	2026	2027	2028	2029	2030
Status Quo Distribution Bill	$562	$641	$732	$835	$954
Status Quo Generation Bill	$1,082	$1,208	$1,349	$1,944	$3,045
Status Quo Distribution and Generation Bill	$1,643	$1,849	$2,081	$2,779	$3,999
Gen. Bill w/ Data Center BYOG	$989	$1,126	$1,284	$1,857	$2,868
Gen. Bill w/ Alleviating Capacity Constraints	$1,082	$1,208	$1,331	$1,658	$2,396
Dist. Bill w/ Dist. And Gen. ROE Reduction	$1,601	$1,806	$2,036	$2,733	$3,951
Dist. And Gen. Bill w/ Managed Charging	$1,636	$1,840	$2,069	$2,766	$3,983
Total Bill w/ All Levers*	**$1,501**	**$1,714**	**$1,941**	**$2,433**	**$3,287**

**The total savings in 2029 and 2030 do not include savings from the Data Centers Self-Supply scenario to account for potential double-counting of benefits between these policy cases. Therefore, the sum of all individual measures in 2029 and 2030 does not equal the total shown above.*

Table 5 provides a summary of the baseline residential bills absent any policy interventions, and the bills experienced by customers if the policy intervention took place.

Table 5. Summary of Virginia commercial bills

	Virginia Commercial Bill, Nominal $				
	2026	2027	2028	2029	2030
Status Quo Distribution Bill	$1,936	$2,211	$2,524	$2,881	$3,289
Status Quo Generation Bill	$3,730	$4,167	$4,654	$6,703	$10,502
Status Quo Distribution and Generation Bill	$5,667	$6,377	$7,177	$9,584	$13,790
Gen. Bill w/ Data Center BYOG	$3,464	$3,955	$4,494	$6,480	$10,072
Gen. Bill w/ Alleviating Capacity Constraints	$3,730	$4,167	$4,601	$5,885	$8,646
Dist. Bill w/ Dist. And Gen. ROE Reduction	$5,477	$6,181	$6,974	$9,374	$13,573
Dist. And Gen. Bill w/ Managed Charging	$5,667	$6,377	$7,177	$9,584	$13,790
Total Bill w/ All Levers*	**$5,211**	**$5,969**	**$6,762**	**$8,556**	**$11,717**

**The total savings in 2029 and 2030 do not include savings from the Data Centers Self-Supply scenario to account for potential double-counting of benefits between these policy cases. Therefore, the sum of all individual measures in 2029 and 2030 does not equal the total shown above.*

Table 6 provides a summary of Virginia residential bill impacts, as percentages.

Table 6. Virginia residential bill impact, percentage of total bill

	Virginia Residential Bill Impact, %				
	2026	**2027**	**2028**	**2029**	**2030**
Data Center BYOG	-6%	-4%	-3%	-3%	-4%
Alleviating Capacity Constraints	0%	0%	-1%	-10%	-16%
Dist. And Gen. ROE Reduction	-3%	-2%	-2%	-2%	-1%
Managed Charging	0%	-1%	-1%	0%	0%
Total - All Levers*	**-9%**	**-7%**	**-7%**	**-12%**	**-18%**

**The total savings in 2029 and 2030 do not include savings from the Data Centers Self-Supply scenario to account for potential double-counting of benefits between these policy cases. Therefore, the sum of all individual measures in 2029 and 2030 does not equal the total shown above.*

Table 7 provides a summary of Virginia commercial bill impacts, as percentages.

Table 7. Virginia commercial bill impact, percentage of total bill

	Virginia Commercial Bill Impact, %				
	2026	**2027**	**2028**	**2029**	**2030**
Data Center BYOG	-5%	-3%	-2%	-2%	-3%
Alleviating Capacity Constraints	0%	0%	-1%	-9%	-13%
Dist. And Gen. ROE Reduction	-3%	-3%	-3%	-2%	-2%
Managed Charging	0%	0%	0%	0%	0%
Total - All Levers*	**-8%**	**-6%**	**-6%**	**-11%**	**-15%**

**The total savings in 2029 and 2030 do not include savings from the Data Centers Self-Supply scenario to account for potential double-counting of benefits between these policy cases. Therefore, the sum of all individual measures in 2029 and 2030 does not equal the total shown above.*

Table 8 provides a summary of Virginia cumulative savings.

Table 8. Virginia cumulative savings from policy levers

	Virginia Cumulative Savings (2026-2030, Nominal $, billions)		
	Residential	**Non-Residential**	**Total**
Data Center BYOG	-$1.9	-$3.1	-$5.0
Alleviating Capacity Constraints	-$3.7	-$7.1	-$10.8
Dist. And Gen. ROE Reduction	-$0.8	-$2.4	-$3.3
Managed Charging	-$0.2	$0.0	-$0.2
Total - All Levers*	**-$5.5**	**-$11.0**	**-$16.6**

**The total savings in 2029 and 2030 do not include savings from the Data Centers Self-Supply scenario to account for potential double-counting of benefits between these policy cases. Therefore, the sum of all individual measures in 2029 and 2030 does not equal the total shown above.*

2. DATA CENTERS CAN SELF-SUPPLY TO MITIGATE WHOLESALE MARKET PRICE INCREASES

Overview of issue

The rise of the data center industry in the mid-Atlantic and midwestern states is driving rapid acceleration in load growth projections across PJM. This surge in demand is occurring in the context of a grid that was already set to see increased load due to electrification of vehicles and buildings. This projected data center load growth has the potential to substantially raise energy costs for ratepayers.

Synapse analyzed the potential cost impacts of this increase in load. We found that data centers increase PJM costs by $25.7 billion from 2026–2030 (net present value), or a 64 percent increase compared to a world without data center growth.[16] Demand growth, coupled with an interconnection process that makes it difficult to build new supply, results in greater dependence on inefficient and costly existing generation sources. As a result, data centers drive an increase in wholesale energy and capacity costs, which are passed on to *all* customers in the form of higher bills.

To confront these price spikes, policymakers can demand that data center operators are required to invest in their own low-cost clean energy generation. In Virginia, residential and C&I customers save a cumulative $5.0 billion from 2026-2030 as a result of data centers self-supplying. This represents an annual bill decrease of up to $90 and $250 for the average residential and commercial customer, respectively.

Potential policy solutions

There is a range of possible policy solutions to increase capacity in PJM that would mitigate the impact of data center load on ratepayer bills. One possibility would be for states to require all data centers to bring their own supply, rather than further exacerbate existing tightening supply conditions which increases prices. State tax incentives could be coupled with requirements for data centers to self-supply with clean generation to help minimize the societal impacts of this new generation capacity.[17] Because all ratepayers are affected by system costs across PJM, not just by the generating resources and load in

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[16] The total system costs include energy market costs, capacity market costs, transmission build costs, and Renewable Energy Certificate (REC) costs. NPV calculation assumes a 7 percent discount rate. This section of the report relies on modeled results and methodologies from our 2024 study for Sierra Club. See Chavin, S., P. Knight, D. Glick, T. Gyalmo, I. Weiss. 2024. *Risks of Rapid Data Center Load Growth in PJM*. Synapse Energy Economics for Sierra Club.

[17] Virginia Economic Development Partnership, *Data Center Retail Sales and Use Tax Exemption*, available at: https://www.vedp.org/incentive/data-center-retail-sales-use-tax-exemption.

their respective state, each state within PJM would need to work with others to set similar requirements, provide incentives, and/or pursue other PJM-wide market reforms that result in data center self-supply. This likely includes collective action by states to work with PJM on regulations and requirements that ensure significant levels of self-supply from new large data centers. At the time of writing, PJM is deliberating how to prevent skyrocketing load growth due to data centers from continuing to drive up capacity market costs for all customers. Stakeholders have proposed various solutions.[18] In the following sections, we analyze the ratepayer impacts of data centers bringing their own supply and present the potential savings to customers in Virginia.

Regulators may also consider creating a "large load tariff" to protect non-data center customers from increased costs driven by these loads. Generally, these tariffs allocate some transmission and distribution-related costs associated with data centers directly to the large load customer class (primarily or exclusively data centers), thereby protecting non-data center customers from the incremental distribution costs. In addition, a recent analysis from the Union of Concerned Scientists identified regional transmission costs driven by data center load growth that could be more appropriately allocated to large loads with sufficient PJM reforms.[19] However, in deregulated regions such as PJM, we note that these tariffs are currently not applied to supply costs that are incurred due to associated with data centers (i.e., energy, capacity, and regional transmission costs). This is likely to remain the case because a) it would be difficult to isolate the impact of data centers on wholesale market prices; b) it may pose legal challenges based on discrimination or other principles; and c) these costs would not be passed through to data center customers on a retrospective basis. Synapse is not aware of any precedent for such a tariff design to mitigate these supply-side costs.[20]

Methodology

To quantify the impact of policies that require data centers to self-supply their load, Synapse modeled bill impacts by comparing prospective future scenarios with and without data center load growth.[21] We assume data centers are able to self-supply from new resources and do not enter into bilateral contracts with existing resources. The net effect of these transactions is that the resulting energy and capacity markets do not experience incremental demand or supply associated with data centers, meaning

[18] For example, NRDC outlines an approach to mitigating those impacts in a recent presentation to PJM. Rutigliano, T., Claire LR. 2025. *Large Load CIFP NRDC Solution Components*. Natural Resources Defense Council. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251014/20251014-item-03c---nrdc-proposed-options.pdf.

[19] Jacobs, M. Loophole Costs Customers Over $4 Billion to Connect Data Centers to Power Grid. *Union of Concerned Scientists*.

[20] DOE has recently requested and FERC has since noticed an Advanced Notice of Proposed Rulemaking (ANOPR) to consider reforms to "ensure timely and orderly interconnection of large loads." Online: https://www.energy.gov/sites/default/files/2025-10/403%20Large%20Loads%20Letter.pdf.

[21] Chavin, S., P. Knight, D. Glick, T. Gyalmo, I. Weiss. 2024. *Risks of Rapid Data Center Load Growth in PJM*. Synapse Energy Economics for Sierra Club.

wholesale market prices are not affected in this scenario. To quantify the impact of data center self-supply on market prices and ultimately customer bills, Synapse leveraged modeling results from a project conducted for Sierra Club in 2024 on this issue.[22] We analyzed electric system costs, resource builds, and residential bills under a Status Quo scenario in which data centers continue to connect to the electric power grid with no new generation resources compared to a Policy scenario in which data centers in the PJM zone must self-supply energy and capacity needs.[23]

The Policy scenario load projection does not include future load due to new data centers (because the increased load is met with other resources). This scenario is based on PJM's 2024 conventional load forecast combined with Synapse's projections of load due to increased EV and heat pump adoption. The Policy scenario load projection includes energy consumption from *existing* data centers, which are embedded within the PJM conventional load forecast.

The Status Quo load projection uses the same projections for load components that are shared with the Policy scenario but also includes projections for new data center load in PJM, based on recent data from EPRI and PJM utilities.[24] Compared to PJM's 2024 load forecast, Synapse's Status Quo scenario load forecast includes an additional 166 TWh of data center load by 2030.

For this study we analyzed electricity bill impacts for two customer groups: residential customers and C&I customers. We calculated monthly bills using energy, capacity, new transmission, and Renewable Energy Credit (REC) costs from capacity expansion modeling results from the Sierra Club data center load growth project. We hold other system costs (existing transmission, distribution, and other sunk costs) constant in both scenarios and assume that they do not contribute to bill impacts. We also include Regional Greenhouse Gas Initiative's (RGGI) revenues at the state level to account for RGGI revenue recirculation.[25]

We project future costs for energy, capacity, new transmission, and RECs using capacity expansion modeling via an EnCompass model (software that allows for capacity expansion modeling across the United States).[26] Non-wholesale market costs (e.g., distribution costs, utility return, legacy plant costs,

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[22] *Ibid.*

[23] The Status Quo future in this analysis is equivalent to the "Data Centers" scenario in the Sierra Club project, which examines a future with significant data center load growth. In this analysis, the Policy case that requires data centers to bring their own supply is equivalent to the Base case scenario in the Sierra Club project where there is no new data center load growth. The difference in costs between these scenarios represents the value of data centers self-supplying all electric capacity and energy needs.

[24] Chavin et al., p. 17.

[25] We assumed that Virginia re-enters RGGI and thus, receives RGGI revenues in this analysis.

[26] EnCompass is an optimization-based power systems model for utility-scale generation planning and operations analysis. It covers all facets of power system planning including short- and long-term unit commitment, economic dispatch decisions, environmental compliance, and market price forecasting for energy, capacity, and environmental programs. It provides unit-specific, detailed forecasts of the composition, operations, and costs of the regional generation fleet given the assumptions taken. As a starting point, Synapse populated EnCompass using the EnCompass National Database, created by Horizons Energy. More information on EnCompass and the Horizons dataset is available at https://www.yesenergy.com/encompass-power-system-planning-software.

etc.) are derived from historical data. Specifically, using recent historical data, we subtract wholesale energy costs (as estimated by EnCompass for historical years) from statewide revenues for each PJM state, as reported in Form 861 by the U.S. Energy Information Administration (EIA). The remaining revenue is assumed to be non-wholesale market costs.[27] For future year projections we assume these costs remain constant in real dollar terms (i.e. increase by inflation in nominal terms). To estimate future revenue requirements, we added this cost component to the modeled energy, capacity, new transmission, and REC costs to estimate total system costs. We also use historical RGGI auction data or state strategic funding plans to inform the allocation for future RGGI allowances.[28] We subtract the portion of state RGGI revenues that are allocated to energy programs from the statewide costs to account for revenue recirculation.

In the Policy scenario, systemwide costs are allocated across two sectors: residential and C&I. Costs are allocated based on recent historical cost allocation, per data published by EIA Form 861, and adjusted for future years based on customer-sector share of load growth.[29] In the Status Quo scenario, costs are allocated across three sectors: residential, C&I, and data centers. Data centers' energy cost allocations are based on their contribution to total system load. They pay the average energy price, as opposed to the PJM load weighted average energy price, because they have a relatively flat load shape and are assumed to consume electricity "around the clock." Data centers' capacity market and transmission cost allocations are based on their contribution to system peak load. We allocated the non-data center costs to the residential and C&I sectors using the same method as in the Policy scenario.

To calculate state-level ratepayer impacts, we identified the PJM subzone, or region, in Encompass that most closely aligns with the state. We then scale the region-wide system costs to state-level system costs based on sales. For this Virginia analysis we further adjusted capacity costs because Dominion Energy is a vertically integrated utility and therefore owns a significant amount of its capacity which it does not need to purchase from the PJM market. Specifically, we calculate capacity costs in Virginia based on Dominion's average projected capacity market imports rather than their total capacity obligation.[30]

Results

PJM data center load is projected to increase from 42 TWh in 2025 to 166 TWh by 2030. This represents an increase from 6 percent of PJM's total load to 20 percent of PJM's total load. We assume that this increase occurs in the context of ambitious building and transportation electrification trajectories in non-data center sectors. While there is uncertainty around future levels of load growth, our study relies

[27] In this case, "costs" and "revenue requirement" are synonymous.

[28] The Regional Greenhouse Gas Initiative. 2025. *The Investments of RGGI Proceeds in 2023.*

[29] In 2025, we allocate 40 and 30 percent of costs to residential customers in the PJM-EMAAC and PJM-Dominion regions, respectively. The remaining costs in 2025 are allocated to C&I customers.

[30] *Virginia Electric and Power Company's 2024 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq. SCC Directed 2024 IRP Supplement*, Commonwealth of Virginia, ex rel. State Corporation Commission Case No. PUR-2024-00184.

on the latest available information at the time of the study, 2024, to indicate the scale of potential impacts of data center growth. Customer-class specific annual savings of the Policy scenario are produced from subtracting the total costs of the Policy scenario from the Status Quo scenario in the EnCompass capacity expansion model. In Virginia, residential and C&I customers save a cumulative $5.0 billion from 2026–2030 as a result of data center self-supply. This measure alleviates a major piece of the mismatched supply-demand problem in PJM and therefore reduces costs. Some of these reductions manifest further out than the scope of this report, 2030. Additionally, the PJM system faces other supply constraints that drive up prices, including grid upgrades and non-supply related issues outside the scope of this analysis.

We estimate the impact of data center self-supply for residential and commercial customers in Table 9 and Table 10. We estimate that Virginia residential customers would collectively save $1.9 billion dollars between 2026 and 2030 from data centers bringing their own supply, with non-residential (commercial and industrial) customers saving an additional $3.1 billion.

Table 9. Annual residential generation bills with and without data center self-supply

	Virginia Annual Residential Bill, Nominal $				
	2026	2027	2028	2029	2030
Status Quo Generation Bill	$1,082	$1,208	$1,349	$1,944	$3,045
Generation Bill After Data Centers BYOG	$989	$1,126	$1,284	$1,857	$2,868

Table 10. Annual commercial generation bills with and without data center self-supply

	Virginia Annual Commercial Bill, Nominal $				
	2026	2027	2028	2029	2030
Status Quo Generation Bill	$3,730	$4,167	$4,654	$6,703	$10,502
Generation Bill After Data Centers BYOG	$3,464	$3,955	$4,494	$6,480	$10,072

3. ALLEVIATING CAPACITY CONSTRAINTS CAN SIGNIFICANTLY REDUCE MARKET PRICES AND CUSTOMER BILLS, PAIRED WITH STATE SITING REFORMS

Overview of issue

PJM is projecting unprecedented growth in electricity demand at a time when capacity prices are already high due to both new data center loads and the restriction in new supply brought by the interconnection delays discussed earlier in this report.[31] As discussed, these capacity constraints and increasing loads are driving up capacity market prices and therefore customer costs, raising concerns about affordability in the region. Alleviating capacity constraints is necessary both to serve new and existing load reliably and to mitigate problematic cost increases to ratepayers. While Section 2 discusses one potential solution to this issue, requiring or encouraging data centers to "bring their own generation," this section discusses and quantifies the economic benefits of alleviating capacity *across* the PJM market, which would likely be necessary even absent data center load growth.

Potential policy solutions to alleviate capacity constraints in PJM

Interconnection queue reform

In recent years, PJM's interconnection process has become a barrier to bringing new resources online. Since 2020, 45 percent of new energy generation projects added to the interconnection queue have withdrawn before completing PJM's interconnection process. Withdrawals were largely due to PJM's study delays, lack of transparency in timing and fees, and high network upgrade costs. Projects still in the queue continue to face long wait times. For example, 64 projects, representing over 5 gigawatts of total capacity, submitted.[32] Meanwhile, network upgrade costs associated with interconnection in the region reached an average of $240/kW in 2020–2022, up from $29/kW in 2017–2019 (a 728 percent increase).[33] In February 2024, Gridlab's Generation Interconnection Scorecard rated PJM's interconnection process a "D-" based on its slow timelines and lack of data transparency. PJM paused accepting new applications from proposed projects due to the large queue backlog.

A potential solution to tackle PJM's capacity constraint is for states to consistently and uniformly advocate reforms at PJM to clear the interconnection queue and accelerate the process of bringing new clean generation online. This path has already been paved in part by Pennsylvania's efforts to unite PJM states to reform PJM processes and reduce consumer costs. As of July 2025, there were 197 GW of active resources in the interconnection queue. Out of these, 92 percent (181 GW) were renewable resources. There were 35 GW of active resources in the engineering and procurement phase, 91 percent (32 GW) of which were made up of renewables. Only 6 GW of the renewable resources in the queue are

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[31] U.S. Department of Energy. 2023. Tackling High Costs and Long Delays for Clean Energy Interconnection. Available at: https://www.energy.gov/eere/i2x/articles/tackling-high-costs-and-long-delays-clean-energy-interconnection.

[32] Chavin S., P.Knight, S. Shenstone-Harris, A. Zeng, A. Fuzaylov, J. Hittinger. 2025. "Tackling the PJM Electricity Cost Crisis" ("Evergreen Study"), Available at: https://www.synapse-energy.com/sites/default/files/Evergreen%20PJM%20Queue%20Report%204.10.25_%20final%2024-145.pdf.

[33] Lawrence Berkeley National Laboratory. 2023. Interconnection Cost Analysis in the PJM Territory. Available at: https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2023.1.12-_pjm_interconnection_costs.pdf.

under construction.[34,35] There is a range of possible queue reforms that could enable PJM to reach the levels of resource builds and the accompanied cost savings that we discuss later in this report. Additional interconnection process improvements have been included in PJM's further compliance filing in October 2025.[36]Effective PJM interconnection reforms should target the following goals:

- **Improve interconnection timeline to meet projected load growth.** The unprecedented load growth in PJM requires that the interconnection process move as quickly as is feasible. It also requires interconnection customers to have a high degree of certainty around the expected interconnection wait times.[37] PJM should revise its existing interconnection processes to match the 150-day study timeline required by the Federal Energy Regulatory Commission's (FERC) Order 2023 (see below). PJM could also create a fast-track process for projects in areas with available transmission headroom, avoiding lengthy network upgrades to get projects online fast.

- **Increase data access and transparency to improve project proposal quality and promote competition.** Improving data transparency would improve developers' abilities to screen and site potential projects, facilitate more process automation, and enable auditing of interconnection processes. Transparency also enables fairness, equity, and competition in the interconnection process.[38]

- **Enhance coordination between transmission planning and interconnection processes**, which would allow for the rightsizing of transmission investments. Updating cost allocation methods would reduce uncertainty for developers and improve allocative efficiency.[39]

- **Ensure nondiscriminatory treatment between different resource types.** The Federal Power Act requires equitable treatment of all resource types,[40] which promotes competition and ultimately delivers the most cost-effective power to consumers. PJM could also ensure that interconnection studies evaluate grid-

[34] Active resources are limited to those that have entered the queue since 2019 and have an expected online date by 2030. Renewable resources include Onshore wind, solar and storage.

[35] PJM. Serial Service Request Status. Available at: https://www.pjm.com/planning/service-requests/serial-service-request-status. Accessed on July 22nd, 2025.

[36] PJM Interconnection, L.L.C., *Order Nos. 2023 and 2023-A Further Compliance Filing*, Docket No. ER24-2045-004 (filed Oct. 23, 2025), available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=877981AD-4EBA-C33F-9FE4-9A0DF3500000.

[37] GridStrategies and Brattle Group. 2024. "Unlocking America's Energy." Available at: https://gridstrategiesllc.com/wp-content/uploads/Exec-Sum-and-Report-Unlocking-Americas-Energy-How-to-Efficiently-Connect-New-Generation-to-the-Grid.pdf.

[38] U.S. Department of Energy. 2024. "Transmission Interconnection Roadmap." Available at: https://www.energy.gov/sites/default/files/2024-04/i2X%20Transmission%20Interconnection%20Roadmap.pdf.

[39] U.S. Department of Energy. 2024. "Transmission Interconnection Roadmap." Available at: https://www.energy.gov/sites/default/files/2024-04/i2X%20Transmission%20Interconnection%20Roadmap.pdf.

[40] The Federal Power Act requires that rates, terms, and conditions of interconnection services must be reasonable and not unduly discriminatory.

enhancing technologies, as well as advanced conductors, that help reduce interconnection costs and time.

Siting reforms

While resolving undue delays in the interconnection queue would significantly increase capacity and reduce market prices, siting reform is also needed to fully unlock the modeled benefits. Local permitting and siting processes can be barriers to developing new resources as well. This includes lengthy permitting timelines, overlapping jurisdictions, and local opposition which can delay energy projects. Policy interventions to reduce these barriers can help alleviate capacity constraints, such as Pennsylvania's recently proposed Lightning Plan. This includes reforms which create a board aimed at streamlining the development process to build energy projects quickly through centralization of regulatory processes, permitting reforms, and other reforms that cut red tape.[41]

FERC Order 2023

FERC Order 2023 directs transmission providers to reform their interconnection procedures to reduce queue backlogs, improve certainty in interconnection processes, and ensure access to the transmission system for new technologies.[42] To comply with the Order, PJM will need to do the following:

- Achieve a 150-day timeline requirement for all interconnection studies
- Implement the first-ready, first-served cluster study approach on time for the regular-order queue
- Implement realistic modeling assumptions around energy storage behavior, rather than assuming energy storage will charge during peak and require associated transmission upgrades
- Require that interconnection studies evaluate a range of alternative transmission technologies, including grid-enhancing technologies
- Dedicate more resources to interconnection, if needed, to address the large queue backlog, reopen the queue, and achieve Order 2023 deadlines

Order 2023 also required that transmission providers face penalties for delays in study timelines. These penalties should come with safeguards that protect electricity customers from price increases.

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[41] Pennsylvania State Senate, https://www.palegis.us/senate/co-sponsorship/memo?memoID=46024.

[42] Federal Energy Regulatory Commission (FERC). 2025. "Explainer on the Interconnection Final Rule." Available at: https://www.ferc.gov/explainer-interconnection-finalrule#:~:text=On%20July%2028%2C%202023%2C%20the,%2C%20or%20May%2016%2C%202024.

FERC Order 1920

FERC issued Order 1920 in May 2024, a new transmission and cost allocation rule that outlines specific requirements regarding how transmission providers must conduct long-term planning.[43] The order includes requirements related to regularly conducting long-term transmission planning (over at least a 20-year horizon) to anticipate future needs, and assessing a broad set of benefits in the planning process. This forward-looking and comprehensive approach helps alleviate capacity constraints by ensuring that grid investments are planned proactively to meet future demand and integrate new resources efficiently, thereby avoiding costly short-term fixes or the need for emergency generation. The order also includes requirements for considering grid-enhancing technologies (GET) in transmission planning. GETs can help increase hosting capacity and reduce grid upgrade fees.

Demand-side reforms

In addition to supply side reforms, state, utilities, and PJM can also help alleviate capacity constraints through demand-side reform. This includes increasing the ability and role of demand response, rate design, and distributed energy resources (DER) to provide peak load reductions that translate into reduced need for capacity resources. DERs have been traditionally ignored by wholesale market operators for their ability to contribute to reducing peak load capacity requirements, for a variety of reasons.[44] If leveraged to their full potential, integrating demand-side resources with supply-side markets can greatly increase the resources available to market operators to satisfy system requirements. While we did not model these measures in this analysis, adoption of these measures would likely reduce costs beyond the savings in this analysis.

This includes the following programs and rates:

- **Demand response** refers to voluntary programs in which end-use customers reduce (or shift) their electricity consumption during peak demand periods in exchange for compensation. Demand response is a potential solution that offers an alternative to bringing new generation online. Demand response helps balance the grid, reduce reliance on expensive peaking power plants, and improve reliability. For example, incentivizing data centers to adjust their

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[43] FERC. 2024. "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation." Available at: https://www.ferc.gov/news-events/news/fact-sheet-building-future-through-electric-regional-transmission-planningand#:~:text=FERC's%20new%20transmission%20and%20cost,projects%20from%20which%20they%20benefit.

[44] As noted by FERC in its discussion of Order 2222, "DERs tend to be too small to meet the minimum size requirements to participate in the RTO/ISO markets on a stand-alone basis, and may be unable to meet certain qualification and performance requirements because of the operational constraints they may have as small resources. Existing participation models for aggregated resources, including DERs, often require those resources to participate in the RTO/ISO markets as demand response, which limits the services that they are eligible to provide to the markets. Such conditions create barriers to the participation of DERs that are technically capable of providing some services on their own or through aggregation." FERC, *Staff Presentation Item E-1,* September 2020, https://www.ferc.gov/staff-presentation-item-e-1.

operations based on grid conditions and market prices and/or shift processes to other geographies in real time can help reduce peak load requirements.

- **Time-of-use pricing and other dynamic pricing options.** Dynamic retail pricing structures, such as time-of-use (TOU) and critical peak pricing (CPP), prices electricity during peak hours at higher rates than during off-peak hours to incentivize load shifting. States can leverage these mechanisms to help flatten the load curve and ease system capacity requirements.

- **Distributed generation.** Ensuring peak load reduction contributions from distributed generation (solar, batteries, diesel, natural gas generators, etc.) are accurately accounted for in system planning and incentivized for dispatch (when applicable) during peak load periods can contribute to increase supply resources constraints. FERC Order 2222 requires tariff revisions so that DERs can aggregate and participate directly in wholesale electricity markets alongside traditional resources. DER aggregation can help alleviate capacity constraints by tapping into existing small-scale resources that can reduce peak demand, provide local capacity, and defer the need for new large-scale generation or transmission investments, thereby lowering costs for consumers.

Potential savings from alleviating PJM capacity constraints

Methodology

To understand the bill impacts of alleviating PJM capacity constraints, we utilize capacity expansion modeling conducted for Evergreen Collaborative in April 2025 that quantified the benefits of interconnection queue reform in PJM.[45] That compares two scenarios which can be equated to the scenarios we compare in this report.

- **Status Quo scenario –** This scenario reflects a future in which PJM's current pace of resource additions is held constant. This scenario included conservative assumptions around interconnection rates and serves as a lower-bound on PJM's ability to build new resources.

- **Queue Reform scenario –** This scenario reflects a future in which PJM implements an expanded set of interconnection reforms and at the same time other supply-side constraints (such as local permitting and siting processes) are assumed to be broadly loosened.

In both scenarios, all other variables aside from the maximum allowable annual build limits, including load growth, resource costs, and fuel costs are held constant.[46] The capacity expansion model was

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[45] Chavin S., P.Knight, S. Shenstone-Harris, A. Zeng, A. Fuzaylov, J. Hittinger. 2025. "Tackling the PJM Electricity Cost Crisis" , Available at: https://www.synapse-energy.com/sites/default/files/Evergreen%20PJM%20Queue%20Report%204.10.25_%20final%2024-145.pdf.

[46] See Appendix A of for a more detailed description of modeling assumptions that are consistent across both scenarios. Chavin S., P.Knight, S. Shenstone-Harris, A. Zeng, A. Fuzaylov, J. Hittinger. 2025. "Tackling the PJM

allowed to economically decide which resources to build based on certain cost and operating assumptions, up to a maximum allowable annual build limit. To model the interconnection queue, Synapse developed a set of assumptions around the maximum quantity of each resource that can be built each year, under each scenario (see Table 11, below).

Table 11. Modeled annual PJM-wide maximum resource additions (MW)

	2027	2028–2035
Status Quo Scenario		
New Gas	1,300	1,300*
New Solar	3,200	3,200
New Storage	800	800*
New Onshore Wind	800	800
Queue Reform Scenario		
New Gas	1,300	1,300-11,700
New Solar	3,200	4,000-39,000
New Storage	800	1,300-32,000
New Onshore Wind	800	1,200-8,400

**The Status Quo scenario also allowed the model to build an additional 6.6 GW of gas, 9.4 GW of storage, and 16 GW of solar over 2031-2033 to reflect PJM's Resource Reliability Initiative (RRI).*[47]

For each state in PJM, the Evergreen Study analyzed electricity bill impacts for two customer groups: residential and C&I customers. We calculated monthly bills using energy, capacity, new transmission, and REC costs from our capacity expansion modeling results. Legacy system costs (existing transmission, distribution, and other sunk costs) are assumed to be held constant in both scenarios and do not contribute to bill impacts. RGGI revenues are credited to RGGI states to account for RGGI revenue recirculation. The bill analysis method follows the approach described in Section 1.

It is important to note that the modeling for this analysis was performed in late 2024, prior to the passage of the OBBA ("One Big Beautiful Bill").[48] As a result, the projections of resource builds and dispatch assume the inclusion of the tax credits allowed under the Inflation Reduction Act. However, despite the removal of these tax credits, renewables remain the most cost-effective supply alternative in many instances.[49] We believe that the current removal of tax credits will have a minimal effect on the

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Electricity Cost Crisis", Available at: https://www.synapse-energy.com/sites/default/files/Evergreen%20PJM%20Queue%20Report%204.10.25_%20final%2024-145.pdf.

[47] In December 2024, PJM proposed the RRI in a filing to FERC which was approved by FERC on February 11, 2025. According to PJM's filing, the RRI will be a one-time expansion of eligibility criteria for Transition Cluster #2 to add more resources to the grid and address resource adequacy concerns in the region in the 2029/2030 delivery year. (*Order Accepting Tariff Revisions Subject to Condition.* 190 FERC ¶ 61,088 (2025)).

[48] One Big Beautiful Bill Act. Available at: https://www.congress.gov/bill/119th-congress/house-bill/1/text.

[49] Lazard, *Levelized Cost of Energy (LCOE)*, June 2025, https://www.lazard.com/media/uounhon4/lazards-lcoeplus-june-2025.pdf.

modeled bill impacts. This is because in both scenarios resource builds are largely "locked in" through 2029. In other words, in both scenarios, resource builds are limited based on our assumptions about how fast PJM queue reforms can proceed; the resources built through this period are largely already known and unlikely to change without the tax credits.

Results

Our modeling indicates alleviating capacity constraints would reduce customer bills by $348 per year by 2030. In the near term, capacity market costs remain high in both scenarios relative to recent historical prices. Although the Policy scenario adds a greater quantity of firm capacity than the Status Quo scenario, the pace of additions is still slower than the rate at which peak load is projected to increase in this period, leading to the capacity market clearing at or near its maximum allowable price in both scenarios. At the same time, near-term energy price increases are slightly lower in the Policy scenario. This is because there are slightly more zero-marginal cost renewable energy and battery storage resources added, which reduces reliance on inefficient, costly generation that would otherwise increase prices for all customers.

In the Status Quo scenario, the model builds an average of 3 GW of utility-scale solar per year, an average of 1 GW of wind per year, 1.4 GW of new gas per year, and less than 1 GW per year of battery storage. In the Policy scenario, new resource builds start to diverge from the Status Quo scenario in 2028. By 2030, the Policy scenario has 10 GW more solar and 5 GW more battery storage than the Status Quo scenario. In the near term, annual CO_2 emissions in each scenario remain similar through 2030 as builds are constrained in both scenarios in the near term.

We estimate the impact of alleviating capacity constraints on residential and commercial customers in Table 12 and Table 13. We estimate that Virginia residential customers would collectively save $3.7 billion dollars between 2026 and 2030 from alleviating capacity constraints, with non-residential customers saving an additional $7.1 billion.

Table 12. Annual residential generation bills with and without alleviating capacity constraints

	Virginia Annual Residential Bill, Nominal $				
	2026	**2027**	**2028**	**2029**	**2030**
Status Quo Generation Bill	$1,082	$1,208	$1,349	$1,944	$3,045
Generation Bill After Alleviating Capacity Constraints	$1,082	$1,208	$1,331	$1,658	$2,396

Table 13. Annual commercial generation bills with and without alleviating capacity constraints

	Virginia Annual Commercial Bill, Nominal $				
	2026	**2027**	**2028**	**2029**	**2030**
Status Quo Generation Bill	$3,730	$4,167	$4,654	$6,703	$10,502
Generation Bill After Alleviating Capacity Constraints	$3,730	$4,167	$4,601	$5,885	$8,646

Potential job impacts from alleviating PJM capacity constraints

We also find that alleviating capacity constraints would boost jobs in the region, mostly linked to clean energy additions (in-region construction of solar, wind, and battery storage).

In Virginia, large increases in employment from alleviating capacity constraints are linked to in-region construction of solar, wind, and battery storage. Job impact estimates include those related to initial construction, ongoing fueling, operations and maintenance (O&M) and re-spending. On average, we estimate an average net increase of 27,000 direct full time equivalent (FTE) jobs per year in the Expanded Queue Reform scenario relative to the Status Quo scenario from 2025 to 2030. Our modeling also shows that on average there is a net increase of 14,000 indirect and induced FTE jobs in the Queue reform scenario than in the Status Quo scenario.[50]

4. RETURN ON EQUITY THAT BETTER REFLECTS UTILITY RISK CAN LOWER UTILITY BILLS

Introduction

For regulated investor-owned utilities, the authorized ROE is the amount of return equity shareholders can collect from customers. The ROE is essentially the profit that equity shareholders are authorized to receive based on capital expenditures of the regulated utility. The formula for profit used in rate cases is typically:

$$\begin{aligned} Equity\ Return = {} & Net\ Investment\ (\$) \\ & * Percent\ equity\ in\ the\ authorized\ capital\ structure\ (\%) \\ & * authorized\ return\ on\ equity\ (\%) \end{aligned}$$

State utility commissions set ROE, in theory, under principles laid out by the Supreme Court in the landmark cases of *Bluefield Water Works v. Public Service Commission* (1923) and *Federal Power Commission v. Hope Natural Gas Co.* (1944). *Hope*, for example, ruled that a fair ROE should be "commensurate with returns on investments in other enterprises having corresponding risks." In practice, that decision has put the focus in the ROE-setting process on the use of financial models that estimate risk based on data from publicly traded companies.

[50] Id.

Despite the use of models that account for objective measurements of risk, the degree to which utility ROEs have been set at a premium to risk benchmarks like U.S. Treasury rates has been growing over time. In other words, as interest rates have fallen, utility ROEs have not fallen as much even though one would expect ROE would also decrease to reflect this steady utility risk premium, assuming the risk premium of utilities is relatively constant over time. A 2019 paper from Carnegie Mellon researchers Rode and Fischbeck found that this risk premium cannot be explained by financial models, leaving the likely explanation that "regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms."[51] When ROE exceeds the actual risk level, utilities have a perverse incentive to over-invest in the grid. A high ROE also makes necessary capital expenditures more expensive. Conversely, an ROE set below the appropriate risk level can discourage necessary investments. Setting an appropriate ROE is therefore a critical aspect of utility regulation for balancing the need to ensure that utilities remain financially viable and successful entities with the need to ensure just and reasonable rates for ratepayers.

These excessive ROEs lead to significant costs for ratepayers. A 2023 paper from Dunkle Werner and Jarvis published by the Energy Institute at the University of California Berkeley's Haas School of Business found that excessive rates of return for electric and gas utilities cost U.S. consumers around $7 billion per year.[52] These costs stem not just directly from the higher amount of the utility bill that goes to ROE, but also from the effects that high ROEs have on utility incentive to over-spend on capital expenditures to earn these excessive returns. Dunkle Werner and Jarvis identified an effect wherein a 1 percent increase in ROE leads to a 3 percent increase in approved rate base (the undepreciated dollar value of all utility capital investments).

Policies to reform return on equity

As policymakers consider ways to confront the problem of rising electric bills, utility ROE has emerged as a potential area for reform. In 2025, at least six states introduced policies aimed at limiting utility ROE.[53] A New Jersey bill would require that state's Board of Public Utilities to "determine and consider the lowest reasonable return on equity as a factor in determining if an increase, change, or alteration to any existing rates, charges, or schedules thereof is just and reasonable," and further requires the board to develop and apply analytic models that adhere to minimum standards for determining such an ROE.[54]

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[51] David Rode and Paul Fischbeck. "Regulated equity returns: A puzzle." Energy Policy, Oct. 2019. Available at https://www.sciencedirect.com/science/article/abs/pii/S0301421519304690?via%3Dihub.

[52] Karl Dunkle Werner and Stephen Jarvis. "Rate of Return Regulation Revisited." Energy Institute at Haas Working Paper 329R. Revised September 2024. Available at https://haas.berkeley.edu/wp-content/uploads/WP329.pdf.

[53] State Net, "Lawmakers Aim to Cut Utility Returns," Aug. 26, 2025, https://www.lexisnexis.com/community/insights/legal/capitol-journal/b/state-net/posts/lawmakers-aim-to-cut-utility-returns.

[54] New Jersey Senate Bill 4304.

Beyond legislative measures like these, governors also can indirectly affect utility ROE through appointments made to state regulatory commissions. Governors can appoint commissioners who recognize the issue of excessive ROEs, understand the analytical paradigm under which they are calculated and support lowering them if current levels cannot be shown to be just and reasonable. Commissions can and should propose ROEs in the rate case process, which would allow discussions to be anchored to that proposed number.[55] That contrasts with the status quo where utilities are usually the party to first propose a number for ROE, causing the ultimate authorized ROE to be anchored to that higher, utility-proposed number. Ultimately, PUCs have the authority to lower ROEs where warranted for all utility investments under the PUC's jurisdiction.

Methodology

To estimate ratepayer savings from a reduction in authorized ROE, Synapse first calculated a "Status Quo" case by which current authorized ROEs continue to persist in the near future. We then calculated a "Policy" using the same inputs as the Status Quo case but adjusting authorized ROE downwards for a range of ROE reductions from 1 to 200 basis points. The difference in revenue requirement between these two cases represents ratepayer savings, which we translated to rate and bill savings.

We note that the savings estimates below are meant to be illustrative of the possible savings that can come from a lower ROE. We do not estimate nor do we suggest a specific lower ROE, but instead encourage appropriate underlying economic and financial analysis of any proposed ROE as a way to identify any possible ROE reductions.

Estimating ratepayer savings due to a lower authorized return on equity

Synapse first determined the total authorized return on common equity for distribution and generation rate base for Virginia Electric and Power Company (Dominion). Dominion filed Virginia jurisdictional distribution and generation rate base calculations for calendar year test years in 2020,[56] 2022,[57] and 2024.[58] We determined a historical compound average growth rate of generation and, separately, distribution rate base over these periods using these rate base values. We escalated the 2024 test year rate base with this calculated growth rate to determine the total rate base in each year.

The Status Quo case return on such rate base was the authorized ROE proposed by Dominion in its 2024 rate case, which has an embedded cost on common equity of 10.40 percent, multiplied by the 52.1 percent share for equity in Dominion's capital structure.[59] This was held constant through 2030.

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[55] This concept would also be helpful for the overall requested increase from utilities in a rate case, which, in most jurisdictions, has no upper bound.

[56] Filing Schedule 19. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/4sq%2401!.PDF.

[57] Filing Schedule 19. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/7t%40901!.PDF.

[58] Filing Schedule 19. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/84tk01!.PDF.

[59] VEPCo Application, Schedule 8. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/84th01!.PDF.

We then calculated the estimated pre-tax return on rate base from 2026 through 2030 for the Status Quo case. We calculated the return on the escalated rate base by applying the Status Quo case ROE to the growing rate base. This return on rate base was then grossed up from post-tax return on to pre-tax return on using estimated state and federal tax rates for the utility.[60] This pre-tax ROE represented the revenue required by customers to meet the Status Quo case ROE.

Estimating the effect of reducing return on equity

Our Policy case illustratively reduces the authorized return on equity by a range of percentage points. For simplicity, we report only a 200 basis point (2 percentage point) reduction in the report.

Dunkle Werner and Jarvis find that a 1 percent increase in approved ROE leads to a roughly 3 percent increase in the approved rate base in the subsequent rate case.[61] We assume that this effect equally applies for a reduction in approved ROE. In other words, if increases to ROE result in over-investment, reductions are equally likely to reduce capital expenditures. We account for this relationship in our modeled scenarios by applying a 3 percent reduction in total rate base for each 1 percent reduction in ROE in the policy case. We only apply this effect for the first year of the Policy case, which we modeled as 2026. Thus, there are two effects being modeled which cause lower ratepayer expenditures: the initial lower authorized ROE, and the subsequent reduction in proposed rate base after the initial lowering of authorized ROE.

These changes were integrated into the calculations of pre-tax ROE.

We allocated policy savings, in the form of reduced payments of ROE, to customer classes based on energy share of each class, using EIA 2023 sales by class.

We escalated electricity sales through 2030 using estimated sales escalation by sector from the alleviating capacity constraints reference case scenario. We estimated the rate impact by dividing the estimated revenue requirement impact of each policy by the sales for each applicable rate class.

Table 14 and Table 15 show the bill impact of reducing distribution and generation ROE by 2.00 percentage points, for residential and commercial customers in Virginia. We estimate that Virginia residential customers would collectively save around $0.8 billion dollars between 2026 and 2030 from reducing distribution ROE by 2.00 percentage points, with non-residential customers saving an additional $2.4 billion.

[60] 1800Accountant, New Federal and State Corporate Tax Rates: 2025 Updated. Available at: https://1800accountant.com/blog/corporate-tax-rates.

[61] Karl Dunkle Werner and Stephen Jarvis, Rate of Return Regulation Revisited, Energy Institute at Haas Working Paper WP 329R, Revised March 2025, pp. 32-33. Available at: haas.berkeley.edu/wp-content/uploads/WP329.pdf.

Table 14. Annual residential distribution and generation bills with and without 2.00 percentage point distribution and generation ROE reduction

	Virginia Annual Residential Bill, Nominal $				
	2026	2027	2028	2029	2030
Status Quo Distribution and Generation Bill	$1,643	$1,849	$2,081	$2,779	$3,999
Distribution and Generation Bill after Reducing Distribution and Generation ROE	$1,601	$1,806	$2,036	$2,733	$3,951

Table 15. Annual commercial distribution and generation bills with and without 2.00 percentage point distribution and generation ROE reduction

	Virginia Annual Commercial Bill, Nominal $				
	2026	2027	2028	2029	2030
Status Quo Distribution and Generation Bill	$5,667	$6,377	$7,177	$9,584	$13,790
Distribution and Generation Bill After Reducing Distribution and Generation ROE	$5,477	$6,181	$6,974	$9,374	$13,573

5. Beneficial Electrification Can Put Downward Pressure on Rates for all Customers

Overview of issue

The growth in EV adoption and increased building electrification, driven by municipal, state, and federal policies, as well as changing consumer preferences, is raising important questions about their impact on electricity rates. EV load, managed proactively, could be beneficial to all customers by introducing more electricity sales, and thus revenue, systemwide. This positive impact will depend on that added revenue being greater than any increased system costs due to meeting the new demand. Additionally, compared with gasoline and diesel-powered vehicles, EVs are significantly more efficient and emit less carbon, the societal benefits of which are not quantified here.

As the electric utility sees more EVs and building electrification in its service territory, its annual sales increase accordingly. As sales grow, the electric utility can collect more revenue from these customers, which can reduce rates for all customers. Yet, as more households and businesses electrify and purchase EVs, electricity system costs will increase to serve that new load. Specifically, more energy will be generated to provide electricity to power EVs and buildings and more generating capacity, including renewable energy facilities, may need to be built to power that new load. Relatedly, the system may need new transmission lines or upgrades to existing ones to move electricity from the point of generation to where more electricity is needed. The distribution grid may also need upgrades or expansions to continue reliably serving growing demand, which can require additional investments for higher capacity power lines, transformers, and substations. To keep rates affordable for customers, jurisdictions can ensure the incremental revenues from electrification offset the costs incurred to serve this load through careful management. Managed electrification of transportation and buildings can reduce rates for all customers by using the grid more efficiently. Specifically, managed electrification can increase grid utilization minimizing the need for system expansion depending on local constraints by avoiding excess electric demand during peak periods. This principle applies to all sources of load growth.

This report illustrates this effect by analyzing the impact of managed transportation electrification. We find that for every 10 percent increase in EV load, rates can be reduced by 1 percent, assuming our assumptions remain constant over time as EV load increases. Synapse analyzed the effect of EVs on customer rates by conducting detailed economic analysis to assess the effect of greater penetration of light-duty EVs on residential electric rates based on previous Synapse modeling for the Natural Resources Defense Council (NRDC).[62] For this study, Synapse modeled high penetrations of managed charging which enables utilities to shift EV load to off-peak periods, particularly focused on the annual peak. This can be accomplished by creating opt-out programs that automatically enroll households with EVs in TOU and CPP programs, which can achieve significant load shifting to off-peak hours. EVs and level 2 chargers can be easily programmed to charge vehicles during off-peak periods, requiring very little effort or opportunity cost on the part of customers to participate.[63]

Potential policy solutions to increase beneficial electrification

There are numerous policy levers states and PUCs can use to increase beneficial electrification. State levers take on increasing importance as federal policy support decreases, such as the elimination of the $7,500 federal tax credit for EVs and the $2,000 federal tax credits for heat pumps under recently passed legislation.[64] Broadly, these are as follows (this list is not meant to be comprehensive):

- ***Vehicle standards and building codes.*** "Zero Emission Vehicle" standards require automakers to sell a certain percentage of EVs and other low-emissions vehicles. Credits or certificates can allow for flexibility to purchase and sell to meet these compliance

[62] Synapse Energy Economics, *Rate Impact of Future Vehicle and Building Electrification,* online: https://www.synapse-energy.com/rate-impact-future-vehicle-and-building-electrification.

[63] We note that it is important for utilities to implement low-cost submetering using EV chargers and/or vehicle telematics to segregate EV from household load. This avoids the potential complication of on-peak household load that cannot be shifted causing higher bill increases than savings from off-peak charging.

[64] CNN, *Goodbye to the $7,500 EV tax credit,* September 23, 2025, online: https://www.cnn.com/2025/09/23/business/ev-tax-credit-expire-prices.

standards.[65] For buildings, electrification standards provide financial certainty for an ecosystem of electrified end uses, and they provide both gas and electric utilities with a degree of certainty to better target their investments (notably, all-electric new construction is now cheaper than alternatives). When paired with Clean Heat Standards that require entities selling fuel used to heat buildings to provide an ever-increasing percentage of ”clean heat,” significant utility investments can be redirected towards managed and stabilized electrification.

- ***Financial incentives*****:** Reducing the cost of EV ownership is a primary lever for states to increase EV adoption. These policies can include state tax credits, rebate programs, reduced registration fees, and waived tolls and congestion charges. For buildings, enacting legislation to create incentives for heat pumps can spur the market transformation that would lead to reduced electricity rates and bills, as revenues outpace costs. Existing Energy Efficiency Resource Standards can be reformed to allow for fuel switching from gas to electric and focus on overall GHG reductions which can direct incentives toward beneficial electrification. Clean Heat Standards can also direct investments toward beneficial electrification. In addition, modifications to electric rates can reduce costs for winter heating and further incentivize electrification while still allowing revenue to outpace costs.
- ***Non-financial incentives:*** Visible non-financial incentives can support EV adoption. These policies include carpool lane access and reserved parking for EVs. For buildings, expedited permitting for all-electric construction could also move markets in spite of residential housing construction slumps, as permit processing times are seen as a pain point and cost multiplier.
- ***Infrastructure:*** Policies that increase public charging infrastructure can support customer acceptance and ease “range anxiety.” These can include tax credits, and direct state investment in public charging. The private market has increased its role in recent years to help build this infrastructure for customers.[66] For buildings, externalizing socialized costs of gas infrastructure for new construction can significantly reduce the cost burden on ratepayers’ utility bills. This would also support increased rates of electrification, thereby accelerating the rate of revenue generation necessary to decrease electricity bills.
- ***Utility support of beneficial electrification:*** Utilities play a key role in enabling beneficial electrification. For example, efficient and transparent interconnection can bring chargers online quickly and cheaply. The availability and widespread enrollment in

[65] An overview of California’s program can be found at U.S. Department of Energy, *Alternative Fuels Center,* online: https://afdc.energy.gov/laws/4249.

[66] Notably, the most successful EV company in the United States by sales and market share, Tesla, developed a privately funded EV charging network.

managed charging programs and TOU rates to shift load to off-peak periods can reduce EV operating costs and costs to the grid, if implemented efficiently and incorporated into planning assumptions. This can be accomplished with default program and/or rate design enrollment for EV customers. This creates a win-win for both EV owners and non-EV ratepayers. For buildings, utilities can incentivize households with heat pumps and heat pump water heaters to enroll in demand response programs to reduce peak load and support greater electrification. Utilities can also look to neighborhood-scale strategies to electrify whole neighborhoods at once to avoid expensive gas system maintenance costs, or to upgrade electric services proactively to avoid additional costs at the point households choose to electrify.

State programs that leverage ratepayer funds to support EV adoption also merit consideration, although they may offset any downward pressure on rates caused by EVs calculated here because all customers pay for these programs. And for buildings, alternative policy ideas could include All-Electric Public Facility Mandates/Beneficial Electrification for Public Facilities, Building Performance Standards, Contractor and Workforce Training, direct install programs for low-income households, and Clean Heat Standards, among others.

Methodology to quantify impact on bills of greater EV adoption with managed charging

As EV adoption along with other electrification continues to grow, we seek to assess how future electrification of the transportation sector might affect electric rates through 2030. We did this through a four-step process; (1) estimating future load associated with vehicle electrification, (2) estimating electricity costs associated with the new electrification load, (3) estimating utility revenues associated with serving that new EV load, and (4) subtracting total revenues from total incremental costs. If the utility revenues from EVs and building electrification exceed the utility system costs, then transportation and building electrification can reduce electricity rates for all customers. Conversely, if the costs are greater than the revenues, non-EV owners could end up paying more for their electricity. We assumed that all customers participate in managed charging programs.

Costs

Increased load from electrification imposes costs on the electricity system. These include supply costs (energy generation, generating capacity) and transmission costs, as well as distribution and delivery costs. We assumed that generation capacity and distribution costs are 20 percent of the applied marginal cost values to reflect the fact that only 20 percent of EV charging occurred on peak. Further, to match the other policy levers evaluated in this study, we removed transmission costs from this analysis. We applied marginal cost values to forecasted load and peak demand to estimate total costs associated with light-duty EVs.

Supply costs: energy and generating capacity

National Renewable Energy Laboratory's Cambium 2023 data sets include forecasted hourly marginal energy and generating capacity costs ($/MWh). These marginal cost estimates are specific to each scenario (Policy and Status Quo), state, and hour. We estimate total supply costs for each scenario by multiplying marginal costs ($/MWh) by the sector-specific load (MWh).

To calculate the change in electricity cost due to increased electrification, we subtracted the Status Quo electricity cost data from the Policy scenario costs. These are the incremental supply costs associated with electrification, presented by sector.

To estimate supply costs for the years not reported in the Cambium 2023, we linearly interpolated total supply costs to get annual supply costs through 2030.

Residential revenues

Synapse calculated residential revenues by multiplying volumetric rates ($/kWh) by load (kWh) for each year. We sourced residential volumetric rates with supply components from current tariffs. We modeled all EV load as being on a two-period TOU rate with 80 percent of EV charging occurring during off-peak periods and 20 percent of charging occurring during on-peak periods. This is based on our experience with typical utility results across the United States.

We then forecast average residential rates through to 2035. For the Status Quo scenario, we assume that annual revenue requirements increase proportionally with increases in load (i.e. we assume that rates will not change from 2024 levels). For the Policy scenario, we estimate total new revenue requirements for each year by adding the annual incremental costs associated with EVs (as outlined in the Cost section above) to the revenue requirements from the Status Quo scenario. New rates are calculated by dividing the new total revenue requirement by the new total kWh sales for each year. Finally, we multiplied these annually calculated rates by projected residential sales to calculate residential revenues.

Net revenues

Synapse compared total costs with total revenues to determine how future electrification might impact rates for each electric utility. We made this comparison on a class-by-class basis to estimate the rate impact of transportation electrification to residential customers.

Results

We found that for every 10 percent increase in EV load, rates can be reduced by 1 percent, assuming our assumptions remain constant over time as EV load increases.

Table 16 shows the bill impact of increasing EV load subject to managed charging, for residential and commercial customers in Virginia. We estimate that Virginia residential customers would collectively save around $0.2 billion dollars between 2026 and 2030 by increasing EV load subject to managed charging.

Table 16. Annual distribution bills with and without increased EV load with managed charging

	Virginia Annual Residential Bill, Nominal $				
	2026	**2027**	**2028**	**2029**	**2030**
Status Quo Distribution and Generation Bill	$1,643	$1,849	$2,081	$2,779	$3,999
Distribution and Generation Bill after increased EV load with managed charging	$1,636	$1,840	$2,069	$2,766	$3,983

Appendix A. METHODOLOGY TO CALCULATE BILL IMPACTS

To estimate bill impacts in this report, we calculated the total revenue requirement impact of each policy lever and allocated a percentage of the total impact to each class per the methodology specified in each policy scenario above. To estimate the rate impact, we divided the revenue requirement impact for each class by sales. Class sales were based on actual sales in 2023, escalated into the future based on sales growth from the Status Quo scenario described in the Alleviating Capacity Constraints section of this report scenario. We divided the revenue impact of each class by the sales of each class to determine a rate impact. We then applied the calculated rate impact of each policy to a typical residential and commercial customer bill to estimate a bill impact.

Synapse obtained the baseline average bill for an average residential customer through Dominion Virginia's "Understand My Bill" bill calculator worksheet.[67] This worksheet contains tariffs as of September 2025 due to some components having an effective date of September 01, 2025.

The bill was split into generation and fuel, transmission, and distribution. We escalated the generation bill component using the growth rate of system-wide weighted average locational marginal pricing from the Status Quo scenario in the Alleviating Capacity Constraints section. The distribution bill component was escalated using the compound average growth rate of distribution rate base, discussed above.

We modeled bill impacts for an average residential customer in Virginia who uses 993 kWh per month.[68] We also modeled bill impacts for a commercial customer in Virginia who uses 4,500 kWh per month, with a billed demand of 15 kW and a load factor of 42 percent.[69]

In addition, to maintain dollar year consistency we utilized future Federal Reserve Bank of St. Louis historical consumer price index of all urban consumers and projected 1, 2, and 5 Year inflation dated August 2025.[70]

[67] Dominion Virginia, Bill Calculator Worksheet. Available at: https://www.dominionenergy.com/virginia/paying-my-bill/understand-my-bill.

[68] Calculated as the average energy per residential customer per month in 2023 per EIA 861 for VA customers. Available at: https://www.eia.gov/electricity/data/eia861/ , sheet Sales to Ultimate Customer.

[69] These billing determinants come from Dominion's bill calculations from their 2025 rate case. Specifically, we model the bill impact for a moderate GS-1 customer. Billing Determinants available at: https://www.scc.virginia.gov/docketsearch/DOCS/84%25s01!.PDF, pdf pp. 58-59.

[70] Federal Reserve Bank of St. Louis, Federal Reserve Economic Data, Time Series CPIAUCSL, EXPINF1YR, EXPINF2YR, and EXPINF5YR. Available at: https://fred.stlouisfed.org.