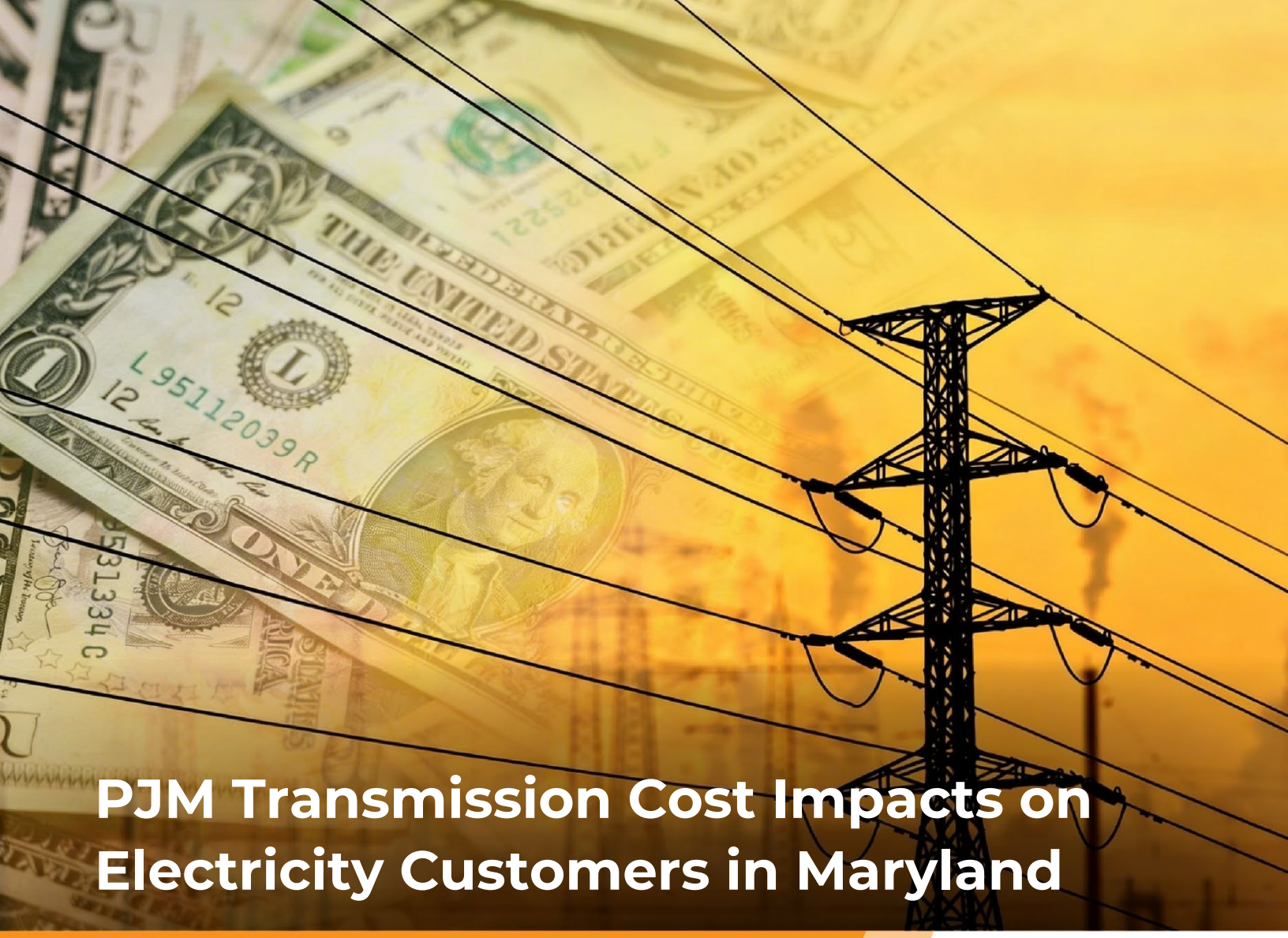


PJM Transmission Cost Impacts on Electricity Customers in Maryland

An Overview of PJM Transmission Planning and Costs

March 2026
(Corrected 3/25/2026)*

OPC
Office of People's Counsel
State of Maryland

CONTENTS

Report prepared for the Maryland Office of People's Counsel by Synapse Energy Economics, Inc., a research and consulting firm specializing in economic and policy research, modeling, and analysis to provide electric sector solutions.

**This version of the report corrects Figure 2 to show the vertical axis in dollars per year.*

FIGURES

TABLES

LIST OF ACRONYMS

Acronym	Term	Definition
APS	Allegheny Power System	A regional transmission area within the PJM grid covering parts of Maryland, Pennsylvania, West Virginia, and Virginia. It is a subsidiary of FirstEnergy.
BGE	Baltimore Gas and Electric Company	A regional transmission area within the PJM grid within Maryland; also refers to the distribution utility serving the same territory. It is a subsidiary of Exelon.
CPCN	Certificate of Public Convenience and Necessity	A CPCN must be issued by the Maryland Public Service Commission (PSC) before a generating station, a qualified generator lead line, an overhead transmission line designed to carry more than 69,000 volts, or certain energy storage devices may be constructed in the State. The CPCN process allows PSC to comprehensively consider the effects of a proposed project. Each proposal is subject to public comment and a public hearing through which various interested parties may provide input. In addition to the public at large, PSC receives input from State agencies with subject matter expertise and representatives of local governments. PSC is then required to weigh the information elicited throughout the application process and make a decision to deny, grant, or, in some cases, conditionally grant a CPCN.
DFAX	Distribution factor analysis	A type of cost allocation for PJM baseline transmission projects. Under this methodology, costs are allocated based on which transmission zones drive power flow on an upgraded transmission facility. This method measures each zone's usage of a transmission line based on changes to its power flow through detailed power flow modeling.
DPL	Delmarva Power & Light	A regional transmission area within the PJM grid serving parts of Maryland and Delaware; also refers to the distribution utility serving the same territory. It is a subsidiary of Exelon.
FERC	Federal Energy Regulatory Commission	The federal agency that regulates wholesale electric power sales and transmission rates.
LSE	Load Serving Entity	A LSE is an entity—such as an electric distirbution company, retail electric supplier, municipal utility, or cooperative—authorized to sell electricity to end-use customers within the PJM region. LSEs must be PJM members and are responsible for procuring adequate supply and transmission to meet their customers' demand.
NERC	North American Electric Reliability Corporation	NERC operates as an electric reliability organization to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators and users for preparedness; and educates and trains industry personnel.
NITS	Network Integration Transmission Service	NITS charges are the core mechanism through which transmission owners recover the costs of owning, operating, maintaining, and upgrading local transmission projects. They reflect each local project's annual transmission revenue requirement, which includes capital costs, operational and maintenance expenses, depreciation, taxes, and an authorized return on investment.

Acronym	Term	Definition
PE	Potomac Edison Company	A distribution utility serving parts of Maryland. It is a subsidiary of FirstEnergy.
Pepco	Potomac Electric Power Company	A regional transmission area within the PJM grid serving parts of Maryland and the District of Columia; also refers to the distribution utility serving the same territory. It is a subsidiary of Exelon.
PSC	Maryland Public Service Commission	The Maryland PSC is an independent state agency that regulates public utilities—including electric, gas, water, and sewage companies. It ensures safe, reliable service, sets utility rates, and manages consumer complaints.
RMR	Reliability Must-Run	A generating unit slated to be retired by its owners but that is needed for reliability reasons. Typically, PJM requests that the unit remain operational beyond its proposed retirement date until transmission upgrades are completed.
RTEP	Regional Transmission Expansion Plan (or Planning Process)	PJM's comprehensive annual process that examines the three interrelated components of electric power system reliability: load, generation and transmission. The RTEP process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEP process is designed to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations.
RTO	Regional Transmission Organization	The organization that coordinates, controls, and monitors a multi-state electric grid. In this report, RTO refers to PJM Interconnection, LLC (or PJM) which operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
SOS	Standard Offer Service	SOS is the default electricity supply provided by a local utility to customers who have not chosen a competitive, third-party supplier. It includes the cost of power, transmission, and related services, often procured through state-regulated, competitive bidding processes. It is sometimes referred to as basic service.
TEAC	Transmission Expansion Advisory Committee	The TEAC is a PJM stakeholder group that advises on the development of the RTEP. It acts as the primary public forum for stakeholders to discuss grid study assumptions, system needs, and proposed, cost-effective, or efficient transmission solutions before board approval.
TEC	Transmission Enhancement Charges	TEC in PJM are fees that recover the costs for tranmission owners of building, upgrading, or expanding the regional transmission grid, as approved through the RTEP. They reflect capital costs, operational and maintenance expenses, depreciation, taxes, and the transmission owner’s authorized return on investment.

EXECUTIVE SUMMARY

PJM could saddle Maryland with an additional $5.4 billion in capital costs for transmission projects built in 2031 to 2035.

Transmission infrastructure—the high-voltage system that delivers electricity from power plants to local utilities—is a growing and increasingly significant driver of higher electricity costs for Maryland households and businesses. In the PJM Interconnection (PJM) region, which includes Maryland, 12 other states, and Washington, D.C., transmission rates have roughly doubled over the past decade.[1] In Maryland, transmission now accounts for 10 percent of residential electricity costs (and 16 percent of supply costs).

To understand how transmission costs are impacting Maryland customers and evaluate possible mitigation measures, the Maryland Office of People's Counsel (OPC) commissioned Synapse Energy Economics (Synapse) to conduct this study. We found these transmission costs will likely increase substantially in the years ahead as load growth escalates in PJM. Marylanders are bearing cost responsibility for $7.1 billion in capital costs from transmission projects built and planned over 20 years from 2010 to 2030.[2] We estimate that PJM could saddle Maryland with an additional $5.4 billion in new capital costs for transmission projects built in 2031 to 2035. Of these new costs, regional transmission projects needed for PJM reliability needs (baseline projects) represent 59 percent ($3.2 billion) while local projects—which are driven by the local utilities and are not subject to meaningful cost review—represent 41 percent ($2.2 billion). The $5.4 billion of new transmission costs would be a major increase over five years compared to the $7.1 billion burden over the preceding 20 years. While transmission costs are subject only to federal regulation, state policymakers can take measures to mitigate the impacts skyrocketing prices are having on Marylanders' electricity bills. Identifying those measures requires a better understanding of how transmission planning works and how the related costs end up in customer bills.

Transmission Planning and Project Types

PJM and transmission-owning utilities are responsible for transmission planning for Maryland, 12 other states, and Washington, D.C. Recent increases in transmission costs fall primarily into two categories of transmission projects: baseline projects and supplemental (local) projects.

- PJM oversees regional **"baseline" transmission projects** through its Regional Transmission Expansion Plan (RTEP). In the RTEP process, PJM evaluates long-term reliability needs, load growth, generator retirements, and market efficiency. It identifies projects to address specific transmission constraints or

[1] In nominal terms. Monitoring Analytics. Components of the Total Cost of PJM Wholesale Power. Data retrieved February 17, 2026. Available at: https://www.monitoringanalytics.com/data/pjm_cost.shtml.

[2] PJM and transmission owners plan projects roughly five years ahead of when they are built.

reliability concerns. Baseline projects often cross state lines and utility service territories and, with important exceptions, are subject to competitive solicitations.

- In contrast, transmission owners unilaterally plan **"supplemental" or "local" transmission projects**. These owners are usually local utilities (such as Baltimore Gas and Electric) or their affiliates which identify and address local needs, such as equipment replacement or local reliability concerns. PJM does not assess whether local projects are necessary, nor does it require them to be competitively procured. Local projects are built and owned by the local transmission utility and paid for entirely by the utility's own customers. Federal regulators treat local projects as presumptively prudent, which means they are rarely, if ever, subject to meaningful review for cost-effectiveness.[3] OPC has advocated for closing this regulatory gap for local transmission projects, including filing a complaint, before federal regulators.[4]

Baseline projects: PJM allocated $4.3 billion in transmission capital costs to Maryland from 2010 to 2030, and we estimate it will allocate an additional $3.2 billion to Maryland from 2031-2035 (see Figure 12). Nearly three quarters of transmission spending reflected in Maryland customer bills—recovered in the "supply" portion of the bill—is driven by load growth, most recently from out-of-state data centers. For projects built or planned for construction from 2010–2030, PJM allocated Maryland $2.7 billion dollars of capital costs for load-growth-related projects and an additional $1.6 billion in non-growth-related projects, such as market efficiency projects, for a total of $4.3 billion allocated to Maryland. Over the next 10 years, from 2026 to 2036, PJM forecasts peak electricity demand will grow by 42 percent across the PJM region,

PJM's method of allocating transmission costs has Maryland customers paying a substantial share of the regional transmission projects needed to serve out-of-state load growth.

[3] *See, e.g.*, *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,151 (2023) (Clements, Comm'r, and Christie, Comm'r, concurring at P 4) ("Indeed, the Commission grants formula rate treatment, including a presumption of prudence, to filings from transmission owners seeking cost recovery for transmission projects without regard to whether such projects have been subject to a serious vetting in any proceeding in which both need and prudence of cost must be demonstrated by the transmission developer. We have expressed concerns about this lack of oversight previously, and this filing by SPP illustrates exactly why that is a major problem pertinent to the issue of rising consumer costs for transmission.").

[4] See *Complaint of Industrial Energy Consumers of America, et. al. v. Avista Corporation, et. al.*, Docket No. EL25-44; *see also* Md. Office of People's Counsel, *Costly local transmission projects that avoid competition are causing unlawful rates, OPC tells federal regulators* (Dec. 19, 2024), https://content.govdelivery.com/accounts/MDOPC/bulletins/3c86285; Comments of the Maryland OPC in Support of the Office of the Ohio Consumers' Counsel Complaint, November 11, 2023. FERC Docket No. EL23-105-000. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/OPC%20Comments%20EL23-105%20-%20OCC%20Complaint.pdf.

largely due to the rapid expansion of data centers in Northern Virginia and Ohio and to a lesser extent in Illinois and Pennsylvania.[5]

In contrast to PJM's forecasted 42 percent growth in peak demand across the RTO region (3.6 percent annually), PJM forecasts Maryland's peak demand will grow by only 12 percent during this period (1.1 percent annually). Maryland's share of the region's peak demand will fall from 8 percent to 6 percent over the period. Despite this disparity, PJM's method of allocating transmission costs has Maryland customers paying a substantial share of the regional transmission projects needed to serve out-of-state load growth. And because transmission asset payments span over 30 to 40 years, today's investment decisions will affect customer bills for decades. Furthermore, data center load forecasts are highly uncertain, raising concerns about unnecessary transmission infrastructure. If data center demand throughout PJM is overestimated, Maryland customers face the risk of paying for unnecessary transmission infrastructure that provides limited long-term benefits.

Local projects: Maryland utilities spent (or will spend) $2.8 billion on local transmission projects from 2010 to 2030, and we estimate they will spend $2.2 billion more from 2031-2035. Local transmission projects are also driving considerable increases in transmission costs in customer bills. For projects built or planned for construction from 2010–2030, Maryland's electric utilities spent or will spend $2.8 billion in capital costs for local transmission upgrades. That spending is accelerating. Maryland electricity customers pay for these investments in the supply portion of their bills. Because these local projects face minimal oversight and lack competitive pressure, they present a great risk of excessive or inefficient investment at the expense of electricity customers. As transmission costs rise, these projects will place sustained upward pressure on retail electric rates and exacerbate affordability challenges for households, small businesses, and low-income customers.

Because these local projects face minimal oversight and lack competitive pressure, they present a great risk of excessive or inefficient investment at the expense of electricity customers.

Recommendations for Maryland Policymakers

Maryland can mitigate rising transmission costs and improve accountability in several ways. The following recommendations outline actions policymakers can pursue to protect Maryland customers:

1. **Improve load forecasting and planning assumptions**
   Require greater transparency from its utilities for more rigorous, transparent, and coordinated forecasting of data center demand within the state to reduce the risk of overbuilding transmission infrastructure; advocate for the same at the regional level.

[5] PJM Interconnection. 2026 Long-Term Load Forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

2. **Advocate for greater oversight of transmission projects at PJM and the Federal Energy Regulatory Commission (FERC)**
   Support reforms such as an independent transmission monitor at PJM that bring local projects into PJM transmission planning processes, expand competitive procurement, and improve access to project data for states and consumer advocates.
3. **Strengthen regulation of transmission projects at the state level**
   Improve the state Certificate of Public Convenience and Necessity (CPCN) process by removing exemptions and waivers and requiring cost-benefit analysis, greater transparency, and evaluation of alternatives for local transmission projects.
4. **Align transmission costs with cost causation**
   Push for federal policies that require new large loads such as data centers to bear the full share of transmission costs directly attributable to their demand.
5. **Promote lower-cost alternatives**
   Encourage the use of grid-enhancing technologies, advanced transmission technologies, and non-wires alternatives that can meet reliability needs at lower cost and with shorter timelines.

Transmission investments made today will shape Maryland electric bills for decades. Without stronger oversight and proactive policy engagement, Maryland customers will continue to bear rising costs—often driven by electricity growth outside the state. Near-term regulatory and policy changes can help ensure future transmission investments are necessary, cost-effective, and fair to Maryland electricity customers.

1. INTRODUCTION

Transmission costs now represent roughly 10 percent of total customer electric bills for most Maryland customers;[6] these rates have been rapidly rising in recent years and will likely continue to increase for the foreseeable future. To understand why costs are going up and what Maryland can do about it, it helps to understand how transmission planning works and how the process allocates costs to Maryland electricity customers.

This report provides an overview of transmission planning and trends in the regional grid system that encompasses Maryland (Section 2). It then details PJM planning, oversight, cost allocation, and cost trends for two different types of transmission projects: regional-level baseline transmission projects (Section 3) and local transmission projects (Section 4). Section 5 lays out the challenges of rising costs and delays specific to network upgrade projects. To connect transmission costs and trends to Marylanders' electricity bills, Section 6 delves into how transmission costs fit into cost recovery and customer rates. And finally, in Section 7, Synapse provides actionable recommendations to help Maryland address the affordability impacts of the region's transmission issues.

2. OVERVIEW OF TRANSMISSION COSTS IN PJM AND MARYLAND

The transmission system is the high-voltage network that transports large amounts of electricity over long distances from power plants to each utility's distribution system. It operates as an interconnected grid that enables the balancing of electricity supply and demand across regions, helping to create an efficient and reliable electricity system.

Several entities are involved in planning, building, and operating the transmission system serving Maryland:

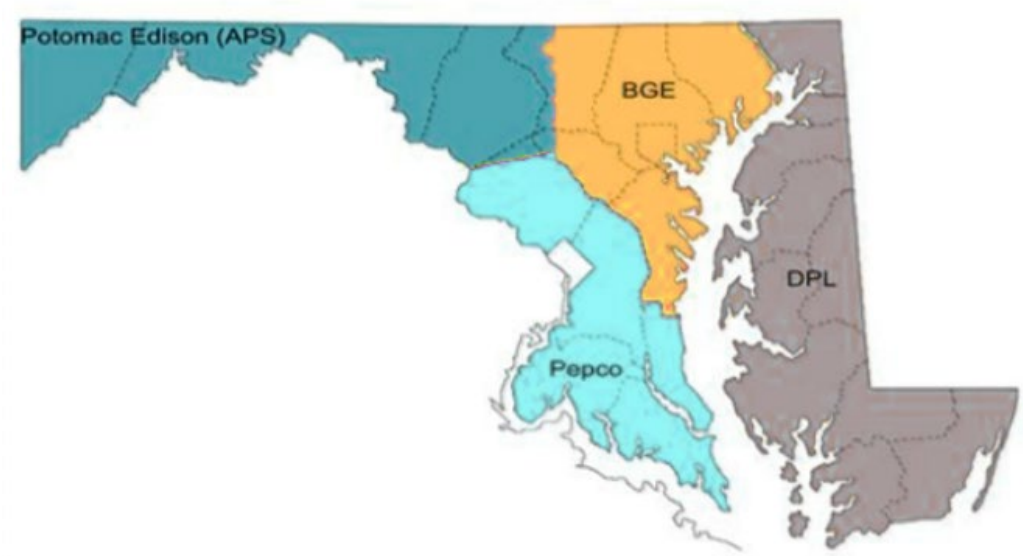
- PJM Interconnection (PJM) is the regional transmission organization (RTO) responsible for regional transmission planning across 13 states and the District of Columbia (DC), including Maryland. While PJM operates transmission lines, it does not own any transmission assets.
- Transmission owning utilities are the entities that own the transmission lines and related equipment within their service territories (transmission zones). These utilities propose, build, and profit from local transmission projects.
- The Federal Energy Regulatory Commission (FERC) regulates PJM and the transmission owners, approves transmission rates and cost allocation

[6] Residential transmission charges relative to total charges. Source: Data collected by the Maryland Office of People's Counsel and provided to Synapse February 19, 2026. For perspective, capacity market costs for 2025 for the Maryland utilities also represent roughly 10 percent of total bills for most customers. Ibid.

methodologies, and determines how much profit the transmission owners can make (i.e., their allowed rate of return).

Maryland has four transmission zones: (1) Pepco, (2) Baltimore Gas and Electric (BGE), (3) Delmarva Power & Light (DPL), and (4) Allegheny Power Systems (APS) (Figure 1). Pepco serves the southern part of Maryland and the DC area, BGE serves Baltimore and the surrounding areas and is located entirely within Maryland, DPL serves both Delaware and portions of the Delmarva Peninsula in Maryland, and APS serves western Maryland[7] along with parts of Pennsylvania, Virginia, and West Virginia.

Figure 1. Map of PJM transmission zones in Maryland



Source: Public Service Commission of Maryland. November 2021. Ten-Year Plan (2021 – 2030) of Electric Companies in Maryland. Prepared for the Maryland Department of Natural Resources. Available at: https://www.psc.state.md.us/wp-content/uploads/2021-2030-Ten-Year-Plan.pdf.

Load growth from data centers, especially those located in Virginia and Ohio, are a primary driver of recent increases in transmission costs.

Across PJM and Maryland's four transmission zones, transmission projects' cost and spending has been increasing rapidly due to load growth unprecedented in timing and scope, aging infrastructure, supply chain issues, inflation, and insufficient regulation of transmission owners. Load growth from data centers, especially those located in Virginia and Ohio, are a primary driver of recent increases in transmission costs. Absent changes in forecasted demand or PJM processes, the PJM grid will require massive transmission expansion projects that will cost electricity customers billions of dollars.

7 The APS zone in Maryland is served by the Potomac Edison (PE) distribution utility company.

Exelon's winter 2026 investor presentation projects that its transmission spending from 2026 to 2028 will amount to $4.8 billion across its Maryland subsidiaries that include Pepco, BGE, and DPL.[8] These investment levels exceed twofold the transmission investment levels Exelon reported to its investors for the same Exelon subsidiaries for the previous three years, 2023-2025, totaling $2.325 billion.[9] Exelon recently announced that it expects to spend $12 billion to $17 billion on transmission buildout over the next 10 years.[10] In February 2025, the PJM board approved $6.7 billion in baseline transmission projects for projects to be built in the next five years across PJM (2024 Regional Transmission Expansion Plan, or RTEP), many of which are driven by load growth.[11] In February 2026, the PJM board approved the 2025 RTEP which includes $11.8 billion worth of new transmission investments.[12] This amount is nearly double the 2024 RTEP cost.

Exelon recently announced that it expects to spend $12 billion to $17 billion on transmission buildout over the next 10 years.

These ballooning transmission upgrade costs are already impacting retail transmission rates and customer bills, which have steadily increased in Maryland over the past 15 years (Figure 2). Since 2010, transmission rates for Pepco, BGE, and DPL have increased by a factor of five to six, while Potomac Edison's rate has remained flat in nominal terms.[13,14] Figure 2 shows the transmission cost component on the average residential customer's bill in Maryland across Pepco, BGE, DPL, and PE from 2015 to 2025.

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8 Exelon Investor Meetings, Winter 2026 (Jan. 12, 2026). Available at https://investors.exeloncorp.com/static-files/0cd39e2e-ea59-432b-afd7-b432025fe649, slides 40, 43, 44.

9 Exelon Investor Meetings, Summer 2022 (June 21, 2022). Available at https://investors.exeloncorp.com/static-files/8a389a43-ea25-4029-ad8c-8c61b90c64c9, slides 24, 27, 28.

10 Howland, E. February 13, 2026. "Transmission drives Exelon's capital spending plan to $41.3B". Utility Dive. Available at: https://www.utilitydive.com/news/exelon-transmission-data-center-capex-earnings/812200/.

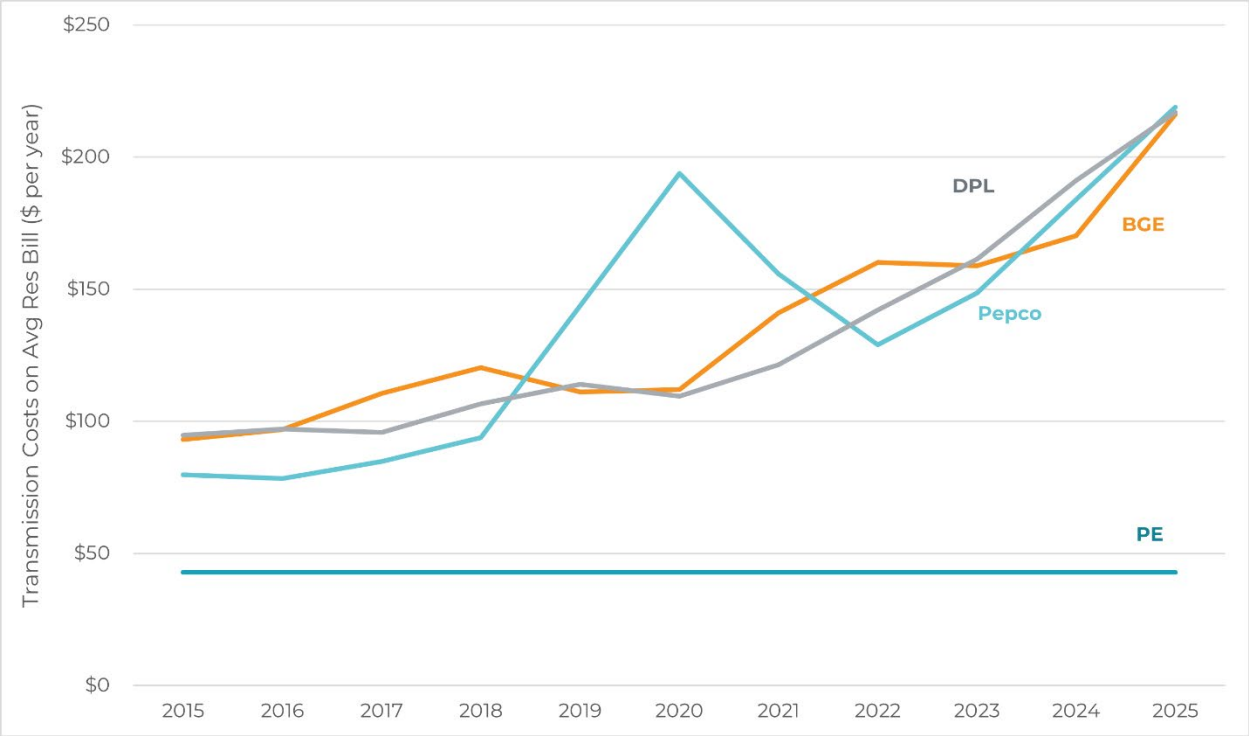
11 PJM Interconnection. February 26, 2025. PJM Board Approves New Transmission Projects to Support Grid Reliability. *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.

12 PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

13 When adjusting for inflation, in real dollar terms, Pepco, BGE, and DPL rates have increased by a factor of four, on average, while PE's rate decreased slightly. Based on rate information provided to Synapse by the OPC in December 2025.

14 The PJM-approved transmission rate that APS charges its transmission customers (such as PE, which converts APS's transmission rate into a retail transmission rate) has remained relatively flat from June 2018 until an uptick in June 2024 (as seen in Figure 10 in Section 5.1). However, APS's capital spending (and thus presumably operations and maintenance costs and other expenditures) has increased from 2010 to 2025. PJM's cost allocation process has also continued to allocate project costs to APS owned by other transmission owners over this same period. This suggests that APS rates, and thus PE's retail transmission rate, should have increased over this period. However, flatness in the PE's retail rate could be explained by load growth in the APS zone (the increase in costs is balanced by an increase in load growth, resulting in a flatter rate). Further analysis is required to fully understand why PE's retail transmission rate has remained flat from 2010 to 2025.

Figure 2. Transmission cost component for the average residential electric bill in Maryland



Source: Data collected by the Maryland Office of People's Counsel, provided to Synapse on February 19, 2026.

2.1. Types of PJM Transmission Projects

There are three types of transmission projects in PJM: (1) baseline projects, (2) supplemental (i.e., local) projects, and (3) network upgrades. Throughout this report, we discuss each of these project types, including their own unique planning and oversight processes, cost drivers, cost allocation methodologies, and cost recovery. We also present trends on project spending for these types of transmission projects and their impact on Maryland electricity customers.

- **Baseline projects** are regional transmission projects primarily required to satisfy reliability standards in the face of new load growth and often span multiple transmission zones or state boundaries. They are also driven by market efficiency, public policy, or operational performance needs such as relieving congestion or mitigating line overloads. PJM identifies and plans baseline projects through its RTEP process, and it subjects most projects to a competitive solicitation process that allows both incumbent utilities that serve the geographic area and non-incumbent developers to propose solutions to a specific PJM-identified need. PJM then evaluates proposals and selects winning projects. The PJM Board ultimately reviews and approves the final set of RTEP projects. Baseline projects are either paid for by electricity customers in the zone where they are located, or more often, are allocated across multiple zones and states.

- **Supplemental projects,** called **local projects** throughout this report, are transmission expansions or enhancements planned and developed by transmission owners to address local system needs such as local load growth and asset replacement. PJM staff does not independently assess the need for these projects, and the Board does not evaluate these projects. Instead, PJM simply ensures the projects will not negatively impact the broader electric system. PJM publicly posts limited data on local projects at its stakeholder forums, such as the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committees, for informational purposes only. Electricity customers in the zones where the projects are located pay for the entirety of the project costs. Federal regulators treat local projects as presumptively prudent, which means they are rarely if ever subject to meaningful review for cost-effectiveness.[15]

- **Network upgrades** are transmission infrastructure upgrades required to accommodate the interconnection of new generation resources. Generator interconnection requests trigger these projects, which ensure that generators can reliably use the PJM transmission system. The interconnecting generators pay for these project costs.

2.2. Recent Trends in PJM Transmission Projects

Across the PJM footprint, annual transmission spending varies, as does the number of approved project types. However, since 2015, total project spending has begun to increase[16] (Figure 3). Across PJM from 2010 to 2030, baseline projects represented 45 percent of costs, local projects represented 48 percent, and network costs made up the remainder (Figure 3).[17]

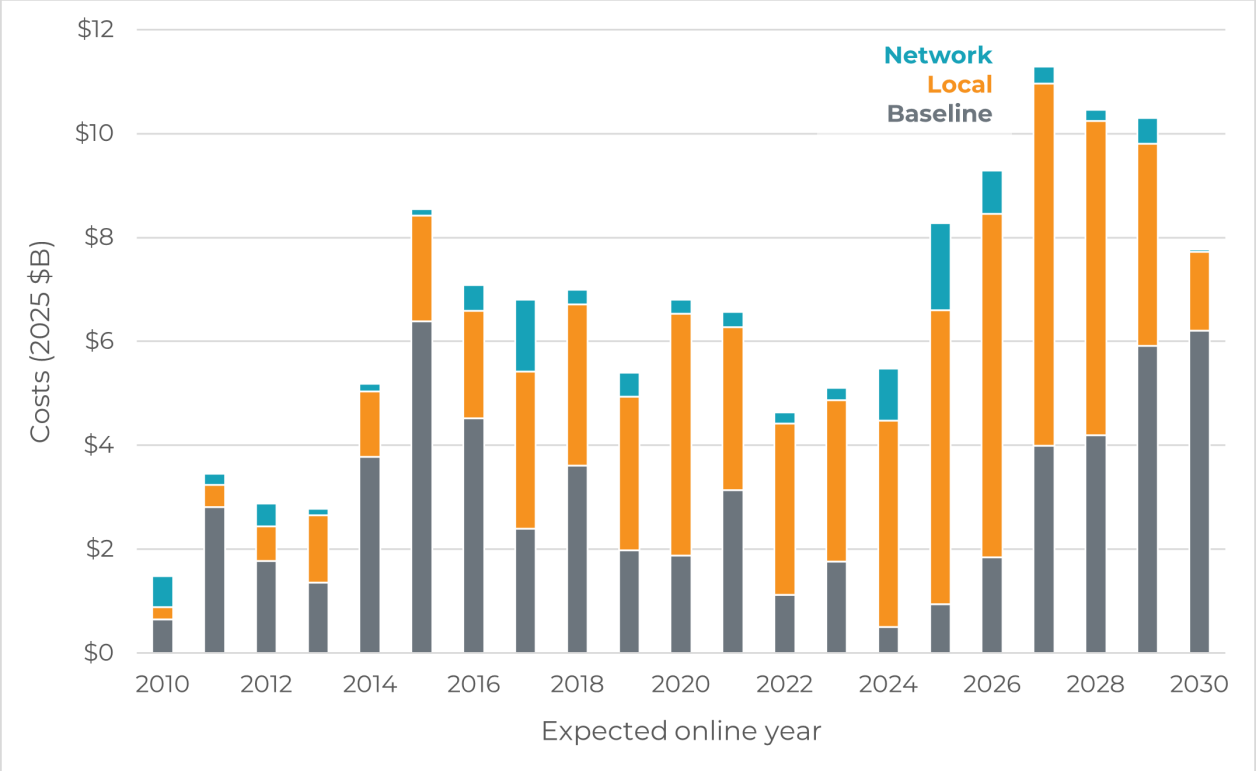
Figure 3 shows the total capital costs of projects by their online or projected online date. Recovery of the costs of baseline and local projects from customers are spread over the project's service life, typically beginning in the year the project comes online.

[15] *See, e.g.*, *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,151 (2023) (Clements, Comm'r, and Christie, Comm'r, concurring at P 4) ("Indeed, the Commission grants formula rate treatment, including a presumption of prudence, to filings from transmission owners seeking cost recovery for transmission projects without regard to whether such projects have been subject to a serious vetting in any proceeding in which both need and prudence of cost must be demonstrated by the transmission developer. We have expressed concerns about this lack of oversight previously, and this filing by SPP illustrates exactly why that is a major problem pertinent to the issue of rising consumer costs for transmission.").

[16] PJM and transmission owners plan projects roughly five years ahead of when they will be built.

[17] For in-service and approved (but not yet online) projects with expected online dates between 2010 and 2030.

Figure 3. Total capital costs of approved and in-service transmission projects in PJM, with expected online dates from 2010 to 2030



Notes: Figure does not include canceled, on-hold, and withdrawn projects. PJM Project Status & Cost Allocation, data as of February 2026. Available at: https://www.pjm.com/planning/m/project-construction.

From 2010 to 2030, PJM-wide baseline capital costs averaged $3 billion per year. This includes the approved $11.8 billion from the 2025 RTEP,[18] which is projected to be built over the next five years. Local project spending during this period averaged $3.3 billion per year, while network upgrades are on average $493 million annually.

Figure 4, below, shows the capital costs of transmission projects allocated to Maryland's four zones from 2010 to 2030.[19] Across all zones, local projects are much more variable across years than baseline projects. Baseline project spending across all zones will increase over the next five years, mostly driven by new load growth outside of Maryland. BGE, in particular, will see a major increase as transmission projects come online that will address a single reliability issue. Two generating stations, called Brandon Shores and Wagner, are under a PJM mandate to continue running despite their operators' request to retire them. This mandate, referred to as "reliability-must-run," or RMR, will be in place until BGE can build enough transmission capacity

[18] PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

[19] For details on estimating the Maryland portion of baseline transmission costs, see description in Section 2.3.

to bring in electricity from outside the zone or meet local reliability needs.[20] The transmission project, called the Brandon Shores Deactivation Project, is evident in Figure 4, where total costs for BGE in 2028 are almost double the maximum listed on the cost axis. The Brandon Shores Deactivation Project will cost PJM customers over $1.6 billion in capital costs; Maryland will pay for 66 percent of the project, totaling $1.1 billion. Of the four zones in Maryland, BGE is saddled with the largest share, paying over $900 million of the projects' costs.

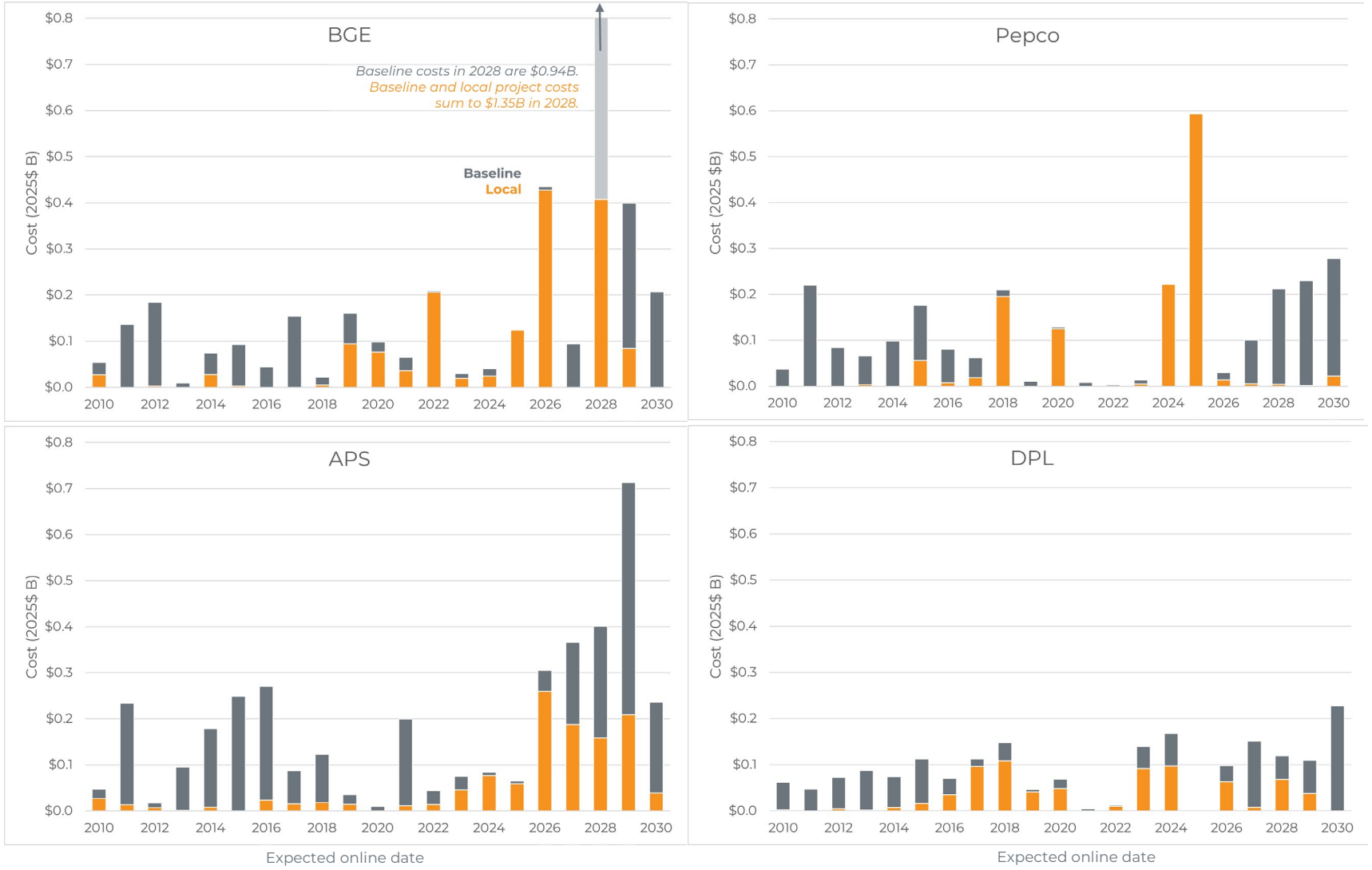
Figure 4 includes approved baseline projects from the 2025 RTEP,[21] with expected in-service dates through 2030. Local and network projects are not included in the RTEP; there will likely be many more local projects in the coming years than those presented in Figure 4.

Project costs are embedded into retail rates over time; they are recovered through depreciation rates and cost recovery mechanisms built into transmission rates. Transmission project depreciation can take over 30 to 40 years, meaning costs are spread across decades of customer bills. For example, a $100 million transmission line with a 3 percent annual depreciation rate would add $3 million per year in depreciation expenses to customer rates until fully depreciated. In addition to depreciation expenses, in the annual revenue requirement used to determine the customer rates that pay for the transmission line customers pay three to four times the project cost of $100 million after including the utility's return, operational and maintenance costs, and for taxes and other charges. For 33 years, these costs will continue to appear in rates, illustrating how long-term infrastructure investments affect electricity bills well beyond the project's online date. The above figures show total transmission project capital costs by expected online date, rather than the period for which customers will pay for these projects.

[20] For more information on the Brandon Shores and Wagner RMRs, see the OPC website's resource adequacy page here: https://opc.maryland.gov/Consumer-Learning/FERC-and-PJM-Issues/Resource-Adequacy

[21] PJM's Board approved the 2025 RTEP in February 2026.

Figure 4. Total capital costs of approved and in-service baseline and local projects that are allocated to Maryland, 2010 to 2030



Source: See description in Section 2.3

2.3. Methodology

Unless otherwise indicated, figures and tables in this report rely on PJM data. They do not include canceled, on-hold, and withdrawn projects as shown in PJM's Project Status & Cost Allocation, data retrieved in February 2026.[22]

For the Pepco, APS, and DPL zones which span multiple jurisdictions, we estimated the Maryland portion of the zone's transmission costs (BGE is located entirely within Maryland). We scaled total zonal capital costs to the Maryland portion using the ratio between Maryland's 2024 peak load[23] and the 2024 zonal peak load from PJM's 2025 Load Forecast Report.[24,25]

3. BASELINE TRANSMISSION PROJECTS

Baseline upgrades are regional transmission projects that PJM determines are necessary to meet reliability standards in the face of load growth, maintain system stability, prevent overloads or voltage violations, and improve market efficiency across the region. These types of projects often span multiple transmission zones or states, and costs are most often allocated to multiple transmission zones, according to how different zones benefit from each project.

3.1. Planning and Oversight Process

PJM plans baseline projects on an annual basis and selects them using its RTEP process through two primary steps: (1) determining transmission needs and (2) identifying specific projects that best meet those needs. This process uses a five-year look-ahead window.

3.1.1. Determining transmission needs

During the RTEP process, PJM conducts transmission system modeling to determine when and where the grid might become constrained. Key inputs include long-term load forecasts, new and retiring generators, and other information about the transmission system. PJM identifies *specific* transmission needs regarding, for example, location, voltage, and project type (e.g., upgrade, new line).

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22 PJM Project Status & Cost Allocation, Transmission Cost Planner (TC Cost Planner). Available at: https://www.pjm.com/planning/m/project-construction.

23 PJM Interconnection. June 2025. 2024 Maryland and District of Columbia State Infrastructure Report, slide 21. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2024/maryland-and-dc.pdf

24 PJM Interconnection. January 2024. Load Forecast Report. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.pdf

25 As of March 10, 2026, the state-specific reports used for scaling costs to Maryland were not available using PJM's 2025 or 2026 Load Forecast. We expect scaling factors to be similar between 2024 and 2025/2026.

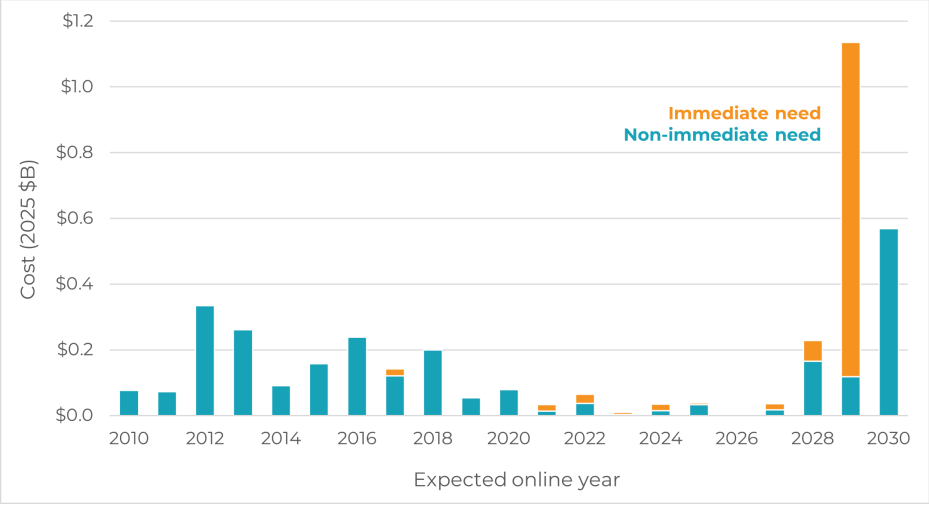
3.1.2. Selecting projects to meet specific transmission needs

After identifying needs, PJM will open an "RTEP Proposal Window" to solicit transmission solutions for each transmission need. PJM identifies most projects through a competitive process where both incumbent and non-incumbent transmission owners can propose a project buildout for a specific need. These types of projects are typically planned and constructed over five years. In some cases, however, PJM will identify "immediate needs," where the need must be addressed in three years or less. Immediate need projects are exempt from PJM's competitive procurement process; PJM selects the incumbent transmission owner to build the project.

Immediate needs projects have been relatively rare over the last 15 years; however, over the next few years they will make up a large portion of the transmission costs for which Maryland electricity customers will pay (Figure 5). Almost 100 percent of the immediate need project costs Marylanders will pay for, and which come online in 2028 and 2029, are part of the Brandon Shores transmission project mentioned above, which addresses the Brandon Shores and Wagner RMRs and their eventual retirements. Furthermore, immediate need projects are typically more costly than non-immediate need projects, as they are not subject to a competitive procurement process. In fact, across the four zones in Maryland, average immediate need project costs are four times more expensive than non-immediate need projects (on a per project basis) (Table 1).[26]

Exempt from competitive procurement requirements, immediate need projects costs across the four Maryland zones are on average four times more expensive than projects competitively procured.

Figure 5. Total capital costs of approved and in-service baseline projects allocated to Maryland, by immediate and non-immediate need, 2010 to 2030



Notes: See description in Section 2.3.

[26] For details on calculation, see description in Section 2.3.

Table 1. Total capital costs, project count, and average dollars in millions of dollars per project, for projects paid for by customers in Pepco, BGE, DPL, and APS zones, from 2010 to 2030

	Immediate Need	Non-Immediate Need
Total Capital Costs (2025$, millions)	$1,658	$6,202
Total Project Count	124	1,832
Average (million dollars (2025$) per project)	$13.4	$3.4

Source: See description in Section 2.3.

3.1.3. Stakeholder involvement and PJM Board approval

PJM's transmission planning and stakeholder involvement process happens at several committee meetings, primarily the TEAC and the subregional RTEP committees (i.e., Mid-Atlantic, Southern, and Western RTEP).[27] PJM allows stakeholder input on submitted proposals in each RTEP Window, but stakeholders cannot vote. Stakeholders participating in these committees and subcommittees can include PJM members (e.g., transmission owners, generation owners, load-serving entities, retail marketers, state consumer advocates, etc.), transmission customers (e.g., large-load customers connected to the transmission system), non-state consumer advocates, and other interested parties (e.g., environmental advocacy organizations). State public service commissions can also participate in the process.

For each RTEP Window, PJM staff selects a final set of projects to meet each identified need and submits them to the PJM Board of Managers for final approval. The final set of recommended projects is meant to include relevant feedback from stakeholders, although multiple stakeholders have pointed out that feedback is not always effectively incorporated. For example in September 2023, the Maryland OPC filed a formal protest with FERC challenging a PJM RTEP baseline project proposal tied to the planned retirement of the Brandon Shores power plant.[28] OPC argued that PJM's planning process lacked rigorous review, transparency, and effective stakeholder engagement, stating that the transmission proposal was not adequately justified and non-transmission alternatives were not discussed. FERC ultimately approved PJM's RTEP transmission solution package associated with the retirement of the Brandon Shores plant, despite protests from stakeholders.

In September 2023, the Maryland OPC filed a formal protest with FERC challenging a PJM RTEP baseline project proposal tied to the planned retirement of the Brandon Shores power plant.

[27] Projects built in Maryland are discussed at the Mid-Atlantic RTEP Committee.

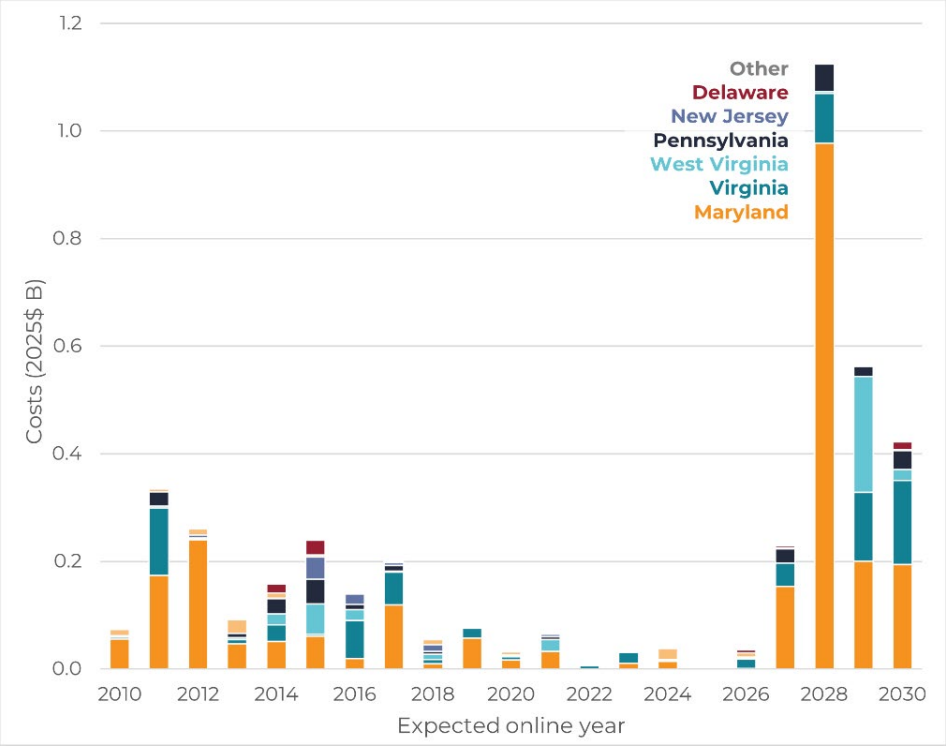
[28] Protest of the Maryland OPC. September 13, 2023. FERC Docket Nos ER23-2612-000, ER23-2612-001. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/Final%20Md%20OPC%20Protest%20ER23-2612%20PJM%20RTEP%20Baseline%20filing.pdf?ver=tgen2T7bSdTQSH44n1SQ6A%3d%3d.

3.2. Cost Allocation Methodology

Because baseline projects address regional reliability needs, PJM usually allocates baseline project costs across multiple zones in the region. Specifically, PJM cost allocation rules require that project costs are allocated to different zones (sometimes across multiple states) based on the share of benefits each zone receives from that project. In some cases, a project's costs are allocated entirely to one zone.[29]

PJM's cost allocation methodology results in Maryland customers paying for transmission projects located both within and outside Maryland. As described below, PJM allocates some, but not all, of the transmission project costs based on how much each zone benefits as determined by a computer simulation of how the new transmission facility changes the flow of power on the system. Figure 6 shows the location of all projects that have costs allocated to Maryland electricity customers. The figure shows that Maryland customers pay significantly for transmission projects located in other states. Over the next five years, the number of projects located in Virginia and West Virginia that Maryland will pay for will increase, mostly driven by data centers located in those states. The large share of costs from projects located in Maryland in 2028 is specifically due to the Brandon Shores Deactivation Project.

Figure 6. Maryland customer cost responsibility for transmission capital costs of approved and in-service baseline projects, by project location, 2010 to 2030



Source:
See description in Section 2.3.

[29] According to *PJM Manual 14B: Attachment A Baseline Reliability Upgrade Cost Allocation Procedures*, lower voltage facilities with an estimated cost below $5 million are allocated 100 percent to the transmission zone in which the upgrade is located, rather than being spread regionally among multiple zones.

PJM has four main cost allocation methodologies for baseline transmission projects:

- *Distribution factor analysis (DFAX)*: Under this methodology, costs are allocated based on which transmission zones drive power flow on an upgraded transmission facility. This method measures each zone's usage of a transmission line based on changes to its power flow through detailed power flow modeling.
- *Load ratio share*: Under this methodology, costs are divided among the benefiting zones based on each zone's non-coincident peak demand.
- *Direct allocation*: 100 percent of the project costs are assigned to the zone where the project is located.
- *State policy approach*: Under this methodology, one or more states will voluntarily pay for the full cost of the project if the upgrade is needed to meet a specific state policy objective, such as offshore wind development or compliance with environmental mandates.

PJM determines the cost-allocation methodologies for baseline projects based on voltage thresholds, usage/load share, and total costs.[30] For higher voltage lines such as double circuit 345 kilovolt (kV) lines, lines greater than or equal to 500 kV, or other regional facilities with estimated costs of $5 million or greater, PJM splits costs evenly between two allocation methods. In such cases, PJM assigns 50 percent of project costs on a load-ratio share basis and the remaining 50 percent using the DFAX methodology.[31] For low-voltage facilities below 500 kV with estimated costs of $5 million or greater, PJM allocates 100 percent of costs using the DFAX methodology.[32] Lastly, for low voltage facilities with estimated costs below $5 million, PJM assigns 100 percent of costs to the local transmission zone (direct allocation).

3.3. Project Cost Drivers for Baseline Projects in Maryland

For projects in service or expected to be in service between 2010 to 2030, PJM allocated $4.3 billion in baseline-project capital costs to Maryland electricity customers (which customers will be paying for well beyond 2030). The $4.3 billion figure includes the recently approved $11.8 billion from the 2025 RTEP.[33] PJM's Transmission Cost Planner categorizes all baseline

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30 PJM Interconnection, "Cost Allocation Education," presentation, September 25, 2020, PJM Planning Committee (Item 04). Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2020/20200925-special/20200925-item-04-cost-allocation-education.ashx.

31 The stability deviation method is sometimes used in situations when the DFAX method is determined to be unjust and unreasonable (e.g., when the typical DFAX flow-based measure does not align well with engineering drivers of the need). Under the stability methodology, costs are allocated to zones in proportion to how much they benefit from stability improvements. Although this approach is not a routine method, it was developed mainly in context of the Artificial Island project. *169 FERC ¶ 61,234: Delaware Public Service Commission and Maryland Public Service Commission v. PJM Interconnection, L.L.C. and Certain Transmission Owners Designated under CTOA RS.* Issued December 19, 2019. PDF, 14 pp. Washington, DC: Federal Energy Regulatory Commission. May 2020. https://www.ferc.gov/sites/default/files/2020-05/E-28_2.pdf.

32 Or stability deviation method, as described in the footnote above.

33 PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-

projects into six main project driver types, as seen below in Table 2. The table shows the percentage of drivers for all baseline projects with costs allocated to Maryland. From 2010 to 2030, load growth and reliability projects drive an average of 62 percent of Maryland transmission costs across its four zones (Table 2). Nonetheless, an increasing share of this load growth is occurring *outside* Maryland. This load growth will likely only worsen as more data centers located in Virginia and other neighboring areas interconnect to the grid and require transmission upgrades and expansions.

Table 2. Total capital costs of baseline projects allocated to Maryland, and proportion of each cost driver, by zone

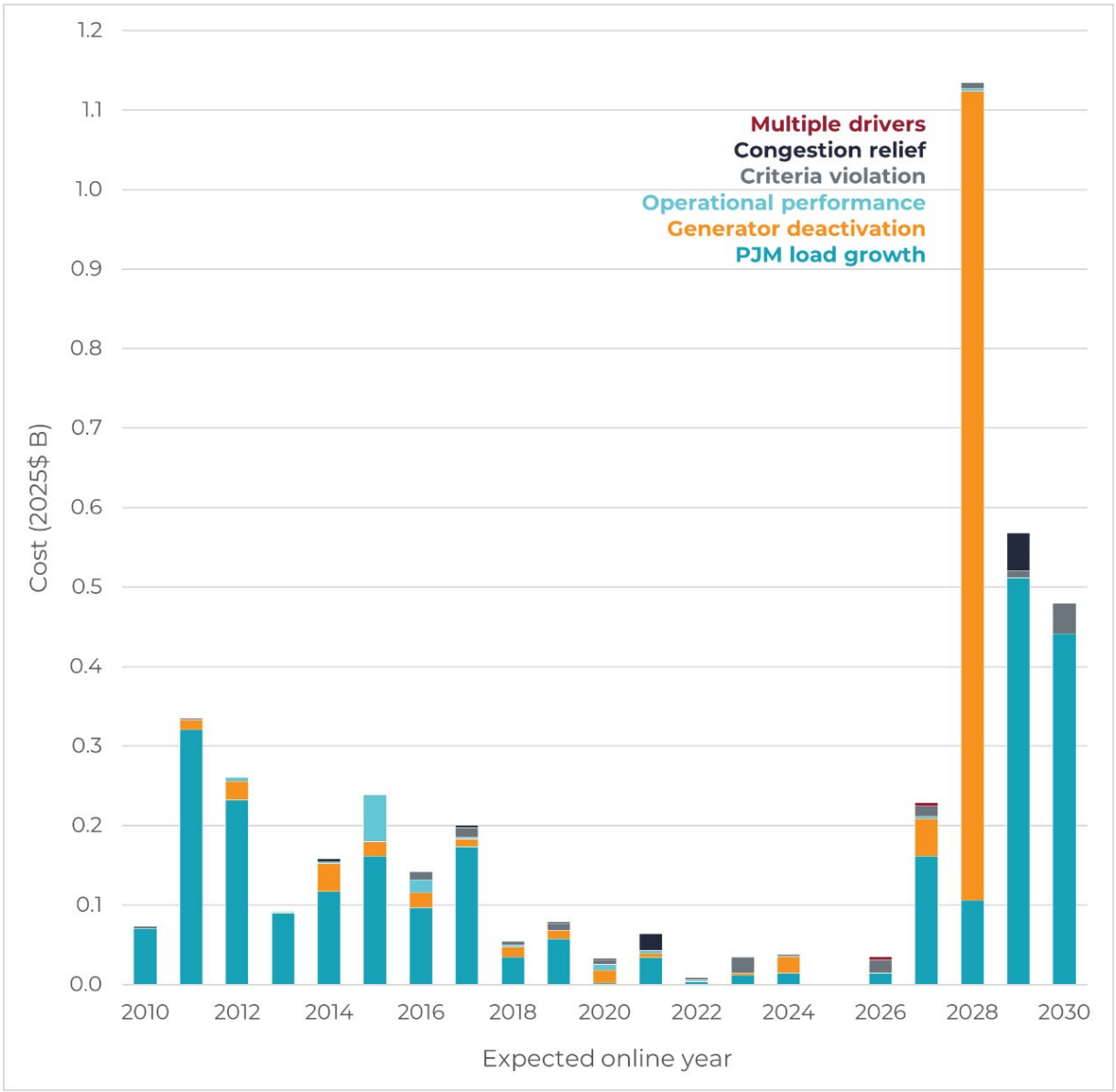
Project Cost Driver	Definition	Pepco	BGE	DPL	APS
Total Baseline Project Capital Costs Allocated to Maryland, 2010-2030 (millions, 2025 dollars)		**$ 1,097**	**$ 2,418**	**$ 352**	**$ 395**
Load Growth & Reliability	Projects needed to maintain compliance with NERC under forecasted system conditions. Includes addressing load growth, thermal/voltage violations, short-circuit issues, and deliverability of resources to load.	75%	53%	66%	81%
Generator Deactivation	Projects triggered by the planned retirement of generation resources that would otherwise result in the system unable to meet reliability or deliverability requirements.	16%	42%	8%	10%
Operational Performance	Projects that address non-NERC reliability issues, which may enhance reliability but may not resolve a formal violation. May include voltage support, dynamic stability, transfer capability, etc.	4%	1%	5%	4%
Transmission Owner Criteria Violation	Upgrades required to satisfy more stringent local reliability standards filed in each transmission owner's FERC Form 715 (beyond PJM's minimum criteria).	3%	2%	20%	4%
Congestion Relief	Projects that reduce congestion and lower overall system production costs. These are identified through PJM's Market Efficiency analysis.	3%	2%	0%	1%
Public Policy	Projects driven by federal, state, or local policy requirements, such as renewable portfolio standards or state-initiated transmission needs. Under PJM's framework, these may be advanced through the State Agreement Approach.	0%	0%	0%	0%
Multiple drivers	More than one of the six drivers above.	<0.5%	<0.5%	<0.5%	<0.5%

Source: See description in Section 2.3.

improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

For Maryland electricity customers, generator deactivation projects are a major cost driver for projects expected to be online in 2028 (Figure 7). This set of projects is associated with the Brandon Shores and Wagner RMRs, where building the transmission projects will enable the eventual retirement of the Brandon Shores and Wagner facilities and end their RMR service. Maryland is saddled with 66 percent of the total Brandon Shores Deactivation Project, with BGE responsible for almost 60 percent of the total. This is on top of the out-of-market RMR costs to keep Brandon Shores and Wagner operating, of which Maryland is also responsible for 66 percent of costs.

Figure 7. Total capital costs of approved and in-service baseline projects allocated to Maryland, by cost driver, 2010 to 2030



Source: See description in Section 2.3.

Figure 7, above, demonstrates how load growth-driven projects are rapidly becoming a major source of new transmission projects and costs, as PJM forecasts accelerating load growth outside of Maryland over the next 15 years. Concerningly, these costs are in addition to other electric system costs associated with data centers, such as rising capacity costs.[34]

Cost allocation is an extremely contentious and challenging aspect of transmission planning. From 2014[35] to 2025, Maryland was responsible for 3 percent of all baseline project capital costs and 6 percent of load growth and reliability project capital costs,[36] while the state represented roughly 9 percent of peak load across the RTO.[37] However, from 2025 to 2030, Maryland is paying for an increasingly greater share of baseline projects (10 and 8 percent in 2029 and 2030, respectively) but is responsible for only 2 percent of the region's total load growth.

Load growth-driven projects are rapidly becoming a major source of new transmission projects and costs, as PJM forecasts accelerating load growth outside of Maryland over the next 15 years.

PJM's 2026 long-term load forecast predicts that across the RTO, peak load will increase by 42 percent from 2026 to 2036, adding an additional 66 gigawatts (GW) to the system peak.[38] Comparatively, PJM expects that Maryland's peak demand will only increase by 12 percent over the same period,[39] indicating that much of the demand growth is occurring outside Maryland. Specifically, across the RTO region, PJM projects that data centers will account for 30 percent (67 GW) of total peak demand by 2036. However, Maryland is projected to account for only 2 percent (1.5 GW) of the total data center peak demand in PJM in that time period (Figure 8).[40] PJM projects that most of the region's data center peak demand growth will occur in the Dominion zone (mostly Virginia) and will account for 30 percent of total data center peak demand growth, followed by the AEP zone (mostly Ohio) making up 25 percent, and the ComEd zone (Illinois) making up 15 percent.[41]

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34 The PJM market monitor estimated that data centers represented 40 percent of capacity market costs in PJM's most recent auction. Monitoring Analytics, January 2026. Analysis of the 2027/2028 RPM Base Residual Auction, Part A. The Independent Market Monitor for PJM. Available at: https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf.

35 Peak load share data is not available from 2010 to 2013.

36 See description in Section 2.3.

37 Based on PJM's 2025 Long-Term Load Forecast and supplemental materials. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

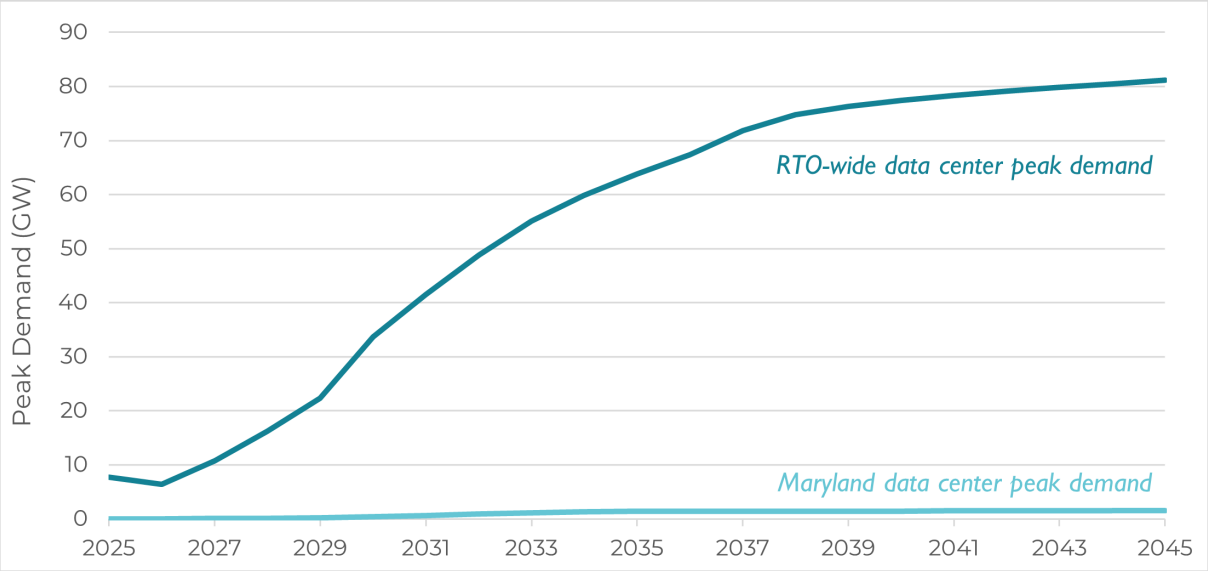
38 PJM Interconnection. 2026 Long-Term Load Forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

39 Ibid.

40 Ibid.

41 Ibid.

Figure 8. Projected PJM and Maryland data center energy consumption



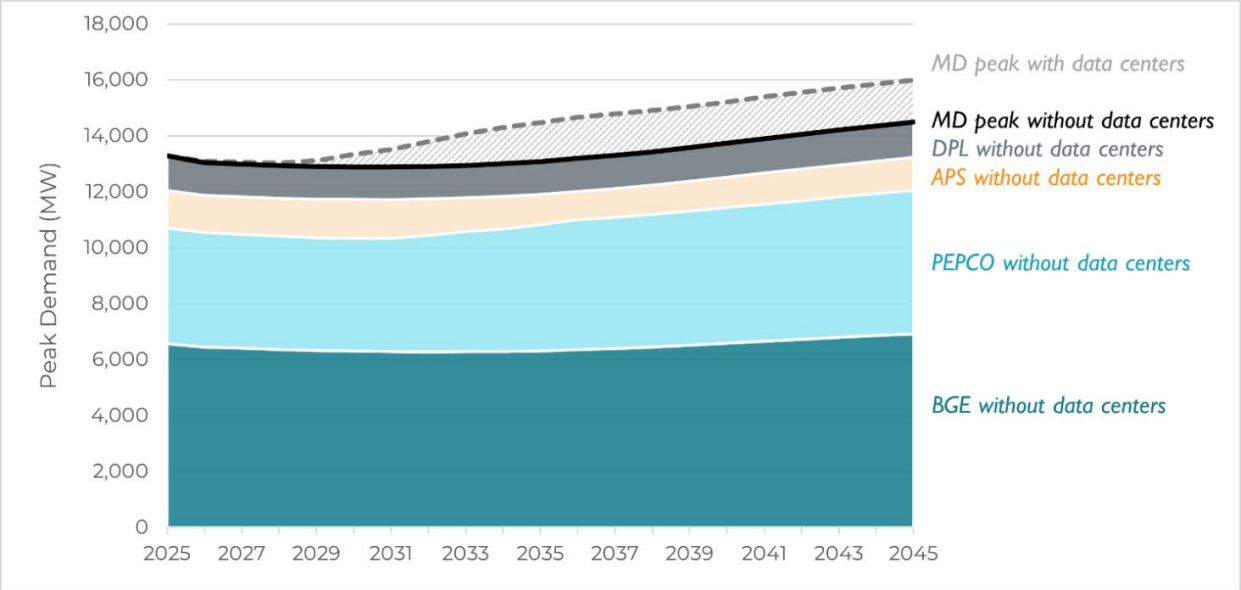
Source: PJM 2026 long-term load forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process. See description in Section 2.3 for details on the Maryland portion of demand.

Comparatively, Figure 9 illustrates Maryland's share of projected peak demand across the Pepco, BGE, DPL, and APS zones—excluding data center load. PJM estimates that peak demand from non-data center sources will remain relatively flat in the next 10 to 20 years. Absent data centers, Maryland peak demand increases by only 1 percent by 2036, compared with a 12 percent increase when projected data center demand is included.[42]

PJM estimates that peak demand from non-data center sources will remain relatively flat in the next 10 to 20 years.

[42] Ibid.

Figure 9. Maryland share of projected peak demand by zone with and without data centers



Source: PJM 2026 long-term load forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process. Source: See description in Section 2.3 for details on the Maryland portion of demand.

PJM approved $11.8 billion worth of transmission projects in its 2025 RTEP,[43] $6.7 billion in its 2024 RTEP,[44] and $5.1 billion in the 2022 RTEP (window 3 (W3)).[45] A total of $2.3 billion—over $900 million,[46] nearly $800 million,[47] and $551 million of the 2025, 2024, and 2022 W3 RTEP costs, respectively—will be passed on to Maryland electricity customers, mostly for transmission investments due exclusively to out-of-state data center growth. Transmission project costs from out-of-state data center growth have represented a growing share of Maryland electricity costs in recent years. For instance, in the 2022 RTEP, BGE requested financial incentives to build an estimated $634 million of transmission projects to meet reliability needs associated with data centers in Northern Virginia. The transmission projects include multiple new 500 kV transmission lines, substations, transformers and rebuilds, all in BGE's service territory in

43 PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." PJM Inside Lines. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

44 Comments of the Maryland OPC. April 28, 2025. FERC Docket No. ER25-1811. Available at: https://opc.maryland.gov/Portals/0/MPC%20Cmts%20ER25-1811%20%5BFinal%5D.pdf?ver=H7cwqPmI1rIghTavBZf1JA%3d%3d.

45 PJM Interconnection. December 2023. Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, PJM Staff White Paper. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx

46 For details on estimating the Maryland portion of baseline transmission costs, see description in Section 2.3.

47 Maryland OPC. April 28, 2025. "PJM proposal would unlawfully saddle Maryland customers with nearly $800 million for out-of-state data center growth, OPC tells federal regulators." Press Release. Available at: https://content.govdelivery.com/accounts/MDOPC/bulletins/3de09c9.

central Maryland. Although these data centers are not located in Maryland, they are adding immediate cost burdens to Maryland electricity customers, who are not only paying for these transmission projects, but also the financial incentives granted by PJM to BGE.[48] Under PJM's proposal, Maryland would pay for $551 million, or around 10 percent of total transmission projects from Northern Virgina data centers. On a per-kilowatt basis, Maryland's cost burden would be similar to Virginia's despite Virginia's much larger load growth. OPC protested the cost allocation for these projects in a 2024 filing to FERC, contending that PJM's cost allocation is unjust and unreasonable because it does not align with cost causation principles.[49] OPC argues that these projects should have been treated as multi-driver projects because they address reliability, economic impacts, and public policy requirements (e.g., Virginia's tax incentives for data center development).

Regardless of cost allocation challenges, data center load forecasts are uncertain. It is unclear to what extent projected data center load will materialize, how flexible such load will be (i.e., impact on peak demand), and how efficient the data centers might become in the future (i.e., how much energy will each data center consume when accounting for technological advancement). Nonetheless, these recent PJM forecasts are already informing PJM's transmission planning and driving new transmission projects across the region. If these load forecasts are overblown, PJM risks overbuilding its transmission system. Building projects today that turn out to be unnecessary in the future could lock in millions of dollars of capital and operations expenses, impacting electricity customers for decades to come.

4. LOCAL TRANSMISSION PROJECTS

PJM does not independently assess the need for local transmission projects.

Local transmission projects are local expansion and enhancement projects planned and developed by transmission owners to address local needs such as equipment upgrades or replacement, or local reliability improvements. Since these projects are not needed for regional reliability, PJM does not independently assess the need for these projects. The projects typically have little to no oversight and are paid for by all customers within the project's transmission zone, regardless of whether the project is in a different state within that zone.

[48] Maryland OPC. August 25, 2025. "OPC asks federal regulators to deny BGE financial incentives to build $634 million of transmission projects driven by Virginia data centers." Press Release. Available at: http://content.govdelivery.com/accounts/MDOPC/bulletins/3ef70f4.

[49] Maryland OPC. February 9, 2024. Maryland OPC Protest and Affidavit of R. Nelson. FERC Docket No. ER24-843. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/MdOPC%20Protest%20and%20Affidavit%20of%20R.%20Nelson%20ER24-843%2002-09-24%20%281%29.pdf

4.1. Planning and Oversight Process

Unlike for baseline projects, transmission owners have sole discretion to initiate these projects. Transmission owners plan for these projects outside PJM's RTEP process, yet still in accordance with the Open Access Transmission Tariff (OATT).[50] PJM requires transmission owners to present projects that are 230 kV and above to the TEAC, and projects below 230 kV to the Subregional RTEP Committees. However, PJM does not require transmission owners to submit these projects to the PJM Board for review or approval,[51] nor does PJM require transmission owners to follow its competitive solicitation process.[52] These projects are instead presented as part of the final RTEP report.[53] PJM's role is limited to evaluating whether the proposed local project imposes any adverse impacts on the broader regional grid through a "do-no-harm" study. PJM does not evaluate whether the proposed local project is necessary, cost-effective, or prudent.

Local projects are not subject to substantial state or federal regulatory review.

Furthermore, local projects are not subject to substantial state or federal regulatory review. For some transmission projects, owners must receive a Certificate of Public Convenience and Necessity (CPCN) from the Maryland Public Service Commission (PSC) before beginning construction in the state, but Maryland law includes certain waivers from CPCN requirements and does not require CPCNs for underground transmission lines.[54] Further, Maryland law does not require the PSC to consider cost-effective alternatives to transmission as part of the CPCN process. As a result, local projects have almost no review standards or oversight compared to baseline projects.[55] For baseline projects, PJM rules require validation of project needs, competitive solicitations (thereby incentivizing lower-cost, innovative solutions), cost analyses,[56] and PJM board approval. Though sometimes

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50 OATT Attachment M-3. PJM Interconnection. July 2021. PJM Manual 14B: PJM Region Transmission Planning Process, Revision 50, effective July 1, 2021, PJM Transmission Planning Department. Available at: https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m14b/m14bv50-pjm-regional-transmission-planning-process-07-01-2021.pdf.

51 PJM Interconnection. April 17, 2025. RTEP 2024: Regional Transmission Expansion Plan. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf, page 74.

52 Local (Supplemental) projects are presented through the TEAC (230 kV and above facilities) or the Subregional RTEP Committees (below 230 kV facilities).

53 PJM Interconnection. April 17, 2025. RTEP 2024: Regional Transmission Expansion Plan. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf.

54 See Maryland Public Utilities Article § 7-207.

55 Comments of the Maryland OPC in Support of the Office of the Ohio Consumers' Counsel Complaint, November 11, 2023. FERC Docket No. EL23-105-000. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/OPC%20Comments%20EL23-105%20-%20OCC%20Complaint.pdf.

56 As described in the PJM Manual 14C, Section 6.1.2.1 Cost Changes, "Significant cost increases to baseline upgrades can change the analysis done to solve criteria violations and therefore need to be communicated to PJM as they are discovered. PJM will use the new cost data to re-analyze the criteria violation and determine if a different, more economical solution is better suited to solve the issue". PJM Interconnection, L.L.C. *PJM Manual 14C: Interconnection Facilities, and Network Upgrade Construction*. Revision 17, effective July 23, 2025.

flawed, these baseline project review processes serve as safeguards for electricity customers. These safeguards are largely absent in the local project planning process. Although stakeholders may comment on proposed local projects during TEAC and Subregional RTEP subcommittee meetings, transmission owners are not required to incorporate stakeholder feedback before moving forward with a project's development. Furthermore, informational asymmetries often exist, and stakeholders frequently lack time, resources, and the transmission-engineering expertise needed to review proposed projects in their entirety.

Because local projects lack regulatory oversight and are exempt from competition, local projects are often much faster and simpler to advance. This lack of oversight and competition creates a perverse incentive for transmission owners who favor capital-intensive investments to invest more heavily in these projects. In recent years, transmission owners in Maryland have been pursuing these projects at a disproportionate rate.

Consumer advocates, including the OPC and the Consumer Advocates of the PJM States (CAPS), of which the OPC is a member, have raised substantial concerns about the PJM's local transmission project process, stating that it lacks transparency, oversight, and meaningful stakeholder engagement. For instance, OPC has a complaint pending before federal regulators on the regulatory gap that exists for local transmission projects.[57] OPC has argued that PJM rules allow transmission owners to determine whether to classify projects as local, allowing them to bypass regional planning, competitive procurement, and rigorous cost-benefit review.[58] OPC and CAPS have noted that information provided to stakeholders is often minimal or incomplete, with limited access to project justifications, cost drivers, alternative solutions, or reassessments after project approval; this information gap undermines the ability of states and consumer advocates to provide informed feedback.[59] From 2017 to 2022, Maryland utilities spent nearly $1 billion on local transmission projects, a figure that does not include the more than $1.6 billion costs of the non-competitively procured Brandon Shores Deactivation Project associated with the planned retirement of the Brandon Shores coal plant.[60] OPC and CAPS have urged FERC to close these

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Prepared by System Planning Division, PJM Interconnection, L.L.C. https://www.pjm.com/-/media/DotCom/documents/manuals/m14c.pdf.

57 See *Complaint of Industrial Energy Consumers of America, et. al. v. Avista Corporation, et. al.*, Docket No. EL25-44; *see also* Md. Office of People's Counsel, *Costly local transmission projects that avoid competition are causing unlawful rates, OPC tells federal regulators* (Dec. 19, 2024), https://content.govdelivery.com/accounts/MDOPC/bulletins/3c86285

58 Maryland OPC. November 20, 2023. "Maryland Utility Customers Vulnerable to Regulatory Gap in Oversight of Costly Transmission Projects, Office of People's Counsel Tells Federal Regulators." Press Release. Available at: https://content.govdelivery.com/accounts/MDOPC/bulletins/37c005f.

59 Consumer Advocates of the PJM States (CAPS). "*Letter Re: Supplemental Projects*," PJM Public Disclosures, accessed December 30, 2025, https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/caps-letter-re-supplemental-projects.

60 PJM Project Status & Cost Allocation, Transmission Cost Planner (TC Cost Planner). Data retrieved February 2026. Available at: https://www.pjm.com/planning/m/project-construction. Brandon Shores Deactivation Projects include baseline projects b3780 and b3781, per PJM Interconnection, February 2025. Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board. PJM Staff White Paper. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250204/20250204-pjm-board-whitepaper-february-2025.pdf.

regulatory gaps by expanding regional planning requirements to include local projects and by strengthening and promoting competition as a primary mechanism to increase discipline on costs and protect consumers.

4.2. Cost Allocation Methodology

The cost allocation methodology for local projects differs from that of regional baseline upgrades. Under Schedule 12 of the PJM OATT, 100 percent of the costs for local transmission projects are assigned directly to the local transmission owner's zone and are not regionally allocated. All customers in that zone pay for its local projects, regardless of whether the zone spans multiple states.

4.3. Project Cost Drivers for Local Projects in Maryland

From 2010 to 2030, Maryland has been or will be responsible for $2.8 billion of capital costs for local projects. When combined with the $4.3 billion in baseline projects (described in Section 3, above), Maryland is responsible for a total of $7.1 billion of transmission capital costs from 2010 to 2030. Local project needs and drivers are distinct and separate from the PJM-identified reliability criteria used for baseline projects. Instead, needs are determined at the sole discretion of the transmission owner. Table 3 below shows the percentage of cost drivers for all local projects in the transmission zones within Maryland. "Customer Service" and "Equipment Material Condition, Performance and Risk" represent the largest cost drivers amongst the Maryland transmission zones.

Table 3. Total capital costs of local projects paid for by Maryland, and proportion of driver type, by zone

Project Cost Driver	Definition	Pepco	BGE	DPL	APS
Total Local Project Costs Per Zone, 2010-2030 (millions, 2025 dollars)		$ 872	$ 1,565	$ 217	$ 177
Customer Service	Service to new and existing customers; address localized customer concerns, interconnect new customer load; address customer transmission and distribution load growth, outage exposure, and equipment loading	76%	27%	23%	26%
Equipment Material Condition, Performance and Risk	Projects justified by asset condition assessments, aging infrastructure, performance limitations, or risk mitigation considerations	19%	57%	65%	51%
Operational Flexibility and Efficiency	Optimizing system configuration, equipment duty cycles and restoration capability; minimize outages	2%	6%	5%	5%

Project Cost Driver	Definition	Pepco	BGE	DPL	APS
Infrastructure Resilience	Projects designed to improve system operability, enhance flexibility, or increase system's ability to anticipate, absorb, adapt to, and/or rapidly recover from a potential disruptive event (including severe weather, geo-magnetic disturbances, and physical and cyber security challenges)	0%	0%	0%	<0.5%
Other	Projects supported by miscellaneous or project-specific justifications that do not fall neatly into the categories above including industry recommendations, potential generation retirements, technology pilot projects, governmental/utility commission regulation, and state policy goals	<0.5%	0%	0%	0%
Multiple Drivers	Projects for which transmission owners cite a combination of two or more of the above drivers as the basis for need	4%	11%	7%	17%

Source: See description in Section 2.3.

Data centers are also driving many local projects in Maryland and across PJM. In 2024 alone, utilities in seven PJM states (Maryland, Illinois, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia) charged their customers more than $4.3 billion in local transmission upgrades to provide transmission services to data centers, and from 2022 through 2024, initiated 130 local transmission projects to connect new data centers.[61] Of the $4.3 billion worth of local transmission upgrades, $108 million were from Maryland data centers in the APS zone.[62]

5. NETWORK UPGRADE PROJECTS

Project developers cover the costs for network upgrades.

Network upgrade projects are transmission infrastructure projects needed to accommodate the interconnection of new service requests to the transmission network. These requests can include new generators, merchant transmission facilities, or new transmission requests in an area with insufficient transmission capacity.[63] Project developers cover the costs for

[61] Jacobs M. Union of Concerned Scientists. 2025. Connection Costs: Loophole Costs Customers Over $4 Billion to Connect Data Centers to Power Grid. Available at: https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20-%20Sep%202025.pdf.

[62] Ibid at Appendix: Compilation of Utility Projects by State. Available at: https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20Appendix%20-%20Sep%202025.pdf.

[63] David Gardiner and Associates. February 2024. Transmission Handbook, Volume IV: Transmission Planning in PJM. Prepared for the Consumer Advocates of the PJM States (CAPS). Available at: https://www.dgardiner.com/wp-content/uploads/2024/03/CAPS-Transmission-Handbook-Volume-4.pdf.

network upgrades; thus, these costs are not direct consumer costs. However, generators recover these costs in the PJM energy and capacity markets, where consumers will pay for these costs indirectly. Planning and oversight process for network upgrade projects happen through the interconnection queue process, including studying upgrade needs and cost development. Network upgrades represent a small percentage of overall transmission spending. Across PJM, they make up 7 percent of total transmission costs.

Network upgrade costs have been increasing in recent years. The PJM interconnection queue has experienced major delays as PJM has sought to overhaul its process. As discussed above, PJM projects data center load will rise at an alarming rate and reach unprecedented levels. In tandem with aging generators nearing retirement, projections of data center growth suggest the PJM system faces resource adequacy risks and needs to bring on more generation. As more resources seek to interconnect to the grid to meet growing demand, total network upgrade costs will continue to rise. Despite PJM's efforts to reform and streamline the interconnection queue process, it is still slow and expensive for resources looking to interconnect.

6. COST RECOVERY, RETAIL RATES, AND LONG-TERM CONSUMER IMPACTS

Transmission charges are the mechanisms by which transmission owners recover the costs of transmission projects. Baseline and local projects are recovered through two different components: Transmission Enhancement Charges (TEC) and Network Integration Transmission Service Charges (NITS), respectively. Utilities ultimately integrate these charges into ratemaking processes and recover them through retail rates.

6.1. Cost Recovery: TEC and NITS

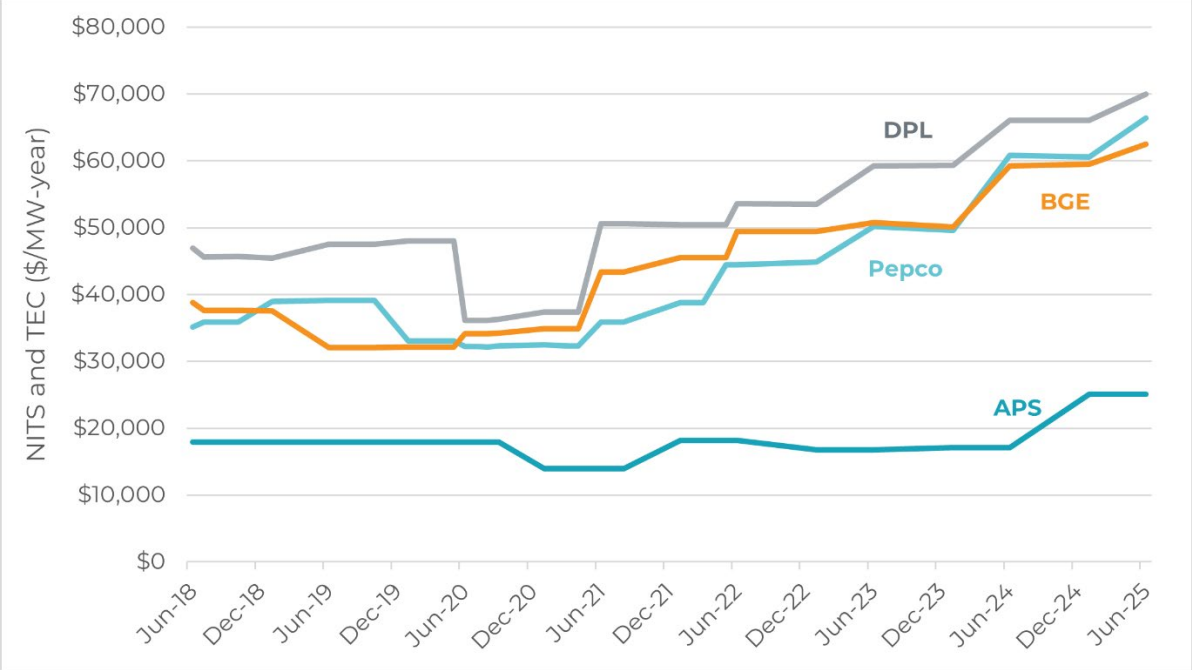
Transmission owners use TEC to recover the costs of baseline projects planned and approved through PJM's RTEP process. Because the benefits of baseline projects are supposed to be regional, PJM cost allocation methodologies assign costs to multiple zones based on which zones benefit from the project. Each benefiting zone is assigned a percentage of the project's annual revenue requirement. The annual revenue requirement includes capital costs, operational and maintenance expenses, depreciation expenses, taxes, and an authorized return on investment. Each zone's allocated share of a baseline project is then converted into a TEC, expressed in dollars per megawatt-month ($/MW-month). Every zone has its own TEC total that PJM charges to its customers, reflecting (1) the allocated share of baseline projects located in that zone that benefit that zone; and (2) the allocated share of baseline projects located in other zones that benefit that zone. For example, for a baseline project built in the Pepco zone, PJM may determine that APS receives 20 percent of the reliability benefit. As a result, APS customers (such as Maryland utility Potomac Edison) pay 20 percent of the project cost through APS's TEC charges, even though the project is physically located in Pepco.

NITS charges are the core mechanism through which transmission owners recover the costs of owning, operating, maintaining, and upgrading local transmission projects. As with TEC, NITS

reflects each project's annual transmission revenue requirement (ATRR), which includes capital costs, operational and maintenance expenses, depreciation, taxes, and an authorized return on investment. For each transmission zone, PJM converts the revenue requirement into a zonal NITS rate, typically expressed in $/MW-Year.

TEC charges for a specific transmission owner are often rolled into a transmission owner's NITS rate. Of the four transmission zones that Maryland is part of, APS is the only zone that does not include its TEC in its NITS rate. Figure 10 shows the combined NITS rate and TEC charges for all four transmission zones in Maryland. The charges have increased over the seven years. Specifically, the combined charges increased by 89 percent for Pepco, 61 percent for BGE, 49 percent for DPL, and 40 percent for APS.[64] The trends in Figure 10 track fairly closely with the residential retail transmission rates shown in Figure 2 (Section 1).

Figure 10. Combined NITS and TEC rates for Pepco, BGE, DPL, and APS (nominal dollars)



Notes: Includes TEC charges and credits, plus NITS charges. PJM Billing, Settlements & Credit. Transmission Enhancement Worksheets and Network Integration Transmission Service Revenue Requirements & Rates. Available at: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit. *Data prior to 2021 from Electricity Transmission Competition Coalition, PJM Network Integration Transmission Service Rates ($/MW-Yr). Available at:* https://electricitytransmissioncompetitioncoalition.org/wp-content/uploads/PJM-Transmission-Rates-History-20215-2024.pdf.

6.2. Retail Rates

Before recovery of TEC and NITS costs begins, rates are filed with FERC. PJM charges each transmission customer its zonal NITS and TEC rates. Transmission customers are typically

[64] When adjusted for inflation, in real dollar terms, the combined charges increased by 51 percent for Pepco, 29 percent for BGE, 19 percent for DPL, and 12 percent for APS.

load-serving entities (LSE), which are distribution utilities (for their standard offer service (SOS) customers) or retail choice suppliers. Under PJM's billing framework, PJM bills the transmission charges to the LSEs in a zone based on their contribution to the zone's maximum peak load on a monthly basis.

LSEs pass these charges down to each of their customer classes using allocation methodologies approved by their state commission. Generally, the allocations are based on each class's contribution to peak load. As a result, retail classes with higher contributions to peak demand bear a proportionally larger share of transmission costs. This allocation methodology ensures that customers with higher demand pay proportionately more for the cost of transmission infrastructure that supports their power needs. Finally, the LSE will then convert the transmission charges for each class into a $/kWh or $/kW charge that appears on customer bills,[65] usually on the supply portion of the bill.

In Maryland, LSEs providing SOS file their retail transmission rates with the PSC before July 1 (or the effective date), along with the allocation calculations for each customer class. These allocations warrant careful examination to ensure that large-load customers are paying for their fair share of transmission costs and that all customers' rates are just and reasonable in this respect.

6.3. Bills and Consumer Impacts

The evolving needs of the grid over the past two decades have led to substantial changes in transmission investments. Even though transmission capital project costs have fluctuated over time, overall spending and the associated rates have entered a sustained period of growth, largely driven by the increase in local projects and more recently from data-center-related baseline projects.

Overall spending and the associated rates have entered a sustained period of growth, largely driven by the increase in local projects and more recently from data-center-related baseline projects.

Transmission project costs are ultimately approved at the federal level and incorporated into utility ratemaking through retail rates. As transmission owners place new projects into service, their associated revenue requirements increase, leading to higher transmission rates. Even if individual project costs appear modest in isolation, the cumulative effect of multiple projects, particularly local upgrades concentrated in certain zones, can increase zonal transmission rates over time. As costs rise, retail rates in Maryland trend upwards, exacerbating the affordability crisis facing residential, small business, and low-income customers. Typically, transmission assets depreciate over 30 to 40 years, meaning that cost

[65] Residential transmission charges typically appear as a $/kWh charge on customer bills.

recovery for an individual asset spans multiple decades.[66] As a result, Maryland customers will continue to see transmission charges for a particular transmission project on their bills over the course of many years.

6.4. Looking Ahead: What to Expect for Future Transmission Costs and Rates

Transmission costs across PJM and for Maryland electricity customers have been rapidly escalating over the last few years, a trend that we expect to continue for the foreseeable future. For example, the 2024 RTEP included $6.7 billion in transmission projects,[67] while the 2025 RTEP is worth $11.8 billion.[68] The following two subsections provide an overview of Synapse's forecast of baseline and local project costs paid for by Marylanders. These forecasts project costs based on the current transmission planning and cost allocation methods used in the PJM region. As discussed elsewhere in this report, OPC has raised objections and challenges to PJM and to FERC regarding these methods.

6.4.1. Baseline project forecasts

Baseline load growth and reliability cost drivers are the largest portion of baseline transmission costs; they represent roughly two-thirds of capital project costs across the PJM footprint and those allocated to Maryland. Although these types of projects are for both reliability and load growth, total project spending for this category tracks closely with peak demand (Figure 11). When peak load is flat, RTO-wide project spending on load growth and reliability projects remains relatively flat and then falls, as can be seen over the last decade from 2014 to 2024. As peak load forecasts have begun to increase at an accelerating pace from 2025 to 2030, approved project costs for load growth and reliability have increased accordingly (Figure 11). We assume that for 2030 to 2035, peak load and reliability projects will continue to track load growth closely, rising at the same annual growth rate as the 10-year peak load forecast from 2025-2035. In reality, costs will be much higher if data center demand continues to grow or could be much smaller if that demand is over-inflated and corrected in the future. Project spending will also likely be much lumpier than appears in Figure 11.

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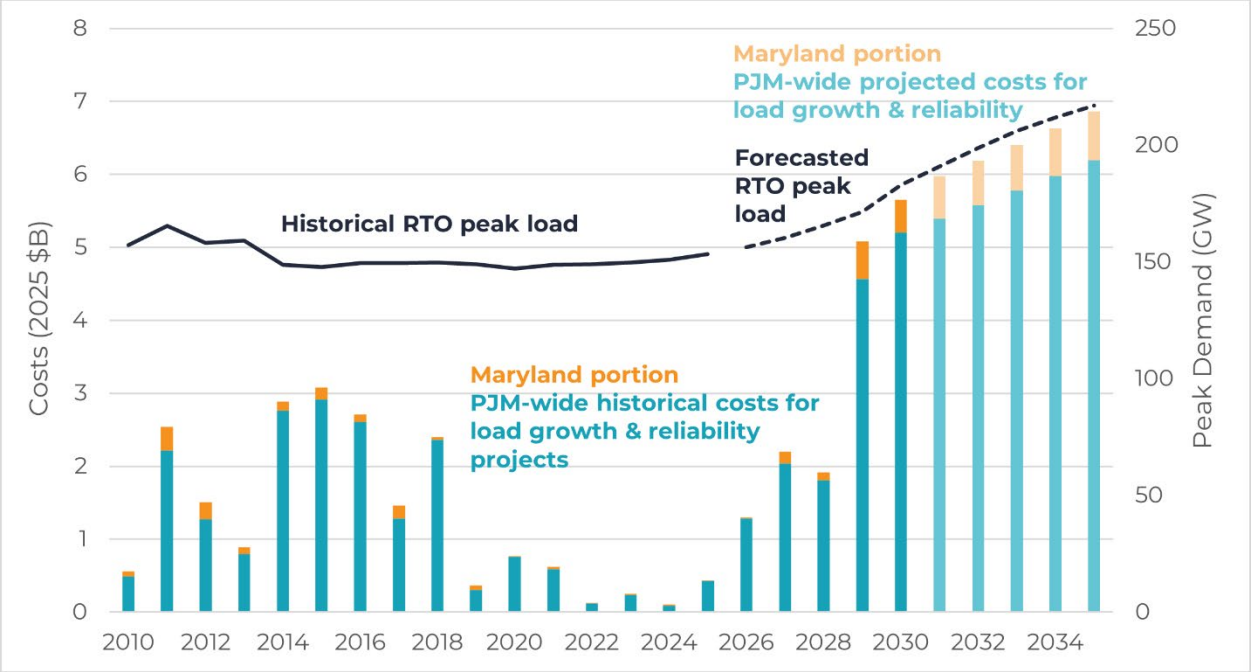
66 Exelon Corporation, *Property, Plant and Equipment – Annual Depreciation Provisions as Percentage of Average Service Life*, SEC Form 10-K XBRL Exhibit R83, Dec. 31, 2021, https://www.sec.gov/Archives/edgar/data/78100/000110935722000076/R83.htm.

67 PJM Interconnection. February 26, 2025. "PJM Board Approves New Transmission Projects to Support Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.

68 PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

Figure 11. RTO-wide historical and forecasted peak load, and RTO and Maryland-only portion of baseline capital project costs for load growth and reliability projects, 2010 to 2035



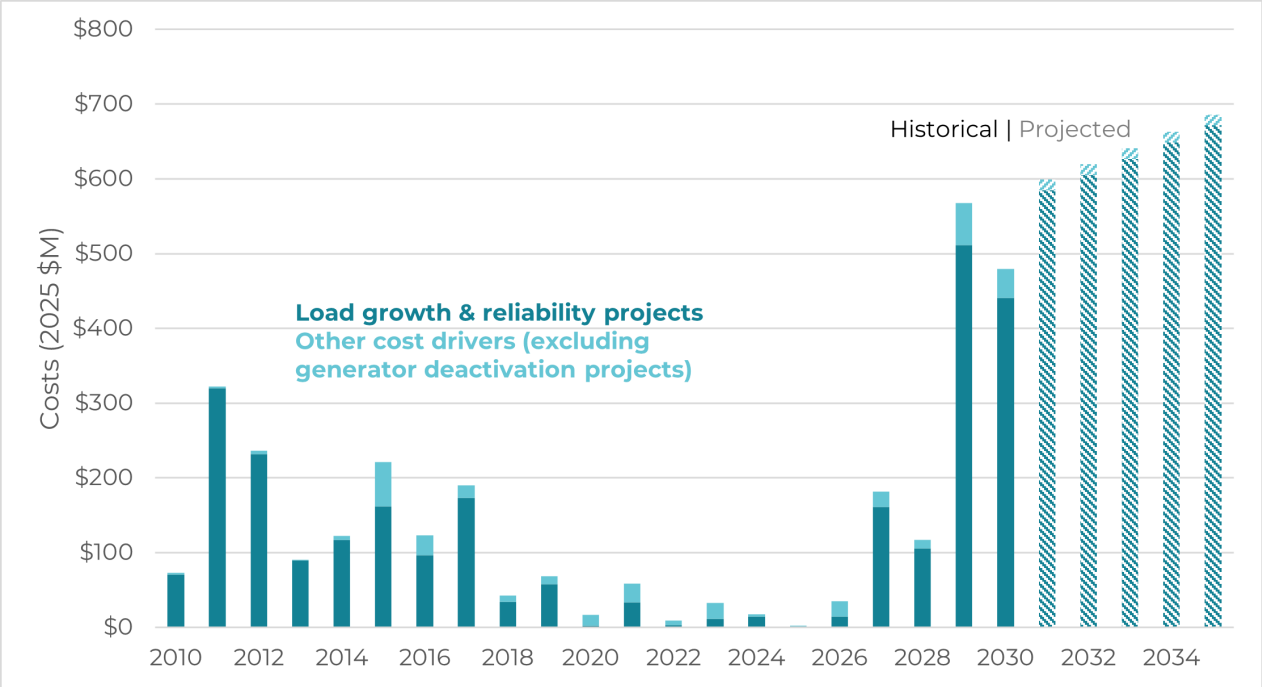
Notes: See description in Section 2.3. Historical and forecasted peak load is from PJM's 2026 Long-Term Load Forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process*. For details on forecasted project costs, see description in text.*

Maryland has historically paid for 8 percent of PJM load growth and reliability projects, on average, with substantial variability across years, as can be seen above in the blue bars in Figure 11. From 2025 to 2030, the share of these projects PJM is allocating to Maryland has increased from less than 1 percent to a maximum of 10 percent, mostly driven by data centers being built in Virginia, parts of Maryland, and the neighboring areas. Although Maryland's load growth is comparatively flat, we assume that Maryland will continue paying 10 percent of PJM load growth and reliability projects in the near future, reflecting continued data center development in Virginia and the surrounding regions. Nonetheless, this number could be substantially different depending on where data centers are built and how costs are allocated across zones. Under these assumptions, we estimate that Maryland electricity customers could be allocated an additional $3.1 billion dollars in capital transmission costs for load growth-related projects from 2031 to 2035 (although actual project costs will be paid for over many decades) (yellow bars in Figure 11).

Although load growth and reliability projects represent the largest share of baseline projects, Marylanders also pay for projects due to other cost drivers. Assuming the historical average annual spending and cost allocation to Maryland remains steady—and excluding generator deactivation projects—Maryland electricity customers in the state could incur an additional $72 million dollars for other baseline project types (e.g., congestion relief) during the 2025–2031 period, on top of the $3.1 billion associated with load-growth and reliability-related projects. This

equates to a total of $3.2 billion for 2031 to 2035, a major increase compared to the $4.3 billion of baseline capital costs PJM allocated to Maryland in the proceeding 20 years (Figure 12).

Figure 12. Maryland-only portion of historical (2010 to 2030) and projected (2031-2035) baseline capital project costs



Notes: See description in Section 2.3. For details on forecasted project costs, see description in text.

This forecast does not include generator deactivation projects, as they are difficult to estimate. These types of projects are rare and very lumpy. Moreover, deactivation can occur anywhere in the PJM region. However, it is possible that we will see more generator deactivation-driven transmission projects (such as those addressing RMRs) across PJM, as load continues to grow rapidly and capacity becomes increasingly constrained across the region. For instance, Exelon (the parent company for Pepco, BGE, and DPL) announced that it expects to spend an additional $12 billion to $17 billion on transmission buildout over the next 10 years, which includes generator deactivation projects, among others.[69]

6.4.2. Local project forecasts

Predicting future local projects is much more challenging than for baseline projects because these local projects are not directly tied to load forecasts and other changes on the electric system. Additionally, local projects are highly variable year-over-year and between zones. Nonetheless, assuming historical growth rates of local project spending across the four transmission zones in Maryland, Synapse estimates that the cumulative local project capital

[69] Howland, E. February 13, 2026. "Transmission drives Exelon's capital spending plan to $41.3B." *Utility Dive*. Available at: https://www.utilitydive.com/news/exelon-transmission-data-center-capex-earnings/812200/.

costs from 2031 to 2035 could reach as high as $2.2 billion, in addition to the $3.2 billion of baseline project capital cost forecast discussed above.

In total, we estimate that baseline and local capital costs for Maryland could total $5.4 billion for 2031 to 2035, a major increase compared to the $7.1 billion of transmission costs from the proceeding 20 years.

Lastly, these estimates of near-future spending will be compounded for consumers by existing projects that were built in the previous decades. Customers are still paying for transmission projects built in the 1980s in their electricity rates—any future projects will be added to those existing projects still on the books and will be paid for over decades.

7. RECOMMENDATIONS

7.1. Government Agency Involvement in Transmission Issues

States, regulatory agencies, and consumer advocates should play an important role in transmission planning, cost allocation, and project oversight. These stakeholders, among others, engage in the transmission planning process through multiple PJM committee meetings, federal regulatory processes at FERC, and regional planning organizations. This process allows stakeholders to review proposed transmission projects, provide input on project needs, and influence policy that affects retail customers. The OPC is regularly active in relevant PJM forums. Nonetheless, the PJM stakeholder process remains flawed and is highly resource-intensive. When resources are limited, stakeholders may find it most strategic to focus on key forums, workshops, committee meetings, and docketed cases where stakeholder input can be the most effective.

The PJM stakeholder process remains flawed and is highly resource-intensive.

7.2. Opportunities for Maryland to Mitigate Rising Transmission Costs

Maryland has several avenues to advocate for measures that can mitigate rising transmission costs.

- **Advocate for more accurate load forecasts, especially with respect to data centers**: Given that data centers are the main driver of projected load growth in PJM, and thus transmission costs, it is critical that the large-load adjustments PJM includes in its load forecasts are realistic, based on best available data, and well-vetted. Increased transparency, oversight, and better data overall is needed to improve the accuracy of PJM's data center load forecasts. Improved regional collaboration around data

It is critical that the large-load adjustments PJM includes in its load forecasts are realistic, based on best available data, and well-vetted.

gathering can reduce the potential for double-counting of data center loads across jurisdictions.

- **Establish an Independent Transmission Monitor**: Advocate for the implementation of an independent transmission monitor (ITM), similar to ISO New England's recent creation of an Asset Condition Reviewer,[70] to review and increase transparency of project needs and costs. An ITM in the PJM region could review benefits and costs to evaluate the cost-effectiveness and consider alternatives. The ITM could promote projects that meet multiple needs over a longer planning period (rather than individual projects to meet one specific need) and ensure that projects are rightsized (but without overbuilding) to account for future load growth and electrification. An ITM would not normally set or change rates, reject projects outright, or change cost allocation and allowable rates of return. Real cost containment requires coordinated engagement at the PJM planning, tariff, and FERC regulatory levels. However, an ITM can be a valuable oversight body that supports consumer advocates with Federal Power Act section 206 filings, to lower the burden of proof and advocate for meaningful changes.

- **Strengthen regulation of transmission projects at the state level:** For local transmission projects, the PSC should require cost-benefit evaluation and consideration of alternatives to costly transmission projects during CPCN proceedings, although additional statutory authority or guidance may be required.[71] This would add an additional layer of regulatory oversight to local projects, which would improve transparency and help mitigate costs, project overbuilds, and unnecessary local projects.

- **Reform transmission cost allocation for large load customers**: Stakeholders can advocate at FERC for rules that specifically align cost allocation with cost causation and require large-load customers to pay for the transmission costs that would not be incurred without them. Although transmission service charges are allocated to specific customers based on their share of peak demand, stakeholders

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70 In the ISO New England region, concerns about rising transmission costs have led stakeholders to advocate for the creation of an Asset Condition reviewer to provide unbiased oversight across transmission planning categories and ensure cost-effective project design. The Asset Condition reviewer has been approved by ISO-NE but is still in its initial design phase. It will act independently from ISO-NE and the incumbent transmission owners, with authority to review transmission projects under the Asset Condition Projects (ACP) category. Advocates argue that this oversight would help with rightsizing and inefficient investments and improve the overall process.

71 In a case involving a Potomac Edison supplemental transmission project that would take down an existing transmission line and build a new line along the same route, the PSC rejected OPC's position that the project was a "new" line under the CPCN statute, and therefore, it determined there was no need for the utility to present evidence on alternatives or for the PSC to find that the proposed project was the least-cost solution. Md. Pub. Serv. Comm'n, Order No. 90684, Potomac Edison Company's Application for a Certificate of Public Convenience and Necessity to Rebuild Doubs-Goose Creek Transmission Line (Case No. 9669, June 27, 2023).

can petition for some large-load customers, such as data centers, to pay for a greater share of projects that are driven entirely by their new service requests.

- **Engage in Federal Power Act Section 206 filings**: Advocates should continue to challenge transmission projects of concern at FERC through filings under the Federal Power Act section 206. Cases could involve reviewing the prudency and/or cost allocation of specific projects or could target specific transmission owner rate cases reviewing rates of return, depreciation, and other areas of cost of service. However, direct intervention at FERC is highly resource-intensive due to the information asymmetry between advocates and transmission owners. Although this form of advocacy can sometimes lead to positive outcomes, it shifts the burden to consumer advocates, state agencies, and other intervenors to demonstrate that existing rates or practices are unjust, unreasonable, or unduly discriminatory.
- **Promote cost-reducing technologies**: Stakeholders can support the use of lower-cost Grid Enhancing Technologies and Advanced Transmission Technologies as encouraged by FERC in Order 1920 to lower transmissions costs and network upgrades. They can also advocate for lower-cost alternatives, such as non-wires alternative as opposed to traditional transmission investments. Such advocacy can be take place at all forums and advocacy avenues discussed above.

Overall, Maryland stakeholders should actively pursue all available avenues to mitigate the risk of substantial transmission cost increases. Collaboration with other consumer advocates, state agencies, and regional partners can further strengthen these efforts. Proactive and coordinated engagement across federal, regional, and state processes will be critical to ensure that transmission investments are justified, cost-effective, and aligned with the interests of Maryland electricity customers.