

**March 10, 2026**

**Chairman Marc Korman  
House Environment and Transportation Committee  
251 Taylor House Office Building  
Annapolis, Maryland 21401**

**POSITION: OPPOSE  
HB 1404 Public Utilities - Energy Generation and Transmission**

Constellation, a Fortune 200 company headquartered in Baltimore, is the largest private-sector power producer in the world, the nation's largest producer of clean and reliable energy, and a leading competitive retail energy supplier to millions of homes, institutional customers, the public sector, community aggregations, and businesses. With 55 gigawatts of generating capacity from nuclear, natural gas, geothermal, hydro, wind, and solar facilities, our current fleet has the capacity to power the equivalent of 27 million homes, providing about 10% of the nation's clean energy and delivering the around-the-clock reliability needed to power America's growing economy.

In Maryland, Constellation produces 90% of the state's clean electricity and powers nearly half of the state's overall electricity use. We have invested over one billion dollars in power generation in the state at the Calvert Cliffs Clean Energy Center, Conowingo Dam and Western Maryland wind projects entirely through the competitive market without guaranteed cost recovery from captive ratepayers. And we're doing more, offering a range of near- and long-term generation and battery storage options for the state that includes 800 megawatts of battery storage, more than 700 megawatts of natural gas-powered generation, and expanded investment in Calvert Cliffs including extending the plant's life to operate for another 20 years, increasing output by 10 percent (190 megawatts), and doubling the site's capacity through the addition of 2,000 megawatts of new next-generation nuclear. Our 2,500 Maryland employees – who have volunteered more than 28,000 of their hours annually with Maryland nonprofits – are working hard every day to demonstrate that private capital and competitive markets are fully capable of meeting Maryland's reliability and clean energy needs.

**Maryland's Energy Framework Has Worked**

Maryland has had a clear energy policy for over 25 years to protect consumers from high utility costs. In 1999, the General Assembly deliberately separated the competitive business of generating electricity from the monopoly business of delivering it. That decision shifted the financial risk of building and operating power plants away from captive customers and onto private investors.

House Bill 1404 would reverse this long-standing policy by allowing Maryland’s monopoly utilities to own generation assets and recover costs through regulated rates. Simply put, utilities like BGE and its Illinois-based Fortune 200 parent Exelon want to expand their monopoly to create a new ratepayer funded profit center in the power generation space. In essence, HB 1404 would guarantee profit for generating electricity — in the same way profits are guaranteed for its distribution system. That means they would earn a 9.5 percent profit on every dollar spent, and these returns would be guaranteed even though building significant amounts of generation capacity carries substantial risks – for example if future electricity demand projections are indeed overinflated or if the AI and data center bubble bursts. HB 1404 would allow utilities to avoid these risks by placing it on utility ratepayers instead.

That structure proposed under HB1404 would reward spending rather than efficiency and expose ratepayers to long-term financial risk if projects are delayed, over budget, or no longer needed. What the utilities aren’t telling you is that current state law already allows utilities like to build power generation, just like any market generator (including Constellation) and take market risk. Current law also allows utilities to go to the PSC and seek permission to build and recover the costs of new power plants in regulated rates.<sup>1</sup> In that scenario, the PSC has broad discretion as to whether the utility generation is in the public interest and at what level of utility return on investment it will allow. Utilities don’t need HB1404 to build new generation, they only need it to guarantee a risk-free return on any investment in new generation, regardless of whether that investment is in the best interests of Maryland ratepayers or at the lowest cost.

Furthermore, utilities cannot get new generation online any quicker or cheaper than the companies that currently produce energy for the state. They would face the exact same approval processes and procurement challenges that current competitive providers face, and in the case of new gas generation in Maryland, the same natural gas infrastructure and supply constraints. Utilities would be subject to the same interconnection queue and would have to manage the same supply chain issues that any other developer does. In fact, the private market is much more likely to have existing inventory and efficiencies in operation to streamline development, including strong relationships with suppliers that stopped doing business with regulated utilities decades ago. If they believe otherwise, then they should begin producing electricity through one of their unregulated affiliates immediately and without a law change.

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<sup>1</sup> Section 7-510(c)(6) of the MD Public Utilities code states: “In order to meet long-term, anticipated demand in the State for standard offer service and other electricity supply, the Commission may require or allow an investor-owned electric company to construct, acquire, or lease, and operate, its own generating facilities, and transmission facilities necessary to interconnect the generating facilities with the electric grid, subject to appropriate cost recovery.”

## **Ratebased Generation Will Further Exacerbate the Increasing Portion of Utility Charges on Customer Bills**

There is no good reason to undo Maryland’s competitive market for power generation, as that law has been a win for consumers by keeping power supply prices essentially flat. That remains true even factoring in recent increases in the cost of generation capacity, which BGE falsely blames as the sole cause of higher energy bills. An FTI consulting report issued earlier this year highlights this analysis.<sup>2</sup> In its analysis, FTI found that transmission and distribution costs charged by monopoly utilities have driven rising electricity bills in Maryland, and that energy costs in states with vertically integrated monopoly utilities grew twice as fast as in Maryland since 2010. The study concludes that the competitive market has resulted in lower costs for ratepayers and protected them from the monopoly utilities’ business model that incentivizes spending on complex, expensive projects with guaranteed profits for their shareholders that may not benefit customers.

Specifically, FTI found:

- Without competitive markets, Marylanders would have paid over \$11 billion more for their electricity over the past 15 years.
- Utility spending on transmission and distribution in Maryland has risen by over 25% in the last five years, exceeding \$1.2 billion per year without meaningfully improving system reliability.
- For the average Maryland household, transmission and distribution costs have increased by over \$500 per year over the past 15 years.

Maryland’s participation in the PJM wholesale market, which provides access to a diverse set of generation resources, has helped meet the state’s power demand efficiently and cost effectively. As a result, consumers across the PJM region save an estimated \$3.2 - \$4 billion each year. These utility cost increases will not end anytime soon, as reflected by the PJM Board of Managers approval in February of a new package of transmission projects with a total estimated cost of \$11 billion. Illinois-based Exelon touted BGE’s performance in its most recent investor earnings call stating, “BGE’s adjusted operating earnings for the fourth quarter of 2025 increased to \$181 million from 4175 million in the fourth quarter of 2024, primarily due to distribution rates associated with updated recovery of investments to serve customers....”. Clearly Exelon’s continued profitability does not require the ability to build and ratebase generation, as there is

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<sup>2</sup> See attached [Competitive-Power-Benefits-for-the-State-of-Maryland](#), by FTI Consulting on behalf of the Alliance for Competitive Power, January 2026

plenty of money being made through their core job relating to the transmission and distribution of energy.

### **HB 1404 is Unnecessary and Untimely**

On January 16<sup>th</sup>, the PJM Board directed its staff to implement a new procurement mechanism to address the tightening supply and demand situation across the region. On the very same day, Governor Moore joined governors from across the PJM footprint to join the federal government in releasing a set of principles to guide PJM's implementation of this procurement mechanism. Constellation is working with other stakeholders, including Maryland utilities, to work with PJM on this effort, and PJM has stated that it will file the new procurement mechanism with federal regulators in May so that it can be implemented this fall. Efforts to enhance the reliability backstop mechanism, which were contemplated as early as August 2025, have since intensified with many parties working together to develop the rules and implement an auction in Q3 2026. It is unnecessary for Maryland to undue decades of policy precedent in advance of implementation of applicable regional proposals.

### **Front-of-the-Meter Storage Should Be Competitively Procured**

Constellation supports front-of-the-meter energy storage as part of a modern, resilient grid. However, these resources should be deployed through competitive procurement to ensure innovation, cost discipline, and accountability. Rate-basing storage investments risks locking customers into long-term costs for rapidly evolving technologies.

### **Conclusion**

HB 1404 is not an affordability solution. It would increase costs by expanding guaranteed utility returns, undermine competition, and dismantle consumer protections that have served Maryland well for decades. **For these reasons, Constellation respectfully urges the Committee to issue an UNFAVORABLE report on House Bill 1404.**

Respectfully submitted,

Mason Emmett  
Senior Vice President, Public Policy  
Constellation

January 2026



# Competitive Power Benefits for the State of Maryland

This report evaluates the benefits that the competitive generation market has provided to the state of Maryland and the significant risks that potential utility owned generation would pose.

*DISCLAIMER*

*This report was commissioned by The Alliance for Competitive Power.*

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## Executive Summary

Aiming to encourage competition within electricity markets, the Energy Policy Act of 1992 prompted state-level restructuring efforts across the United States, including in the state of Maryland. Following enactment of this federal legislation, the Maryland General Assembly passed the 1999 Electric Customer Choice and Competition Act, restructuring its electricity sector to promote greater market efficiency. Under this law, utilities retained monopolies on distribution and transmission but were required to divest from all generating assets, passing the responsibility of owning and operating power plants to Independent Power Producers (“IPPs”) competing in an open market. To promote and encourage consumer choice, the act also allowed customers to choose alternative electricity suppliers rather than requiring them to use power contracted for by local utilities.

These changes encouraged a more efficient market and shifted the financial risk associated with building and operating power plants away from Maryland’s utility customers and on to IPPs. In restructured markets, customers may be served under what is commonly known as a Standard Offer Service (“SOS”) model. Under this framework, utilities procure electricity for customers through competitive bidding processes designed to achieve fair market prices. This approach led to lower costs as well as reliable supply, transparent pricing, and regulatory protection. Specifically,

- Competitive markets have protected Marylanders from growth in power supply costs. Had retail rates in the state grown at the same pace as vertically integrated states, Marylanders would have paid over \$11 billion more for their electricity over the past 15 years.<sup>1</sup>
- Rate growth in Maryland over the past 15 years has been driven by services provided by regulated utilities, not IPPs. For the average Maryland household, transmission and distribution costs have increased by over \$500 per year. In contrast, generation costs have fallen over the same period, saving households nearly \$300 per year.<sup>2</sup>
- Meanwhile, utility spending on transmission and distribution in Maryland has risen by over 25% in the last five years, now exceeding \$1.2 billion per year, but has not delivered meaningful reliability improvements. Recent analysis found that reliability in Maryland’s largest electric utility territory was deteriorating despite increased investment and cost overruns.<sup>3</sup>
- Large infrastructure projects managed by utilities often exceed their planned budgets, with captive ratepayers ultimately responsible for bearing cost overruns. This includes over \$750 million in cost overruns, thus far, on an ongoing transmission project to mitigate the retirement of a major generation asset in Maryland.<sup>4</sup>
- Maryland benefits from its participation in the PJM power market through resource pooling and access to a diverse set of generation that reduces costs for customers across the region

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<sup>1</sup> EIA, *EIA-861 Annual Electric Power Industry Report* ([link](#))

<sup>2</sup> Ibid.

<sup>3</sup> PSC, Case 9353, *OPC Comments on the Maryland Electric Distribution Companies’ 2024 Annual Reliability Performance Reports* ([link](#))

<sup>4</sup> PJM, *Reliability Analysis Update* ([link](#))

by \$3.2 to \$4 billion each year.<sup>5</sup> Recent power system modeling has confirmed that the upgrades to PJM's interconnected transmission network already underway will be sufficient to accommodate 2,980 MW of near-term demand growth in Maryland and meet Maryland's long-term demand requirements until at least 2042.<sup>6</sup>

- Maryland does not produce natural gas and must import either electricity or natural gas to fuel local generators to serve the State's growing energy needs. Maryland electric generation is expected to be at least 25% more expensive to produce than the cost of imported electricity.<sup>7</sup>

Despite these consumer benefits, some stakeholders in certain states, including Maryland, have been advocating for legislative changes that would undermine competition by allowing utilities to own and operate certain new generation assets, with the costs plus a guaranteed return paid by ratepayers, that would directly compete with privately owned and operated generation. Proponents of this change claim that this is necessary to meet rapidly increasing demand and ensure reliability. These arguments critically ignore the significant and long-term financial risk that ratepayers would again face under the utility ownership model that rewards utilities and their shareholders for maximizing spending.

This report assesses the benefits that the competitive market for generation has provided in Maryland and evaluates the risks that ratepayers would be exposed to if rate-based utility owned generation were allowed to participate in the competitive markets. The analysis concludes that utility ownership of generation assets in Maryland would expose ratepayers to unnecessary risk, lead to higher energy costs, and undermine the efficient functioning of the competitive market.

Independent ownership of power generation protects electric customers from bearing the financial risk of project delays and cost overruns during large infrastructure projects, and from the burden of paying for stranded assets should future energy demand fail to meet current projections. Competitive markets are more adaptive than vertically integrated markets in response to changing market conditions, such as the shift away from coal generation assets during the U.S. shale boom. Allowing utilities to build new generation in Maryland under cost-of-service rates would chill market participation from private companies. Utilities can establish competitive affiliates if they wish to participate in the competitive wholesale electricity market on a level playing field.

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<sup>5</sup> PJM, *Fact Sheet for Policy Makers* ([link](#))

<sup>6</sup> OPC, *Impact of Brandon Shores deactivation projects on Maryland generation needs* ([link](#))

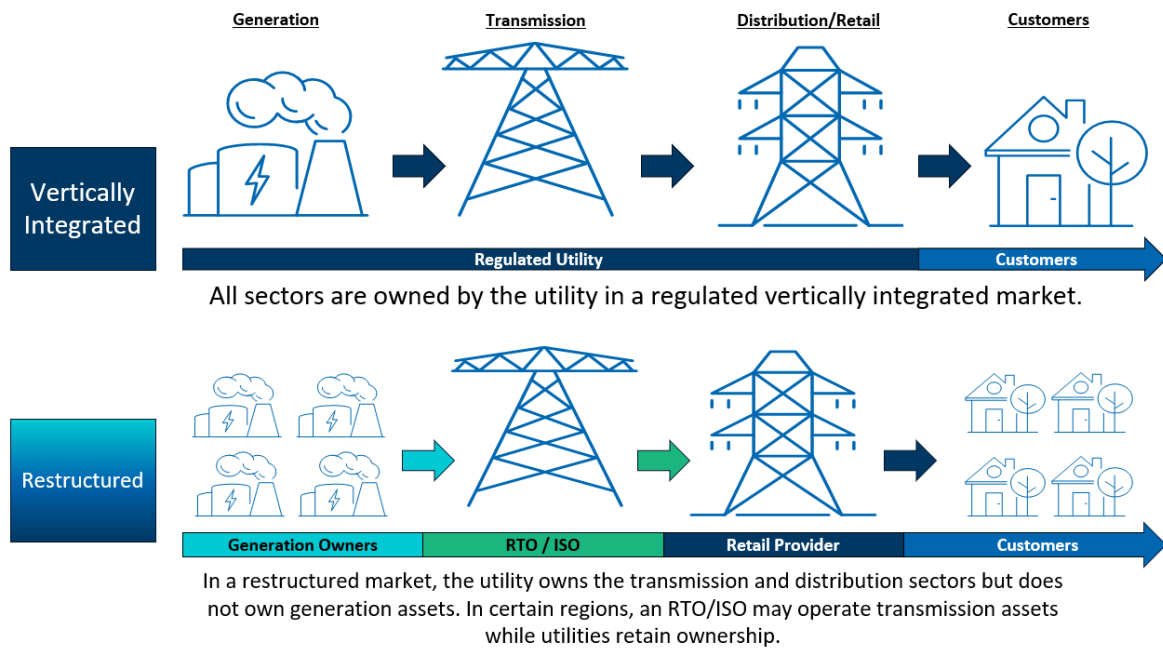
<sup>7</sup> FTI Analysis

## Competitive Generation Ownership Benefits in Maryland Electricity Market Structures

The electric grid consists of three interconnected systems: generation, transmission, and distribution. Power plants generate electricity, high-voltage transmission lines move that power over long distances, and low-voltage distribution lines deliver it directly to consumers. The Federal Energy Regulatory Commission (“FERC”) regulates interstate commerce, including most long-distance transmission. States retain jurisdiction over generation, intrastate transmission, and distribution. To manage this interconnected system, many regions utilize a Regional Transmission Organization (“RTO”) or Independent System Operator (“ISO”). These neutral, independent entities coordinate the movement of electricity and manage competitive markets.

Over time, states have generally adopted one of two electricity market structures: “vertically integrated” or “restructured” markets.

Figure 1: Vertically Integrated vs. Restructured Electricity Markets<sup>8</sup>



Under the vertically integrated model, states grant utilities a monopoly on power generation, in addition to transmission and distribution, subject to oversight by state regulatory agencies (“regulators”). Utilities are guaranteed cost recovery plus a reasonable rate of return on their capital expenditures (“CAPEX”), called the “rate base.” The financial risk associated with a utility’s

<sup>8</sup> Vertically integrated utilities may operate within an RTO/ISO by retaining ownership of their generation and transmission assets while ceding functional control of the grid and wholesale market dispatch to the independent regional operator to ensure coordinated energy flow across the region.

rate base is implicitly underwritten by ratepayers who must pay for these investments even if the final costs are higher or final benefits lower than a utility's initial estimate.<sup>9</sup>

To manage this risk, regulators are empowered to oversee the costs that utilities recover from ratepayers through several monitoring and enforcement mechanisms. In most states, vertically integrated utilities must follow a multi-step process to receive regulatory approval and cost recovery for new capital investments. This multi-stage oversight mechanism is necessary to ensure utilities act prudently because rate-of-return regulation creates a natural incentive for utilities to overspend on the projects that contribute to their rate base, often referred to as “gold-plating.” Customers must pay the costs for utility projects, plus a return, and may do so even for projects that ultimately prove to be unneeded (i.e., “stranded costs”).

Several states, including Maryland, addressed the limitations of vertically integrated electricity markets through a restructuring of the electric industry. Maryland legislation passed in 1999 effectively required utilities to divest from their power-generating assets. Instead of generating power and selling it directly, utilities started purchasing electricity through new competitive wholesale markets and selling it to customers.<sup>10</sup> IPPs took on the role of developing and operating the power plants that supplied these wholesale markets and now supply nearly all power in the state of Maryland.

Competition drives down the cost of generating electricity by stimulating innovative improvements to plant efficiency and enabling flexible responses to price signals. Retail prices paid by customers include the cost of generating, transmitting, and distributing electricity; taxes; and all other fees.<sup>11</sup> As shown in Figure 2 below, retail prices have risen more than twice as fast over the last 15 years in regions with vertically integrated markets relative to Maryland and other restructured markets. Had retail prices in Maryland increased at the same rate as vertically integrated markets, customers in Maryland would have paid over \$11.5 billion more for their electricity over the 15 year period.

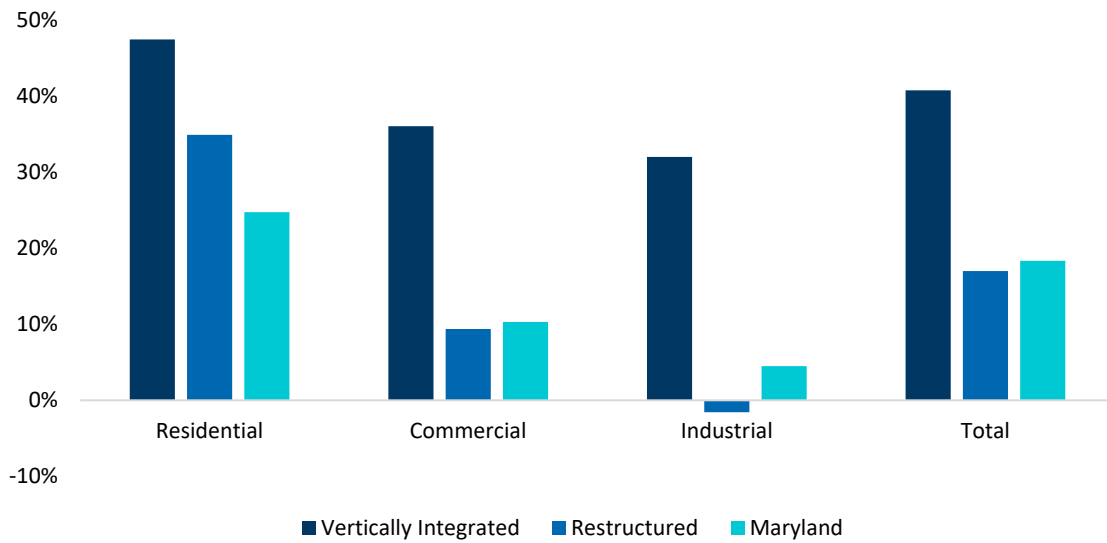
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<sup>9</sup> For utility-owned portions of electric service, state regulators oversee customer rates, ensuring they cover a utility's operational and investment costs, along with a reasonable rate of return. In contrast, the costs of generation and purchased power is passed on to customers without markup.

<sup>10</sup> Maryland's restructuring also created “retail competition,” where third-party companies could sell power directly to consumers. Customers who did not elect a third-party supplier default to the utility's SOS, where utilities sell power purchased from the competitive wholesale market.

<sup>11</sup> EIA, *Electric Power Annual Technical Notes* ([link](#)); OPC, *Utility Rates and Basics* ([link](#))

Figure 2: Percentage Retail Price Change by Market and Customer Type (2010-2024)<sup>12</sup>



The restructured generation model also shifts the risk of project delays and cost overruns from ratepayers to private companies because IPPs recover the cost of building and operating power plants by selling electricity on the competitive wholesale market, not through regulated rates that guarantee cost recovery. When an IPP exceeds a power plant's construction budget or operates a plant inefficiently, IPP shareholders incur the financial loss rather than captive utility customers. Restructuring also protects ratepayers by shifting the risk of stranded assets to private shareholders. With current forecasts predicting significant demand growth to serve data center load, there is risk of overbuilding if new large power consumers fail to materialize or power demand declines before the end of new assets' useful lives.<sup>13</sup> Were utilities to build new generators based on these high forecasts, customers could end up paying for assets they do not need. Under the current restructured model, that stranded asset risk is borne by private investors, not Maryland customers.

Maryland recognized the potential benefits of competition and responded by restructuring its electricity market decades ago. State policymakers concluded that allowing utilities to own generation stifled innovation and prevented the electricity market from accessing the inherent benefits of competitive markets observed in other industries. The model proposed by utilities today, in which both utilities and independent producers own power plants, would put the competitive benefits realized by Maryland at risk.

### History of Restructuring in Maryland

Prior to the 1990s, electric service in the U.S. was primarily provided by vertically integrated utilities that owned generation, transmission, and distribution assets. Under this model, utilities had significant market power over pricing and resource planning due to their ownership and control

<sup>12</sup> EIA, *EIA-861 Annual Electric Power Industry Report* ([link](#))

<sup>13</sup> PJM, *PJM Long-Term Load Forecast Report* ([link](#))

across the electricity supply chain. Maryland formally identified the potential for electricity market restructuring to deliver lower electricity prices in 1994. An investigation by the Maryland Public Service Commission (“PSC”) into restructuring concluded that although it was not in the public interest at the time, largely because the rules for wholesale competition had not been established at the federal level and no other states had restructured their electricity industries, they did “see the need to begin a process of sensible and progressive change,” because, “when a competitive market can be established, it can create strong incentives to cut costs, increase efficiency, and develop new products and services.”<sup>14</sup>

Maryland began restructuring with the passage of the Electric Customer Choice and Competition Act of 1999, which took effect in July 2000.<sup>15</sup> This legislation effectively forced the separation of the function of generating power, best structured as a competitive market where costs are driven down by many suppliers competing for market share, from the function of delivering power, which is considered a natural monopoly due to the extremely high up-front costs and complexity of building and operating power grid infrastructure. To comply with restructuring, Baltimore Gas & Electric (“BG&E”) and Delmarva Power and Light Company (“DPL”) transferred their generating assets to competitive affiliate power generation companies, while Potomac Electric Power Company (“PEPCO”) auctioned off their assets to unaffiliated companies.<sup>16,17</sup> Under the new retail competition model created by the legislation, customers could purchase electricity from a third-party supplier instead of a utility. For customers who did not choose a third-party supplier, the legislation required utilities to procure power from IPPs, who compete with one another, at regular auctions and deliver it to those customers instead of generating the power themselves.

Under Maryland’s restructured framework, utilities stopped generating power and began to focus on their regulated transmission and distribution businesses. As market forces evolved after restructuring, these dynamics increasingly favored the separation of competitive generation from regulated utility operations, as seen through Exelon’s divestiture of Constellation in 2022.<sup>18</sup> Separating generation from transmission and distribution shifted the financial risk of building and operating generation assets away from captive ratepayers and onto IPP shareholders, who must recover their costs through competitive wholesale market revenues rather than from captive ratepayers.

Allowing utilities to re-enter the business of generating power, even to a limited degree, would be a step backward for Maryland’s electricity industry and would create an incentive for utilities to unfairly favor their own facilities. For example, utilities could use their influence over the interconnection and siting process to place their facilities in locations that are expected to receive

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<sup>14</sup> PSC, Case 8678, *Order 72136 (Docket No. 101)* ([link](#))

<sup>15</sup> PSC, *State Analysis and Survey on Restructuring and Re-Regulation* ([link](#))

<sup>16</sup> During Maryland’s restructuring, an “affiliate” was defined as any entity that controls, is controlled by, or holds an economic interest in the utility. These generation affiliates, like existing IPPs, must compete in the competitive market and are not guaranteed return on their investments from Maryland ratepayers.

<sup>17</sup> PSC, *State Analysis and Survey on Restructuring and Re-Regulation* ([link](#))

<sup>18</sup> Joe Cornell, *Exelon Completes Spin-Off of Constellation Energy* ([link](#))

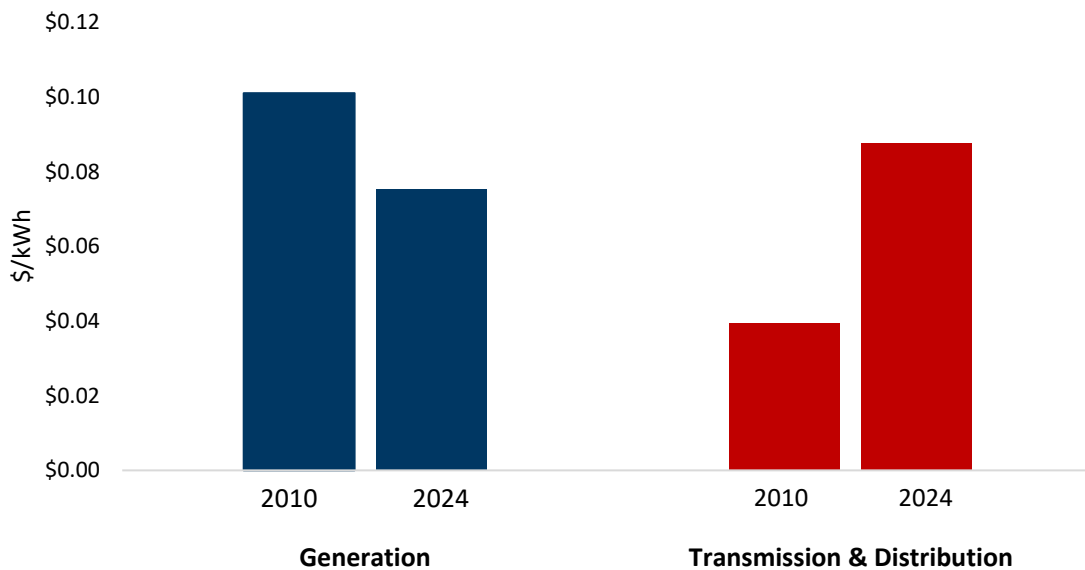
higher prices from existing or potential transmission constraints. Similarly, utilities could attempt to influence regional transmission planning and favor projects that most benefit their own assets.

**Affordability and Reliability**

Since 2010, the cost of power generated and delivered to residential customers in Maryland has declined by over 25%, reducing bills for the average residential customer by nearly \$25 per month. In contrast, the cost of transmission and distribution services provided by utilities has increased steadily, more than doubling over the last 15 years, increasing bills for the average residential customer by almost \$45 per month. This increase in transmission and distribution costs has more than offset the savings to customers from declining generation costs, such that the average residential customer bill is over 20% higher now than it was in 2010.

Electricity infrastructure in Maryland and across the U.S. is in significant need of repairs, upgrades, and additions, all of which will require significant utility capital. The Edison Electric Institute (“EEI”), a trade organization that represents investor-owned utilities (“IOUs”), projected that IOUs will invest more than \$1.1 trillion into the grid between 2025 and 2029, while Exelon’s Fall 2025 investor report shows that across BG&E, PEPCO, and DPL, Exelon plans to spend \$11.6 billion from 2025 to 2028 on electric transmission and distribution.<sup>19,20</sup>

*Figure 3: Maryland Residential Customer Bill Components<sup>21</sup>*



Utilities satisfy their core mandate to provide safe and reliable electricity service by investing in transmission and distribution to maintain and enhance the physical power grid that moves electricity from power plants to homes and businesses. Over the last 10 years, despite transmission

<sup>19</sup> Exelon, *Fall 2025 Investor Presentation* ([link](#))

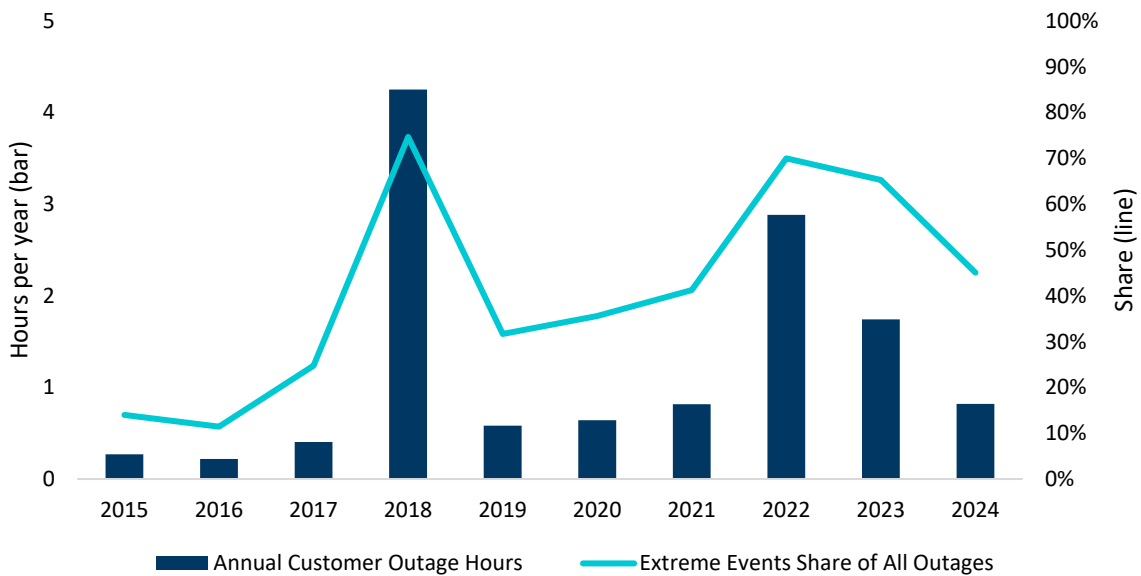
<sup>20</sup> Edison Electric Institute, *Strengthening America’s Energy Infrastructure to Increase Reliability & Lower Costs* ([link](#))

<sup>21</sup> EIA, *EIA-861 Annual Electric Power Industry Report* ([link](#))

and distribution spending rising steadily, maintaining reliable service has become increasingly difficult for utilities, in large part due to extreme weather events.

Recent survey results from Maryland’s Office of the People’s Counsel (“OPC”) note that Marylanders “don’t want to pay for marginal improvements” and “are most concerned about major outage events.” As shown in Figure 4, the impact of outages attributable to “major events” has been growing over the last 10 years.<sup>22</sup> Prior to 2022, major events only accounted for approximately 33% of the average total time customers experienced outages over the year, but in recent years that impact has nearly doubled to approximately 60%.

Figure 4: Maryland Reliability Trends<sup>23</sup>



This trend has emerged despite greater utility spending on transmission and distribution, which will only accelerate in the coming years as Exelon plans to “invest \$38 billion over the next four years to strengthen and modernize the T&D system” across all of its service territories in the Mid-Atlantic and Northern Illinois.<sup>24</sup> The effectiveness of these future investments is questionable: A recent report from the OPC concluded that utilities “are increasingly investing in capital-intensive projects that fail to deliver corresponding improvements in reliability or resilience.”<sup>25</sup> For example, the report notes that increased spending has actually been associated with declining reliability in BG&E’s service territory, while at the same time the company overspent its combined transmission and distribution CAPEX budget by over \$75 million in 2024, a more than 20% increase over budget.

<sup>22</sup> The EIA-861 survey collects reliability information measured by the System Average Interruption Duration Index (“SAIDI”), with and without Major Event Days (“MED”). SAIDI measures outages as the sum of customer outage hours divided by the number of customers served. MED is an abbreviation for Major Event Days, which are defined as days with a SAIDI more than 2.5 standard deviations from the historical average.

<sup>23</sup> EIA, *EIA-861 Annual Electric Power Industry Report* ([link](#))

<sup>24</sup> *Exelon Sustainability Report 2024* ([link](#))

<sup>25</sup> PSC, Case 9353, *OPC Comments on the Maryland Electric Distribution Companies’ 2024 Annual Reliability Performance Reports* ([link](#))

Utilities must focus on delivering these projects as efficiently and on as short a timeline as possible. Taking on the additional responsibility of building generation at a time when the electric grid requires historic levels of investment in transmission risks distracting utilities from their core function and places an unnecessary risk on Maryland ratepayers.

### **Improving Customer Outcomes in Maryland**

Since 1956, Maryland has been a member of the Pennsylvania-New Jersey-Maryland Interconnection (“PJM”), the RTO that is responsible for managing the transmission grid and balancing electricity supply and demand in a competitive wholesale market across 13 states and the District of Columbia. The integration of Maryland’s electricity market into the combined footprint of the PJM grid grants access to out-of-state generation provided by a diverse pool of resources to meet growing demand and reliability requirements in the state.

As a member of PJM, Maryland benefits from several distinct mechanisms. First, the expansive geographic footprint of PJM increases the diversity of accessible resources, allowing the state to import surplus power from regions with excess generation at any given time. Power transfers throughout the region also reduces the amount of power capacity Maryland must hold in reserve. Because peak electricity demand does not occur simultaneously across the entire PJM footprint, the total amount of generation capacity needed to maintain overall PJM reliability is significantly lower than the sum of each state’s individual capacity requirements. Lastly, PJM’s competitive energy and capacity markets force IPPs to compete on the cost of generation, with generation dispatched across the region based on lowest marginal cost, forcing out inefficient generators that cannot match the marginal cost of newer, more efficient or lower-cost units.

Historically, Maryland has imported power to meet a significant portion of its needs.<sup>26</sup> This is not an indication that the state lacks adequate local resources, but rather the result of the wholesale market operating economically. As the largest regional grid operator in the United States, PJM leverages its scale to generate significant economic efficiencies through the coordination of wholesale markets, strategic transmission planning, and centralized grid management. These integrated operations result in estimated cost reductions for regional consumers totaling between \$3.2 billion and \$4 billion each year.<sup>27</sup> If not for this participation, the state would be required to build and maintain enough generation to meet peak demand, plus a reserve margin, strictly with local generation assets. This would necessitate maintaining expensive peaking plants that might only run for a few hours per year during the periods of highest demand.

Existing plants in Maryland are often available to generate additional power but not dispatched by the grid operator because it is less expensive to import power from out-of-state resources. It is generally most economically efficient to site generation near optimal fuel sources, for example wind farms in regions where the wind blows faster and more often, or natural gas plants in regions

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<sup>26</sup> PJM, *Maryland Needs Energy Infrastructure* ([link](#))

<sup>27</sup> PJM, *Fact Sheet for Policy Makers* ([link](#))

with direct access to low-cost shale gas. A lack of local generation is not the critical vulnerability for Maryland because transmission allows for the lowest cost power to flow freely into the state.

In 2023, Talen Energy, the owner of two large coal plants in Maryland, determined that operating the aging units was no longer economically viable and notified PJM that it intended to deactivate the facilities in 2025. PJM determined that the retirement of these units would result in severe reliability violations, and that the units could not be taken offline before a robust replacement solution was put in place.<sup>28</sup> While various options were considered to address the issues presented by the retirement of these units in Maryland, it was ultimately determined that additional transmission capacity that allowed for increased power imports into Maryland was the optimal solution. Expanding transmission was determined to be the best option because it allowed Maryland to access diverse, lower cost, out-of-state resources while avoiding the long-term inefficiency of building more expensive local generation.

The Brandon Shores replacement project significantly enhances Maryland’s ability to import power by creating a high-capacity transmission corridor. A power flow analysis commissioned by the OPC concluded that the increase in Maryland’s import capabilities attributable to the Brandon Shores replacement project would be “sufficient to accommodate at least 2,980 MW of load growth” and “exceed PJM’s projected 2028 peak load in Maryland’s service territories by more than 24 percent,” enabling Maryland’s grid to meet demand until at least 2042.<sup>29</sup>

Additionally, key cost differentials between new in-state generation relative to new out-of-state generation imported into Maryland further supports the conclusion that importing power is preferable to building potentially unnecessary and expensive in-state generation, based on an evaluation of new 800 MW natural gas combined cycle (“NGCC”) plants built in Maryland and neighboring Pennsylvania.

### Natural Gas Fuel Prices

Natural gas generators are long-lived assets, and projected fuel costs over a 30-year technical life suggest a stark difference between delivered natural gas prices in Maryland and Pennsylvania. Pennsylvania sits atop the Marcellus and Utica Shale Basins and is one of the largest natural gas producers in the United States. Maryland produces almost no natural gas and acts purely as a downstream consumer. As a result, it is generally less costly to deliver gas in Pennsylvania due to its proximity to the production regions. A power plant located in Maryland could pay a significant natural gas price premium relative to Pennsylvania, particularly if import pipelines into Maryland are constrained.

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<sup>28</sup> PJM, *PJM Working to Mitigate Reliability Impacts of Retiring Wagner Units* ([link](#))

<sup>29</sup> OPC, *Impact of Brandon Shores deactivation projects on Maryland generation needs* ([link](#))

Since 2020, natural gas delivered to Maryland citygates has been priced \$1.37 higher per MMBtu on average than gas delivered to Pennsylvania citygates.<sup>30,31</sup> As shown in Table 1, an 800 MW NGCC operating over a 30-year technical life located in Pennsylvania would pay \$1 billion less in fuel costs.

*Table 1: Projected Natural Gas Fuel Costs (800 MW NGCC at 60% Annual Capacity Factor)<sup>32</sup>*

State	30-year Fuel Consumption (Million MMBtu)	Delivered Price (\$/MMBtu)	Fuel Costs (\$MM)
MD	784	\$6.64	\$5,203
PA	784	\$5.27	\$4,129
Difference	-	\$1.37	\$1,073

### Natural Gas Infrastructure

As shown in Table 2 below, a review of the most recently completed gas pipeline projects in Maryland and Pennsylvania indicates that constructing a new lateral pipeline to connect to the bulk natural gas transportation system for a NGCC plant may be more than 60% more expensive in Maryland than Pennsylvania.

*Table 2: Projected Gas Pipeline Interconnection Costs (800 MW NGCC)*

State	Project Name	Completion Year	Cost/Mile (2025 \$MM)	Average Cost/Mile (2025 \$MM)	Connection Length (Miles)	Connection Cost (2025 \$MM)
MD	Line MB extension project	2014	\$8.6	\$9.2	13.1	\$120
	Rock Springs Expansion	2016	\$9.8			
PA	UGI Sunbury Pipeline	2017	\$6.8	\$5.7		\$74
	Line N to Monaca Project	2019	\$5.7			
	Birdsboro Pipeline Project	2018	\$4.6			

In addition, Pennsylvania boasts a robust natural gas pipeline network that has been expanded and maintained over many years due to the state's role as a top natural gas producer. A new natural gas plant sited in Pennsylvania would likely have more access to large interstate pipelines than a plant located in Maryland. This could potentially avoid the need to expand the bulk natural gas transportation system, which can be costly. For example, the proposed Capital Area Project on the Eastern Gas Transmission and Storage pipeline would increase deliverability from Pennsylvania into Maryland and Virginia by 67,500 DTH/day to serve gas utility demand.<sup>33</sup> This marginal increase is estimated to cost over \$170 million and require upgrades to three separate compressor stations but would only supply approximately half the fuel consumed by an 800 MW NGCC.

<sup>30</sup> A citygate is "a point or measuring station at which a distributing gas utility receives gas from a natural gas pipeline company or transmission system." ([link](#))

<sup>31</sup> EIA, *EIA-857*; EIA, *EIA-910* ([link](#))

<sup>32</sup> Annual capacity factor is based on historical monthly capacity factors for similar units, as detailed in the Appendix.

<sup>33</sup> FERC, *Notice of Application and Establishing Intervention Deadline; Eastern Gas Transmission and Storage, Inc.* ([link](#))

Projects to expand the bulk natural gas transportation system are also subject to a complex regulatory and legal environment, spanning many different local, state, and federal jurisdictions. This can lead to construction delays, cost overruns, or even project abandonment after capital investments have been made. Table 3 illustrates the high variability in timelines and costs for recent pipeline expansions large enough to support the fuel requirements of an 800 MW NGCC.

*Table 3: Example Natural Gas Pipeline Expansion Costs<sup>34</sup>*

State(s)	Project Name	Application Year	In-Service Year	Cost (2025 \$MM)	Additional Capacity (DTH/day)	2025\$ per DTH/day
VA,NC	Southgate Amendment Project (MVP)	2025	2028	\$524	550,000	\$953
PA,MD,NJ	Regional Energy Access Expansion Project	2021	2024	\$978	829,400	\$1,180
NY,MA,CT	Atlantic Bridge Project	2015	2021	\$762	132,705	\$5,741
NY,CT,MA,RI	Algonquin Incremental Market	2014	2017	\$1,519	342,000	\$4,443
NY,NJ,CT	Ramapo Project	2006	2008	\$404	325,000	\$1,243
MA	HubLine Project	2000	2003	\$565	230,500	\$2,451

Detailed assumptions, calculations and sources for the natural gas analysis are provided in the Appendix.

## Assessing Customer Impacts of Utility-Owned Generation

### Customer Risks of Utility-Owned Generation

#### Utility Project Management Failures and Cost Control Deficiencies

Under rate of return regulation, the financial risk of large, complex generation projects is transferred away from investors and onto captive ratepayers. If a utility project is delayed or exceeds its budget, the utility is most often able to recover those additional costs, plus a rate of return, directly from customers — sometimes even when assets have become stranded.

Projects that have been guaranteed by utility ratepayers frequently feature significant cost overruns and delays, as has been the case in Maryland. For example, BG&E’s transmission project to support the Brandon Shores deactivation has seen its budget increase from \$739 million to \$1.5 billion, a 105% overrun. Multiple planning and operational oversights have been cited as contributing to this increased cost, including underestimated equipment cost, a substation redesign, and additional reviews of design and engineering plans.<sup>35</sup>

<sup>34</sup> EIA, *Pipeline Projects, October 2025* ([link](#)); FTI analysis of Federal Register FERC Notices

<sup>35</sup> PJM, *Reliability Analysis Update* ([link](#))

Cost overruns and projects delays in Maryland have not been limited to electric utilities. Maryland’s gas utilities have also demonstrated an inability to control costs when granted additional flexibility from regulators. In 2013, the state passed the STRIDE Act to encourage proactive replacement or repair of gas infrastructure by authorizing early recovery of project costs during, or even before, construction.<sup>36</sup>

Under the STRIDE framework, utilities are directed to propose infrastructure replacements and repairs to the PSC that they expect to complete in the upcoming five-year period, along with a budget. In 2022, the PSC found that Washington Gas had, “overpromised and under-delivered, depriving customers of the benefits anticipated under the STRIDE statute, including accelerated pipeline replacement” by “materially deviating from its projections regarding the amount of work that would be completed, the costs of the projects, and the benefits.”<sup>37</sup> In four out of five years, the utility had completed only 60% of its planned main distribution pipeline mileage and yet remained on track to exceed its five-year budget. In 2025, the STRIDE legislation was significantly revised so that utilities would be required to make stronger justifications for projects in terms of the magnitude of the risk addressed and the cost-effectiveness of the proposed solution.<sup>38</sup>

Additional examples of costs being passed on to customers for budget overruns, delays and project failures include:

- An abandoned \$1 billion joint PEPCO-DPL transmission project, the Mid-Atlantic Power Pathway, cost ratepayers \$80 million over three years despite never breaking ground. The costs of abandonment were calculated in a “black box” settlement between the project owners, state regulators, and other stakeholders.<sup>39</sup>
- The Potomac-Appalachian Transmission Highline project ultimately cost ratepayers \$250 million despite never reaching commercial operation.<sup>40</sup> The project was proposed in 2007 to bring power generated by West Virginia coal plants to high-demand areas of Virginia and Maryland.<sup>41</sup> The project was canceled in 2012 after changing market conditions greatly reduced the projected benefits of the project, making it uneconomical to complete.<sup>42</sup>
- Virginia’s State Corporation Commission staff estimated in 2020 that continuing to operate Dominion’s coal-fired Virginia City Hybrid Energy Center would cost ratepayers \$472 million over ten years compared to discontinuing plant operations.<sup>43</sup>

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<sup>36</sup> OPC, *STRIDE* ([link](#))

<sup>37</sup> PSC, Case 9486, *Order 90099* ([link](#))

<sup>38</sup> Emily Scarr, *Factsheet: Ratepayer Protection Act of 2025* ([link](#))

<sup>39</sup> FERC, *MAPP Offer of Settlement*, (Docket ER13-607) ([link](#))

<sup>40</sup> FERC, *Commissioner Christie’s Concurrence to Letter Order Approving PATH Settlement*, 185 FERC ¶ 61,198 (2023) ([link](#))

<sup>41</sup> Ethan Howland, *FERC transmission incentives ‘way out of whack,’ drive up consumer costs: Commissioner Christie* ([link](#))

<sup>42</sup> *PJM Interconnection, LLC*, 141 FERC ¶ 61,177, at P 6 (2012) ([link](#))

<sup>43</sup> IEEFA, *Virginia Coal Plant’s Future Isn’t Bright: Preparation for Transition Should Commence Now* ([link](#))

- The cost of Mississippi Power’s Kemper County IGCC power plant increased from \$2.9 billion to more than \$7.5 billion.<sup>44,45</sup> Although the public service commission ordered the utility to bear the costs of the failed coal-to-gas project, ratepayers were still charged for the costs associated with the natural gas power plant component of the project. In 2016, whistleblowers alleged that poor utility project management was responsible for the cost overruns.<sup>46</sup>
- In 2023, El Paso Electric completed the Newman 6 natural gas combined-cycle power plant 6 months behind schedule and 27% over the initial budget.<sup>47</sup> Whether ratepayers are responsible for the increased costs will be determined by the Texas public utility commission. However, a panel of Texas administrative law judges recommended that the full \$217 million should be passed on to El Paso Electric’s customers in Texas and New Mexico.<sup>48</sup>

Utilities in Maryland no longer have institutional expertise building and operating generation assets; indeed, as noted above, Exelon divested from its generating business and expertise completely in 2022. It is unreasonable to expect that they will be capable of building new generators more efficiently, faster, or at lower cost than IPPs. Examples like those discussed above demonstrate that utilities are capable of severely underestimating costs and timelines. Allowing utilities to rate-base new generation in Maryland would leave ratepayers financially responsible for projects that may prove to be unneeded or uneconomical.

If utilities are interested in building new generation, they can establish competitive affiliates that can compete with IPPs on even footing. The fact that they wish to retain a cost-of-service model while participating in the competitive market suggests reliance on cost recovery mechanisms that guarantee costs and a return are covered even if there are management failures.

### The Regulated Utility Cost-Plus Model

In the vertically integrated utility model, utility profits grow when they are allowed to spend more on capital investments, increasing the utility’s “rate base.” When increased electricity demand creates a need for new infrastructure like transmission lines, utilities earn a profit on the cost of developing those projects. However, recent demand growth for Maryland utilities has been limited, as seen in Figure 5. Without load growth driving the need for additional infrastructure, utilities can turn to other means of increasing profits.

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<sup>44</sup> The relevant CCS portion of Kemper County CCS was officially cancelled in 2017, though onsite natural gas combined cycle assets have been generating power since 2014.

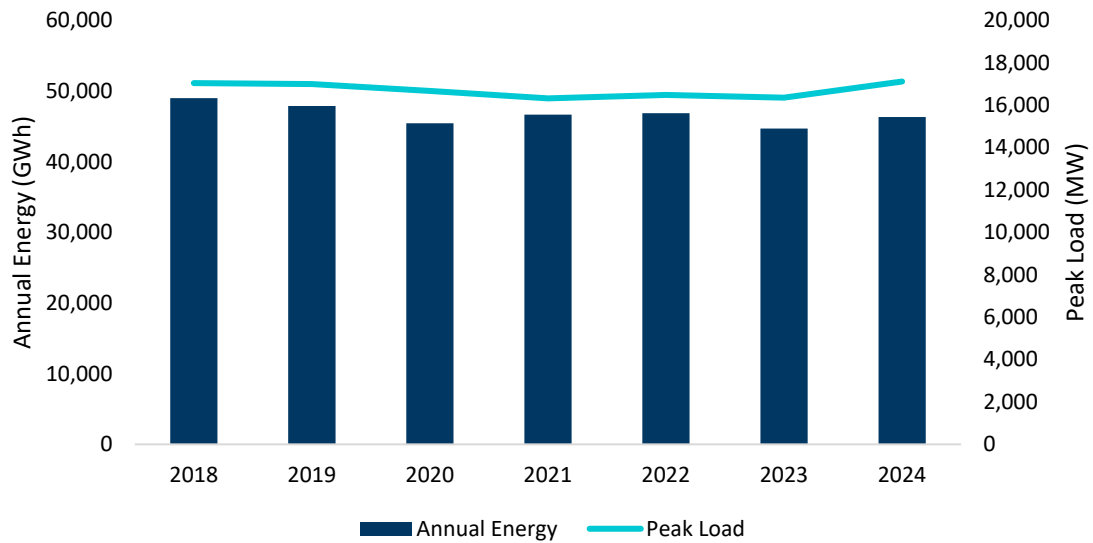
<sup>45</sup> Darrel Proctor, *Regulators Back Settlement for Costs of Failed Kemper IGCC Project* ([link](#))

<sup>46</sup> Gavin Bade, *Southern suspends work on Kemper coal gasification units* ([link](#))

<sup>47</sup> Diego Mendoza-Moyers, *As El Paso Electric rate increase looms, some say utility is seeking to make too much profit* ([link](#))

<sup>48</sup> Julia Spencer, *El Paso Electric’s rate hike faces resistance as judges recommend lower profit margin* ([link](#))

Figure 5: BG&E, PEPCO, and DPL Annual Energy and Peak Load<sup>49</sup>



The amount of profit, or rate of return, that a utility is allowed to earn on its rate base is determined by state regulators during a rate case. Regulators exercise the most influence over a key component of rate of the return, the utility’s allowed return on equity (“ROE”).<sup>50</sup> In 2024 alone, Maryland utilities were allowed to earn \$399 million from ROE, or about \$200 per customer.<sup>51</sup>

During a rate case, utilities often justify requests for a higher ROE with the argument that an increase is necessary to attract investors, who want high rates of return. If regulators approve an increase, then the utility can earn more profits on their existing rate base without making new investments; however, as seen in Figure 6, the authorized ROE for utilities that operate in Maryland has been stable over the past 15 years.

Utilities can also increase the size of the rate base by choosing capital-intensive projects to address the electricity grid’s needs. This means that, absent rules that direct utilities to invest in cost-effective solutions before pursuing capital intensive projects, utilities may choose not to pursue less expensive solutions like distributed energy resources or demand response initiatives. A recent report on the state of virtual power plants, essentially large groups of synchronized “smart” meters that can reduce electricity demand (and therefore prices) during peak hours, found evidence that suggests utilities have been obstructing virtual power plant providers from accessing PJM’s capacity market by refusing to share necessary smart meter data.<sup>52</sup>

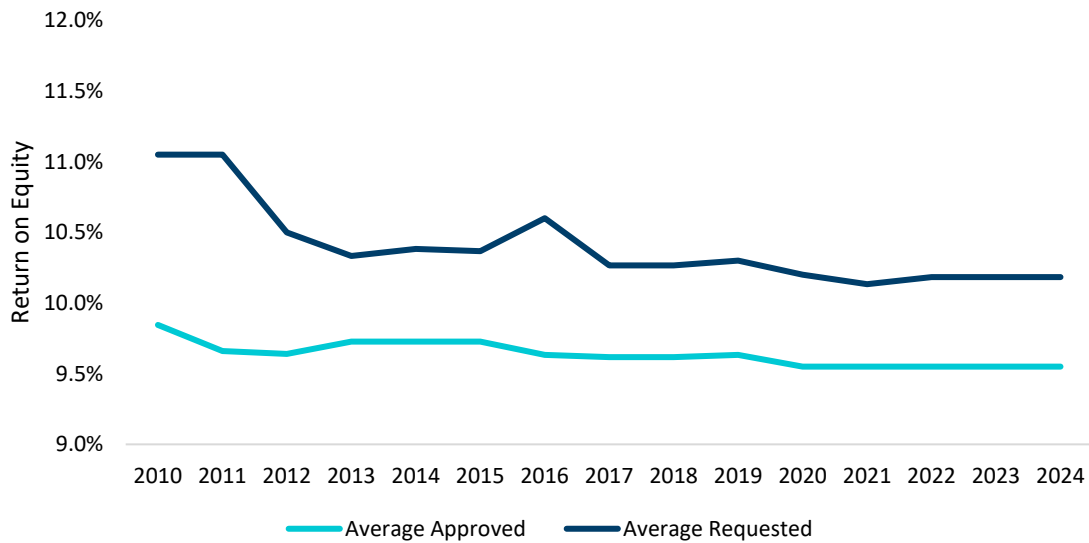
<sup>49</sup> EIA, *EIA-861 Annual Electric Power Industry Report* ([link](#)) ([link](#)); PJM, *Network Service Peak Loads* ([link](#)). Network Service Peak Load data for PEPCO includes customers in the District of Columbia.

<sup>50</sup> ROE is the rate of profit utilities are permitted to earn on capital investments.

<sup>51</sup> FTI calculations; EIA, *EIA-861* ([link](#)); PSC, BG&E Case 9692, *Order 90948* ([link](#)); PSC, PEPCO Case 9702, *Order 91181* ([link](#)); PSC, DPL Case 9681, *Order 90445* ([link](#))

<sup>52</sup> Open Markets Institute, *Fair and Open Markets for Virtual Power Plants* ([link](#))

Figure 6: Average Requested vs. Approved Return on Equity (BG&E, PEPCO, DPL)<sup>53</sup>



Utilities can also expand their rate bases through “gold-plating” capital projects, increasing the size or complexity and unnecessarily adding costs. For example, if a transmission line needs to be upgraded, utilities are incentivized to convince the relevant transmission planner to approve a large, expensive transmission line instead of making smaller investments in grid-enhancing technologies that increase transmission capacity through improvements to existing infrastructure.

Maryland utilities sometimes attempt to increase profits by asking the PSC to move operational expenditures into the rate base. The PSC makes difficult, sometimes controversial decisions on whether to approve these additions. For example, since 2016, BG&E paid the City of Baltimore to lease space in an underground tunnel system of wires, including electricity distribution equipment. In 2023, BG&E signed a new deal with the City that allowed them to pay in-kind for access from 2023-2027 by working on the tunnels.<sup>54</sup> BG&E argued in its most recent rate case proposal that the cost of access to the tunnels should be reclassified from an operational expense to a capital expense because of their work on the tunnels.<sup>55</sup> The PSC approved this reclassification, thereby allowing BG&E to start earning a profit on, and raise customer bills for, what had been a rental fee.

Maryland’s current system allows utilities to earn more when they spend more. Because utilities make a guaranteed profit based on how much they spend on physical assets, they have little incentive to control costs and save customer money.

<sup>53</sup> FTI analysis of Maryland utility rate case filings.

<sup>54</sup> Wambui Kamau and Kristen Mosbrucker, *Baltimore City approves controversial conduit deal, two members don’t show up* ([link](#))

<sup>55</sup> OPC, *OPC appeals regulators’ decision allowing BGE to bill customers for profits on Baltimore City conduit system work* ([link](#))

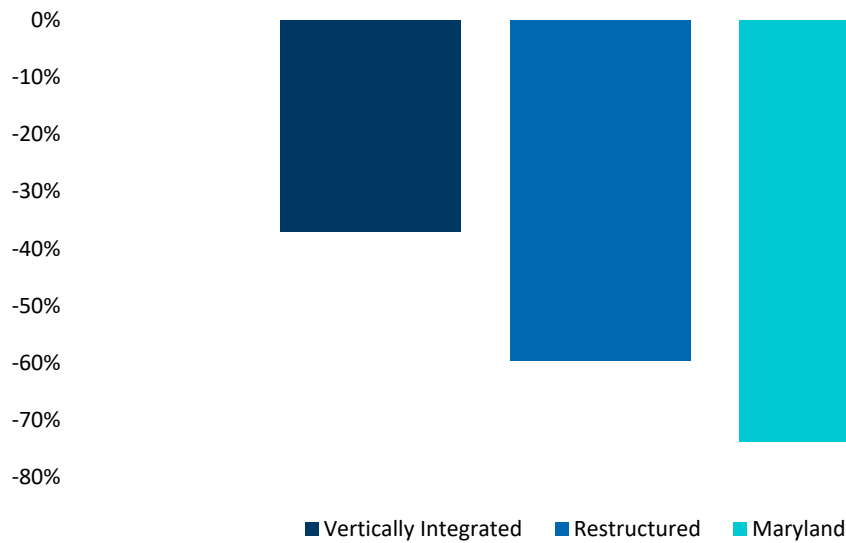
### Customer Benefits of Competitive Generation

IPPs shield ratepayers from financial liability, as they recover costs only through competitive market revenues, making their investors the sole bearers of failure risk. In contrast, construction delays, cost overruns and potential stranded investments are transferred directly onto captive consumers under rate-based utility models.

An IPP can only recover the costs of building a power plant by selling electricity into the competitive market. An IPP's investors take on the risk that revenues from electricity sales may not cover the cost of their investment. If the plant does not consistently generate sufficient revenue, investors lose their investment. Utility shareholders do not take on this risk because utilities are guaranteed a return of and on their investment. If a project goes over budget or fails, utilities increase electricity rates to recover unexpected costs. Ratepayers, not investors, take on the risk of utility-owned power plants.

Unlike utilities, which earn on deployed capital once projects are approved, IPPs must compete with one another under uncertain market conditions. As a result, private generation owners are more responsive to changes in price signals and market conditions. For example, in the mid-2000s the shale revolution in the U.S. dramatically impacted the relative cost of coal- and natural gas-fired generation. Figure 7 below shows how restructured markets shifted away from coal-fired generation more rapidly than vertically integrated markets as natural gas generation became more economic. Conversely, coal-fired generation was more likely to be retained in vertically integrated markets, in part because utilities were able to continue earning a return on those investments even when the plants were no longer cost-competitive.

Figure 7: Change in Coal Capacity from 2005-2024 by Market Type<sup>56</sup>



### Hybrid Ownership Model Risks Chilling Private Investment

As many states moved away from vertically integrated utility models following the wave of electric sector restructuring in the late 1990s, they established competitive wholesale and retail electric markets that supported equal playing fields for IPPs to compete, provided more favorable prices for customers, and spurred innovation across the sector. Reintroducing utility ownership of generating assets risks undermining the consumer and reliability benefits that restructuring has provided for over two decades.

A hybrid ownership model, where utilities would regain the rights to own certain generating assets, would introduce regulatory uncertainty and create an unsteady market for private developers. Investors rely on free and fair competitive markets to provide trustworthy price signals. Because utility-owned investments can recover development costs outside of capacity and energy markets, IPPs would lose visibility into true market prices created by competitive supply and demand dynamics. This instability would discourage private investment and ultimately undermine the competitive market framework. Facing competition from utilities with guaranteed cost recovery would reduce private investment in Maryland and shift investor interest to states where markets remain competitive.

Regulated utilities that wish to participate in the generation space can and should do so through competitive affiliates that compete on equal footing with IPPs. Allowing regulated utilities to own and rate base new generation assets is unnecessary, would directly introduce regulatory risk, and would destabilize the free and fair competitive market Maryland established over 25 years ago.

The conflicts associated with utility ownership of competitive generation are well-documented and have prompted industry leaders to exit the space entirely. Following Exelon's acquisition of Constellation Energy Group in 2012, Exelon became a dominant market force in U.S. power

<sup>56</sup> EIA, *EIA-860 Annual Electric Generator Report* ([link](#))

markets. However, strategic considerations eventually led Exelon to separate its regulated utilities from its competitive generation business in 2022. This move allowed the new Exelon to “focus on customer and community interest in clean, reliable, and affordable energy delivery systems” while providing the “financial and strategic independence to focus on its specific customer needs, while executing its core business strategy.”<sup>57</sup>

## Conclusion

Allowing utilities to re-enter the business of power generation in Maryland would expose consumers to the financial risks of the regulated “cost-plus” model. This structure creates a natural incentive for utilities to maximize their rate base and shareholder returns by pursuing capital-intensive generation projects. Under this framework, captive ratepayers would bear financial responsibility for budget overruns, project delays, and management failures that can often occur during large-scale infrastructure projects. These risks are further compounded by the fact that Maryland utilities have divested their generating expertise, making it unlikely they could build new facilities more efficiently or at a lower cost than IPPs.

Any utility seeking to enter the competitive generation market can do so already through competitive affiliates without the safety net of guaranteed ratepayer recovery. This ensures that all market participants compete on even footing. By requiring utilities to compete alongside independent producers, Maryland can ensure that market signals remain transparent and avoid the negative impact on private investment that would result from a hybrid ownership model.

Maryland is already well-positioned to meet its power demand needs thanks to its commitment to a restructured electricity sector. Moving to a restructured model has benefited Maryland customers for more than 25 years and supported a market that incentivizes power supply efficiency while protecting the public from stranded costs.

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<sup>57</sup> *Exelon 2023 Proxy Statement* ([link](#))

## Appendix

### Cost Comparison of a New Combined Cycle Gas Plant in Maryland and Pennsylvania

#### Natural Gas Pipeline Interconnection Costs

To interconnect to the natural gas interstate pipeline system, power plants generally require the development and construction of both a gate station and a pipeline lateral to be able to ship the gas from the interconnection point to the power plant site. Gate station costs are likely to be independent of location, but pipeline construction costs are impacted by many factors that can vary between states including navigating natural terrain, population density, and state and local permitting requirements.

To approximate pipeline interconnection costs for Maryland and Pennsylvania, comparable pipeline projects were identified in both Maryland and Pennsylvania constructed since 2014. Cost and mileage data collected and published by the EIA for these projects were used to calculate a dollar per mile cost.<sup>58</sup> Comparable project costs in Maryland are based on the Line MB extension project and the Rock Springs Extension projects, and UGI Sunbury Pipeline, Line N to Monaca Project, and the Birdsboro Pipeline Project in Pennsylvania.

- The Line MB, operated by Columbia Gas Transmission, was selected as it is the only pipeline expansion project since 2014 to be completely within Maryland’s borders. It included the installation of a 21 mile 26-inch pipe alongside an existing pipeline run through Baltimore and Harford County.
- Rock Springs Extension project, operated by Transcontinental Gas Pipeline, was selected as a comparable project as it was a lateral built specifically to deliver natural gas to a generation facility in Cecil County, MD. This included the construction of 11 miles of new greenfield 20-inch pipeline.
- UGI Sunbury Pipeline is a 35 mile 20-inch pipeline lateral in northeast PA operated by UGI Energy Services to deliver gas out of the Marcellus to northeast PA markets and other interstate pipelines.
- Line N to Monaca is a 4.5 miles 12-inch-diameter pipeline lateral from delivering gas to the Shell ethane cracker plant. This lateral is operated by National Fuel Gas Supply Corporation.
- Although classified as a “New Pipeline System” in the EIA dataset, the Birdsboro Pipeline Project is a lateral extending from the Texas Eastern Transmission interstate pipeline to deliver natural gas to the 485 MW Birdsboro natural gas power plant. This project is a 13-mile 12-inch pipeline located in Southeast PA and is operated by DTE Midstream Appalachia, LLC.

Additional details for the selected pipeline projects are provided in Table 4 below.

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<sup>58</sup> EIA, *Pipeline Projects, October 2025* ([link](#))

*Table 4: Proxy Gas Pipeline Construction Projects*

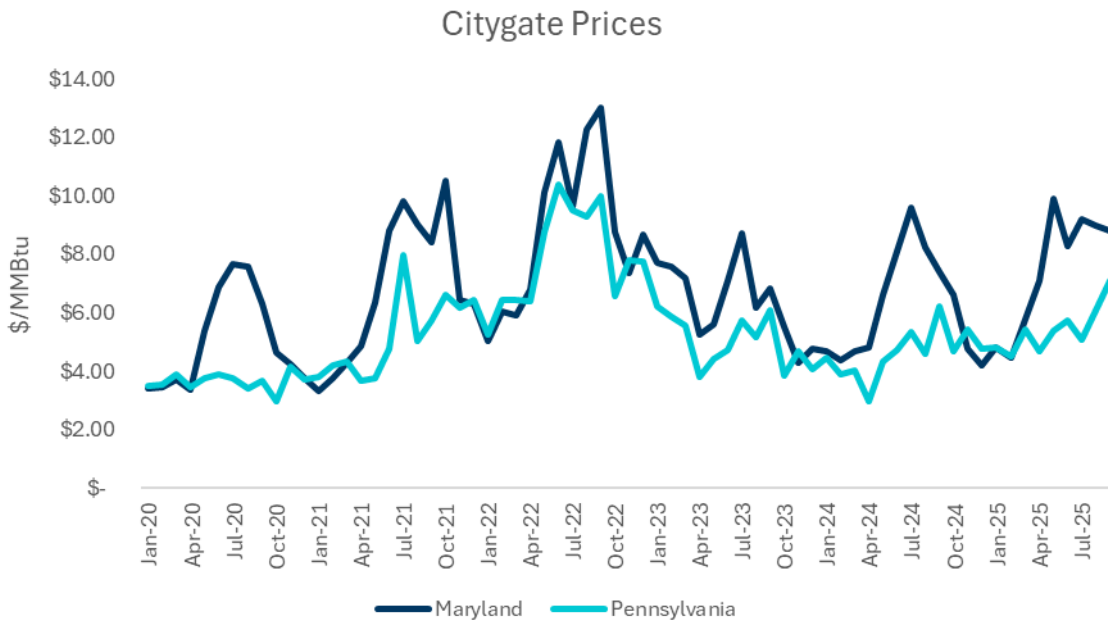
Project Name	Pipeline Operator Name	Year Complete	Beginning State	Ending State	Pipeline Length (miles)	Pipeline Diameter (inches)	Project Cost (2025 \$MM)	Cost per Mile (2025 \$MM)
Line MB Extension Project	Columbia Gas Transmission	2014	MD	MD	21	26	\$180	\$8.6
Rock Springs Expansion	Transcontinental Gas Pipeline	2016	PA	MD	11	20	\$108	\$9.8
UGI Sunbury Pipeline	UGI Energy Services	2017	PA	PA	35	20	\$237	\$6.8
Line N to Monaca Project	National Fuel Gas Supply Corp	2019	PA	PA	5	12	\$25	\$5.6
Birdsboro Pipeline Project	DTE Midstream Appalachia, LLC	2018	PA	PA	13	12	\$61	\$4.6

The length of a typical lateral required to connect a new gas plant to an existing pipeline was estimated using the same EIA dataset and was based on the average length of laterals constructed to serve new gas plants in the US over the last 10 years, approximately 13 miles.

### Natural Gas Fuel Costs

Natural gas prices are highly seasonal and vary by location. Monthly historical pricing published by the EIA for Citygate prices in PA and MD, are used to represent the fuel costs a power plant in each state could rely-on without acquiring additional upstream pipeline capacity rights to source gas from outside of the state. In other words, these in-state Citygate prices are a reasonable representation of the difference in the cost of delivered gas between the two states. Historical monthly pricing for each hub is shown below in Figure 8.

Figure 8: Historical Natural Gas Prices by State



The fuel driven operating cost for each generation technology type is also dependent on the technologies overall efficiency as measured by a generators heat rate (MMBtu/MWh). This analysis uses publicly available data from the National Laboratory of the Rockies (“NLR”) as the estimate of a baseline efficiency level of 6.196 MMBtu/MWh for a new natural gas combined cycle plant.<sup>59</sup>

Total annual costs will be dependent on how often a gas plant is running. Monthly estimated power output is calculated using capacity factors published by EIA using the formula below.<sup>60</sup>

$$MWh_m = NPCap * CF_{m,t} * DIM_m * 24$$

Where the subscript *m* indexes the month, *MWh* is the megawatt hours of generation, *NPCap* is the nameplate capacity, *CF* is a monthly capacity factor, *DIM* is the number of days in the month, and 24 is the hours in a day. This analysis assumes that both the nameplate capacity and monthly capacity factors are the same for a plant operating in either Maryland or Pennsylvania, such that the generation output and fuel consumption do not differ across scenarios. Monthly capacity factors applied are based on the average of the 2023 and 2024 capacity factors for natural gas combined cycle units published by the EIA.

<sup>59</sup> NLR, *Annual Technology Baseline 2024* ([link](#))

<sup>60</sup> EIA, *Electric Power Monthly* ([link](#))