

September 10, 2026

Chair Korman, Vice Chair Guyton, and Members of the Environment & Transportation Committee:

Thank you for the opportunity to provide comments ahead of the committee briefing on implementation of the Utility RELIEF and other issues. We are closely tracking several of the provisions of the bill, which have open dockets at the PSC or pending reports over the next many months and are looking forward to getting insight and updates on these topics at the briefing. As available, we also hope to better understand what to expect from the state's data center study if it has not been released yet, as well as any updates on the hiring of a Director for the State Energy Planning Office, and implementation of the PSC's discount rate for limited-income utility customers.

We hope the briefing will also cover the energy and affordability needs still unaddressed, such as modernizing the state's RPS, Maryland's role in PJM reforms, and utilities' rate of return, as well as the danger in backsliding on the progress we have made. Maryland LCV is working to Power Maryland Forward, supporting **energy affordability** through **deployment of solar and storage, defense against more fossil fuels** and **unchecked utility profits**, while **getting the most out of the electricity grid we have**. The Utility RELIEF Act took steps forward in all of these areas. At the same time, we see continued attacks on climate and clean energy programs in our state and nationally.

This is why the state of Maryland needs to take a **Clean Energy First** approach: a directive to plan, procure, permit, and invest in energy generation and supporting infrastructure that prioritizes the resources that are cheapest and fastest to deploy, which today means clean, renewable energy.

Build what works best, first.

Energy options are not interchangeable. We must start acting on what the data already shows: clean and renewable energy sources are now frequently the fastest, most cost-effective way to meet Maryland's growing energy needs.

Maryland faces rising demand, rising bills, and a fossil fuel buildout that keeps getting proposed as the default answer even though it's often slower and more expensive than the alternative. **Clean Energy First** brings the state to where the market and the technology already are.



Through the Climate Solutions Now Act of 2022, Maryland has already made a commitment to its residents: to cut greenhouse gas emissions and build a clean energy economy. The Climate Pollution Reduction Plan provides a roadmap to achieve these goals. Fully implementing the plan is projected to generate up to \$1.2 billion in public health benefits, \$2.5 billion in increased personal income, and a net gain of 27,400 jobs by 2031, with average households saving as much as \$4,000 annually on energy costs. Looking further out, the plan's modeling calculates the societal benefit of our collective emissions reductions at \$135 billion through 2050. Clean Energy First is not a new commitment; it is a means of achieving the commitment we have already made. This is not about relitigating that commitment; it's about making sure it actually happens.

Progress towards these goals is happening. Maryland's 2025 Climate Subcabinet Annual Report shows real progress. All 26 state agencies made measurable gains this year, from an all-electric heating and cooling policy for new state facilities to 46 electric fleet vehicles added across eight agencies. Since Fiscal Year 2021, the Department of General Services alone has cut state government energy use by 6,600 megawatt hours and saved \$1.4 million in operating costs just by replacing light fixtures. But these are some of the lower hanging fruits, and implementation is running into real headwinds: federal funding and tax incentives that supported clean energy deployment are now uncertain or being clawed back, regional grid interconnection queues remain backlogged, and supply chain and workforce constraints are slowing how fast projects can actually get built. Clean Energy First doesn't deny those obstacles, but it does put Maryland in a stronger position to work through them, prioritizing the sources and supporting infrastructure that are fastest and most cost-effective to deploy.



September 10, 2026

RE: Energy Oversight Briefing: Implementation of the Utility RELIEF Act

Chair Korman, Vice-Chair Guyton, and members of the Environment and Transportation Committee,

The Utility RELIEF Act directs the Public Service Commission to transition Maryland from the current net energy metering (NEM) structure to a successor program design, including approval of that design by February 1, 2027 and full implementation by July 1, 2027. This briefing is an important opportunity to ensure that framework reflects a transparent, workable valuation approach for rooftop, commercial, industrial, and community solar resources.

The Joint Solar Parties (Chesapeake Solar and Storage Association, Solar Energy Industries Association, Coalition for Community Solar Access, and the Maryland Rooftop Solar Coalition) have been active participants in the PC78 NEM Successor Proceeding. As part of that process, the Joint Solar Parties retained CrossBorder Energy to provide technical input on potential successor valuation frameworks for residential, commercial and industrial, and community solar resources. We are submitting a copy of our suggestions for what a new framework could look like. Given the short timeframe for Commission approval and implementation, we recommend beginning with a simple, administrative framework that ensures solar adopters have the EmPower charges on their electric bills. This approach is consistent with what the PSC consultant, Customized Energy Solutions, is currently evaluating. With additional time and stakeholder engagement, Maryland can then move toward a more comprehensive value-based approach that better reflects the benefits provided by distributed solar and solar-plus-storage resources. However, the limited time has restricted the depth of analysis that the PSC consultant can conduct and what level of program reform can actually be acted on by July 1, 2027.

The attached materials include our proposed framework, feedback on relevant valuation issues, and illustrative value-stack calculations for community solar and solar-plus-storage projects in BGE territory.

We are happy to answer additional questions and will submit supplemental comments after this briefing.

Respectfully Submitted/

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Joint Solar Parties Conceptual Proposal for Maryland NEM 2.0

The Joint Solar Parties (Chesapeake Solar and Storage Association, Solar Energy Industries Association, Coalition for Community Solar Access, and the Maryland Rooftop Solar Coalition) submit the following conceptual proposal for a successor net metering program (NEM 2.0) in Maryland, as requested in the Public Comment 78 Working Group. This proposal would establish differently structured net metering tariffs for different types of behind-the-meter net metering customer-generators.

The Joint Solar Parties (JSP) do not currently propose a framework for community solar projects. This proposal will reflect stacked and quantified grid values. We refer the Commission, consultants, and stakeholders to our submitted “Comments of the Joint Solar Parties on Valuation for NEM 2.0” for our detailed response for what data inputs should be used and how grid values should be quantified. We will submit additional comments with a community solar proposal for NEM 2.0 tariffs.

Background

The Utility RELIEF Act directs the Commission to develop a net metering successor framework but does not prescribe or limit the authority of the Commission to develop differentiated offerings for traditional, behind-the-meter (BTM) net metering customers. In recognition of the fact that eligible customer-generators under § 7-306 have unique attributes as compared to front-of-the-meter (FTM) facilities, the Utility RELIEF Act directs the Commission to consider how the successor framework will “increas(e) benefits to ratepayers by lowering electric system costs through the use of flexible customer-sited renewable energy resources” and “make progress toward meeting the state’s demand-side, energy storage, and clean energy goals.” § 7-306.4(B). Thus, apart from valuing injections of power from the grid, which is an attribute of virtually all solar facilities participating in net metering (community solar and traditional BTM eligible customer-generators), the Utility RELIEF Act sought to ensure that the successor framework for demand-side (i.e., customer-sited, BTM) renewables would be harmonized with other demand-side programs (e.g., EmPOWER, DRIVE, Electric System Planning).

To do this, the Commission can look holistically at the eligible customer-generator and consider the demand-side attributes that might not otherwise be considered in a traditional value of solar analysis and consider additional tools—namely ratemaking—to fine tune the successor to accomplish these overarching goals of inter-program harmonization. Ultimately, the Commission has greater tools at its disposal through its ratemaking authority to fine tune the successor framework for BTM net metering to assure that it captures the cost-of-service benefits of these systems (which influence the load shape of participating customers and may reduce cost allocations to the relative class). Working within the existing ratemaking paradigm applicable to BTM customer-generators makes sense as these customers will continue to receive electric service. They already interact with the grid and

utility via their rate class and retail rate restructure. These customer-generators have their demand-side value determined by the retail electric rate they choose. Adjusting the retail electric bill of these BTM participating eligible customer-generators can provide a simple and quickly implementable change in compensation that complies with the spirit of the law and achieves the multiple other objectives contained within its text.

This flexibility given by the legislature to the Commission also parallels how behind the meter and front of the meter solar is treated in different markets. New York has been discussed significantly in the NEM Successor Working Group. When designing and implementing its VDER approach, NY recognized the complexity and allows residential rooftop and other “mass market” customers to stay on retail 1:1 net metering with a Customer Benefit Contribution (CBC) fixed charge. The Value Stack applies to community solar and other project-scale resources, not residential homeowners who are customer-generators. This is the same framework that the Joint Solar Parties are proposing.

Proposed NEM 2.0 Tariff Elements

Compensation for behind-the-meter solar has to be simple and legible for the homeowner, so a family can understand what they will save before they sign. When an energy consumer installs solar on their home or business behind their utility meter, the electricity they generate is interacting directly with the energy they consume from the grid - and therefore directly interacting with their utility bill. Only a portion of the electricity generated from a BTM solar system is exported to the grid - the balance is consumed instantaneously onsite, essentially acting the same as energy efficiency on the customer’s electric load.

A community solar system is fundamentally different from a residential solar system, beginning with their electrical configurations. Residential and commercial systems enrolled in traditional net metering sit behind the customer meter. Community solar systems generate in front of the meter, regardless of whether the property it is sited on has any electrical load. Any attempt to create a “one size fits all” solution would cause one or all market segments to be harmed due to the vast differences across financing, project development, and customer acquisition.

Residential Solar

Below is a proposal for adopters of residential solar. It follows the principle of gradualism and recognizing that rate design reflect customer-generator ability to respond to rate design structure, price signals, and grid events. The rate design is also chosen in order to not become an obstacle for project financing (customer-provided or solar company-provided).

Battery storage and system dispatchability are not common characteristics of distributed solar projects currently operating or in development in Maryland. Over time, that will change, as should the underlying rate design for distributed generation projects.

Phase I. Apply principle of gradualism, in one of two ways

Option 1: Maintain 1:1 retail NEM and add an EmPower Fixed Charge to recover EmPower costs that are offset by 1:1 export compensation.

Option 2: Encourage new solar customers to adopt time-varying retail rates and to pair solar with storage. The crediting method for monthly exports in excess of usage would change from accounting on a kWh credit basis to a monetary value basis. With this more granular accounting of exported energy value, the EmPower Fixed Charge would not be applied to the customer-generator.

The Commission would continue to iterate on time-varying rates and time-of-use (TOU) periods, evolving residential time-varying rate design to recognize peak load reduction values and on-peak generation. The JSP envisions this could lead to shorter, more focused TOU periods and greater differences in on-to-off-peak retail rate values.

Phase II. Layer grid services and time-varying energy values as residential solar paired with energy storage adoption becomes more common

Coordinate DRIVE Act permanent programs and any other storage incentive programs with TOU rates to develop a robust residential solar plus storage market. Once these programs can accommodate the annual capacity of a robust residential market and the market has shown that technical and permitting barriers are minimal to wide-spread adoption of residential solar plus storage, require new solar customers to use a TOU rate and to pay the EmPower Fixed Charge. An additional trigger for entering Phase II is if the Participant Cost Test for a residential system shows that solar-only systems can be reasonably supported under a TOU rate.

Any transition from Phase I to Phase II should also follow the principle of gradualism, with a 6-month lead time from announcement to effective date. This will provide time for companies to adjust sales practices, financial models, marketing materials, and general business strategies. Additionally, projects with interconnection applications submitted before the end of this 6-month period should have the option to remain under Phase I.

Commercial and Industrial (C&I)

Commercial customers can adopt larger capacity solar systems versus residential energy consumers, however many of the same principles apply for both. Residential and smaller commercial consumers are not typically considered sophisticated energy consumers. The complexity of their electric rates already reflect these principles. The JSP proposes NEM 2.0 tariffs that follow those principles, balancing the statutory goals of this proceeding and the Utility RELIEF Act and preventing complex rate design from becoming an obstacle to solar and storage adoption.

With commercial-scale systems, project finance becomes more complex. It is just as important that the rate design of a NEM 2.0 tariff be compatible with project finance constraints and realities.

Just as with residential solar NEM 2.0 tariffs, the JSP propose shifting the accounting of exported credits from a kWh basis to a monetary basis.

Phase I: Apply the principle of gradualism

1. Maintain current NEM structure

2. Add the EmPower Fixed Charge, except for solar customers on C&I schedules with demand charges
3. For C&I rates with TOU volumetric rates, change the crediting method for monthly exports in excess of usage, from kWh to dollar credits.

Phase II: Evolve rate designs as typical systems add ability to react to grid events

1. Move to a Value Stack for exported power
 - a. Energy – at actual LMP prices
 - b. Capacity value (ICAP)
 - i. Generation
 - ii. Transmission
 - iii. Lock in the Generation ICAP for 10 years if the PJM generation capacity value is capped or based on Net CONE
 - c. Environmental value (ENV) – Grid environmental impact of displacing emissions from wholesale fuel mix
 - d. Demand Reduction Value (DRV) – avoided distribution costs at the system level – lock in for 10 years
 - e. Locational System Relief Value (LSRV) – available in constrained locations as incremental to the DRV – lock in for 10 years
 - f. Transition value (if needed)
2. No EmPower Fixed Charge

Conclusion

The Joint Solar Parties submit these conceptual proposals for differentiated NEM 2.0 tariffs based on customer type. The JSP looks forward to the forthcoming discussions on our own proposal as well as those from other stakeholders. We also look forward to submitting a proposal for community solar systems soon

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Outline of JSP Community Solar Proposal

I. Front-of-meter

A. Community Solar – start simple

1. Remove EmPower volumetric rate from subscriber bill credits

B. Community Solar – add complexity

1. Move to a Value Stack for exported power
 - i. Energy – at actual LMP prices
 - ii. DRIPE – based on EmPOWER DRIPE analysis.
 - iii. Capacity value (ICAP)
 - a. Generation
 - b. Transmission
 - c. Lock in the Generation ICAP for TBD years.
 - iv. Environmental value (ENV) – REC value, if REC is transferred
 - v. Demand Reduction Value (DRV) – avoided distribution costs at the system level – lock in for TBD years
 - vi. Locational System Relief Value (LSRV) – available in constrained locations as incremental to the DRV – lock in for TBD years
 - vii. Transition Element – “Community Credit” in NY VDER. As needed to ensure a viable program.

II. Plan for Development of the Maryland Value Stack

1. Develop protocols for use of LMPs
2. Determination of ICAP and ENV values, and process for updating
3. Review of utility marginal COS studies to develop DRV and LSRV
4. Determination of need for a Transition Element.

Comments of the Joint Solar Parties on Valuation Issues for NEM 2.0

The Solar Energy Industries Association (SEIA), the Chesapeake Solar and Storage Association (CHESSA), the Coalition for Community Solar Access (CCSA), and the Maryland Rooftop Solar Coalition (MRSC) – together, the Joint Solar Parties (JSP) – appreciate the opportunity to provide feedback to the Public Service Commission staff and its consultants on the valuation issues concerning the analysis that the PSC is conducting as part of formulating a proposal for the structure of Net Energy Metering 2.0 (NEM 2.0) in Maryland. We have organized these comments according to the principal components of a typical NEM value stack.

1. Energy

The Joint Solar Parties support the conclusion of the Maryland Unified Benefit-Cost Analysis report (UCBA Report) issued July 7, 2026 that power systems modeling performed by a new Strategic Energy Planning Office would be the preferred approach for determining future avoided energy costs. However, as recognized in the UCBA Report, such modeling will not be available for the NEM 2.0 analysis. We recommend that the next-best interim approach is to use the EmPOWER avoided energy cost model,¹ with the caveats and changes recommended below.

a. NLR Cambium Results

We do not recommend the use of the other interim option suggested in the UCBA Report – the use of modeling results for PJM East from the National Lab of the Rockies (NLR) Cambium model – for these reasons:

- To our knowledge, the most recent Cambium modeling was conducted in 2024 and key assumptions for natural gas prices and resource costs appear to us to be out of date.²
- The Cambium avoided energy cost results for 2025 and 2026 are far below actual recent PJM locational marginal prices (LMPs).
- We question whether Cambium will be reasonably updated given changing federal priorities.
- The PJM East footprint used in Cambium is much larger than Maryland, and includes most of the PJM footprint except for the area around Chicago.

¹ Released May 2026, available with the accompanying models, at: https://drive.google.com/drive/folders/1ToapaXd_jV9GqKnojbGyM6lxt0Y3HBsi.

² See the 2024 Cambium scenario view and datasets at <https://www.nlr.gov/analysis/cambium>. The [Cambium 2024 Scenario Descriptions and Documentation](#) states, at page 8, that the “[n]atural gas input price points are based on the trajectories from AEO2023 (EIA 2023).”

b. Natural gas forecast used for EmPOWER avoided electric energy costs

We have also significant concerns, discussed below, with the EmPOWER avoided energy cost model that accompanies the May 2026 *EmPOWER Avoided Cost Forecast Report* (EmPOWER Report), but we hope that these concerns can be addressed through reasonably simple changes in inputs or straightforward adjustments to the spreadsheet model for avoided energy costs.

It is our understanding that the natural gas forecast used in the EmPOWER model for avoided electric energy costs uses three years of forward gas prices at the Henry Hub benchmark, then escalates the third year of forward prices to subsequent years based on the escalation rates for Henry Hub prices in a 2025 Energy Information Administration (EIA) *Annual Energy Outlook* (AEO) forecast.³ We have the following concerns with this forecast:

- The forecast uses an outdated 2025 AEO forecast of benchmark Henry Hub gas prices to provide the long-term escalation rate in the gas forecast. There is a more recent 2026 EIA AEO forecast that should be used.⁴
- The EIA AEO forecasts are fundamentals-based long-term forecasts of natural gas prices; they are not just forecasts of escalation rates for gas prices. In other words, they are forecasts of what the actual Henry Hub price will be in the future based on an assessment of the cost to produce new gas supplies. They are not meant to be scaled up or down based on changes to short-term gas forward prices, which is effectively what the EmPOWER gas forecast does by only using the EIA AEO forecast to determine the escalation in prices.⁵

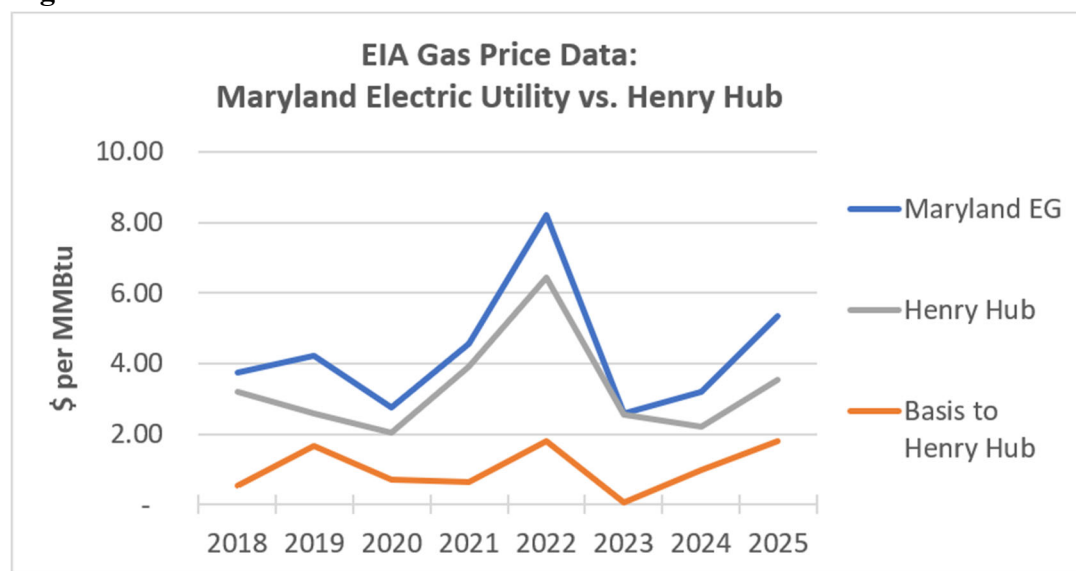
³ The EmPOWER Report states, at page 25: “We use three years of Henry Hub future prices as the forecasted gas price for January 2027 through December 2029. Beginning January 2030, we escalate the Henry Hub future prices using the U.S. EIA’s most recent AEO forecast of annual percentage changes in Henry Hub prices for years 2030 through 2050. These values serve as the foundation for our monthly gas prices.”

⁴ For the 2025 AEO forecast, see the natural gas spot price at Henry Hub (2024 \$/MMBtu), in the tables at <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2025&cases=ref2025&sourcekey=0>. For the similar tables for the more recent 2026 AEO Forecast, see <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2026&cases=cb2026&sourcekey=0>.

⁵ For example, forward prices for natural gas in the near future can change suddenly and significantly, as has been observed due to price shocks such as Hurricanes Katrina and Rita in the 2000s and the onset of the war in Ukraine in 2022. But a major percentage change in near-term futures prices does not indicate that the long-run, fundamental cost of producing gas has changed by the same percentage. However, that unrealistic relationship is what is assumed if a long-term fundamentals gas forecast is used simply as a source of escalation factors for near-term futures prices.

- The EmPOWER gas forecast uses the third year of a forward strip of Henry Hub prices as its starting point for the longer-term forecast. Gas futures prices are robustly traded out 18 to 24 months, but the open interest declines rapidly after that.⁶
- The EmPOWER avoided energy cost model appears to use a different, and much lower, gas commodity cost forecast for electric generation than the forecast used in the separate model for avoided natural gas costs. This forecast appears to be based on an EIA projection for Mid-Atlantic gas prices for electric generators (EGs), with little or no basis differential from the Henry Hub. Maryland is in EIA's South Atlantic group of states, and recent historical EIA data on gas costs for Maryland EGs shows a significant basis differential to the Henry Hub, averaging \$1 per MMBtu over the years 2018-2025.⁷ See **Figure 1**. In addition, there is often a significant basis differential between the Henry Hub and Transco Zone 6, which is the typical gas pricing reference point for Maryland utilities. The EmPOWER gas forecast for electric generation does not appear to use a basis differential to Transco Zone 6.⁸ **Figure 2** is a recent snapshot of forward prices for the Transco Zone 6 basis to the Henry Hub over the next 12 months, from *Natural Gas Intelligence*. The basis to Transco Zone 6 can be particularly high in winter months.

Figure 1

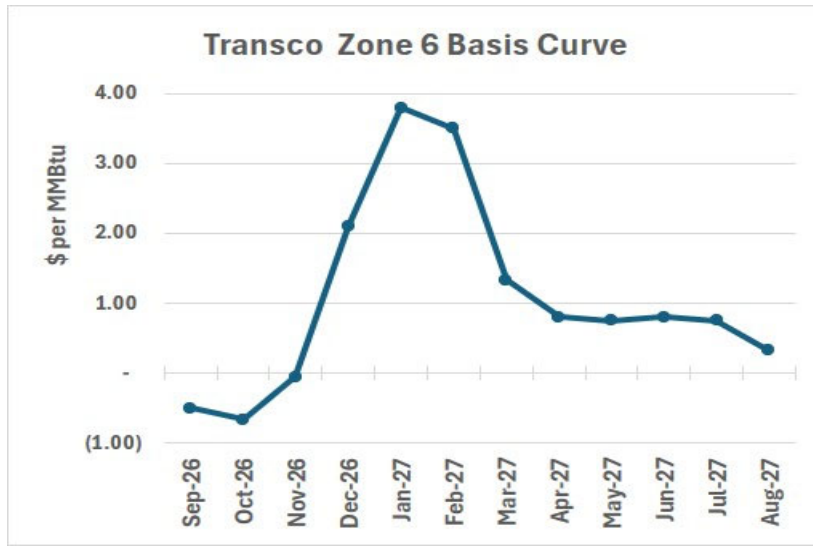


⁶ For example, recent CME settlements for Henry Hub futures (August 4, 2026) show that 98% of total open interest is concentrated on the months from September 2026 to December 2028. See the data available at <https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.settlements.html>.

⁷ Data in Figure 1 is from the EIA “Electricity Data Browser,” which has historical EG gas costs by state: <https://www.eia.gov/electricity/data/browser/>.

⁸ See the “Gas Commodity Forecast” tab of the EmPOWER gas model (“UBCA Gas Commodity Price Adjustment.xlsx”) which shows (in the embedded figure and column G) a significantly lower “Gas Price to Electric Power.”

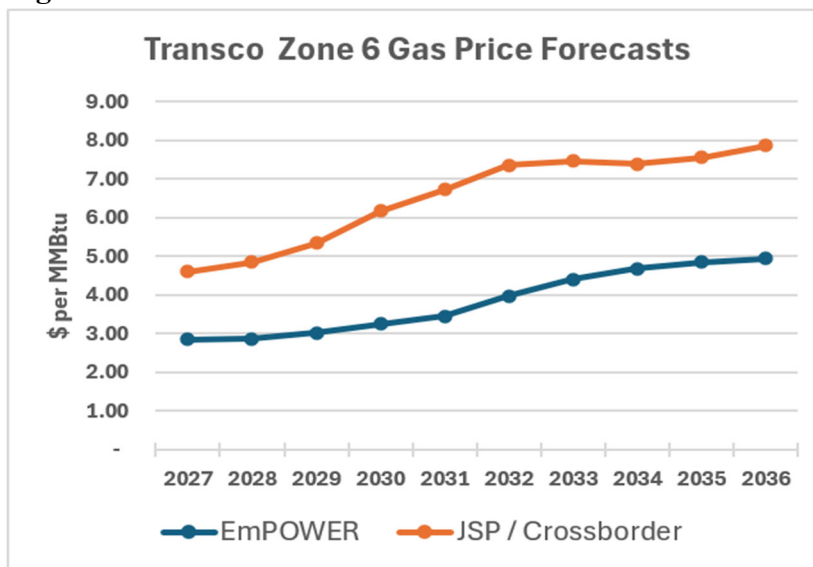
Figure 2



- The EmPOWER model applies an anomalous monthly shape to the annual gas prices, apparently based on historical prices in 2024-2025, in which the highest prices occur in the months of March and April. We recommend that this monthly shape should be based on multiple years of monthly gas price data, not on a single year that may not be representative.

Figure 3 is a comparison of the EmPOWER gas forecast used for electric avoided costs to a revised forecast that we recommend to address the above concerns. The revised forecast (1) uses two years of Henry Hub forward prices (2027 and 2028), then moves to the 2026 EIA *AEO* forecast, and (2) includes the forward basis differential to Transco Zone 6 shown in Figure 2.

Figure 3



c. EmPOWER “Full Requirements” avoided costs

The EmPOWER avoided costs include several flavors of avoided costs: “Marginal Costs” and “Full Requirements” avoided costs.⁹ The Full Requirements costs include Marginal Costs plus the following:

- **Congestion and Losses:** Costs associated with electricity flow limits and energy lost in transmission on the PJM system
- **Shaping Factor:** Cost to procure more energy at higher prices (which the JSP interpret to be scarcity effects in the PJM market).
- **Auction Revenue Rights (ARR) Credit:** Credit paid to network transmission customers serving load
- **Ancillary services:** Various charges associated with serving load (e.g. black start, operating reserve, regulation, and administrative fees)
- **Renewable Portfolio Standard (RPS):** Set of annual renewable energy requirements by Maryland with associated alternative compliance payment amounts
- **Risk Factor:** Risk and return associated with serving load

We recommend that the avoided energy component of the NEM valuation should correspond as closely as possible to the costs included in LMP prices in PJM, with a demonstration of how this is accomplished. As a result, the avoided energy component should include, at a minimum, Marginal Costs plus the Congestion/Losses and Shaping Factor components. The NEM valuation should explain clearly how the other components of the Full Requirements avoided costs are handled. For example, there could be a separate avoided cost component for avoided ARR credits and ancillary service costs, to the extent that distributed energy resources (DERs) are load modifiers that avoid these credits and costs. RPS-related costs can be included in a distinct Environmental/REC Value, as they are in the New York Value of DER (VDER) program. The procurement Risk Factor is discussed further below in the section on the Operating Risks that distributed energy resources (DERs) can avoid.

d. Energy DRIPE

The JSP support the EmPOWER report’s discussion and quantification of the Demand Reduction Induced Price Effect (DRIPE) component for energy.¹⁰ DER generation provides a clear benefit to all ratepayers by reducing the demand that the PJM market must serve, and thus also reducing the market-clearing price for electricity in PJM. This reduction in the market-clearing price benefits all ratepayers who buy market-priced power.

⁹ See EmPOWER Report, at pp. 10-13.

¹⁰ See EmPOWER Report, at pp. 14-17.

2. Generation Capacity

a. Avoided generation capacity costs in PJM

The JSP have reviewed the avoided cost of capacity projections in the EmPOWER Report, and concur with the avoided generation capacity cost forecasts presented for the four Maryland utilities in Figure 9 of the report. This forecast starts with the currently capped values for capacity in PJM, then transitions in 2029 to the net cost of new entry (Net CONE) for a gas-fired combustion turbine and then in 2033-34 to the Net CONE for battery storage. We think that this forecast is a reasonable starting point, but emphasize that the current capping of the capacity price in PJM clearly understates the critical need for new generating capacity on the PJM footprint. If uncapped, the current price for capacity would be far higher, at more than 70% above the capped values.¹¹ The JSP are not asking for uncapped PJM capacity prices to be included in the Maryland value stack, but instead request the Commission to recognize that, for as long as PJM capacity prices remain capped, new distributed capacity developed in Maryland will provide substantial capacity benefits for all ratepayers. These are benefits which customers who invest in DER capacity will provide to other ratepayers without compensation.

b. Capacity DRIPE

The JSP understand the logic that an avoided DRIPE component for capacity is not indicated because (1) the PJM capacity price is capped through 2028 and (2) in subsequent years the avoided capacity price is based on the cost of new entry, not on a market-clearing price for capacity. There clearly would be a substantial current capacity DRIPE benefit if the PJM capacity market price were not capped. This further underscores our point above that, in the near-term, new distributed capacity will provide substantial capacity benefits for all ratepayers, at no cost.

c. Seasonal allocation of capacity value

The EmPOWER report includes a proposed seasonal split in the avoided capacity value between summer and winter which shows a rapid increase in the value of winter capacity.¹² The JSP are still evaluating this information. We are concerned that this rapid change is not supported by the data on the relative frequency of summer and winter peaks; for example, the

¹¹ In the recent 2028/2029 PJM capacity auction, most of PJM would have cleared at a price of \$555 per MW-day, far above the applied cap of \$325 per MW-day. See the *PJM 2028/2029 Base Residual Auction Report* (July 14, 2026), at Table 2 of the Appendix, available at <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2028-2029/2028-2029-bra-results-report.pdf>.

¹² See EmPOWER Report, at pp. 20-21. This split is based on recommendations from a separate EmPOWER Seasonal Capacity Working Group Report.

data on the five coincident peak hours (5 CP) in PJM show that all 5 CP hours in the last 5 years have occurred in the summer.¹³

d. The generation capacity contribution of solar and solar-plus-storage

The JSP support the use of a 5 CP method to assess the contribution of solar and solar-plus-storage to reducing avoided generation capacity costs. This capacity contribution should be based on the output of typical solar and solar-plus-storage units during the 5 CP hours that the utilities use to allocate PJM generation capacity costs among their customers.¹⁴ Over the last 5 years, the 5 CP hours in PJM have occurred in hours ending 16 to 18 during the summer months of June-September.¹⁵ This 5 CP-based capacity contribution provides a direct measure of the ability of DERs to reduce the utility's generation capacity costs.

We oppose the use of capacity contributions based on the results of PJM's effective load carrying capacity ("ELCC") modeling. The PJM ELCCs for solar declined sharply and suddenly, from 33% (for fixed arrays) in December 2023 to 10% for the 25/26 BRA.¹⁶ This occurred without the large increase in solar penetration on the PJM footprint that one would expect to be necessary to produce such a drop.¹⁷ The PJM market monitor has criticized the volatility in PJM's ELCC calculations, noting that "the ELCC calculations are disproportionately affected by historical winter availability" and are "based on a relatively small number of historical winter performance hours."¹⁸ Modeling changes that impact the weight assigned to the few winter peak hours can have a major impact on solar's ELCC value, due to the low output of solar in early morning winter hours. Such volatility in key input assumptions needs to be avoided in order to provide a certain and sustainable environment for customers to invest in renewable DERs. The use of a 5 CP metric, with the 5 CP hours sampled over multiple historical years with diverse weather conditions, represents a more stable, transparent, and reliable metric

¹³ See, for example, <https://www.pjm.com/-/media/DotCom/committees-groups/cifp-ra/2023/20230628/20230628-item-04d---summer-2021-peaks-and-5cps.pdf>.

¹⁴ See, for example, BGE's "Capacity Peak Load Contribution - Peak Hours and Default" discussion on its Energy Choice Supplier Site, at <https://supplier.bge.com/electric/load/plc-peak-hours.asp>.

¹⁵ *Id.*

¹⁶ See PJM, *December 2023 Effective Load Carrying Capability (ELCC) Report*, at 8 and Figure 3 (33% value for 2024, 24% for 2025); also *ELCC Class Ratings for the 2025/2026 Third Incremental Auction*.

¹⁷ A 10% solar ELCC is similar to the lowest solar ELCC calculated for the California Independent System Operator (CAISO) system, with its far higher penetration of solar compared to PJM. Solar ELCCs in California now appear to be rising, due to the growing importance of solar as a clean energy source for charging storage.

¹⁸ See Monitoring Analytics, LLC, *2024 State of the Market Report for PJM*, at 2.

for the solar contribution during the hours when PJM demand peaks and it has the greatest need for capacity.

3. Transmission and Distribution (T&D)

The JSP support the conclusion of the *UBCA Work Group Report to the Commission on Methods for Quantifying Impacts in Maryland's UBCA Test and Associated Implementation Recommendations* (UCBA Methods Report), released on July 7, 2026, concerning the preferred approach for calculating system-wide avoided capacity-related T&D costs – a forward-looking the “Ratio of Cost to Load Growth” method. We commend the UBCA working group for the comprehensive and thoughtful discussion of the issues, data, and time frames involved with applying that method. We recognize that it would be challenging to develop and apply that approach for the immediate purposes of making changes to NEM by July 1, 2027. However, even if an alternative source for avoided T&D values is used initially for NEM 2.0, the Commission should begin soon the work to develop this forward-looking approach, which will be needed if Maryland wants to refine DER compensation to be more comprehensive and location-based, similar – for example – to the New York VDER program.

For alternative methods to use immediately, the JSP do not recommend the use of the current EmPOWER avoided T&D values, which are outdated.¹⁹ These values are simply escalations of the avoided T&D values from the 2024-2026 EmPOWER cycle, and, for Potomac Edison, appear to date from work done in Pennsylvania as long ago as 2019.²⁰ Instead, the JSP recommend the following:

- **Avoided transmission capacity costs:** a “shifted” avoided transmission cost method that uses current Network Integration Transmission Service (NITS) rates and a 1 CP method for determining the capacity contributions of solar and solar-plus-storage.
- **Avoided distribution capacity costs:** use a version of the Ratio of Cost to Load Growth method, with readily available recorded data, instead of forward-looking forecasts. The recorded data on capacity-related distribution investments and peak loads are available from each utility's FERC Form 1.

The sections below on avoided T&D capacity costs discuss these interim approaches.

1. Marginal line losses

The most basic T&D costs that DERs allow the utility to avoid are line losses, because distributed resources produce power either behind the customer's meter (serving the on-site load first), or on the distribution system (close to end use loads). We are looking for the change in the utility system's line losses as a function of a change in DER generation, i.e. marginal losses, not

¹⁹ See UCBA Methods Report, at pp. 47 and 52.

²⁰ See the EmPOWER Report, at p. 24.

average losses. The JSP agree with the conclusion of the UCBA Methods Report that “Marginal loss rates should be estimated for both (A) average annual energy impacts; and (B) peak demand impacts of DERs.” As noted in that report, marginal losses typically are 1.5 times average losses, which provides a convenient method for adjusting average losses if a utility does not have a marginal line loss study.²¹ The appropriate marginal distribution line loss factors should be applied to avoided energy costs (assuming that the modeling of PJM LMP prices already includes transmission losses). The appropriate peak hour marginal loss factors should adjust avoided capacity costs for generation, transmission, and distribution.

2. Avoided transmission capacity

As an interim, simplified approach to avoided transmission capacity costs, the JSP recommend using a “shifted” avoided transmission cost method which recognizes that, if DERs reduce the coincident peak load of a Maryland utility, this will shift existing transmission costs to other PJM zones. This is the approach used by parties, including the utilities, to measure avoided transmission costs in recent NEM proceedings in Virginia.²² What is required for this approach is (1) the current NITS rates and (2) a calculation of the capacity contribution of solar and solar + storage projects to reducing the coincident peak (1 CP) loads that drive both the causation and allocation of transmission costs. The Commission should recognize that this approach will understate avoided transmission costs to the extent that (1) transmission costs are growing (i.e. marginal transmission costs are higher than the average costs represented by the NITS rate) and/or (2) a utility owns transmission facilities in its service territory not covered by the PJM NITS rate.

The JSP submit that a 1 CP metric is the most direct measure of the capacity contribution of DERs to avoided transmission costs. We are aware that BGE uses a Network Transmission Peak Load Contribution method to allocate transmission costs that is based on “the five highest

²¹ See Jim Lazar & Xavier Baldwin, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*, Regulatory Assistance Project (Aug. 2011) at 5, <https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-eeandlinelosses-2011-08-17.pdf>. From Ohm's Law one can derive the fact that the marginal line losses in an electric circuit are double the average losses. In practice, if a portion (typically about 25%) of the overall losses on a utility system are “no-load” losses associated with energizing the system, then the marginal losses equal 1.5 times average losses (i.e. $1.5 = 2 \times [1 - 25\%]$), where average losses include both the resistive (load-related) and fixed (no-load) losses. Assuming that marginal losses for solar energy production are 1.5 times the system average losses across all hours is a conservative (i.e. low) assumption, because much of the solar output occurs in the afternoon hours when system loads, and losses, are higher than average.

²² See Virginia Case No. PUR-2024-00161, *Petition of Appalachian Power Company for Approval to Revise its Net Metering Program Pursuant to §56-594 of the Code of Virginia*, Testimony of Nicole M. Coon, at pp. 18-19.

unrestricted load hours that occurred on different days” during a 12-month period.²³ The JSP are not necessarily opposed to the use of this alternative to 1 CP, but ask the Commission’s consultant to justify the use of any such alternative to 1 CP.

Another possible approach to avoided transmission capacity costs is to use the Ratio of Cost to Load Growth method, with recorded FERC Form 1 data on transmission investments and peak load growth, rather than forward-looking data. An application of this method to the calculation of avoided distribution capacity costs for BGE is presented in the next section.

3. Avoided distribution capacity

The JSP recommend using a version of the Ratio of Cost to Load Growth method, with recorded FERC Form 1 data, as the interim method to calculate avoided distribution capacity costs. This approach is a standard regression method used by other utilities to determine their long-run marginal distribution capacity costs as a function of changes in load.²⁴

We present below an example of this method applied to BGE, and will share the workpapers with the working group. The regression model fits PGE’s capacity-related distribution investment additions over the past 10 years (2016-2025) to its peak load growth over time.²⁵ The regression separates out the long-run influence of load across the utility’s investments in overhead circuits and substation equipment, which are the categories of distribution costs that are most directly related to providing distribution system capacity.²⁶ See **Figure 4**. The slope of the resulting regression line in the figure provides an estimate of the marginal cost of distribution investments associated with changes in peak demand. We then annualize this marginal cost using a real economic carrying charge (“RECC”), and add associated loaders to include the general plant and O&M costs associated with the avoided investments.²⁷ **Table 1** summarizes the results of this analysis, using 10 years of historical BGE FERC Form 1 data.

²³ See BGE’s “Network Transmission Peak Load Contribution - Peak Hours and Defaults” discussion on its Energy Choice Supplier Site, at <https://supplier.bge.com/electric/load/plc-peak-hours.asp>.

²⁴ For example, Southern California Edison has used this approach for many years to calculate its marginal distribution costs in California regulatory proceedings. See CPUC Application A. 20-10-012, at Exhibit SCE-02, at 27–32. See [356561376.pdf](#).

²⁵ If a utility has experienced years with declines in peak demands, one can use a rolling series of the utility’s previous recorded maximum annual peak loads from prior years. This can eliminate distortions from periods of declining peak loads and recognizes that the utility will add to and maintain its system to at least meet the peak demand that it has experienced.

²⁶ These are the investment additions in FERC Accounts 365 and 368, as recorded in FERC Form 1.

²⁷ The loaders used in the calculation of marginal distribution capacity costs are also derived from FERC Form 1 data for BGE. We note that the UBCA Methods Report, at p. 53, discusses how distribution O&M costs are not marginal. This appears to be a completely different context than this distribution O&M loader. The UBCA Methods report is discussing whether distribution O&M costs for existing distribution

Figure 4

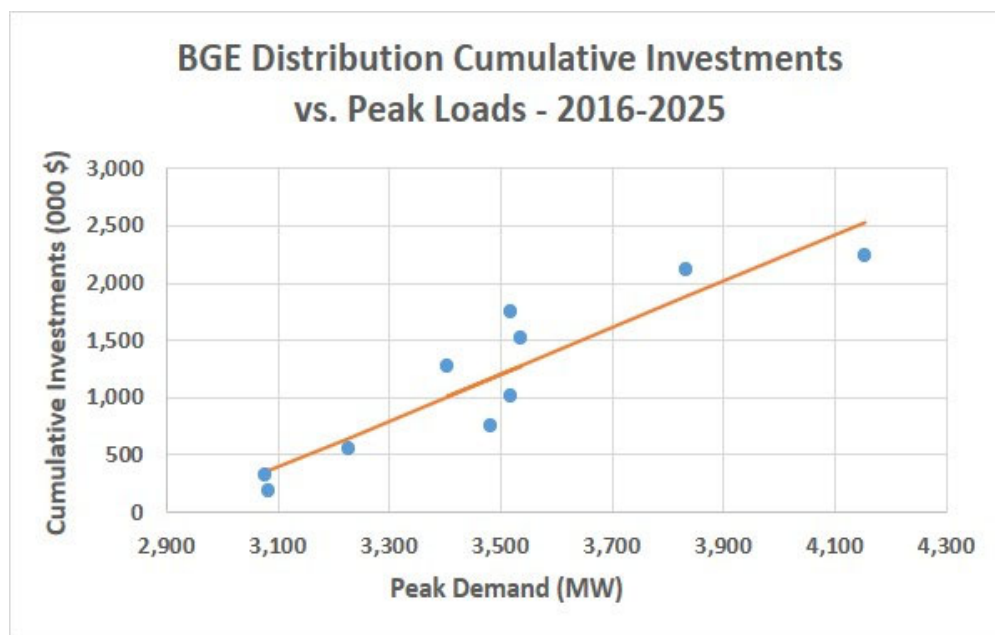


Table 1: BGE Marginal Distribution Cost

Parameter	Value	Unit	Source
Regression Slope from Figure 1	2,152	\$/kW	Regression analysis
General Plant Loader	6.7%		FERC Form 1 data
General Plant Loader	145	\$/kW	= 0.067 x 2152
Total Marginal Distribution Cost	2,297	\$/kW	Regression slope + general plant loader
RECC Factor	5.7%		BGE financial data
Annualized Marginal Distribution Cost	131	\$/kW-year	= 0.057 x 2297
Distribution O&M	43	\$/kW-year	FERC Form 1 data
Total Marginal Distribution Cost	174	\$/kW-year	= 131 + 43

To estimate the solar capacity contribution to reducing distribution costs, we used the hourly profile of BGE's loads to determine an hourly allocation of system demands that exceed 90% of the load in the annual system peak hour. In this allocation, hours with loads above the threshold of 90% of the annual peak hour load are weighted by how much the load in an hour exceeds the 90% threshold; thus, the annual peak hour receives the greatest weight. Hours with loads below the threshold receive no weight. This is commonly called the Peak Capacity

facilities change with load growth, and concludes – probably correctly – that they do not. In the context of avoided distribution investments, however, we are talking about the O&M costs associated with distribution plant that is never built. If DERs allow the utility to avoid or defer a distribution investment, it will also avoid or defer the O&M costs that would have been necessary to operate and maintain that investment – this is the distinct avoided distribution O&M cost that the loader captures.

Allocation Factor (PCAF) approach to allocating capacity costs to peak hours.²⁸ The PCAF approach is a broader measure of contribution to reducing peak demand which recognizes that portions of the distribution system can peak at different times. We applied the BGE PCAF hourly allocation based on its system loads to the typical meteorological year profile of hourly solar output in Baltimore provided by PVWATTS. The result is a capacity contribution of 37% of solar nameplate to reducing the highest distribution loads on BGE's system. The resulting avoided distribution capacity cost is \$38.90 / MWh or **3.9 cents/kWh**, as shown in **Table 2**. The same PCAF approach also can be used to determine the solar capacity contribution of solar + storage projects (either BTM or FTM) to avoiding distribution capacity costs.

Table 2: BGE Avoided Distribution Capacity Cost

Parameter	Value	Unit	Source
Avoided Distribution Capacity Cost	174	\$ / kW-year	From Table 1
Solar Contribution to BGE Distribution Load	37%		PCAF calculation
Solar Output – Annual kWh per kW-AC	1,669	kWh/kW-AC	NLR PVWATTS
Solar Avoided Distribution Capacity Cost	38.90	\$/MWh	= 174 x 0.37 / 1669

The PCAF approach described above uses system load data. The method can be easily extended to capture even more accurately the peak load diversity on the distribution system, if hourly load data at each of a utility's distribution substations is used for a PCAF analysis of each substation. To derive an overall capacity contribution across the whole system, the individual PCAF allocations at distribution substations then can be combined using a weighting of each substation's allocation by either (1) the peak load at each substation or (2) the installed DER capacity at each substation. The result using either weighting is an allocation of avoided distribution costs across a broader set of hours that better reflects the diversity of distribution system loads.

²⁸ PCAFs are used extensively, for example, to allocate avoided transmission and distribution costs across the hours of the year in California's Avoided Cost Calculator (ACC), the state's equivalent of the EmPOWER avoided costs. See the documentation for the 2024 California ACC, at pp. 49-50, 61-63, and 93-102. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2024-acc-documentation-v1b_clean_posted_nowm.pdf.

4. GHG Impacts / Avoided RPS Compliance Costs

As discussed on the July 29 Working Group call, the JSP recommend inclusion of the benefit of reduced compliance costs for the Maryland Renewable Portfolio Standard (RPS). This benefit applies to DERs – such as BTM solar – that directly reduce utility sales that are the basis for each utility's RPS compliance requirement. A portion of the DER output is used to serve customer load behind the meter, reducing power imports from the utility. Exported power can also reduce utility sales, if the monthly netting of production and usage results in only monthly net loads being counted as the basis for RPS compliance.

The quantification of this benefit can use a forecast of renewable energy credit prices, or, alternatively, the future schedule of alternative compliance payments, times the RPS compliance requirement (percentage of utility sales) in each year.

5. Electric Utility System Risks

Section 4.2.8 of the UCBA Methods report discusses a number of risks that DERs can allow a utility to avoid:

- Reducing exposure to future energy and capacity price uncertainty (if a DER reduces demand);
- Reducing exposure to the cost of future environmental regulations (if a DER reduces emissions);
- Providing “option value” – i.e., slowing load growth and buying time to recalibrate needs assessments and allows for the emergence of lower cost solutions;
- Diversifying the resources relied upon to meet customers' electricity needs; and
- Increasing the modularity and flexibility of utility resources – i.e., “not putting all your eggs in one basket” and by retaining the ability to shift emphasis from lesser performing DERs to better performing DERs.

As the report notes, these risks reductions have economic value. The report recommends that these benefits be recognized by an adder of 10% on “all electric generation and T&D cost reductions resulting from... distributed generation, and distributed storage initiatives.”²⁹

The JSP support the recognition of these risk reductions. The 10% adder would be a minimum, conservative estimate of the value of these risk reductions. For example, it is straightforward to quantify the first risk reduction listed – the value of renewable generation at reducing exposure to future energy price uncertainty. Fossil energy prices are uncertain and volatile, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 5** below.³⁰

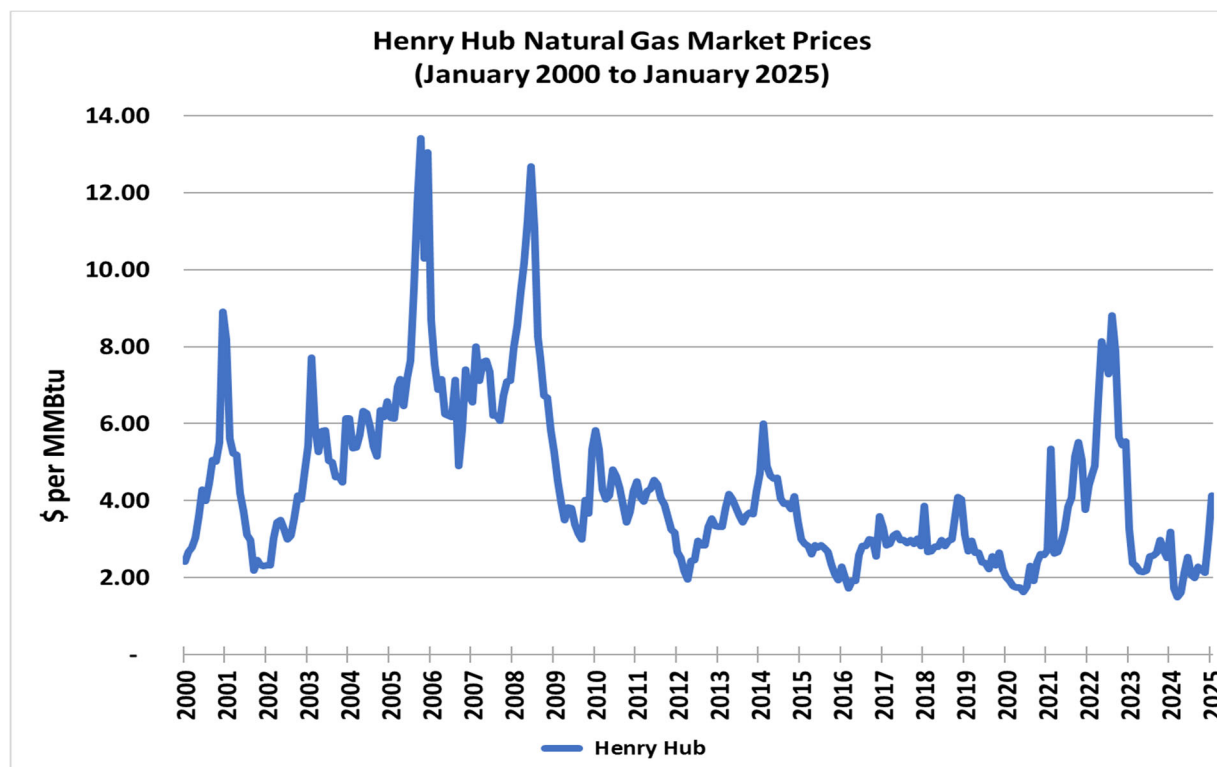
²⁹ See UCBA Methods Report, at p. 59.

³⁰ Data in **Figure 5** is from the Energy Information Administration's Henry Hub monthly spot prices.

By reducing a utility's use of gas resources, renewable generation decreases the long-term exposure of ratepayers to gas price volatility. This benefit is widely acknowledged:

Many renewable resource types also incur no fuel costs - in other words, there is no need to purchase commodities like coal or natural gas for them to use during power production. This reduces Dominion Energy customers' exposure to price spikes in the market for those fuel commodities, promoting stability in electric rates.³¹

Figure 5: *Historical Benchmark U.S. Natural Gas Prices*



The value to ratepayers from this reduction in exposure to “price spikes in the market for those fuel commodities”³² can be readily quantified. The value is what it would cost to fix the price of gas for 25 years, that is, for the economic life of a solar DER that displaces gas. A methodology to calculate this benefit has been developed by Clean Power Research for the Maine Public Utilities Commission.³³ This approach recognizes that one could contract for future gas supplies today, and then set aside, in risk-free investments, the money needed to buy that gas in the

³¹ See <https://www.dominionenergy.com/about/delivering-energy/renewable-projects>.

³² *Id.*

³³ See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (Mar. 1, 2015) at 39–40, <https://www.maine.gov/tools/whatsnew/attach.php?id=639056&an=1> (“Avoided Fuel Price Uncertainty” section).

future. This would be equivalent to fixing the cost of fuel for the life of the resource and paying for that fuel up front—which is what renewable resources do. This would eliminate the uncertainty in future gas costs and ratepayers' long-run exposure to commodity price swings. However, doing this is expensive, which is why ratepayers typically are left to bear this risk. The additional cost of this approach (compared to purchasing gas on an “as you go” basis and using the money saved for alternative investments) quantifies the benefit of reducing the uncertainty in the costs for the fuel that solar DERs displace.

These calculations were recently performed for the utilities in Virginia in the NEM dockets in that state, using the EIA *AEO 2025* natural gas forecast, U.S. Treasuries (at current yields) as the risk-free investments, and a marginal heat rate of 7,500 Btu per kWh. The results were values of \$23 per MWh for Dominion Energy and \$14 per MWh for Appalachian Power as the 25-year levelized benefit of reducing fuel price uncertainty.³⁴ Thus, this benefit alone would be a substantial share of, or perhaps even exceed, the 10% risk reduction adder suggested in the UCBA Methods Report.

A Risk Factor of a similar magnitude is used in the EmPOWER projection of Full Requirements avoided costs, as a measure of the “risk and return associated with serving load.” The EmPOWER documentation says that the values are derived from “a portion of the actual bids during the base residual auction each year,” suggesting that it is related to risks in the capacity market.³⁵ Thus, this risk factor may not be duplicative of the value discussed above for avoiding fuel price volatility.

The JSP recommend, at a minimum, the use of the 10% risk factor suggested in the UBCA Report, with consideration of whether the combination of the analysis presented above and the one used in the EmPOWER avoided costs would justify a higher percentage.

³⁴ See the testimonies of R. Thomas Beach on behalf of Appalachian Voices in the recent Virginia NEM dockets, at [849v01!.PDF](#) (pp. 25-27) and [894701!.PDF](#) (pp. 37-39). The results vary based mainly on changes to forecasted gas prices and interest rates over time.

Other methods of calculating this benefit produce similar results. For example, the market value of gas price volatility can be approximated by the straddle in the options market (the spread between the prices of simultaneous put and call options). The well-known consultant Amory Lovins has noted that this market value of gas price volatility is typically of the same size as the underlying commodity gas price. As a result, he has observed that “plant and grid operators that don’t count the gas-price risk are imposing on customers all the burdens of acting as if gas cost only about half as much as it actually does on a risk-adjusted basis.” See Amory Lovins, *Do Coal and Nuclear Generation Deserve Above-Market Prices?*, 30 *The Electricity Journal* 6 (July 2017) at 28.

³⁵ See EmPOWER Report, at pp. 11.

6. Conclusion

The Joint Solar Parties appreciate this opportunity to provide comments on the issues associated with the valuation of DERs in Maryland. We look forward to further participation in the NEM 2.0 Working Group and the Commission's PC 78 process.

Respectfully,

R. Thomas Beach
Patrick G. McGuire
Crossborder Energy

Consultants to the Joint Solar Parties



September 10, 2026

MAREC ACTION TESTIMONY for Energy Oversight Briefing: Implementation of the Utility RELIEF Act and Other Issues

Chair Korman, Vice Chair Guyton, members of the Environment and Transportation Committee,

MAREC Action (informally, “Mid-Atlantic Renewable Energy Coalition”) is a coalition of over 50 utility-scale solar, wind, and battery storage developers and manufacturers dedicated to the growth and development of renewable energy in Maryland and across the PJM grid region. We applaud the committee for holding this briefing and appreciate the opportunity to provide comments on the Utility RELIEF Act and other pressing energy issues in the state.

Maryland’s demand for electricity is rising at a time when capacity market supply is diminishing, creating an environment where consumer costs will rise dramatically. Changes should be made to both reform capacity market function and, importantly, to increase supply of electricity and dispatchable resources. Almost 75% of the megawatts in Maryland’s latest round of interconnection queue applications are for standalone energy storage and solar plus storage hybrid projects. Adding energy storage capacity in Maryland will have a price suppressive effect on the capacity market, reducing the overall impact of capacity prices on all customers. Other benefits of deploying energy storage resources include deferred or avoided investments in transmission lines built purely for reliability reasons, and expensive peak-demand serving natural gas facilities.

The Next Generation Energy Act competitive solicitations for front-of-the-meter storage projects are creating significant investment interest in the state, and we commend the PSC and its staff for all their work thus far. Additional procurements to fill the rest of Maryland’s 3 GW goal should be established, with tweaks to the program to allow for more flexibility and greater certainty for developers. This will ensure the best and most competitive outcome from future solicitations. Examples could include allowing flexibility to reprice bids during the PSC proceeding, allowing bidders to submit either a partial or full toll bid (bundled or capacity-only revenue), allowing for rolling applications, and clarifying the process for and amount of termination payments.



While current federal challenges are inhibiting offshore wind development, Maryland should begin thinking about how to structure future procurements to ensure the greatest chance of successful projects. Offshore wind can provide clean, high-capacity, stable-priced power to the state, helping to keep the lights on during winter peak demand events. Data shows South Fork Wind and Vineyard Wind performed as well as gas-fired power plants and better than coal-fired facilities during Winter Storm Fern earlier this year.¹ For large-scale energy investments with long construction timelines, including both offshore wind and nuclear, allowing for flexibility in pricing can increase the chance of success for a project. Inflation, supply chain issues, and changes to federal policy can be unforeseen hurdles at the time a projects bids into a procurement, and even after an award is issued. Under the Utility RELIEF Act, nuclear projects are given the opportunity to update their pricing by up to 15% of total project costs. This should be the standard for future offshore wind procurements as well.

Under the Next Generation Energy Act, nuclear procurements were granted other flexibility measures that the Legislature should consider for future offshore wind. These include allowing the PSC to set a price cap, unlike the legislatively set ratepayer cap for offshore wind, allowing for 30-year contracts compared to 20 for offshore wind, and it did not require a pass back of any state, federal, or local tax incentives to the ratepayer as was originally required for offshore wind. It's important for the Maryland to have parity between procurement structures for all large, time-intensive energy projects.

Additionally, we are supportive of providing additional authority for the PSC to pursue long-term transmission planning in coordination with other states. These kinds of projects can address multiple needs for Maryland ratepayers beyond offshore wind. The PSC could, for example, explore coordinated transmission investments with Delaware that bring reliable offshore wind power to shore, open up new land-based energy development opportunities, and deliver clean electrons into the BGE (Baltimore) zone where the greatest demand exists to replace retiring fossil fuel generators. This should be done in conjunction with FERC Order 1920 transmission planning efforts.

¹ <https://www.canarymedia.com/articles/offshore-wind/offshore-wind-showed-up-big-east-coast>



Thank you again for the chance to provide public comment prior to the briefing, and we look forward to continued discussion on these points during next year's legislative session.

Best regards,

Caroline Fletcher
State Affairs Manager
MAREC Action
PO Box 3335
Silver Spring, MD 20918

September 10, 2026

**Energy Oversight Briefing
Environment and Transportation Committee
250 Taylor House Office Building,
Annapolis, Maryland 21401**

Re: Energy Oversight Briefing: Implementation of the Utility RELIEF Act and Other Issues

Dear Chair Korman, Vice Chair Guyton, and Members of the Committee,

The Maryland Energy Efficiency Advocates (MEEA) appreciate the opportunity to provide stakeholder comments on the implementation of updates to the EmPOWER Maryland Program driven by the Utility RELIEF Act. MEEA represents a diverse group of advocates committed to the equitable implementation of Maryland's energy programs because of their unique ability to reduce energy costs for ratepayers, support Maryland's climate goals, and provide non-energy benefits to participants, such as healthier and safer living conditions. MEEA has actively participated in EmPOWER proceedings and workgroups for over a dozen years, filing stakeholder comments supported by evidence and analysis to raise important issues for the Commission's consideration. In this spirit MEEA wishes to share its concern that the Utility RELIEF Act's EmPOWER Maryland provisions are not being implemented to comply with the Act's requirements.

MEEA Support for EmPOWER

MEEA believes strongly in the value of energy efficiency and supports continuation of EmPOWER Maryland's role as the state's largest and most impactful energy efficiency program. We appreciate the committee's continued support for the program, and wish to emphasize the following points as the committee considers implementation of the Utility RELIEF Act.

1. In times of concerning utility rate increases, EmPOWER is the best tool for helping customers manage their energy costs.

- EmPOWER helps customers reduce their energy bills by offering rebates on major appliances, funding home energy audits and weatherization, providing demand response programs that pay people to shift their energy usage during grid emergencies, providing incentives for building new construction to high efficiency standards, and more. Millions of customers interact with the program directly every year.
- Importantly, EmPOWER helps Maryland residents make changes to manage their energy costs when rates increase and energy bills are rising. Many of the homes with the highest

energy costs need long-term solutions such as updated appliances or insulation. EmPOWER makes those changes more affordable, providing support to identify and implement the improvements that will help the most.

2. EmPOWER is a critical program to help manage the cost of meeting Maryland's energy needs because it reduces the cost of energy supply and transmission/distribution investments through local investment in demand side resources.

- [A February report](#) from the American Council for an Energy Efficient Economy (ACEEE) finds that energy efficiency (~\$21/MWh) and load flexibility (<\$40/kW-year) are currently the lowest-cost resources for reducing electricity consumption and peak demand. These “demand-side measures” are also quicker to implement and provide a “no-regrets” approach to new energy demands.
- EmPOWER provides immediate benefits to customers. [With PJM facing grid-emergencies](#), EmPOWER helps provide immediate energy savings and peak demand reductions every year.
- Reductions to EmPOWER savings means energy demand will increase, and must be met with resources that cost more.
- EmPOWER achieves savings locally. It supports local jobs in the home performance and HVAC industry, invests in upgrades to Maryland homes, and supports local businesses meeting their energy needs.

3. EmPOWER is cost effective, providing significantly more in economic benefits than it costs.

- In 2024, the statewide residential programs had a cost-benefit ratio of 1.84 (returning a net present value of \$1.84 in benefits for every \$1.00 invested). The commercial programs had a cost-benefit ratio of 1.50. The most recent [PSC annual report](#) on EmPOWER notes that these results correspond to a net benefit of approximately \$316 million in net present value.
- With the costs of energy capacity, energy supply, and infrastructure upgrades all driving up rates, the cost saving benefits of energy efficiency are even higher - meaning that bill savings from efficiency increase as rates go up.
- In the 2027-2029 program cycle, the estimated cost-effectiveness ratios in the utility plans filed earlier this month range from 2.2 to 1.8 at the portfolio level.

MEEA Concerns with Implementation of the EmPOWER Maryland Provisions of the Utility RELIEF Act

MEEA recognizes that the General Assembly determined to temporarily reduce EmPOWER goals with the intent to reduce near term program expenditures and associated bill impacts, but is deeply concerned that the Public Service Commission has directed the EmPOWER utilities to

save less than the 1.75% required by statute based on a faulty analysis of the law's requirement. This concern led MEEA to file a rehearing request with the PSC in response to its July goal-setting order, which MEEA believes will fail to achieve the legally-required savings. The issue is a technical one, however, the impact is that Maryland households and businesses would have fewer opportunities for energy savings than they are entitled to under the law.

Concerns with PSC Interpretation of Statute

The RELIEF Act requires that EmPOWER achieve lifecycle GHG savings equal to at least 1.75% annual electricity savings. This marks a reduction from the 2.5% savings that was in statute before the Utility RELIEF Act changes. The lifecycle greenhouse gas emissions equivalent of annual electricity savings depends on the length of time that those energy savings measures last, known as their "Estimated Useful Life ("EUL")."

The statute requires the PSC to establish a goal that will "achieve at least the greenhouse gas emissions reduction equivalent, measured on a lifecycle basis using the emission intensities under paragraph (2) of this subsection, of [1.75%] annual electricity savings calculated as a percentage of the electric company's 2016 weather-normalized gross retail sales and electricity losses." [§7-223(b)(4)]. In other words, the law states that compliance with the statutory requirement is based on the actual program results – not just hitting a PSC-given goal. Therefore, the goals must be based on an EUL value that is at least the average EUL of the expected program savings in order to ensure that the lifecycle GHG savings will be at least equal to 1.75% annual electric savings.

Because the Commission established goals using a shorter EUL than the programs will ultimately deliver, the utilities will not be on track to meet the statutory savings requirement. MEEA's rehearing request notes that current assumptions for EUL used by the PSC in the goal setting process (7 to 9.6 years) are lower than a reasonable expectation for what would be in the plans filed by the utilities, a concern that is born out in an initial analysis of the plans that were filed 9/1. In addition to utility planning preferences, this is a result of allowing 20% of each utility's savings coming from claiming credit from solar interconnections. These solar measures will have long-lived savings of 25 years, but this was not factored into the Commission's determination of the utility goals.

Costs of Incorrect Goal Determination

In the PSC workgroup process established to recommend goals to the Commission, MEEA, the Office of People's Counsel, and other parties supported a methodology developed by the American Council for an Energy Efficient Economy ("ACEEE") which incorporated an EUL that included the longer-lived solar measures allowed by the Utility Relief Act. MEEA believes that the ACEEE-calculated goal is the minimum required by the law. Given that the program remains cost effective, provides an important tool for Maryland utility customers to manage their

energy bills, and contributes to lower long-term utility costs, MEEA recommends the PSC correct its calculation error and establish goals to comply with the statute.

In a related analysis, ACEEE has determined that the flawed goals determined by the Commission will result in \$13 million to \$40 million less in net economic benefits than the ACEEE proposal.

MEEA is happy to share additional information with the Committee. All filings are publicly available in the [EmPOWER 2024-2026 docket #9705](#). ACEEE has previously offered to provide additional information to the Commission in support of their analysis and has shared they would be willing to do the same for the Committee.

We thank the committee again for their work on Maryland energy policy and for the opportunity to provide comment.

Sincerely,
Maryland Energy Efficiency Advocates

MEEA includes the following organization that have signed on to these comments: Earth Justice, Green & Healthy Homes Initiative, Maryland PIRG, Center for Progressive Reform, Maryland Legislative Coalition-Climate Justice Wing, and HoCo Climate Action

Dear Chair Korman, Vice Chair Guyton, and members of the House Environment and Transportation Committee,

Solar Landscape submits this update on implementation of the Utility Relief Act and the PC78 NEM Successor Working Group. We support the Working Group's pragmatic shift toward an interim compensation value given the compressed timeline, but flag several issues that will determine whether Maryland's rooftop community solar pipeline remains financeable and whether the program continues to deliver on the Act's affordability and equity goals:

- **Rooftop needs to be modeled as its own configuration.** The consultants' recent action of treating rooftop CapEx as a distinct line item is a meaningful first step, but that differentiation needs to be carried through every remaining input, including lease rates and value-stack assumptions, not treated as a one-off fix. National cost benchmarks have also shifted away from rooftop-representative data, making this modeling distinction even more critical.
- **Financeability requires clear guidelines for maintaining eligibility.** Projects financed under NEM 2.0 interim values could become unfinanceable overnight if compensation is changed abruptly. We recommend the Committee support retaining eligibility under any NEM 2.0 interim framework for qualifying projects while a longer-term value-stack framework is built out.
- **The ultimate value cannot be set too low that it ends rooftop community solar development.** Options like a Standard Offer Service-based value would be an order-of-magnitude cut incompatible with continued rooftop development. This is not just a developer financeability issue: undervaluing rooftop also means forgone grid-cost savings for all ratepayers and forfeited LMI bill credits for the households the Act was designed to help.
- **Timing compounds the risk for rooftop solar specifically.** A reduced NEM value will land alongside the scheduled ACP step-down and the looming expiration of the Brighter Tomorrow Small Solar Generator Incentive (SGI) program, squeezing both major components of project compensation at once for the project type least able to absorb the shock.
- **The SGI should be extended and expanded to serve as a bridge to durable REC/RPS reform.** As Maryland considers broader incentive and RPS reform, differentiated, preferred-siting incentives like those SGI provides today need to continue. Extending SGI's in-service deadline to align with the federal ITC's expiration and expanding capacity for large systems allows the legislature and Commission time to design a more durable reform, without letting preferred-siting incentives lapse.

We appreciate the Committee's continued attention to these issues and welcome the opportunity to provide further detail below. For questions or to follow up, please reach out to Damali Harding, Senior Director of Policy and Markets, at dharding@solarlandscape.com

Thank you.

On Implementation of the Utility Relief Act and the PC78 NEM Successor Working Group

Solar Landscape appreciates the opportunity to update the Environment and Transportation Committee on how implementation of the Utility Relief Act is proceeding, specifically within the PC78 Net Energy Metering ("NEM") Successor Working Group. Since the Act took effect, we have participated actively in the Working Group, and we want to provide feedback on the current implementation and where we think the Committee's continued attention would help keep the process on track. Due to the compressed timeline, the consultants for the working group appear to be moving toward an interim approach, which we support, but several open issues, chief among them how rooftop community solar is valued and modeled, will determine whether projects already in the pipeline remain financeable.

Background

Founded in 2012, Solar Landscape is a vertically integrated solar developer and national leader in community solar deployment. We focus on developing community solar projects on commercial and industrial rooftops using a roof-lease model in which we lease the rooftops of large warehouse and storage facilities to host solar installations that deliver power back to the grid through community solar in Maryland.

Maryland is a central part of our portfolio, and our work aligns directly with the state's clean energy and equity priorities. Currently our portfolio consists of 102 projects, 49 of which have energized and are already delivering clean energy to Marylanders. The other 54 projects are currently under development. All our current projects have been awarded funding under the Maryland Energy Administration's Community Solar LMI PPA Grant and are committed to providing at least 51% of energy produced to either low-income or low-to-moderate-income households. Solar Landscape is ranked the #1 Maryland Commercial Solar Contractor, reflecting our sustained investment in the state's community solar program. We remain committed to helping Maryland meet its renewable energy targets and advance energy equity.

PC78 Status Update

A Compressed Timeline Is Pushing the Working Group Toward an Interim Value

The consultants retained by the Working Group are operating under a very short timeline, and as a result, discussions have shifted toward adopting an interim value for NEM compensation, before later shifting to the more nuanced type of value-stack approach that we believe was originally envisioned for the successor program. A value stack approach would set compensation based on the actual costs and benefits a distributed energy resource provides to the grid at its specific location, rather than a single rate applied broadly across projects. Building that kind of locational, data-driven model requires new data collection and intensive



stakeholder involvement that is not feasible under the current timeline, which is why the consultants are proposing to start with a simpler interim value that is refined over time. The interim value would be less than retail rate to meet the intent of the Utility Relief Act. Currently the consultants consider two main methodologies for export energy compensation:

1. Full retail less a new non-bypassable charge modeled after current riders that are derived from EmPOWER values
2. Standard Offer Services

Therefore, we support the pragmatic path forward of adopting an interim value. From our perspective, a workable interim value is preferable to further delay, and we encourage the Commission and ENT members to support this approach given the deadline the Working Group is facing.

Of these two options, the first, full retail rate less applicable EmPOWER based non-bypassable charge, would result in a value lower than the current NEM rate without clear visibility into how the charge is calculated. We have asked that additional information on the EmPOWER charges be shared with and reviewed by stakeholders before that component is finalized. The consultants have described the EmPOWER methodology as a vetted framework in Maryland, but numerous stakeholders have raised concerns about the specific inputs feeding that methodology. In order for a full value stack methodology to be implemented, those EmPOWER inputs should be updated with current data before they are relied on for a successor program.

Rooftop Community Solar Needs to Be Modeled as Its Own Configuration

The working group's consultants presented recent modeling that, for the first time in the proceeding, treats rooftop community solar CapEx as its own distinct line item and rooftop as its own distinct configuration for the modeling of impacts. Although this is a meaningful first step, the modeling notably does not account for differential lease rates between ground-mount (lower, typically rural lease rates) and rooftop systems (higher, typically urban/suburban lease rates). Their preliminary findings show that under NEM1.0 and their proposed interim compensation values, ground-mount community solar generates unlevered IRRs nearly double those of similar sized rooftop community solar. That means any reduction in compensation will fall disproportionately on rooftop community solar, which isn't capturing the same higher returns as ground-mount but offers unique value to the distribution grid as discussed below.

This kind of differentiation needs to be carried through every remaining piece of the successor program's modeling; not just CapEx, but lease rates, value stack assumptions, and any other input where economics and benefits of rooftop systems diverge from those of ground-mount systems. Treating today's CapEx adjustment as a one-off fix, while leaving the rest of the compensation or future policy calibrated to ground-mount assumptions/preference, risks creating a patchwork that will systematically undercompensate rooftop community solar



projects. We're glad to see the consultants acknowledging the difference that project siting creates, and we will continue advocating that this same distinction be applied consistently in the current proceeding as well as more broadly in Maryland policy

That said, because we represent a relatively small segment of the broader community solar industry, there is a real risk that, given the tight schedule, the consultants treat today's step as sufficient and don't carry the differentiation through other remaining inputs or eventual benefits calculations. We want to flag that risk for the Committee, who have been supporters of C&I rooftop community solar. If those remaining inputs aren't brought in line with rooftop's actual economics, compensation will still be partly set using ground-mount assumptions that don't reflect how our projects operate or benefits provided to the grid.

There is also a data problem working against us here. National cost benchmarking has drifted away from rooftop as its reference point for this configuration: the National Laboratory of the Rockies (renamed from NREL by DOE in December 2025) modeled its "Commercial PV" representative system, historically the closest publicly available proxy for community solar Capex, as a 200-kWdc rooftop installation from 2010 through 2022, but shifted to a 3-MWdc ground-mounted system starting with its Q1 2023 cost benchmark report, citing industry feedback on growing project sizes and New York's 2.5-MWdc mean community solar system size.¹

In other words, a generic "community solar" Capex figure pulled from current national benchmarks is really a ground-mount number, not a rooftop one, underscoring why incorporating a rooftop-specific configuration into the consultants modeling matters and why that distinction needs to be reflected across every input, not just Capex. The value/benefits side also helps to support the unique value; Brattle's study found that urban rooftop community solar is worth 1.3 to 2.2 cents per kWh more than rural, ground-mounted solar in a base case, and 2.9 to 4.1 cents more in a high case, primarily due to avoided transmission and distribution costs.² Those avoided costs lower utility bills for all ratepayers, not just rooftop subscribers. That very real grid-cost savings is not accounted for if rooftop's value is folded into a generic, ground-mount-calibrated value stack. If the successor framework ends up applying a single, ground-mount-calibrated value stack to all community solar, it will undervalue rooftop's benefit at the same time it understates rooftop's cost, compounding the risk described above.

Financeability Depends on Grandfathering During the Transition

¹ *Documenting 15 Years of Reductions in U.S. Solar Photovoltaic Costs*, National Laboratory of the Rockies (formerly NREL), DOE/GO-102025, 2025, Figure ES-1 note (confirming "Commercial PV costs...represent a 200-kWdc rooftop application for 2010–2022 and a 3-MWdc fixed-tilt ground-mount system from 2023–2024"). Available at osti.gov/servlets/purl/2522804.

² *Maryland Value of Commercial Rooftop Solar*, The Brattle Group, prepared for Solar Landscape, January 2026.



Recent discussions within the Working Group have rightly raised financeability as a central issue. Projects will be underwritten based on the compensation available under an interim NEM structure if it is adopted. If that value is reduced abruptly, projects that are under development, and that financing partners have already committed capital to, could become unfinanceable overnight. We recommend that the Committee support extending grandfathering under the temporary NEM 2.0 structure for projects that meet maturity requirements similar to those applied under NEM 1.0, while the new value-stack calculator is built out. This preserves financeability for near-term projects without holding up implementation of the successor program for new development.

The Ultimate Value Cannot Be Set So Low That C&I Rooftop Community Solar Projects Stop Being Economical

Our primary concern in this proceeding is the ultimate value that will be established for rooftop community solar exports. The interim methodology proposed that subtracts a non-by-passable EmPOWER surcharge is not detrimental to the current economics, so it does not, on its own, drive this concern. However, other options the consultants have floated as interim solutions could materially harm rooftop community solar projects if adopted. If the value is set too low, projects simply will not be financeable. Existing commercial solar rooftops represent about 6 gigawatts of potential solar generating capacity.

This is not only a financeability problem for developers, but also an affordability problem for the state. Rooftop projects tend to be sited in higher-congestion, capacity-constrained parts of the distribution grid, leading to greater avoided transmission and distribution costs than ground-mount projects, which are typically sited away from load centers. When rooftop projects get built, developers pay for the grid upgrades needed to interconnect them, such as new transformers and substation upgrades, strengthening the grid at no cost to ratepayers. When a project fails to get built, those upgrades don't happen now, but the grid will still need them eventually. The utility will then have to pay for that same work itself, and ratepayers absorb the cost through higher charges.

Those same unbuilt projects also forfeit the LMI bill credits they were designed to provide, savings that matter just as much, even if they aren't unique to rooftop. A successor value needs to be calibrated to protect both halves of that affordability equation, not just avoid a NEM cost shift.

As an example, the consultants have proposed setting an interim value at the Standard Offer Service rate. This would be an order-of-magnitude cut relative to current compensation, a change that would be incompatible with continued rooftop community solar development in Maryland and which we believe would not represent the intent and spirit of the Utility Relief Act. Our preferred path remains a full value-stack methodology, with real weight given to



locational value, so compensation also helps direct grid investment to where distributed generation can provide the most grid benefits, and in turn the most ratepayer savings.

Future Incentive and RPS Reform Considerations

The value the consultants ultimately recommend for NEM compensation will not be set in isolation. REC value and energy value are the two main components of project compensation, and NEM's decline is set to occur at the same time as the scheduled step-down of the ACP. Compounding that pressure, the Brighter Tomorrow Small Solar Generator Incentive (SGI) program, created specifically to incentivize rooftop and other preferred-siting projects, is set to expire, with projects required to be placed in service by January 1, 2028 to qualify. Together, a lower NEM value and a declining ACP put pressure on both of the main revenue streams project economics depend on, at the same moment the incentive designed to support preferred siting is disappearing.

This combination is especially consequential for rooftop community solar. As rooftop projects carry higher build and interconnection costs than ground-mount, they have less margin to absorb a simultaneous decline in both value streams. At the same time, rooftop's siting profile makes these projects uniquely valuable to the grid, particularly as load growth continues to increase demand on Maryland's distribution system. That combination of lower ability to absorb reduced compensation and outsized value to the grid is exactly why Maryland should continue to incentivize rooftop and other preferred-siting projects.

Maryland should take up RPS and REC incentive reform with that in mind. The clearest path is to extend and expand the SGI program itself, discussed further below. However, if reform instead proceeds through broader RPS restructuring, that reform should preserve the same differentiation, continuing to recognize and incentivize the projects that deliver unique value to the grid, rather than treating all resource types as interchangeable.

SGI Performance and Impact

The SGI program is a clear example of the kind of preferred-siting incentive Maryland should be protecting, and it is already doing real work for the state beyond supporting individual projects. It also helps utilities meet growing Renewable Portfolio Standard ("RPS") obligations more efficiently: credits from SGI projects carry a 1.5x multiplier, so utilities can meet compliance targets faster with in-state generation and avoid additional Alternative Compliance Payments ("ACP"). Put simply, two RECs from a qualifying project effectively provide three credits toward compliance. That reduces reliance on penalty payments and instead turns compliance dollars into real projects connected to Maryland's grid, keeping compliance costs — and the affordability pressure they place on ratepayer bills — lower than they would otherwise be.

The large project category, with a total allocation of 270 MW, is already 53 percent utilized, representing 154.53 accredited under the program. Those projects could generate as much as 225,000 RECs annually. With the 1.5x multiplier applied, that output counts as approximately



337,500 credits toward RPS compliance. Without the multiplier, utilities would receive credit only for the projects' actual REC production, a gap of roughly 112,500 credits. At the 2027 solar ACP level of \$35 per MWh, that gap would translate to roughly \$3.9 million a year in ACP payments if utilities had to make up the shortfall rather than benefiting from the multiplier. The multiplier is delivering measurable compliance value while making sure ratepayer dollars support in-state solar deployment rather than penalty payments. As the ACP continues its scheduled step-down, this multiplier becomes an increasingly important tool for preserving compliance value while keeping ratepayer dollars flowing to in-state solar deployment rather than penalty payments.

Why the SGI Needs to Be Extended and Expanded

We recognize that the SGI was intended to be a bridge, however as it stands today there is no viable reform that the bridge is leading to. Extending the SGI would allow more time for the legislature and the Public Service Commission to design a reform. The SGI needs two targeted changes to remain viable in the interim: extending the in-service deadline to 2031 and expanding the available capacity for large eligible systems. Both are necessary to preserve the program's momentum and give today's market the certainty it needs. Extending the deadline to 2031 would align the SGI with the end of the federal Investment Tax Credit ("ITC"), which developers are already racing to meet.

C&I rooftop solar projects run on 12- to 24-month development timelines. If a C&I rooftop lease is signed today, financing partners cannot be confident the project will be placed in service before the current January 1, 2028 expiration date, so they underwrite it as though the incentive will not be available at all, even if the project ultimately does come online in time to qualify. That conservative assumption materially weakens project economics and slows deployment. Aligning the SGI's sunset date with the federal ITC's would give projects entering development today the multi-year certainty they need to stay financeable.

Expanding capacity for large systems matters just as much. Capacity in the category is more than halfway allocated and demand keeps climbing. As developers race to finish projects before the federal ITC deadline, a meaningful amount of volume will likely get pulled forward into 2026. Without additional capacity, the program risks creating an artificial bottleneck just as the market is scaling, cutting off Maryland's ability to draw down federal ITC dollars while they are still available, and undercutting the very projects that deliver the most value to a grid under growing load pressure.

Future Reform: Differentiated Incentives for Rooftop Systems



The same configuration issue we raised earlier in this update applies to incentive design, not just export compensation. If rooftop community solar is grouped together with ground-mount for purposes of any successor incentive, rooftop systems will be undervalued for the same reasons they risk being undervalued in the NEM compensation methodology, despite the outsized value their siting profile delivers to a constrained grid. Paired with a reduced export rate coming out of the NEM successor process, that combination could materially damage Maryland's rooftop community solar market at the exact moment the state needs more of this capacity.

We would ask the Committee to keep that link in mind heading into next session, where distributed generation incentive reform may be a focus. Whether reform proceeds through an expanded and extended SGI or through broader RPS restructuring, compensation and incentives need to be considered together, and both need to reflect rooftop's distinct cost and value profile.

Solar Landscape has built its Maryland business around the state's community solar program because Maryland has been a stable and predictable place to invest. As the Working Group's process under the Utility Relief Act continues, we will keep pressing for the pieces that preserve that stability and bring increased generation to the state.





Comments of Third Act Maryland

Energy Oversight Briefing: Implementation of the Utility RELIEF Act
House Environment and Transportation Committee
September 15, 2026

Chair Korman, Vice Chair Guyton, and Members of the Committee:

On behalf of Third Act Maryland, we applaud the Committee's decision to hold this oversight briefing on implementation of the Utility RELIEF Act. This complex legislation touches many issues at the heart of Marylanders' concerns about energy and climate policy and affordability.

Third Act Maryland is a volunteer organization that brings together older adults who want to build a better future for our children and grandchildren – in this instance, by strengthening clean energy policies and reducing energy costs to consumers. Our comments will focus on just one aspect of the law, section 7-306.4, concerning the Public Service Commission's implementation of the state's net energy metering program.

In that section, the Utility RELIEF Act states the General Assembly's intent to transition to a net energy metering program that:

- (1) increases benefits to ratepayers by lowering electric system costs through the use of flexible customer-sited renewable energy resources;
- (2) provides fair compensation to eligible customer-generators;
- (3) is designed to make progress toward meeting the State's demand-side, energy storage, and clean energy goals; and
- (4) provides incentives for the development of distributed generation that are less than the incentives provided by the net energy metering program under section 7-306 of this subtitle.

In May the Public Service Commission convened a Net Energy Metering Successor Program Working Group to seek a broad range of input from utility companies, owners and developers of net metered projects, renewable energy industry experts, consumer advocates, and other stakeholders. Third Act Maryland has been a participant in this working group.

To date, however, the working group has focused almost exclusively on reducing the rate paid to customer-generators. In doing so, it has completely ignored "meeting the State's

demand-side, energy storage, and clean energy goals,” which may result in unfair compensation to eligible customer-generators. We believe this approach is grossly out of balance, and we ask that the Committee direct the Commission to give equal weight to all of the General Assembly’s four stated objectives.

Regarding the state’s clean energy goals, the Commission’s consultant, Customized Energy Solutions, showed that the reduction in greenhouse gas (GHG) emissions provides a very large benefit to the state. In fact, they found that GHG reductions make up 38% of the total lifetime benefits associated with a 5 MW solar installation. Yet they concluded – incorrectly, in our view – that that GHG benefits should **not** be included in the calculation of total benefits.

Given the consultant’s assumptions about the output of a 5 MW installation, the GHG benefit would amount to \$135.99 per MWh. But the consultant argued that it could ignore that benefit because it was already reflected in the solar renewable energy credit (SREC). However, the consultant also assumed that an SREC would be worth only \$31.50 per MWh. The difference between the GHG benefit of \$135.99 and the assumed SREC of \$31.50 is a benefit of \$104.49 per MWh that the consultant ignores – to the detriment of customer-generators.

With regard to a rate reduction for customer-generators, the Commission’s consultant proposed three alternatives to the current rate – labeled NEM 2a, 2b, and 2c. All three reduce the payments to customer-generators. To illustrate: For a PEPCO customer who buys 1000 kWh a month and sells 1200 per month, under NEM 2a, the customer would get a credit of \$44.92, and under NEM 2b a credit of only \$27.39. NEM 2c reduces the credit even further by applying the total of the standard offer service rate and the transmission charge to all kWh sold to the utility. In this case, the customer would pay PEPCO the total retail rate for 1000 kWh purchased and receive the lower rate for 1200 sold. Instead of receiving a credit, the customer would owe PEPCO \$60.29. Under no stretch of the imagination is that “fair compensation,” nor would it encourage the installation of solar energy systems.

We understand the desire to reduce system costs to consumers – a worthy goal. However, we are concerned that the Commission is developing a net metering program that will neglect the General Assembly’s intent to provides fair compensation to eligible customer-generators and make progress toward meeting the State's demand-side, energy storage, and clean energy goals. We ask the Committee to remind the Commission of the equal importance of those objectives.



UPGRADE MARYLAND

SAFE AND HEALTHY ENERGY FOR EVERY HOME

Energy Oversight Briefing
Environment and Transportation Committee
September 15, 2026
Comments from Upgrade Maryland

The Upgrade Maryland Campaign is a diverse group of businesses, community groups, consumer advocates, environmental organizations, and faith groups working to upgrade Maryland homes and buildings to be more efficient, pollution free, and run on energy that is clean, renewable, and safe. We want to protect residents from unnecessary rate hikes to pay for methane gas equipment and jumpstart an equitable transition to clean heat.

Chair Korman, Vice Chair Guyton, and Committee members,

Thank you for the opportunity to submit pre-hearing written comments regarding implementation of the Utility RELIEF Act and other issues. We appreciate the work of the Governor, legislature and state agencies to support the transition to a clean energy future and protect consumers through the Next Generation Energy Act, Utility RELIEF Act, and other proceedings, regulations, and Executive Actions.

The focus of our comments is to update you on the implementation of reforms to the STRIDE program (passed within the Next Generation Energy Act) and changes to ratemaking policies (from both the Next Generation Energy Act and Utility RELIEF Act).

For both of these issues, we have concerns that electric and/or gas utilities are evading the law or laws' intent. And in some instances, such as addressing the maintenance of the gas system, we are concerned that the Public Service Commission is not adequately enforcing the law and may need more direction from the legislature. We are also sharing an update on the PSC's Future of Gas Proceeding.

Next Generation Act - implementation of changes to Public Utilities Article.
AKA Implementation of STRIDE Reform and the Ratepayer Protection Act

The Next Generation Act went into effect on June 1, 2025 and included changes to PUA § 4-210 (commonly known as the STRIDE law) and § 4-214 to require gas utilities to prioritize safety and demonstrate that gas pipeline spending is cost-effective.

The struggle to implement the law reinforces the need to take more decisive action. It's time for the legislature to seriously consider repealing the STRIDE law, while maintaining these safety and financial safeguards. The gas utilities are legally obligated to maintain the safety of their gas systems without additional financial incentives provided by STRIDE and other forms of forecast ratemaking. These surcharges and incentives should end.

Utility non-compliance and regulatory delay

Since the passage of the NGEA, BGE and WGL have proceeded with planned 2026 gas pipeline replacement programs without making any changes to project plans or demonstrating compliance with the law. After pushback from the Office of the People's Counsel and other stakeholders on WGL's 2026 project plans under STRIDE (case no. 9708), the [Commission issued a February order](#) beginning a rulemaking process, directing staff to file draft regulations by the end of June. In July, the Office of People's Counsel filed a legal appeal against the PSC for [failure to enforce the law](#).

The failure to implement the Next Generation Energy Act and apply its legal standards to active and planned gas infrastructure projects is troubling for a variety of reasons.

First, as noted, the Next Generation Energy Act is a self-actuating law that has been in effect since June 1, 2025. The PSC has never issued regulations to implement STRIDE since the program's creation in 2013. Gas utilities that have been able to operate under STRIDE for a decade are now requesting regulations before complying with changes to the law that require documentation to confirm safety prioritization and cost controls. The PSC's June order approving the WGL project list and silence on the BGE 2026 project list is delaying implementation of an active law. This delay could be adding unnecessary costs to customer bills and increasing safety risk of the gas system.

Second, although Upgrade Maryland questions the need for regulations to implement the relevant provisions of NGEA, we and other stakeholders have participated in the process in good faith. That being said, we are concerned that the process may not result in regulations that fully implement the letter of the law and the spirit of the legislature's intent. We are also concerned that the delay in implementation has already caused harm to ratepayers.

Specifically, in creating regulations in rulemaking 95 (RM95), there have already been multiple delays. Staff filed [draft regulations in August](#) which mirrored, almost in entirety, draft regulations submitted by Washington Gas. The draft does not meet the requirements in the law and may cause more harm than good. Since then, Staff have made additional changes, submitting yet another draft, but serious problems persist, and a delayed rulemaking hearing isn't scheduled until the end of October. This date is so late that we are seriously concerned the regulations cannot be finalized in time to apply to the 2027 project lists, and that the regulations will not be finalized until mid 2027.

This delay in regulations, of course, should not absolve gas utilities from having to comply with the law, but past behavior suggests the PSC may not require them to do so.

Growing evidence suggests pipe replacement programs are critically flawed

The draft regulations were submitted at the same time as [new research](#) shows that gas utilities' pipe replacement programs are failing to deliver safety improvements and evidence suggests aggressive replacement programs are themselves a source of safety risk.

This builds on 2025 research from Maryland PIRG Foundation [on BGE's 2025 gas pipeline work](#) which found that the company is not adequately prioritizing safety. If BGE completes its \$4 billion in STRIDE-related spending without intervention, the Office of People's Counsel projects customers will

repay [\\$19.5 billion over time](#), including interest and utility profits. Washington Gas has also proposed \$3.9 billion in gas pipeline spending, which could cost customers \$22 billion to pay back.

Due to BGE's aggressive spending, its rates have shot up. The average BGE customer has seen their gas delivery charges [more than triple from 2010 to 2024](#), while BGE profits have more than doubled from \$211 million in 2014 to \$578 million in 2025. BGE gas customers now pay BGE \$2 for delivery for every \$1 they pay for the gas itself. While WGL customers have yet to see this level of rate increases, they risk experiencing a similar fate if spending continues as planned.

In order to move forward, the Commission must enforce consumer protections on safety and cost effectiveness, including considerations of non-pipeline alternatives. We'd also encourage the Commission to use its regulatory authority to deny STRIDE plans altogether.

It's time for a more sensible approach to gas system safety management. One that prioritizes safety, supports the gas system we need, protects consumers from wasteful spending, and smooths instead of hinders the transition to a clean energy future.

Forecast Ratemaking and the Reconciliation Process

Through the Next Generation Energy Act and the Utility RELIEF Act the legislature made changes to state ratemaking policies including what types of costs are recoverable. One key change was prohibiting the use of a "reconciliation" process where the utility company, when operating under a multiyear rate plan or other form of forecast rates using a "future test year," overspends projections and returns to the Commission asking for additional revenue via a rate increase or temporary rider.

In 2026, under the Utility RELIEF Act, the legislature also instituted a one year moratorium on the PSC granting a rate increase based on forecast rates and directing the PSC to submit a study on the use of multi-year rate plans and forecast rates due in April 2027.

There are four updates since this legislation passed that are worth highlighting.

1. Although final comments were collected in September, 2025, the PSC has still not issued an order in response to its lessons learned proceeding evaluating the BGE multi-year rate plan pilot. [According to Exelon's recent report to shareholders](#) (p.10- or see below), the results of the proceeding and the April 2027 report to the MGA could result in \$1.8 billion in rate base growth for the company through 2029.
2. Thanks to the Utility Relief Act, PEPCO quickly rescinded a [portion of its proposed rate increase](#) that was based on forecasts. And in its August order on the rate case, the Commission rejected spending that was based on forecasts including, "[projected expectations of inflation, labor, and capital spend](#)." This experience demonstrated that utilities are able to share plans for future projects and spending without being granted advanced approval or reduced financial oversight on spending enabled by forecast test year ratemaking.

3. In July, BGE filed an \$156 million electric rate case increase using a historic test year of April 1, 2025, through March 31, 2026. There are several concerns from consumer groups on the rate case, including:
 - i. BGE claims that this request is a bare bones approach. But, the request is 40% higher than their last electric rate hike request in 2023. BGE electric delivery rates have nearly doubled since 2010, increasing at about twice the rate of inflation. BGE gas delivery rates have tripled.
 - ii. BGE is proposing to recoup storm costs more quickly to reduce the company's financial risk for storm management and ensure profits;
 - iii. BGE is pushing to increase its profit rate from 9.45% to 10.4%;
 - iv. BGE is proposing a so-called "flex play" program which would weaken termination protections for participants, enabling BGE to more quickly shut off service.
 - v. While BGE has not filed a rate case for its gas customers, the company has still [projected over \\$2 billion in gas capital spending to Exelon shareholders](#) in the upcoming years (page 42). This means that the company is likely to ask for a rate increase at some point down the road to cover current spending.
 - vi. BGE argues that its high profit numbers (which are on track to break another record in 2026) are somehow less relevant because they "reinvest" 95% of profits. But reinvestment isn't a donation to customers, it is simply turning profits into more profits due to the company's high return and low risk.
4. BGE and Delmarva Power are refusing to return [\\$32 million to customers that the companies overcollected](#). On August 31st, the OPC [filed a complaint on the issue with the PSC](#), asking the Commission to hold a hearing on the matter.

The Future of Gas Proceeding

First requested in 2023 by OPC as a petition for review of "[Near-Term, Priority Actions and Comprehensive, Long-Term Planning for Maryland's Gas Companies](#)," the future of gas proceeding (Case No. 9707) is underway this fall. Key dates include:

- Evidentiary hearings are October 5th - 9th;
- A virtual public hearing at 6pm on October 13th;
- Stakeholder comments, including comments from the public and elected officials, are due November 12;
- The Special Master's Report to the Commission will be filed on January 29th; and
- All interested parties can submit comments on the Special Master's Report until February 15th.

Upgrade Maryland has been engaged with this proceeding since 2024 and we appreciate the OPC, MEA and PSC's thoughtful approach to addressing both near and long term ramifications of the cost and emissions impact of Maryland's gas utilities infrastructure planning, as well as the role of electrification in future planning.

The Commission may issue orders to implement the findings and recommendations of this proceeding. We encourage the legislature to engage in the process and review the January 29th special master report and Feb.15th comments from stakeholders. Upgrade Maryland recommends that this committee

plan to schedule a similar convening of PSC, OPC, and MEA, to evaluate the recommendations of the Special Master in February of 2026.

Upgrade Maryland would like to flag an example of where the future of gas proceeding has hit a snag. In evaluating near-term priorities for gas infrastructure, the Commission ordered a rulemaking (Order No. 91683) to end a policy that forces existing customers to pay the cost of building pipelines for new customers, [a move which is projected to save gas customers \\$1 billion over the next decade.](#)

Line extension allowance (LEAs) allow gas companies, like Washington Gas and BGE, to charge existing customers for some or all of the costs to extend methane gas pipelines to new customers, driving up gas delivery charges, and adding to utility profits over a decades long payback period. In 2025 alone, BGE planned to spend [\\$103.5 million](#) on gas pipeline expansion, costing customers \$397 million, while Washington Gas planned to spend \$56.25 million, costing customers \$238 million.

Under the draft regulations, filed earlier this year, new customers would still be able to choose to connect to the gas system, but will be responsible for the cost of doing so. Existing customers will no longer be on the hook to cover the cost of system expansion.

However, in a rulemaking hearing In May, the Commission decided to [delay moving forward with the regulations](#) and directed Staff to revisit the draft regulation. Since that date, no public communication has been taken to advance LEA policy change.

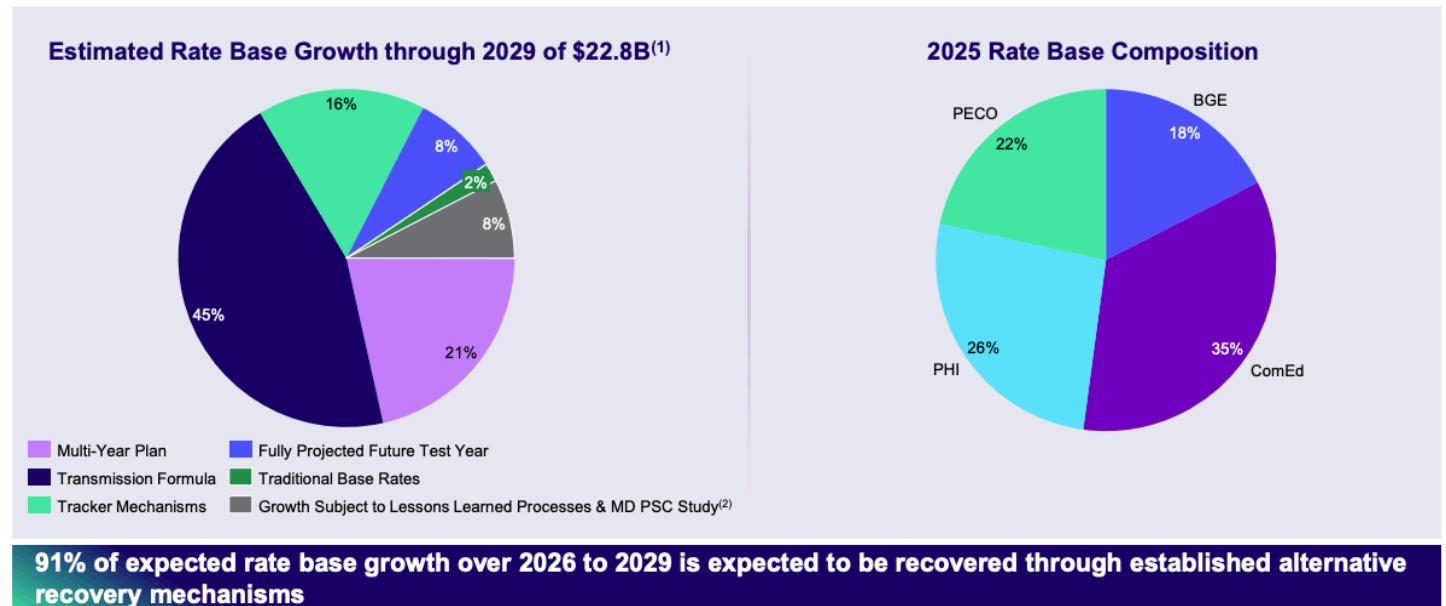
We hope the legislature can work with the Commission to bring policy recommendations, such as ending LEA's, over the finish line through a combination of legislative and regulatory action. Doing so requires a balance of thoughtful review and expedient action required to protect ratepayers from stranded assets and support state clean energy goals.

Thank you for your attention to these matters and your service to Maryland, Upgrade Maryland looks forward to the opportunity to provide follow up through post-hearing comments, and support the members of the Environment and Transportation Committee however we are able.

Sincerely,

Emily Scarr, Maryland PIRG
Bryan Dunning, Center for Progressive Reform
Brittany Baker, CCAN Action Fund
Cedar Lane Unitarian Universalist Environmental Justice Ministry
Jeff Mauk, Ceres
Jennifer Kunze, Clean Water Action
Susan Miller, Earthjustice
HoCo Climate Action
Laurel Peltier, Maryland Energy Advocates Coalition
Dave Arndt, Maryland Legislative Coalition-Climate Justice Wing
Max Socol, Progressive Maryland
Third Act Maryland

Alternative Regulatory Mechanisms Across Variety of Jurisdictions



⁽¹⁾ Reflects expected rate base growth for 2026E-2029E as of Q1 2026 disclosure dated May 6, 2026.

⁽²⁾ See Additional Disclosures slide 30 for additional detail.

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10