ELECTRIC SYSTEM PLANNING

Public Utilities Article, §7-802

December 1, 2025

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I. Background

The Maryland Climate Solutions Now Act (CSNA) of 2022 establishes measures to reduce statewide greenhouse gas (GHG) emissions by implementing a range of strategies. These include revising statewide GHG targets; the development of certain energy efficiency and emission reduction requirements for certain buildings, requiring electric companies to increase their annual incremental gross energy savings through certain programs and services; authorizing investor–owned electric companies to apply to the Public Service Commission (Commission) to implement an electric school bus pilot program with a participating school system if the pilot program meets certain standards; requiring the Commission to implement and administer the pilot program; authorizing investor-owned electric companies to recover certain costs under the pilot program, subject to the approval of the Commission; and establishing certain State policy goals for Maryland's electric distribution system.

The CSNA, which became effective on June 1, 2022, adopted the language now codified in *Annotated Code of Maryland*, Public Utilities Article (PUA), §7-801 *et seq*. Those sections directed the Commission to adopt regulations or issue orders to implement specific policies for electric distribution system planning and improvements. The CSNA also required annual reports on electric distribution planning to the General Assembly starting in December 2023.

Subsequently, House Bill 1393 (2024) for Electric System Planning – Scope and Funding (HB1393) modified PUA Title 7 Subtitle 8 to focus on electric system planning in place of electric distribution planning and to also require that the Commission report on the projects to promote specific State policy goals in its annual report, among other things. Specifically, PUA §7-802 directs the Commission to submit a report, in accordance with §7-1257 of the State Government Article, to the General Assembly, by December 1 each year, with information regarding the status of projects designed to promote the goals listed below, including information on planning processes and implementation that promote the following twelve specific State Policy goals:[1]

(1) measures to decrease greenhouse gas emissions incident to electric distribution, including high levels of distributed energy resources and electric vehicles;
(2) giving priority to vulnerable communities in the development of distributed energy resources and electric vehicle infrastructure;
(3) energy efficiency;
(4) meeting anticipated increases in load;
(5) incorporation of energy storage technology as appropriate and prudent to:
    a. support efficiency and reliability of the electric system; and
    b. provide additional capacity to accommodate increased distributed renewable electricity generation in connection with electric transmission and distribution system modernization;
(6) efficient management of load variability;
(7) electric system resiliency and reliability;

[1] The State Policy Goals are hereafter referred to as Goal 1 or CSNA Goal 1, *etc*.

(8) bi-directional power flows;
(9) demand response and other non-wire and non-capital alternatives;
(10) increased use of distributed energy resources, including electric vehicles;
(11) transparent stakeholder participation in ongoing electric system planning processes; and
(12) any other issues the Commission considers appropriate.

Prior to the enactment of the CSNA and HB1393, the Commission held a legislative-style hearing to discuss recommendations contained in the final Task Force[2] on Comprehensive Electricity Planning Report. On June 23, 2021, the Commission issued Order No. 89865, formally establishing a Distribution System Planning (DSP) docket in Case No. 9665 and initiating a DSP Workgroup (Workgroup or DSP Workgroup).[3] The Workgroup was tasked with conducting a comprehensive evaluation of distribution system planning in Maryland and providing input into possible reforms of the distribution planning process. The Workgroup has since produced several reports in response to Commission directives. On February 6, 2023, the Workgroup filed its first report culminating its Phase I efforts to perform a comprehensive examination of distribution system planning in Maryland.[4]

The Commission further directed the Workgroup in Order No. 90777 on August 24, 2023, to continue its efforts in Phase II. On May 1, 2025, in accordance with the CSNA and the Electric System Planning – Scope and Funding Act, the Workgroup filed draft regulations culminating the Workgroup's Phase II efforts. Subsequently, on May 2, 2025, the Commission docketed rulemaking proceeding RM 89.[5] Recently, the new Code of Maryland Regulations (COMAR) 20.50.15 Electric System Planning regulations that were approved by the Commission in the RM 89 rulemaking proceeding were published in the Maryland Register on November 14, 2025, with an effective date of November 24, 2025.

The Commission also issued Order No. 91751 on July 28, 2025, launching a Phase III effort to further implement electric system planning improvements in addition to developing recommendations regarding the scheduling of an annual electric system planning technical conference and related activities.

The Commission's 2025 CSNA Report to the General Assembly on the status of projects designed to promote the CSNA goals also addresses new legislation currently shaping Maryland's electric system planning. Several recent key legislative mandates influenced the Electric Companies'

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[2] The Task Force on Comprehensive Electricity Planning is a forum for the development of state-led pathways towards a more resilient, efficient, and affordable grid and provided by the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO), in partnership with the U.S. Department of Energy.

[3] *Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer Centered, Affordable, Reliable and Environmentally Sustainable in Maryland, Distribution System Planning for Maryland Electric Utilities,* PC 44, Case No. 9665, Order No. 89865, Maillog No. 235860 (June 23, 2021) at 1.

[4] Maillog No. 301185

[5] RM 89, Distribution System Planning Policies for Maryland Electric Utilities. These regulations became effective on November 10, 2025.

updated strategies for achieving the State Policy Goals of PUA §7-802 in 2025. The passage of House Bill 864 (2024), "Energy Efficiency and Conservation Plans" [6] marked a pivotal shift for the foundational EmPOWER Maryland program (Goal 3), formally expanding its objectives from focusing solely on electricity demand reduction (MWh) to primarily targeting greenhouse gas (GHG) emissions reduction (Lifecycle CO_2e Metric Tons) and beneficial electrification.[3] The enactment of Senate Bill 959 (2024), the Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act (Goal 1, 10) continued to propel planning for two key initiatives: Vehicle-to-Grid (V2G) charging programs and Virtual Power Plants (VPPs.)[7] These programs were mandated to enable electric vehicles (EVs) and customer-owned distributed energy resources (DERs) to support the electric grid, reduce system peak load, and accelerate the use of DERs. For the PHI Utilities, implementation progressed to the proposal stage for Distribution System Support Services (DSSS) Pilots and Time-of-Use (TOU) Tariffs, though the Commission issued a subsequent order in October 2025 directing that these initial pilots be compressed from a three-year plan to a two-year plan.

Finally, a significant accelerator in 2025 was the enactment of Senate Bill 937/House Bill 1035 – the Next Generation Energy Act (NGEA) — (Goal 5), which established a new goal for investor-owned electric companies to procure 150 MW of distribution-connected, front-of-the-meter energy storage devices.[8] This mandate directly impacted utility planning timelines, requiring submission of procurement plans for approximately one-third of the target by November 1, 2025 and thereby immediately escalating the strategic incorporation of energy storage technology to support grid efficiency, reliability, and renewable generation capacity.[9] The electric transmission-connected energy storage parts of the NGEA require the Commission to issue at least two solicitations for a cumulative 1,600 MWs of front-of-the-meter transmission-connected energy storage with each energy storage device having a minimum 4-hour duration. The first 800 MW capacity solicitation must be issued on or before January 1, 2026 and the second 800 MW capacity solicitation must be issued on or before January 1, 2027.

The next sections of this report convey the Companies' 2025 annual electric system planning reports filed with the Commission.[10]

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[6] House Bill 864, "Energy Efficiency and Conservation Plans" (2024).

[7] House Bill 1256, Senate Bill 959, "Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act" (2024).

[8] House Bill 1035, Senate Bill 937, "Next Generation Energy Act" (2025); PUA § 7-216.2(B)(1).

[9] *Id.*

[10] *Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland,* PC 44, Case No. 9665, Baltimore Gas and Electric Co., Annual Climate Solutions Now Act DSP Report 2025, Maillog No. 323971 (Oct. 31, 2025); Potomac Electric Power Co. and Delmarva Power & Light Co., Joint Annual Climate Solutions Now Act DSP Report 2025, Maillog No. 323953 (Nov. 3, 2025); Potomac Edison, Annual Climate Solutions Now Act DSP Report 2025, Maillog No. 323881 (Oct. 31, 2025); Southern Maryland Electric Cooperative, Inc., Annual Climate Solutions Now Act DSP Report 2025, Maillog No. 323917 (Nov. 3, 2025).

II. Baltimore Gas and Electric Company (BGE)

According to BGE, the initiatives outlined in this CSNA Annual Report present a comprehensive approach to integrating renewable energy sources, enhancing energy efficiency, and facilitating the transition to electric vehicles.[11] BGE also states that these initiatives align with the framework established by the CSNA and drive BGE's contribution to Maryland's climate goals and foster development of a resilient energy future. Consistent with a DSP Workgroup developed template, BGE provides a description of the projects intended to support the specific CSNA goals, how the project connects to and helps achieve the specific CSNA goals and the reasons for the selection of the project, and progress of implementation of indicators.[12]

- Goal 1 – Measures to decrease greenhouse emissions from the electric distribution system

i. DRIVE Program

BGE submitted a proposal for VPP and V2G pilots to the Commission in accordance with the Maryland DRIVE Act on July 1, 2025. The DRIVE Act pilots will explore ways to coordinate customer-owned distributed energy resources with renewable on-site generation for electric distribution system support services. The intended mandates being tested include system peak load reduction, GHG emissions reduction, and acting on signals mirroring an electric distribution system need that is non-coincident with system peak and understanding customer sentiment to program design and compensation/participation structure. Implementation of the DRIVE Act supports customer interconnections for all storage which exports energy, both mobile and stationary, along with bi-directional DERs that may run in parallel with the grid. Finally, the DRIVE Act mandates that the utilities propose TOU rates for appropriate customer classes. This will be addressed by leveraging the lessons from and building upon the recent delivery and supply TOU rate pilot that is currently an option for all residential customers. BGE plans to engage customers and increase participation through marketing campaigns. BGE stated that it plans to engage customers and increase participation through marketing campaigns. BGE asserts that the DRIVE program will help enable CSNA goals 1, 4, 5, 6, 9, and 10. The company states that it will comply with the reporting requirements for DRIVE included in Order No. 91218.

ii. BGE EV Charging Program

As in 2024, BGE stated that EVs produce zero tailpipe emissions, directly mitigating air pollution and enhancing public health by improving air quality. BGE states that the integration of EVs also supports the increased utilization of renewable energy sources, as utilities can optimize charging times to coincide with peak renewable generation, thereby promoting energy efficiency in the transportation sector. BGE reported that its current suite of EV programs has been and will

[11] BGE's Annual Climate Solutions Now Act Report, 2025/Distribution Planning System Report, 2025 (Maillog No. 323971).

[12] BGE notes that this section may be removed from this report if indicators have not been established.

continue to play a crucial role in the adoption of EVs, successfully educating customers about benefits and opportunities associated with EVs and EV charging, promoting EV adoption, and managing grid impacts. BGE stated that it submitted its proposal for Phase II of the EVSmart program portfolio on December 20, 2024.

BGE stated that it has proposed a number of revised and new programs in Phase II that will continue to support increasing access to EV charging stations, thereby encouraging consumers to transition to electric vehicles. BGE stated that it will continue to use its expertise in grid management to ensure that the electric grid can accommodate the increased demand from EV charging, integrating advanced technologies such as smart grid systems, smart and managed charging systems, and energy storage solutions.

BGE stated that it is an active member of the Zero Emission Electric Vehicle Infrastructure Council (ZEEVIC) and the Commission's PC44 EV Work Group, in which a joint utility proposal was submitted to the Commission in early 2018 for a robust program offering electric vehicle incentives and infrastructure. Over the past six years, BGE's EVSmart portfolio, composed of residential, commercial, and BGE-operated programs, has pursued goals in alignment with the State's policy directives. BGE's pilot was designed to coordinate seamlessly with Maryland policy initiatives such as Maryland's Advanced Clean Cars Act II and the CSNA, driving towards a future and resulting in substantial reductions in GHG emissions. BGE's programs focused on further EV adoption throughout the State by expanding public charging availability and focused on ensuring an equitable investment in transportation electrification. BGE promoted early EV adoption within the State through rebates and incentives for residential, multifamily and commercial customers, and expanded EV public charging availability throughout central Maryland.

BGE reports that its EV Charging Programs will help enable CSNA goals 1, 2, and 10. BGE further states that additional monitoring information will be updated annually consistent with Case No. 9478.[13]

iii. Conservation Voltage Reduction (CVR) Program

As in 2024, BGE stated that CVR saves energy by lowering the voltages provided to customers within an acceptable voltage bandwidth, resulting in a reduction in energy demand and associated GHGs. This is possible because the voltage provided for normal 120V service can be between 114 volts and 126 volts. Some loads like incandescent and CFL lighting, refrigerators, heat pumps, and AC units (though notably not LED lighting) run more efficiently at lower voltages which results in energy savings to the grid and the consumer. In 2024, BGE stated that it used switched capacitor banks and single-phase operation to lower service voltage dynamically at approximately 900 circuit feeders across 123 substations. In 2024, BGE stated that its assets with CVR installed have a combined summer peak load of 5,800 MW and a winter peak of 5,000 MW, representing approximately 90% of the peak load for the BGE service territory. In 2025, BGE reported increases

[13] *In The Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio,* Case No. 9478.

in these numbers, stating that BGE used switched capacitor banks and single-phase operation to lower service voltage dynamically at approximately 1060 circuit feeders across 165 substations. BGE's assets with CVR installed now have a combined summer peak load of 5,800 MW and a winter peak of 5,000 MW, representing approximately 90% of the peak load for the BGE service territory, meaning CVR deployment is nearly territory-wide.

In 2024, BGE forecasted that its CVR Program will reduce lifecycle carbon dioxide equivalent (CO_2e) emissions from 2024-2036 by 97,479 metric tons. In 2025, BGE increased that forecast, stating that it now expects its CVR Program to reduce Lifecycle CO_2e from 2024-2036 by 2.5 million (metric tons).

BGE asserts that the CVR program reduces GHG emissions in the electric distribution system and enables CSNA Goal 1. According to BGE, as predicted in its 2024 report, BGE's CVR implementation reached saturation of available feeders for CVR at the end of 2024. However, BGE stated that, on an annual basis, the exact number of feeders with CVR applied will vary due to system reconfigurations. BGE stated that it will continue to report forecasted lifecycle CO_2e reductions (metric tons).

iv. Path to Clean

According to BGE, the Path to Clean is an ongoing initiative overseen by Exelon, BGE's parent company, in support of jurisdictional goals for each of Exelon's operating companies. There are two pillars to the Path to Clean strategy: reducing the company's operational emissions and empowering customers to take part in the clean energy transition. Operations-driven emissions are those that the utility directly controls, including emissions associated with its buildings, fleet vehicles, use of SF_6 insulating gas, and the company's gas distribution system infrastructure. In a new development, BGE reported that it has launched pilot projects focused on energy efficiency and reducing GHG. One such initiative is a partnership with Carbon Reform, whose carbon capture unit is being piloted at a BGE facility. This technology delivers three main benefits: increased energy efficiency, enhanced air quality, and direct air carbon capture and sequestration. BGE stated "In the near term, we are focusing on aspects of our business where we can directly control GHG emissions through evolved work practices, building and fleet vehicle investments, alternative fuel strategies, and deployment of new and expected future technologies to meet climate goals." As of year-end 2024, Exelon has reduced operations-driven GHG emissions by 41%.

With regard to empowering customers and communities, BGE stated that, as reported in 2024, it continues to implement strategies that will facilitate customer's decarbonization goals by enabling the delivery of lower GHG emissions energy and reducing customer's direct emissions through electrification. In addition to the 2024 report, BGE stated that it supports the interconnection and development of renewable energy through its DER, DERMS, and Community Solar programs. BGE also supports delivering low-carbon fuels. BGE is improving the grid operations and efficiency through its Distributed Battery Energy Storage Program (D-BESS), CVR and V2G programs, as well as improving gas distribution efficiency by upgrading pipeline materials. BGE is supporting electrification of transportation through its EV and charging programs. And BGE is also supporting building electrification and efficiency through its EmPOWER and proposed Networked Geothermal pilots.

In addition to the initiatives described above and elsewhere in this document, as part of its Path to Clean initiative, BGE stated that it is preparing to deliver a range of lower-carbon energy options to support its customers. The company is developing roadmaps to integrate alternative fuels into their systems by 2035. Fuels such as hydrogen and renewable natural gas (RNG) have the potential to reduce the overall methane or carbon dioxide equivalent lifecycle emissions associated with the gas BGE delivers to customers.

As in 2024, BGE noted that RNG, produced from the capture, refining, and reuse of methane, is the most market-ready of these options today, and BGE has already established interconnection standards and tariff provisions to connect RNG to its system. BGE reached a major milestone in 2022 after completing the interconnection of RNG through its gas distribution system. This RNG came from a newly constructed RNG plant owned and operated by Bioenergy Devco. Located in Howard County, the plant is Maryland's flagship anaerobic digestion facility which produces RNG from food waste. BGE is also exploring emerging hydrogen technology options via R&D partnerships and industry collaborations in a way that can be delivered through existing gas infrastructure, helping reduce gas customers' carbon footprint. BGE is developing an isolated hydrogen blending pilot at its Spring Gardens facility to study the impacts on its distribution system and simulated customer appliances. BGE stated that the estimated start of this pilot has been moved to the fourth quarter of 2025.

According to BGE, the Path to Clean programs help enable CSNA Goals 1 and 3. BGE stated that it will continue to develop new programs and report on the achievement of program GHG reduction goals.

v. Working for Accessible Renewable Maryland Thermal Heat (WARMTH) Act Network Geothermal Pilot

As expected in its 2024 report, BGE stated that it has now developed a networked geothermal pilot to align with the requirements of the WARMTH Act, House Bill 937/Senate Bill 570 (2024). BGE stated that it submitted the pilot proposal to the Commission on July 1, 2025, identifying two communities with 80% low- to moderate-income (LMI) customers who are currently served by natural gas. BGE plans to retrofit the residential and commercial properties for geothermal heating and cooling to reduce emissions from natural gas usage. The company plans to also weatherize the homes and replace all natural gas appliances with electric appliances. During the development of its proposal, BGE stated that it conducted a benefit-cost-analysis and found that when compared to air source heat pumps as a means of electrification, ground source heat pumps reduce GHG emissions by 100,000-110,000 pounds of CO_2e. BGE stated that its WARMTH Pilot helps enable CSNA Goals 1 and 4. In a new development, BGE added that it filed a Network Geothermal Pilot proposal on July 1, 2025, in Case No. 9479.[14] BGE attended a hearing on these proposals on September 30 and October 1, 2025 and is awaiting a Commission decision by December 31, 2025.

[14] Maillog No. 320109.

- Goal 2 – Giving Priority to Vulnerable Communities in the Development of Distributed Energy Resources (DERs) and Electric Vehicle Infrastructure

  i. BGE Community Solar Pilot Program

Community solar energy generating systems (CSEGS) provide access to solar-generated electricity without the need for property ownership. Customers can participate by purchasing a subscription for a portion of the energy generated by a CSEGS from a Subscriber Organization. Once the CSEGS produces electricity, customers who want to participate must pay a monthly subscription fee to the Subscriber Organization. In return, they will receive a monthly credit on their electric bill that reflects their subscribed share of the CSEGS energy production.

As in 2024, BGE reported that, by 2026, BGE plans to deploy a new community solar portal which will be integrated with the company's customer care and billing system and used to automate the program processes. The portal will be the new interface for Subscriber Organizations to enroll or disenroll subscribers, specify subscription allocations, and provide access to reports. It will also allow Subscriber Organizations to opt-in to utilize Consolidated Billing. According to BGE, the CSEGS help enable CSNA Goals 2 and 10.

- Goal 3 – Energy Efficiency

  i. BGE EmPOWER Maryland (EmPOWER) Program

BGE is required to file an EmPOWER Maryland semi-annual report with the Commission which provides EmPOWER Maryland program portfolio information and results. The report contains both narrative updates and highlights for each program, along with program data such as participants, measures, budget and spend, MWh and Therm savings, and megawatt (MW) reduction resulting from the EmPOWER suite of energy savings programs. According to the company, since its inception, BGE's multiple award-winning EmPOWER Maryland programs have: (1) provided BGE customers nearly over $1.5 billion in rebates and bill credits, an increase from $1.4 billion in 2024; (2) performed over 580,000 home energy audits and check-ups, an increase from approximately 512,000 in 2024; and (3) achieved annualized energy savings of over 7.7 million MWh of electricity, an increase from 7.1 million MWh in 2024.

BGE stated that its EmPOWER portfolio of programs continued their strong performance into 2025. Beginning in 2025, the statutory target for the EmPOWER MD programs changed from MWh to Lifecycle GHG reduction measured in Metric Tons of CO_2e. For the six months ended June 2025, BGE's EmPOWER program portfolio has achieved nearly 59% of its GHG target using 37% of the overall 2025 program budget. The entire portfolio achieved over 363,000 MWh in annualized electric energy savings. Natural gas savings as of YTD June were nearly 1.5 million therms. In addition to the energy savings realized and associated environmental benefits customers generated by choosing more efficient alternatives, BGE customers received incentives and bill credits of approximately $88 million. Avoided generation from the over 363,000 MWh 2025 portfolio savings over the estimated life of the energy efficiency measures and services installed YTD June 2025 is nearly 2.3 million MWh.

BGE highlighted energy efficiency programs that have exceeded their YTD June 2025 targets. These programs differed from those highlighted in 2024. The Residential New Construction Program achieved extremely strong results in the first half of the year, attaining 254% of their filed lifecycle GHG annual savings target. Strong performance and the conversion methodology used to establish GHG savings targets which reward long measure life resulted in this high GHG achievement. The Appliance Rebates program achieved 61% of their YTD June 2025 filed lifecycle GHG annual savings target. Key drivers of the performance include the success of the ESRPP channel, expansion of the Advanced Power Strip ("APS") offering in the markdown channel, increased incentives for Heat Pump Water Heaters, and the distribution of energy efficiency kits to nonprofit organizations. For commercial customers, the Midstream Program achieved 93% of its 2025 lifecycle GHG annual savings target. A new suite of offerings, and teaming up successfully with the school systems, brought about this increased GHG reduction. For the first half of 2025, the Prescriptive Program has achieved 79% of its filed lifecycle GHG annual savings target. Completion of key projects along with nurturing strategic partnerships with contractors and lighting distributors to increase participation, helped to achieve this goal. BGE added that it is currently participating in 14 work groups relating to EmPOWER goals.

According to BGE, the EmPOWER program enables CSNA Goal 3.

- Goal 4 – Meeting Anticipated Increases in Load

  i. Ten-Year Distribution Capacity Plan

According to BGE, the existing annual forecasting process is a multi-part activity that incorporates numerous data sources to project growth on the distribution system over multiple timescales. BGE produces forecasts for approximately 230 substations, nearly 500 substation transformers, and over 1,500 feeders. The BGE system includes feeders and substations with summer peaks in electricity demand driven by air conditioning, like most utilities, as well as winter peaks in demand driven by electric heating, generally in regions with no natural gas service.

BGE provided a description of its planning process that differed from its 2024 report. In its 2025 report, BGE stated that the distribution planning process consists of four main bodies of work, developing the forecast, identifying system constraints, developing constraint solutions, and building a prioritized plan. In the 2026 distribution planning cycle, BGE will be incorporating a new application to develop the Load and DER forecasts for each feeder and substation. The forecasting process begins with a review of known future load additions, planned distribution systems changes, and development of customer technology adoption and behavioral changes that impact electricity usage and generation on the distribution system. In September, observed SCADA, AMI, and weather station systems data was analyzed to determine baseline feeder and substation peak load behavior. From October to December, the utility begins developing the 15-year forecast. The weather normalized base net loads are combined with known future load and generation interconnections, system topology changes, and allocated customer growth, technology adoptions, and/or behavior changes impacting loads. The result is a 15-year forecast for each feeder, transformer and substation. Next, analyses are performed comparing equipment forecasted peak demand to its associated capabilities to identify system constraints. Based on the findings of those analyses, from January to May, the utility develops solutions for identified constraints within the next 10 years. Concurrently, the utility creates short-term summer and winter plans to address load and feeder issues for the next year to maintain the safety and reliability of the system.

The Distribution System Planning process is anchored in BGE's customer load and DER forecasts and the investments needed to support the anticipated increasing load and deployment of DERS. This represents just one part of the company's overall investment plan (approximately 5-15%). See below for improvements being made to BGE's load forecasting and capacity planning processes and timelines.

ii. DER and Load Forecasting System Project

BGE stated that the Distributed Energy Resources and Load Forecasting (LF) System Project is the deployment of an advanced distribution planning system intended to meet the evolving needs of the distribution grid as Maryland transitions to a more electrified and decarbonized future. The company noted that its existing load forecasting system is an in-house built application that is more than 20 years old. The tool uses observed feeder loads and historical weather to develop a weather-normalized seasonal peak demand for each feeder and substation transformer. This peak value serves as a baseline to which known new customer load and distribution configuration changes are added to derive a forecast. This system did not contemplate the widespread adoption of photovoltaics (PV), EVs, or forecast more than the peak seasonal (winter/summer) hour load. As such, the existing load forecasting system no longer meets the future distribution planning needs.

In 2025, BGE chose the DER and LF system that it had been considering at the time of its 2024 report. According to BGE, the DER & LF System Project implements three key capabilities. First, it produces a load forecast of representative peak days (monthly peak days) up through every hour of the entire year, expanding on the legacy forecasting for only the peak hour of the season. This is key to forecasting different technologies, their daily/seasonal load curve, and their impacts on feeder/substation behavior. Second, the spatial allocation of future development or technology adoption, allows future load changes to be reflected in areas and along feeders where they are more likely to occur rather than dividing system-level impacts evenly across the entire system. Third, the ability to perform multiple forecast scenarios. Leveraging those three capabilities creates an intelligent forecasting system that understands future grid constraints and informs potential solutions. This intelligent forecasting is essential for achieving many of the CSNA goals, particularly goals 4, 5, 9, and 10.

BGE stated that it is using the DER & LF system to create the forecast for the 2026 distribution planning cycle (*i.e.*, 2026 – 2040). The initial planning cycle will focus on the development of hourly forecasting capabilities, automatic integration of new load and DER interconnections, and forecasted adoption of EVs and photovoltaic generation systems. As outlined above, the capabilities of this new forecasting system can be transformative but also exceedingly complex.

Transitioning a utility planning organization from single scenario peak hour net load forecasting to hourly multi-scenario net and gross load forecasting will be an ongoing process with expanding forecasting capabilities in subsequent distribution planning cycles.

iii. Distribution Planning Guidelines Evolution Initiative

As in 2024, BGE reported that the Distribution Planning Guidelines Evolution Initiative is the expansion of guidelines to account for increased distributed generation and load growth on the system. As noted above in the DER and LF System Project, BGE stated that it plans to expand its DER and LF capabilities to include hourly forecasting of both DER and load on the system. BGE stated that this advanced capability is foundational to the evolution of the planning guidelines.

According to the company, the primary purpose of the distribution planning process is to forecast the load, compare it to existing equipment ratings, identify if the load is expected to exceed those capabilities (under normal or certain contingency situations), and initiate action to mitigate the violation before it occurs. Historically, with one-directional energy flows on the distribution system (*i.e.*, from substation to feeder to customer), peak load forecasting was sufficient to accomplish this task. The peak load forecasting was based on observed loading at the head of the feeder which represented the total gross load on that feeder.

BGE stated that, as distributed generation penetration increases, observed load at the head of the feeder is no longer the true gross load on the feeder. Instead, it is now net loading minus gross load minus the contribution of the distributed generation. As the distribution system evolves, the distribution planning guidelines that are the purpose of this project must also evolve. The Distribution Planning Guidelines initiative will extend capacity planning guidelines to include the load masking effects of DER when making decisions about system adequacy by considering both gross and net loading under normal and contingency situations. Included in these criteria are: ensuring net load remains below rating capacity of components; contributions of DERs can be a solution to maintaining feeder loading below normal rating; and loading should not exceed component emergency rating for contingency scenarios, including loss of a portion of distributed generation.

According to the company, the Distribution Planning Guidelines Evolution helps enable CSNA Goals 1, 4, 5, and 8. The updated Distribution Planning Guidelines are enabled by the deployment of the DER and Load Forecasting Application. As noted in the DER and LF application description, being used to create the forecast for the 2026 distribution planning cycle (*i.e.*, 2026 – 2040). The expanded planning guidelines will roll out and evolve concurrently as advances in forecasting and constraint identification are achieved.

iv. DER Management System (DERMS) Project

As in 2024, BGE stated that the DERMS Project is the deployment of an advanced distribution control system functionality intended to meet the evolving needs of the distribution grid as Maryland transitions to a more interactive distribution grid with high deployment rates of generation and dispatchable resources. The company noted that there are limits to the amount of

DER interconnected to a feeder without coordination of at least a percentage of the resources in order to maintain the distribution system within operating limits. BGE further noted that its existing capabilities for coordinating DERs are limited and have generally involved one-off solutions that are unsuited to scale to broad system deployment because they are costly and time-consuming to implement and hard to maintain after deployment.

The DERMS project implements a scalable centralized coordination system closely tied to the existing distribution monitoring and control system with the goal of having repeatable and maintainable implementations for coordinating DER systems on a feeder. According to BGE, the DERMS project will be implemented over several years in multiple phases.

In an update to its 2024 report, BGE stated that the initial phase of the DERMS, Project 1, is currently in active development and is planned to go live by the fourth quarter of 2025. This initial phase is focused on DERMS system deployment and establishing basic capabilities such as battery energy storage system (BESS) control and estimating unmetered PV system outputs.

The second phase of BGE's DERMS implementation, Project 2, is scheduled to begin in the first quarter of 2026 and run through the end of 2026. The goal of the second project is to enable and facilitate the integration, monitoring, and control of utility-owned distributed battery energy storage systems (DBESS) that will be deployed as part of BGE's DBESS program and in alignment with Maryland's energy storage goals. In addition to DBESS enablement, BGE plans to improve its DER integration testing capabilities by procuring and installing DER test equipment. The goal of the test equipment is to allow BGE to safely simulate, validate, and evaluate how different DER technologies integrate with utility systems, interconnection standards, and grid operations.

BGE stated that it is also planning for future phases of DERMS deployment. Longer-term DERMS projects will be focused on enabling advanced DERMS capabilities through integrations with third-party DERs, Distributed Energy Resource Aggregator (DERAs) and Grid-Edge DERMS.

BGE stated that the DERMS project helps enable CSNA goals 1, 4, 5, 6, 8, and 9.

- Goal 5 – Incorporation of Energy Storage Technology as appropriate

  i. Hosting Capacity Maps

As in 2024, BGE reported that it currently publishes a quarterly PV Hosting Capacity Map that provides information on how much solar generation can be added to an area before the feeders supplying that area reach capacity without needing significant system upgrades. The map displays the sum of the remaining capacity in kilowatts (kW) up to a quarter square mile. This remaining capacity is based on feeder constraints after accounting for in-service and approved DERs on each feeder. As of 2025, the map also shows in-service and approved DERs on feeders passing through the square-mile grid. In addition, BGE stated that it publishes a Restricted Circuits Map that displays circuits that are limited to PV interconnections of certain sizes without making significant system upgrades at the customer's or developer's expense. Limits on circuits are based on circuit-specific analysis and are intended to provide allowance to accommodate residential-scale or smaller commercial applications.

As customer adoption of DER increases, BGE stated that it will need to collaborate more with customers to enable smooth interconnections and the company continues to listen to feedback from customers and developers concerning the information on the maps that would be useful to them. BGE stated that it continues to work to advance its planning tools and capabilities to facilitate more targeted and granular distribution system analyses. Increasing penetrations of DER will require a better understanding of the conditions of the distribution system at a more detailed temporal and locational level. Distribution Planning is updating the current planning models and tools used by reducing the number of applications used. Currently, multiple software applications are used to run analyses on the distribution system and manual updates and information handoffs are required. BGE notes that consolidating to one application reduces the complexities and time required to maintain multiple models. BGE is also adding new modules to existing distribution system modeling applications to perform more advanced analyses, increasing its capabilities to help meet current and future planning requirements established by the Commission and the legislature.

By utilizing the additional granular data from the DER and LF tool, BGE stated that it will analyze historical and forecasted loads to evaluate various scenarios and assess non-wires solutions (NWS). In an update from 2024, BGE stated that BGE recent updates will allow more granular data beyond feeder and substation level, specifically AMI, to be used for locational and temporal analyses which will enable BGE to make more accurate decisions regarding investment needs and options. For example, with more data, the utility can find where the minimum and maximum loads are during the day and further analyze the load and generation forecast down to the sub-feeder level to provide more specific guidance for necessary grid upgrades or NWS needs. According to the company, Hosting Capacity Maps help enable CSNA Goal 4. BGE stated that improvements to the Hosting Capacity Maps will be reported here as they are developed.

ii. Distributed Battery Energy Storage Program

As in 2024, BGE reported that the DBESS is a new program to develop a repeatable, standardized utility-owned and operated BESS system design that will allow BGE to efficiently deploy distribution front-of-meter storage as a solution. The program is focused on sourcing one-sized battery assets (0.5 MW/1 MWh) that can be connected to distribution feeders in an area where they will be most impactful. These standardized units can be grouped to provide additional storage where needed and integrated with DERMS (see above).

BGE stated that its current experience with BESS installations has been individual, tailored projects that were engineered, procured, and constructed by suppliers. While these initial installations have provided customer benefits and increased BGE familiarity with energy storage solutions, BGE stated that continuing the practice of individual solutions is inefficient for utility deployment. The company is developing this standardized approach to drive efficiencies in procurement, engineering and design, construction standards, operation and maintenance, and integration with internal IT systems. In turn, these systems become a standardized tool—in the toolbox—to address forecasted capacity constraints via peak shaving on feeders and on the substation transformer. As standards develop, technology matures, and customer benefits are quantified, additional use cases for DBESS are anticipated, such as resilience.

In a change from the 2024 report, BGE reported that in response to the directives of Order No. 91705 and the NGEA, BGE is filing a plan with the Commission for the deployment of 29 MW of BESS, both utility and third-party owned. BGE stated that this proposal includes 3 MW of DBESS, up to 15MW of Commercial and Industrial (C&I) sited, and approximately 11 MW of third-party owned BESS. BGE stated that the initial deployments of the DBESS program are anticipated in 2027. Deployments in subsequent years will be determined by grid needs and the development of additional use cases.

- Goal 6 – Efficient Management of Load Variability

    i. Smart Charge Management (SCM) Demonstration Project

BGE provided new information on its Smart Charge Management (SCM) Demonstration Project in its 2025 report. BGE stated that the SCM pilot was a four-year demonstration initiative conducted from 2021 to 2024, supported by a grant from the U.S. Department of Energy ("DOE"). Its primary goal was to evaluate managed charging strategies for residential, commercial, and public (EV customers, with the aim of minimizing the impact of EV charging on the electric grid.)

During the demonstration, customers were grouped into virtual distribution assets and their EV charging was managed based on the asset they were assigned to. For example, customers in neighboring zip codes were grouped into a single virtual feeder or circuit. This allowed BGE to simulate how a utility might manage residential EV load if all customers were connected to the same physical feeder.

Charging prioritization was determined by two key factors: (1) battery state-of-charge (*e.g.*, customers with battery levels below 20% were prioritized) and (2) declared departure time (*e.g.*, customers needing their vehicles early the next day were prioritized).

BGE stated that, with the support of pilot research vendor, Argonne National Laboratory, BGE proved that each participating vehicle offered nearly $300 in value for the downstream distribution system while only costing up to $120 in annual bill credits awarded to the customer. This is a conservative estimate as the evaluation used distribution asset costs from 2019. This does not include other system benefits, such as generation capacity, transmission capacity, energy savings, carbon reduction benefits, and market price effects, nor the operating costs of the program. The benefits of Smart Charge Management are likely to grow as EV adoption and subsequently program participation grows as well.

The pilot phase officially concluded in December 2024. In August 2024, BGE received regulatory approval to scale the SCM program to 30,000 participants by the end of 2027, marking a significant milestone in the utility's load management strategy. The expanded program now includes a broader range of eligible devices and vehicles, enabling more customers to participate in managed EV charging. In addition, incentives are now awarded per participating device rather than per BGE account, allowing households with multiple EVs to benefit more equitably. BGE stated that the SCM program, which remains under development, has shown strong customer engagement and effective load shifting, with over 97% of participants charging occurring during off-peak, low stress periods, contributing to a more resilient and efficient electric grid.

BGE reported that the SCM Project helps enable CSNA Goals 1, 4, 6, and 10, and is currently under development.

- Goal 7 – Electric System Resiliency and Reliability

    i. BGE's Resiliency and Reliability Programs

BGE's reliability objectives are focused on minimizing the number and duration of electric service outages experienced by customers each year. BGE tracks this performance through system-wide reliability metrics, including SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), and CAIDI (Customer Average Interruption Duration Index). It is BGE's intention to meet or exceed the standards established by the Commission. In order to meet these standards, BGE has established a variety of projects and programs that address outage issues at the system, feeder, community and individual customer levels. BGE's 2025 report indicated that those programs have been expanded since 2024 and now include: projects to replace or repair defective transformers in order to restore service, address potential safety issues, and improve reliability; projects to identify and mitigate public safety concerns, enhance reliability by eliminating defects, corrosion, and comply with NESC standards; projects to upgrade poor performing 4kV feeders to 13kV which will reduce the number of outages due to aging equipment, enable additional switching capabilities, provide opportunities to deploy new equipment and technology, and reduce restoration time; projects to replace existing 13kV or 34.5kV distribution circuit equipment where the replacement is being performed for aging infrastructure reasons rather than to increase capacity; projects designed to improve the reliability of existing 13kV or 34.5kV distribution circuit equipment where the improvement is not being performed for capacity reasons; pole replacement projects involving the reinforcement and replacement of damaged, decayed or deteriorated wooden poles. Those projects also include cable and pole replacement, customer reliability improvements, and improvements to distribution and transmission substation equipment.

As in 2024, BGE also states that, in Case No. 9353, BGE is actively discussing resilience in a work group in which BGE is developing the framework for resilience-based projects and metrics that support the ability to prepare for and adapt to changing conditions, withstand, recover from, and minimize the magnitude and/or duration of disruptive extreme events. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.

According to the company, the reliability and resilience programs help enable CSNA Goal 4.

- Goal 8 – Bi-directional Power Flows

    i. BGE's Distribution System Enables Bi-directional Power Flows

As in 2024, BGE stated that its distribution system, generally, already allows for bi-directional power flows at the feeder and substation level, and as such there are no programs or projects directly targeted at feeder or substation upgrades to allow for bi-directional power flow. There are thermal, voltage, and operational constraints that can limit the amount of load or generation on a particular feeder, transformer, or substation. However, those constraints will exist regardless of the direction of power flow. The exception to allowance for bi-directional flows is on BGE's secondary network system. This secondary voltage network system supplies approximately 900 customers in the downtown Baltimore area. Bi-directional power flow between the low voltage secondary network and the 13 kV supply feeders is not permitted due to system operational limitations. While the BGE system is generally capable of handling bi-directional power flow, how that bi-directional power flow is measured, managed, and forecast is improving as older protection and metering devices reach end-of-life and are upgraded. BGE states that no additional opportunities for implementing bi-directional power flows have been identified since the 2024 report.

BGE states that bi-directional power flow capabilities enable CSNA Goal 8.

- Goal 9 – Demand Response and other Non-Wire and Non-Capital Alternatives

    i. BGE's Demand Response (DR) Programs

As in 2024, BGE reported that it implements a range of DR programs to reduce the burden on the electrical grid during periods of peak demand by reducing residential customer's HVAC energy use. According to the company, these programs have evolved to meet customer needs and expectations, address technological advancements, and have ultimately been successful in educating customers about the benefits of load management and effectively managing their impact on the electrical grid. On August 15, 2024, BGE filed a supplemental DR program that is currently under review that includes plans for winter peak reductions, showcases innovation in DR by proposing and testing flexible load management strategies (daily, weekly, or monthly DR dispatch with minimal comfort impact to customers), and explore locational DR to avoid capital investments.

According to the company, DR programs help enable CSNA Goals 4, 6 and 9, and additional details regarding demand response programs will be included in the EmPOWER Annual Reports.

    ii. BGE Battery Storage Pilots

As in 2024, BGE reported that it has implemented two Battery Storage Pilot projects. According to the company, these projects mitigate a system constraint identified on a 34kV feeder in southern Anne Arundel County that could experience a winter post-contingency overload of up to 3.5 MW. Specifically, if BGE were to lose two of its Marriott Hill sub-transmission circuits, both on a single right-of-way and shared pole line, customer load at three BGE substations would be transferred to an alternate Marriott Hill circuit. At peak load, this would result in the Marriott Hill alternate circuit exceeding its emergency rating. In February 2015, this contingency resulted in rotating customer load shed. To address this overload, BGE considered possibly undergrounding approximately 10 miles of one of the Marriott Hill circuits to separate the 34kV circuits on the shared pole line. BGE instead used the Chesapeake BESS (a 1 MW/2 MWh project owned and operated by Ameresco, Inc.), and the Fairhaven BESS (a 2.5 MW/9.74 MWh project owned and operated by BGE) to mitigate the system constraints and the projects went into service in 2023. Both BESS projects also participate in PJM markets and all revenues to BGE are used to defray customer rates.

According to BGE, the BESS Pilots help enable CSNA Goals 9 and 10, and detailed metrics about the Pilots are filed annually in PSC Case No. 9619.[15]

- Goal 10 – Increased Use of DERs, including EVs

    i. Maryland Cost Allocation Method (MCAM) Implementation

As in 2024, BGE noted that the implementation of Maryland's Cost Allocation Model (MCAM) in 2026 will change the DER Interconnection process from a "Causer Pays" model to support a reduction in cost obstacles for interconnections. According to the company, MCAM helps enable CSNA Goal 10. Reporting requirements for MCAM are included in COMAR 20.50.09.14C.

    ii. FERC Order 2222 Implementation

As in 2024, BGE stated that implementation of Federal Energy Regulatory Commission (FERC) Order 2222 will enable smaller DERs to aggregate together and, in doing so, be able to participate directly in PJM's wholesale markets (energy, capacity, and ancillary services). BGE stated that FERC Order 2222 implementation will help enable CSNA Goal 10. BGE further noted that its MCAM proposal has been filed but not yet approved by the Commission.

- Goal 11- Transparent Stakeholder Participation in ongoing Electric System Planning Processes

    i. Customer Connection Initiative

In a new development, BGE reported that it has launched a new initiative called *Customer Connections* to enhance the company's understanding of industry-specific energy needs, innovations, and challenges. Unlike previous customer meetings that focused on presenting BGE initiatives, this format reversed the engagement—emphasizing listening to customers' experiences and insights.

The first session took place on April 30th and featured leaders from the hospital sector. These participants shared how their organizations were leveraging energy innovations to support efficient

[15] *In the Matter of the Maryland Energy Storage Pilot Program,* Case No. 9619.

operations for patients, staff, and surrounding communities. Approximately 30-40 stakeholders attended the session which included a Q&A segment aimed at fostering meaningful dialogue and identifying opportunities for stronger partnerships.

The second session was held on July 23rd and featured three key customers representing municipal, research, and federal sectors. Hosted by the Large Customer Services ("LCS") team, the panel offered valuable insights into each organization's relationship with BGE and highlighted opportunities to enhance collaboration. Panelists shared perspectives on operational resiliency, discussed current challenges, and showcased technologies being adopted to improve energy reliability and efficiency across their facilities and jurisdictions.

The third session took place on October 1st and focused on small and medium-sized businesses ("SMBs"). The event explored how to better serve SMB customers by moving away from a one-size-fits-all strategy toward understanding each business's unique challenges and priorities.

BGE also listed the monthly Questline Newsletter that the company uses to provide managed customers with articles of interest including articles on BGE's efforts on Path to Clean and customer projects supporting the State's goals. In addition, BGE hosts community meetings to gauge community interest and perspectives. From October 2024 through September 30, 2025, BGE participated in 243 community engagement events. Those events include community meetings, resource fairs, including hosting open house events and presentations educating the community and customers about BGE resources and initiatives.

The company reported that its Customer Connections Initiative enables CSNA Goals.

III. Pepco Holdings, Inc. (PHI)[16]

- Goal 1 – Measures to decrease greenhouse emissions from the electric distribution system

    i. Path to Clean Strategy

The Path to Clean strategy is an Exelon-wide quantitative and aggregate commitment to reduce Scope 1 and 2 operations-driven GHG emissions[17] by 50% by 2030 from a 2015 baseline and to achieve net-zero operations-driven GHG emissions by 2050. Operations-driven emissions are those that the PHI Utilities (i.e., Pepco and Delmarva Power) directly control, including those associated with buildings, fleet vehicles, and the use of SF_6 insulating gas. According to the PHI Utilities, in the near term, they are focusing on aspects of the business where they can directly control GHG emissions through evolved work practices, building and fleet vehicle investments, alternative fuel strategies and deployment of new and expected future technologies to meet climate goals. The PHI Utilities included the following graphic in their 2025 report:

[16] Potomac Electric Power Company (Pepco) and Delmarva Power & Light Company (Delmarva Power).

[17] Operations-driven emissions include 100 percent of Scope 1 GHG emissions and the portion of Scope 2 GHG emissions associated with building energy use.

Focus Areas and Actions to Cut Operations Emissions in Half by 2030

Company and Operations	
Buildings	Focus on energy efficiency (EE) and clean electricity for our operations **Examples:** audits, efficiency upgrades, zero-carbon electricity (nuclear) and renewable energy credit (REC) purchases, space optimization
SF_6	Invest in equipment and processes to reduce SF_6 leakage from our systems **Examples:** aging breaker replacement, leak management, and maintenance, SF_6 alternatives
Vehicle Fleet	Electrify 30 percent of our own vehicle fleet by 2025 and 50 percent by 2030 **Examples:** light-duty vehicle electrification and focus on fuel and operational efficiency

The PHI Utilities stated that they are beginning to explore GHG offsets and recognize that they will be needed to meet the 2050 net-zero goal for emissions that cannot be otherwise reduced (currently estimated at 20% of the expected operations-driven GHG emission inventory in 2050). The PHI Utilities stated that they are also observing that the science and guidance around the use of GHG offsets is still emerging (with a current focus being placed on carbon removal and/or sequestration offsets).

The PHI Utilities stated that they also recognize that there are opportunities to influence emissions beyond operations (Scope 3) as detailed in other sections of their report. The PHI Utilities also stated that they continue to work on strategies to empower customers and support communities to further reduce GHG emissions by exploring efficient grid and energy management and grid modernization technologies to minimize system losses; advance transportation electrification and efficiency as well as conservation programs for customers; and partner with communities to develop and implement clean infrastructure solutions that are accessible to all customers. The PHI Utilities reported that this initiative aims to assist jurisdictions in achieving their climate and clean energy objectives by providing necessary resources and guidance. It also focuses on investing in and supporting small businesses that are addressing climate change challenges within local communities. Additionally, the strategy seeks to leverage digital solutions to facilitate the integration of clean technologies, enhancing efficiency and driving innovation in the transition to a sustainable energy future.

ii. Electric Vehicles (EVs) Discussion

The PHI Utilities stated that, in Maryland, EV registrations have increased from 64,395 at the end of January 2023 to 102,540 as of April 30, 2024, and reaching approximately 126,986 as of January 2025. The PHI Utilities stated that this increase represents a near doubling of registrations in two years, reflecting the State's expanding incentives and investment in charging infrastructure. With new EV models entering the market in 2024-2025, expanded point-of-sale tax credits, and Maryland's ongoing excise tax credit program, EV adoption is expected to maintain strong momentum. At the federal level, the PHI Utilities stated that tax credits established under the Inflation Reduction Act (IRA) have supported EV affordability, although those incentives are scheduled to phase out by late 2025. Nationally, the PHI Utilities stated that EV sales are projected to reach approximately 1.3 to 1.6 million vehicles in 2025, representing 9% to 11% percent of new vehicle sales according to Bloomberg New Energy Finance. The PHI Utilities note, however, that while earlier forecasts from Bloomberg New Energy Finance anticipated that Evs would reach 51% of U.S. new vehicle sales by 2030 (around 8.2 million Evs), more recent projections from the Edison Electric Institute and J.D. Power estimate a more moderate range of 36 to 46% by 2030.

The PHI Utilities stated that the transition to EVs remains instrumental in advancing the objectives of the CSNA in Maryland, particularly in achieving substantial reductions in GHG emissions. As the transportation sector constitutes one of the largest sources of GHG emissions in Maryland, promoting EV adoption is critical to the CSNA's goals.

By integrating Evs with innovative rates, the PHI Utilities enable customers to charge during off-peak hours, helping support a cleaner, more efficient energy system. The CSNA encourages the development of extensive EV charging infrastructure, fostering economic growth through job creation while facilitating greater accessibility for Maryland residents. In addition, prioritizing EV adoption in underserved communities aligns with the CSNA's commitment to environmental justice, ensuring equitable benefits from cleaner transportation options. Furthermore, the CSNA helps support the requirements of the Advanced Clean Cars II rule, which stipulates an increased share of new cars must be electric, up to 100% in 2035.

The PHI Utilities stated that they play a crucial role as partners in the adoption of EVs, contributing significantly to the development of a sustainable transportation ecosystem. By investing in and expanding the necessary charging infrastructure, the PHI Utilities facilitate greater access to EV charging stations, thereby encouraging consumers to transition to EVs. The PHI Utilities also stated that utilities also leverage their expertise in grid management so the electric grid can accommodate the increased demand from EV charging, integrating advanced technologies such as smart grid systems and energy storage solutions.

iii. PHI Utilities' EV Infrastructure and Incentives

This section provides an overview of the history and strategic plans surrounding EV infrastructure and rebate programs aimed at promoting EV adoption. The PHI Utilities stated that they are an active member of the Commission's PC44 EV Work Group in which a joint utility proposal was submitted to the Commission in early 2018 for a robust program offering electric vehicle incentives and infrastructure. The PHI Utilities are also a member of the ZEEVIC, formed by legislation in 2011 to overcome barriers to EV adoption in the state. The PHI Utilities stated that they engage through ZEEVIC on coordinated EV utility marketing plans with other State agencies.

According to the PHI Utilities, the initial program offerings include special TOU and whole house rates for customers with an EV as well as a discounted installation of a smart Level 2 charging station. Smart charging stations are also being proposed for workplace, multi-unit dwelling locations, and community public spaces. Direct-current fast chargers (DCFC) and Level 2 chargers are also offered for strategic placement throughout the area as public access charging stations for customers and visitors. On January 14, 2019, the Commission issued Order No. 88997 approving the following offers: Utility-owned public chargers – DCFC and Level 2; discounted Level 2 chargers for multi-unit dwelling locations; discounted level 2 chargers for residential customers; $300 residential rebates for a Level 2 charger; EV rates/credits for off peak charging including a whole-house time of use rate; and a customer education and outreach fund.

In May 2021, the Commission approved the PHI Utilities' provision of an off-bill credit incentive to customers who charged their vehicles during off-peak times through the Off-Peak Off-Bill Incentive. In January 2022, the Commission, through the Mid-Course Report, issued a corrected Order No. 90036 approving the following program modifications: $50 annual incentive credit for continued participation in data collection; make ready and 100% incentive for multiunit dwelling participants; fleet calculator tool, and the Workplace Charging Rebate Program.

In August 2022, the Commission approved the modifications proposed by the PHI Utilities to: increase the maximum number of enrollees from 750 to 1,500 for Pepco's $50 residential annual incentive program; increase the education and outreach budget by $100,000 - $50,000 for Pepco and $50,000 for Delmarva Power; and rebalance the overall program budget.

In September 2022, the Commission approved the consensus fleet proposals of the Exelon Utilities as filed and reflected in Appendix B of the June 30, 2022, Fleet Subgroup Summary Report. Approval included the following: Fleet online calculator extension; fleet assessments; make-ready incentives; electric vehicle supply equipment (EVSE) incentives; education and outreach costs; and project administrative costs.

The PHI Utilities stated that they filed their implementation plan on April 19, 2019, and launched its Evsmart program on July 1, 2019. Since then:

- The PHI Utilities' EVSmart initiatives have expanded their network of utility-owned and operated public EV chargers, provided EV smart charger incentives to consumers, and implemented innovative EV-only TOU rates. The Maryland Exelon utilities have supplemented these State programs with federal funding for additional programs, including advancing smart charge management and deploying EV rideshare fleets and infrastructure.

- Pepco's first public charging station was completed in September 2019 in Takoma Park, Maryland. As of June 2025, the PHI Utilities have increased the number of commissioned Level 2 charging stations from 302 (215 Pepco, 87 Delmarva Power) in 2024 to 350 in 2025 (250 Pepco, 100 Delmarva), and increased the number of commissioned Fast Charging stations from 30 (17 Pepco, 13 Delmarva Power) in 2024 to 37 (24 Pepco, 13 Delmarva Power) in 2025. The Commission approved the PHI Utilities' request to extend the utility-owned public charger program to December 31, 2025.

- The $300 residential rebates for a Level 2 charger, $50 annual incentive, and Off-Peak Off-Bill Incentive programs ended in 2023. In no change from 2024, the PHI

Utilities reported that, as of June 19, 2024, 891 PHI Utilities residential rebates (740 Pepco, 141 Delmarva Power), 1,713 $50 annual incentives (1,557 Pepco, 156 Delmarva Power) and $49,740 in off-peak off-bill incentives ($37,045 Pepco, $12,695 Delmarva Power) were provided.

- The Discounted Level 2 chargers for Residential Customers program ended in 2023. The PHI Utilities reported that 75 PHI Utilities' customers (62 Pepco and 13 Delmarva Power) are enrolled in the program, which is no change from 2024.

- The Multi-Unit Dwelling Program and Workplace Charging Rebate Program ended in 2023. As of June 2025, in no change from 2024, the PHI Utilities have rebated 91 charging stations/163 ports (76 stations/144 ports Pepco, 15 stations/19 ports Delmarva Power) and continue to work with customers toward completion of an additional multi-unit dwelling station in Pepco and Delmarva Power's service territories.

- The whole-house TOU rate (R-PIV rate) and Plug-In Vehicle TOU Rate (PIV rate) remain available to the PHI Utilities' customers. The PHI Utilities also offer a rate schedule for their public-facing charging stations, including a discounted fleet rate for customers that have five or more Evs registered in Maryland.

- The Fleet program offerings[18] launched August 31, 2023. The PHI Utilities reported that, as of September 2025, the number of assessments they have completed have increased from one (Delmarva Power) in 2024 to nine (eight Pepco, one Delmarva Power) in 2025, and the number of make ready incentives have increased from two (Pepco) in 2024 to 11 in 2025 (eight Pepco, three Delmarva Power) and from one EVSE incentive (Pepco) in 2024 to 10 (seven Pepco, three Delmarva Power) in 2025.

In a new development, the PHI Utilities stated that they are working to accelerate Maryland's EV adoption by reducing barriers, enhancing customer awareness, and preparing the grid for increased EV usage. The PHI Utilities filed a Phase II EVSmart Program Proposal with the Commission in December 2024, with supplemental comments submitted in April 2025. The proposal builds on the success of Phase I by expanding public charging, introducing additional managed-charging initiatives, and targeting small business and underserved community participation. A Commission decision on Phase II offerings is pending. If approved, Phase II will focus on ensuring a reliable public charging infrastructure, improving load management, and offering targeted incentives for small businesses and underserved communities. Program objectives include managing grid demand with load management programs and ensuring accessible, reliable public charging for

[18] The Fleet program offerings for EVs typically refer to a set of incentives, services, or infrastructure provided by utility companies, governments, or other organizations to encourage the adoption and use of EVs in commercial or public fleets. These programs aim to reduce emissions, promote sustainability, and support climate goals.

those without residential options. The PHI Utilities are awaiting Commission approval of Phase II before determining any potential future phases.

The Phase II proposal included the following programs:

- Destination Make-Ready provides incentives for the installation and deployment of new smart L2 and DCFC charging stations at destinations such as retail centers, workplaces, places of worship, and municipal garages. The program prioritizes investment in small businesses and Environmental Justice (EJ) communities to enhance equitable access to EV infrastructure.

- Public Transportation Make-Ready is for the installation of new charging infrastructure primarily to support public transportation fleet operations.

- Multifamily Make-Ready provides incentives for the installation of smart L2 charging ports at multifamily locations to increase convenient at-home charging access.

- EJ Fleet Make-Ready provides incentives for the installation of smart L2 and DCFC EV charging sites used by public and private fleet customers operating in or serving EJ communities.

- EV Make-Ready Site Assessment Services provides a comprehensive technical assessment to perform siting of EV charging stations for commercial customers to streamline the EV charging interconnection process and participate in a make-ready program.

- EV TOU encourages EV owners to charge their vehicles during off-peak hours, providing a net off-peak charging credit to participants.

- SCM Program will expand upon the existing SCM Pilot. The SCM Program aims to reduce system upgrade costs by shifting load off-peak, as well as timing charging sessions to avoid overloading the distribution system. It optimizes charging based on the customer's preferences and grid needs. Works in conjunction with and requires enrollment in the EV TOU program.

- EVSmart Public Charging Station Operations and Maintenance Program provides continued operation and maintenance to ensure reliability of the 250 Pepco-owned and 100 Delmarva Power-owned public EV charging stations that were installed in Maryland from 2019-2024.

The PHI Utilities stated that, to ensure continuity in advancing these goals, Pepco and Delmarva Power have requested and received approval to extend their existing 2022 Commercial EV Fleet Programs beyond the original sunset date of September 14, 2025. This interim extension would allow them to maintain customer engagement and support fleet electrification while the Commission reviews the proposed Phase II EV Portfolio. Under this extension, PHI Utilities would continue processing applications and offering incentives for fleet assessments, make-ready work, and EVSE installations through June 30, 2026, or until Phase II programs are launched. Additionally, refundable deposits for fleet assessments would remain available through June 30, 2027, provided customers initiate electrification projects within one year of receiving their assessment report.

iv. PHI Utilities' EV Fleet

As part of the Path to Clean program, the PHI Utilities stated that they are electrifying their fleet as part of its efforts to reduce GHG emissions and contribute to the State's climate goals. The PHI Utilities stated that investments in fleet electrification is an important strategic initiative for the companies, as it helps support both Maryland's climate change initiatives as well as the companies' Path to Clean initiatives. The PHI Utilities reported that the number of EVs in their fleet has increased from a total of 432 in 2024 to 606 in 2025.

v. Distributed Energy Resources (DER) Limits

On October 1, 2024, the PHI Utilities stated that they removed the larger DER limits by voltage class, removed the 750kW Direct Transfer Trip (DTT) requirement for DER, and removed the hard length limits of express circuit requirements from their technical interconnection requirements (TIR). They stated that those three changes will allow for more DER integration into the grid and allow more DER usage. In addition to these changes, the PHI Utilities stated that they are also working to enhance their public-facing maps to improve the customer experience and to provide more information on grid conditions to customers prior to the submission of interconnection applications. The survey was completed in September 2024, and the team focused on internal alignment to identify which enhancement suggestions to prioritize. The PHI Utilities reported that, as of the second quarter of 2025, they had finalized and implemented these improvements, including updates to its distribution and interconnection maps. These updates incorporated enhancements to the Territory Boundary Line, Expanded Substation Data and In-Review Status Content, Update Timestamps, and the consolidation of Network and Radials. The PHI Utilities continue to increase DER resource limits across their territory through further enhancements to its TIR and the implementation of a new Level 4 analysis template.

The Level 4 analysis template was developed through consensus stakeholder feedback during the 2025 Maryland Public Service Commission Interconnection Working Group, supported by the Coalition for Community Solar Access (CCSA), Maryland utilities, and DER developers. PHI plans to implement the Level 4 analysis template and updated TIR document in late Q4 2025. These updates will increase transparency for DER developers into the PHI DER study process, increase transparency for DER developers into the PHI DER study process, and increase the amount of DER on substation transformers, and achieve Future Compliance with new Maryland Interconnection Regulations expected during the 2026 rulemaking session. The PHI Utilities stated that the development of formalized Level 4 analysis templates alongside the TIR enhancements that standardize feasibility, impact, and facilities studies documentation, represents a significant achievement for the PHI Utilities and Maryland; and will be essential to interconnecting more community solar DERs to meet the State's renewable energy goals.

In addition, the PHI Utilities stated that they recently revised their hosting capacity analysis methodology, which has resulted in increased feeder hosting capacity trends. As demand for renewable energy grows, an accurate and optimized hosting capacity analysis allows the utilities to assess and enhance the grid's ability to handle additional energy from decentralized sources without risking stability or reliability. This improved capacity is particularly important in meeting regulatory clean energy goals. By January 1, 2025, in accordance with COMAR 20.50.09.06P requirements, the PHI Utilities stated that they had implemented the flexible interconnection process and had posted their limited export agreement on their websites to allow more DER integration.

The PHI Utilities also stated that, to further streamline the review of smaller rooftop solar interconnections across its territory, the PHI Utilities developed an automated Level 1 review screening tool for solar interconnection applications in Maryland. The screening tool has been officially operating since July 2025, allowing 42% of residential rooftop solar applications to be reviewed automatically, improving processing efficiency so DER customers can interconnect to the grid more quickly.

vi. Interconnections

The PHI Utilities stated that they are committed to providing transparent, efficient, and clear processes for review and approval of interconnection to the utilities' distribution systems of proposed renewable-energy projects and other DERs.

As interconnection applications continue to accelerate in both volume and total capacity (MW) across the country, there is an increasing need to streamline the interconnection application review process to minimize delays, decrease operating issues, and improve the overall customer interconnection experience. The review process also ensures safe and reliable operation of the distribution system and that no customers are detrimentally impacted by the introduction of DERs operating in parallel with the distribution system.

The PHI Utilities indicated that they work together to identify and implement best practices in both the DER application review processes as well as effectively integrating DERs to the electric distribution systems. The following table presents interconnection data including applications received and approved, number of active systems, and number and MW of systems connected to the PHI system by the end of 2023.
The following Table presents the number of interconnection applications received and approved by year-end 2024.

Table 2: Number of interconnection received/approved by PHI Utilities in Maryland in 2024

	Pepco	Delmarva Power
Number of Applications Received in 2024	4,720	826
Number of Applications Approved in 2024	4,615	658

The following Table presents the number of DERs connected to each of the PHI Utilities in Maryland in 2024, by number of systems and MW.

Table 3: Number of Active Systems and Megawatts (MW) Connected in 2024

	Pepco	Delmarva Power
Number of New Systems Connected in 2024	3,081	474
MW from New Systems Connected in 2024	51.654	9.573

The following Table presents the total number of active systems interconnected to each of the Pepco and Delmarva Power as of December 31, 2024.

Table 4: Total Number of Active Systems and MW Connected as of December 31, 2024

	Pepco	Delmarva Power
Total Connected Systems as of December 31, 2024	35,490	7,066
Total MW from New Connected Systems as of December 31, 2024	439.153	142.056

The PHI Utilities stated that these metrics provide transparency by tracking the expansion of renewable energy systems and their integration into the grid. The number of interconnections received and approved reflects the growth in renewable energy projects, while the active systems and MW connected demonstrate the scale of renewable energy generation and the state's capacity to reduce carbon emissions. Cumulatively, these metrics offer a view of the state's achievements in renewable energy deployment, helping to evaluate the effectiveness of policies so Maryland remains on track to meet its climate targets.

vii. Conservation Voltage Reduction (CVR) Program

CVR is a strategic approach to improve energy efficiency by optimizing the voltage delivered to customers. Through CVR, the PHI Utilities stated that they reduce voltage levels to the lower end of the acceptable range while still maintaining reliable service, which results in lower overall energy consumption without affecting the performance of most electrical devices. CVR is achieved through the use of advanced technologies such as AMI voltage control systems, and real time monitoring. CVR not only helps utilities reduce operational costs by decreasing energy demand but also benefits consumers by lowering electricity bills. The reduced energy consumption also contributes to a reduction in GHG emission, supporting broader climate objectives such as those outlined in the CSNA. By managing grid loads more effectively, CVR also enhances grid reliability, particularly during peak demand periods, reducing the need for costly infrastructure upgrades. Overall, CVR serves as a cost-effective and environmentally sustainable tool in modernizing the grid and achieving energy efficiency goals. Below is a summary of Pepco's and Delmarva Power's CVR implementation.

Pepco CVR Implementation

Pepco deployed CVR beginning in August 2013 across seven substations, and soon after increased the count to 43. At the end of 2024, Pepco estimated that over 72% of its customers were served by a distribution asset controlled by CVR, and Pepco operated CVR on 43 substations serving approximately 428,654 customers during Q1/Q2 2024. When capped at 20% of YTD reported portfolio savings, the reported savings for this program in 2024 was 16,272 MWh of energy for the year, and without the 20% cap, this program saved 53,852 MWh of energy in 2024. In 2025, the company operated CVR on 41 substations, serving approximately 428,696 customers, and the program reported 9,333 metric tons of CO_2 equivalent ($MTCO_2e$) of lifecycle GHG savings in the first half of that year.

Delmarva Power CVR Implementation

Delmarva Power shares the same assumptions and methodologies with Pepco, but a smaller share of its distribution circuits is controlled by CVR due to the more rural nature of the service territory. In 2024, Delmarva Power operated CVR on 41 substations serving approximately 68,947 customers during Q1/Q2 2024. When capped at 20% of YTD reported portfolio savings, the reported savings for this program was 6,451 MWh of energy in 2024, and without the 20% cap, this program saved 8,290 MWh of energy in 2024. In 2025, Delmarva Power operated CVR on 36 feeders serving approximately 59,836 customers and reported 1,716 metric tons of CO_2 equivalent ($MTCO_2e$) of lifecycle GHG savings in the first half of the year.

- Goal 2 – Giving Priority to Vulnerable communities in the development of distributed energy resources (DERs) and electric vehicle infrastructure

The PHI Utilities stated that they continue to invest in communities in a way that advances equity and affordability and supports economic development and environmental and sustainability goals in the jurisdictions they serve. The PHI Utilities acknowledge that prioritizing vulnerable communities in their efforts to meet the goals of CSNA is crucial, as these populations often face disproportionate impacts from climate change and have historically lacked access to clean energy solutions. This focus aligns with the CSNA's commitment to environmental justice and ensures that the benefits of climate action, such as improved air quality, lower energy costs, and enhanced public health, are equitably distributed. Vulnerable communities, which often experience higher energy burdens and poorer air quality, stand to gain significantly from targeted energy efficiency programs, renewable energy adoption, and infrastructure upgrades. By focusing on these areas, the PHI Utilities not only address social inequities, but also achieve meaningful GHG reductions, as many of these communities have older, less energy-efficient infrastructure.

The PHI Utilities stated that successful inclusion of LMI households in electrification efforts will require strong collaboration between Maryland utilities, the Department of Housing and Community Development (DHCD), and the Maryland Energy Administration (MEA). In 2025, MEA and DHCD began coordinating new home energy rebate and weatherization initiatives to assist LMI households, complementing existing EmPOWER Maryland programs. While the federal IRA initially expanded funding opportunities for EVs, home electrification, and appliance rebates, those provisions are now being phased out under recent federal policy changes. Moving forward, alignment of remaining State and utility programs will be critical to maintaining equitable access to energy efficiency and electrification resources for LMI households.

In addition, the PHI Utilities stated that they will continue to invest in infrastructure and grid modernization to support increased electrification in these communities. Aligning State and utility resources will help ensure that Maryland's clean energy transition delivers tangible benefits for LMI customers and contributes to a more resilient, equitable energy future.

i. Pepco's Strategies to Promote Electrification to LMI Households

The PHI Utilities stated that Pepco employs targeted strategies to promote electrification among LMI households, supporting access to energy technologies and affordability through rebates, education, and managed charging initiatives. Pepco advanced its electrification strategy through EmPOWER Maryland programs for the 2024–2026 cycle, providing rebates and bill credits to offset electrification costs and performing home energy audits for income-qualified customers. Pepco also expanded EVSmart initiatives, offering smart charger incentives and EV-only time-of-use rates to encourage off-peak charging and reduce costs. Pepco supports Maryland's permanent Community Solar Program, which provides bill credits to LMI households and renters, contributing to over 150 MW of operational projects and thousands of subscribers statewide. To further affordability, Pepco leverages smart meter data for usage alerts and DR programs. Pepco also administers Maryland-specific energy assistance programs, including the Electric Universal Service Program (EUSP), Utility Service Protection Program (USPP), and Arrearage Retirement Assistance, which help mitigate bill impacts for income-qualified customers. These combined strategies—rebates, managed charging, community solar, and assistance programs—promote equitable electrification while minimizing financial burdens for LMI households.

ii. Delmarva Power's Strategies to Promote Electrification to LMI Households

The PHI Utilities stated that Delmarva Power has proposed an EJ incentive bonus to encourage participation from communities facing disproportionate energy and environmental burdens. These bonuses, combined with higher incentives for fuel-switching measures, help offset incremental costs for heat pumps and reduce potential bill impacts from increased electricity usage.

The PHI Utilities reported that in 2024, Delmarva Power expanded its electrification strategy for LMI households through EmPOWER Maryland programs. Advancing transportation electrification with EVSmart initiatives, including utility-owned public chargers, smart charger incentives, and innovative EV-only time-of-use rates, as discussed further in Section III.iii for PHI Utilities' EV Infrastructure and Incentives. To promote equitable access to clean energy, Delmarva Power supported the now permanent Community Solar Program, integrating operational projects and providing bill credits to thousands of subscribers. These efforts, along with smart meter deployment and targeted energy assistance programs such as MEAP, EUSP, and Arrearage Retirement, helped mitigate bill impacts and supported an inclusive energy transition for LMI households.

iii. Climate Change Investment Initiative

Since 2019, the Exelon Foundation and Exelon Corporation have been growing the $20 million Climate Change Investment Initiative (2c2i) to cultivate innovative climate-solution startups. 2c2i portfolio companies are developing and deploying new technologies and products to reduce GHG emissions and address climate change in Exelon's territories. The 2c2i program blends the social and environmental impact objectives of the Exelon Foundation with the investment objectives of venture capital by investing in startups that focus on climate change, clean energy and the environment. Under 2c2i, the Exelon Foundation will invest $10 million in startups over 10 years, and Exelon Corporation will provide those startups with up to $10 million of in-kind services, such as access to Exelon networks and expertise to scale their businesses. At the end of 2023, 66% of Exelon Foundation's 2c2i investments were in minority and women-led startups and 41% were headquartered in a city in Exelon's footprint. At the end of 2024, 64% of Exelon Foundation's 2c2i investments were in minority and women-led startups and 42% were headquartered in a city in Exelon's footprint.

- Goal 3 – Energy Efficiency

The PHI Utilities stated that energy efficiency plays a critical role in CSNA, as it is a key strategy for reducing GHG emissions and achieving the CSNA's climate goals. By improving energy efficiency, the PHI Utilities can help lower overall energy consumption, reduce the demand for electricity generation, and decrease reliance on fossil fuels. This reduction in energy demand not only helps to cut GHG emissions but also supports the transition to a cleaner, more sustainable energy grid. The PHI Utilities noted that encouraging the adoption of energy-saving technologies and practices among residential, commercial, and industrial customers is critical. These programs may include rebates for energy efficient appliances, lighting, and HVAC systems, as well as incentives for building retrofits and improvements. In addition, demand-side management initiatives help balance energy usage during peak demand periods, reducing the need for additional power generation and lowering emissions. Ultimately, energy efficiency not only helps electric distribution utilities meet regulatory requirements under the CSNA but also enhances grid reliability, lowers costs for consumers, and contributes to a sustainable energy future.

i. EmPOWER Maryland (EmPOWER)

The passage of HB864 (2024) marked a pivotal shift for the EmPOWER Maryland program, expanding its objectives beyond electricity demand reduction to formally include GHG emissions reduction and beneficial electrification.[19] While energy savings targets remain a component of program evaluation, 2025 marks the first year that EmPOWER Maryland's goals are measured by GHG emissions reductions in alignment with the state's climate objectives.

Pepco's EmPOWER Portfolio

Pepco's EmPOWER Portfolio. The PHI Utilities reported that in 2024, Pepco achieved 258,000 MWh in total reported annualized electricity savings, representing 1.77% of the 2016 baseline energy sales, and equaling 89% of its 2% annual target.[20]

In the first half of 2025, Pepco's EmPOWER Maryland portfolio achieved 174,717 metric tons of lifecycle CO_2e emissions reductions. The Residential program portfolio reached 33% of its annual forecasted lifecycle GHG savings target, while C&I programs achieved 44% of its target. The programs reported 115,195 MWh in electricity savings during this period.[21]

Delmarva Power's EmPOWER Portfolio

The PHI Utilities stated that, in 2024, Delmarva Power achieved 87,341 MWh in total reported annualized electricity savings, representing 2.08% of the 2016 baseline energy sales, exceeding its 2% target. The company's performance reflected balanced contributions across residential, commercial, and other programs including continued growth in DR and CVR efforts.[22]

Delmarva Power achieved 53,286 metric tons of lifecycle CO_2e emissions reductions during the first half of 2025 and is on track to meet or exceed its annual GHG reduction target. 33,258 MWh in electricity savings. The Residential program portfolio achieved 43% of its annual forecasted

[19] Maryland General Assembly, House Bill 864 – Energy Efficiency and Conservation – EmPOWER Maryland Program – Alterations (Chapter 407, 2024 Laws of Maryland); Maryland Public Service Commission, *Order No. 91461 – In the Matter of the EmPOWER Maryland 2024–2026 Plans*, issued March 27, 2024; and *2025 EmPOWER Maryland Standard Report* (Maryland PSC, May 2025).

[20] Case No. 9705 Pepco Semiannual EmPOWER MD Report YTD Q3Q4 2024.

[21] Case No. 9705 Pepco Semiannual EmPOWER MD Report YTD Q1Q2 2025.

[22] Case No. 9705 Delmarva Power Semiannual EmPOWER Maryland Report YTD Q3Q4 2024.

GHG reduction target, while C&I programs achieved 32%. The programs reported 33,258 MWh in electricity savings during this period.[23]

- Goal 4 – Meeting Anticipated Increases in Load

PHI noted that the electric grid is becoming more complex as centralized, fossil-based generators are replaced by renewable, inverter-based resources, such as solar PV. The inherent variability of renewable generation introduces uncertainty to electrical power system operations that can challenge grid stability. New models capable of leveraging real-time data from advanced monitoring and communications infrastructure to ensure grid reliability and resilience can help with uncertainty. The PHI Utilities further noted that an Advanced Distribution Management System (ADMS) plays a key role in meeting Goal (4) of the CSNA, which is to address anticipated increases in load. ADMS enables utilities to manage and optimize the distribution grid more effectively as demand grows, especially with the rising adoption of EVs, heat pumps, and other electrification measures.

i. Management of Growing DERs

The PHI Utilities stated that the increasing adoption of DERs among customers highlights the need for ADMS, which are essential for enabling the seamless integration and management of these decentralized energy sources. PHI also notes that ADMS is fundamental to enabling a DERMS by providing essential real-time visibility, automation, and control capabilities across the distribution grid. ADMS integrates data from grid assets, allowing DERMS to monitor and manage DERs. The PHI Utilities reported that customers, now empowered by technologies such as rooftop solar, energy storage and EVs, are shifting from being passive energy consumers to active participants, seeking greater control over their energy production and consumption. This shift is driven by a desire for sustainability, cost savings, and enhanced energy resilience in the face of grid disruptions.

ii. PHI Utilities DERMS Plans

In a new development, the PHI Utilities stated that advancing a dedicated DERMS project is a strategic priority to ensure PHI is positioned to effectively manage the accelerating growth of DERs. This project is intended to mitigate potential system integration risks associated with DER challenges. A market analysis was completed earlier this year, and PHI is entering a scoping phase to gather and prioritize business requirements. A DERMS would allow PHI to use real-time power output data from each DER to make more accurate decisions. This flexibility will enable PHI to safely increase the number of DERs on feeders, potentially reducing the number of "locked" feeders and allowing more customers to connect distinct types of DERs to the system. PHI is leveraging the company's three-phase approach to project conceptualization and scoping, planning / design, and execution to implement its DERMS solution, which will follow an agile approach to requirements development for operational capabilities. Authorization for Phase I, scoping, has been received; the remaining phases of planning / design (Phase II) and

[23] Case No. 9705 Delmarva Power Semiannual EmPOWER Maryland Report YTD Q1Q2 2025.

implementation (Phase III) will proceed according to PHI's process for capital authorization. The project began in August 2025 through the release of an RFP soliciting a vendor. The overall goal is for the DERMS platform to be functionally capable of supporting the initial use cases by Q1 2027.

Project Approach and Objectives: The PHI Utilities reported that they are employing a capability-led approach, which prioritizes identifying and defining operational needs first, rather than beginning with specific technologies. This method is designed to avoid a siloed, technology-only approach and instead create vendor-agnostic requirements that can adapt to PHI's DER needs.

Benefits of Implementation: The PHI Utilities stated that the DERMS Project enhances PHI's grid management by securely integrating DERs. This connectivity enables new use cases and allows for more dynamic, efficient grid operations, supporting reliability and scalability across the system. Integrating DERs allows the PHI Utilities to use them to strengthen the grid. During outages, DERs can help stabilize circuits and reduce stress on overloaded substations and other equipment. This not only improves service reliability but also extends the lifespan of grid assets. This diversification also minimizes the impact of any single outage.

The PHI Utilities' current visibility into DERs is limited. A DERMS will provide PHI's operators with clear, detailed visibility to DERs on the system—including the locations, current operations, and additional capabilities. This real-time information is critical for making informed decisions about additional capabilities. Current interconnection policies often use DERs full nameplate capacity as a conservative assumption, treating every DER as if it is always exporting 100% of its power to the grid. This assumption is inaccurate and can lead to unnecessary system upgrades or the denial of new DER interconnections, even when there is available capacity.

iii. 10-year Distribution Capacity Plan

The PHI Utilities noted that planning for future load growth starts with the development of load growth projections. A forward-looking, 10-year peak load forecast is developed and maintained for all distribution feeders and substations to plan for and inform large capital project proposals. Short-term forecasts are developed to address required system upgrades relative to new business requests and regional load growth. Short-term forecasting includes the examination of the historical loads for each feeder and substation on a two-year cycle. New customer load from submitted class of service forms and other available development reports, planned changes in feeder configuration, emergency transfers and reductions due to DER are also analyzed.

The PHI Utilities stated that they currently use a forecasting software package that compares historical load values against a 30-year record of regional weather data. Weather normalized historical load values are projected for the ten-year forecast, through adding new customer load requests and anticipated area growth trends, including anticipated electric vehicle charging loads and heating system conversions. The forecasting process also incorporates the variable impact of DERs, to assess coincidental peak load reductions for both installed and projected DER installations. Forecasted loads do not include prospective electrification projects driven by legislative actions that have not been finalized. Potential NWS are assessed in the long-term forecasting process, identifying potential solutions that could defer or replace the need for capital upgrades. Planners will review the load projections for predicted feeder or substation constraints and will recommend mitigation actions where needed.

iv. DER and Load Forecasting System Project

The DER and LF Project is the deployment of an advanced distribution planning system, intended to meet the evolving needs of the distribution system. According to the PHI Utilities, this project and the software's advanced capabilities will be essential for the PHI Utilities' progress towards achieving Maryland's CSNA goals and updated Distribution System Planning processes as part of RM89 Regulations.

The DER and LF Project and its novel software will allow for: greater input hourly load shape processing, data cleaning (i.e., identifying and correcting errors, inconsistencies, and missing values in historical data) and weather normalization; typical load year models and customer profile generation; spatial load allocation, regional growth and technology adoption calculations; scenario-based planning and forecast flexibility for jurisdictional and technical targets; and DER projections and long-term impacts, optimal mix outputs and DER benefit-cost analyses. In addition, the software uses geospatial predictive modeling to allocate corporate system level predictions for load or resources spatially for the forecast. These allocations use infrastructure, sociocultural and topographic factors that influence the application of load or resources across the service territory.

The DER and LF project is currently in the implementation phase after go-live. The software will be used in the current forecasting cycle in parallel with the existing forecasting software. Utilizing both packages will allow for comparison of the outputs and current forecasting key performance indicators (KPIs) to evaluate the variance between forecasted and actual load.

- Goal 5 – Incorporation of Energy Storage Technology as appropriate

According to the PHI Utilities, Wood Mackenzie's 2024 U.S. DER Outlook projected that DER capacity is expected to grow by approximately 217 GW through 2028 — equivalent to 70% of anticipated bulk generation additions during the same period. Distributed solar and storage will account for nearly half of this growth, while flexible EV charging and building automation systems will make up the remainder.[24] Meanwhile, third-party companies are introducing tools to aggregate DER in a manner that can benefit the grid, customers and operations.

Energy storage costs have continued to decline. According to the National Renewable Energy Laboratory's (NREL) 2023 Cost Projections for Utility-Scale Battery Storage, battery costs could fall by up to 47% by 2030 under low-cost scenarios, and the NREL 2024 Annual Technology Baseline confirms that costs are expected to keep decreasing across all modeled cases, driven by

[24] Wood Mackenzie. *U.S. Distributed Energy Resources (DER) Outlook 2024*. Key findings on DER capacity growth and resource composition. Available at: https://www.woodmac.com.

falling battery component prices and manufacturing efficiencies.[25] Increased use of energy storage is anticipated by customers, other parties, and utilities. The PHI Utilities stated that energy storage systems can be installed in a variety of configurations, each of which will have different impacts and implications for the distribution grid. Various technical and regulatory issues will need to be addressed to provide safe and reliable integration of energy storage systems into the distribution grid in an efficient manner to not inhibit growth in energy storage development.

The PHI Utilities stated that they are actively seeking opportunities to site and implement energy storage where it makes sense to mitigate a power quality issue, increase reliability, increase hosting capacity or load factor on a distribution feeder(s) or to defer the need for capacity.

Pepco and Delmarva Power are participating in the PC 44 Maryland Energy Storage Initiative (MESI) Working Group, which is considering issues relating to energy storage deployment in Maryland. In alignment with Senate Bill 937– the NGEA – and House Bill 910, Pepco and Delmarva Power continue to advance energy storage initiatives. As part of the commitment, both utilities will submit plans on November 3, 2025, to achieve one-third of their megawatt procurement targets.

As of April 2025, Delmarva Power's Ocean City Battery Energy Storage project became operational. Pepco's Fairmont Heights Microgrid and Livingston Road projects were withdrawn following implementation challenges. Pepco continues to participate in the Maryland Energy Storage Pilot Program through reporting and lessons learned requirements under Order No. 91742.

i. Pepco's Energy Storage Projects

The PHI Utilities reported new developments relating to Pepco's energy storage projects that differ from those reported in the 2024 report. The PHI Utilities stated that the current Equipment Maintenance and Transit Operations Center (EMTOC) Battery Energy Storage Project, projected to be operational in January 2026, is part of a planned microgrid third party owned and operated microgrid located in Derwood, Maryland. The microgrid will include 5.65 MW of rooftop and canopy solar generation, and 2 MW of battery energy storage. The project will support the largest renewable energy powered transit depot in the United States, aligning with Montgomery County's climate goals of achieving an 80% reduction in carbon emissions by 2027 and 100% by 2035. This initiative is a collaborative effort between Montgomery County, the customer and AlphaStruxure, the microgrid developers and installer.

The microgrid will be interconnected to the Pepco utility and is engineered to operate in island mode indefinitely, ensuring uninterrupted service for the County's constituents during extended grid or power outages and emergency situations. Additionally, it can export up to 2MW back to

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[25] National Renewable Energy Laboratory (NREL). (2023). *Cost Projections for Utility-Scale Battery Storage: 2023 Update*. https://www.nrel.gov/docs/fy23osti/85332.pdf; and National Renewable Energy Laboratory (NREL) (2024). *Annual Technology Baseline: Utility-Scale Battery Storage*. https://atb.nrel.gov/electricity/2024/utilityscale_battery_storage.

the grid for the utility to call upon, as necessary. Once built, the microgrid will be able to power all the depot's energy needs, including powering 200 zero emission buses and 5 existing buildings.

ii. Delmarva Power's Energy Storage projects

As in 2024, the PHI Utilities reported that Delmarva Power has two energy storage projects, the Elk Neck VPP and the Ocean City BESS.

1) <u>Elk Neck Virtual Power Plant (VPP)</u>

The Elk Neck VPP is a 0.5 MW/1.5 MWh virtual power plant (aggregated behind-the-meter (BTM) residential batteries) that is a third party-owned-/ third party-operated project at Elk Neck, an isolated peninsula in the Chesapeake Bay. The Elk Neck VPP that went into service in July 2022.

According to PHI, the Elk Neck VPP is an innovative energy project designed to enhance grid reliability and support the integration of renewable energy in Maryland. This project leverages advanced technology to create a network of DERs, including residential solar panels, battery storage systems, and smart thermostats, which can be aggregated and managed as a single, flexible resource. By coordinating these individual systems, the Elk Neck VPP enables the region to optimize energy use, reduce demand during peak periods, and provide backup power during outages, thereby improving the overall resilience and efficiency of the grid.

PHI notes that this project plays a critical role in advancing Maryland's clean energy goals by facilitating the integration of renewable energy sources, such as solar power, into the grid while minimizing the environmental impact of conventional energy production. It also offers economic benefits to participating homeowners by providing incentives for the installation of DERs and enabling them to potentially earn revenue through demand response programs. The Elk Neck VPP aligns with Maryland's commitment to creating a more sustainable, decentralized energy system and provides a scalable model for future VPP initiatives across the state, enhancing energy security and driving the transition to a cleaner, more resilient power grid.

The PHI Utilities stated that the Elk Neck VPP was installed in Delmarva Power's northeast Maryland region to increase the electricity reliability for the end users on the peninsula. PHI further states that the VPP and the batteries within it have proven for the better part of 2.5 years that the reliability for the critical loads of each of the residences has been significantly improved.

During 2024, varying combinations of the batteries at the 110 customer locations were triggered due to loss of power 491 times, totaling 18,645 minutes of backup power supplied. Delmarva Power Maryland feeders MD3454, 3484 & 3487 feed the customers at the VPP. The battery usage resulted in an overall CAIDI benefit of 78.62 outage hours saved.

Additionally, the battery usage resulted in an overall SAIFI benefit of .11 outages & SAIDI) benefit of 22.77 outage hours saved. In 2024, across all three feeders, on average the batteries prevented an additional .15 outages on the system, ~ 23hrs of power on the system as well as an additional ~ 79hrs of power per customer.

2) Ocean City BESS

The PHI Utilities stated that Delmarva Power's Ocean City BESS Project is a utility-owned and operated storage facility with a capacity of 1 MW with an energy output of 3.0 MWh over the lifetime of the project. According to PHI, the Ocean City BESS Project is aimed at enhancing the reliability and efficiency of Maryland's energy grid while supporting the state's transition to renewable energy. Located in Ocean City, Maryland, the BESS is designed to store excess energy generated by renewable sources, such as solar and wind, and discharge it during periods of high demand or when renewable generation is low. This system helps to stabilize the grid by providing quick-response backup power, reducing the need for traditional, fossil fuel-based peaking power plants.

The PHI Utilities stated that, by integrating energy storage with renewable generation, the Ocean City BESS not only improves grid reliability, but also contributes to reducing carbon emissions and advancing Maryland's clean energy goals. The PHI Utilities further stated that the Ocean City BESS enables a more flexible, resilient grid capable of incorporating a higher share of renewable energy, which is essential for meeting the state's ambitious climate targets. The project also benefits local communities by providing energy security, particularly during extreme weather events or other grid disruptions. As a part of Maryland's broader strategy to modernize its energy infrastructure, the Ocean City BESS represents a significant step toward building a more sustainable and reliable energy future for the state. According to PHI, the project does not defer any distribution upgrades but is expected to provide peak shaving capabilities during periods of high winter or summer loads and during emergency grid conditions, reducing the number of customer outages. The project will also support a public library in the Ocean City area that will serve as a resiliency center for the community. PHI noted that when the project is not providing peak shaving benefits, it will participate in the wholesale market.

The Ocean City BESS was originally projected to be operational in February 2022, but was granted two extensions by the Commission, first to December 2023 and then to December 2024. Although the project achieved in-service status on April 30, 2025, telemetry and PJM market integration are currently still in progress.

iii. Hosting Capacity

The PHI Utilities stated that they currently publish a hosting capacity map that is updated monthly and have added various improvements since 2024. The map provides information on how much solar generation can be added to a network area or radial feeder before the grid reaches its capacity without needing significant system upgrades to address system constraints. The map displays the sum of the remaining capacity in kW. The capacity is based on feeder constraints not being violated and accounts for in-service and approved DERs on each feeder. In 2025, timestamps were added to the feeder profiles to inform customers of the most recent updates, enabling them to make informed pre-application decisions. PHI territory boundary lines have been added as a layer to the hosting capacity maps to guide developers on which jurisdiction they should apply to and for customers that are around cross-border feeders. Substation Hosting Capacity for large applications has been added to the maps, in addition to "In-Review" DER kW, providing additional granularity in constraints for large applications. Further, one- and two-phase laterals were added as a separate togglable layer, and new network feeder visuals were implemented and merged into the radial hosting capacity map.

The PHI Utilities reported that a new hosting capacity analysis methodology was recently implemented, consisting of a computational method that takes system variables as inputs, and a new methodology of reserving hosting capacity for small DERs**.** This methodology has significantly increased hosting capacity on each feeder, as well as removed the large DER limits per feeder. Hosting capacity limits are now determined on a feeder-specific basis, and the trends have shown significant increases. In addition to the existing feeder-level hosting capacity analysis, the PHI Utilities are advancing toward a more granular, section-based hosting capacity approach.

A key component of the energy transition is customer-based local renewable energy installations, primarily solar photovoltaic integrated into the utility distribution systems. The PHI Utilities stated that they continue to provide public education around opportunities to take advantage of this option.

The PHI Utilities stated that they also provide distribution system restricted circuit and/or hosting capacity maps to build awareness about locations on the systems with sufficient capacity for more renewable energy. Going forward, the PHI Utilities stated that they will continue refining these tools to provide even more useful information to customers, including augmenting distribution map resources with information on EV charging and battery storage.

The hosting capacity map gives an indication of how much generation (expressed in kW) can be added to a feeder before the feeder reaches capacity or other limitations that reduce the reliability of service to electric customers on the feeder. Although the values are meant to provide the user with a general idea of availability, space on the desired feeder is not guaranteed and/or may change at any time. All applications for interconnection will still require a full review and may also require additional interconnection costs.

PHI Utilities' Distribution Feeder Hosting Capacity:

https://pepco.maps.arcgis.com/apps/dashboards/940e65bff6294b589f5832ab1521c93f

and Regional Capacity Planning:

https://storymaps.arcgis.com/stories/f4f45b890f504c21935c177d6
cf545a5

- Goal 6 – Efficient Management of Load Variability

As in 2024, the PHI Utilities stated that the increased integration of variable renewable energy sources like solar and wind power necessitates strategies to balance supply and demand. The PHI Utilities stated that managing load variability is crucial for maintaining grid stability, preventing disruptions, and ensuring a reliable power supply. In addition, optimizing energy consumption through demand response and other measures can lead to significant cost savings for both consumers and utilities. Finally, by reducing overall energy consumption and enabling the electrification of transportation and buildings, the PHI Utilities stated that efficient load management contributes to greater resource efficiency and reduced environmental impact.

i. PHI Utilities' Managed Charging Program

Like 2024, the PHI utilities stated that managed charging programs play an important role as EV adoption continues to gain traction, and utilities across the country are conducting research and hosting pilots to learn how to maximize grid and customer benefits. In the summer of 2020, DOE awarded funding to Exelon for three of their Maryland operating utilities - BGE, Delmarva Power, and Pepco—to carry out their SCM pilot program. The objective of this project is to research, develop, and conduct a widescale demonstration of a utility SCM system to determine optimal managed charging structures for grid value, assess the impact of EV charging on local distribution utility operations, and evaluate the utilities' ability to control EV charging load based on grid conditions.

PHI noted that the program seeks to: understand and reduce grid impacts of EV charging on the utility's distribution and transmission systems; lessen Exelon customers' capital investment required to manage EV charging demand as EV ownership grows; identify potential cybersecurity risks and vulnerabilities of EVSEs and vehicle telematics software; and design managed charging plans for residential, commercial, and public customers that can be shared industry-wide. According to the PHI Utilities, the findings of this project indicate that leveraging research and customer feedback to build and amend managed charging programs will ultimately lead to a flexible program that meets driver and grid needs. In addition, the team found that automating program functions maximize efficiency and scalability of the program. The automation of EV charging to maximize benefits for the EV drivers and the grid is a technology that is still evolving conceptually and technically. On December 18, 2024, PHI received approval to extend the SCM pilot to the end of 2025. This extension supports continued enrollment of new customers, while in parallel seeking approval in a Phase II EV Smart program filing that proposes a full SCM program. The findings have been positive and will lend themselves to a program that will be beneficial for both the utility and their customers.

ii. Time of Use Rate (TOU) Plan Pepco

Pepco and Delmarva Power's TOU rate plans in Maryland provide residential customers with a strategic way to manage energy costs while supporting grid efficiency and sustainability. Under these programs, electricity prices vary throughout the day based on demand—offering lower rates during off-peak periods, such as early mornings, evenings, and weekends, and higher rates during times of peak demand. This structure encourages customers to shift energy-intensive activities—such as running appliances or charging EVs—to times when electricity is less expensive. By adjusting their energy usage patterns, participants can reduce their monthly bills, ease pressure on the electric grid, and support a more reliable and sustainable energy system.

As outlined in Section 9.2 of this report, the DRIVE Act has prompted both Pepco and Delmarva Power to propose enhancements to their existing TOU offerings-making them more appealing to customers encouraging higher participation. They have also filed proposals for enhanced customer education and outreach plans to help customers understand their rate options and maximize their potential benefits. The TOU component of the DRIVE Act will inform a Commission report on the feasibility of opt-out TOU rates in Maryland.

- Goal 7 – Electric System Resiliency and Reliability

  i. Reliability

As in 2024, the PHI Utilities stated that reliability and resiliency are critical to effectively implementing the CSNA, as they provide a stable and dependable energy supply while facilitating the integration of renewable energy resources. Reliability guarantees that consumers have continuous access to electricity, which is essential for supporting economic activities and maintaining public trust in the energy system. Resiliency, on the other hand, enables the grid to withstand and quickly recover from disruptions, such as extreme weather events or cyberattacks, which are increasingly relevant in a changing climate. While reliability and resiliency will be discussed separately, it is important to note that they are interrelated; a reliable grid enhances resiliency by providing a solid foundation for integrating diverse energy sources, while a resilient infrastructure ensures that reliability is maintained even in challenging circumstances. Together, they are vital for achieving the ambitious climate and energy goals set forth in the CSNA.

The PHI Utilities also stated that widespread reliability is more important to customers than ever given increasingly frequent storm activity, the post-pandemic hybrid work environment, and the increased local, regional, and national expectation of overall electrification to enable a cleaner carbon-free future. The CSNA emphasizes reducing GHG emissions and accelerating the adoption of renewable energy sources, which depend on the seamless integration of variable generation like solar and wind. A reliable grid guarantees that PHI Utilities can manage these renewable sources efficiently, maintain stability, and prevent outages that could undermine the progress toward climate goals. In addition, the PHI Utilities stated that strong reliability supports customer trust, COMAR 20.50.12.02 regulatory compliance, and the long-term viability of sustainability initiatives, reinforcing the utilities' role in meeting both environmental objectives and public expectations for continuous service.

According to the PHI Utilities, the improvements in reliability performance based on data excluding major outage events under COMAR exclusion data criteria provide evidence that customers are continuing to benefit from reliability investments. On average, customers are now experiencing fewer outages and better restoration times than in the past.

Reliability in Maryland is measured primarily through two key performance indicators: SAIFI and SAIDI. SAIFI measures the average number of interruptions a customer experiences over a given period, reflecting the frequency of service disruptions. SAIDI, on the other hand, measures the total duration of interruptions that a customer experiences, providing insight into the length of outages. Together, the PHI Utilities stated that these metrics are critical in evaluating the reliability of an electric utility's service, as they highlight both the consistency and duration of power delivery. In Maryland, utilities are required to track and report these indices to ensure they meet regulatory standards and deliver dependable service to customers. Pepco and Delmarva Power have met or exceeded their reliability SAIFI and SAIDI COMAR requirements. The PHI Utilities stated again this year that, since 2021, both Pepco and Delmarva Power are also in the top quartile of their electric utility peers for reliability.

The PHI Utilities added that Pepco has implemented automated switching technology across Maryland's grid, enabling the system to automatically reroute power around faults and minimize outage times. The PHI Utilities assert that this technology has been effective in responding to localized outages, allowing crews to identify and address issues more swiftly. Furthermore, Pepco has smart meters for Maryland customers, which aid in quickly detecting outages and providing real-time data to support faster restoration efforts. The PHI Utilities stated that in 2024, Pepco and Delmarva Power had over 1.6 million smart meters installed and activated for over the air meter reading, remote provisioning and interval data provided to customers via My Account. In 2025, the PHI Utilities stated that the number of smart meters installed and activated had increased to 1.7 million.

ii. Distribution Automation (DA)

In a significant addition to their 2025 report, the PHI Utilities added a lengthy description of the PHI Utilities' Distribution Automation (DA). According to the PHI Utilities, DA improves system reliability through the deployment of technology. These projects involve installing advanced control systems across the distribution system in order to automatically identify and isolate faults in real time and restore service to customers in the unaffected parts of the system.

The purpose of the DA initiative is to improve the reliability of the distribution system. Automated Sectionalizing and Restoration (ASR) technology is the main DA tool and is part of the PHI Utilities' overall smart grid strategy. The PHI Utilities have been implementing ASR on its overhead system and are now piloting the technology on underground radial feeders.

Through the deployment of DA and the activation of ASR schemes, the PHI Utilities are improving infrastructure reliability, enhancing customer experience, and providing enhanced interaction levels with the grid. The PHI Utilities' DA approach involves installing advanced control systems, ultimately across the distribution system, to automatically identify and isolate faults in real time and promptly restore service to customers in the unaffected parts of the system. The goal of this DA strategy is to deploy technology that will enhance reliability by improving the speed of isolation of trouble spots on the system, in coordination with automated restoration capability. The PHI Utilities' DA efforts include: (1) fault identification and isolation: DA can isolate critical pieces of the infrastructure to minimize customer impact in a fault area and/or allow for quicker restoration; and (2) System/Data management: DA can provide accurate and real-time information regarding the overall integrity of the distribution system, which allows for targeted deployment of corrective maintenance and upgrade measures for critical assets.

DA devices such as reclosers and auto-switches are equipped with intelligent controllers which are integrated into the Energy Management System (EMS) via a comprehensive telecommunications network, providing the PHI Utilities with the ability to monitor system status on a near real-time basis. For instance, when an ASR scheme operates through the control of reclosers and switches, the system operator can see which devices opened and closed, and in turn can dispatch crews to a more specific fault location. In addition, the operator can operate the devices remotely and return the system to normal once the trouble areas are fixed.

DA/ASR is first deployed in areas that can most benefit from this technology. For instance, feeders that experience multiple lockouts (large feeder main outages) per year are the best candidates for automation on a priority basis. Along with intelligent devices and a comprehensive telecommunications network, ASR must have feeders with an adequate number of feeder ties that have adequate reserve capacity to accept a transfer of customers during times of emergencies. Specifically in Delmarva Power's territory, line extensions and wire upgrades are needed to add additional ties and further build out ASR.

The PHI Utilities stated that in 2024, they installed 150 new reclosers, replaced 98 reclosers, integrated 5 existing reclosers into the SCADA, and deployed ASR on 57 distribution feeders. Pepco also deploys network remote monitoring system (RMS) on the network transformers across its underground network system and distribution VAR dispatch (DVD) project deploying two-way communications to the distribution capacitor banks. RMS is used by the utilities' operations control centers remotely to isolate and troubleshoot underground network faults faster. RMS also has various alarms that can be monitored remotely to address issues before they become outages. As further deployment occurs of this technology, PHI intends to use this information proactively for equipment replacements.

iii. Resilience

As in 2024, the PHI Utilities stated that resilience is a key focus of the CSNA, as it helps Maryland's energy infrastructure withstand and recover from the growing impacts of climate change, such as extreme weather events and rising sea levels. The Act emphasizes strengthening the grid through investments in technologies like energy storage, microgrids, and grid modernization, which improve reliability and support renewable energy integration. By prioritizing resilience, the Act protects vulnerable communities and enables the State to meet its clean energy goals while maintaining grid stability and public safety.

- Goal 8 – Bidirectional Power Flows

As in 2024, the PHI Utilities noted that bi-directional power flows are crucial as they directly support enhanced grid reliability and resilience. Unlike traditional one-way power flows, bi-directional systems allow electricity to flow both to and from the grid, enabling greater integration of DERs such as rooftop solar, battery storage, and EVs. DER integration is critical to reducing the dependence on centralized fossil fuel-based power generation. Moreover, bi-directional flows contribute to the grid. The PHI Utilities stated that Pepco has participated in several pilots - as outlined in Section 10.1 of this report - that aim to leverage bi-directional power flows to support the grid. These projects are largely focused on a key technology known as V2G and EVSE which utilize energy storage DERs to deliver grid services such as peak load shaving support, frequency and voltage support, and participation in virtual power plant markets or FERC Order 2222 markets. The key orchestrating technology to leverage V2G and EVSE for energy storage is DERMs.[26] The DERMs initiative at PHI is essential to leveraging reverse power flows created by DERs, such as V2G and EVSE energy storage devices. The V2G pilots PHI has participated in have concluded that PHI will be limited to using static schedules and profiles to leverage these types of DERs. Until a DERMs system is implemented, PHI will be limited in its ability to fully leverage these DERs to provide "grid services."

i. PHI Utilities' Distributional System Enables Bidirectional Power Flows

As in 2024, the PHI Utilities stated that its utilities already enable bi-directional energy flow and are now evaluating ways to provide additional capability and support to accommodate bi-directional energy flows onto the grid. The PHI Utilities recognize the advantages of a bi-directional grid in maximizing the value of DER on the grid. Accordingly, the PHI Utilities stated that they are investing in the technologies that will accommodate bi-directional flow, allowing real and reactive power to be exchanged at an interface between customer-to-utility without compromising system reliability, safety or power quality.

<u>Pepco's ability to accommodate bi-directional flow on underground networked feeders</u>

Again, as in 2024, the PHI Utilities stated that on underground networked feeders within the Pepco electric distribution system, the ability to accommodate bi-directional flow is dependent on the load within the network and the aggregated size of the DER systems within the network.

Interconnection to network systems, which are designed to enhance reliability through redundant service, present a greater challenge with respect to bi-directional energy flow when compared to radial interconnections because reverse power can result in disconnection from the grid and the loss of service. Prevention of reverse power in network protectors is essential to avoid loss of grid connections serving network load. For larger systems connected to networks, telemetry is needed to support feeder monitoring and service status.

For most PHI Utilities' feeders and substations, the ability to accommodate bidirectional flow depends on the equipment used to regulate voltage and the DA equipment used to maintain system power quality and reliability. To maintain acceptable voltage along the feeder, regulators, capacitors, and substation load tap changers are generally not allowed to accommodate

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[26] Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company. Joint Consolidated Conceptual Reports. Case No. 9778 (Maillog No. 323218), filed Oct. 10, 2025.

bidirectional flow unless the equipment is specifically designed for that function. Likewise, to maintain system reliability, substation transformer relays, substation feeder relays, and recloser driven DA schemes generally are not allowed to accommodate bi-directional flow unless they are specifically designed for that function.

In a change from 2024, the PHI Utilities stated that despite these challenges to bi-directional flow, the PHI Utilities seek to identify opportunities to upgrade the electric distribution system via customer- or utility-funded projects. The PHI Utilities can upgrade regulators to make the equipment bidirectional and their control systems capable of regulating voltage appropriately in both directions. At some substations, the PHI Utilities have upgraded to Load Tap Changer (LTC) controller and relay protection equipment on the distribution substation power transformers to accommodate up to 40% of reverse power flow without significantly de-rating the transformers' normal and emergency rating.

From a DA and secondary network standpoint, the PHI Utilities require and use DER remote monitoring, as well as remote monitoring of reclosers and network protectors, to promote bidirectional flow without decreasing the reliability of the DA system and secondary networks.

The PHI Utilities are also investigating increasing bi-directional penetration on its distribution system by improving electrical models (inclusive of DERs and their facility equipment) that could be used to conduct planning and system protection analysis. The PHI Utilities are considering opportunities to standardize and develop these types of electrical models that could enable a more optimized and less conservative approach when evaluating hosting capacity and technical impacts of bidirectional flow.

- Goal 9 – Demand Response and other Non-Wire and Non-Capital Alternatives

As in 2024, the PHI Utilities stated that Demand Response (DR) and other non-wire and non-capital alternatives are pivotal in enhancing grid reliability and reducing the need for traditional infrastructure investments, and the DRIVE Act and CSNA emphasize the integration of these alternatives as key components of a sustainable and resilient energy future. DR programs incentivize customers to adjust their energy usage during peak demand periods, helping to alleviate grid stress without additional infrastructure. Similarly, NWS, such as energy storage, distributed generation, and energy efficiency measures, offer cost-effective, environmentally-friendly solutions that reduce the need for costly grid upgrades. By advancing these strategies, the PHI Utilities can align with climate goals, promote renewable energy integration, and improve overall grid resilience.

i. Demand Response

In 2023, the Commission approved the PHI Utilities' Energy Efficiency and Demand Response programs for the 2024–2026 EmPOWER Maryland cycle. Pepco and Delmarva Power filed comprehensive EmPOWER plans in August 2023, which included customer incentives and rebates for transportation and building electrification.

As in 2024, the PHI Utilities stated that DR programs are operated by PJM and/or utility companies to elicit energy savings to reduce demand during an emergency and provide customers with opportunities to save money by curtailing usage. Energy Efficiency (EE) programs available to customers are designed to lower overall energy consumption and reduce peak demand. Some of these programs are administered by utility companies, typically pursuant to state utility commission-approved plans, while other programs are administered by external agencies. Dynamic Pricing programs provide residential customers the ability to receive a bill credit for reducing use during critical peak hours as called by the utility.

<u>Demand Response Pepco</u>

Pepco has been implementing both dispatchable and non-dispatchable DR initiatives to lower overall peak demand through its Energy Wise Rewards program. In their 2025 report, the PHI Utilities stated that during the second half of 2024, Pepco experienced 3 DR events and in the first half of 2025 Pepco experienced 4 DR events. The company currently has approximately 234MW of dispatchable load and has awarded more than $9 million annually in participation rebates. These programs are working to reduce Pepco's peak demand during critical times to the system.

<u>Demand Response Delmarva Power</u>

Like Pepco, Delmarva Power has been implementing both dispatchable and non- dispatchable demand response initiatives to lower overall peak demand through its Energy Wise Rewards program. In their 2025 report, the PHI Utilities stated that during the second half of 2024, Delmarva Power experienced 1 DR event and in the first half of 2025 Delmarva Power experienced 2 DR events. The company currently has approximately 36 MW of dispatchable load and has awarded more than $1.7 million annually in participation rebates. These programs are working to reduce Delmarva Power's peak demand at times critical to the system.

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ii. DRIVE Act

Maryland recently passed the DRIVE Act, which mandates the establishment of bi-directional EV charging programs and VPPs. This legislation requires utilities to enable EVs to not only draw power from the grid but also supply it back, effectively allowing them to act as mobile energy storage units.

<u>PHI Utilities VPP (DRIVE Act)</u>: PHI stated that in 2022, Delmarva Power energized the first VPP in the PJM region, partnering with PJM and Sunnova to harness the capabilities of BTM batteries for grid support.

On July 1, 2025, the PHI Utilities filed with the Commission proposed Distribution System Support Services (DSSS) Pilots and TOU Tariffs, expanding on the VPP pilot demonstrations as required by the DRIVE Act.[27] Both Companies proposed a three-year plan for pilot

[27] Potomac Electric Power Company's and Delmarva Power & Light Company's Revised Tariff Pages: Proposal for Distribution System Support Services Pilots and Time-of-Use Tariffs, Case No. 9761 (Maillog No. 320092).

implementation, which the Companies believe will allow for thorough evaluation of battery and EV system integration and expanded customer outreach and enrollment. On October 21, 2025, the Commission issued an order requesting the pilot operate for two years and directed the PHI Utilities to refile the tariffs in Case No. 9761 to comply with this change.

Evaluation of Non-Wires Solutions (NWS): The PHI Utilities stated that they have a process to consider NWS through the capital project initiation process.

- Goal 10 – Increased Use of DERs, including EVs

The PHI Utilities added a new discussion of this goal in their 2025 report as follows. They stated that the DRIVE Act is set to significantly enhance the adoption of DERs, including EVs by supporting the infrastructure, incentives, and regulatory frameworks needed to expand these technologies. Through targeted investments and policy support, the Act encourages the integration of DERs such as solar, wind, and battery storage, making it easier for consumers and businesses to adopt these sustainable energy solutions.

For EVs, the DRIVE Act promotes the development of a more robust charging network and offers incentives that help reduce barriers to ownership. By enabling bi-directional power flows and fostering grid modernization while improving grid stability, allowing DERs and EVs to be integrated efficiently. Overall, the DRIVE Act positions DERs and EVs as essential elements of a resilient, low-carbon energy system, supporting both economic growth and environmental goals.

i. Pepco Vehicle to Grid (V2G) Initiative

In another change from their 2024 report, the PHI Utilities stated that Pepco and Toyota Motor North America (Toyota) are working together on V2G research for BEVs using a Toyota bZ4X. This collaborative effort will explore bidirectional power flow technology that will allow BEV owners to not only charge their vehicle's battery but also send power back to the local energy grid. V2G technology has the potential to support and provide benefits to customers through improved energy reliability and resilience, the integration of renewables, and the possibility of reduced electricity costs.

This collaboration aims to understand the needs of EV owners through their charging habits and vehicle usage, which will be crucial in driving widespread adoption of V2G technology. Nearly 80% of owners currently charge their EVs at home overnight when demand for energy is lower. With bidirectional capability, these vehicles could send power back to the local energy grid during peak demand hours or at other critical times, such as severe weather.

The PHI Utilities stated that Pepco is committed to driving clean energy transition by embracing innovative technologies. By partnering with Toyota to explore V2G technology, Pepco aims to enhance grid reliability, improve customer service, and contribute to a more sustainable future. This collaboration will provide valuable insights into the potential benefits of V2G technology and its role in a decarbonized energy landscape.

The V2G research will take place at Pepco's Watershed Sustainability Center, located at the company's Rockville Service Center in Montgomery County, Maryland, using a bi-directional charger. Pepco will facilitate the effort to design and evaluate a variety of EV charging and discharging use-cases that can potentially provide grid and customer benefits. The demonstration project will also assist Pepco in understanding the infrastructure needed to enable the rapid growth of EV charging infrastructure and the nuances of interconnecting large numbers of V2G assets to the grid to better prepare the utility to implement requirements of the DRIVE Act and support customer adoption of this technology. Currently, Pepco is in the process of finalizing an agreement with Toyota on V2G research, as the initiative is still in its planning phase.

ii. Community Solar

Maryland's Community Solar Energy Generating System Program established a pilot program under the authority of the Commission, which became permanent in 2023. As of 2024, the PHI Utilities had collectively integrated over 120 MWs of operational community solar projects for the benefit of over 19,000 subscribers. As of 2025, the PHI Utilities have collectively integrated over 150 MWs of operational community solar projects benefitting over 22,500 subscribers.

Through subscription-based community solar, customers subscribe to a portion of the electricity generated and receive credits on their bill for the solar energy produced by the community solar generating system.

iii. MCAM Implementation

In another change from their 2024 report, the PHI Utilities stated in 2025 that the MCAM is a result of the Commission's adoption of RM81, now part of COMAR 20.50.09.06. MCAM will change DER Interconnection projects from a "Causer Pays" model to a Cost Allocation model. This change is expected to reduce one of the barriers to solar deployment and thus promote DER adoption by customers and equitable cost allocation (in connection to PUA § 7-802). By December 12, 2025, PHI Utilities will submit a service tariff for Commission approval for: (1) a primary voltage hosting capacity cost sharing and allocation methodology for interconnection customers and (2) a secondary voltage cost sharing and fee for both residential and commercial interconnection customers.

- Goal 11 – Transparent Stakeholder Participation in Ongoing Electric System Planning Processes

As in 2024, the PHI Utilities stated that transparent stakeholder participation can lead to better decision-making by providing valuable insights into local energy needs, potential barriers to implementation, and innovative approaches to integrating renewable energy resources. By facilitating open dialogue and collaboration, utilities can identify opportunities for co-benefits, such as economic development, job creation, and enhanced resilience, which align with the goals of the CSNA. Furthermore, public involvement is crucial for building broader support for clean energy initiatives and policies, ultimately leading to more sustainable outcomes. The increased use of DERs, including EVs, is reshaping Maryland's distribution system planning. As DERs grow, the PHI Utilities must adapt to allow grid stability and support the State's climate goals under the CSNA.

IV. Potomac Edison Company (Potomac Edison)

- Goal 1 – Measures to decrease greenhouse emissions from the electric distribution system

Potomac Edison stated that it has a long history of providing energy efficiency programs to customers that not only help customers save energy and money but also decrease GHG emissions. The company's initiatives below are designed to decrease GHG emissions incident to electric distribution. The company's energy efficiency programs are discussed in detail later in this report.

i. Conservation Voltage Reduction (CVR) Program

Potomac Edison stated that it aims to reduce GHG emissions through the CVR program and through system upgrades that reduce line losses. Under the CVR program, the company reported that it will implement, monitor, and maintain the reduction of voltage at select substations and distribution circuits, on an annual basis, across its service territory to achieve additional energy savings. The program will be implemented at the selected substations and distribution circuits by company employees who will perform the voltage set point changes. Potomac Edison's CVR program has reported an increase from 59,685 MWh last year to 88,981 MWh of incremental annual energy savings for the program to date this year. An additional 19,895 MWh of incremental annual savings are projected for 2025.

ii. High Efficiency Transformer Replacement Program

Potomac Edison stated that it continues to purchase and implement energy efficient transformers in its Maryland service territory. According to the company, the analysis of energy and demand savings relative to other energy efficiency requirements shows that the High Efficiency Transformer Replacement program has reported an increase from 7,261 MWh last year to 7,400 MWh of incremental annual energy savings for the program to date this year. Information on 2025 results will be available in the second quarter of 2026.

iii. High Efficiency Street Lighting Program

Potomac Edison reported that it has street lighting tariffs that provide for the installation of more efficient lighting fixtures which result in energy savings over standard street lighting installations. Potomac Edison's High Efficiency Street Lighting program has also reported an increase from 1,220 MWh last year to 1,254 MWh of incremental annual energy savings for the program to date this year.[28] An additional 21 MWh of incremental annual savings are projected for 2025.

[28] Case Number 9705, Maillog No. 311694.

iv. Utility Distribution/Transmission Improvement Program

This program captures system upgrades that reduce line losses including reconductoring lines with larger wires that will reduce the impedance of the distribution system and capacitor additions that will provide power factor correction on the distribution system. These improvements can result in significant energy savings. Potomac Edison's Utility Distribution/Transmission Improvements program has reported 30,348 MWh of incremental annual energy savings for the program to date.[29]

v. Planning Criteria

Potomac Edison completed a comprehensive review of its distribution planning criteria in 2024 and early 2025 along with its parent company FirstEnergy Corp. Some of the primary drivers for this review were related energy efficiency and demand response trends and to better integrate DER in planning along with potential changes due to the integration of electric vehicle or other electrification load additions, which are potentially changing the load profile and growth projections. Another topic reviewed is appropriately sizing primary conductors for new lines or line upgrade projects. Potomac Edison states that minimizing line losses is one of the factors considered when selecting the conductor size based on circuit characteristics while enabling stronger circuit ties to support neighboring feeders with bidirectional power flow. Updates to the planning criteria are anticipated to take effect with projects initiated for the 2026 planning cycle.

vi. Electric School Bus Pilot

Potomac Edison's Electric School Bus Pilot program, approved by Order No. 91918 on October 22, 2025, will result in decreased GHG emissions by incentivizing the deployment of electric school buses to replace diesel buses, with the benefit of testing vehicle-to-grid technologies to provide distribution grid services. The pilot program plans to measure, track, and report on several emissions metrics including reductions in GHG nitrogen oxides (NOx), sulfur oxides (SOx), and particulate matter of 2.5 microns or less in diameter (PM2.5).

- Goal 2 – Giving priority to vulnerable communities in the development of distributed energy resources (DERs) and electric vehicle infrastructure

i. Grid Resilience and Innovation Partnerships (GRIP) Grant

Potomac Edison stated that it has applied for, and received, a grant from the DOE's GRIP Program. The projects funded by this grant will target upgrades benefiting disadvantaged communities. These projects will focus on improving reliability and resilience of circuits in disadvantaged communities to enable distribution automation and will increase circuit capacity and enable electrification of buildings and transportation.[30] The company stated that, like last year, approximately $3.5 million will be dedicated to Potomac Edison's distribution service territory in western Maryland.

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[29] Case Number 9705, Maillog No. 311694.

[30] *See* Public Conference 56, Potomac Edison Monthly Report on IIJA Applications (filed Nov. 1, 2024).

ii. Electric School Bus Pilot Program

Potomac Edison's Electric School Bus Pilot program, approved by Order No. 91918 on October 22, 2025, will consider, when selecting school systems to participate, the health and economic effects on low-income and minority communities. In addition, all participating school systems will be required by law, when deploying buses, to consider criteria that benefit students who are eligible for free and reduced-price meals.[31]

iii. Electric Vehicle Charging Pilot Program

Potomac Edison stated that, throughout the first phase of its EV charging pilot, it has installed 59 public electric vehicle charging stations across its service territory. While placing stations in defined areas representing vulnerable communities, the company made efforts to install stations in each county and municipality that expressed interest in the program. According to Potomac Edison, these efforts resulted in a network of charging stations that was not only focused on installations where the majority of electric vehicles are registered, but also in areas where the adoption may be lagging

- Goal 3 – Energy efficiency

Potomac Edison highlighted below programs that are part of its Energy Efficiency and Conservation Plan for the 2024-2026 EmPOWER Maryland program cycle. The company stated that the plan was designed to achieve the incremental annual energy savings targets established in the CSNA. The company's revised plan for the 2024-2026 program cycle, which continues these programs with modifications including, but not limited to electrification of space and water heating equipment with heat pumps to increase the focus on achieving lifecycle GHG savings targets, was approved by the Commission on December 27, 2024. Full details on the below programs and the overall programs and plan are included in the company's August 15, 2024, filing in Case No. 9705.[32]

i. The Energy Efficient Products – Appliance Recycling Subprogram

This subprogram provides an incentive for pick-up and recycle services to customers for turning in qualifying, inefficient, appliances. Qualifying appliances will be picked up at the customer's residence. Periodic events may be offered at centralized drop-off locations where the customer can drop off qualified inefficient appliances.

ii. The Residential – ENERGY STAR for New Homes Program

This program provides a rebate to builders for achieving EE savings and targets through a combination of building shell and installed measures, including appliance and equipment upgrades with updated incentive amounts and expanded focus on installation of additive measures (*e.g.*,

[31] PUA § 7-217; Case No. 9741, Brief of The Potomac Edison Company (Maillog No. 313124).

[32] *See* Maillog No. 311732.

smart thermostats, heat pump water heaters and central air conditioners and heat pumps). To qualify for this program, a builder must construct a home to qualify to meet the energy efficiency requirements established by the ENERGY STAR program, specifically tiers established that meet or exceed the current ENERGY STAR requirements including the NextGen tier, or a Code+ tier.

iii. The Small Business Solutions Direct Install Program

This program provides an audit with the installation of direct install measures including, but not limited to, high efficiency lighting, heating ventilation and air conditioning (HVAC), and refrigeration measures to small business customers. This program also provides incentives for the implementation of comprehensive energy efficiency improvements, including electrification of space heating equipment and water heaters with heat pumps, including wiring upgrades, that are recommended as part of the audit. This subprogram continues an expanded focus on installation of complementary measures (HVAC, food service, appliance replacement and recycling, controls, building envelope and weatherization, updated incentive structure and enhanced targeted customer outreach) with the addition of beneficial electrification.

iv. The Energy Solutions for Business – Prescriptive Subprogram

This subprogram provides incentives to commercial and industrial customers to purchase and install qualifying energy efficient equipment. Prescriptive incentives are offered to reduce the customer's investment for qualifying energy efficient measures to overcome first cost barriers to participation and to encourage the adoption of higher efficiency equipment and electrification of space heating equipment and water heaters with heat pumps and wiring upgrades.

v. The Energy Solutions for Business – Custom Subprogram

This program provides incentives to commercial and industrial customers to purchase and install qualifying energy efficient equipment or retrofit specialized processes and applications to higher efficiency processes and applications or implements qualifying high efficiency building shell or systems improvements. Calculated or performance-based incentives are offered to reduce the customer's investment for qualifying energy efficient measures or projects to overcome first cost barriers to participation and encouraging the adoption of higher efficiency equipment, processes, and buildings.

- Goal 4 – Meeting Anticipated increases in load

In addition to the energy efficiency programs discussed above, Potomac Edison has the following processes to ensure that it meets anticipated increases in load.

i. Electrification

Potomac Edison stated that it is monitoring potential loads from electrification (transportation, heating, and industrial). The company stated that it has partnered with the Electric Power Research Institute (EPRI) on the eRoadMAP™ initiative to identify approximate demands of energy needs at a local level to electrify transportation for light-, medium-, and heavy-duty electric vehicles.

Potomac Edison anticipates that this data will be added to Potomac Edison's feeder level load forecasts to help identify constraints and needs in the future.

ii. Winter Peak and Electrifications

Potomac Edison stated that its distribution system typically sees its annual demand peak during the winter season. This tendency is due in part to the limited access to natural gas in portions of its service territory, which results in more customers heating their homes with electricity. As temperatures drop, system demand increases due to this heating load and the dramatic reduction of load diversification on the system causes a system peak. This peak typically occurs at around 6:00 a.m. and slowly decreases as the sun rises and temperatures increase. In this way, Potomac Edison has experience operating an electrical system more similar to those expected to exist after significant electrification. The company stated that its experience with operating a winter peaking territory and specific areas that do not have natural gas has better prepared Potomac Edison to handle heating electrification in the future.

iii. Load Forecasting

Potomac Edison stated that it uses a circuit specific load forecasting tool to project future loads, utilizing historical data and adding additional site-specific loads to the forecast. A load forecast for each distribution substation power transformer is derived from historical peak loads recorded using SCADA systems where available and also utilizing manual readings of substation load recording equipment. Substation readings are validated and transferred into FirstEnergy's standard forecasting tool, Load Forecasting Data Management System (LFDMS), to summarize historical and forecasted peak load patterns for each substation transformer and circuit exit. This tool accounts for general load growth in an area that happens over time (such as residential EV adoption) and spot load additions like a new large customer load which may not be representative of area load growth.

Potomac Edison noted that load on the company's distribution system is weather sensitive. During the summer, peak loads are higher during extended hot weather and lower during cooler periods. Because these variations do not reflect positive or negative growth, the Company adjusts historic peaks to compensate for abnormally hot and cool summer weather so that future peak loads are forecasted based on more typical seasonal temperatures. Using the Cumulative Cooling Degree Day (CCDD) method, past summer and winter peak loads are adjusted to a 90/10 weather condition. This method normalizes the load forecast with the assumption that, on average, 90% of the past weather conditions were less extreme and 10% were more extreme.

iv. Planning Criteria

Potomac Edison stated that the distribution planning criteria used by the company standardizes the process for identifying limiting circuit components and recommending cost effective projects to mitigate constraints in a timely manner based on predicted load growth. Adjustments were made in 2023 to FirstEnergy's criteria to adjust project timelines with the longer lead times experienced across the industry for substation power transformers. The comprehensive review of the distribution planning criteria in 2024 was completed in early 2025 to make sure Potomac Edison has procedures and systems in place to track projected demand with appropriate granularity for changing loads. Potomac Edison stated that projects initiated in the 2026 cycle will follow the new criteria.

v. Managed Electric Vehicle Charging

As part of its revised EV Phase II program, Potomac Edison stated that it intends to propose an active managed charging pilot for residential customers. This proposal will allow the company to test how effectively residential electric vehicle charging can be spread out during off-peak periods while prioritizing convenience for participating drivers. The company stated that, by managing this load and not just simply pushing it to off-peak hours, utilities can work to smooth out daily distribution demand curves and potentially reduce capital investments that may otherwise have been needed to accommodate transportation electrification.

vi. Data Center Load

In a new development from last year, Potomac Edison reported that given the increase of data center demand in the Potomac Edison service territory, and the request to serve some of this load from the Distribution System, Potomac Edison has approved the use of larger underground conductors and larger substation transformers. This high load requires the use of more robust conductor calculations to confirm the capacity of the conductor when it is near other conductors. Potomac Edison has had discussions with both contracting firms as well as other utilities across the industry to better provide services to these large-use customers.

- Goal 5 – Incorporation of Energy Storage Technology as appropriate

i. Energy Storage Pilot Projects

As part of the energy storage pilot program directed by the Commission, Potomac Edison completed two battery storage projects in 2022 and 2024. The company stated that it will continue to evaluate the ability, reliability, and benefits of the pilot program. Options to use energy storage as appropriate will be considered based on the pilot evaluation. Potomac Edison states that, in compliance with applicable law and Order Nos. 91705 and 91812, Potomac Edison intends to file energy storage program proposals in Case No. 9715, and that details of its proposals will be accessible in that docket when filed.

ii. Hosting Capacity Maps

Potomac Edison stated that it will be pursuing a model-based procedure to calculate hosting capacity on affected feeders. Information learned from this process can then be used to improve available data on publicly available hosting capacity maps.

iii. Customer Energy Storage Installations

As part of its generator interconnection process, Potomac Edison stated that it allows customers to operate energy storage devices in parallel with its distribution system. Since the company began tracking these interconnections, Potomac Edison states that it has connected an increase from 329 systems in 2024 to 370 systems in 2025, resulting in an increase in total storage capacity from 5.3 MW in 2024 to 6.1 MW in 2025. Potomac Edison notes that while customers operating these systems are not permitted by Maryland regulations to output energy to the grid, they may use them to offset load behind their retail electricity meter.

- Goal 6 – Efficient Management of Load Variability

i. Smart Inverters

At the beginning of 2024, utilities were required to start requiring interconnecting customers to use smart inverters with utility-specified smart inverter settings under UL-1741-SB. The settings are intended to conform to IEEE 1547-2018. Settings other than these defaults, within the ranges of allowable settings in IEEE 1547-2018, may be required on a case-by-case basis and are subject to review and approval by Potomac Edison. Potomac Edison stated that it has worked with developers on a case-by-case basis when site specific settings would reduce additional hosting capacity upgrades to implement the project.

ii. Voltage Control

Potomac Edison stated that it uses multiple devices paired together to control voltage levels on the distribution system. Potomac Edison further stated that it utilizes transformer load tap changers at the larger substations to regulate the voltage and utilizes single-phase voltage regulators at smaller substations. Potomac Edison adds that it also utilizes single-phase voltage regulators as necessary on the distribution lines to regulate the voltage levels of the system.

iii. Power Factor Control

Potomac Edison stated that it utilizes capacitor banks that are both fixed and switched based on local conditions to regulate the power factor of the system. Potomac Edison states that it does this at both the substation level as well as dispersed throughout the distribution lines as required.

- Goal 7 – Electric System Resiliency and Reliability

i. Reliability

In addition to its energy efficiency programs discussed above, Potomac Edison stated that it has various explicit projects and programs that improve system resiliency and reliability. These projects and programs are detailed in the company's Annual Reliability Report filed pursuant to COMAR 20.50.12.02E. Specifically, they are described in section 20.50.12.11A(5) of that report. For Potomac Edison's most recent report, see Case No. 9353, 2024 Annual Performance Report filed April 1, 2025.[32]

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[32] Maillog No. 317339.

ii. Resilience

In accordance with COMAR 20.50.12.15B, the company also stated that it has a resilience plan to prepare for, and recover from, various credible events. In addition, Potomac Edison states that it is actively participating in the Electric Resiliency Work Group, which filed a status report on January 1, 2025, in accordance with Commission Order No. 91307.[33] Potomac Edison states that a second status report was filed on July 8, 2025,[34] and that the Commission found in Order No. 91799 that the Work Group had concluded its work.

- Goal 8 – Bi-directional Power Flows

i. Bi-directional Power Flows

According to Potomac Edison, while the majority of its feeders were initially designed for one-way power flow, engineers now have a handful of mitigation techniques to allow bi-directional flows. These techniques are used to solve issues identified during DER interconnection technical reviews. Most of the time this involves replacing power system component controllers or protective relays. Potomac Edison stated that it is working towards "standardizing on models" capable of bi-directional power flow for new equipment installations, when appropriate.

ii. Distribution Automation

In addition to enabling bi-directional current flow to optimize DER installations, Potomac Edison stated that it continually looks for opportunities to implement distribution automation as a reliability improvement tool. The company stated that since 2017, it has installed equipment intended to automatically isolate a fault and then restore unaffected portions of the circuit from the opposite direction and an alternative feeder on 12 pairs of distribution feeders. Potomac Edison states that since July 2018, these operations have avoided approximately 47,000 customer outages, an increase from 39,000 in 2024, and have saved an increase from almost 6 million customer minutes of interruption in 2024 to almost 7.4 million customer minutes of interruption in 2025.

- Goal 9 – Demand Response and other Non-Wire and Non-Capital Alternatives

i. Demand Response

As proposed in the company's revised plan for the 2024-2026, program cycle,[35] and approved by the Commission in Order No. 91461,[36] Potomac Edison states that it has expanded its Residential Demand Response Program to include winter peak load reductions. The Residential Demand Response Program is designed to target reduction of winter peak loads in addition to summer peak

[33] Maillog No. 314603.
[34] Maillog No. 320278.
[35] Maillog No. 311732.
[36] Maillog No. 314502.

loads through control of connected devices. The program will market and enroll customer program eligible connected devices, initially including customers' smart thermostats, for control of air conditioning and heat pumps to reduce peak loads. The program includes two opportunities, one for summer-only participation and the second for annual participation (including both summer and winter seasons). See Section 5.0 of the company's Revised 2024-2026 EmPOWER Maryland Plan filed on August 15, 2024, for additional details.[37]

ii. Battery Storage Projects

As required by the Energy Storage Pilot Program, Potomac Edison proposed two battery storage projects in its service territory. Each project utilizes a different ownership model and value streams. While the company continues to develop its experience in this area, it filed a report on learnings from the pilot in May 2024.[38]

According to the company, since that filing, it has interconnected the Town Hill Energy Storage Project. Potomac Edison reported that this project specifically has led to a better understanding of how to implement and the benefits available for battery storage projects in Potomac Edison's service territory. The company noted that the project required utilization of flexible interconnections to reduce the need for additional system upgrades to implement the battery project. Potomac Edison stated that it will utilize the experience with each of the projects to better determine additional use cases and locations to install battery storage projects in the future.

In compliance with applicable law and Order Nos. 91705 and 91812, Potomac Edison states that it is also filing energy storage program proposals in Case No. 9715. Details of the company's proposals will be accessible in that docket when filed.

iii. Residential Time-Of-Use (TOU) Rate Schedule

In a new development since last year's report, Potomac Edison states that in accordance with the DRIVE Act, PUA § 7-1003, Potomac Edison filed on July 1, 2025, a Residential TOU Rate Schedule proposal. This voluntary opt-in tariff is designed to encourage load shifting from on-peak to off-peak hours, thereby mitigating distribution system impacts of electrification and supporting GHG reduction goals under the CSNA. The TOU structure incorporates both generation and distribution components to maximize cost differentials, with on-peak periods limited to certain hours on weekdays. Potomac Edison states that the Commission approved the proposal on October 21, 2025, subject to modifications of on-peak hours. The company adds that it is beginning implementation work, targeting a launch of the offering no later than the second quarter of 2026.

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[37] Maillog No. 311732.

[38] Case No. 9619. The Potomac Edison Company – Learnings on the Development of Battery Energy Storage Systems Report (Maillog No. 309420).

- Goal 10 – Increased Use of DERs, including EVs

i. Electric Vehicle Pilot Program Phase I

Potomac Edison reported that it has delivered on its offerings in its Electric Vehicle Pilot Phase I program to increase electric vehicle adoption and the availability of EVSE. In this program, Potomac Edison noted that it issued 1,000 rebates for residential Level 2 (L2) chargers, implemented an EV-only TOU rate with an increase from 810 customers enrolled in 2024 to 1,824 customers enrolled as of October 23, 2025. As in 2024, Potomac Edison stated that as of 2025 it had also installed three utility-owned chargers at multi-unit dwelling (MUD) locations and installed 59 publicly accessible utility-owned chargers, 20 of which are DC fast chargers with the remaining 39 being L2 chargers. Details of the Phase I program can be found in the final Case No. 9478 semi-annual report filed March 12, 2024.[39]

ii. Electric School Bus Pilot

In accordance with PUA § 7-217, Potomac Edison stated that its Electric School Bus Pilot program, approved by the Commission in Order No. 91918 on October 22, 2025, will aid local school systems with the adoption of electric school buses in Potomac Edison's service territory. According to the company, the program is designed to incentivize the deployment of 28 electric school buses, which will reduce GHG emissions and other emissions such as PM2.5, NOx, and SOx by reducing the number of vehicle-miles traveled by diesel buses. Furthermore, Potomac Edison stated that the batteries of the buses funded under the pilot will be available for use as vehicle-to-grid resources, which will be studied for their potential as a distributed energy resource to reduce constraints on the distribution system. Additional information can be found in Case No. 9741.

iii. EV Phase II

Potomac Edison stated that it filed an updated proposal for Phase II of its EV program on December 20, 2024, in accordance with the deadline established in Order No. 91297.[40] In that updated proposal, Potomac Edison stated that it proposed several changes to its program in accordance with the Commission's direction, including: (1) explaining how residential charging data will be acquired for future planning; (2) including a managed charging program element; (3) including integration of net metering customers into the EV charger TOU rider and managed charging programs; (4) including infrastructure incentives and a charging as a service offering for multifamily housing charging; (5) including technical assessments, make-ready incentives, and charger rebates for fleets; and (6) explaining how Potomac Edison is preparing for future medium-heavy duty vehicle load, among other things. Potomac Edison added that it is awaiting a Commission order on Phase II and has continued to run certain Phase I programs in the interim. Potomac Edison also intends to continue leveraging data collected from these various programs to help with distribution planning purposes.

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[39] Maillog No. 308205.

[40] Maillog No. 314457.

iv. Electric Distribution System Support Services (“EDSSS”) Pilot Program

The DRIVE Act requires utilities to submit pilot EDSSS programs to the Commission for approval that include distribution system peak load reduction. Potomac Edison states that it proposed a Bring Your Own Device (BYOD) Pilot program designed to integrate battery energy storage systems and bi-directional EVs into distribution grid operations. The Pilot targeted residential customers and included a cap of 300 participating devices. Under the proposed Pilot, Potomac Edison states that customers would receive incentives for providing grid services, with payments of up to $300 per kW per performance period based on event participation and nominated device capacity. In addition, Potomac Edison states that participants would be eligible for an annual connectivity bonus of $150 to ensure communication with the utility. Potomac Edison stated that on October 21, 2025, the Commission issued an order requiring resubmission of the programs proposed by all investor-owned utilities, and Potomac Edison is working to comply with that order.

v. Maryland Cost Allocation Method (MCAM)

In December 2024, the Commission adopted regulations requiring electric companies to implement a cost sharing system intended to socialize the cost of system upgrades required to interconnect DER systems among current and future interconnection customers. Potomac Edison stated that it is finalizing a tariff that will streamline the implementation of MCAM in its territory.

vi. Meter Collar Adapters

The Commission approved regulations requiring electric companies to approve meter collar adapters for installation by residential customers. Potomac Edison stated that it has approved several meter collar adapter models that have been requested for approval. Potomac Edison states that this will potentially reduce customer costs for incorporating DER or electrification upgrades into their home electrical system.

vii. Interconnection Portal

Potomac Edison stated that it has released a new online customer interconnection portal. The portal intends to enhance the customer experience of the interconnection process by providing a central and standardized approach to interconnection applications. The company noted that the interconnection portal reduces queue times through the interconnection process while opening visibility to the customer on where their application is in the process. Potomac Edison states that the portal also helps it establish a DER database, which assists engineering in the electric planning processes.

viii. Flexible Interconnections

Potomac Edison stated that it has, and continues to, utilize flexible interconnections as needed in order to reduce the need for Hosting Capacity upgrades or wires solutions for battery storage projects.

- Goal 11 – Transparent Stakeholder Participation in ongoing Electric System Planning Processes

Potomac Edison stated that as part of the DSP Workgroup, electric companies including the Potomac Edison proposed regulations establishing a DSP process that includes measures for stakeholder participation. That process includes, among other things, an opportunity for stakeholders to view the utilities' plans and participate in an annual Technical Conference. Potomac Edison states that it will continue to work with the DSP Work Group and interested stakeholders to continuously refine this process in order to allow for meaningful stakeholder participation in determining the future of Potomac Edison's distribution system.

V. Southern Maryland Electric Cooperative Inc. (SMECO or the Cooperative)

- Goal 1 – Measures to decrease greenhouse emissions from the electric distribution system

According to SMECO, it has a variety of programs that help to decrease GHG emissions incident to electric distribution. Examples of such programs include the Smart Temp (demand response), Smart Home Pilot (demand response), and various residential and commercial programs as part of the Cooperative's EmPOWER Maryland portfolio. SMECO states that these programs include EE measures, as discussed above, and select electrification offerings currently under consideration by the Commission in Case No. 9705.[41] Additionally, SMECO is deploying CVR on select feeders.

SMECO also stated that it has been operating a Residential EV Pilot since December 2023, which includes three different offerings: Residential Managed Charging, Residential Off-Peak Savings, and Residential Charging Data Access. The Residential EV Pilot is scheduled to end in December 2025, and a Phase II proposal is currently being considered. Other ongoing efforts SMECO is undertaking to support electric vehicles include the SMECO EV Recharge program, utility-owned public charging stations located on government properties and a MUD utility-owned electric vehicle charging program. Below is a summary of these offerings, but additional details can be found in SMECO's most recent EmPOWER Maryland and EV Portfolio semi-annual reports.[42]

i. Smart Temp (Demand Response) Program

SMECO stated that its SmartTemp Program is a voluntary BYOD residential demand response program for residential members who have eligible smart thermostats connected to their central air conditioner or heat pump. Participants agree to brief thermostat adjustments of 1-4 degrees or less during peak electric demand periods or times of higher energy costs. Unless there is a system emergency, peak periods do not occur on weekends or holidays. Enrollment options include year-round or summer only, and adjustments to thermostats occur on weekdays only. The adjustment

[41] The 2024-2026 EmPOWER Maryland Program, Maillog No. 311740.

[42] Maillog Nos. 321536, 320943.

durations are typically 15-minutes to one hour, lasting no more than four hours. Participation is voluntary, and members retain control of their thermostat and can easily opt out of an event for any reason. SMECO stated that marketing will continue to drive program enrollments. Direct mail and social media marketing will continue to play a key role while other media and events will continue to be used. SMECO stated that it will continue cross-marketing its demand response and energy efficiency programs. All marketing materials and program collateral will continue incorporating the EmPOWER Maryland logo and tagline.

ii. Smart Home Pilot – Phase 3 (Demand Response Pilot)

SMECO stated that this successful flexible load management pilot continues to evolve after the initial launch of the latest iteration in 2022 as a demand response program testing more granular demand control strategies for residential members. The Phase 3 pilot is exploring the overall orchestration of multiple grid-connected devices with a focus on connected water heaters.

iii. Residential Electrification

SMECO reported that, while SMECO is already made up of a majority of electric-only members, the Cooperative has incorporated electrification measures related to heating and water heating into its EmPOWER portfolio as a response to the passing of HB864 and subsequent Commission orders. In a change from 2024, SMECO now offers rebates for electrification through the existing delivery channels of the energy efficiency programs.

iv. Conservation Voltage Reduction (CVR) Program

SMECO's CVR program aims to reduce the substation bus voltage by 2 volts (on a 120V base) at select transformer/feeders where the functionality and system topology permit CVR operation. Distribution feeders with CVR enabled operate in constant "on mode" 24/7, and the CVR can be disabled when needed to support switching operations or under other abnormal conditions. The Cooperative stated that the current iteration of the CVR program was initiated in 2024 as part of a three-year evaluation cycle.

v. Residential Managed Charging

SMECO reports that its Managed Charging Pilot offers incentives to residential EV owners for enrolling their device and allowing SMECO to control EV charging schedules. The Managed Charging program has yet to call any demand response events, but the Cooperative's program team is currently strategizing as to how such an action might look. Additionally, the program team is working on flexible load management strategies, which enables SMECO to place load limits on specific grid assets and curtail charging on devices connected to stressed assets.

vi. Residential Off-Peak Savings (EV-TOU)

SMECO's EV TOU rate offers monthly bill corrections (bill credits) to residential EV owners who enroll their device in the program. This is an EV-only rate and calculates bill credits based on EV time-of-use consumption only.

vii. Residential Charging Data Access

SMECO's Charging Data Access (Data Share) program offers incentives to residential EV owners who enroll their devices in the program and allow SMECO to intake their charging data. According to SMECO, this program does not exhibit any control over EV charging and is meant to serve as a control group to measure effectiveness of Managed Charging and EV-TOU.

viii. SMECO EV Recharge

SMECO stated that it engaged a third-party vendor, Shell Recharge, to install up to 60 charging stations throughout SMECO's service territory on property leased, owned, or occupied by a unit of State, county, or municipal government for public use. In Order No. 91297, the Commission directed SMECO and all Maryland utilities to cease development of public charging stations. Locations for the SMECO EV Recharge stations are being considered with the support of State, municipal, and local governments. With 40 sites in operation, 26 of which are Level 2 charger sites, and four of which are Direct Current Fast Charger (DCFC) sites, SMECO's focus is on maintaining the reliable operation of its installed public charging stations.

ix. Multi-Unit Dwelling (MUD) Charging Program

SMECO stated that, under the MUD program, it will own, install, and operate up to 35 Level 2 charger installations on MUD member properties. The Cooperative stated that it will be responsible for all equipment, installation, and ongoing operations and maintenance costs. MUD members partnering with SMECO will not contribute any capital to the project but must meet certain eligibility requirements to proceed to an application process.

x. Time of Use Rates

The TOU program offers a lower rate during off-peak times, thus encouraging customer members to shift their energy usage to off-peak times. A benefit of shifting energy usage from on-peak hours to off-peak hours will reduce the need to run on-peak generation to serve load, which will contribute positively to reducing energy portfolio emissions. SMECO states that customer-members with an eligible electric vehicle or Level 2 EV charger can enroll in the SMECO Residential customer-members, and some commercial customer-members, can also elect to enroll in SMECO's - whole-building - TOU rate as an alternative to the Standard Offer Service rate. SMECO states that the TOU program offers a lower rate during off-peak times, thus encouraging customer-members to shift their energy usage to off-peak times.

- Goal 2 – Giving Priority to Vulnerable communities in the development of distributed energy resources (DERs) and electric vehicle infrastructure

SMECO stated that it recognizes the importance of including low and moderate-income communities in its energy efficiency portfolio and acknowledges the challenges in reaching limited-income members. The Cooperative stated that building on its previous collaboration with DHCD, SMECO has committed dedicated funds to the DHCD Coordination Program in the 2024-2026 EmPOWER program cycle. This program aims to connect low-income members with DHCD programs and includes a marketing budget to enhance existing outreach efforts to educate members about these resources.

The DHCD Coordination Program also features the Affordability Solution, launched in September 2024. This solution is designed to assist members facing a high energy burden and to increase awareness of available assistance programs, with a primary focus on those offered by DHCD. SMECO members who may have a limited income or are energy-burdened are directed to the Savings Hub tab in their SMECO Online Account Manager tool. The Savings Hub includes a brief six-question survey that collects basic demographic and participation data from members. The results of this survey help curate and display various energy assistance and financial programs tailored to each member's needs, guiding them to the most beneficial options.

According to the Cooperative, while the Affordability Solution and Energy Savings Hub are specifically targeted at members experiencing high energy burdens, they remain accessible to all residential members.

SMECO stated that customer-member participation rates in EmPOWER programs is consistent across all census tracts, including those qualifying as now being in the top 75th percentile, compared to the 60th percentile in 2024, for “overburdened communities,” as calculated through the MDE indicators used when assigning a Maryland Environmental Justice (“EJ”) score. SMECO stated that it has also invested in public EV charging infrastructure. In its 2024 DSP report, SMECO identified 13 chargers as being located within census tracts qualifying as “overburdened communities” based on Maryland’s 2024 EJ criteria. However, following the State’s update to its EJ calculation, these EV charger locations no longer fall within the revised criteria.

In addition to SMECO’s offerings in support of DERs and EV infrastructure, SMECO stated that it has also been awarded a substantial federal grant through the DOE GRIP Program to improve grid resiliency in southern Maryland. Completion of the GRIP projects will directly benefit Census Tract 24017850901 in Charles County, Maryland. The Biden Administration had previously designated this census tract as a Justice40 Disadvantaged Community identified by the White House Climate and Economic Justice Screening Tool.

- Goal 3 – Energy efficiency

SMECO has a variety of EE offerings across the residential, commercial, and industrial sectors. SMECO’s EE program participation and forecasted annualized energy savings, by sector, is included in the following table for 2025:

2025 Forecast - Energy Efficiency Programs

Program	Forecasted Participants	Reported Participants	Forecasted Lifecycle GHG Reduction In Metric Tons (CO2e)	Reported Lifecycle GHG Reduction In Metric Tons (CO2e)
EmPOWER Maryland Utility Portfolio				
Residential EE&C Programs				
Energy Efficient Products	12,070	20,234	12,818	6,187
Appliance Rebates	10,020	19,401	10,612	5,323
Appliance Recycling	2,050	833	2,206	864
Home Optimization and Retrofit	50,797	27,267	28,922	7,376
Home Energy Improvement	6,595	1,281	6,900	2,686
Audits	-	619	-	111
Completed Projects	-	145	-	2,271
Smart Thermostat & HVAC Tune up	-	517	-	304
HVAC	1,202	1,031	3,685	2,155
My Energy Target	18,000	19,633	389	72
Energy Efficiency Kits	25,000	5,322	17,948	2,463
New Construction	1,214	827	4,711	5,543
Behavior Based Program Res	75,000	71,428	3,221	728
School and Education Program	1,750	690	2,208	271
DHCD Cross Promotion	-	-	-	-
Residential Rewards	5,500	3,281	-	-
Residential DR Transition Program	15,840	331	4,457	299
Residential Energy Efficiency Programs	**162,171**	**124,058**	**56,337**	**20,403**
Commercial and Industrial EE&C Programs				
Small Business Program	794	156	13,238	6,124
Efficient Buildings	205	143	20,344	8,700
Prescriptive	47	107	13,316	7,218
Custom	106	5	4,039	189
Retrocommissioning	52	31	2,989	1,293
Combined Heat and Power	1	-	-	-
Midstream Products	135	168	4,287	3,345
Large Industrial and Commercial Energy Efficiency Programs	**1,135**	**467**	**37,870**	**18,170**
Total EE&C Programs-EE				
Energy Efficiency and Conservation Programs Subtotal	**163,306**	**124,525**	**94,206**	**38,573**
Other EE&C Programs				
Conservation Voltage Reduction	-	-	1,577	789

A summary of SMECO's EE offerings follows, and further details can be found in the EmPOWER Maryland semi-annual report.[43]

i. Residential Portfolio

Residential Energy Efficient Products

SMECO stated that this program consists of two sub-programs, Appliance Rebates and Appliance Recycling. These programs offer rebates through multiple delivery channels for energy efficient home appliances and an opportunity to recycle old, inefficient appliances recognizing both energy savings from taking those appliances off the grid as well as non-energy GHG reductions through responsible recycling of appliance materials and refrigerants.

[43] Maillog 321536.

Home Optimization and Retrofit

SMECO reported that this program consists of four sub-programs, serving existing homes with energy efficiency opportunities and incentives. (1) the Home Energy Improvement Program – offers home energy analysis appointments, incentivized home retrofit upgrades, and HVAC tuneup services; (2) HVAC Midstream – incentivizes the purchase of energy efficient HVAC equipment; (3) My Energy Target – engages customer-members with a custom energy consumption target, unique to their home and needs; and (4) Energy Efficiency Kits – offers a group of low cost, easy to install energy efficiency measures for homeowners to install in their own homes.

Residential New Construction

This program offers incentives for builders to construct more efficient new homes with tiers for multiple levels of the ENERGY STAR® Certified New Homes program and other measures.

Home Energy Reports (Behavior Based)

This SMECO offering motivates members to consume less energy by providing mailed and emailed reports offering information on their energy use along with personalized energy saving advice.

Schools and Education

This program encourages energy efficiency at home among diverse populations, sets behaviors for long-term adoption of energy efficient behaviors, and introduces low- or no-cost energy efficiency measures to students, parents, teachers, and school leaders.

Residential Demand Response Transition

SMECO's DR Transition Program is designed to transition households participating in SMECO's Cool Sentry Demand Response program that sunset recently into one of the SmartTemp programs. Currently, it is available to any residential customer-member. Participants in the DR Transition program agree to sign up for the SmartTemp program and receive an upgraded smart thermostat and HVAC tune-up to ensure their system is working in the most efficient capacity.

ii. Commercial and Industrial (C&I) Portfolio

Small Business Solutions

This program offers direct-installation services and retrofit energy efficiency opportunities to small business members.

Business Solutions Efficient Buildings

The Business Solutions Efficient Buildings program offers a suite of energy efficiency rebates and technical support services upgrading buildings with simple, proven energy conservation measures, as well as more complex systems and energy efficiency projects. The program also includes retro-commissioning to help buildings and building operators fine-tune their existing buildings to make them operate optimally and more efficiently through scheduling, sequencing, controls programming, and optimizing setpoints.

Combined Heat and Power

This program provides incentives for installation of combined heat and power systems for non-residential members with high electric and thermal energy requirements where this efficient technology is economically beneficial.

Instant Savings for Business

This midstream program extends discounted pricing to SMECO commercial members for qualifying energy efficient products.

- Goal 4 – Meeting Anticipated increases in load

According to SMECO, the Cooperative's load forecast uses historical summer and winter seasonal load information in conjunction with the Maryland Department of Planning forecast statistics to develop a 20-year base forecast for customer-member accounts, including a forecast of MWh energy sales, and summer and winter seasonal system peak demands. SMECO works with local area developers to understand where new load centers are likely to be built, and the forecasted system-wide load is allocated to distribution substation and feeder loads based on anticipated local area load growth. The Cooperative states that the distribution system model includes load profiles to enable system studies for peak loading conditions as well as during other times of day. These load profiles are built for every month of the year, by load class, and include profiles for weekday, weekend, peak day, and minimum day loading over a 24-hour load cycle. Existing net energy metering customer-members with rooftop solar are explicitly factored into the distribution model.

SMECO is also exploring opportunities to enhance its forecasting procedures to include modeling of electric vehicle growth adoption and projected usage for electric vehicle charging.

- Goal 5 – Incorporation of Energy Storage Technology as appropriate

SMECO evaluates non-wire and battery energy storage solutions when developing its capital improvement project list and developing the Construction Work Plan (CWP). In addition, SMECO stated that it proposed an energy storage solution as part of a federal government grant application, which was rejected. At present, SMECO stated that it does not own or operate any battery storage on its electric system.

SMECO maintains a public-facing online solar hosting capacity map at ArcGIS which provides a high-level overview of SMECO's electric distribution system and how much solar generation can safely and reliably be introduced to different line sections throughout SMECO's service territory. SMECO's main distribution feeder backbone utilizes overhead conductor and underground cables rated for a nominal 10 MVA per feeder. SMECO reported that it has not identified the need for any hosting capacity expansion plans at this time.

- Goal 6 – Efficient Management of Load Variability

SMECO states that it offers TOU rates which can also contribute positively to management of load variability as these programs encourage customer-members to shift their energy use to off-peak times (Peak times are weekdays: 2-7 p.m. in summer; 6-9 a.m. and 5-8 p.m. in winter). The TOU programs are available to residential and some commercial customer members, and SMECO offers a rate comparison tool through "account manager" that allows customer-members to compare rates and make an informed decision. SMECO notes that the TOU rates are not available for customer-members who are purchasing energy from an alternate supplier.

Additionally, SMECO operates a variety of demand response programs to help manage variability on the system. In 2025, SMECO stated that event calls are based largely on projected Locational Marginal Pricing for energy deliveries to help manage costs. SMECO is also operating a Residential Managed Charging Pilot which will explore the opportunity to manage charging load for distribution benefit (*e.g.,* avoiding equipment overloads). The Cooperative's residential EV-TOU Pilot is exploring the effectiveness of shifting loading to off-peak times, which may also help mitigate equipment overloads.

In a change from the 2024 report, SMECO stated that it has initiated a process to implement an ADMS, which will replace SMECO's outage management system (OMS) and distribution management system (DMS) with a single, integrated solution that streamlines control room operations and enables future automation. Subject to receipt of any required internal and SMECO Board of Directors approvals, this implementation will occur in three phases:

(1) ADMS Foundation – The initial ADMS application will provide a singular integrated solution that includes OMS, DMS, and Distribution SCADA. This phase also includes a Switch Order Management solution. Phase I is scheduled to be commissioned by the fourth quarter of 2028.

(2) DMS Advance Applications – The ADMS will provide near real-time distribution system power flow modeling for SMECO's distribution system operations personnel. Operations personnel will be able to monitor loading and voltage profiles across the distribution system from the main feeder head-end to the last customer-member location at the end of a tap line. This modeling will help the distribution system operator identify potential load—related issues on the distribution system so that corrective

action can be taken before the onset of reliability issues on the distribution system. SMECO stated that the ADMS is a key investment to enable efficient management of load variability on the system. In addition, during Phase 2, SMECO stated that it intends to introduce DERMS functionality to provide visibility into DER impacts, support switching decisions, and ensure compliance with FERC Order No. 2222. At the onset of the DERMS functionality, the ADMS will begin to model DER contributions at the feeder level, providing full visibility into renewable generation impacts and enabling advanced voltage and load management strategies. The ADMS will also capture key attributes such as DER location, type, capacity, and controllability. Integrating real-time telemetry from SCADA, AMI, and other sources will help support situational awareness and informed operational decision-making. Phase II is scheduled to begin by the fourth quarter of 2029.

(3) DMS Advanced Applications with Distribution Automation – SMECO stated that it will consider the implementation of advanced DMS functionality and enable future DERMS capabilities for active control of DERs within the ADMS. The ADMS functionality may include volt-var control (VVC), Feeder Reconfiguration, and Fault Location Isolation and Service Restoration (FLISR). The DERMS functionality can incrementally expand DER capabilities in future phases by incorporating DER data into load flow analysis and advanced DMS applications, such as VVC and FLISR. This step will allow SMECO to better forecast system behavior, identify localized impacts of DERs, and prepare for more dynamic distribution operations. Phase 3 is scheduled to be commissioned in the fourth quarter of 2030.

SMECO added that ADMS is the fundamental building block on which a future Enterprise DERMS solution will be built. Enterprise DERMS provide insights into third-party developer DERs such as wind, solar, battery energy storage systems (BESS, and demand response. This enhanced visibility will enable SMECO to better integrate BTM generation and DERs into SMECO's operation of its electric distribution system. SMECO stated that it will evaluate future Enterprise DERMS implementation once the ADMS power flow application is fully vetted.

- Goal 7 – Electric System Resiliency and Reliability

SMECO stated that it completed a 12-year Electric System Plan (ESP) study document in March 2023. The ESP provides a guide to ensure SMECO's distribution system has the capacity and operational flexibility to provide reliable, quality service to its members at a reasonable cost. The ESP is a fiscally responsible living document intended to help guide the orderly development of SMECO's electric system over the longer-term horizon.

In addition to the ESP, SMECO also develops a CWP every three years. The CWP is developed using guidance embedded within the 12-year ESP including load forecasts and power flow model analysis that readily identifies potential facility overload conditions or marginal voltage areas. The CWP development process ensures the SMECO electric system has sufficient capacity to reliably serve existing and future customer-member loads over the near-term horizon. According to the

Cooperative, the next generation of the CWP is under development with final Board of Director approval expected by December of 2025. This updated document outlines projects for the 2026-2028 planning period. In addition to creating additional system capacity, the CWP analysis process also considers investments to improve system reliability and to address potential power quality related issues.

Specific actions & programs to support reliability and resiliency include:

- Strategically converting legacy overhead copper distribution conductors to underground and upgrading aging facilities to make the electric system less susceptible to outages resulting from severe weather in heavily wooded areas.
- SMECO considers its vegetation management program to be a key component in providing reliable electric service to its members. Calendar year 2024 was the end of the previous four-year vegetation management cycle, and 2025 marks the start of a new cycle.
- SMECO continues to perform annual infrared inspection of all switching stations, substations, and overhead distribution circuits accessible by truck. Any facility demonstrating abnormal heating characteristics is photographed and documented in SMECO's electronic system inspection application, which is now called "MimsMobile." Each electronic record is later reviewed and assigned to a field crew for follow-up repairs as needed. Infrared inspections help identify potential overhead distribution circuit issues that could lead to a future customer-member outage event if not proactively addressed. These inspections are inputs to the distribution system planning process so that proactive replacements and upgrades can be prioritized before failures cause reliability problems.
- SMECO continuously monitors cable failure outage events to identify cable section areas that warrant a proactive cable replacement project to best prevent future area outages. Such events can derive from deteriorating neutral or phase conductor issues on either 15 kV primary or 600-volt secondary rated cable. SMECO's 3-year CWP identifies specific areas of focus for non-jacketed cable replacement in locations that impact a large number of customer members and where the outage history indicated multiple fault locations.
- On a similar note, SMECO is embarking on a multiple-year project to replace and update distribution shunt capacitors to avoid potential failure of the aging assets, thus supporting reliable operation for power factor control and system efficiency.

- Goal 8 – Bi-directional Power Flows

SMECO operates a total of 54 substation site locations comprising 75 distribution power transformers, all of which are SCADA enabled and actively monitored. Upon implementation of an ADMS, downstream feeder visibility will be enhanced in the real-time operations model and operators will have greater awareness of bidirectional power flows.

According to the Cooperative, reverse power flow on the system has not yet been an issue. SMECO line regulation and switched capacitor controllers are bi-directional capable, and the main distribution feeder backbone utilizes large overhead conductor and underground cables rated for a nominal 10 MVA per feeder. SMECO stated that customer DER inverter-based systems interconnecting to the SMECO electric system after January 2, 1014, are required to have volt-var and secondary fail-safe volt-watt smart inverter settings to help manage feeder voltage profiles which can be impacted by bi-directional power-flow. SMECO stated that it will continue to monitor DER growth and will take corrective action where future increases in reverse power flow suggest the need for operating or design changes.

- Goal 9 – Demand Response and other Non-Wire and Non-Capital Alternatives

SMECO stated that it is presently operating demand response pilots and programs, which include the Smart Temp Program, Smart Home Pilot, and Residential Managed Charging Pilot further described above in discussion of CSNA Goal 1. Additional details regarding the Cooperative's demand response programs are included in Case Number 9705, EmPOWER Program.

Beyond its demand response programs, SMECO stated that it evaluates non-wire and battery energy storage solutions when developing its CWP capital improvement project list. Because the business cases for incorporating such solutions have not yet demonstrated cost effectiveness, SMECO has not implemented any non-wire solutions. An example of a study that was performed for a NWS is provided in the response to CSNA Goal 5 discussion above. Reports have been filed through the Storage Working Group (MESI Phase I Final Report, filed October 1, 2024) and the Unified Benefit Cost Analysis Working Group (UBCA Framework, Case No. 9674, filed May 17, 2024), which may offer further guidance on consideration of non-wire and noncapital alternatives pending stakeholder feedback.

- Goal 10 – Increased Use of DERs, including EVs

In another change from its 2024 report, SMECO stated that it continues to see modest growth in DERs, including electric vehicles in its service territory. Through Phase I of the Electric Vehicle Pilot Program, SMECO stated that it has supported increased electric vehicle adoption and the availability of electric vehicle charging stations. In Phase I, SMECO reported that it has installed 40 public charging stations and implemented both a managed charging program and an EV-only TOU rate that currently has over 500 and 140 participants, respectively. SMECO estimated that there are approximately 8,900 electric and hybrid vehicles in its service territory.

In another new development on this front, SMECO stated that it has a well-established online portal that supports the DER interconnection application process, and that its portal allows for the timely and transparent review and processing of interconnection applications. SMECO reported that there are currently 9,370 distributed solar and 349 energy storage systems connected to SMECO's distribution grid. In November 2024, the Commission adopted the MCAM regulations that require utilities to implement a cost sharing mechanism that socializes the cost of system upgrades amongst interconnection customer-members. SMECO is in the process of developing a tariff, modifying its online portal, and updating processes to implement MCAM.

- Goal 11- Transparent Stakeholder Participation in ongoing Electric System Planning Processes

Within the EmPOWER Maryland Program, SMECO stated that it collaborated on scenario development using the input of multiple stakeholders. Over a period of two years prior to the development of the 2024-2026 scenarios, SMECO collaborated with Commission Staff, other EmPOWER utilities, evaluation providers, and other stakeholders. SMECO also stated that it was deeply involved in the Future Programming Working Group, the Evaluation Advisory Group, and the overall EmPOWER planning process which provided information and feedback during the development of these scenarios. Commission Staff, the Office of People's Counsel, the Maryland Energy Administration, DHCD, and other organizations provided invaluable feedback and guidance during the planning process. Implementation vendors, service providers, and other industry experts helped to inform measure selection and overall program designs.

In addition, the Cooperative worked with the Evaluation, Measurement and Verification (EM&V) stakeholders during scenario development in the EmPOWER Maryland Program. This work with the EM&V members ensured that measures and scenarios maintain consistency with the other EmPOWER utilities to provide cost effective energy savings for SMECO members who participate in the offered programs.

Pursuant to Order No. 90546, Commission Staff hosted the EmPOWER Utility Planning and Stakeholder Collaboration Meeting which provided utilities with a forum to engage with stakeholders. An additional EmPOWER Stakeholder Technical Conference was also organized by the Commission Staff. SMECO added that it has been an active participant in Case No. 9665 and RM 89, including related work groups, to develop and implement new ESP processes.

Finally, SMECO noted that, as an electric cooperative, SMECO is governed by a Board of Directors that is democratically elected by customer-members. The Board has visibility across all of SMECO's operations, including electric system planning, and has ample opportunity to provide feedback to management on the direction of electric system planning from the customer member perspective. SMECO further noted that this opportunity for direct and extremely transparent stakeholder participation is unique to SMECO as an electric cooperative.