BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

Distribution System Planning for Maryland Electric Utilities	**Administrative Docket RM89**

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INTRODUCTION

Maryland's electric grid is entering a new era—one defined by a proliferation of distributed energy resources (DERs), urgent climate imperatives to curtail generation emissions, and growing public expectations of plentiful, reliable, and affordable energy. The way we plan this system will determine who gets access to clean energy, where new infrastructure is built, how resilience is prioritized, and what customers ultimately pay. In an era of rising demand, worsening climate risks, and growing economic inequality, the stakes are high. The General Assembly recognized the importance of system planning, and with laws like the Climate Solutions Now Act[1] and the Electric System Planning—Scope and Funding Act (HB 1393),[2] made clear that yesterday's planning processes are not sufficient—the transformation of our grid demands more than business as usual. Modern grid planning must be forward-looking, integrated, and accountable to the people it serves.

Although the proposed regulations represent incremental progress, they remain insufficiently detailed and lack clear accountability measures to ensure utilities develop comprehensive and transparent system plans. But in the electric system planning context, settling for incremental improvements is simply not acceptable. Planning decisions made today will shape the grid and impact customers' bills for decades. As explained in our comments, each missed opportunity compounds the problems caused by yesterday's planning processes. Under the proposed regulations, utilities will be required to submit

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[1] 2022 Md. Laws 38.
[2] 2024 Md. Laws 540.

full system plans just once every three years—plans that chart grid investments 5, 10, even 20 years into the future. Without early, informed input and clear regulatory expectations, those plans will lock in infrastructure choices that shape the grid for decades. The longer Maryland waits to course-correct, the harder and more expensive it becomes to pivot from the energy system of the present to the energy system we need. Without a stronger framework now, Maryland risks binding itself to a system that cannot meet State policy goals, is less reliable, and fails to take advantage of low-cost DERs—with all these costs borne by ratepayers.

Our comments not only provide proposed edits to the regulations, but also map out the changes needed to make an electric system planning process that ensures that utility investments align with the public interest and that every household, business, school, and hospital can rely on the grid to provide them affordable electricity when they need it.

This is not merely regulatory housekeeping—it's foundational governance. Maryland's electric distribution system is the backbone of its economy, and a robust electric system planning process ensures our grid is planned openly, transparently, and with meaningful stakeholder input so as to best serve our state. We urge the Commission to keep the stakes of this process in mind as it considers these regulations.

COMMENTS

The Office of People's Counsel urges the Commission to quickly adopt more robust and integrated electric system planning regulations. OPC's recommendations reflect years of active participation in the Distribution System Planning ("DSP") Work

Group and are firmly rooted in the statutory directives set forth in §§ 7-802 through 7-804 of the Public Utilities Article.

To assist the Commission's deliberations, OPC provides three sets of proposed regulatory language. Appendix A contains OPC's targeted redlines to the current draft regulations. Appendix B includes additional regulatory provisions that OPC recommends be adopted during this rulemaking phase. Appendix C sets forth further proposed regulatory language that OPC recommends the Commission delegate to the DSP Work Group for development in a future Phase III proceeding. Appendix D sets forth a set of uniform planning disclosures developed by OPC, which should be incorporated into the Electric System Planning (ESP) process and required of all utilities.

Part I describes the essential elements of an integrated electric system planning process, identifies the shortcomings in the current proposed framework, and situates those gaps in the context of how the DSP Work Group process has unfolded over the past several years.

Part II outlines OPC's proposed redline edits to the draft regulations, showing how each targeted revision—covering data access, DER forecasting, hosting capacity, solution identification, locational value, and planning metrics—would enhance transparency, accountability, and meaningful stakeholder participation in the ESP process. While broader structural gaps remain, these improvements would materially strengthen the process as proposed. Part II also addresses practical implementation issues, including how discovery should be structured to improve the efficiency and usability of the ESP framework. These redlines to the proposed regulations are attached as Appendix A.

Part III identifies additional actions the Commission should adopt immediately—beyond the targeted redlines in Part II—to improve the Electric System Planning (ESP) framework. These are items that have been discussed in the Work Group process and are sufficiently developed for immediate adoption. They include Commission approval of the initial utility plans and other procedural refinements that would strengthen transparency and ensure that stakeholder engagement begins on solid footing. Each recommended action is supported by prior discussion and is within the Commission's authority to implement without delay. This draft regulatory language is attached as Appendix B. OPC has also attached a draft set of standardized uniform planning disclosures as Appendix D.

Part IV addresses foundational planning dimensions that the proposed regulations still fail to capture elements critical to ensuring Maryland's electric grid can meet emerging demands and evolving policy imperatives. These include coordinated transmission and distribution planning, integration of supply-side and gas system considerations, and strategies to manage high-growth electric demand, such as from data centers. OPC recommends that these issues, and any items from Parts II and III that the Commission chooses not to adopt now, be considered in a dedicated Phase III Work Group process. To facilitate that process, OPC provides draft regulatory language and recommends the Commission gives clear direction to the Work Group on these next-phase priorities. The draft regulatory language is attached as Appendix C.

Collectively, these revisions are intended to address critical omissions in the current proposal and to ensure that the Commission's regulations establish a planning process that is transparent, data-driven, and capable of delivering a distribution system that is equitable, resilient, cost-effective, and aligned with Maryland's climate and energy mandates.

I. Maryland must build an integrated, transparent electric system planning process.

Maryland stands at a turning point in how it plans and builds the electric distribution system that underpins daily life. The energy landscape is shifting—spurred by lower-cost renewables, a surge in customer adoption of distributed technologies, and ambitious state climate laws like the Climate Solutions Now Act and the Electric System Planning—Scope and Funding Act (HB 1393). These changes require more than business as usual; they demand a new kind of electric system planning—one that looks ahead, breaks down silos, and centers the public interest. That means more than improving coordination; it means building a framework that evaluates needs and options holistically, incorporates public input at every stage, and delivers on equity, resilience, and climate alignment.

Integrated electric system planning entails more than coordinating separate work streams or consolidating filings. It is a forward-looking process that systematically evaluates grid needs over multiple time horizons and geographies, assesses a full suite of options—including non-wires solutions—and aligns system investments with state goals. It must incorporate transparent data, include cross-cutting issues such as equity and climate resilience, and support regulatory oversight by enabling comparative evaluation of utility proposals. Integration is not a vague aspiration—it is a concrete planning structure that ensures Maryland's energy transition is cost-effective, equitable, and reliable.

Unfortunately, the proposed regulations fall short. They reflect a fragmented structure that divides planning responsibilities across multiple work groups with separate scopes and timelines. This has produced a regulatory framework that lacks coherence and prevents the Commission from effectively evaluating the full range of planning needs and outcomes.

A. Narrow interpretations of conflicting Commission guidance have obstructed an integrated planning framework.

The proposed regulations reflect how the DSP Work Group process unfolded—and why that process fell short. Over the past several years, multiple Commission orders have sought to guide the Work Group's approach. But rather than advancing a unified planning vision, the process was shaped by ambiguous guidance in Commission orders regarding the scope of the Work Group, narrow readings of those orders by utilities, and reluctance among utilities to engage on topics they argued were outside the group's jurisdiction. This section summarizes the relevant Commission guidance, how it was applied, and how it ultimately limited the development of a coherent, integrated planning framework.

In Order No. 89865, the Commission launched the DSP Work Group with a broad mandate to develop regulations that would establish transparent stakeholder participation and advance the state's energy goals.[3] Order No. 90777 reaffirmed the importance of holistic planning that incorporates equity, resilience, and the integration of distributed

[3] Order No. 89865 (June 23, 2021).

energy resources (DERs).[4] This mandate of holistic planning, however, was complicated by Order No. 91256, which directed the DSP Work Group to collaborate with other work groups "on areas of overlap," and to avoid overreach into areas "clearly" within the scope of other groups.[5] The Commission reiterated its language about "yield[ing] to other Work Groups in matters where they are responsible" in Order No. 91490, which reinforced the separation of key planning topics across groups.[6]

These orders, taken together, send conflicting signals. While the Commission calls for integrated planning, it simultaneously limited the DSP Work Group's ability to address critical components of that integration. In practice, utilities interpreted Order No. 91256 as a directive to reject engagement on topics such as resilience metrics, hosting capacity enhancements, battery storage, EmPOWER, or climate risk—even where those topics were essential to distribution planning. As a result, the regulatory framework that has emerged does not reflect an integrated process. It is instead a patchwork of uncoordinated initiatives, disconnected from a unified planning vision.

This disjointed framework impedes progress on grid modernization. Stakeholders will be forced to participate in multiple, often disconnected processes with little opportunity to understand or shape how different pieces of the planning puzzle fit together. Regulatory oversight becomes more difficult as the connections between planning activities grow less transparent. And without a centralized venue to synthesize

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[4] Order No. 90777 (Aug. 24, 2023).
[5] Order No. 91256 at 9 (July 30, 2024).
[6] Order No. 91490 at 11-12 (Jan 21, 2025).

planning inputs, Maryland risks falling short of its policy goals—not for lack of ambition, but for lack of integration.

The Commission should therefore refine and clarify its directives on the interactions between the DSP Work Group and other work groups. The DSP Work Group must serve as a clearing house for all information relating to the ESP process. Accordingly, the Commission should clarify that the Distribution System Planning Work Group is not limited in its information-gathering efforts by the subject matter assigned to other work groups. The DSP Work Group can and should attempt to harmonize reporting requirements with other work groups, but it should be empowered to consider reporting and metrics that touch on every element of the ESP process, even if other work groups also cover that area. While implementation of programs may be the domain of issue-specific work groups, forecasting the outcomes of those programs must occur in the DSP Work Group, and assumptions in other work groups regarding outcomes must harmonize with the ESPs utilities produce.

B. Integrated planning is essential for delivering an affordable, resilient, and equitable grid.

Integrated electric system planning is not just a buzzword or an academic ideal. It's a practical, necessary approach to making smart, transparent decisions about how we build and operate the grid. At its core, it means looking at the electric system as a whole—across time, across geography, and across technologies—so that every investment and policy choice works together, not at odds.[7] It means breaking down the old habit of tackling problems in isolation and instead building a coordinated process that connects the dots between power lines, rooftop solar, electric vehicles, energy storage, energy efficiency and demand response, affordability, climate risks, and community needs.

A truly integrated process ensures that utilities, regulators, and stakeholders are planning for the future together—not just reacting to problems as they arise. It provides a structure that helps identify the best options, the lowest-cost solutions, and the greatest public benefits. Integration doesn't just make planning smarter; it makes it fairer, more forward-looking, and more capable of delivering the energy system Marylanders deserve.

An integrated electric system planning framework includes the following components:

- **Policy alignment.** Utility plans must start with Maryland's goals in mind—climate targets, equity mandates, and affordability—and not treat them as afterthoughts.

- **Resilience metrics.** Planning must account for how the grid can withstand and recover from extreme weather, using clear, forward-looking measures to guide investment.

- **Comprehensive coordination.** Utilities must plan distribution and transmission upgrades together and alongside customer-side solutions like energy efficiency, storage, and demand response.

- **Data transparency.** The planning process must include accessible data and clear feedback loops—linking DER forecasts, hosting capacity maps, and EV infrastructure planning—so that stakeholders

[7] *See* Order No. 91256 at 12 (July 30, 2024) ("Unlike traditional siloed distribution planning, integrated DSP will look to the interconnected relationships of the § 7-802 Climate Solutions Now Act goals for distribution planning and other State policy goals to lead to more effective grid investments.").

that may be able to solve for system needs (such as DER aggregators and developers) can analyze and help shape decisions.

- **Process integration.** Electric system planning must serve as the hub for aligning work group outputs, reconciling overlapping mandates, and tracking progress against clear, measurable targets.

Recent planning efforts in Maryland demonstrate both the limitations of siloed approaches and the promise of an integrated model. Several examples from ongoing work groups illustrate why integration must be a regulatory requirement—not an optional aspiration:

- The Maryland Energy Storage Initiative (MESI) Work Group acknowledged Delegate Fraser-Hidalgo's call for grid resilience strategies, akin to the Zero Outages Initiative.[8] However, it confined its scope to evaluating ownership models for storage technologies.[9] By declining to assess resilience strategies more broadly, MESI missed an opportunity to shape coordinated investments across the grid that could support resilience, reliability, and cost-effectiveness.

- The Energy Resilience and Efficiency Work Group (EREWG) documented the importance of distributed energy resources in protecting vulnerable communities during outages. But those insights were not translated into any actionable reforms within the DSP regulatory framework, leaving a disconnect between policy awareness and planning implementation.[10]

- Some Maryland utilities have pushed back against using forward-looking planning tools like those in EPRI's ClimateREADi initiative, which includes metrics to assess restoration effectiveness and climate risk. These utilities argue that such metrics are suitable only for retrospective reporting—not for guiding future planning.

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[8] *See* Case No. 9715, Maryland Energy Storage Initiative Work Group Final Report, at 91-92 (ML 312609) (Oct. 1, 2024). The Zero Outages Initiative is a series of infrastructure investment and programs run by Green Mountain Power, a utility in Vermont, to reduce outages for its customers.

[9] *Id*.

[10] Yury Dvorkin et al., Energy Resilience and Efficiency in Maryland, https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Doclib_ERE/EREWG%20Study%20Report%20--%20Energy%20Resilience%20and%20Efficiency%20in%20Maryland.pdf.

> This position limits the ability to prepare the grid for long-term resilience challenges.[11]

These examples show that even well-intentioned work groups may fall short when integration is not mandated or facilitated by the regulatory framework. Important concepts surface but are lost without a centralized planning structure to absorb and act on them.

Meanwhile, other states are demonstrating the benefits of integration in practice. Utilities such as Green Mountain Power and Portland General Electric are coordinating substation upgrades, community-scale storage, and grid modernization strategies through transparent, holistic planning processes. These utilities appear to be delivering more reliable, equitable, and cost-effective outcomes because their planning models prioritize coordination, not fragmentation.[12]

To ensure Maryland's electric grid is prepared to meet the state's climate and equity mandates, the Commission should explicitly identify the Electric System Planning process as the centralized venue for integrating work group outputs, engaging stakeholders meaningfully, and guiding utilities toward investment decisions that serve the public interest. Without this integration, Maryland will continue to lose opportunities to deliver the grid its future demands.

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[11] Electric Power Research Institute, Metrics to Evaluate Effectiveness of Resilience Strategy Deployment at 13 (May 2025), https://www.epri.com/research/sectors/readi/research-results/3002031834.

[12] *See generally* Lawrence Berkley National Lab,
State Requirements for Electric Distribution System Planning (Dec. 2024), https://eta-publications.lbl.gov/sites/default/files/2025-01/state_requirements_for_electric_distribution_system_planning_20250103_0.pdf

II. The draft regulations require targeted fixes to make the electric system planning functional and meet the State goals.

Throughout the Work Group process, OPC consistently advocated for an ESP framework that is holistic, transparent, and aligned with the urgency of Maryland's climate and equity goals. Unfortunately, the proposed regulations fall short of that standard. To realize the full value of electric system planning, significant structural improvements are needed. Sections III and IV of these comments offer a roadmap—supported by specific regulatory language—to remedy those gaps.

But within the existing structure, OPC has proposed targeted edits (shown in redline) that would materially strengthen the process. The sections that follow explain the rationale behind those edits and the consequences of failing to adopt them. While these edits cannot substitute for a fully integrated planning framework, they represent immediate, actionable steps the Commission can take to improve transparency, stakeholder participation, and long-term system accountability.

A. Data transparency must be guaranteed to support robust stakeholder participation – COMAR 20.50.15.03.B(4) – *Data Sources, Scope, and Access*.

Robust electric system planning is impossible without clear, consistent access to high-quality data. Yet the draft regulations fall short on one of the most foundational aspects of the planning process: they acknowledge the importance of data in general terms but fail to define what data must be shared, with whom, in what format, or on what timeline. This lack of specificity invites utility discretion—and with it, delays, denials, and disputes that undermine meaningful stakeholder participation.

OPC's edits aim to correct the lack of specificity by establishing a clear data access framework. First, they require utilities to proactively provide anonymized, aggregated data to the public and make more granular datasets—such as power flow models and feeder-level net load profiles—available to stakeholders with confidential access approval. Second, the edits eliminate the need for stakeholders to rely solely on ad hoc, reactive data requests by requiring baseline planning datasets to be shared as a matter of course.

The shift to proactivity matters. A request-driven system places the entire burden on stakeholders to identify, justify, and obtain data they may not even know exists. It also fosters a contentious dynamic, where disagreements over relevance or claims of burdensome requests slow down the process and exclude newer or resource-constrained participants.

OPC's edits instead propose a predictable and practical starting point. The redlines identify a concrete list of foundational datasets that utilities already use internally—such as seasonal transformer ratings, substation peak loads, DER interconnection queues, historical outage data, and feeder-level billing data. These are not novel asks; they are standard inputs in modern utility planning and are already shared in other jurisdictions.[13]

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[13] *See, e.g.,* Vermont Department of Public Service, Guidance for Integrated Resource Plans at 18, https://publicservice.vermont.gov/sites/dps/files/documents/Guidance%20for%20Integrated%20Resource%20Plans%20and%20202%28f%29%20Determination%20Requests%20-%20April%202023.pdf ("To the extent not covered in other sections of its IRP, each utility should provide a brief overview of its transmission (if applicable) and distribution systems. This should include … a description of each substation including transformer capacity."); *Interconnection*, Xcel Energy, https://co.my.xcelenergy.com/s/renewable/developers/interconnection (showing monthly updates on DER interconnection queue data for the distribution system under the "Public Distributed Energy Resources

To ensure continued progress, OPC requests the Commission institute a formal feedback mechanism. After the first ESP cycle, the Commission should convene a post-cycle technical conference with:

- A utility presentation on what data was used, what was shared, and how it aligns with national data standards such as the Lawrence Berkeley National Lab's Bridging the Gap report;[14]

- A stakeholder response identifying access barriers and proposing improvements; and

- Commission-led deliberations to assess where data-sharing protocols must evolve.

Planning without accessible data is not planning—it's performance. Maryland cannot achieve its energy, equity, and climate goals through a black-box planning process. By adopting OPC's proposed data access framework and laying the groundwork for a more transparent and future-ready system, the Commission can ensure that stakeholders are equipped to hold utilities accountable and help shape a resilient, least-cost electric grid.

(DER Queue)" tab); Minnesota Public Utilities Commission, Docket No. E-002/M-18-684 at 14 (Aug. 15, 2019), https://www.edockets.state.mn.us/documents/%7B30A8966C-0000-C718-A194-CB1FBC13A490%7D/download ("In spreadsheet format, Xcel shall provide hosting capacity data by substation and feeder, with appropriate disclaimers about the data's accuracy, precision, and timeliness. The data shall include, when available, peak load, daytime minimum load, installed generation capacity, and queued generation capacity.").

[14] Sean Murphy et al., Bridging the gap on data and analysis for distribution system planning: Information that utilities can provide regulators, state energy offices and other stakeholders at 1 (Jan. 2025) https://eta-publications.lbl.gov/sites/default/files/2025-01/bridging_the_gap_between_utilities_and_regulators_20250106.pdf.

B. DER forecasts must be location-specific, forward-looking, and technically relevant – COMAR 20.50.15.03.D – *DER Forecast.*

The proposed regulations acknowledge the need to forecast distributed energy resources (DERs), but they stop short of specifying how such forecasts should be performed, what they must include, or how they should evolve. As written, the regulations fail to require utilities to identify where DERs are likely to appear on the grid—information that is critical for using DERs to their full potential as tools for system optimization and cost avoidance.

OPC's edits close this gap by requiring utilities not only to estimate aggregate DER growth, but to forecast where that growth is expected to occur on the distribution system. This locational specificity is not an academic concern—it is a precondition for making DERs useful in real-world planning. A battery or solar system can only defer a substation or feeder upgrade if it's in the right place. Without knowing where DERs are likely to emerge, utilities cannot reasonably rely on them to avoid capital expenditures or reduce system stress. In short, failing to forecast where DERs will show up significantly undercuts the role DER forecasts can play in system planning.

OPC's edits also push the DER forecasting process to evolve over time, in line with growing capabilities. Advanced metering infrastructure (AMI), for instance, can help distinguish between firm and flexible loads—data that is essential to planning for demand response. Similarly, DERs such as batteries should not be modeled only as generators discharging to the grid; they must also be understood as loads with charging profiles that affect grid conditions. OPC's redlines ensure that forecasts will begin to account for these dual characteristics and incorporate locational value price signals, which help steer DER deployment toward areas of highest system benefit.

These changes to DER forecasting are not just technical refinements—they safeguard against wasteful investment. Without improving DER forecasting, Maryland risks building infrastructure that DERs could otherwise make unnecessary. That's a textbook case of path dependency: investments made today will lock in system configurations and cost trajectories for decades. Planning decisions should reflect the value of flexibility and ensure that DERs are not sidelined because the planning process couldn't account for them properly.

OPC also recommends removing "as feasible" qualifier in this section of the proposed regulations.[15] While this language may seem innocuous, it operates as a blanket exception with no accountability. If a utility can opt out of a requirement merely by deeming it infeasible—without having to explain why—that deprives the Commission and stakeholders of insight into both current limitations and future potential. OPC proposes a more transparent and constructive alternative, modeled after Colorado's DSP regulations.[16] If a utility cannot comply with a requirement, it should be required to explain why, what it could provide instead, and how it plans to close the gap in future filings. This turns noncompliance into a roadmap for progress—not a dead end.

[15] The "as feasible" caveat appears elsewhere in the proposed regulations besides Identifying Possible Solutions to Grid Needs (see sections covering DER Forecast, Hosting Capacity, and Locational Value Assessment). We recommend striking this language from these other areas as well for similar reasons.
[16] *See* 700 Colo. Code Regs. § 3528. OPC's proposed waiver language appears in OPC's edits to proposed COMAR regulation 20.50.15.01(E).

Accurate, location-specific, and continuously improving DER forecasts are foundational to a modern planning framework. OPC's proposed edits ensure that DERs are treated not as afterthoughts, but as core elements of the grid—and that Maryland avoids locking in a system that fails to account for the resources it is actively trying to promote.

C. Hosting capacity assessments must reflect both generation and load growth needs – COMAR 20.50.15.03.F – *Hosting Capacity Assessment*.

The proposed regulations touch on hosting capacity but fail to fully reflect their evolving role in grid planning.[17] Historically, hosting capacity assessments have focused on enabling DER interconnection by identifying where new generation can be added without triggering costly infrastructure investments.

However, that view is now incomplete. With the accelerating pace of transportation electrification—particularly the projected growth in medium- and heavy-duty electric vehicles—hosting capacity must account not only for where generation can be added, but also for where load will increase significantly.[18] A robust planning process must evaluate both sides of the equation.

As drafted, the regulations do not clearly require that hosting capacity methods consider load-driven needs or reflect transparent, consistent methodologies across

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[17] "Hosting capacity" refers to the maximum amount of DERs that can be connected to a specific location on the electric distribution system without adversely impacting power quality, reliability, or requiring significant infrastructure upgrades. Hosting capacity analyses help identify where the grid can support additional DERs such as rooftop solar, battery storage, or electric vehicle charging infrastructure.
[18] Priti Paudyal et al., EV Hosting Capacity Analysis on Distribution Grids (2021).

utilities. This gap limits the usefulness of hosting capacity assessments in long-term planning and undermines stakeholder confidence in the results.

OPC's edits correct this gap by requiring utilities to use consistent and transparent methodologies that evaluate both DER and load hosting capacity. This broader view is essential to ensure that the grid can accommodate increasing electrification without unnecessary or duplicative investment. For example, grid upgrades made to support EV charging may also expand capacity for DER interconnection—and vice versa.[19] Treating them in isolation risks overbuilding and lost efficiencies.

OPC's edits also require that utilities publish hosting capacity maps on their websites, a common-sense transparency measure that directly benefits DER developers and stakeholders. Publishing these maps allows developers to make informed siting decisions and reduces friction in the interconnection process. It also allows stakeholders to evaluate where the grid has capacity and where targeted investments could unlock more value.

If the Commission does not adopt OPC's redlines, it should at a minimum require utilities to hold a technical workshop explaining their current hosting capacity methodologies. That forum should invite public input and feed directly into future ESP updates. But a workshop is no substitute for regulatory clarity. Hosting capacity

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[19] Grid upgrades to support EVs can expand capacity because of the impact of EVs on the Daytime Minimum Load (DML), which is often the primary constraint for solar hosting capacity. Planners typically evaluate hosting capacity by anticipating how increased solar generation during DML periods will increase the risk of backfeeding, which can damage substation equipment under certain conditions. However, electrified transportation adds load throughout the day, thereby increasing DML and potentially influencing the timing of needed hosting capacity upgrades.

assessments are a core planning tool—and Maryland's regulations must ensure that they are comprehensive, transparent, and useful to all participants in the planning process.

D. Utilities must be required to seriously evaluate non-wires alternatives—not just default to traditional investments – COMAR 20.50.15.03.H – *Identify Possible Solutions to Grid Needs*.

Identifying and evaluating possible solutions is a foundational step in any credible electric system planning process. Utilities are typically comfortable proposing conventional capital investments—feeder upgrades, reconductoring, transformer replacements, or new substation builds. These are familiar tools in the utility playbook, and they have a clear rate base pathway. But these traditional "wires" solutions are not always the most cost-effective, equitable, or flexible options—particularly in the context of Maryland's evolving energy landscape. Non-wires alternatives (NWAs)—which can include distributed energy resources (DERs), targeted energy efficiency, demand response, storage, and other flexible grid solutions—offer a fundamentally different approach. Rather than building new infrastructure, NWAs use smart deployment of distributed assets to defer or avoid the need for conventional grid investments.

When planned correctly, NWAs can reduce ratepayer costs, increase resilience, accelerate decarbonization, and offer communities more control over energy outcomes. That is why NWAs must be more than an afterthought. Unfortunately, in the current draft regulations, they are barely a footnote. The term "non-wires alternative" appears only once, buried in a conditional clause that invites utilities to disregard them unless specific, undefined criteria are met. This is not just a technical omission—it is a policy failure that undermines the core intent of integrated system planning.

The Commission has already stated its expectation that utilities identify NWAs as part of their planning processes, and that they explain when and why they are rejected. That guidance must now be backed by enforceable regulation. OPC's redlines to COMAR 20.50.15.03.H correct this oversight by requiring utilities to:

- Explicitly identify and assess a wide range of potential solutions, including non-wires alternatives for every identified grid need;
- Analyze how distributed energy resource forecasts affect the feasibility of NWAs, including whether existing or projected DERs can mitigate or eliminate system constraints; and
- Evaluate hybrid solutions that combine traditional and non-traditional investments where appropriate to deliver better value and performance for ratepayers.

These requirements are not just about fairness or completeness. They are about making smart, accountable decisions. NWAs offer modular, scalable, and rapidly deployable options that can often address local constraints at lower total cost and with lower community and environmental impact than traditional upgrades. They are particularly well-suited to addressing short-duration constraints, managing growth in hard-to-reach areas, and targeting solutions in overburdened communities that face both grid reliability challenges and disproportionate pollution burdens.

Recent work group activity underscores the importance of advancing NWAs. The Maryland Energy Storage Initiative (MESI) Work Group, for example, recommended the development of peak reduction programs that incorporate location-specific pricing and event structures—a clear endorsement of NWA-like strategies that not only reduce system stress but also deliver targeted benefits to disadvantaged communities.[20] These approaches reflect national best practices and growing consensus among state regulators, consumer advocates, and technical experts alike: NWAs must be part of the standard toolkit, not a theoretical option utilities can dismiss without analysis.

Moreover, Maryland cannot afford to ignore NWAs while pursuing aggressive decarbonization and electrification goals. The growth of electric vehicle charging, building electrification, and distributed generation will fundamentally change load shapes and grid stress points. Planning that ignores NWAs risks overbuilding traditional infrastructure that will soon be obsolete or underutilized—stranding ratepayer dollars on yesterday's solutions.

For all these reasons, OPC's proposed edits ensure that NWAs are not just referenced but required as part of the core solution identification process. By embedding these expectations into regulation, the Commission will ensure that Maryland's electric system planning aligns with state policy, maximizes system value, and reflects the full spectrum of available tools—not just the tools utilities are most comfortable deploying.

E. Utilities must be held accountable for outcomes, not just plans – COMAR 20.50.15.03.L – *Assessing Results*.

Evaluation is not optional—it's the only way to determine if the ESP process is working. Yet the proposed regulations contain minimal direction on how utilities should assess the results of their plans. OPC's redlines address this failure of accountability by

[20] Case No. 9715, Maryland Energy Storage Initiative Work Group Final Report, at 96 (ML 312609) (Oct. 1, 2024).

requiring that utilities report on the outcomes of their investment decisions, including whether planned projects were completed, delayed, or altered, and why. Just as importantly, utilities would need to evaluate whether forecasts—especially for DERs and load—proved accurate, and how those forecasts influenced decisions.

Without an evaluation step, ESP becomes a one-way exercise in projection with no accountability. OPC's proposed changes add this feedback loop by requiring structured evaluation and public reporting. They ensure that mistakes can be corrected, assumptions can be challenged, and future plans can evolve based on actual outcomes—rather than proceeding on autopilot.

F. Metrics must be defined, measurable, and tied to regulatory oversight – COMAR 20.50.15.05 – *Electric System Planning Metrics*.

Metrics are the measuring stick of effective planning. They provide the structure to assess whether goals are being met, identify course corrections, and ensure accountability. Without them, planning becomes guesswork and neither the Commission nor stakeholders can judge whether the system is evolving in line with State policy, ratepayer value, or grid needs.

Metrics define what success looks like and whether plans are delivering it. Yet the current proposed regulations include no concrete metrics—only placeholders. This is unacceptable. The entire point of a DSP framework is to move from reactive infrastructure investments to proactive, policy-driven planning. That shift is impossible if regulators and stakeholders lack common yardsticks for measuring progress, evaluating trade-offs, or spotting failures early. This gap is especially concerning given the sweeping mandates in the Climate Solutions Now Act and the Electric System Planning—Scope and Funding Act (HB 1393).

Stakeholders in this proceeding proposed 119 discrete metrics to track system performance, DER integration, affordability, reliability, and equity. Utilities dismissed most of them as outside the ESP's scope,[21] but Staff found that only 15 of those metrics are actually addressed in COMAR. That leaves more than 100 unaccounted for—many of which concern core system planning topics like energy storage, DER performance, transportation electrification, and equity in grid investments. The fact that 100 metrics are absent in COMAR undermines the utilities' objection and reveals a regulatory vacuum—one that must be filled if ESP is to serve its intended purpose.

Metrics are especially important for emerging and cross-cutting areas of system transformation that don't neatly fall within traditional silos. Take transportation electrification: metrics such as peak load contribution from EVs, average charging power, charging station accessibility in overburdened communities, and location-specific capacity constraints are essential to evaluating the pace and equity of EV deployment. Yet no existing work group has taken responsibility for defining or tracking these metrics. The same is true for storage utilization rates, DER performance, and locational value indicators—key inputs to meaningful non-wires alternatives analysis.

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[21] Of the 119 metrics proposed, utilities agreed that two metrics should be considered in the ESP docket: substation and feeder overloads. These were in fact the only two concrete metrics included in the proposed regulations, reflected in proposed regulation 20.50.15.05(C)(7). Of the 119 metrics proposed, 15 are reported under another COMAR provision, and an additional 3 are partially reported under another section of COMAR. As a result, there will be little, if any, ability to assess the impacts of ESP planning without further revisions to the proposed regulations.

Commission precedent supports integrated planning and coordinated metric development. In Order No. 91490, the Commission stressed the importance of avoiding duplication across work groups; it did not prohibit ESP-specific metrics where clear gaps remain. While coordination is essential, the order leaves room for the ESP process to address planning metrics that fall outside the jurisdiction of other workgroups. Electric System Planning should function as a unifying framework for tracking these cross-cutting metrics—especially where no other group has taken the lead. In this role, ESP must serve as the clearing house for planning-relevant data streams, ensuring that key indicators do not fall through the cracks.

OPC's edits to the proposed metrics regulations offer a reasonable starting point. They propose a limited set of practical metrics tied directly to planning outcomes. If the Commission is not ready to adopt those metrics outright, it should, at a minimum, direct the Work Group to determine which of the 119 proposed metrics must be codified to meet planning obligations under the Climate Solutions Now Act and the Electric System Planning—Scope and Funding Act (HB 1393). In the long run, ESP filings should be the vehicle through which the Commission consolidates reporting across multiple dockets—similar to successful models in Minnesota and Oregon, where electric system planning functions as a unifying platform for tracking grid transformation.

Metrics must not be siloed by technology or spread thinly across disjointed proceedings. Electric system planning requires a holistic, integrated view of grid conditions, investment needs, and policy progress. Planning without metrics is planning without accountability. And accountability is non-negotiable when billions in infrastructure investment are on the line.

OPC urges the Commission to adopt its proposed redlines and establish a modern, transparent, and metrics-based planning framework that reflects the urgency and complexity of Maryland's energy transition.

III. Strengthening the electric system planning framework is necessary to ensure oversight, accountability, and public benefit.

OPC's edits to the proposed regulations are a starting point, but they are not enough to ensure a robust electric system planning process that meets Maryland's needs. Accordingly, OPC presents the following proposed additional regulations, which are outside the scope of the proposed regulations, but are ready for immediate implementation, and do not require further refinement and discussion from the DSP Work Group.

A. Commission approval of utility plans is essential to enforce policy alignment.

OPC again urges the Commission to adopt a requirement that utilities' final ESPs be subject to Commission approval. This approval would not require the Commission to second-guess where a utility locates each pole or transformer. Nor would it constitute pre-approval of capital expenditures or predetermine prudence in future rate cases. Instead, plan approval would represent a finding that the utility's planning approach is reasonably calculated to support Maryland's climate, equity, and reliability mandates—particularly under the Climate Solutions Now Act and the Electric System Planning Scope and Funding Act.

The Commission has already expressed support for a "Case No. 9353-style" approach to ESP review.[22] But the analogy fails if the core function of Case No. 9353—applying objective metrics to assess performance—is stripped away. In Case No. 9353, the Commission holds utilities accountable for annual reliability performance against defined benchmarks. The current ESP framework, by contrast, offers no comparable standard, no clear metrics, and—critically—no requirement for plan approval. Without that anchor, the ESP process risks becoming a paper exercise: utilities file, stakeholders comment, and nothing is enforceable.

1. Plan approval is a policy alignment determination, not cost recovery authorization.

Commission approval of a utility's Electric System Plan is a critical regulatory tool—not because it pre-approves specific expenditures, but because it ensures the utility's planning approach aligns with Maryland's public policy objectives. The State's mandates under the Climate Solutions Now Act, the Electric System Planning Scope and Funding Act, and related laws require utilities to build decarbonization, equity, and affordability into long-range planning. Plan approval affirms that the utility's strategy reflects a good-faith effort to meet those goals.

Crucially, approval of the plan does not constitute pre-approval of any capital project or guarantee cost recovery in a future rate case. Rather, it affirms that the utility's

[22] Order No. 91256 at 10-11 (July 30, 2024).

approach to planning is consistent with the law and with Commission expectations. It is a policy alignment check—not a cost recovery decision. Maryland's existing framework ensures utilities retain the burden to demonstrate that specific investments are prudent, reasonable, and cost-effective.

A prudence review is a fact-specific inquiry into whether the utility acted reasonably at the time it decided to incur a cost. The Commission assesses not only the ultimate outcome of a project, but also whether the utility properly considered alternatives, evaluated timing and need, and executed the work efficiently. Approval of a long-range system plan neither guarantees recovery for projects that eventually flow from the plan, nor limits the Commission's discretion to disallow recovery based on flawed implementation or changed circumstances.

Thus, planning approval is a forward-looking policy judgment; prudence review is an after-the fact cost evaluation. The two serve complementary but distinct regulatory functions. The Commission retains full authority to assess project-level prudence, cost-effectiveness, and alternatives when individual expenditures are later proposed for recovery in rate cases.

This separation is well-established in other jurisdictions. Many public utility commissions—particularly those overseeing integrated resource planning or distribution system planning—routinely approve utility plans while explicitly preserving their authority to reject specific cost recovery requests later. These jurisdictions recognize that effective oversight requires both stages: early-stage approval to ensure planning aligns with public policy and stakeholder priorities, and later-stage scrutiny to ensure project execution meets standards of efficiency and accountability. These commissions preserve full authority to disallow recovery for any investment that fails to meet cost-effectiveness, timing, or implementation standards.[23] Maryland should follow this proven model by codifying the separation between planning approval and cost recovery. This clarity will give utilities the policy guidance they need while preserving the Commission's full adjudicatory authority over costs.

To eliminate any ambiguity, the Commission could explicitly codify this separation of functions. For example:

> "Commission approval of an Electric System Plan shall not constitute a determination of prudence or rate recoverability for any specific project or investment proposed in the plan."

Such language would make clear that plan approval is not a blank check. It preserves the essential gatekeeping role of the Commission at the planning stage—ensuring transparency, process compliance, and directional alignment with State law—while reserving its full authority to evaluate costs, timing, and alternatives at the execution stage.

Without plan approval, the ESP process risks becoming little more than a stakeholder suggestion box: utilities file what they choose, and while others may

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[23] *See, e.g.,* Virginia State Corporation Commission, *Final Order, In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.* at 4 (June 27, 2019) ("In sum, we approve Dominion's IRP as legally sufficient, and we recognize the appropriateness of spending on capital projects when need is proven by factual evidence in actual cases. We do not, however, express approval in this Final Order of the magnitude or specifics of Dominion's future spending plans."); Oregon Public Utility Commission, Order No. 23-114, *In the Matter of Idaho Power Company Acceptance of 2022 Oregon Distribution System Plan* at App. A, pg. 3 (Mar. 24, 2023) ("Commission acceptance of the [Distribution System] Plan does not constitute a determination on the prudence of any individual actions discussed in the Plan.").

comment, there is no mechanism to compel course correction or ensure alignment with Maryland's goals. Plan approval creates structure, accountability, and enforceability. It signals to utilities that planning is not a private exercise but a public obligation—and that the Commission will use its oversight powers to ensure that those obligations are met.

2. Without Commission approval, planning lacks consequences and accountability.

Requiring Commission approval of ESPs is not merely procedural—it is foundational to making the planning process enforceable. Without approval, there is no mechanism to compel utilities to revise deficient plans, no consequence for ignoring stakeholder input, and no basis for tracking improvement over time. Planning becomes voluntary rather than regulatory.

OPC proposes adding language requiring each utility to file a final Electric System Plan for Commission approval following its response to stakeholder input. The revised regulations should make clear that Commission review must continue until a plan is approved. If an electric company's plan has not been approved by the date its Annual Electric System Plan Update is due, the electric company must restart the planning process by submitting a revised Preliminary Electric System Plan and initiating a new stakeholder engagement cycle, unless the Commission waives this requirement for good cause shown. OPC recommends that plan approval occur within 60 days of the utility's response to stakeholder input. However, the central principle is that the utility cannot conclude its planning cycle without direction from the Commission. It would not serve the public interest for a utility to file an update to a plan that has never been approved; instead, the utility should be required to begin the process anew.

This procedural consequence gives the Commission meaningful leverage. Utilities will have a clear incentive to submit plans that are complete, responsive to feedback, and aligned with Commission expectations. Requiring a plan re-filing provides a corrective mechanism short of outright denial—enabling the Commission to redirect flawed planning efforts while preserving transparency and procedural fairness.

Plan approval is not a blank check—it is a public determination that a utility's planning direction is sound. If that finding cannot be made, the process must reset. This structure brings much-needed accountability to utility planning in Maryland.

Proposed Regulatory Language
Replace COMAR 20.50.15.04(J) with the following:
.04.J Commission Approval of Electric System Plans and Electric System Plan Updates.

(1) No later than thirty (30) days after an electric company files its response to Stakeholder feedback with the Commission, an electric company shall file for approval of an updated final Electric System Plan under the electric system plan docket assigned to each electric company.

(2) The review of an electric company's electric system plan shall continue until a plan has been approved by the Commission.

(3) If an electric company's Electric System Plan has not been approved by the time its Annual Electric System Plan Update is due, the company shall instead file a revised Preliminary Electric System Plan and initiate a new stakeholder feedback cycle pursuant to this chapter, unless the Commission waives this requirement for good cause shown.

(4) Commission approval of an Electric System Plan shall not constitute a determination of prudence or rate recoverability for any specific project or investment proposed in the plan.

B. Standardized discovery rules and reporting requirements are essential to level the playing field and ensure data access.

Effective stakeholder participation in electric system planning depends on access to timely, relevant, and comprehensive information. Discovery is the principal tool that allows stakeholders to understand a utility's planning process—how it develops forecasts, what assumptions it makes, what risks it identifies, and which alternatives it evaluates. Yet the current draft regulations include no formal discovery process. That omission risks undermining the transparency, credibility, and utility of the entire Electric System Planning (ESP) framework.

Unlike traditional rate cases—where discovery centers on cost recovery—ESP proceedings involve broader, forward-looking questions. Stakeholders need more than just datasets or model outputs; they need visibility into the rationale behind planning decisions: Why was this scenario selected? How was need determined? What alternatives were considered, and why were they rejected? Without this level of transparency, meaningful engagement becomes guesswork.

Compounding the problem, the absence of codified discovery procedures leaves stakeholders in the dark. They may not know what information can be requested, in what format it will be provided, or whether utilities are obligated to respond at all. This uncertainty disadvantages smaller or less-resourced participants, delays the process, and creates inefficiencies that benefit incumbents.

To mitigate these challenges, "Uniform Planning Disclosures" should serve as a baseline. These disclosures would provide a consistent set of foundational planning information that every utility must file at the outset of its ESP cycle—without waiting for stakeholder requests. Topics could include substation capacity constraints, DER interconnection queues, locational value assumptions, prioritization methods, and non-wires alternative screening tools. Standardizing this information would streamline participation, avoid redundant data requests, and enable better cross-utility comparisons.

To ensure consistent and equitable access to information, OPC recommends that the Commission adopt a formal, standardized discovery framework. The core components of that framework should include:

- *Defined discovery windows:* The regulations should establish specific periods within the ESP timeline during which stakeholders may serve discovery requests. These windows would open shortly after the utility's filing and remain open for a fixed number of days. Responses should be due within ten (10) business days of receipt, ensuring a timely exchange that supports meaningful participation without unnecessary delay.

- *Broad scope of permissible requests:* The scope of discovery should include any information reasonably related to evaluating the utility's plan, including (but not limited to) load forecasts, DER projections, hosting capacity assumptions, cost-benefit analyses, scenario modeling inputs and outputs, asset condition data, and planning criteria. Requests should not be limited to publicly available data or previously disclosed materials.

- *Uniform planning disclosures:* To streamline the planning process and reduce duplicative data requests, the Commission should adopt a standardized set of foundational reporting requirements—referred to as Uniform Planning Disclosures—that all electric companies must address during each Electric System Planning cycle. These disclosures shall be filed concurrently with each utility's Electric System Plan and must be answered as a matter of course, without the need for stakeholder initiation. Required topics could include substation capacity constraints, DER interconnection queue status, locational value assumptions, prioritization methodologies, and tools used for non-wires alternative (NWA) screening. OPC has proposed a draft set of Uniform Planning Disclosures in Appendix D.

- *Ongoing access for state agencies:* To support their continuing oversight responsibilities, state agencies including the Office of People's Counsel, the Maryland Energy Administration, and Commission Technical Staff should be authorized to serve discovery requests outside of formal discovery periods. Electric companies should be required to respond to such requests within fifteen (15) business days. Allowing ongoing agency discovery ensure these agencies have access to timely information throughout the planning cycle, promoting accountability without disrupting process efficiency.

Together, these components establish a transparent, predictable, and enforceable discovery process that supports the Commission's goals of fair, evidence-based, and participatory planning. Without such a framework, utilities will retain disproportionate control over the flow of information, and the ESP process will risk devolving into a pro forma exercise devoid of meaningful input or challenge.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.04.K – Discovery Procedures:
.04.K Discovery Procedures.

(1) Discovery shall begin immediately upon the filing of an electric company's Preliminary Electric System Plan.

(2) A discovery window of not less than sixty (60) calendar days shall be open following the filing of the Preliminary Electric System Plan.

(a) During the discovery window, any party or interested person may serve discovery requests on the utility.

(b) An electric company shall respond to all discovery requests, including those from state agencies, within ten (10) business days of receipt.

(c) If the electric company objects to a discovery request, it must serve written objections on the requesting party within three (3) business days of receipt. The parties shall meet and confer in good faith to resolve any dispute before seeking Commission intervention. If the dispute remains unresolved, the requesting party may file a motion to compel.

(d) If an Electric Company designates any portion of its discovery response as Confidential or Critical Energy Infrastructure Information (CEII), it must clearly label the material and provide a written justification for the designation within ten (10) business days of receiving the discovery request. If the requesting party disputes the designation, the parties shall meet and confer in good faith to resolve the issue. If the dispute remains unresolved, the Electric Company may file a motion for a protective order. Until the Commission issues a ruling on the motion, the requesting party shall treat the disputed information as confidential or CEII.

(e) Subject to subsection (3), discovery outside of the discovery window may only be served with leave of the Commission for good cause shown, unless the electric company voluntarily elects to respond.

(3) The Office of People's Counsel, the Maryland Energy Administration, and the Commission's Technical Staff may serve discovery requests under this Chapter on an electric company at any time. Outside of the discovery window set out in subsection (2), an electric company shall respond to such agency discovery requests within fifteen (15) business days of receipt.

(4) Discovery shall be liberally construed to include any information reasonably related to the evaluation of the Electric System Plan or an Electric System Plan Update. Such information includes, but is not limited to, load forecasts, scenario assumptions, model inputs and outputs, cost estimates, asset condition data, hosting capacity maps, non-wires alternative analyses, and planning methodologies.

(5) At the time a Preliminary Electric System Plan is filed, the electric company shall concurrently file responses to the Uniform Planning Disclosures approved by the Commission. These standardized disclosures establish a common baseline of planning data and shall be provided without the need for stakeholder initiation.

(6) Discovery responses shall be provided in machine-readable, searchable formats when feasible, and must include all supporting workpapers, datasets, and explanations necessary to interpret the response. Failure to respond in good faith may be subject to enforcement action, including motions to compel or other appropriate remedies.

(7) Access to information designated as confidential or as Critical Energy Infrastructure Information (CEII) shall be subject to applicable protections. A party or interested person may access such information only upon obtaining requisite approval or by executing a Commission-approved confidentiality or nondisclosure agreement.

IV. Maryland cannot achieve its climate and reliability goals without system-wide planning, but the current framework overlooks the structural reforms required for a modern grid.

The proposed electric system planning regulations represent a meaningful first step—but they are not enough. Several foundational elements—essential to ensuring Maryland's electric system can meet the scale and complexity of future needs—remain entirely unaddressed. These omissions cannot be resolved with edits to the proposed regulations alone; they require an expanded regulatory framework—one that reflects the reality of how today's electric system operates: as an integrated, interdependent network shaped by transmission infrastructure, wholesale markets, and shifting, concentrated demand.

The Electric System Planning—Scope and Funding Act (HB 1393), requires the Commission to adopt regulations that "implement specific policies for improvements in order to promote the State's policy goals under § 7-802."[24] Yet the current proposed regulations omit core planning dimensions needed to achieve that directive. This section

[24] PUA § 7-804(a)(3).

identifies those missing elements and explains why Maryland must adopt a more holistic electric system planning process. Several foundational planning elements—transmission and supply-side integration, data center load forecasting, gas-electric coordination, and DER contributions to bulk system reliability—remain either absent or too loosely defined to ensure meaningful implementation. These gaps are not technical oversights; they represent structural blind spots that will undermine the Commission's ability to manage system-wide risks, avoid stranded investments, and evaluate the full range of cost-effective options available to meet future grid needs.

For example, recent federal signals regarding fossil generator prioritization and the rapidly accelerating transmission buildout tied to data center development require Maryland to plan beyond the distribution grid.[25] Similarly, without clear requirements for sequencing grid modernization technologies like Distributed Energy Management Systems and (DERMS) and Advanced Distribution Management System (ADMS), the State risks locking in outdated infrastructure or missing opportunities to leverage smarter, more flexible systems. System reliability and affordability are increasingly determined by how well state-level planning coordinates with wholesale markets, upstream transmission

[25] *See* Exec. Order No. 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, 90 Fed. Reg. 15,521 (Apr. 14, 2025) (Noting that "[t]he United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers" and directing the Secretary of Energy to "prevent … an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity."); Exec. Order No. 14260, *Protecting American Energy From State Overreach*, 90 Fed. Reg. 15,513 (Apr. 14, 2025) (Declaring that the "[Trump] Administration is committed to unleashing American energy, especially through the removal of all illegitimate impediments to the identification, development, siting, production, investment in, or use of domestic energy resources—particularly oil, natural gas, coal, hydropower, geothermal, biofuel, critical mineral, and nuclear energy resources.").

decisions, and behind-the-meter technologies. That coordination must be built into the process, not left to utility discretion. Moreover, many of the metrics and transparency requirements introduced in the regulations are useful, but they fall short without being clearly tied to planning decisions, ratepayer impacts, and Commission oversight. Without expanding the scope of the regulations in this phase of the DSP workgroup process, the Commission risks missing a rare opportunity to establish the kind of comprehensive, forward-looking planning framework essential to a just and affordable energy transition.

A. Transmission and supply-side integration must be central to distribution system planning.

The proposed regulations make only passing reference to transmission planning and PJM, and they omit any meaningful consideration of upstream energy supply issues—including generation resource adequacy, interconnection constraints, or fuel-related risks. This limited scope is inconsistent with the Electric System Planning—Scope and Funding Act (HB 1393) and the Climate Solutions Now Act, which collectively charge the Commission with ensuring that electric system planning is conducted in a manner that promotes cost-effective, reliable service aligned with decarbonization and climate resiliency goals. The electric system is not a set of disconnected silos; decisions made about generation siting, fuel mix, and transmission system layout have direct implications for the distribution grid and its long-term investment needs. A credible electric system plan must evaluate and account for these upstream conditions.

This omission is particularly problematic given recent federal signals that could reshape wholesale market dynamics. For example, proposed legislation requiring FERC to prioritize dispatchable generation like natural gas in interconnection queues, if implemented, could shift the resource mix available to Maryland utilities over the planning horizon.[26] In the absence of state-level planning requirements that account for such developments, utilities may pursue grid investments that conflict with State policy, fail to anticipate shifts in regional power flows, or unnecessarily overbuild distribution infrastructure. Without regulatory direction to examine these interactions, Maryland's planning framework risks missing the forest for the trees.

Accordingly, OPC recommends that the Commission implement a Phase III DSPWG to revise the regulations to require that Electric System Plans include an explicit analysis of relevant upstream transmission and generation factors that may affect grid needs over the planning horizon. This should include—but not be limited to—assumptions about generation retirements, PJM transmission expansion, interconnection queue outcomes, and federal or regional policy shifts that could materially impact Maryland's electric system. The planning process should also identify where local distribution investments may either complement or conflict with upstream infrastructure plans. By integrating these factors, the Commission can ensure that utility planning decisions are better aligned with broader system reliability, climate, and affordability objectives.

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[26] *See, e.g.,* GRID Power Act, H.R.1047 119th Cong. (2025); Department of Energy, Order No. 202-25-4 (May, 30 2025) https://www.energy.gov/articles/us-department-energy-issues-202c-emergency-order-safeguard-electric-grid-reliability-pjm (Ordering the continuing operation of the Eddystone gas and oil generator).

Proposed Regulatory Language

Add the following as new subsection COMAR 20.50.15.03 – Transmission and Supply-Side Considerations
.03.J Transmission and Supply-Side Considerations.

(1) An Electric System Plan shall include an assessment of upstream system factors that may influence distribution system needs, including:

> (a) Projected generation additions and retirements within the PJM region that may affect power flows, voltage stability, or local resource adequacy in the utility's service territory;
>
> (b) Known or anticipated PJM Regional Transmission Expansion Plan (RTEP) or long-term regional transmission projects that may impact substation loading or distribution system configuration;
>
> (c) Constraints or delays in the PJM interconnection queue that may limit the availability of planned generation resources;
>
> (d) Relevant federal or regional policies or market rules that may alter the generation mix or location of generation resources affecting the distribution system; and
>
> (e) Interactions between planned distribution system investments and transmission-level grid conditions, including potential duplicative or conflicting upgrades.

(2) The Electric Company shall identify any planned distribution system investments that may be influenced by, or may influence, transmission system configuration or generation siting.

B. Coordination between electric and gas utilities must be mandatory and start immediately.

The proposed regulations state that electric-gas utility coordination "may be performed but shall not be required"[27]—a permissive framing that undercuts the State's statutory mandates to decarbonize and modernize its energy infrastructure in a coordinated, cost-effective manner. This is a fundamental deficiency. As building electrification expands and heating systems are converted from gas to electric, gas and electric utilities will face interdependent challenges involving infrastructure investment, load forecasting, and system capacity. Allowing each utility to plan in isolation risks duplication, stranded costs, and conflicting investments—particularly where aging gas infrastructure is slated for repair or replacement in areas poised for rapid electrification.

Moreover, Maryland law no longer supports siloed utility planning. The Climate Solutions Now Act and related statutes envision a coordinated energy transition that minimizes ratepayer burden and maximizes system efficiency.[28] Gas utilities must be required to participate in electric system planning in jurisdictions where their infrastructure and customer base overlap. That coordination should include the exchange of data, alignment of forecast assumptions, and joint evaluation of infrastructure investment plans that could be affected by electrification trends. The lack of coordination

[27] Proposed COMAR 20.50.15.01(D). This language was adopted by the Work Group based on the Commission's direction in Order No. 91490 at 5-6, in which the Commission found that "electric and gas utility coordination can be deferred to a future DSP phase once there are decisions made in the Long-Term Gas Future, Case No. 9707."

[28] The Commission recognized as much in Order No. 91256 at 12, finding that "an integrated DSP shall include gas and electric planning coordination, to ensure synchronized infrastructure development due to the impacts of electrification and decarbonization on both gas and electric systems."

is not a speculative concern; real-world examples from other jurisdictions show that failure to coordinate leads to both overbuilding and missed opportunities for cost savings through targeted load shifting or non-pipe alternatives.[29]

OPC recommends the Commission adopt the language below or refer this proposal to a Phase III workgroup. The draft language is designed to clarify coordination requirements without forcing jurisdictional overreach, and to ensure that electrification planning is conducted in an integrated, policy-aligned manner.

Proposed Regulatory Language

Add the following as new subsection COMAR 20.50.15.03 – Coordination Between Electric and Gas Utilities

.03.L Coordination Between Electric and Gas Utilities.

(1) Where an Electric Company shares service territory with a gas company regulated by the Commission, the Electric Company shall coordinate with that gas company during the electric system planning process to support:

(a) Consistent assumptions regarding electrification of buildings and transportation;

(b) Identification of opportunities to avoid duplicative or conflicting infrastructure investments;

(c) Shared customer data, where feasible and consistent with Commission rules, for the purpose of load forecasting and electrification impact analysis; and

(d) Evaluation of non-pipe and non-wires alternatives, where applicable.

(2) The Electric System Plan shall:

[29] *See* Aryeh Gold-Parker et al., Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California (December 2023) available at https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California_u.pdf.

(a) Identify geographic areas where electric and gas infrastructure overlaps, particularly in regions subject to planned electrification, aging gas infrastructure, or known constraints;

(b) Describe coordination efforts undertaken with relevant gas utilities during the planning cycle, including points of contact, data exchange, and areas of alignment or divergence; and

(c) Include a qualitative assessment of electrification-related impacts on existing gas infrastructure and any implications for electric system investments.

(3) The utility may be required to submit additional reporting or joint filings in future proceedings where electrification trends create significant cross-system planning needs.

C. Grid modernization must be sequenced strategically and implemented on clear timelines.

The current regulations refer to grid modernization technologies—such as Advanced Distribution Management Systems (ADMS), Advanced Metering Infrastructure (AMI), and Distributed Energy Resource Management Systems (DERMS)—as long-term goals or future capabilities, but do not require utilities to explain when or how those systems will be deployed. This permissive approach allows utilities to cite the absence of enabling technologies as a reason not to evaluate distributed energy resource (DER) integration or non-wires solutions—while simultaneously offering no regulatory guardrails to ensure those enabling technologies are ever pursued or prioritized. This dynamic undermines the very planning process the Commission is trying to build.

A credible system planning framework should require utilities to identify the modernization tools they rely on to deliver future value, and then lay out when, how, and under what conditions those tools will be implemented. Without clear expectations about deployment timelines and sequencing, utilities can effectively freeze progress by claiming that locational value, DER coordination, or load flexibility are still "three to five years away." Sequencing matters: some technologies (e.g., AMI) are necessary foundations for others (e.g., DERMS). Likewise, investment decisions made today—such as transformer upgrades or hosting capacity expansion—should reflect what tools will be available within the investment's useful life. A planning framework that fails to account for these dependencies risks misallocating ratepayer dollars and slowing progress toward grid optimization.

To address this gap, OPC recommends the Commission adopt the regulatory language below or direct the DSP Work Group to address this issue in Phase 3. The proposed provisions require each utility to develop a modernization roadmap tied to its planning assumptions and system needs, while preserving Commission flexibility to review and adapt these roadmaps over time.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – Grid Modernization Sequencing and Enablement Planning
.03.M Grid Modernization Sequencing and Enablement Planning.

(1) Each Electric System Plan shall include a Grid Modernization Roadmap that:

(a) Identifies enabling technologies that are necessary to or would enhance implementation of proposed forecasting methods, DER integration strategies, Non-Wires Solutions, or locational value application;

(b) Provides a timeline for planned deployment of each enabling technology, including expected procurement, design, construction, and integration milestones;

(c) Assesses the cost of implementing such technologies and the marginal benefits enabled by the technology including, but not limited to grid benefits, operational cost reductions, or furtherance of non-quantified state policy goals; and

(d) Explains how the anticipated availability or absence of these technologies informed decisions made in the planning process, including solution selection and project prioritization.

(2) The Roadmap shall include, at a minimum, status updates and sequencing plans for:

(a) Advanced Metering Infrastructure (AMI);

(b) Distributed Energy Resource Management Systems (DERMS);

(c) Advanced Distribution Management Systems (ADMS);

(d) Hosting capacity tool enhancements; and

(e) Other grid management or monitoring tools impacting future resource decisions included upon in the plan.

(3) The Electric Company shall explain in its plan how it intends to coordinate grid modernization implementation with load growth, electrification, and DER deployment trends to minimize costs and optimize system efficiency.

D. DERs must be treated as reliability resources in system planning.

Distributed energy resources have evolved far beyond simple customer-side technologies. Inverter-based resources such as rooftop solar, battery storage, and electric vehicle chargers are now capable of supporting voltage regulation, frequency response, and even black start services. Technologies like grid-forming inverters and virtual power plants can contribute to overall grid reliability and resilience when properly planned for. Yet the current draft regulations treat DERs primarily as load modifiers or hosting constraints, rather than as grid assets with reliability value that must be assessed holistically across multiple layers of aggregation and DER types to identify system risks and potential benefits.[30] The current framing is outdated and increasingly misaligned with federal direction, technical standards development, and emerging industry best practices.

FERC Order 2222 and the evolving IEEE 2800 standards reflect a national consensus that DERs, especially when aggregated or controlled through smart inverters and DERMS, can provide critical bulk system services. Maryland cannot afford to exclude these functions from its distribution system planning framework. By failing to require utilities to evaluate DERs' reliability contributions—including their interactions with transmission-level operations—the regulations leave potential system benefits unquantified and unleveraged. This failure leads to more costly and potentially redundant infrastructure investments, and undermines the ability of the Commission to direct cost-effective, clean energy system transformation.

OPC recommends that the Commission adopt the following regulatory language or refer this issue to the DSP Work Group for resolution in a Phase III process. The language is designed to integrate DER reliability considerations into the existing planning framework, without pre-judging how or when those functions will be monetized or operationalized.

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[30] Topics of technical interconnection standards for inverter-based resources should continue to be the purview of the Interconnection Work Group. However, controllable loads and other, non-inverter-based DERs can provide similar grid services to inverter-based resources, and must be considered as part of a holistic assessment of grid assets. Assessing the use cases and value of non-inverter-based DERs provide yet another example of why a holistic, not siloed, electric system planning process is required for Maryland to maximize the benefits associated with electric system planning. *See* Smart Inverter Operationalization (SIO) Working Group Report: Business Cases and Use Cases at i and n.4 (February 1, 2024), https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – DER Contributions to System Reliability
.03.N DER Contributions to System Reliability.

(1) An Electric System Plan shall identify and evaluate the potential reliability and resilience contributions of distributed energy resources (DERs), including both individual DER technologies and aggregated DERs operating as Virtual Power Plants (VPPs).

(2) The plan shall include consideration of:

(a) Grid-forming inverter capabilities to support voltage and frequency stability;

(b) DERs capable of providing black start, ride-through, or system restoration support;

(c) Smart inverter functionalities that support reactive power management, voltage regulation, or other ancillary services;

(d) EV charging and managed discharging strategies that support transmission fault recovery or peak shaving; and

(e) DER contribution to reducing customer outages or contributing to system operational flexibility in the event of planned or unplanned N-1 or N-2 scenarios.

(3) The Electric Company shall describe how DER contributions to system reliability were incorporated into the identification of Grid Needs, solution evaluation, and project prioritization. This may include discussion of scenario-based modeling, qualitative assessment, or technical studies, as appropriate.

(4) The Electric Company shall describe any coordination with transmission planners, PJM, or regional reliability entities related to DER integration.

E. Planning metrics must drive accountability and be tied to regulatory oversight.

While the proposed regulations include a discussion of planning metrics, they do not establish any clear link between those metrics and actual Commission decision-making. Without defined thresholds, progress benchmarks, or consequences for underperformance, these metrics function more like reporting requirements than regulatory tools. That structure could serve to promote transparency, but it does not serve accountability. A planning framework without regulatory levers cannot ensure compliance with the State's goals under the Climate Solutions Now Act and the Electric System Planning—Scope and Funding Act (HB 1393), nor can it be used effectively to evaluate whether a utility's plan warrants approval.

To be effective, planning metrics must be tied to Commission oversight in two core ways. First, Electric System Plans should be required to demonstrate alignment with specific targets—such as emissions reduction, DER integration, reliability improvements, and affordability—using those metrics. Second, there must be a mechanism for the Commission to assess whether a utility's performance against those metrics justifies adjustments in planning assumptions, project selection, or implementation strategy. This assessment does not require rigid performance-based ratemaking, but it does require meaningful integration of metrics into the regulatory process.

OPC recommends that the Commission adopt the following regulatory language or refer the issue to the DSP Work Group for further refinement in a Phase III process. This language would not impose hard performance mandates but would ensure that the metrics listed in § .05 are actually used to evaluate plan quality, consistency with state goals, and the utility's own planning progress over time.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – Use of Metrics in Plan Evaluation

.03.E Use of Metrics in Plan Evaluation.

(1) The Electric Company shall, in its Preliminary Electric System Plan and final Electric System Plan, provide a narrative assessment of how the metrics listed in § C of this Regulation:

(a) Inform or validate the utility's load and DER forecasts;

(b) Support or challenge the justification for proposed projects or solutions; and

(c) Reflect progress toward applicable State policy goals under Public Utilities Article §§ 7-801 through 804 and the Climate Solutions Now Act and any future State policy goal.

(2) The Electric Company shall identify any metrics for which performance trends are inconsistent with stated plan objectives or prior planning assumptions and explain:

(a) Whether planning adjustments were made in response; and

(b) If not, why continued use of the original assumption remains appropriate.

(3) The Commission may consider Electric System Plan metrics and related progress trends as part of its review and approval of the plan, and may direct the utility to revise planning assumptions or evaluate alternative solutions based on those trends.

F. Stakeholder access to data and planning models must be enforceable, not discretionary.

The proposed regulations include some provisions for stakeholder data access, but they leave too much to utility discretion. Utilities are required to provide "transparency" into their data sources, but there is no mechanism to guarantee timely, consistent, or complete access to the information that underpins the Electric System Plan. Without enforceable rights to access critical planning assumptions, hosting capacity maps, load forecasts, and modeling tools, stakeholders—including state agencies—cannot effectively scrutinize the utility's analysis, offer meaningful alternatives, or assess whether the proposed plan aligns with State policy.

Utilities currently control the models, the inputs, and the documentation for the distribution system. And direction to ensure "transparency into data sources, data and assumptions" allows for significant interpretive room for utilities to withhold critical data needed to fully understand how they created their models. That dynamic undermines transparency and invites strategic withholding of information. The result is a process that appears participatory on the surface but lacks the underlying procedural fairness necessary for true collaboration or regulatory accountability. If stakeholders cannot see how the forecasts were developed or what assumptions were used in project justification, then the planning process becomes a black box. This is especially problematic where system constraints are used to justify capital investments.

Moreover, having data spread across filings and data requests—even well-defined ones—is an imperfect model. Maryland should begin building toward a modern solution: a centralized data portal, such as the one used in Illinois by ComEd, that allows stakeholders to explore, analyze, and download planning data without needing to initiate a request.[31] This solution would enable mid-cycle engagement and support meaningful transparency for all parties.

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[31] *See* Illinois Commerce Commission consolidated case 22-0486, 23-0055, and 24-0181, Order on Refiling, at 253 ("ComEd and JNGO have agreed that they will collaborate on the development of an integrated data platform ('platform') to access customer, system, tariff/rates, program, P.A. 102-0662 goals and data with a goal of ensuring authorized third parties can easily access such data. ComEd explains that the goal of the integrated data platform is to ultimately provide a single, cost-effective portal to access this data in a standardized, machine-readable format including via an application programming interface.").

The Commission should adopt enforceable data access provisions either in this rulemaking phase or through a structured Phase III Work Group process. The language below is designed to balance confidentiality concerns with the need for legitimate stakeholder oversight, and to create a baseline level of transparency across all utilities.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.04 – Stakeholder Access to Data and Planning Models
L. Stakeholder Access to Data and Planning Models.

(1) Each Electric Company shall provide Stakeholders with timely access to planning models, input assumptions, and relevant datasets used to develop the Electric System Plan, subject to appropriate confidentiality protections and Commission rules on information access.

(2) At a minimum, the following materials shall be made available to Stakeholders approved to access confidential information:

(a) Power flow models and associated network data used to evaluate grid constraints;

(b) Hosting capacity calculation methodologies and underlying assumptions;

(c) Load and DER forecast methodologies, including scenario-specific input assumptions, including but not limited to customer counts by revenue class, baseline appliance saturations showing relative fuel usage by major end-use category, baseline appliance efficiency levels, adoption trajectories, and DER adoption eligibility criteria (if any);

(d) Locational value frameworks and benefit-cost input values; and

(e) Project screening and prioritization criteria.

(3) Electric Companies shall maintain a publicly accessible planning portal or docket containing:

(a) All anonymized, non-confidential versions of the materials listed above;

(b) Historical Electric System Plans and Annual Updates; and

(c) A log of all data requests submitted by Stakeholders, along with their status and resolution.

(4) The Commission may issue further guidance on data standardization and access protocols to support consistency across Electric Companies and facilitate meaningful participation in the planning process.

CONCLUSION

Maryland is out of time for half-measures. With the first round of full electric system plans due in 2026 and submitted only once every three years, the Commission faces a narrow and fast-closing window to shape how billions of dollars in grid investments are planned, evaluated, and deployed. Once those plans are filed under a weak framework, the State will have little ability to course-correct before long-lived infrastructure—and its costs—are locked in.

The planning rules under consideration are not academic. They are the foundation for how Maryland will build the grid that powers its homes, protects its most vulnerable residents, and meets its climate goals. But as drafted, the proposed regulations fall far short of the integrated, transparent, and accountable framework the moment demands. They defer critical decisions, fragment responsibility across disconnected silos, and fail to require the very basics of modern utility planning: stakeholder access to data, forward-looking DER forecasts, actionable metrics, and Commission oversight.

The Commission must act now. Every delay makes transformation harder, more expensive, and more inequitable. Every three-year planning cycle missed is a generation of wires, poles, substations, and costs that ratepayers will carry—whether or not they reflect the State's priorities.

OPC's proposals are not speculative. They are based on proven regulatory practices from other jurisdictions, grounded in Commission precedent, and aligned with Maryland's statutory mandates under the Climate Solutions Now Act and the Electric System Planning—Scope and Funding Act (HB 1393). These recommendations are designed to do what the proposed regulations do not: build a planning process worthy of the challenges ahead and capable of delivering the energy future Marylanders deserve. Accordingly, OPC urges the Commission to adopt the recommended revisions and to initiate a Phase III process without delay.

The Commission has the authority. The statute provides the mandate. The record shows the need. All that remains is for the Commission to act—with the urgency this moment requires.

Respectfully submitted,
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Appendix A

<u>20.50.15.00</u>

Title 20 PUBLIC SERVICE COMMISSION

Subtitle 50 SERVICE SUPPLIED BY ELECTRIC COMPANIES

Chapter 15 Electric System Planning

Authority: Public Utilities Article, §1-101, §2-113, §2-121, §7-216, §7-801, §7–802, §7-803, §7-804, Annotated Code of Maryland

20.50.15.01

.01 Applicability.

A. This Chapter applies to electric system plans for the advancement of the State policy goals and legislative intent set forth at Public Utilities Articles §§ 7-801 through 804, et seq., *Annotated Code of Maryland* and all other relevant State goals and targets in effect during plan development. The objective of the final electric system plan is an electric system that advances State policy goals and is built in a manner that enables an electric company to provide safe, reliable, and cost-effective services and otherwise operates for the public good.

B. An electric system plan shall demonstrate a holistic approach to grid planning by:
   (1) considering cost-effective solutions to electric system needs;
   (2) incorporating new cost-effective technologies and analytical tools into planning processes to create a modern distribution system; and
   (3) utilizing real-time data, as feasible, to improve forecasting and planning for grid investments.

C. This Chapter shall not become effective for electric cooperatives and municipal electric companies until January 1, 2028.

D. Electric company and gas company coordination on electric system plans may be performed, but shall not be required, unless required by law or as otherwise directed by the Commission.

E. Waiver of Regulations. Upon written request, a regulation in this Chapter may be waived by the Commission ~~for "good cause shown."~~ if the requirement is not yet practicable to provide or is currently cost-prohibitive to provide. The Electric Company requesting a waiver shall indicate for each requirement:
   (1) Why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives;
   (2) How the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;
   (3) What the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and
   (4) If the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives

20.50.15.02

.02 Definitions.

A. Terms Defined.

(1) "Annual Electric System Plan Update" means the update that electric companies publish annually at the end of the distribution system planning cycle in the years that they do not publish an Electric System Plan and that contains the information in Regulation .04(B) of this Chapter.

(2) "Baseline scenario" means an expected future state of a system or situation if no new interventions or policies are implemented beyond those already in place. It serves as a point of comparison to assess the impact of proposed actions or policies.

(3) "Cost-effective" means having projected benefits that are greater than projected costs while considering other factors as determined by the Commission.

(4) "Demand Response" means changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or ensure system reliability.

(5) "Distributed energy resource" or "DER" has the meaning stated in Subtitle 50, Chapter .09, Regulation .02B.

(6) "Distributed generation" means the same definition as Small Generator Facility in Subtitle 50, Chapter .09, Regulation .02B.

(7) "Electric company" has the meaning stated in Public Utilities Article, §1-101, Annotated Code of Maryland.

(8) "Energy burdened" means a household that spends 6% or more of its income on utility bills.

(9) "Energy storage device" has the meaning stated in the Public Utilities Article, §7-216, Annotated Code of Maryland.

(10) "Electric System Plan" means the plan that electric companies publish that concludes the distribution system planning cycle that contains the information in Regulation .04 (F) of this Chapter.

(11) "Electric Vehicle" or "EV" has the meaning stated in Subtitle 50, Chapter .09, Regulation .02B.

(12) "Goal Scenario" means a potential future state of a system or situation if policy goals are fully realized. It serves as a point of comparison to assess the progress towards policy goals.

(13) "Grid Needs" means the need for a specific mitigating action to alleviate an identified System Constraint found during the electric system planning process. The specific characteristic of the system constraint and commensurate grid need will inform the solution that will mitigate the issue.

(14) "Grid Services" means the dispatch and control of one or more DERs to provide service to the Electric Company's electric grid pursuant to an Electric Company tariff, service contract between the Electric Company and the owner of DERs or providing transmission-level Grid Services by participating in PJM Interconnection, LLC wholesale markets.

(15) "Hosting Capacity" has the meaning stated in Subtitle 50, Chapter .09, Regulation .02B.

(16) "Locational value assessment" means a process that provides price signals based on the benefits and costs of deploying distributed energy resources in a specific location and over time, considering grid conditions and the potential to defer or avoid traditional electric distribution infrastructure investments.

(17) "Low Scenario" means an expected future state of a system or situation if policy goals are fully realized but load is significantly lower than forecasted in the Goal Scenario, provided that the load forecast must still be plausible.

(18) "Non-wires Solution" or "NWS" means a project or other solution that makes use of one or more DERs, technologies, and/or leads to the introduction of new or modification of existing energy management practices, standards, or protocols to address a constraint or provide other grid services ~~to the electric distribution system.~~

(19) "Planning Metrics" means quantifiable measurements used to assess performance, track progress, and/or measure success of a process that an Electric Company Electric System Plan directly affects.

(20) "Preliminary Electric System Plan" means the plan that electric companies file before the Annual Technical Conference that contains the information in Regulation .04(F) of this

Chapter.

(21) "Rightsizing" has the meaning stated in Subtitle 50, Chapter .09, Regulation .02B.

(22) "System Constraints" means specific violations caused by physical characteristics of the electric distribution system exceeding Electric Company planning criteria, the result of which would threaten safe and reliable delivery of power.

(23) "Stakeholder" means a person who is granted leave to intervene in an electric system plan proceeding pursuant to Public Utilities Articles § 3-106, *Annotated Code of Maryland*.

(24) "Traditional Wires Solution" means a solution to address a System Constraint that would be deferred or replaced by a Non-Wires Solution.

(25) "Virtual Power Plant" or "VPP" has the meaning stated in Public Utilities Article §7-216, *Annotated Code of Maryland*.

20.50.15.03

.03 Electric System Planning Process

A. An electric system planning process shall align with the following components for each planning cycle and scenario and related requirements specified in this Chapter:
   (1) Considerations Feeding into Types of Projections
   (2) Goals/ Objectives
   (3) DER Forecast
   (4) Load Forecast
   (5) Hosting Capacity Assessment
   (6) Grid Needs and Locational Value Assessment
   (7) Identify Possible Solutions to Grid Needs
   (8) Screen and Evaluate Possible Solutions
   (9) Choose Solutions and Publish Plan
   (10) Program and Project Design
   (11) Assess Results

B. Considerations Feeding into Types of Projections:
   (1) Time Horizons for DER and Load Forecasting:
      (a) DER and load forecasting processes for Electric Companies other than electric cooperatives and municipal Electric Companies shall include at least three planning time horizons:
         i. one to three years;
         ii. four to six years; and
         iii. seven to ten years.
      (b) DER and load forecasting processes for electric cooperatives and municipal Electric Companies shall include at least two planning time horizons:
         i. one to three years; and
         ii. four years up to twenty years.

   (2) Level of Granularity: The granularity of information in an Electric System Plan may vary as described in other sections of this Regulation.
      (a) As a near-term objective:
         i. Information shall be provided in an Electric System Plan at the substation level as a minimum requirement.
         ii. Feeder-level information shall be provided as part of the planning process in situations where there are identified System Constraints
      (b) As a longer-term objective:
         i. Electric Companies shall report on progress regarding incorporating more granular electric system and customer information and data into forecasting and planning processes in their Electric System Plan or Annual Electric System Plan Update.

   (3) Scenarios/Projections to be Analyzed: An Electric System Plan shall include a minimum of two scenarios, additional to the Baseline Scenario, to provide a range of outcomes to inform planning analysis and the determination of the scale and pace of Grid Needs:

(a) A Baseline Scenario; ~~and~~
(b) A Low Scenario; and
(c) A Goal Scenario.
(d) The Commission may request an Electric Company to analyze scenarios in addition to a Baseline Scenario, a Low Scenario and Goal Scenario.

(4) Data Sources, Scope, and Access: Electric companies shall provide for data collection and access that:
(a) Allows Stakeholders the opportunity to provide data inputs at pre-identified time periods defined by the Electric Company.
(b) Provides collected data in a format that can be easily accessed by ~~s~~Stakeholders.
(c) Provides Stakeholders transparency into data sources, data and assumptions used to develop Electric System Plans and Annual Electric System Plan Updates.
i. Electric Companies shall provide anonymized information and data at an aggregate level appropriate to the planning decision in question, pursuant to Regulation § .05 of this Chapter, and make more detailed levels of data available upon request to Stakeholders approved for accessing confidential information.
ii. Electric Companies shall make relevant power flow models, engineering studies, and associated network data available upon request to Stakeholders approved for accessing confidential information.

(5) Already-Approved Resource Retirements and Additions: Electric companies shall consider in their Electric System Plans whether distribution-level electric system planning can be used to mitigate potential gaps caused by generation retirements.

(6) PJM Wholesale Markets: Electric Companies shall consider DERs and VPPs that participate or could participate in the PJM wholesale markets in electric distribution planning as applicable.

(7) Resource Costs and Capabilities: Electric Companies contracting decisions to implement Electric System Plans and Annual Electric System Plan Updates shall be left to Electric Company discretion.

C. Goals/ Objectives: An Electric System Plan shall promote applicable State policy goals and other applicable goals and targets as directed by the Commission pursuant to Public Utilities Article §§ 7-801 through 804, *et seq., Annotated Code of Maryland*.
(1) State policy goals including other applicable goals and targets, that are extant at the initiation of each planning cycle, shall be addressed in mid-and long-term Electric System Plans, but not retroactively to near-term projects that have already been initiated.

D. DER Forecast.
(1) An Electric System Plan shall account for the following considerations for each electric system planning cycle and scenario~~, as feasible~~:
(a) As a starting point:

i. Electric Companies shall develop separate forecasts for each relevant DER type, including energy efficiency, Demand Response, Distributed Generation, Energy Storage Devices, VPPs and managed EV charging-discharging.
ii. Electric ~~e~~Companies shall develop hourly DER forecasts.
iii. Electric Companies shall develop methodologies for disaggregating DER forecasts at the system level to the substation level, conducting bottom-up DER forecasts, or a hybrid approach.

(b) As a longer-term objective:
i. Electric Companies shall increase the use of AMI in developing forecasts and to disaggregate between load and generation, as well as flexible and inflexible loads.
ii. Electric Companies shall account for the nature of storage as both a load and generation source by utilizing time-series forecasting that accounts for the behavior of charge/discharge patterns for residential storage devices, commercial and industrial storage devices, and utility-owned or contracted storage.
iii. Electric Companies shall assess the feasibility of developing more refined methods of forecasting locational adoption of DERs considering customer and building stock characteristics, local policy goals, and programs designed to leverage Locational Value price signals pursuant to § G of this Regulation.

(2) Electric Companies shall cost-effectively pursue improvements to their forecasting methodologies for DER, based on stakeholder suggestions and Electric Company discretion, and report progress towards modernizing forecasting methodologies at the annual technical conference.

E. Load Forecast: Load forecasts shall account for the following considerations for each planning cycle and scenario as follows:
(1) Electric companies shall incorporate load impacts of current and future transportation and building electrification based on known information and assumptions.
(2) Electric Company distribution-level forecasts in aggregate shall be aligned to a reasonable extent with available Electric Company developed transmission-level forecasts and with PJM-developed system-level forecasts with an explanation provided in Electric System Plans for any differences and the associated factors, including differences in assumptions.

F. Hosting Capacity Assessment: An Electric System Plan shall account~~, as feasible,~~ for the following considerations for each planning cycle and scenario:
(1) Hosting capacity calculations shall be determined using a circuit-specific calculation including installed and forecasted DER interconnections~~, as feasible~~;
(2) DER forecasting shall be incorporated into reserve Hosting Capacity determinations and the Rightsizing of Hosting Capacity upgrades~~, as feasible~~;
(3) Hosting capacity forecasts should consider forecasted changes to load and load profiles; and

(4) Electric ~~e~~Companies shall establish methodologies for calculating available Hosting Capacity and, in the Annual Electric System Plan Update and Electric System Plan, discuss planned Hosting Capacity capability improvements.
  (a) Electric Companies methods for calculating available Hosting Capacity shall utilize actual Distributed Generation performance data, where available, or reasonable estimates.
  (b) Electric Companies shall work with Stakeholders to develop a holistic hosting capacity framework that considers interactions between Distributed Generation, Energy Storage Devices, Smart Inverter capabilities, and Demand Response.
  (c) Electric Companies shall develop a repeatable process for data validation that is documented and shared with Stakeholders.
(5) Electric Companies shall publish hosting capacity maps on their websites and update them at minimum quarterly. Additionally, utilities shall report on progress toward implementing monthly hosting capacity updates in their annual filings.

G. Grid Needs and Locational Value Assessment:
  (1) Grid Needs assessment
    (a) An Electric Company's Grid Needs assessment shall include current and forecast distribution substation and feeder constraints identified as part of each planning cycle, including the timing, magnitude and other relevant characteristics for each identified System Constraint.
    (b) The Annual Electric System Plan Update shall discuss changes to an Electric Company's Grid Needs assessment that may occur between planning cycles.
    (c) Electric Companies shall Cost-effectively pursue industry best practice methods and analytical tools to improve their planning analysis and processes, the choice of which to adopt shall be at the discretion of the Electric Companies.
  (2) Locational Value Assessment:
    (a) An electric system plan shall provide, as ~~feasible and appropriate~~ applicable, locational value for each identified electric System Constraint.
    (b) Locational value shall include the potential deferral or avoided value of a Traditional Wires Solution, as appropriate.
    (c) Electric Companies shall develop a Locational Value Assessment using the Commission's Uniform Benefit Cost Analysis framework.
    (d) Electric companies shall report on the progress towards implementation of Locational Value Assessments at annual technical conferences.

H. Identify Possible Solutions to Grid Needs: An Electric System Plan shall account for the following considerations for each planning cycle and scenario:
  (1) Near-Term Objective:
    (a) An Electric System Plan shall identify feasible solutions for identified Grid Needs.
    (b) Electric companies shall ~~consider~~ ~~feasible~~ identify possible Non-Wire Solutions to address System Constraints. For any proposed upgrade projects resulting from Regulations .03H and .03I of this Chapter, Electric Companies' assessment of Non-Wire Solutions shall:
        i. Consider DER forecast levels from the Goal Scenario from Regulation .03(B).3 and potential DER adoption levels beyond the Goal Scenario as

informed by results from the Locational Value price signals pursuant to § G of this Regulation.

ii. Consider interactions with long-run transmission system needs.

iii. Assess how elevated DER adoption in a Non-Wires Solution helps to reduce GHG emissions.

iv. Assess whether a combination of Non-Wires Solution and a Traditional Wires Solution would result in lower net cost for comparable levels of reliability.

(c) For any proposed upgrade projects resulting from Regulations .03H and .03I of this Chapter, future Hosting Capacity constraints that incorporate DER forecasts shall be considered, as appropriate.

(2) As a longer-term objective:

(a) Electric companies ~~may~~ shall assess the feasibility of utilizing new Cost-effective technologies and methodologies for solutions to grid needs.

(b) Electric companies shall report on the progress towards utilizing new Cost-effective technologies and methodologies at annual technical conferences.

(3) Pursuant to Public Utilities Article §7-804, *Annotated Code of Maryland*, Electric Companies shall consider investment in or procurement of Cost-effective demand-side methods and technology to improve reliability and efficiency, including VPPs.

I. Screen and Evaluate Possible Solutions: An Electric Company shall screen and evaluate possible solutions for each planning cycle and scenario. The Electric System Plan shall include the criteria used to evaluate possible solutions, including Cost-effectiveness considerations.

(1) Electric Companies shall evaluate Cost-effectiveness for alternatives considered, if applicable.

(2) Electric Companies shall utilize the Commission's Unified Benefit Cost Analysis framework for solutions involving DERs, as ~~feasible~~ appropriate, in determining Cost-effectiveness.

(3) Electric Companies shall utilize Locational Values developed pursuant to § G of this Regulation, as applicable.

J. Choose Solutions and Publish Plan: An Electric Company shall choose a solution or solutions for each scenario and publish a plan for each planning cycle as described in Regulation .04 of this Chapter.

(1) Electric companies shall present their rationale for solution selection in Electric System Plans, including why alternative solutions were not selected.

(a) Information and data shall be provided in an Electric System Plan at the substation level.

(b) When project solutions are proposed in response to System Constraints, electric companies shall provide feeder-level information, where applicable.

K. Program and Project Design:

(1) Program and project design including construction, procurement and Electric Company contracting are factors in the Electric Companies' mandate to provide safe and reliable

service and a consideration in overall cost which shall be estimated in Electric System Plans.

(2) Program and project design including construction, procurement and Electric Company contracting decisions, shall be left to Electric Company discretion in executing an Electric System Plan, although these factors will remain subject to review in rate cases.

L. Assess Results: An Electric Company shall account for the following considerations for each planning cycle:

(1) An Electric Company shall assess the results of their Electric System Plans to determine lessons learned and changes to future planning assumptions as appropriate.

(a) This assessment shall include the determination of progress as documented by the metrics established in the cycle's electric system plan.

(2) Rate case filings shall provide explanations for projects that do not reconcile with Electric System Plans.

(3) An Electric Company shall present a review of any projects which were planned to be in service since its last Electric System Plan including if the projects were completed, delayed, or altered, and, if the projects were delayed or altered, why.

(4) An Electric Company shall assess the extent to which forecasts for DERs, load, hosting capacity, and EV adoption diverged from actuals; and

(a) Discuss if such divergence, if any, requires reconsideration of long-term Electric System plans; and

(b) Discuss modifications it intends to make to forecasting methodology, if any, in response to the divergence, if any.

(5) An Electric Company shall assess the extent to which EmPOWER program plans align with and support the goals of this regulation, including:

(a) Development of geographically-targeted energy efficiency and demand response programs that are capable of responding to the Locational Value price signals developed pursuant to § G of this Regulation; and

(b) Leveraging information provided in Electric System Plans to increase opportunities for vulnerable communities to participate in DER programs.

20.50.15.04

.04 Electric System Plan, Annual Electric System Plan Update and Preliminary Electric System Plan: Development, Reporting, and Stakeholder Engagement Process.

A. Electric System Plan Frequency:

(1) Electric Companies shall retain flexibility to determine the frequency of their respective Electric System Plan that best aligns with their internal planning cycles and considerations based upon their unique processes, system characteristics, and customer needs.

(2) An Electric Company's Electric System Plan publishing frequency shall be a minimum of every three years.

(3) Electric Companies shall publish a Preliminary Electric System Plan and the Electric System Plan on the Electric Companies' websites and file these plans with the Commission under the Electric System Plan docket assigned to each Electric Company.

(4) An Electric Company shall file an Annual Electric System Plan Update during the years in which a complete Electric System Plan is not filed.

(5) An Electric Company shall redact all confidential information from the Electric System Plan published to its website or otherwise submitted on a public basis. However, a full version of the Electric System Plan, including any confidential information, shall be filed with the Commission in accordance with the Commission's rules for filing confidential material, unless otherwise restricted from doing so by applicable law.

B. Annual Electric System Plan Update:

(1) Electric Companies shall include the following Annual Electric System Plan Updates:

(a) A narrative describing the existing planning and forecasting processes, current capabilities that exist, and plans for potential future improvements;

(b) Relevant planning criteria utilized to identify System Constraints;

(c) Description of any new market or policy conditions that are impacting the planning environment, and, if feasible, how they plan to incorporate them into future planning.

(d) Description of any updates to System Constraints or constraint solutions that may have changed from the previous year, including, but not limited to updates on progress regarding projects and programs that have changed from previous year and rationale for the change;

(e) A report using a common framework for Electric Company reporting as directed by the Commission, with information regarding the current status of projects designed to promote State policy goals identified in Public Utilities Article §7-802, *Annotated Code of Maryland*, including information on planning processes and implementation that promote these goals; and

(f) Electric System Plan targets and Planning Metrics pursuant to Regulation § .05 of this Chapter.

(2) Electric Companies shall file an Annual Electric System Plan Update no less than 75 days prior to the annual technical conference.
(3) In the year an Electric Company files a Preliminary Electric System Plan, an Annual Electric System Plan Update is not required.

C. Data Collection: Electric Companies shall identify a discrete opportunity to collect Stakeholder inputs for consideration in the Electric System Plan.
(1) The Electric Company shall provide an overview of the already-collected data including data sources.
(2) Electric Companies shall provide a method for collecting this data.
(3) Electric Companies shall provide a list of the parties they engaged as part of their published Electric System Plan.

D. Align Inputs and Assumptions: Electric Companies shall develop electric system planning inputs and assumptions or develop forecasts, scenarios, or other electric system planning criteria and identify a discrete opportunity for stakeholders to provide feedback.

E. Run Analyses: Electric Companies shall run analyses using data, planning inputs and assumptions while considering Stakeholder feedback from § C and § D of this Regulation and provide a Preliminary Electric System Plan in years that an Electric System Plan is due.

F. Provide Preliminary Electric System Plan.
(1) Electric Companies shall include the following in their Preliminary Electric System Plan:
(a) Lessons learned and process improvements from the previous Electric System Plan cycle;
(b) A narrative describing the existing electric system planning process, current capabilities, and plans for potential future changes including the methodology used to develop aggregate electric distribution-level net load forecasts;
(c) Descriptions of electric system planning scenarios describing the data used as inputs and assumed adoption rates used for Load and DER forecasting;
(d) Summary of feedback received in § C and § D of this Regulation;
(e) Electric Company response to feedback received in § C and § D of this Regulation;
(f) Any change in System Constraints since the last Electric System Plan;
(g) The nature, magnitude and timing of System Constraints;
(h) System Constraint solutions that have not yet been initiated as projects, including, for each solution:
i. Projected timeline for solution implementation to address System Constraints and policy targets over the forecast period.
ii. Projected budget for solutions to address System Constraints and policy targets over the forecast period.
1. Share of projected solution budget dedicated to addressing reliability and resilience invulnerable communities.

iii. Implementation interdependencies with current and identified System Constraint solutions and other Electric Company projects.

(i) Cost-effectiveness analysis for identified System Constraint solutions, if applicable;

(j) Provide a description of the final methodology, inputs, and results of the analyses~~; and~~

(k) Locational value for each identified System Constraint~~, as feasible~~; and

(l) Electric System Plan targets and Planning Metrics pursuant to Regulation §.05 of this Chapter.

(2) The Preliminary Electric System Plan shall be published to align with the Electric System Plan Frequency pursuant to § A of this Regulation.

(3) An Electric Company shall publish on its website and file with the Commission its Preliminary Electric System Plan no less than 75 days prior to the annual technical conference.

G. Comments filed by Parties.

(1) Comments shall be filed by any Stakeholders no less than 30 days prior to the annual technical conference.

(2) Stakeholders and Electric Companies shall have the opportunity to obtain discovery.

H. Annual Technical Conference.

(1) The annual technical conference shall provide a venue for Stakeholders to comment on the assumptions, inputs, and results of the Preliminary Electric System Plan and Annual Electric System Plan Update.

I. Electric Companies' Consideration of Feedback.

(1) The Commission may provide an Order noting the Preliminary Electric System Plan after an annual technical conference which may include direction for the Electric Companies.

(2) Electric Companies shall evaluate any feedback received from the Commission in any Order following the annual technical conference.

(3) Electric companies shall evaluate feedback received from stakeholders in § C, § D, § G and § H of this Regulation.

(4) Within 90 days of the annual technical conference, Electric Companies shall publish on their website and file a response to Stakeholder feedback with the Commission, including what Stakeholder proposals will be considered or not considered in the development of the Electric System Plan and the reasoning for these decisions, under the Electric System Plan docket assigned to each Electric Company.

J. Electric System Plan Publishing.

(1) Electric Companies shall publish a final Electric System Plan under the Electric System Plan docket assigned to each Electric Company after the consideration of feedback in Regulation § I of this Regulation.

20.50.15.05

.05 Electric System Planning Metrics.

A. An Electric Company shall include Planning Metrics listed in §C of this Regulation in its Preliminary Electric System Plan and other Planning Metrics as determined by the Commission.

B. An Electric Company shall include Planning Metrics listed in §C of this Regulation in its Annual Electric System Plan Update and other Planning Metrics as determined by the Commission.

C. An Electric Company shall include in its Preliminary Electric System Plan, Electric System Plan, and Annual Electric System Plan Update a set of Planning Metrics that will allow monitoring of progress in at minimum the following plan areas:
   (1) State goals and targets;
   (2) Reliability;
      (a) Reliability indicators for substations serving vulnerable communities, including:
         i. SAIFI;
         ii. SAIDI; and
         iii. CAIDI.
   (3) Resilience;
      (a) Number of Customers Experiencing Long Interruption Durations (CELID), defined as greater than 12 consecutive hours, by customer class.
      (b) Number of Customers Experiencing Multiple Interruptions (CEMI)
      (c) Customers Experiencing Multiple Sustained Interruptions and Momentary Interruptions Events (CEMSMI)
      (d) Restoration effectiveness, defined as sum of customers without power for a given time period to be determined by utilities in collaboration with stakeholders, divided by the sum of sustained customer interruptions and the sustained interruptions avoided by deploying adaptation measures
      (e) Percentage of distribution infrastructure hardened.
   (4) DER integration, by DER category;
      (a) Distributed Generation:
         i. Number of systems with IEEE 1547-2018 UL1741SB approved inverters vs. total number of systems;
         ii. Number of systems with IEEE 1547-2018 UL1741SB approved inverters with Volt-VAR activated vs. # of systems with IEEE 1547-2018 UL1741SB approved inverters; and
         iii. Number of systems with IEEE 1547-2018 UL1741SB approved inverters with Volt-watt activated vs. # of systems with IEEE 1547-2018 UL1741SB approved inverters.

(b) Energy Storage Devices: Total capacity (kW and kWh) of Energy Storage Devices interconnected and in queue at the time of filing, by the following groupings:
   i. Behind-the-meter vs. front-of the-meter;
   ii. Energy Storage Devices paired with other types of Distributed Generation;
   iii. Energy Storage Devices co-located with EV charging infrastructure;
   iv. By customer segment (residential, commercial, industrial)
   v. Utility-owned Energy Storage Devices
   vi. Energy Storage Devices deployed in vulnerable communities

(5) Load and demand management;

(a) Demand Response: Total Load Reduction Capability in terms of nominated value (MW) by program and cumulatively. Further, total Load Reduction Capability (MW) shall be reported by:
   i. PJM zone (if a utility serves more than one zone in PJM);
   ii. Season (winter and summer, as applicable);
   iii. Notification lead time; and
   iv. Product-type.

(b) Time of Use and Dynamic Rates:
   i. Number of customers enrolled on TOU or dynamic pricing rates by rate type and customer class (residential, commercial, industrial);
   ii. Percentage of eligible customers on TOU or dynamic pricing rates by rate type and customer class (residential, commercial, industrial); and
   iii. Total Peak Load Reduction (MW) from TOU or other pricing programs by TOU rate type and customer class (residential, commercial, industrial).

(c) EV Charging:
   i. Number of EVs registered in the Electric Company's service area, broken out by vehicle weight class (light-duty, medium-duty, heavy-duty);
   ii. EV charging ports in the Electric Company's service area (number of ports and kW nameplate capacity) by market segment (Single family residential, shared private residential, shared private commercial, and public) and charging power level (Level 2, DCFC);
   iii. Total EVSE capacity (kW) interconnected in vulnerable communities;
   iv. Total number of charging sites, charging ports, and connected capacity (kW) deployed under programs offered by the Electric Company;
   v. Number of EV customers enrolled in each managed charging program or time-varying rate offered by Electric Companies, by customer class (residential, commercial, industrial), and demand charge alternative ("DCA") rates;
   vi. Annual total system peak load reduction (MW) from managed charging programs and time-varying rates by market segment (Single family residential, shared private residential, shared private commercial, and public);
   vii. Total EV charging load (kWh) occurring during peak hours and off-peak-hours, segmented by enrollment in EV managed charging program or time-varying rates versus un-managed charging;
   viii. Greenhouse gas (GHG) emissions reductions attributable to EV adoption in Electric Company service area, calculated according to state Zero Emission

Vehicle or other governing policy, as applicable, and compared to baseline federal vehicle efficiency baselines.

(6) Hosting capacity;

(a) Interconnection metrics are reported annually pursuant to Chapter .09 of this Subtitle. The following additional interconnection metrics shall be collected for electric system planning purposes:

i. Total number of Distributed Generation systems and nameplate capacity (MW) interconnected and in queue for customers in vulnerable communities;

ii. Total number of Energy Storage Devices and nameplate capacity (MW) interconnected and in queue for customers in vulnerable communities;

iii. Total nameplate capacity (MW) of community solar and number of community solar customers in vulnerable communities;

iv. Total system MWh of estimated Distributed Generation consumed on-site, by month and hour;

v. Total system MWh of estimated Distributed Generation exported to the grid, by month and hour; and

vi. Total system MWh of Distributed Generation curtailed, by month and hour.

(7) System Constraint resolution including;

(a) Substation Overload Conditions: ~~defined as overload conditions observed on substations that require remediation~~.

i. ~~defined as~~ Number of substation transformers experiencing conditions exceeding established planning criteria thresholds;

ii. Number of substation transformers experiencing conditions exceeding normal operational loading limits;

iii. Number of substation transformers experiencing conditions exceeding emergency seasonal loading limits;

iv. Number of substation transformers identified that require remediation; and

v. Number of substation transformer overloads remediated by Traditional Wires Solutions or Non-Wires Solutions.

(b) Feeder Overload Conditions: ~~defined as overload conditions observed on substations that require remediation.~~

i. Number of primary feeders experiencing conditions exceeding established planning criteria thresholds;

ii. Number of primary feeders experiencing conditions exceeding normal operational loading limits;

iii. Number of primary feeders experiencing conditions exceeding emergency seasonal loading limits;

iv. Number of primary feeders identified that require remediation; and

v. Number of primary feeder overloads remediated by Traditional Wires Solutions or Non-Wires Solutions.

(8) NWS incorporation; ~~and~~

(a) NWS to defer substation transformer upgrades;

i. Number of NWS projects identified by resource type (including, but not limited to, battery storage, energy efficiency, demand response NWS);

ii. Total MW of NWS potential identified by resource type;

iii. Number of NWS projects deployed by resource type;
iv. Total MW of NWS deployed by resource type; and
v. Total cost savings over Traditional Wires Solution by NWS project deployed.

(b) NWS to defer primary feeder upgrades;
i. Number of NWS projects identified by resource type;
ii. Total MW of NWS potential identified by resource type;
iii. Number of NWS projects deployed by resource type;
iv. Total MW of NWS deployed by resource type; and
v. Total cost savings over Traditional Wires Solution by NWS project deployed.

(9) Energy burden and societal impacts
(a) Number of customers who are energy burdened;
(b) Ratepayer and bill impacts from proposed Electric Company spending; and
(c) Tons of GHGs avoided due to Electric System Planning initiatives.
(d) Number and type of Grid Needs identified impacting vulnerable communities.

(10) Stakeholder engagement.
(a) Number of DSP stakeholder engagement events; and
(b) DSP Stakeholder Diversity at Engagement Events.

20.50.15.06

.06 Legislative Reporting Requirements.

A. Annual Maryland General Assembly Report.

(1) On or before November 1 annually, each Electric Company shall file material updates to project status reported pursuant to Regulation .04B(1)(e) of this Chapter.

(2) On or before December 1 annually, the Commission's Technical Staff shall submit a report to the Maryland General Assembly regarding the current status of projects designed to promote the State's policy goals identified in Public Utilities Article §7-802, *Annotated Code of Maryland*, including information on planning processes and implementation that promote these goals.

Appendix B

Proposed Regulatory Language
Replace COMAR 20.50.15.04(J) with the following:
.04.J Commission Approval of Electric System Plans and Electric System Plan Updates.

(1) No later than thirty (30) days after an electric company files its response to Stakeholder feedback with the Commission, an electric company shall file for approval of an updated final Electric System Plan under the electric system plan docket assigned to each electric company.

(2) The review of an electric company's Electric System Plan shall continue until a plan has been approved by the Commission.

(3) If an electric company's Electric System Plan has not been approved by the time its Annual Electric System Plan Update is due, the company shall instead file a revised Preliminary Electric System Plan and initiate a new stakeholder feedback cycle pursuant to this chapter, unless the Commission waives this requirement for good cause shown.

(4) Commission approval of an Electric System Plan shall not constitute a determination of prudence or rate recoverability for any specific project or investment proposed in the plan.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.04.K – Discovery Procedures:
.04.K Discovery Procedures.

(1) Discovery shall begin immediately upon the filing of an electric company's Preliminary Electric System Plan.

(2) A discovery window of not less than sixty (60) calendar days shall be open following the filing of the Preliminary Electric System Plan.

> (a) During the discovery window, any party or interested person may serve discovery requests on the utility.
>
> (b) An electric company shall respond to all discovery requests, including those from state agencies, within ten (10) business days of receipt.
>
> (c) If the electric company objects to a discovery request, it must serve written objections on the requesting party within three (3) business days of receipt. The parties shall meet and confer in good faith to resolve any dispute before seeking Commission intervention. If the dispute remains unresolved, the requesting party may file a motion to compel.
>
> (d) If an Electric Company designates any portion of its discovery response as Confidential or Critical Energy Infrastructure Information (CEII), it must clearly label the material and provide a written justification for the designation within ten (10) business days of receiving the discovery request. If the requesting party disputes the designation, the parties shall meet and confer in good faith to resolve the issue. If the dispute remains unresolved, the Electric Company may file a motion for a protective order. Until the Commission issues a ruling on the motion, the requesting party shall treat the disputed information as confidential or CEII.
>
> (e) Subject to subsection (3), discovery outside of the discovery window may only be served with leave of the Commission for good cause shown, unless the electric company voluntarily elects to respond.

(3) The Office of People's Counsel, the Maryland Energy Administration, and the Commission's Technical Staff may serve discovery requests under this Chapter on an electric company at any time. Outside of the discovery window set out in subsection (2), an electric company shall respond to such agency discovery requests within fifteen (15) business days of receipt.

(4) Discovery shall be liberally construed to include any information reasonably related to the evaluation of the Electric System Plan or an Electric System Plan Update. Such

information includes, but is not limited to, load forecasts, scenario assumptions, model inputs and outputs, cost estimates, asset condition data, hosting capacity maps, non-wires alternative analyses, and planning methodologies.

(5) At the time a Preliminary Electric System Plan is filed, the electric company shall concurrently file responses to the Uniform Planning Disclosures approved by the Commission. These standardized disclosures establish a common baseline of planning data and shall be provided without the need for stakeholder initiation.

(6) Discovery responses shall be provided in machine-readable, searchable formats when feasible, and must include all supporting workpapers, datasets, and explanations necessary to interpret the response. Failure to respond in good faith may be subject to enforcement action, including motions to compel or other appropriate remedies.

(7) Access to information designated as confidential or as Critical Energy Infrastructure Information (CEII) shall be subject to applicable protections. A party or interested person may access such information only upon obtaining requisite approval or by executing a Commission-approved confidentiality or nondisclosure agreement.

Appendix C

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – Transmission and Supply-Side Considerations
.03.J Transmission and Supply-Side Considerations.

(1) An Electric System Plan shall include an assessment of upstream system factors that may influence distribution system needs, including:

> (a) Projected generation additions and retirements within the PJM region that may affect power flows, voltage stability, or local resource adequacy in the utility's service territory;
>
> (b) Known or anticipated PJM Regional Transmission Expansion Plan (RTEP) or long-term regional transmission projects that may impact substation loading or distribution system configuration;
>
> (c) Constraints or delays in the PJM interconnection queue that may limit the availability of planned generation resources;
>
> (d) Relevant federal or regional policies or market rules that may alter the generation mix or location of generation resources affecting the distribution system; and
>
> (e) Interactions between planned distribution system investments and transmission-level grid conditions, including potential duplicative or conflicting upgrades.

(2) The Electric Company shall describe how upstream system conditions were incorporated into the development of DER forecasts, load forecasts, hosting capacity assumptions, and identification of Grid Needs.

(3) The Electric Company shall identify any planned distribution system investments that may be influenced by, or may influence, transmission system configuration or generation siting.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – Coordination Between Electric and Gas Utilities
.03.L Coordination Between Electric and Gas Utilities.

(1) Where an Electric Company shares service territory with a gas company regulated by the Commission, the Electric Company shall coordinate with that gas company during the electric system planning process to support:

(a) Consistent assumptions regarding electrification of buildings and transportation;

(b) Identification of opportunities to avoid duplicative or conflicting infrastructure investments;

(c) Shared customer data, where feasible and consistent with Commission rules, for the purpose of load forecasting and electrification impact analysis; and

(d) Evaluation of non-pipe and non-wires alternatives, where applicable.

(2) The Electric System Plan shall:

(a) Identify geographic areas where electric and gas infrastructure overlaps, particularly in regions subject to planned electrification, aging gas infrastructure, or known constraints;

(b) Describe coordination efforts undertaken with relevant gas utilities during the planning cycle, including points of contact, data exchange, and areas of alignment or divergence; and

(c) Include a qualitative assessment of electrification-related impacts on existing gas infrastructure and any implications for electric system investments.

(3) The utility may be required to submit additional reporting or joint filings in future proceedings where electrification trends create significant cross-system planning needs.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – Grid Modernization Sequencing and Enablement Planning
.03.M Grid Modernization Sequencing and Enablement Planning.

(1) Each Electric System Plan shall include a Grid Modernization Roadmap that:

(a) Identifies enabling technologies that are necessary to or would enhance implementation of proposed forecasting methods, DER integration strategies, Non-Wires Solutions, or locational value application;

(b) Provides a timeline for planned deployment of each enabling technology, including expected procurement, design, construction, and integration milestones;

(c) Assesses the cost of implementing such technologies and the marginal benefits enabled by the technology including, but not limited to grid benefits, operational cost reductions, or furtherance of non-quantified state policy goals; and

(d) Explains how the anticipated availability or absence of these technologies informed decisions made in the planning process, including solution selection and project prioritization.

(2) The Roadmap shall include, at a minimum, status updates and sequencing plans for:

(a) Advanced Metering Infrastructure (AMI);

(b) Distributed Energy Resource Management Systems (DERMS);

(c) Advanced Distribution Management Systems (ADMS);

(d) Hosting capacity tool enhancements; and

(e) Other grid management or monitoring tools impacting future resource decisions included upon in the plan.

(3) The Electric Company shall explain in its plan how it intends to coordinate grid modernization implementation with load growth, electrification, and DER deployment trends to minimize costs and optimize system efficiency.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – DER Contributions to System Reliability
.03.N DER Contributions to System Reliability.

(1) An Electric System Plan shall identify and evaluate the potential reliability and resilience contributions of distributed energy resources (DERs), including both individual DER technologies and aggregated DERs operating as Virtual Power Plants (VPPs).

(2) The plan shall include consideration of:

(a) Grid-forming inverter capabilities to support voltage and frequency stability;

(b) DERs capable of providing black start, ride-through, or system restoration support;

(c) Smart inverter functionalities that support reactive power management, voltage regulation, or other ancillary services;

(d) EV charging and managed discharging strategies that support transmission fault recovery or peak shaving; and

(e) DER contribution to reducing customer outages or contributing to system operational flexibility in the event of planned or unplanned N-1 or N-2 scenarios.

(3) The Electric Company shall describe how DER contributions to system reliability were incorporated into the identification of Grid Needs, solution evaluation, and project prioritization. This may include discussion of scenario-based modeling, qualitative assessment, or technical studies, as appropriate.

(4) The Electric Company shall describe any coordination with transmission planners, PJM, or regional reliability entities related to DER integration.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.03 – Use of Metrics in Plan Evaluation
.03.E Use of Metrics in Plan Evaluation.

(1) The Electric Company shall, in its Preliminary Electric System Plan and final Electric System Plan, provide a narrative assessment of how the metrics listed in § C of this Regulation:

> (a) Inform or validate the utility's load and DER forecasts;
>
> (b) Support or challenge the justification for proposed projects or solutions; and
>
> (c) Reflect progress toward applicable State policy goals under Public Utilities Article §§ 7-801 through 804 and the Climate Solutions Now Act and any future State policy goal.

(2) The Electric Company shall identify any metrics for which performance trends are inconsistent with stated plan objectives or prior planning assumptions and explain:

> (a) Whether planning adjustments were made in response; and
>
> (b) If not, why continued use of the original assumption remains appropriate.

(3) The Commission may consider Electric System Plan metrics and related progress trends as part of its review and approval of the plan, and may direct the utility to revise planning assumptions or evaluate alternative solutions based on those trends.

Proposed Regulatory Language
Add the following as new subsection COMAR 20.50.15.04 – Stakeholder Access to Data and Planning Models
L. Stakeholder Access to Data and Planning Models.

(1) Each Electric Company shall provide Stakeholders with timely access to planning models, input assumptions, and relevant datasets used to develop the Electric System Plan, subject to appropriate confidentiality protections and Commission rules on information access.

(2) At a minimum, the following materials shall be made available to Stakeholders approved to access confidential information:

(a) Power flow models and associated network data used to evaluate grid constraints;

(b) Hosting capacity calculation methodologies and underlying assumptions;

(c) Load and DER forecast methodologies, including scenario-specific input assumptions, <u>including but not limited to customer counts by revenue class, baseline appliance saturations showing relative fuel usage by major end use category, baseline appliance efficiency levels, adoption trajectories, and DER adoption eligibility criteria (if any)</u>;

(d) Locational value frameworks and benefit-cost input values; and

(e) Project screening and prioritization criteria.

(3) Electric Companies shall maintain a publicly accessible planning portal or docket containing:

(a) All anonymized, non-confidential versions of the materials listed above;

(b) Historical Electric System Plans and Annual Updates; and

(c) A log of all data requests submitted by Stakeholders, along with their status and resolution.

(4) The Commission may issue further guidance on data standardization and access protocols to support consistency across Electric Companies and facilitate meaningful participation in the planning process.

Appendix D

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Uniform Planning Disclosures

1. For each feeder in the Electric Company's service territory please provide:
    a. The feeder name and/or ID by which the Electric Company identifies the feeder;
    b. The number of customers on the feeder by customer class;
    c. The aggregate 12-month billing data (in $/kWh for each month over the last 3 years) for each customer class;
    d. The seasonally-adjusted nameplate MVA of the feeder;
    e. The baseline measured peak net load by season;
    f. The baseline 24-hour net-load profile from the peak load day by season;
    g. The baseline measured daytime minimum net load and day-time stamp for when the daytime minimum occurred;
    h. The baseline 24-hour net-load profile from the daytime minimum load day; and
    i. The number of customers on the feeder with a Medical Certification Form on file.

2. For each substation transformer in the Electric Company's service territory please provide:
    a. The substation name and/or ID by which the Electric Company identifies the substation;
    b. The number of customers served by the substation transformer by customer class;
    c. The aggregate 12-month billing data (in $/kWh for each month over the last 3 years) for each customer class;
    d. The seasonally-adjusted nameplate MVA of the substation transformer.
    e. The baseline measured peak net load by season;
    f. The baseline 24-hour net-load profile from the peak load day by season;
    g. The baseline measured daytime minimum net load and day-time stamp for when the daytime minimum occurred;
    h. The baseline 24-hour net-load profile from the daytime minimum load day; and
    i. Total critical customer-hours of outages.

3. For circuit in the lowest quintile of SAIFI and SAIDI reliability metrics for the Electric Company please provide:
    a. The circuit name and/or ID by which the Electric Company identifies the circuit;
    b. The substation name and/or ID of each substation that feeds the circuit;
    c. The location of the circuit;
    d. The voltage level of the circuit;
    e. The circuit length;
    f. The number of customers receiving service off the circuit, by customer class;
    g. The number of customers receiving service off the circuit with Medical Certification Forms;

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h. The outage and interruption event history of the circuit including, for each event:
    i. The date of the event;
    ii. The number of customers imp[acted by the event, by customer class;
    iii. The length of event;
    iv. The cause of the event;
i. The number of years in which the circuit has been in the lowest quintile of SAIFI and SAIDI reliability metrics;
j. The date of the last tree trimming relevant to the circuit;
k. The date of the last inspection of the circuit;
l. A description of measures already taken to address previously identified reliability issues on the circuit; and
m. The cost and timeline for actions already taken to address previously identified reliability issues on the circuit.

4. Please provide the following information relating to Distributed Energy Resources (DERs) on the Electric Company's system:
    a. For each feeder in the Electric Company's system:
        i. The total megawatts of DERs connected, by DER type;
        ii. The total megawatt-hours of DERs connected, by DER type;
        iii. The total megawatts of DERs in the interconnection queue, by DER type and interconnecting customer class;
        iv. The total megawatt-hours of DERs in the interconnection queue, by DER type and interconnecting customer class;
        v. The forecasted total megawatts of DERs, by DER type;
        vi. The forecasted total megawatt-hours of DERs, by DER type; and
        vii. If the feeder serves a vulnerable community.
    b. For each substation in the Electric Company's system:
        i. The total megawatts of DERs connected, by DER type;
        ii. The total megawatt-hours of DERs connected, by DER type;
        iii. The total megawatts of DERs in the interconnection queue, by DER type and interconnecting customer class;
        iv. The total megawatt-hours of DERs in the interconnection queue, by DER type and interconnecting customer class;
        v. The forecasted total megawatts of DERs, by DER type;
        vi. The forecasted total megawatt-hours of DERs, by DER type; and
        vii. If the substation serves a vulnerable community.

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5. Please provide the following information relating to the reliability of the Electric Company's system.
   a. For each feeder on the Electric Company's system please detail:
      i. The number of Customers Experiencing Long Interruption Durations (CELID), defined as greater than 12 consecutive hours, by customer class;
      ii. The number of Customers Experiencing Multiple Interruptions (CEMI), by customer class; and
      iii. The number of Customers Experiencing Multiple Sustained Interruptions and Momentary Interruptions Events (CEMSMI), by customer class.
   b. Please detail the SAIDI contribution on the Electric Company's system from overload-caused outages for each substation.

6. For each violation identified in the Electric Company's modeling for the Electric System Plan or Electric System Plan Update please provide:
   a. The cause of the violation (including, but not limited to, thermal or voltage violations);
   b. The planning criteria used to identify the constraint (i.e., system normal operating condition for constraint violation type);
   c. The hours (in an hour-ending format) the system is constrained;
   d. The level of load (in MVA), voltage, or both, for each hour the system is constrained, depending on the type of violation;
   e. The total number of constrained hours throughout the year (if using time series power flow); and
   f. The non-wires solutions considered to address the violation including:
      i. The non-wire solution type(s) considered (including, but not limited to, battery storage, energy efficiency, demand response, or a combination thereof with or without a traditional wire component);
      ii. The estimated cost(s) of the non-wires solution(s); and
      iii. The reason the Electric Company selected, or did not select, the non-wires solution(s).

7. For each proposed investment which will enhance system Hosting Capacity please provide:
   a. A description of the type of system violation(s) addressed;
   b. A description of the scope of the project work to be completed;
   c. Projected project budget; and
   d. If the project involves "rightsizing" a facility.

8. For each proposed investment which will enhance system reliability please provide:
   a. A description of the type of reliability violation(s) addressed;

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b. A description of the scope of the project work to be completed;
c. Projected project budget; and
d. If the project involves “rightsizing” a facility.

9. Please provide the following information related to interconnections for each of the past five years:
    a. The number of interconnection applications;
    b. The total nameplate capacity of resources requesting interconnection;
    c. The average interconnection approval time, in days; and
    d. The average approval time, in days, for resources seeking to interconnect in a vulnerable community.