STATE OF MAINE

PUBLIC UTILITIES COMMISSION

CENTRAL MAINE POWER COMPANY

Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. § 307

Docket 2022-00152

JOINT DIRECT TESTIMONY OF

RON NELSON, CAROLINE PALMER AND NIKHIL BALAKUMAR

Sponsored by

MAINE GOVERNOR'S ENERGY OFFICE

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I. Introduction and Qualifications

Q. Please state your names, titles, and employer.

A. **Nelson:** My name is Ronald Nelson. I am a Senior Director at Strategen Consulting.

Balakumar: My name is Nikhil Balakumar. I am a Manager at Strategen Consulting.

Palmer: My name is Caroline Palmer. I am a Senior Regulatory Consultant at Strategen Consulting.

Strategen Consulting is located at 10265 Rockingham Dr. Suite #100-4061, Sacramento, CA 95827.

Q. Who is sponsoring your testimony?

A. Our testimony is sponsored by the Governor's Energy Office.

Q. Please describe your formal education and professional experience.

A. **Nelson:** I am currently a Senior Director at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and deep expertise in regulatory innovation, performance-based regulation, rate design, renewable program development, grid modernization, new grid technologies, gas decarbonization, and electric vehicles ("EVs"). During my time at Strategen, I have worked with numerous state offices, consumer advocates, nongovernmental organizations, utilities, and commissions on issues related to cost-of-service modeling, rate design, grid modernization, distributed energy resource valuation and integration, and performance-based regulation.

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led that office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University where I also minored in Mathematics. My resume is attached as Exhibit REN-1.

Balakumar: I am currently a Manager at Strategen Consulting. At Strategen I have worked with consumer advocates, non-governmental organizations, and commissions on issues related to distributed energy resources, electric vehicles, open data, grid modernization and power systems architectures.

Before joining Strategen in 2021, I served as Head of Market Development at Utilidata where I advocated across the East Coast with Governor's Offices, legislatures and Commissions for grid investments that would digitize the distribution system and support a distributed DER control approaches to enable a future proof grid architecture to meet clean energy goals. Before that, I served as Principal at my own independent consulting firm – the Greentel Group, where I worked to develop Distribution System Operator (DSO) and open data laws for four years. During my time here, I co-led the 'DER Industry Data Initiative' which helped facilitate the landmark regulatory order issued by the New York Department of Public Service (NY DPS) establishing the Integrated Energy Data Resource (IEDR) – the first of its kind independent, statewide data platform opening access to customer, system and market energy data. Prior to Greentel, I led the Research & Development group at Incentive Technology Group (ITG) where we developed a residential energy management platform to empower customers to make clean energy investments. I have a Bachelor of Science in Management from the University of Maryland, Robert H. Smith School of Business. My resume is attached as Exhibit NPB-1.

Palmer: I am currently a Senior Regulatory Consultant at Strategen Consulting. At Strategen, I have worked with consumer advocates, non-governmental organizations, and commissions on issues related to cost-of-service modeling, advanced rate design, beneficial electrification. distributed energy resource valuation and integration, and avoided cost rates.

Before joining Strategen in 2019, I conducted a Fulbright Research Fellowship in Greece, and held intern positions conducting ratepayer advocacy at The Utility Reform Network ("TURN") and providing technical assistance to Massachusetts municipalities at the Metropolitan Area Planning Council ("MAPC"). I have also had experience developing best practices in clean energy policy at Meister Consultants Group (now Cadmus). I hold a Master of Public Policy from the Goldman School at UC Berkeley and a Bachelor of Science in Foreign Service from Georgetown University. My resume is attached as Exhibit MCP-1.

Q. Have you previously testified before state regulatory bodies?

A. **Nelson:** Yes. I have testified in approximately 50 proceedings across the states of New Hampshire, Vermont, Massachusetts, Minnesota, Michigan, Ohio, Pennsylvania, Oklahoma, Georgia, Utah, and Maryland. The issues covered in these proceedings include marginal and embedded cost of service studies, revenue apportionment, rate design, load management, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, distributed energy resource ("DER") interconnection, DER compensation, DER integration, pilot frameworks, automated metering infrastructure, prudence review, distribution system planning, capital investment plan review, and smart inverter settings. I also consult to the Hawaii, Kentucky, and Connecticut commissions. Specifically, I have worked with commissions on implementing performance-based regulation frameworks, which has included evaluation and development of numerous regulatory mechanisms, include decoupling, multi-year rate plan structure, and performance incentive mechanisms, among others. I have acted as the Hawaii Commission's advanced rate design expert in Docket No. 2019-0323, and have assisted the Kentucky Commission on all net metering dockets since 2020. I am also co-leading Connecticut's PBR implementation, a two-year process that will consist of evaluating the shortcomings of the current regulatory framework and developing regulatory mechanisms culminating in a comprehensive PBR framework.

I have also assisted with additional testimonies and regulatory analysis in Hawaii, Washington, D.C., Maryland, Minnesota, Massachusetts, California, North Carolina, South Carolina, Iowa, Kentucky, Washington, Oregon, and the Federal Energy Regulatory Commission ("FERC").

Balakumar: No. I have not previously testified before state regulatory bodies.

Palmer: Yes. I have testified before the Massachusetts Department of Public Utilities.

Q. Have you previously testified before the Maine Public Utilities Commission (Commission)?

A. **All**: No.

Q. What is the purpose of your testimony and how is it organized?

A. The purpose of our testimony is to evaluate and provide recommendations regarding the proposals included as part of Central Maine and Power's case. In Section II, we outline why a comprehensive framework is needed to evolve the Company's grid to support Maine's energy goals. In Section III, we discuss how Multi-year Rate Plans (MRPs) should be considered within a performance-based regulation (PBR) framework. In Section IV, we evaluate and provide recommendations regarding Central Maine Power's (CMP) cost studies. In Section V, we review recent Commission orders related to rate design and analyze how the Company's rate design proposals in the current proceeding measure against our evaluation framework. In Section VI, we evaluate and make recommendations regarding the Company's grid modernization proposal.

II. A Comprehensive Framework is needed to evolve the Company's grid to support Maine's clean energy goals

Q. How have Maine's energy goals impacted the Company's distribution system?

A. Maine has ambitious energy goals to address the challenges posed by climate change and aging infrastructure while creating a more resilient, modern, clean, and affordable grid. These energy goals require the Company to rapidly evolve its distribution system, including clean energy integration and the electrification of the heating and transportation sectors. In addition, the emergence of new technologies – such as distributed energy resources ("DERs") and grid-edge management systems – provide new opportunities for the Company to leverage cost-effective solutions to improve the efficiency and reliability of the distribution system as they work to achieve Maine's energy goals. To achieve these goals, the grid will need to evolve into a platform where the Company, State and quasi-state agencies responsible for implementing Maine's energy policies, consumers, companies, and other stakeholders can work together to develop the economic and technical foundation for a decarbonized grid.

Q. What structural components of the distribution system need to evolve to support Maine's energy goals?

A. There are two primary structural components that drive the need to evolve the distribution system to support Maine's energy goals: (1) the financial and economic structure and (2) the technical and engineering practices. The financial and economic structure must evolve to align utility incentives with Maine's climate and clean energy goals, modernize how costs are allocated and recovered, create favorable market conditions for DER market participants to deploy solutions, and fairly compensate DER market participants for grid services, all while striving to ensure beneficial outcomes for ratepayers. Technical and engineering practices must be modernized so that the distribution system is planned, invested in, and operated to support Maine's energy goals by providing clean, safe, affordable, reliable energy service that is resilient to storms and disruptions, rapidly and cost-effectively. Specifically, the grid needs to enable the capacity to rapidly electrify the heating and transportation sectors, integrate substantial amounts of DERs while optimizing flexible third-party and utility assets, and be able to provide resilient service, recovering from emergency conditions and disruptions quickly, efficiently, and cost-effectively.

Q. Has Maine taken policy actions regarding the (1) financial and economic structure and (2) technical and engineering practices of the distribution system?

A. Yes. Maine State leadership has taken significant policy actions regarding performance-based ratemaking, distribution system planning as well as the design and operation of the distribution system.

On May 2, 2022, L.D 1959 was enacted addressing major policy issues including performance-based regulation and grid planning. L.D 1959 requires the Commission to adopt rules for utilities including specific, quantitative metrics pertaining to utility operations and activities including service quality, customer service, field service and

DER interconnection.[1] L.D 1959 also requires the Company to file a "Climate change protection plan" that spans 10-years and includes specific actions for addressing the expected effects of climate change on the utility's assets needed to transmit and distribute electricity to its customers.[2] Finally, L.D 1959 establishes a 5-year integrated grid planning ("IGP") process in which the Commission will work with stakeholders to identify priorities for the IGP and issue an order directing the Company to file an IDP per the priorities established and the additional requirements established in L.D 1959.[3]

On December 1, 2021, the Commission initiated an investigation in Docket No. 2021-00039 to provide a comprehensive examination of the design and operation of the electric distribution system in Maine to accommodate the integration and operation of DERs and the potential for substantial increases in load resulting from climate change policies and initiatives that seek to encourage the electrification in the heating and transportation sectors.[4] The Commission contracted with Electric Power Engineers (EPE) to perform this investigation in three phases.[5] In the first phase, EPE investigated and issued reports regarding the capabilities and status of the Company's and Versant's distribution systems.[6] In the second phase, EPE developed and issued a "Gap Analysis,"

[1] L.D 1959 An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future, Sec. 1 at 1.
[2] L.D 1959 An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future, Sec. 8, at 6.
[3] L.D 1959 An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future, Sec. 8, at 6-7.
[4] Docket No. 2021-00039, Investigation of the Design and Operation of Maine's Electric Distribution System, Procedural Order, December 1, 2021.
[5] Docket No. 2021-00039, Investigation of the Design and Operation of Maine's Electric Distribution System, Procedural Order, December 1, 2021.
[6] Docket No. 2021-00039, Investigation of the Design and Operation of Maine's Electric Distribution System, Procedural Order, December 1, 2021.

which examined technical and directional goals for Maine's distribution systems as well as any improvements or modifications to existing utility processes, practices, and technologies that may be necessary to meet those goals.[7] In the third phase, EPE developed and issued a "Roadmap" to meet the identified goals based on established best practices, consensus state adoption, or individual state or utility leading examples.[8] After EPE completed all three phases, the Commission closed the docket on June 6, 2022 stating "it appears to be most efficient to consider EPE's work in the context of individual cases, such as general rate cases and/or as part of the integrated grid planning process recently established by An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future."[9]

Q. Is evolving the (1) financial and economic structure and (2) technical and engineering practices of the distribution system interrelated and interdependent on each other?

A. Yes. Determinations made on the (1) financial and economic structure and (2) technical and engineering practices of the grid will have a significant impact on whether Maine achieves its energy goals expeditiously and cost-effectively. These structural components

[7] Docket No. 2021-00039, Investigation of the Design and Operation of Maine's Electric Distribution System, Procedural Order, December 1, 2021.
[8] Docket No. 2021-00039, Investigation of the Design and Operation of Maine's Electric Distribution System, Procedural Order, December 1, 2021.
[9] Docket No. 2021-00039, Investigation of the Design and Operation of Maine's Electric Distribution System, Procedural Order, June 6, 2022.

and specifically performance-based regulation, distribution system planning, grid needs assessment, as well as the design and operation of the distribution system must be pursued in coordination and in the appropriate sequence. Addressing these issues in siloes will lead to suboptimal and potentially costly outcomes. For example, proposing grid modernization investments without understanding what planning and operational capabilities are needed to support Maine's goals could lead to outdated technologies and stranded assets. Thus, a comprehensive framework is needed that considers (1) the areas of concern and issues that must be addressed, (2) how they should be sequenced and (3) what topics within these issues can be addressed in parallel.

Q. Given Maine's recent policy actions and the coordination required, what is the scope of your recommendations for this rate case?

A. How the Commission structures and investigates major policy topics including the performance-based metrics and grid planning requirements from L.D 1959 will play a significant role in whether Maine achieves its energy goals. A significant portion of the Company's proposal touches on issues across these topics, some of which may be premature without a determination from the Commission in other dockets. Thus, our recommendations throughout this testimony are two-fold: (1) long-term recommendations on frameworks and processes to address these issues comprehensively outside of this rate case and (2) short-term recommendations on aspects of the Company's proposals we recommend rejecting or approving with modifications as the longer-term issues are addressed in other dockets.

III. The Company's Rate Plan Should be Rejected

Q. What is the purpose of this section of your testimony?

A. The Company is proposing to adopt a three-year rate plan (MRP) effective 2023 through 2025. This section will discuss how Multi-year Rate Plans (MRPs) should be one component of a performance-based regulation (PBR) framework that consists, not only of an MRP, but numerous complementary regulatory mechanisms. Until such a framework is in place, the Commission should reject any MRP.

Q. Why is it important to understand how the MRP is related to PBR?

A. A multi-year rate plan (MRP) can be structured to create benefits for ratepayers. However, an MRP must be carefully structured and complemented by multiple mechanisms for these benefits to be realized by ratepayers. The careful MRP design and complementary regulatory mechanisms are necessary to achieve state policy goals, bind utility performance to providing reliable, equitable, and resilient service, and also ensure revenue collection sufficient to keep the utility financially stable. These design characteristics require significant stakeholder engagement and process, which have only just begun in Maine. Without a comprehensive PBR framework in place, the Commission should reject any MRP. Permitting poorly designed MRPs will not only create poor precedent, but will likely result in a shift of risk from utility shareholders onto ratepayers. Risk is shifted by improving revenue recovery performance for the utility, while not providing tangible, measured benefits to ratepayers.

Q. Is there legislation that the Commission should consider when evaluating the reasonableness of the Company's Rate Plan proposal?

A. Yes. This year, Governor Mills signed L.D. 1959 into law. The legislation is entitled "Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future" (P.L. 2022, ch. 702 hereinafter "Act"). The Act seeks to establish formal service standards for Maine electric utilities. Especially pertinent to an MRP, the Act requires the Commission to adopt rules on service quality, customer service, field services, DER interconnection, data collection and sharing, the creation of targets and penalties for poor performance in certain service areas, publishing of reports to convey performance, a benchmarking process for utility expenditures, and a proceeding on integrated grid planning, among other things. As we discuss below, the Act should be at the center of the Company's Rate Plan, but it does not explicitly address many, if any, of the Act's requirements. Furthermore, the proposed Rate Plan is proposed to extend to the middle of 2026, which would, at a minimum, delay meaningful integration of the Act, and may, in a worst-case scenario, send the Company down the wrong path by approving investments and other proposals that do not align with the Act's intent or the priorities identified by Stakeholders in the forthcoming integrated grid planning process.

Q. Have certain aspects of PBR been implemented since enactment of the Act?

A. Yes, some. In Docket 2022-00052, the Commission adopted performance standards addressing certain reliability, customer service and billing metrics.

A. Overview of Performance-Based Regulation

Q. What is Performance-Based Regulation?

A. PBR is an approach to regulation that combines a set of alternative regulatory mechanisms and processes with an aim to focus on desired outcomes tfor state policy objectives, customers, and utilities. Stated simply, a PBR framework can provide clear incentives for the utility to manage costs without compromising service or reliability, while calibrating financial incentives with the public interest.

Q. Why is PBR an increasingly important regulatory approach for the electric power industry?

A. The electric power industry is in a significant transition from mainly centralized fossil-fuel-based generation systems towards increasingly distributed and renewable generation systems. This transition includes the incorporation of copious amounts of variable renewable generation resources, distributed energy resources ("DER"), including demand response ("DR") resources, and a considerable focus on enhancing customer choice.

It is widely acknowledged that the factors driving this energy transition are of sufficient breadth and magnitude that state regulatory frameworks must also continue to evolve to meet new challenges and opportunities arising in the transition, maintain safety and reliability, offer new opportunities to create value for customers, and result in affordable rates.

PBR enables regulators to enhance legacy regulatory structures to foster innovations within modern power systems. An old regulatory paradigm built to ensure safe and reliable electricity at reasonable prices from capital-intensive electricity monopolies is now adjusting to a new era of disruptive technological advances that change the way utilities make money and what value customers expect from their own electricity company. Inherent to traditional cost-of-service regulation ("COSR") is an incentive for the utility to invest in capital expenditures regardless of whether the investments are in the interest of its customers. PBR seeks to better align the Company's financial incentives with its customers' interests by incentivizing the utility to focus on performance and alignment with public policy.

Q. What are some core characteristics of a well-designed PBR framework?

A. Well-designed PBR frameworks should result in a risk-sharing structure that encourages exemplary utility performance irrespective of the nature of its investments (e.g., in capital expenditures versus investment in efficiency measures). By encouraging specific outcomes and objectives, a PBR framework should provide a utility with the opportunity to earn a fair return based on a business model that is well aligned with the public interest. As demonstrated by experience in other jurisdictions (see discussion below), PBR can provide a variety of benefits, including: advancing regulatory goals; providing utilities with increased flexibility, opportunity, and accountability to pursue identified goals; ensuring utility investments are cost-effective; and freeing up limited regulatory resources to focus on overseeing utility success in achieving public priorities.

Q. Can you describe the types of alternative regulatory mechanisms that are typically used in PBR frameworks?

A. While performance-based regulatory mechanisms can overlap, they may be grouped according to three broad categories:

- **Revenue adjustment mechanisms** focus on how an electric company's target revenues are determined, collected, and/or adjusted over time, and include policy tools that shift regulation away from a backward-looking focus on costs and sales to a more forward-looking approach that promotes cost control and improved performance.
- **Performance mechanisms** provide focused incentives for an electric company to reach performance targets aligned with public policies and identified customer priorities through the use of metrics or scorecards, or more overtly through financial rewards for achieving certain levels of exemplary performance or penalties for poor performance.
- **Other regulatory mechanisms** include those that provide electric companies an opportunity to earn revenues from the procurement of cost-effective, third-party solutions, such as cloud-based computing or aggregated DERs.

A summary of specific alternative regulatory mechanisms that fall under each of the three categories listed above can be viewed in the following table:

Table 2 – Summary of Alternative Regulatory Mechanism Components

Revenue Adjustment Mechanisms	
Multi-Year Rate Plan (MRP)	MRPs permit utilities to operate for several years without a traditional, general rate case. The rate plan period typically lasts three to five years. This is a key component of a comprehensive

	PBR framework, but should not be adopted alone without the whole framework in place.
Attrition Relief Mechanism (ARM)	Between plan periods, ARMs automatically adjust rates or the revenue requirement according to a predetermined formula that adjusts with expected utility cost pressures without tracking actual costs. ARMs are commonly based on cost forecasts, indexed trends in utility costs, or a combination of the two.
Revenue Decoupling (Revenue Regulation)	Revenue decoupling (revenue regulation) eliminates the throughput incentive by ensuring utility recovery of allowed revenue regardless of megawatt-hour (MWh) and megawatts (MW) of utility system use. Under this approach, the impact on utility revenues between rate cases from energy efficiency, DR programs, and customer-sited distributed generation can be reduced.
Earning Share Mechanisms (“ESMs”)	ESMs divide surplus or deficit earnings between the utility and its customers, to provide customers with a share of savings achieved through operational efficiency or other measures, while maintaining utility incentives to pursue cost savings.
Performance Mechanisms	
Performance Incentive Mechanism	PIMs consist of performance metrics, targets, and financial incentives or penalties. PIMs have been employed for many years to address performance in areas such as reliability, safety, and energy efficiency. In recent years, PIMs have received increased attention as a way to provide utilities with regulatory guidance and align utility and customer interests regarding DER and the implementation of new technologies and practices.

Scorecards	Scorecard metrics permit the collection of information on utility performance or the achievement of targets in specific areas compared to a peer group of other utilities. Typically, financial incentives are not initially linked to a scorecard, but scorecards can assist in defining baseline conditions and provide a way to evaluate and measure changes to performance over time.
Reported Metrics	Reported metrics can serve as a helpful reporting requirement, meaning that the data reflected by the unit of measurement is tracked and published to illuminate progress towards a prioritized outcome and, in turn, toward the attendant regulatory goal. The simple act of tracking and reporting metrics can encourage stronger utility performance by using transparency as a regulatory tool.
Other Regulatory Mechanisms	
CAPEX/OPEX Equalization	Alternative regulatory mechanisms explore the development of other approaches to equalize treatment of capital expenditures ("CAPEX") and operating expenses ("OPEX"), such as a return on service-based solutions and the capitalization of prepaid contracts**.**
Innovation Mechanisms	Other mechanisms support utility and third-party innovation, such as an expedited innovative pilot framework.

A comprehensive PBR framework would have a combination of each of the mechanisms noted above. However, a PBR framework is most often tied directly to the use of an MRP. The MRP is often considered the core of a PBR framework because it can be structured to control costs and incentivize innovation by setting a budget constraint over the plan's duration.

Q. What are the benefits of an MRP?

A. A well-designed MRP can provide benefits for the utility, its customers, and the Commission. For the utility, it permits predictable revenues and a reduction or elimination of regulatory lag, all of which should reduce the Company's risk and bolster its financial health.[10] Customers benefit from predictable rates and an incentive for the Company to control costs during the rate plan. The Company's revenues are set for the entirety of the MRP and, as such, it cannot come back to the Commission to increase rates if its costs exceed its revenues. Commissions, for their part, benefit from a reduction of the frequency of rate cases and reappropriate that administrative time to other proceedings and issues, such as advancing state policy goals.

Q. Will you please expand upon the potential benefits of an MRP to customers?

A. Yes. The primary benefit of an MRP for customers is cost containment. In an MRP, the Commission sets a revenue requirement for the utility for the plan's duration. The Company then must monitor its spending so that it is operating at or below the O&M budget throughout the term of the MRP. The Company is incentivized to control its spending to ensure that the revenue is sufficient to cover its costs and earn a return for its shareholders. This encourages the utility to be more efficient in its management and operations.

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[10] Costello, Ken. "Multiyear Rate Plans and the Public Interest" National Regulatory Research Institute, 2016. P. 16.

MRPs are also beneficial to customers as they are almost always accompanied by performance measures. Indeed, the other states that CMP notes have multi-year rate plans – New York, Connecticut, Massachusetts, New Hampshire, Rhode Island, and Vermont – each have PBR frameworks in place.[11] A utility has an obligation to ensure that its service is safe and reliable. Since a MRP encourages the utility to contain its costs, there is a fear that the utility may not make sufficient investments to maintain safe and reliable service. Thus, most MRPs are paired with performance metrics to ensure that customers' service and reliability is maintained or improved throughout the plan.

Q. Why is the length of an MRP important?

A. One key issue with plan length is that it determines how long the Company must manage an approved budget. The longer the term the more cost containment pressure that is put on the Company. Terms are commonly 3 to 5 years.

Q. Could you speak to why a comprehensive and balanced performance-based regulatory framework is key to achieving public policy goals?

A. Developing an effective, performance-based regulatory framework necessitates a comprehensive approach composed of a balanced and holistic set of alternative regulatory mechanisms. A customer-centric regulatory framework cannot be constructed

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11 Policy Plan Testimony p. 19.

in an ad hoc, “à la carte” manner. Rather, a suite of alternative regulatory mechanisms should be adopted by the Commission and informed by a regulatory process that invites and considers various viewpoints, in the right combination, to achieve a balanced approach that is in the public interest.

Q. Can you elaborate as to what you mean by a balanced approach?

A. When we speak to the need for a balanced approach, we are speaking about assembling a set of regulatory mechanisms in a precise manner to ensure that neither customers nor the electric utility are left bearing a disproportionate and undue amount of risk within the regulatory framework. Moreover, balance means providing appropriate consumer protections and safeguards coupled with the right incentives to achieve public policy objectives on the one hand, while providing a reasonable opportunity to earn a reasonable return on equity for the utility.

Achieving balance within an advanced regulatory framework will involve some combination of the structural components across revenue adjustment mechanisms, performance mechanisms, and other regulatory mechanisms as outlined above. Our view is that creating a comprehensive set of structural components to create a productive regulatory framework is a singular, and foundational element of PBR. An appropriately structured PBR framework provides clear regulatory boundaries, highlights areas of focus, aligns utility interests with both customer interests and public policy goals, and creates fair, transparent risk sharing.

Q. What are some guiding principles that should ground and inform performance-based regulatory frameworks?

A. There are three guiding principles that should help inform development of performance-based regulatory frameworks: (1) customer-centric approach; (2) administrative efficiency; and (3) utility financial integrity.

Q. Could you speak to each of these three guiding principles in turn?

A. A customer-centric approach speaks to expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions. Administrative efficiency reflects the potential that PBR frameworks offer to simplify the regulatory framework and enhance overall administrative efficiency. With regard to utility financial integrity, from the inception of utility regulation, a fundamental goal has been to ensure the utility's financial health. The financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers. Moreover, the utility is a critical community partner and plays an integral role in achieving the State's energy policy goals.

Q. Do specific jurisdictional characteristics need to be considered when developing a performance-based regulatory framework and identifying an appropriate balance of mechanisms?

A. Yes. Every jurisdiction and utility company service territory has unique features, and a well-designed performance-based regulatory framework should be tailored to the specific needs of the local context.

Q. What type of consideration should be given to the existing regulatory environment when evaluating a prospective performance-based regulatory framework?

A. A prospective performance-based regulatory framework should be evaluated against the specific context of the regulatory framework it would be modifying or refining. How well is the current regulatory framework operating today? How fairly is risk shared between the utility and customers? Does it include a set of structures that facilitate achievement of the jurisdiction's regulatory goals and outcomes? How well has the utility been performing under the current regulation plan (e.g., cost containment, environmental performance, customer satisfaction)?

B. Overview of the Company's Rate Plan

Q. Please provide a high-level summary of the Companies' proposed Rate Plan proposal.

A. The Company is proposing to adopt a three-year rate plan (MRP) effective 2023 through 2025. The Company maintains that a three-year rate plan will provide the Company with greater certainty for cost recovery on large programmatic capital investments that span multiple years, while also reducing the regulatory lag for recovery on capital investments. According to the Company, its vision has three parts: (1) Build a smarter, stronger, and more resilient grid to service our customers, (2) Serve as a catalyst to cost-effectively advance Maine's clean energy policy; and (3) Provide predictability over time in rates.[12] The Company's vision, apparently, maps to five key initiatives: (a) electric operations and reliability, (b) customer service, (c) vegetation management, (d) grid modernization and clean energy transformation, and (e) rate design. These five initiatives represent key investments and changes proposed within the Rate Plan. Finally, the Company proposed several MRP design elements that involve annual reviews of plant additions, capital adjustments for 5 investment categories, inflation reconciliation, and actual tax adjustments.

C. Analysis of the Company's Rate Plan

Q. Do you have a high-level response to the Company's proposal?

A. We categorize our issues with the Company's Rate Plan into two areas.

First, we do not find the process used to inform the Company's Rate Plan to be sufficient. The Company's Rate Plan does not sufficiently integrate performance measures, cost containment, or the achievement of state policy goals into its design. From the outset, the Company did not work with stakeholders to inform and design its Rate Plan. Given the newly passed legislation and pressing energy goals, there is a clear need for comprehensive process to ensure that the Company's financial incentives are aligned

[12] Policy Panel at 3.

with its customers. Commissions in other states, such as Hawaii and Connecticut, have undertaken process that explicitly leverages a goals, outcomes, metrics hierarchy that is informed by stakeholders engagement to help focus PBR frameworks—aligning utility and customer goals. No such process has been conducted to inform the Company's Rate Plan.[13]

Additionally, the Company's Rate Plan pre-empts the implementation of "An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future" (Act). The Act requires that numerous performance metrics and data reporting and sharing activities be created. Additionally, the Act requires that an integrated grid planning process be created. Each of these initiatives should be created and integrated into the ultimate PBR framework. Again, creating robust and comprehensive performance metrics should be done before a MRP is approved.

Q. Can you explain the other area of concern you have with the Company's Rate Plan?

A. Yes. Generally, we are concerned with many of the regulatory mechanisms proposed within the plan.

First, the Company is proposing five capital adjustment mechanisms (also known as rate riders). Adding rate riders is highly concerning because it undermines the cost

[13] We have reviewed the Maine Utility/Regulatory Reform and Decarbonization Initiative. This report represents an initial step in creating a share utility and customer vision, but more work is needed to imbed these findings into the regulatory structure to create a comprehensive PBR framework that can cost-effectively achieve the identified outcomes.

containment incentives that should be created with the MRP. It also clearly undermines one of the three “visions” the Company noted was a driver of its Rate Plan: providing predictability over time in rates. The Company can use these rate riders to propose rate increases by as much it desires, which is in direct opposition of the Company’s stated goal and the intent of the MRP. Rate riders should be used very sparingly and should be vetted through additional process. If the Commission chooses to continue with components of the Rate Plan, we recommend that the proposed rate riders be rejected. If the Company has estimated costs for rate riders, that information should be presented in Rebuttal and considered for inclusion in the capital investment plan.

Second, we do not find the performance metrics to be sufficiently developed. Numerous performance targets and metrics should be created that evaluate the utility’s reliability, customer service, interconnection, load management (passive and active, where applicable), and equity, among others. Specifically, we believe there is a need for goals, outcomes, and metrics to be developed prior to the MRP being approved.

Third, we do not find the inflation reconciliation to be reasonable. We find this to shift risk to ratepayers.

Finally, as a general observation, the Company has not excelled in all instances at mapping significant grid investments to improved outcomes and services for customers. Ensuring that the customer services that are being created with investments are important when proposing investments. Utilities often do not want to discuss customer facing benefits because it creates implicit, or explicit accountability. However, customer expectations are changing and making accountability explicit is exactly what is needed.

For example, the Company notes that it is working towards implementing an Automated Distribution Management System (ADMS). The Company should be identifying, not only the investment required, but tangible, quantifiable benefits and services that will be enabled and when they will be available to customers.

Q. What is your recommendation to the Commission for the Company Rate Plan?

A. We recommend rejecting the Company's proposed Rate Plan. Additionally, we recommend that the Commission initiate a proceeding with the goal of creating a comprehensive PBR framework.

IV. Cost of Service

Q. What is the purpose of this section of your testimony?

A. We highlight the tendency of CMP's cost studies to encourage distribution system cost collection via fixed customer bill components. Specifically, the Company's subjective methodological choices – the MCOSS' local distribution facility approach and the ECOSS' minimum system method – allow the Company to consider a higher proportion of costs as customer-related than demand-related.

A. The Influence of Economic Incentives on Cost of Service Studies

Q. Before you discuss the details of the cost studies, please explain how economic incentives may influence cost studies.

A. When evaluating cost studies and the rate designs they inform, decision-makers should consider how the economic incentives of utilities can impact assumptions within utility-sponsored cost of service studies. It is important for decision-makers to understand how a utility's economic incentives may not always align with public policy goals and ratepayer interests, so that decision-makers can evaluate cost of service modeling and rate design proposals more effectively.

Q. Please provide examples of where a utility's economic incentives may not align with policy goals or ratepayer interests.

A. There are two interrelated issues that can impact the utilities' perspective when conducting cost studies.

First, the price elasticity, or sensitivity, of demand and variability of demand for electricity differs across customer groups. The elasticity of demand measures how much a consumer changes their electricity consumption given a change in its price. In many instances large customers have more elastic demand than residents, meaning that large customers will decrease their demand for electricity more than residents following an equivalent price change, all else constant. This could become increasingly true as grid-interactive buildings grow to be more common because of heating electrification. Additionally, commercial and industrial loads are often more responsive to economic fluctuations, making their load and associated revenues more variable over time. These relationships suggest that utilities can benefit financially from shifting costs from large to residential customers. This presents the utility with an incentive to shift subjective cost allocations in the cost of service study (and there are many in cost studies) to classes with less elastic and variable demand.

Second, third-party services can act as substitutes for utility services. Traditionally, electric utilities have not faced competition on the distribution system. Currently, technological improvements, such as solar plus storage, are providing service opportunities that compete with those provided by the utility because those technologies provide an alternative to utility-distributed electricity. In general, the presence of this competition impacts utility incentives in many ways, potentially prompting them to take actions to make their services more cost competitive through otherwise inefficient rate design changes.

Q. How do the economic incentives of a utility impact cost studies in practice?

A. The utility perspective is largely informed by its economic incentives. For this reason, when subjective determinations are made within a cost of service study or rate design, utilities are likely to make assumptions that benefit their bottom line – as would any for-profit business in a similar position. This can be especially problematic in cost studies and rate design because each process involves numerous subjective assumptions.

B. Objectives and Background

Q. What is the purpose of a Cost of Service Study (COSS)?

A. The purpose of a COSS is to decipher, with as much detail and accuracy as possible, which customer classes cause the utility's various costs associated with providing service. A COSS provides information that can be used to allocate the revenue requirement to customer classes and inform rate design. A marginal COSS (MCOSS) identifies the incremental costs to serve one additional unit of demand or one additional customer on a distribution system, while an embedded COSS (ECOSS), on the other hand, uses historic service costs to assign cost responsibility among customer classes, rather than forward-looking costs.

Q. How is a COSS performed?

A. A COSS has three steps:

1. Functionalize costs into various categories such as generation, transmission, and distribution.
2. Classify costs as related to energy/commodity, demand/capacity, or customers. Energy costs relate to a customer class's energy usage, measured in kilowatt-hours (kWh). Capacity costs relate to a customer class's contribution to peak demand within the system, measured in kilowatts (kW). Finally, customer costs are those required to provide service to customers, regardless of whether the customers consume electricity. For a distribution rate case, a COSS focuses on determining the portion of distribution costs related to demand and to customer.
3. Allocate costs to the various customer classes based on each class's contribution to each classified cost, using allocators specific to energy, demand/capacity, or customer characteristics.

C. Analysis of CMP's Cost Studies

Q. Have you reviewed CMP's MCOSS?

A. Yes, we have done so at a high level.

Q. Do you have concerns with CMP's MCOSS?

A. Yes. I am concerned about CMP's suggestion that marginal local facilities costs are best recovered via a monthly fixed charge.

Q. Describe CMP's treatment of marginal facilities costs.

A. CMP asserts that marginal cost-based distribution rate design would include a monthly facilities charge to recover costs associated with line transformer and local conductors. [14] CMP estimated the cost per-kW of "design demand" using average transformer capacity per customer as a proxy.[15] That calculation assumes "the expected maximum loads over the service life of the transformer can be considered the customer's 'design demands' or connected load per customer".[16]

The Company claims that there is a "misalignment" between the existing fixed charge and cost causation because the existing fixed charge does not recover the per-customer facilities-related costs associated with design demand. Specifically: the "residential and small commercial customer charge is higher than marginal customer cost, but significantly below the sum of marginal customer plus local facilities costs."[17]

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[14] Nieto Direct Testimony at 7.
[15] Nieto Direct Testimony at 18.
[16] Exhibit AN-2 at 11.
[17] Nieto Direct Testimony at 19.

CMP indicates that solving the claimed 'misalignment' would entail "gradually increasing customers' fixed charges for higher recovery of facilities cost."[18]

Q. What is your concern with CMP's treatment of marginal facilities costs?

A. We are concerned that CMP is oversimplifying the cost causation of the demand-related costs of local distribution facilities in order to connect those costs to the fixed charge component of customer bills. CMP's design demand concept does not reflect cost causation because design demand is static when customer demand is not. To estimate design demand, CMP divides the cost of local facilities by the average number of customers. It assumes that a transformer, for example, serves a fixed average number of customers, based on a rate class's average maximum connected demand. The cost of the transformer is then divided among the estimated number of customers sharing the facility.[19] The problem with that assumption is that the expected maximum kW of demand per customer can change over time. Changes in expected maximum demand would in turn change the number of customers who can share the transformer and the cost burden that each of them should be responsible for.

Additionally, basing design demand on *connected* load creates a problem when using the estimate to inform rates. The problem is that as connected loads change,

[18] Nieto Direct Testimony at 21.

[19] This is our understanding of CMP's methodology, based on Exhibit AN-2 at 11. We have not yet had access to the Company's confidential Excel work files, and we are also awaiting responses to discovery requests.

because of electric vehicle ownership or energy efficiency, for example, the average number of customers per facility changes, but the monthly fixed charge does not change. This differs from a non-coincident or coincident peak charge that is traditionally used to collect demand related costs for some customer classes. When using a non-coincident peak demand charge, the price paid for facilities changes with the customer's load. CMP's local marginal facilities cost concept is not only inequitable – in that customers with lower demand subsidize customers with higher demand within a shared rate class – but also sends an inefficient price signal to the customer.

Q. Please provide an example of when the assumption of fixed customer demand would not hold true.

A. Say, for example, that customers begin to invest in electric vehicles. Their demand will increase substantially, and potentially at peak times when they find it convenient to charge. Because CMP's design demand concept translates to a fixed bill charge, it sends those customers a price signal that the customer has no control over that part of the bill, and therefore less incentive to charge at off-peak times. All else constant, this approach will lead to more transformers being overloaded.

CMP's justification for the fixed price signal suggests that fluctuating customer demand cannot impact the transformer: "The planners' expectation is that local facilities will not be expanded in response to month-to-month or year-to-year variations in actual customer usage."[20] However, when multiple customers buy EVs without strong off-peak charging incentives or storage options, they certainly will impact their transformers and force a resizing.[21]

Q. Like the MCOSS, does CMP's ECOSS also encourage greater cost collection via fixed bill components?

A. Yes. CMP selected a classification methodology for its embedded cost study that considers more costs – relative to other reasonable methods – to be customer-related. Specifically, the Company selected the minimum system approach, which reasons that distribution system costs "are related to both the peak amount of load that the system is designed to deliver and the number of customers and premises that it is designed to serve."[22] Classifying more costs as customer-related often translates to collecting those costs through a higher monthly customer charge.

Q. Can you compare CMP's minimum system approach to an alternative approach for classifying distribution system costs?

A. Yes: the basic customer approach. According to the basic customer approach, only costs that can be traced to a specific customer should be assigned as customer costs, because

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[20] Nieto Direct Testimony at 18.
[21] Similar can be said for exporting distribution generation.
[22] Rimal Direct Testimony at 11.

those are the only costs that vary based on the number of customers in a class. Under this theory, the costs of the distribution system cannot be attributed directly to a customer, because adding one customer to the system would not increase the costs of the distribution system. Instead, the basic customer approach recognizes that the distribution system is built to serve peak demand, and so its costs should be classified as demand. Specifically, the basic customer approach classifies FERC accounts 364-368 (referred to generally as "distribution system") as 100 percent demand related and FERC accounts 369-370 as customer related, while the minimum system approach most commonly classifies FERC accounts 364-369 as both demand and customer related.[23] Indeed, CMP's minimum system study classifies poles and conductors as both demand and customer related.[24]

Q. Why is it appropriate to classify distribution system costs as 100 percent demand?

A. There are two main reasons that cost analysts have traditionally found it reasonable to classify the distribution system as 100 percent demand costs. First, distribution system equipment will not be designed or installed if it is incapable of serving peak demand reliably and safely. This indicates that the cost of distribution equipment is caused by the requirement to meet peak demand. As one analyst of cost of service methods put it: "The

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[23] CMP subfunctionalizes several accounts into primary and secondary distribution and only classifies secondary distribution as partly customer-related.

[24] Rimal Direct Testimony at 11.

theoretical basis for (the basic customer) approach is that the distribution system is sized to a certain capacity, that capacity is available to the total population of customers served by a system, and any capacity used by one customer is generally not available to another."[25] That is, from an engineering perspective, the distribution system is designed to meet localized peak demand of a group of customers, and from an economic perspective demand reflects how the system is utilized by customers. Therefore, all distribution costs are more properly classified as 100 percent demand related and not customer related.

A second, similar explanation is that demand costs are the fixed costs that the utility incurs to be ready to provide service. According to Alfred Kahn, a distinguished regulatory economist, demand costs are those caused by "the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of capacity . . . the fixed, capital costs . . . And the proper measure of that responsibility is the proportionate share of each customer in the total demand placed on the system at its peak."[26] Said another way, it is a customer's demand that causes the fixed costs of the distribution system, not simply the numerical addition of that customer to the system.

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[25] Jim Lazar, *Cost Elements and Study Organization For Embedded Cost of Service Analysis: Applicable to the Tucson Electric Power Company* 19 (1992).
[26] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* 95 (1988) Vol. I.

Q. Do other regulatory commissions in the United States use the basic customer approach?

A. Yes, numerous commissions use methods that do not classify distribution system equipment upstream of the service line as a customer cost, and many have recognized the reasonableness of the basic customer approach.[27]

Q. Do you support CMP's marginal customer cost methodology?

A. No. Based on the Company's testimony, it appears that the Company used the rental method to calculate marginal customer costs.[28] The rental method has theoretical and computational issues that may result in a higher marginal customer cost.[29]

Q. What do you conclude regarding CMP's cost studies and their implications?

A. Both the MCOSS and ECOSS employ methodologies that result in a higher proportion of costs being treated as customer-related or connected to a monthly fixed charge. The subjective decisions made in these cost of service studies are not industry standards nor best practice – but instead serve the Company's financial incentives when used to influence rate design toward fixed cost recovery, as I will discuss in the following

[27] For example, in Utah, Colorado, and Massachusetts.
[28] Nieto Direct Testimony at 19 and Exhibit AN-2 at 13.
[29] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual.* Montpelier, VT: Regulatory Assistance Project. At 208.

section. I am more supportive of using the basic customer approach which would classify only meters and services as customer-related.

V. Rate Design

Q. What is the purpose of this section of your testimony?

A. In this section, we review recent Commission orders related to rate design and analyze how the Company's rate design proposals in the current proceeding measure against our evaluation framework. We recommend that the Commission reject the Company's proposed residential service charge increase and establish an advanced rate design proceeding and process. We also recommend some rate design revisions to ensure that the Company's proposed TOU period selection and on- and off-peak price differentials provide the most meaningful price signals, that the Company develop additional tariffs for non-firm customers, and that the Company provide additional information to justify the cost of its proposals.

A. Background on Recent Rate Design Dockets

Q. Have recent dockets, outside of the current rate case, addressed issues related to the Company's rate design proposals?

A. Yes. The Commission recently addressed several issues related to rate design and the Company's rate proposals in Docket Nos. 2013-00168, 2018-00194, and 2021-00325.

Q. What did the Commission order in Docket No. 2013-00168?

A. The Commission concluded:

- That customers that pay demand charges continue to pay distribution demand costs based on the customer's highest demand in each month within a given diurnal period (customer non-coincident peaks). However, the Commission acknowledged that existing diurnal periods reflected in CMP's rate design may not align well with cost differentials and would be re-examined and potentially revised in a future proceeding to be conducted in conjunction with the development of a new billing system.
- That distribution demand rates for all rate classes with existing demand charges should be twenty percent higher in July and August than in the other ten months of the year.
- That an optional demand rate should be developed for the residential and small general service customer classes subject to a review of billing system costs.[30]
- That consideration of the capabilities of CMP's new customer billing system should include allowing for demand rates that vary with each month and within a more flexible set of diurnal periods.

[30] The Commission reasoned that 1) demand charge based rates would provide superior price signals given that distribution system costs are driven by demand rather than energy usage and 2) demand charges may reduce customer confusion by more clearly delineating between kWh-based supply charges and kW-based delivery charges. See: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7b23D813ED-0229-4F03-B718-71700E5847DF%7d&DocExt=pdf&DocName=%7b23D813ED-0229-4F03-B718-71700E5847DF%7d.pdf at 18-19

- That the customer charge applicable to the optional Super Saver and Savings Plus programs shall be set to equal the customer charge for Rate A-TOU.[31]

Q. What did the Commission order in Docket No. 2018-00194?

A. In Docket No. 2018-00194, the Company proposed phased increases to the customer charge for residential and Small General Service (SGS) customers, an optional demand charge for residential and SGS customers, and refreshed seasonal and TOU periods for each class taking service on a time-differentiated rate schedule. The Commission declined to adopt the Company's proposals, finding that it was an inopportune time to redesign rates given the results of recent Commission investigations. These investigations found that mismanaged implementation of the Company's billing system had led to billing errors and caused customer confusion and distrust, and that "customer service in recent years had been unreasonable and imprudent, leading to customer dissatisfaction and confusion."[32] As such, the Commission found that rate stability was needed to mitigate against heightened customer confusion. In addition, the Commission found that the $1.8M cost of the Company's demand charge and TOU proposals appeared high

[31] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7b23D813ED-0229-4F03-B718-71700E5847DF%7d&DocExt=pdf&DocName=%7b23D813ED-0229-4F03-B718-71700E5847DF%7d.pdf

[32] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7bDE349FF6-C112-4FAE-A86E-CDAC6129A5C2%7d&DocExt=pdf&DocName=%7bDE349FF6-C112-4FAE-A86E-CDAC6129A5C2%7d.pdf at 9

given the relative benefits of the Company's rate proposals and the potential to exacerbate customer confusion.[33]

Q. What did the Company agree to in Docket No. 2021-00325?

A. In the stipulation approved in Docket No. 2021-00325, the Company agreed to several provisions related to encouraging beneficial electrification and customer adoption of distributed storage technologies, including:

- Changes to Rate A-LM: The Company agreed to remove restrictions on which end use devices may qualify and to allow customers to enroll in the rate as a separately - metered service while using existing TOU periods.
- Changes to Rate A-TOU-OPTS: The Company agreed to modify pricing in accordance with the MCOSS filed in Docket No. 2018-00194 and to file the optional rate as an interim whole-house tariff to encourage beneficial electrification technologies while developing a long-term tariff that better reflects contributions to peak demand.
- Changes to Rate B-DCFC: The Company agreed to phase-in expanded eligibility to all EV charging stations and remove all end-use restrictions such that all MGS, IGS, and LGS customers may enroll as a whole-facility rate.

[33] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7bDE349FF6-C112-4FAE-A86E-CDAC6129A5C2%7d&DocExt=pdf&DocName=%7bDE349FF6-C112-4FAE-A86E-CDAC6129A5C2%7d.pdf

- Conducting an Updated MCOSS: The Company agreed to conduct an updated MCOSS and proposed updated TOU periods in its current distribution rate case.
- Piloting a Residential Heat Pump Rate: The Company agreed to pilot a heat pump rate, which was approved by the Commission in October 2022 and consists of flat hourly rates differentiated by season. The rate will be in effect until October 31, 2024 or until the adoption of a replacement residential beneficial electrification rate by the Commission.[34]
- Embedded Metering: The Company agreed to work with Efficiency Maine Trust (EMT) and other stakeholders to learn about possible uses of embedded metering including for billing purposes.
- Continued Stakeholder Discussions: The Company agreed to hold continued discussions about further improvements to the Company's rate design that would provide better incentives for the growth of beneficial electrification.

B. Advanced Rate Design (ARD) Evaluation Framework

Q. Can you describe your approach to evaluating rate design?

A. Yes. Our framework for evaluating rate design, including the Company's proposal, reflects the following principles:

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[34] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7b6334203C-0A27-415C-96AF-4793FB476FB5%7d&DocExt=pdf&DocName=%7b6334203C-0A27-415C-96AF-4793FB476FB5%7d.pdf

- Tariff diversity: As we enter the energy transition, each customer class should have a suite of tariffs to choose from so that they can best achieve customer and grid benefits.
- Balance cost causation with policy goals: Tariffs should be informed by both traditional rate design principles, such as reflecting cost causation, and by state policy goals.
- Simple default tariffs: Default tariffs should reflect cost causation and state policy goals with the least amount of complexity reasonable for a given customer class.
- Clear objectives and metrics: Tariffs should be designed with specific objectives in mind, such as energy shifting or demand reduction or combinations of grid services (e.g., a TOU with a critical peak pricing component). Each objective should be linked with metrics to ensure the tariff is achieving the stated objective and to track the utility performance with respect to load management. Metrics can vary in complexity depending on the objectives and priorities of the Commission. However, each optional tariff should have a set of tracking metrics which the utility reports on an annual basis, at a minimum.
- Iterative rate design process: As experienced in Maine, policy goals shift and market prices change rapidly. The only way to integrate distributed resources and successfully manage electrification more cost effectively will be to create more nimble and iterative rate design processes that can be quickly re-adapted to reflect evolving policies and grid conditions.

We have used this high-level qualitative ARD framework to evaluate many of the Company's rate design proposals.

C. The Company's Proposals

Q. Please summarize the Company's rate proposals.

A. The Company proposes a range of rate design proposals, including:

- Updated TOU hours for all time-differentiated rate schedules and beneficial electrification rates to reflect shifting system peaks;
- Optional, updated TOU rates for residential and SGS customers with time-differentiated cost recovery of the distribution expenses that are not allocated to the service charge, and elimination of current Rate-A TOU and Super Saver options;
- New, optional rates for residential and SGS classes with time-differentiated recovery of transmission costs, via a demand charge, available to be taken either as a whole-house rate or, on a separate meter, for just EV charger(s) or other dedicated load;
- Updated monthly service charges for all customer classes, including a $5/month increase in Rate Year 1, a $2/month increase in Rate Year 2, and an additional $2/month increase in Rate Year 3 for residential and SGS customers;
- Expanded eligibility for Rate A-LM to all technologies;
- Redesigned C&I rates to align with new TOU hours;

- Expanding eligibility for Rate B-DCFC to all demand-billed customers.[35]

Q. Are the Company's proposals generally reasonable?

A. The Company's efforts to develop rates and price signals that reflect shifting system peaks and incentivize more efficient grid utilization appear to be substantive.

However, the Company has not sufficiently justified the cost of the proposals. In Docket No. 2018-00194, several stakeholders argued, and the Commission found, that the $1.8M cost of the Company's TOU and demand charge proposals appeared high.[36] In the current docket, the Company has proposed spending $2.35M to implement its proposals. The Company should explain why the benefits of its proposals are worth this even greater cost.

Q. What do you recommend regarding CMP's rate proposals?

A. We recommend that the Commission:

1. Reject CMP's residential service charge increase; and
2. Establish an advanced rate design proceeding and process.

We also recommend that CMP:

3. Consider net load in its TOU period selection;

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[35] Marini, Laiho, Rauch, and Smith Direct Testimony

[36] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7bDE349FF6-C112-4FAE-A86E-CDAC6129A5C2%7d&DocExt=pdf&DocName=%7bDE349FF6-C112-4FAE-A86E-CDAC6129A5C2%7d.pdf

4. Increase the on- to off-peak price differential for the optional TOU rate;
5. Develop additional options for non-firm customers capable of deferring T&D infrastructure upgrades; and
6. Provide more information to justify the high cost of its proposals, including breaking out the cost of the demand-based rates for residential and SGS customers.

We describe each recommendation further in the questions below.

Residential Service Charge

Q. How does CMP justify its residential service charge increases?

A. CMP notes that the "increases are supported by the MCOS study"[37] which "supports collecting both customer-related (services, meters, customer-related functions) and local facilities (transformers, secondary lines, local primary lines) costs through the service charge."[38]

CMP also generally advocates for increasing fixed charges under a marginal cost framework, claiming that the best way to achieve a class revenue target – when marginal cost rate components alone do not achieve the target – is to increase "the least elastic components of the rates, namely the fixed charge, or the facilities charges, which allows

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[37] Marini, Laiho, Rauch, and Smith Direct Testimony at 25.
[38] Marini, Laiho, Rauch, and Smith Direct Testimony at 24.

keeping the kWh charge or metered demand charge as close as possible to marginal costs."[39]

Q. Do you disagree with CMP's customer charge increase and justification?

A. Yes, for several reasons: 1) CMP's MCOSS does not support a higher service charge; 2) CMP's economic analysis is overly focused on utility revenue stability without sufficiently considering policy goals and impacts on all low-income customers; and 3) revenue stability should not be a primary justification for a rate design.

First, as we discussed in Section IV on Cost of Service, it is not appropriate to collect local distribution facilities costs through a monthly service charge. Customer peak demand is not static; it interacts dynamically with the ability of local facilities to serve a number of customers. Therefore, costs should not be collected via a fixed monthly charge but rather should be used to send a price signal to customers.

Second, CMP's focus on raising fixed charges is not about economic efficiency, but rather about revenue assurance. It may be most socially desirable to align rates with the costs to the grid of meeting load at a specific time and location, rather than to bury price signals in a large fixed charge. The existing grid is designed to have enough electricity to meet peak demand at any time, even if that peak occurs for only a couple minutes a few times a year, and then much of that infrastructure is under-utilized the rest

[39] Nieto Direct Testimony at 8.

of the year. It would be economically efficient to maximize the utilization of the existing grid, and rate design decisions that prioritize Maine's energy goals – such as energy efficiency and load management – could incentivize this economic efficiency, rather than utility revenue stability. The decision of how utilities collect fixed costs, beyond those that are customer specific marginal costs, should factor in policy goals and other tradeoffs.

Third, the Company's proposal suggests that it is more focused on revenue stability than on other policy objectives. However, other regulatory mechanisms – such as revenue decoupling – already serve the objective of revenue stability. Revenue assurance is better addressed elsewhere outside of rate design rather than distorting price signals and impeding achievement of state policy goals and grid benefits.

Q. Please provide an example of a policy objective that the Company has deprioritized by proposing to raise the monthly service charge.

A. Maine statute sets a goal for the procurement of 750 MW of distributed generation under net energy billing programs.[40] A higher residential service charge will likely reduce the relative financial incentive of shared Distributed Generation (DG) for customers and therefore hinder the ability to achieve this policy goal. Because fixed charge increases are offset by corresponding decreases in volumetric energy rates, increasing fixed charges

[40] 35-A MRS §3209-A (7)

increases the payback period – thus decreasing the economic attractiveness – of investment in distributed generation. For the same reason, lower volumetric rates decrease the economic attractiveness of investing in energy efficiency upgrades and do not encourage conservation relative to higher volumetric rates. With that said, we do understand that electrification may benefit from higher fixed and lower volumetric rates; however, this can be achieved through an optional tariff.

Q. Would increasing the fixed charge harm low-income customers?

A. Yes. Increasing the fixed charge would disproportionately harm low-income customers because, all else equal, low-income customers tend to use less electricity than higher income residents, and often face a higher energy burden, that is, a larger percentage of the household budget that is allocated to energy costs when compared to other customers. When this is true, increasing fixed charges shifts costs onto lower income residential customers, increasing their energy burden and producing a highly regressive energy cost structure. The Company's aggressive proposal to increase fixed charges by 86% over three years[41] would be particularly burdensome.

The Company appears to suggest that customers enrolled in the Low Income Home Energy Assistance Program ("LIHEAP") and the Company's Electricity Lifeline Program ("ELP") are not necessarily low-usage.[42] The subset of customers receiving

[41] The total proposed increase of $9 divided by the current $10.48 base distribution service charge equals 86%.
[42] Marini, Laiho, Rauch, and Smith Direct Testimony at 28-29.

energy assistance, while perhaps the only proxy for income available to the Company, is not an appropriate sample to draw conclusions about energy usage among low-income customers as a whole. In Docket No. 2018-00194, OPA used EIA data to demonstrate a strong relationship between income and electricity consumption in New England, and importantly, "that customers with incomes between $20,000 and $39,999 who receive energy assistance tend to use almost twice as much electricity as non-recipients with the same income range."[43] In addition, it is notable that only 21 percent of eligible households in Maine receive LIHEAP assistance.[44] The Company's focus on the subset of customers who receive assistance is not an appropriate justification for a proposal that would disproportionately harm low-income customers not receiving assistance.

Finally, the Company appears to justify its proposal by noting that some low-usage customers are not low-income, such as those owning seasonal or vacation homes.[45] The fact that not every low usage customer is low-income does not address our central concern: that many low-income customers *are* low usage and would thus be disproportionately harmed by the Company's proposal.

Q. Do you recommend that the Commission reject the residential service charge increase?

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[43] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={E038A096-2F45-4633-87D7-2B3DCB7C5330}&DocExt=pdf&DocName={E038A096-2F45-4633-87D7-2B3DCB7C5330}.pdf at 8, lines 2-4
[44] https://neuac.org/wp-content/uploads/2021/02/Maine-State-Sheet-2022.pdf
[45] Marini, Laiho, Rauch, and Smith Direct Testimony at 28

A. Yes. Given the equity implications and importance of price signals that serve policy goals, there are likely better ways to design rates. For example, instead of raising the fixed charge for the optional TOU rate, CMP could collect its revenue requirement by increasing the on- to off-peak ratio to bring it closer to 3:1. A recent report found that low and moderate income customers responded to TOU price signals as much or nearly as much as other customers, and enjoyed similar levels of bill savings.[46] CMP could evaluate – via the ARD process that we recommend below – the benefits of a widespread TOU rate as opposed to increased fixed charges.

TOU Periods Informed by Net Load

Q. How does the Company justify its proposed TOU period?

A. According to the Company, the new TOU periods are designed to reflect shifting system peaks and to reduce transmission expenses for all customers. The Company notes its growing regional load ratio share and resulting increase in Regional Network Service ("RNS") (i.e., regional transmission expenses) passed to all Maine customers, and that "load and distributed generation on CMP's system is evolving and anticipated to continue to change due to policy efforts to advance distributed energy resources and beneficial

[46] https://www.brattle.com/insights-events/publications/study-by-brattle-economists-evaluates-time-of-use-tou-pilots-for-maryland-utilities/

electrification technologies."[47] The Company claims that its current TOU periods fail to send price signals that incentivize consumption away from system peaks.

Q. Do you have any recommendations regarding the Company's proposed TOU periods?

A. Yes. We recommend that the Company's new TOU periods be informed by net load.

Q. What is net load?

A. Net load is a utility's aggregate load (electricity demand) minus renewable energy generation.

Q. Did the Company consider net load when developing its revised TOU period proposal in the current docket?

A. Based on direct testimony, CMP did not utilize net load data when evaluating the likelihood of system peak load in order to define TOU periods.[48]

Q. Why do you recommend that the Company's revised TOU periods be informed by net load?

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[47] Marini, Laiho, Rauch, and Smith Direct Testimony at 13-14, lines 22-3

[48] The Company did not specify that net loads (which subtract utility-scale solar and wind) were considered when discussing the load data it used for its analysis – only that it accounted for behind-the-meter solar. *See* Nieto Direct Testimony at 22-23 and 25. We have issued discovery with the Company to confirm this assumption.

A. Increased electricity supply from zero-marginal-cost renewable resources means that net load is more likely than aggregate load to drive system costs into the future. In addition, aligning TOU periods with net rather than aggregate loads can incentivize emissions reductions because net loads incorporate the hours in which renewables are (or are not) on the margin – thereby helping achieve state policy goals. CMP should at least consider the impacts of clean energy integration on supply and transmission constraints.

On- to Off-Peak Price Differentials

Q. Are the Company's on- to off-peak price differentials sufficient to incentivize shifting consumption towards off-peak periods?

A. We estimated on- to off-peak price differentials for residential customers by adding 2023 supply costs, which are $0.176310/kWh in 2023,[49] to the Company's A-TOU proposal for Rate Year 3. As indicated in Table 1 below, this yields an on- to off-peak ratio of 2.3:1 and a shoulder to off-peak ratio of 1.2:1.

Table 1: Rate A-TOU Price Differentials

	RY3 $/kWh + 2023 Supply	**Ratio to Off-Peak**
On-Peak, Jul-Aug & Dec-Feb	0.501984	2.3
Shoulder	0.262667	1.2
Off-Peak	0.222023	1

[49] https://www.maine.gov/mpuc/regulated-utilities/electricity/standard-offer-rates/cmp

Although we do not find this price differential to be unreasonable, increasing the differential would send a stronger price signal. A general rule-of-thumb is that on- to off-peak price differentials of approximately 3:1 can sufficiently balance incentives for off-peak consumption with acceptability to customers.

Non-Firm Customer Rate Option

Q. Are there any additional tariffs that the Company should offer?

A. Yes. The Company should develop additional tariffs to facilitate non-firm customers in deferring T&D infrastructure upgrades. For example, Southern California Edison's (SCE) Wholesale Distribution Access Tariffs (WDAT) was designed to better integrate energy storage systems by allowing connecting customers to choose portions of non-firm and firm capacity during the line extension or interconnection process, allowing the utility to avoid T&D infrastructure upgrades to serve what would otherwise be firm capacity requirements. This is essentially a form of locationally-specific demand response which can be applied to other technologies including EV charging equipment co-located with energy storage. This tariff would also facilitate Maine's policy goals to deploy 300 MW of energy storage by 2025 and 400 MW by 2030,[50] and align with the GEO's findings, through its legislatively mandated Energy Storage Market Assessment, that adjustments

[50] 35-A MRS §3145

to customer rate design that align customer price signals with societal avoided costs and locational values would support achievement of these goals.[51]

It appears that the Company's investments in real-time visibility and automation should make these tariffs possible. If the Company is not able to offer these tariffs, additional review of the Company's investments should be conducted, as the benefits received by ratepayers will be greatly diminished without such tariffs.

Demand Charges for Residential and SGS customers

Q. Are the Company's demand charge proposals for residential and SGS customers reasonable?

A. The Company has proposed optional rates that would recover transmission costs through on-peak demand charges for both residential customers and SGS customers, and which would be available as standard time-of-use rates (Rates A-TOU-OPTS and SGS-TOU-OPTS) or as rates designed to encourage electrification (Rate A-LM-OPTS). In other jurisdictions, we have not found demand charges to be successful in attracting residential customers nor have they been found to be understandable by these customers.[52] However,

[51] https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/GEO_State%20of%20Maine%20Energy%20Storage%20Market%20Assessment_March%202022.pdf

[52] For example, see: Pennsylvania Public Utility Commission, Docket No. R-2021-3024750, OCA Statement No. 6-SR, Surrebuttal Testimony of Ron Nelson on Behalf of the Office of the Consumer Advocate (August 10, 2021), pp. 18-21

given that the rate is optional, we would not oppose it unless it would be costly to implement.

Q. Do you have any recommendations regarding the Company's demand charge proposal for residential and SGS customers?

A. We recommend that the Company provide additional details in rebuttal on the cost of its demand charge proposals for residential and SGS customers, specifically. If the proposal is found to be too costly or is not attractive to customers, one alternative could be to spread transmission expenses across shoulder and on-peak energy (per kWh) rates.

D. Improving Future Rate Designs Through an Iterative ARD Process

Q. What is your impression of the Company's efforts to iterate on rate design proposals?

A. The Company's proposals demonstrate iterations on rate design; however, many of the Company's proposals were developed in response to a Commission order and findings from 2014. The power grid is continuing to evolve at pace that will require a much nimbler process in which rates are updated in far less than eight years. The Company and stakeholders appear to have had multiple iterative exchanges on the issue of Advanced Rate Design (ARD). Formalizing an ARD process that occurs outside of, but in coordination with, rate cases may result in improved clarity (e.g., explicitly stated goals), lower administrative burden, and better outcomes. For example, Hawaii recently completed its first iteration on its ARD proceeding that resulted in the formation of an iterative process and platform to evaluate all default and optional tariffs across customer types. An ARD proceeding would provide a structured, nimble, and comprehensive process to consistently re-align rates with the needs of an evolving power grid.

Q. Can you provide a high-level overview of an ARD process?

A. Yes. An ARD proceeding can ensure efficiency and consistency by consolidating initiatives that are currently scattered across multiple dockets into a single proceeding, facilitate regular opportunities for iteration and re-alignment with the needs of an evolving power grid, and provide opportunities for stakeholders to advise on rate modifications in ways that are streamlined and less resource intensive (for often resource-constrained stakeholders) than intervening in numerous dockets.

An ARD process could include an overhaul to existing rate design and put in place an iterative process that incorporates feedback from multi-stakeholder working groups. The Commission could (through the working groups and any additional procedural steps) examine, evaluate, and make determinations to inform successive phases of TOU rate rollout. In certain jurisdictions, such as Hawai'i, the ARD Framework is rolled out in phases of implementation, as additional technologies become available and increasing quantities of load profile data (from advance meters) becomes attainable.

Q. Would an ARD process facilitate the development of load management programs?

A. Yes. An ARD process would enable stakeholders to develop and consistently evaluate both passive and active load management programs, including identifying goals and metrics, through a structured, unified proceeding.

Q. Can you provide additional detail on the ARD process that occurred in Hawai'i?

A. Yes. In Hawaii, the Commission initiated an ARD process, noting that "rate design is … intertwined with growing market-based service opportunities and may further be enabled by newer and more advanced metering technology," and to ensure dockets are harmonized to prevent overlap and conflicting outcomes. The Hawaii PUC also noted the need to integrate load management offerings to derive customer benefits from grid modernization efforts, including advanced meters, and resource planning related investments.

The Hawaii PUC's ARD process has and will, among other things, include: a timeline for the Companies to offer updated dynamic rates for all residential and commercial customers (including, the introduction and/or evaluation of time-varying rates, critical peak pricing, real time pricing rate structure, and DER grid service programs), potential rate reform considerations to support low-income customer participation, and evaluation plans for monitoring, verifying, and improving the effectiveness of advanced rate designs. Additionally, the ARD process evaluated underlying embedded and marginal costs to better inform rate and program priorities as well as cost allocation approaches. The ARD process is envisioned to be an iterative process to improve rates and programs inside and outside of multi-year rate cases.

VI. Grid Modernization

Q. What is the purpose of this section of your testimony?

A. How grid modernization is defined and process by which it is implemented will play a significant role in whether Maine can achieve its clean energy goals both expeditiously and cost-effectively. Strategen proposes a grid modernization framework and implementation plan to avoid the pitfalls of previous utility proposals for the Commission's consideration. We then leverage the proposed framework and implementation plan to evaluate the Company's grid modernization proposals including the (1) Electric Vehicle program, (2) Grid Model Enhancement Project (GMEP) and (3) CMP Innovation Pilots, Partnerships and Collaborations.

A. A comprehensive framework for grid modernization proposal

Q. Please explain the term "grid modernization."

A. The Company currently plans, invests in, and operates the distribution system leveraging a certain set of grid capabilities to provide customers safe, affordable and reliable service. Grid modernization entails determining how these grid functions and capabilities should be modernized to support Maine's energy goals and prepare for the impacts of climate change.

Q. Please describe the pitfalls of previous grid modernization proposals in other jurisdictions.

A. Grid modernization proposals typically consist of a wide variety of proposed investments in hardware (to collect and process data), communications networks (to transmit data) and software (to monitor, analyze data, and control). While these categories of investments are generally appropriate, utility proposals often fail to meet their intended objectives for a variety of reasons. First, it can be unclear what broader grid outcomes the proposed investments intend to enable and how each investment correlates to said outcome. Second, it can be unclear what new planning and operational capabilities the investments intend to enable and how each investment correlates to each new capability. Third, it can be unclear what the utility's grid design and architecture is and specifically how the utility's current systems and various proposed grid modernization investments in hardware, communications networks and software work together to enable new planning and operational capabilities. This poses a significant risk of siloed, duplicative, and costly investments. For example, a utility may propose investments in line sensors to gain increased visibility into feeders but also propose deploying advanced metering infrastructure (AMI) which may be able to provide the same capability. Similarly, utilities often propose to deploy multiple communication networks with insufficient consideration for whether a single (or fewer) communication network(s) could be used to support the capabilities and outcomes they intend to enable. Finally, it is unclear what outcomes and capabilities utilities can enable with existing technologies and how these outcomes and capabilities will become more advanced over time as new investments are made.

Q. How can Maine avoid the pitfalls of grid modernization proposals in other jurisdictions?

A. Maine can avoid these pitfalls by leveraging a comprehensive framework and process to ensure that grid investments are considered together as part of one comprehensive grid design and architecture while being clearly mapped to planning and operational capabilities as well as grid outcomes. This is the intention of the integrated grid planning stakeholder process established by P.L. 2022 ch. 702, and we recommend that the Commission does not approve any multi-year rate plan until that stakeholder process is completed. The specific structure of that process has not yet been defined in Docket 2022-00322, and we recommend the following components be incorporated:

1. **Define grid outcomes:** Clear grid outcomes (clean energy, resiliency, reliability, and customer benefits etc.) with phased goals should be defined upfront so that the associated planning, operational and grid-design & architecture roadmaps can be developed to support these phases. For example, the Maine's energy storage goals including reaching 300 MWs of installed capacity by 2025 and 400 MWs by 2030. With these clear storage targets, the planning, operational and grid-design & architecture roadmaps can be developed to support the 2025 and 2030 storage goals.
2. **Develop grid planning capabilities roadmap to support outcomes:** Grid planning capabilities should be defined based on what is required to achieve each phase of the defined outcomes. For example, the Company will likely need to develop a maturity roadmap for conducting hosting capacity analysis based on the

outcomes. **S**tatic hosting capacity analysis, which are often based on worst case assumptions and not calculated to the degree of granularity necessary to reflect every grid level, from feeder node to substation (but rather as a single value per feeder),[53] may be sufficient to support the 2025 storage goals. However, as storage penetration increases to meet 2030 goals, the utilities may need to improve the sophistication of the methodology and leverage dynamic hosting capacity analysis, which represents the concept of calculating the hosting capacity for a specific location in the distribution grid in real-time at given time intervals.[54] This level of granularity will be critical to understand the true hosting capacity of the system and utilize the distribution system as efficiently as possible to accommodate DERs.

3. **Develop grid operational capabilities roadmap to support outcomes:** Grid planning capabilities should be defined based on what is required to achieve each phase of the defined outcomes. For example, the Company will likely need to develop a maturity roadmap for how they optimize and coordinate across third party storage assets and DERs more broadly. Curtailments and autonomous inverter functions may be sufficient to support the initial deployment of storage. However, as storage and DER penetration overall increases, the Company will

[53] Opus One Solutions, Dynamic Hosting Capacity, A dialogue on extracting distribution maximum value from interconnected Distributed Energy Resources for distribution utilities and customers, at 3.
[54] Electric Power Research Institute, Understanding Flexible Interconnection, at 3.

likely need to investigate new technologies and control approaches to coordinate across thousands and potentially millions of third-party DERs.

4. **Develop grid architecture roadmap to support planning and operational capabilities:** Finally, the grid architecture should be defined based on what is required to achieve each phase of the defined planning and operational capabilities roadmap. Specifically, an understanding is needed of what visibility and control of the distribution system is currently available vs. what is needed. A grid architecture roadmap should be developed where the Company and stakeholders (1) assess how the Company's existing hardware, communications networks and software (ADMS, DERMS, AMI, line sensors etc.) can work together to enable the defined planning and operational capabilities, (2) assess what a future grid architecture should look like to support the phased objectives and (3) identify key technological investments in hardware, communications networks and software that will be needed to support these objectives.

We also note that the Electric Power Engineers' reports in Docket 2021-00039 provides a good starting and reference point to inform the grid modernization process described above.

Q. How should Maine implement the grid modernization framework once this process is completed?

A. Maine need not wait for new grid modernization investments to begin achieving its ambitious clean energy goals – the Company's existing capabilities can drive basic clean energy outcomes today. Any implementation plan should balance what basic outcomes can be achieved with existing capabilities while upgrading capabilities over time to drive more advanced outcomes. We recommend the following implementation process:

1. **Leverage existing visibility and control systems to drive a basic set of grid outcomes:** Driving grid outcomes ultimately depends on the visibility the Company has into the distribution system and the accuracy of the grid models providing that visibility. This will determine the Company's ability to make precise planning and operational decisions. While the Company's grid models may not be entirely accurate, this should not preclude the Company from using the visibility available to drive grid outcomes even if they are more conservative decisions. Thus, the Company should leverage existing systems to drive grid outcomes as well as planning and operational capabilities in parallel to any upgrades being made to their systems.
2. **Open access to energy data to enable market-driven clean energy solutions:** Various key stakeholders require access to different types of energy data to perform their respective roles. DER companies require access to customer, system, and market data to identify opportunities for and ultimately deploy DER solutions. Stakeholders involved in the distribution planning process require system data to review the Company's proposals. State government agencies and entities delivering services and programs, such as Efficiency Maine Trust, may also require system data to understand the Company's progress on achieving Maine's energy goals. By making this information available upfront, all of these

key stakeholders can effectively play their respective roles in modernizing the Company's grid and achieving Maine's clean energy goals. While some of this data (ex: system data) may not be entirely accurate, this data can be updated over time as the grid models become more accurate and more granular data is made available from new investments.

3. **Upgrade capabilities over time to drive advanced grid outcomes:** In parallel to implementing steps 1 & 2, the Company can begin making investments based on the grid architecture roadmap to support the grid planning & operational capabilities roadmaps. To start, the Company should ensure that their grid models providing system visibility are up to date and accurate by assessing the accuracy of their current grid models and develop a sustainable, scalable approach to keep these models updated to inform grid planning & operations as well as clean energy market activity.

B. Electric Vehicle Programs

Q. What is your understanding of the Company's request for EV program cost recovery?

A. Our understanding is that the Company has not included the EV program costs within the Rate Plan request, but these costs would be subject to a proposed capital adjustment mechanism. We discuss the capital adjustment mechanism later in our testimony.

Q. How does your proposed grid modernization framework relate to the Company's electric vehicle proposal?

A. Electrifying the transportation sector is a critical grid outcome to achieve Maine's energy and climate statutory requirements and goals. Each of the components (grid planning, operations, architecture, etc.) in our proposed framework are critical to cost-effectively and expeditiously achieving this outcome. Specifically, when developing an EV proposal, an initial plan should be included for each of these components as they are interrelated to and interdependent on each other. Failure to take this comprehensive approach may slow the pace of transportation electrification, lead to stranded assets and a lack of future-proof strategies, and ultimately increase costs for ratepayers. Thus, we evaluate the Company's proposal based on the proposed grid modernization framework to determine whether they comprehensively considered EV outcomes, planning and operational capabilities and grid architectures as part of their proposal.

i. Outcomes

Q. Does the Company identify specific EV-related outcomes as part of their proposal?

A. Yes. The Company's proposed Light-Duty EV Make-Ready and Medium- and Heavy-Duty EV Make Ready Program are intended to support policy goals set forth by the Maine Climate Action Plan, which sets targets to achieve 41,000 light-duty EVs as quickly as 2025 and 219,000 by 2030, as well as to increase the share of zero-emission vehicles in the medium- and heavy-duty sector to 12% in 2025 and 55% by 2030.[55] For the Light-Duty EV Make-Ready Program, the Company used the U.S. Department of Energy ("DOE") EVI-Pro Lite tool to estimate the number of EV chargers required to meet these goals, estimating Maine would need to install 1,676 L2 workplace charging ports, 1,236 publicly accessible L2 charging ports, and 303 L3 charging ports to meet the 2025 goals. With an assumed 80% of the statewide EV charger need located in CMP service territory, 2,000 L2 charging ports and 138 L3 charging ports will be needed in CMP service territory. For the Medium- and Heavy-Duty EV Make-Ready Program, the Company proposes to support up to 300 new electric school bus chargers, 15 electric transit bus chargers, and 100 chargers for other vehicles such as refuse vehicles and delivery vehicles.[56] However, the Company does not explain how it arrived at these figures.

Q. Do you have concerns with the Company's assumptions on EV outcomes?

A. No. We find that leveraging the Maine Climate Action Plan EV targets and the DOE EVI-Pro Lite tool to estimate the number of EV chargers to be a reasonable approach to establish clear outcomes when developing an EV proposal. As part of evaluating the Company's EV proposal, our recommendations address what is necessary to achieve the

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[55] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 6, 12-15.
[56] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11, 1-6.

first phase of Maine's transportation electrification goals which sets targets for Mainers to adopt 41,000 light-duty EVs as quickly as 2025.

Q. Are there additional assumptions on EV outcomes the Company should consider in their EV proposal?

A. Yes. We recommend the Company should incorporate Maine's National Electric Vehicle Infrastructure (NEVI) plan into their assumptions for their EV proposals. Based on the Company's direct testimony, it is unclear whether NEVI was considered at all. NEVI should factor heavily into the timing and prioritization of utility EV investments and this requires coordination with Maine's Department of Transportation as well as Efficiency Maine Trust who are coordinating the NEVI program with the GEO.

ii. Grid Planning

Q. Does the Company address grid planning for EVs as part of their proposal?

A. Yes. The Company proposes both a (1) Light-Duty EV Make-Ready Program; and (2) a Medium and Heavy-Duty EV Make-Ready program. The Company also proposes dedicated funding to support studies and analysis related to EVs and their potential system impacts.[57] Finally, the Company proposes to scale an EV fleet assessment tool it is currently piloting, if successful, to all fleet customers.[58]

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[57] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11, 16-17.
[58] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11-12.

Q. Please describe the Company's proposed Light-Duty EV Make-Ready Program.

A. The Light-Duty EV Make-Ready Program would cover a percentage of utility-side electrical infrastructure costs for publicly accessible charging sites as well as charging sites at workplaces and multi-unit dwellings ("MUDs").[59] The bottom 50% of areas (either zip code or census tract) in terms of average or median income (for the zip code of the census tract where the property is located) would be eligible to receive an incentive up to 100% of the utility-side make-ready cost, and the top 50% of areas in terms of average or median income would be eligible to receive an incentive up to 80% of the utility-side make-ready cost.[60]

Q. Do you have concerns with the Company's proposed Light-Duty EV Make-Ready Program?

A. Yes. First, the Company does not describe whether or how it will promote managed charging. Second, the current incentive structure does not incentivize the use of ALM (also known as EV Energy Management Systems) by customers to limit ratepayer funding for make-ready costs. Third, the program does not prioritize chargers located at publicly accessible locations. Finally, the program's proposed graduated incentive structure does not address disadvantaged communities (DACs) holistically enough.

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[59] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 8-9.

[60] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 8-9.

Q. Why is managed charging important for EVs?

A. EVs are more flexible than many other traditional loads, meaning that in most cases, the customer, utility, or another third party (e.g., aggregator, fleet operator, etc.) can control the timing and speed of charging (or discharging, through vehicle-to-grid, or V2G, technology). If customers are sufficiently educated and provided useful managed charging offerings, the flexibility of EV load could help reduce rate pressure by spreading rates over more sales units and minimize peak demand impacts on the grid. The availability of rates and programs that incentivize managed charging also allows customers to align their charging with grid needs and save on charging costs, thereby lowering the total cost of ownership of EVs and facilitating transportation electrification.

On the other hand, if unmanaged, he majority of EV load could occur during peak periods and create considerable rate pressure by not only necessitating a significant infrastructure buildout to accommodate the higher system peak load but also consuming energy when prices are the highest. A study conducted in 2020 by the Lawrence Berkeley National Laboratory suggests that California can save between $90 to $690 million, or up to 10%, of total grid operating costs by 2025 with managed charging compared to a scenario with only unmanaged charging, saving about 50% of the incremental cost of adding the new EV loads to the grid.[61] While these figures may not be directly applicable to Maine, they illustrate the potential impacts of unmanaged EV load.

Q. What are your recommendations regarding managed charging?

A. While utility support for infrastructure deployment can be useful in certain instances, managed charging should be a central priority. The Company should detail in its rebuttal testimony the rates and programs it will leverage to provide EV customers with incentives for managed charging.

Q. What is Automated Load Management (ALM)?

A. ALM, also referred to as EV Energy Management Systems, includes a range of behind-the-meter software and hardware approaches to limiting EV charging load demand at the service connection, such as distributing charging capacity among multiple charging ports at the same charging site or co-location with battery energy storage. ALM helps safely connect multiple charging ports whose total nameplate load would otherwise exceed the rated capacity of the customer connection. This capability may in turn avoid or defer the need to upgrade certain customer-side and utility-side infrastructure to accommodate the

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[61] Julia K. Szinai, et al., Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management, Energy Policy, Vol. 136 (January 2020) https://doi.org/10.1016/j.enpol.2019.111051.

new EV charging load, saving both time and money.[62] Widespread deployment of ALM may lead to significant savings for ratepayers and ensure that investments in transportation electrification are used efficiently, as well as accelerate the speed at which charging infrastructure can be deployed.[63] Unlike managed charging, which limits the ongoing costs that EV charging load can cause to the grid, ALM specifically refers to the use of load management technologies to limit the need to upgrade the customer's grid connection.

Furthermore, ALM can have equity benefits. Many low-income customers may be served by existing utility infrastructure that may require significant and costly upgrades to be able to accommodate EV charging load. The use of ALM may help mitigate these infrastructure upgrade costs and make charging infrastructure more affordable for such customers. ALM technologies are also particularly well-suited for multi-unit dwellings,

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[62] For example, if a multi-unit dwelling seeks to deploy a charging station with 5 ports, each with a 10-kW capacity, the distribution upgrades would normally be sized to accommodate 50 kW of incremental coincidental charging demand, equal to all 5 ports charging at full capacity. However, a software-based ALM approach can lower the coincident charging demand to 30 kW, or 6 kW per port on average, when all 5 ports are occupied, thus reducing distribution system upgrade requirements to what would be required for only 3 ports. In this scenario, when 3 or fewer ports are occupied, the EVs can still charge at full speed. Alternatively, a hardware-based ALM approach may involve the charging site being equipped with a stationary storage system that can offset the charging load when 5 ports are occupied, so that the grid only needs to support the charging load of 3 ports.

[63] For example, Pacific Gas & Electric has worked with EV service providers to implement EV EMS solutions at MUD and workplace host sites as of Q4 2020 and saved between $30,000 and $200,000 per project. *See* Pacific Gas & Electric, *Presentation at CPUC ALM/EV EMS Workshop*, Panel 2, 2021. Southern California Edison also implemented EV EMS to deploy 168 charging stations at $3,000 per port, significantly less than comparable deployments at $10,000-$15,000 per port without EV EMS. *See* EPIC Policy + Innovation Coordination Group, *Transportation Electrification Workstream Report,* 2021, epicpartnership.org/resources/Transportation_Electrification_Workstream_Report_Final.pdf.

workplace, and public charging sites, where low-income customers may be more likely to charge.

Q. How does the Company's proposed program not provide sufficient incentives for ALM?

A. As stated, ALM can help reduce or avoid both customer-side and utility-side make-ready infrastructure upgrades. Under normal circumstances (without a utility make-ready program), the customer installing EV charging is responsible for at least a portion of both customer-side and utility-side make-ready costs and therefore would have an inherent financial incentive to use ALM to reduce the cost of the installation on both sides of the meter. However, if the utility covers all utility-side costs via ratepayer funds as proposed by the Company, the customer is not responsible for any utility-side costs, thus has no incentive to reduce them and therefore shifts the costs to other ratepayers through rates. Thus, in cases where there is only cost saving potential on the utility side but not on the customer side, the customer would likely opt against ALM – forgoing any benefits to ratepayers – because it would not affect the customer's costs.

Q. What are your recommendations regarding ALM?

A. In order to maintain an incentive for the customer installing EV charging to limit both customer-side and utility-side make-ready upgrades, the customer should be exposed to both customer-side and utility-side costs. This can be accomplished by shifting some of the funds for utility-side costs towards customer-side costs such that CMP covers a fraction of total make ready costs, rather than 100 percent of utility-side costs.

Additionally, EV charging customers must be made aware of the cost savings potential of ALM approaches. To this end, CMP should, in coordination with stakeholders such as the GEO and Efficiency Maine Trust, develop a standard site evaluation methodology that would be applied to all EV charging sites during the preliminary site design process to determine if ALM can be used to cost-effectively meet the customer's charging needs.[64] If ALM is deemed suitable for a particular site, this information can then be communicated to the customer for the customer to review and make any modifications to the project before signing off on the construction of the charging site.

Q. Please provide your reasoning behind the third concern – that the program does not prioritize chargers located at publicly accessible locations – and any recommendations to resolve this concern.

A. Unlike publicly accessible charging sites, which provides access to EV charging for all segments of the EV driving public, charging sites located at MUDs or workplaces only benefit the residents or employees of those establishments. The incentives for which each

[64] See Pacific Gas & Electric's proposed site evaluation criteria, Electric Vehicle Charge 2 Prepared Testimony, Chapter 5, Attachment A, Case Number A.21-10-010, https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=675449.

site type is eligible should reflects the difference in the public benefit that each site type provides. Accordingly, publicly charging sites should be eligible for higher incentive levels than workplace and MUD sites in order to encourage the deployment of more publicly accessible charging sites.

Q. Please provide your reasoning behind the fourth concern – that the program's proposed graduated incentive structure linked to socio-demographics does not address disadvantaged communities holistically enough – and any recommendations to resolve this concern.

A. While we appreciate the Company's focus on equity, the proposed program could be further modified to provide stronger and more targeted support for disadvantaged communities. Instead of targeting the incentive levels only based on income, the Company should target incentives based on a more holistic definition of disadvantaged communities. Specifically, we recommend that the Company identify disadvantaged communities using the Council on Environmental Quality's Climate and Economic Justice Screening Tool, which designates specific census tracts as disadvantaged communities based on a combination of factors, including income, environmental, and other socio-economic and demographic factors.[65] This tool was also utilized by the Maine

[65] Council on Environmental Quality. Climate and Economic Justice Screening Tool. https://screeningtool.geoplatform.gov/en/#11.35/43.7057/-70.2486.

Department of Transportation in the state's NEVI Program implementation plan.[66] We also recommend that the Company targets at least 40% of the program budget towards disadvantaged communities in order to align with President Biden's Justice40 Initiative and the requirements of federal funding allocated through the Bipartisan Infrastructure Law and the Inflation Reduction Act.[67]

Q. Should the Commission approve the Company's proposed Light-Duty EV Make-Ready Program?

A. If the Commission approves a Light-Duty EV Make-Ready Program, the following modifications should be made:

- The program incentives should be restructured to cover a percentage of total make-ready costs, rather than a percentage of utility-side make-ready costs.
- The incentive levels should be modified to prioritize publicly accessible chargers, as well as chargers located in disadvantaged communities.
- The Company should target at least 40% of program funds towards disadvantaged communities.
- The Company should reallocate a significant portion of its charger deployment target for non-transit fleets towards the target for transit buses.

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[66] MaineDOT. Maine Plan for Electric Vehicle Infrastructure Deployment, pg. 38-41. https://www.efficiencymaine.com/docs/pevid-2022.pdf.
[67] https://www.whitehouse.gov/environmentaljustice/justice40/.

- The Company should explicitly, and in coordination with Maine's DOT and Efficiency Maine Trust, factor in Maine's approved NEVI plan and other ongoing programs and initiatives.
- The Company should address in detail in rebuttal testimony how EV rates and managed charging offerings will be incorporated into the program.

However, we have not made a determination in direct testimony as to whether the Company's proposal should be approved and shall do so in surrebuttal based on the other stakeholder's testimony and the Company's response. Additionally, we request the Company provide additional information on the estimated costs of the program and whether there is a cap on total costs.

Q. Please describe the Company's proposed Medium- and Heavy-Duty EV Make-Ready Program.

A. As part of the Medium- and Heavy-Duty EV Make-Ready Program, the Company proposes to cover utility-side costs to support school buses, transit buses, municipal vehicles, and other private sector vehicle fleets may include delivery vehicles.[68] Incentives will cover 100 percent of utility-side make-ready costs for school and transit buses and 80 percent of utility-side make-ready costs for other medium- and heavy-duty vehicles.[69] The program will target make-ready support for up to 300 new electric school

[68] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 9-10
[69] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11

bus chargers and 15 electric transit bus chargers through 2025, as well as up to 100 chargers for electrification of other medium- and heavy-duty vehicles such as refuse and delivery vehicles.[70]

Q. Do you have concerns with the Company's proposed Medium- and Heavy-Duty EV Make-Ready Program?

A. Yes. Similar to our discussion on the Light-Duty EV Make-Ready Program above, we are concerned that the Medium- and Heavy-Duty EV Make-Ready Program does not (1) address managed charging, (2) appropriately incentivize customer adoption of ALM to limit make-ready costs, (3) sufficiently prioritize mass transit fleets and fleets located in or serving disadvantaged communities, (4) consider future federal funding opportunities and overall ratepayer impacts.

Q. What do you recommend to incentivize medium- and heavy-duty fleets to adopt ALM to limit make-ready infrastructure upgrades?

A. As we recommended for light-duty vehicles, program incentives should cover a percentage of the total make-ready costs (utility-side and customer-side), rather than a percentage of utility-side costs. We also recommend that the Company implement the

[70] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11

same site evaluation methodology to identify opportunities for cost savings through ALM.

In addition, the experiences of other jurisdictions lend further credence to our recommendation that some funds should be re-allocated from utility- to customer-side expenses. Particularly, New York's make-ready pilot for medium- and heavy-duty vehicles had very low participation because medium- and heavy-duty fleets often did not require utility-side make-ready infrastructure but were not eligible for customer-side incentives.[71] Covering a portion of both utility-side and customer-side make-ready costs will ensure that all fleets can benefit from the program, regardless of the specifics of the grid infrastructure at each site.

Q. What do you recommend to further prioritize mass transit fleets?

A. While we appreciate the Company's focus on school buses and transit buses through its proposed incentive levels, this prioritization was not reflected in the Company's charger deployment target. We recommend that the Company re-allocate a significant portion of the 100 chargers proposed for other vehicles towards chargers for transit buses, of which the Company is only proposing to target 15. Transit buses provide widespread access to clean transportation to the general public, including those who do not personally own

[71] New York State Department of Public Service. Make-Ready Program Midpoint Review Kickoff Meeting Presentation, pg. 31. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D2C47A8F-F3DE-49EE-8E4D-867DDFBFCABC}

EVs. On the other hand, the electrification of other medium- and heavy-duty vehicles, despite having air pollution reduction benefits, does not expand access to clean transportation for the general public. Given the higher public benefit of mass transit fleets, they should be prioritized through both higher incentive levels and greater charger deployment targets.

Q. What do you recommend to further prioritize disadvantaged communities?

A. Similar to our recommendation for the Light-Duty EV Make-Ready Program, the Company should target at least 40% of the program budget towards disadvantaged communities, as identified by the Council on Environmental Quality's Climate and Economic Justice Screening Tool. Chargers for fleets that are located in or operate in disadvantaged communities should also be eligible for higher incentive levels than those that are not.

Q. Should the Commission approve the Company's proposed Medium- and Heavy-Duty EV Make-Ready Program?

A. If the Commission approves a Medium- and Heavy-Duty EV Make-Ready Program, the following modifications should be made:

- The program incentives should be restructured to cover a percentage of total make-ready costs, rather than a percentage of utility-side make-ready costs.
- The incentive levels should be modified to prioritize school buses and transit buses, as well as fleets that are located or operates in disadvantaged communities.

- The Company should target at least 40% of the program budget towards disadvantaged communities.
- The Company should reallocate a significant portion of its charger deployment target for non-transit fleets towards the target for transit buses.
- The Company should address in detail in rebuttal testimony how EV rates and managed charging offerings will be incorporated into the program.

However, we have not made a determination in direct testimony as to whether the Company's proposal should be approved and shall do so in surrebuttal based on other stakeholders' testimony and the Company's response. Additionally, we request the Company provide additional information on the estimated costs of the program and whether there is a cap on total costs.

Q. Please describe the Company's proposed EV planning and analysis activity.

A. The Company is proposing dedicated funding to support studies and analysis related to EVs and their potential system impacts.[72] The Company states that as the EV sector grows across all vehicle markets, increased analysis and studies that forecast both vehicle adoption and load impacts from vehicle charging is necessary.[73] The Company also states they are committed to supporting decarbonization of the transportation sector and

[72] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11, 16-21.
[73] [73] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11, 16-21.

ensuring its system has the available capacity in the right locations to support growth which requires robust forecasts.[74]

Q. Do you have concerns with the Company's proposal for EV planning and analysis activity?

A. Yes. While we agree planning for EV load growth is important and that dedicated funding may be needed to support studies and analysis related to EVs and their potential system impacts, the Company does not provide sufficient detail in their current proposal to justify using ratepayer funds for the project. First, the proposal does not provide details regarding the planning methodologies the Company intends to use for forecasts or how these methodologies would evolve over time. Second, the Company offers no proposals on how EV load will be managed in the short and long-term. Third, the proposal appears to be disconnected from integrated distribution planning process established in docket 2022-00322.

Q. Please elaborate on your first concern.

A. While the Company proposes to forecast EV adoption and load growth, no details have been provided on methodologies the Company intends to use or how these methodologies would evolve over time. The Company appears to indicate that electrification hosting

[74] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 11, 16-21.

capacity map will be published in the near future but does not include this initiative as part of this proposal. When developing a distribution planning proposal for EVs, the Company should collectively identify all the planning activities they intend to employ and why, their methodologies and how they expect these planning activities to evolve over the short and long-term.

Q. Please elaborate on your second concern.

A. The Company offers no plan to manage EV load or to work with other entities to do so, though EV load is expected to have a significant impact on the grid as Maine gets closer to reaching its energy goals. With increased DERs expected to be integrated to the grid in the near term, and increased load from EVs, the Company's load management approach will need to quickly evolve. For that reason, EV load management should be addressed within the broader ARD process outlined above.

Q. Please elaborate on your third concern.

A. The Company's proposal appears to be disconnected from the integrated distribution planning process established in docket 2022-00322. Any EV distribution planning activities should be conducted in close coordination with the activities in Docket 2022-00322. Specifically, any results from the Company's EV planning and analysis activities should be incorporated into the distribution planning process. While we acknowledge that developing a comprehensive strategy for transportation electrification requires its own dedicated process beyond Docket 2022-00322, it is critical that both these processes are conducted in close coordination.

Q. Should the Commission approve the Company's EV planning and analysis activity proposal?

A. No. While we appreciate the Company's proposal to conduct EV planning and analysis activities, the current proposal does not provide sufficient detail and contradicts the spirit of L.D 1959, which envisioned significant stakeholder input regarding any distribution planning activities. A rate case does not afford the appropriate process to evaluate and iterate upon the Company's EV distribution planning proposal. The Commission should consider the development of an EV distribution planning roadmap as part of a broader EV grid modernization proposal outside of this rate case that includes stakeholder input and the following requirements:

- The Company details all the EV planning activities they intend to employ and why, their methodologies and how they expect these planning activities to evolve over the short and long-term
- The Company develops a sufficient EV load management plan
- The Company, through the broader ARD process outlined above, develops sufficient rate design options
- The Company details how all EV planning activities will be coordinated with the integrated distribution planning process established in docket 2022-00322

The roadmap should also be incorporated into the integrated distribution planning process.

iii. Grid Operations

Q. Does the Company address EV grid operations as part of their proposal?

A. No. As previously mentioned, the Company does not offer any proposals to manage load or how this would be operationalized. At a minimum, the Company should offer an initial plan for how managing load would be operationalized.

Q. What is your recommendation to resolve the lack of EV grid operations as part of the Company's proposal?

A. The Commission should consider the development of an EV distribution operations roadmap, as part of a broader EV grid modernization proposal, outside this rate case that has stakeholder input. This roadmap should be informed by and could be developed in tandem with the EV distribution planning roadmap as recommended in our proposed grid modernization framework. The roadmap should also be incorporated into the integrated distribution planning process.

iv. Grid Architecture

Q. Does the Company address the EV grid architecture as part of their proposal?

A. No. The Company does not offer any proposals regarding a specific grid architecture and the associated technologies required to scale transportation electrification.

Q. What is your recommendation to resolve the lack of an EV grid architecture as part of the Company's proposal?

A. The Commission should consider the development of an EV grid architecture roadmap, as part of a broader EV grid modernization proposal, with stakeholder input and outside of this rate case. This roadmap should be informed by the recommended EV distribution planning and operations roadmaps as recommended in our proposed grid modernization framework. The roadmap should also be incorporated into the integrated distribution planning process.

C. Grid Model Enhancement Project (GMEP)

Q. Please describe the Company's proposal for a Grid Model Enhancement Project (GMEP).

A. CMP states they have recognized the need to improve the quality of its system data to support future integrated system planning and real-time operations, especially with regards to as-built in the field, phase connectivity and customer transformer mapping, and is proposing a GMEP to resolve these challenges.[75] Specifically, the Company proposes to (1) Complete a comprehensive field connectivity survey of the Company's entire distribution network from substation to customer and true up historical records against field collected data, in order to address data gaps between the current infrastructure and

[75] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 20-21.

the appropriate system of record, (2) Develop and implement streamlined processes covering the entire life cycle of distribution assets and their data to maintain the accuracy of the information collected and (3) Enhance current planning and operating processes based on the improved distribution asset descriptions.[76]

Q. Do you have concerns with the Company's proposal?

A. Yes. While we appreciate the Company's proposal as it aligns with our proposed grid modernization implementation plan, we are concerned that the Company has not detailed how it will implement the GMEP. Per our recommendations, the Company should develop a sustainable, scalable approach to keep these grid models updated.

Q. What is your recommendation to address these concerns?

A. Prior to Commission approval of the GMEP, we recommend the Company detail what methodologies and technologies will be used to implement the GMEP. We also recommend the Company investigate leveraging a machine-learning based Digital Twin to implement the GMEP in a sustainable and scalable manner. A machine-learning based Digital Twin creates a real-time, digital representation of the grid that will automatically update the grid model based on the latest data collected from the distribution system. This creates an automated and scalable way to maintain the accuracy of the grid models as

[76] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 20-21.

opposed to manual updates which could become costly and time consuming as significant upgrades are made to the grid over time to support Maine's energy goals. A Digital Twin can also provide the Company a modern solution to better plan and operate the grid to support Maine's energy goals.

D. CMP Innovation Pilots, Partnerships and Collaborations

i. UMaine Collaboration

Q. Please describe the Company's proposed UMaine Collaboration.

A. The Company proposes to work with Maine stakeholders and UMaine to establish an annual Innovation Program that provides a mechanism to quickly test innovative products and services, while ensuring consumer protection and customer benefits.[77] As appropriate, the Company proposes to work with academic institutions like UMaine to jointly explore and seek additional financial and institutional support for projects from federal, state, and other sources.[78] The Company will provide research grants (ranging from $75,000 to $150,000) to enable education, research, and development by faculty and graduate level research focused on smart grid research and development and overcoming challenges related to planning and deploying electricity generation, transmission, and distribution technologies.[79]

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[77] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 26-27.
[78] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 26-27.
[79] 2022 Distribution Rate Case, Grid Modernization and Clean Energy Transformation, at 26-27.

Q. Do you have concerns with the Company's proposed UMaine Collaboration?

A. Yes. While we agree with the Company, that a "sandbox" is needed to test new innovative products and services, we have multiple concerns with the proposal. We are concerned that 1) the Company appears to be solely responsible for determining what innovative products and services will be tested, 2) the lack of clarity regarding stakeholder input and collaboration beyond academic institutions, and 3) the likelihood that scalable solutions will be created through the proposed framework. While we appreciate the Company's expertise, other stakeholders such as DER companies, industry experts, and state agencies should have input developing a framework for what potential initiatives will be piloted, how they will be evaluated for success and how these pilots will be scaled if successful. On a similar note, the Companies proposal constrains participation from other universities and partners with no justification, which creates questions. Applying this constraint to the program design will necessarily constrain the types of innovations and testing that can be conducted. While this may be appropriate, it is not sufficient for testing and scaling concepts to advance the clean energy transition. The Public Utilities Regulatory Authority (PURA) in Connecticut recently issued an order establishing such a program.[80]

[80] Public Utilities Regulatory Authority (PURA), Docket No. 17-12-03RE05, PURA Investigation into Distribution Planning of the Electric Distribution Companies – Innovative Technology Applications and Programs (Innovation Pilots, Decision, March 30, 2022.

Q. What are our recommendations to address these concerns?

A. We take no position on the reasonableness of the Company's and UMaine's collaboration. Regardless of the Commission's action on the Company's proposal, we see a need for a broader, more structured platform for innovation. As a starting point, we recommend the Commission investigate the development of Innovative Energy Solutions (IES) program whereby innovative pilot programs, technologies, products, and services can, on a limited basis, be deployed, investigated, and evaluated for overall impact, costs, and benefits, and scaled if ratepayer benefits are demonstrated. Additionally, we recommend the Commission investigate establishing an independent governance comprised of a diverse set of stakeholders to implement the IES program.

ii. Active Network Management (ANM) Pilot

Q. What is active network management (ANM)?

A. ANM refers to a scheme in which a system continually monitors the constraints on an area of a distribution network, in real-time, and allocates the maximum amount of capacity available to customers in that area based on the date their connection was accepted.[81] More generally, ANM is one form of flexible interconnection.

Q. Why is ANM important?

[81] https://www.ssen.co.uk/our-services/active-network-management/

A. ANM is important because it allows the utility to curtail the use of DERs at critical system hours when they may otherwise cause grid constraints (e.g., low net load), thereby reducing or eliminating the violations of the constraint of the grid, as identified by the utility, and/or reducing the capacity requirement through improved system utilization. A utility can implement ANM in complement with, or under certain circumstances, in lieu of upgrading the distribution grid to increase its capacity, therefore avoiding potentially significant upgrade costs.

Q. Are there other forms of flexible interconnection?

A. Flexible interconnection is a form of interconnection service that can be implemented through a number of approaches. It can be implemented autonomously, via enabling volt-watt through smart inverters. Or it can be implemented through controlled curtailment of export, through ANM, to avoid causing distribution constraints and increasing the hosting capacity of the system, which reduce the need for system upgrade costs. The simpler Volt-watt approach, which is particularly suitable for small DG facilities, has been implemented in Hawaii,[82] while New York has demonstrated successful pilots through controlled curtailment.[83]

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[82] Find and cite the Sunrun deck

[83]https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/33858072.pdf/Flexible%20Interconnection%20Scalability_V3%20-%20ITWG%20-%20Final.pdf

Q. What details did the Company provide on its proposed ANM pilot?

A. The Company noted that the pilot would be deployed to address constraints within a cluster area. The Company also discussed the potential benefits of ANM.

Q. Did you find the information provided by the Company to be sufficient?

A. No. It is unclear what the objective of the pilot is, how the objective of the pilot will be measured, what the cost of pilot is, who is paying for the pilot (e.g., interconnecting DERs or ratepayers), and how the pilot could be scaled to a full service offering, among other things. The Company's lack of details is a good example of why a regulatory sandbox may be needed to provide structure, such as initial filing requirements, for pilots.

While we are supportive of piloting ANM in general, measurement and documentation are important to ensure stakeholders have the ability to learn from pilots. Additionally, ANM may be an appropriate solution for a DER cluster area, but more comprehensive solutions for enhancing hosting capacity and avoiding distribution and transmission upgrades need to be investigate. As discussed above, Volt-watt is likely a much more cost-effective solution for increasing hosting capacity as it relies on autonomous curtailment. Volt-watt should be evaluated as one part of a more comprehensive solution for increasing hosting capacity. In general, non-firm export services, including ANM and Volt-watt, need to be made available to all interconnection DERs during the connection process to take full advantage of the flexibility of these resources.

Offering non-firm service at the time of interconnection, even when there is no system constraint, will create flexible export capacity that can later be curtailed to prevent system upgrades (contingent to certain thresholds and DER protections). At the moment, a circuit could have sufficient capacity to let 100 DG facilities interconnect, but as hosting capacity tightens, the 101 made be seen as needing to take non-firm export service through ANM or Volt-watt. But eventually, system 102, 103, etc. will require the circuit to be upgraded. But if all 100 initial facilities opted to non-firm service, when the circuit was not congested, the circuit could integrate far more capacity because it could curtail all facilities, not just those after 100. To create such a framework, export services need to be priced so that DERs can determine whether firm export is worth the cost versus a discounted non-firm export. Australia has been developing such an export-based framework.

Q. Do you recommend that the Commission approve the proposed ANM pilot?

A. We recommend that the approval of the ANM pilot be contingent upon the CMP developing a plan for scaling flexible interconnection and/or export-based tariff schemes prior to and contingent with the pilot. First, the PUC should order CMP to begin enabling flexible interconnection schemes for DERs seeking to interconnect. Specifically, the Commission should initiate a process (this could be a series of technical sessions or a working group that includes the relevant industry stakeholders) by which CMP would be required to implement flexible interconnection service options into interconnection tariffs.

The objectives of this process are to define CMP's export rights and develop and operationalize associated tariff changes that provide explicit and transparent options for firm and non-firm service, including non-firm and limited export interconnection options. This process may need to be open to future iteration in order to implement newer flexible interconnection options as grid constraints change over time. The Commission would then require CMP to implement these flexible interconnection options via the provision of more varied tariff options, such as non-firm or limited export tariffs. This would result in technical changes to the interconnection tariff. The more basic Volt-watt approach should be implemented in the first phase of this process, while in the long-term, flexible interconnection could be supported by limited or full-scale DERMS and ANM scheme that can significantly reduce the need for upgrade costs.

VII. Conclusion

Q. Does this conclude the panels direct testimony?

A. Yes.