STATE OF MAINE PUBLIC UTILITIES COMMISSION

DOCKET NO. 2022-00152

CENTRAL MAINE POWER COMPANY
2022 DISTRIBUTION RATE CASE

RATE DESIGN AND REVENUE ALLOCATION

August 11, 2022

Testimony and Exhibits of

Mark Marini
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Dr. Jason Rauch
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On behalf of
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I. INTRODUCTION AND OVERVIEW

A. Witness Panel and Qualifications

Q. Please state the names of the members of the Rate Design and Revenue Allocation Panel (the "Panel").

A. We are Mark Marini, Mary Alice Laiho, Jason Rauch, and Weston Smith.

Q. Mark Marini, please state your title and business address.

A. I am the Director, Regulatory at Avangrid Networks, Inc. ("Avangrid Networks"). My business address is 89 East Avenue, Rochester, NY 14649.

Q. Please summarize your work experience and educational background.

A. My curriculum vitae ("CV") is provided in Exhibit RD-7.

Q. Ms. Laiho, please state your title and business address.

A. I am the Manager, Pricing and Analysis at Central Maine Power Company ("CMP" or the "Company"). My business address is 83 Edison Drive, Augusta, ME 04336.

Q. Please summarize your work experience and educational background.

A. My CV is provided in Exhibit RD-7.

Q. Dr. Rauch, please state your title and business address.

A. I am the Manager of Markets & Transmission Policy at Avangrid Networks. My business address is 83 Edison Drive, Augusta, ME 04336.

Q. Please summarize your work experience and educational background.

A. My CV is provided in Exhibit RD-7.

Q. Mr. Smith, please state your title and business address.

A. I am the Manager, Smart Metering at Avangrid Networks. My business address is 83 Edison Drive, Augusta, ME 04336.

Q. Please summarize your work experience and educational background.

A. My CV is provided in Exhibit RD-7.

B. Summary of Testimony

Q. Please summarize your testimony.

A. We present CMP's rate design proposals, which are designed to recover the revenue requirement supported by the Revenue Requirement Panel. In addition, in order to assist the State in meeting its energy policy goals and in an effort to reduce costs for customers, we propose new seasonal and time of use ("TOU") hours that are reflective of shifting system peaks. The new seasonal and TOU hours should help reduce regional transmission expense for all Maine customers. We also propose new innovative rate designs to advance uptake of electric vehicles ("EVs"), heat pumps, batteries, and other distributed energy resources, and rate design enhancements for existing rate classes.

Specifically, we are proposing:

- Updated TOU hours for the TOU classes and beneficial electrification rates to reflect shifting system peaks;
- Proposed re-design of our residential TOU rate and elimination of the current Rate A-TOU and Super Saver options (with all customers currently taking service under Rate A-TOU and Super Saver allowed to choose service under either the redesigned A-TOU rate option, Rate A or a beneficial electrification option);
- Expanded eligibility for Rate A-LM to all technologies consistent with the anticipated outcome of Docket No. 2021-00325;
- Redesigned SGS-TOU, MGS-S-TOU, MGS-P-TOU, IGS and LGS distribution classes to align with the new TOU hours;

- An optional rate for residential and small general service ("SGS") classes targeted to advance the deployment of EVs and heat pumps, saving these participating customers in the range of $20/month for the average residential customer with an EV and that respond to the price signals provided in the rate design;
- Innovative new rates from the Stipulation submitted in Maine Public Utilities Commission ("Commission") Docket No. 2021-00325, including giving all demand-billed customers the option to take delivery service under the B-DCFC rate structure, so as to help enable deployment of distributed battery storage, heat pumps, or other advanced solutions desired by customers that may work well with an economically efficient cost-based dynamic delivery rate, resulting in savings for new participating customers that respond to the price signals provided in the rate design. For example, the Maine Clean Transportation Road Map projects that light-duty EV fast charging stations participating in CMP's existing B-DCFC rate would save on average 45% in delivery costs over a ten year period;[1] and
- Updated monthly service charges for all classes.

Q. What information are you relying upon to guide revenue allocation and rate design?

A. As we describe in further detail below, we derived the revenue by service class by applying the distribution rates proposed in this testimony to the forecasted billing units for the rate year beginning May 10, 2023.[2] We utilized the results of recently conducted Embedded Cost of Service ("ECOS") and Marginal Cost of Service ("MCOS") studies,

[1] Maine Clean Transportation Road Map, Figure 17 at 37 (December 2021), located at the following link: https://www.maine.gov/future/sites/maine.gov.future/files/inline-files/Maine%20Clean%20Transportation%20Roadmap.pdf.

[2] Though the rate year begins May 10, 2023, for simplicity, the rate design exhibits use a May 1 – April 30 billing period for all rate years.

which are being filed separately, to support revenue allocation, the new TOU periods and rate design proposals. Concentric Energy Advisors ("CEA") conducted the ECOS study and PA Consulting ("PA") conducted the MCOS study. Such cost studies traditionally have served as fundamental tools for guiding the ratemaking process.

Q. Has the Company considered previous rate case outcomes when developing revenue allocation and rate design proposals?

A. Yes. In CMP's 2013 distribution rate proceeding in Docket No. 2013-00168, the Commission stated in its October 14, 2014 Order on Rate Design Issues (Part II) (hereinafter "2014 Rate Design Order") that (1) "optional demand rates should be developed for the residential and SGS customer classes, subject to a review of billing system costs," and implemented after CMP's new customer billing system is operational and (2) the existing seasonal and TOU periods embodied in CMP's current rate design "may not align well with cost differentials and will be re-examined and may be revised in a future proceeding to be conducted in conjunction with the development of a new billing system." As part of CMP's 2018 distribution rate proceeding in Docket No. 2018-00194, CMP presented its proposals for new seasonal and TOU periods for all current TOU classes and optional demand rates for residential and SGS customers, but these proposals were not adopted.

In this proceeding, CMP offers revised proposals for TOU hours and beneficial electrification rates that reflect learning and Commission guidance from these prior dockets.

Q. How will the Company make customers aware of these proposals?

A. The Company proposes a customer engagement campaign to raise awareness of the updated TOU periods as well as the optional rates that help advance cost-efficient beneficial electrification and distributed energy resource deployment. The Company describes the proposed customer engagement campaign in more detail below.

C. Identification and Summary of Exhibits

Q. What exhibits is the Panel sponsoring?

A. The Panel is sponsoring the following exhibits:

Exhibit RD-1 – Proposed May 2023, May 2024, and May 2025 Distribution Rates by Service Class

Exhibit RD-2 –Revenue Allocation by Service Class

Exhibit RD-3 –Residential Rate Design and Bill Impacts (distribution, delivery, bundled)

Exhibit RD-4 – SGS Rate Design and Bill Impacts (distribution, delivery, bundled)

Exhibit RD-5 – MGS Rate Design and Bill Impacts (distribution, delivery, bundled)

Exhibit RD-6 – IGS and LGS Rate Design and Bill Impacts (distribution, delivery, bundled)

Exhibit RD-7 – CVs for Mark Marini, Mary Alice Laiho, Jason Rauch, and Weston Smith

II. DISTRIBUTION REVENUE ALLOCATION

A. Introduction

Q. What is the distribution revenue allocation process?

A. The distribution revenue allocation begins with the Rate Year 1 distribution revenue requirement presented by the Revenue Requirement Panel. The distribution revenue requirement consists of base delivery revenues (customer, demand, distribution kilowatt hour (“kWh”) and kilovar (“kVar”) revenues). The Panel allocated the proposed total revenue increase to each service classification and designed rates for each class. CMP summarizes its development of base distribution revenues by service classification in Exhibit RD-1.

Q. Please describe the Company's revenue allocation methodology.

A. As an initial step in the revenue allocation process, the Company reviewed the results of both the ECOS and MCOS studies and compared the ratios of the revenue to revenue requirement for each class. Using the ECOS study, current revenues were compared to the revenues required from each service class to achieve a rate of return equal to the overall system rate of return. A similar analysis was conducted using the MCOS study results. The Company compared the forecast of revenues at current rates to the revenues for each class priced at marginal costs, which were adjusted using an equi-proportional ratio to reflect the overall marginal cost revenues to forecast revenues at existing rates. The results of this analysis are presented in Exhibit RD-2. The comparison of revenue to revenue requirement ratios indicates which classes warrant an increase higher than an overall average revenue increase because they are under-contributing to revenue requirement recovery and which classes should receive no increase as they are over-contributing.

Recognizing that some judgments and approximations are part of any cost analysis, the Company applied a tolerance band to the results of the cost studies to account for potential variation in results. That is, if the revenue to revenue requirement ratios of both the ECOS and MCOS studies for any of the service classes fall outside of the +/-15% tolerance band in the same direction, the contributions for those classes would change by a percentage other than an overall average revenue increase.

B. Findings and Proposed Adjustments

Q. What findings resulted from the Company's revenue allocation process?

A. As can be seen in Exhibit RD-2, the LGS-ST-TOU service class is the only class[3] that shows an over-contribution for both the embedded and marginal cost analysis. CMP adjusted the revenues allocated to the LGS-ST-TOU service class such that the revised allocation was within the tolerance bands. CMP then adjusted the Rate A and SGS classes to collect the revenues removed from the LGS-ST-TOU class. The Rate A and SGS classes showed the most symmetry between the embedded and marginal revenue to revenue requirement ratios and allocating the small amount of revenues removed from the LGS-ST-TOU class did not affect rate design for the Rate A and SGS classes. The Rate A and SGS service class revenue allocation remain within the tolerance bands after the adjustment.

Q. Has the Company's revenue allocation methodology changed from the methodology presented in previous CMP distribution rate cases?

A. No. The proposed revenue allocation is consistent with the revenue allocation process approved by the Commission in Docket No. 2013-00168 and makes movement toward an appropriate allocation of cost responsibilities among the various service classes, as indicated by the results of the ECOS and MCOS studies.

[3] The A-TOU service class also shows an over-collection, but CMP made no adjustment to the A-TOU revenue allocation because CMP combined the all-hours Rate A service class with the Rate A-TOU service class to design rates and the combined residential grouping was within the tolerance band.

Q. Does the Company propose changing the revenue allocation for each year of the proposed rate plan?

A. The Company proposes this revenue allocation for the first year of the three-year rate plan. CMP is proposing no additional interclass revenue allocation in Rate Years 2 or 3.

III. OVERVIEW OF RATE DESIGN

Q. What are the Company's guiding principles regarding revenue allocation and rate design?

A. The Company's primary revenue allocation and rate design goals are adequacy, efficiency, and fairness. Adequacy ensures that the rates are designed to recover the necessary revenue requirement set forth by the Revenue Requirement Panel. Efficiency means designing rates to recover costs from customers in a way that reflects, as closely as possible, how the Company incurs these costs. Fairness calls for allocating the total revenue cost of providing service to each class. Also important is the goal of rate stability, which recognizes that rates based solely on the goals mentioned above must often be tempered because of impacts to customer total bills.[4]

Q. How has the Company addressed the adequacy goal?

A. The Company has addressed adequacy by designing rates to recover the distribution revenue requirement proposed by the Revenue Requirement Panel from the respective service classes. In developing the proposed revenue allocation, the Company used the

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[4] James C. Bonbright, who wrote a seminal text on utility rate design, lists three primary criteria for ratemaking. First is the financial-need objective; the need to ensure proper revenue requirement recovery. Second is the fair-cost-apportionment objective; that the burden of payment for the revenue requirement is fairly distributed among the beneficiaries of service. Third is the consumer-rationing objective; the need to set rates to optimize consumption so as to discourage wasteful use of service while promoting economically justified use. CMP's rate designs aim to achieve these criteria. Bonbright, James C. *Principles of Public Utility Rates*. 1961 ed.

results of the ECOS and MCOS studies as guidance for allocating the revenue requirement among the service classes.

Q. How has the Company addressed the efficiency goal?

A. Collecting costs on the same basis as they are incurred to achieve economically efficient pricing is consistent with 35-A M.R.S. § 3152, which "require[s] the Commission to relate transmission and distribution rates more closely to the costs of providing transmission and distribution service."[5] Economic theory states that, with efficiency being the goal, the pricing of services should be based on the marginal costs of providing those services. In addition, 35-A M.R.S. § 3153-A(1)(B) expressly requires rate design proposals to "reflect marginal costs of services at different voltages, times of day or seasons of the year, including long-run marginal costs associated with the construction of new transmission and distribution facilities."[6] The Commission's obligation to incorporate economic efficiency in rate design was strengthened by the Omnibus Energy Act of 2013.[7]

Q. How has the Company addressed the fairness goal?

A. The Company is using the results of the MCOS study conducted by Ms. Nieto to guide its rate design proposals. The MCOS study measures the marginal cost of CMP's electric distribution system over three components. The first component is customer-related costs, which are the costs associated with meters, services and the associated operation and maintenance expenses, as well as other customer-related costs such as customer accounts, customer service and billing. The second component is local distribution

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[5] 35-A M.R.S. § 3153-A (1) (A).

[6] 35-A M.R.S. § 3153-A (1) (B).

[7] 35-A M.R.S. §§ 3152(1) (D) & 3153-A (4).

facilities costs, which are the costs associated with connecting a customer to the grid, consisting generally of line transformers, secondary lines and local primary lines. Local distribution facilities are sized based on the maximum expected loads, or design demand, of customers using them over the life of the equipment. The expectation is that local distribution facilities will not be expanded in response to month-to-month or year-to-year variations in actual customer usage. The third component is upstream distribution costs, which consist of upstream distribution stations, distribution substations and trunkline feeders. These facilities are expanded to accommodate growth in distribution peak load and maintain reliability. Ms. Nieto discusses the MCOS study results in her testimony.

As she explained, an efficient rate design would mirror the structure of CMP's marginal costs. The filed MCOS study presents the details that guide the rate design proposed in this case. The MCOS study supports recovery of customer-related costs and local distribution facilities costs through a $/month per-customer service charge. Upstream distribution costs would be recovered through time-differentiated per kWh charges or per kW demand charges. The proposed rates do not precisely equal the marginal costs as presented by the MCOS study, as the Company must develop its rates to recover the class distribution revenue requirement.

Q. How has the Company addressed the rate stability goal?

A. In fashioning its rate design proposal, CMP also considered rate stability. Moving strictly to a cost-of-service based rate design could cause changes that result in more significant bill impacts on certain customers. Consequently, the Company considered customer bill impacts during the rate design process. The Company describes the specifics of these constraints in the respective sections below.

Q. What other considerations factored into the Company's rate design proposals?

A. CMP also seeks to enable State policy and stakeholder consensus objectives. The State of Maine has established aggressive greenhouse gas ("GHG") emission reduction targets, requiring emissions to be reduced 45% below 1990 levels by January 1, 2030, and 80% below 1990 levels by January 1, 2050.[8] Per the Maine Department of Environmental Protection ("DEP") Eighth Biennial Report on Progress toward Greenhouse Gas Reduction Goals,[9] 54% of Maine's emissions from fossil fuel combustion arise from the transportation sector. Another 30% of emissions arise from the residential and commercial building sector. Maine established its first Climate Action Plan, *Maine Won't Wait* ("Maine Climate Action Plan"),[10] to begin scoping analyses and strategies to achieve GHG emission reductions. The first Maine Climate Action Plan strategy, Strategy A, is to embrace the future of transportation in Maine, with the first objective to accelerate Maine's transition to EVs. The Nature Conservancy sponsored a stakeholder engagement process managed by the Great Plains Institute, dubbed the Maine Utility/Regulatory Reform and Decarbonization Initiative ("MURRDI"), that culminated in an April 2021 report ("MURRDI Report") containing a set of stakeholder recommendations.[11] The MURRDI Report included a recommendation to have load flexibility enabled by dynamic rate designs. As such, CMP seeks to provide rates to

[8] 38 M.R.S. § 576-A

[9] Available at http://www.maine.gov/tools/whatsnew/attach.php?id=1933469&an=1

[10] The DEP's Eighth Biennial Report on Progress toward Greenhouse Gas Reduction Goals is available at http://www.maine.gov/tools/whatsnew/attach.php?id=1933469&an=1.

[11] More information regarding the MURRDI process and the MURRDI Report are available at https://www.nature.org/en-us/newsroom/maine-modernizing-electric-grid/.

customers that while adhering to the principles of cost-based rate design, can also serve to advance the State and stakeholder decarbonization and load flexibility priorities.

IV. MAY 2023 RATE DESIGN

Q. What is the Company proposing for rate design in Rate Year 1 (May 2023 – April 2024)?

A. The Company proposes to retain the current TOU periods and rate structure for core rates effective May 1, 2023 to provide time to make the necessary system changes described below in Section IX of this testimony. CMP will adjust revenue allocation for the classes as described above as well as adjust rate components as described below to reflect MCOS results using current TOU periods. Exhibit RD-1 provides the May 2023 rates applied to the forecasted rate year billing determinants to collect the revenue requirement presented in the Revenue Requirement Panel testimony. The Company provides individual rate class rate design in Exhibits RD-3 (residential), RD-4 (SGS), RD-5 (medium general service ("MGS")), and RD-6 (intermediate ("IGS") and large general service ("LGS")).[12]

[12] The Company developed all-hours rates and beneficial electrification rates under the new TOU hours, for the residential, SGS, and MGS classes as follows:

- Residential – combined revenue requirement from the Rate A, Rate A-TOU, and Super Saver classes;
- Small General Service – combined revenue requirement from the SGS and SGS-TOU classes;
- Medium General Service – combined revenue requirement from the MGS-S and MGS-S-TOU classes. These customers take service at secondary voltage levels; and
- Medium General Service – combined revenue requirement from the MGS-P and MGS-P-TOU classes. These customers take service at primary voltage levels.

V. MAY 2024 AND MAY 2025 RATE DESIGN

A. Overview

Q. Please summarize the Company's rate design proposals for Rate Year 2 (May 2024 – April 2025) and Rate Year 3 (May 2025- April 2026).

A. For Rate Year 2, CMP proposes that the rate design under the proposed TOU hours for the TOU classes and the optional beneficial electrification price structures become effective July 1, 2024. The Rate Year 2 rates are designed to collect the revenue requirement for Rate Year 2 by service classification. CMP adjusted rate components as described below to reflect MCOS results using proposed TOU periods. The Rate Year 2 rates are presented in Exhibits RD-3 through RD-6.

For Rate Year 3, the May 2025 rate proposal is similar to the May 2024 Rate Year 2 rate design.

B. Time of Use Periods

Q. Why is the Company proposing changes to its time of use periods?

A. CMP's TOU periods need to be updated. The Company is concerned about CMP's growing regional load ratio share[13] and resulting increase in Regional Network Service ("RNS") expense responsibility to CMP customers (*i.e.*, regional transmission expense that flows to all Maine customers). CMP estimates this additional load ratio share change from 2018 to 2020 is costing CMP customers over $5 million annually. Misaligned TOU peak periods send improper price signals to customers and do not motivate consumption away from actual system peaks, hindering alleviation of CMP's growing load ratio share and increasing transmission expense overall for Maine customers. Further, load and

[13] The regional load ratio share for CMP was 7.2% in 2018; 7.5% in 2019; and 7.8% in 2020.

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 electrification technologies. For these reasons, and based upon the further analysis provided in PA's MCOS testimony, the Company believes that updating TOU periods is necessary.

Q. How will TOU hours change based on the Company's proposal?

A. CMP proposes to redefine its TOU periods for all TOU classes in accordance with the MCOS study results.[14] As described in PA's MCOS testimony, the Company considered several TOU options and ultimately decided an option which consists of three seasonal periods – Summer (May – August), Winter (December – February), and Shoulder (March – April, September – November) - and offers an on- peak/shoulder/off-peak TOU structure as set forth in Figure 1 below.

Figure 1: Proposed TOU Periods and Hours (On-Peak, Shoulder, and Off-Peak)

Period	Months Included in Period	On-Peak Hours	Shoulder Hours	Off-Peak Hours
Summer	July - August	Weekdays 4 p.m. to 9 p.m.	Weekdays 2 p.m. to 4 p.m.	All other hours
Winter	December – February	Weekdays 4 p.m. to 9 p.m. Weekends & Holidays 4 p.m. to 9 p.m.	Weekdays 7 a.m. to 10 a.m.	All other hours
Shoulder	March – June; September – November	None	Weekdays 4 pm to 9 pm Weekends & Holidays 4 pm to 9 pm	All other hours

[14] In Docket Nos. 2013-00168 and 2018-00194, the Company made no changes to its TOU periods, although the Commission approved CMP's proposal to apply the same price to usage occurring during the on-peak and shoulder periods in Docket No. 2013-00168. This proposal affected the per-kW charges for demand-based rate classes and the per-kWh charges for the other classes. CMP did propose changes to its TOU periods in Docket No. 2018-00194 which the Commission ultimately decided not to accept.

Q. When would the Company be able to implement its TOU proposal, if approved?

A. As discussed in Section IX of this testimony, CMP anticipates the Company will need approximately 15 months to implement the system changes necessary to implement the new TOU structure once the Commission approves it.

Q. What are the benefits of the proposed TOU hour change?

A. The proposed TOU option reduces the number of peak hours and designates the same consecutive blocks of weekday hours as peak/shoulder times across all seasons. The TOU hours for residential and non-residential customers will be the same under CMP's proposal. As stated in the MCOS testimony, this option balances the goal of reflecting the variation in marginal costs during the day with minimizing complexity for customers.

Q. How will the Company inform customers of the proposed TOU period and hour change?

A. CMP realizes that the proposed TOU structure may present initial challenges to some customers to understand the new time periods and adjust usage patterns. During the period that CMP is configuring its systems to support the new TOU periods, CMP plans to develop and share educational materials for customers to help with the transition to the new TOU periods.

C. Time of Use Rate Design for Residential Customers Effective July 1, 2024

Q. Is the Panel proposing other changes that affect TOU customers?

A. As noted above, for the residential class, the Company combined the revenue requirements for Rate A, A-TOU, and Super Saver[15] to develop new rates reflecting the proposed TOU periods. With the redesigned TOU Option, CMP proposes to eliminate

[15] Currently, approximately 5,100 customers take service under Rate A-TOU and about 230 customers take service under Super Saver.

the current A-TOU and Super Saver classes. CMP's redesigned residential TOU Option collects a significant portion of the distribution revenue not allocated to the service charge through the on-peak per-kWh price to provide differentiation between on-peak, shoulder, and off-peak pricing, as indicated by the MCOS study. This differential will provide an opportunity for customers to shift their usage to the off-peak period. CMP still intends to apply non-distribution revenues (*e.g.*, stranded cost and Efficiency Maine Trust ("EMT") assessment) equally to the on-peak, shoulder, and off-peak per-kWh price. CMP is proposing an option to apply transmission charges to the on-peak kWh only for non-demand TOU classes.

VI. OTHER RATE DESIGN PROPOSALS

A. New Optional Residential and SGS Rates

Q. Is the Panel proposing optional beneficial electrification rates for the Company's residential and SGS customers?

A. Yes. CMP proposes new optional rates for the residential class and SGS class targeted at advancing beneficial electrification technologies, such as EV charging and heat pumps. The two rates would be available to be taken either as a whole-house rate or, on a separate meter, for just EV charger(s) or other dedicated load. The customer would not be required to have an EV charger or heat pump if taking the rate as a whole-house rate.

The rates consist of a fixed monthly charge for distribution revenue requirement recovery and a peak demand charge for transmission revenue requirement recovery. The peak periods over which the demand charge is applied correspond to the peak periods shown in Figure 1. Other costs such as stranded costs, low income, and the EMT assessment, are recovered via volumetric kWh charges as is done in existing rates.

Q. What benefits are associated with these optional EV or heat pump rates?

A. The customer and societal benefits of these rates for EV or whole-house loads include: 1) minimization of cross-subsidies between customers because the rate design is consistent with marginal costs; 2) customer understandability due to its relative simplicity and predictability while preserving cost-causation; 3) providing rate options to customers, which customers value per the JD Power and Associates' Customer Satisfaction Survey;[16] 4) providing opportunity for customers to lower their delivery charges by avoiding heavy use of the system during peak times; and 5) responding to stakeholder and State policy interest in enabling EVs while also utilizing transmission and distribution infrastructure efficiently.

Q. How do economic considerations and rate design goals factor into the design of the optional EV or heat pump rates?

A. This delivery rate option has been designed with both marginal cost economics and modern behavioral economics in mind. As evident in the submitted MCOS study, most of the marginal distribution delivery costs are fixed. These new optional rates have a fixed charge that comes closer to the marginal fixed costs than do the old existing standard Rate A or SGS rates. As such, these new optional rates are more consistent with the economic efficiency espoused in the economics of marginal costs and with Maine law.[17] At the same time, the rates are customer-focused, and provide a level of simplicity and predictability that enables customer satisfaction via easy budgeting and management

[16] The J.D. Power and Associates' Customer Satisfaction Survey is available at https://www.jdpower.com/sites/default/files/file/2020-11/JDP_US_2020_ResidentialElectric_Brochure_FINAL_103020.pdf.

[17] 35-A M.R.S. §§ 3153-A (1) (B), 3152(1) (D), & 3153-A (4).

for cost savings. Per behavioral economics, the relative understandability of these optional rates responds to human cognitive biases to seek out simple solutions in the face of complexity and cognitive overload.[18]

Q. Did the Company consider outcomes from previous regulatory proceedings when developing these optional EV or heat pump rates?

A. Yes. It is worth noting these new optional rates also try to satisfy – in an alternative form than what was proposed, but not ultimately accepted in the 2018 rate case – the Commission's desire for CMP to introduce a demand rate option for residential and SGS classes. In CMP's 2013 distribution rate proceeding in Docket No. 2013-00168, the Commission stated in its October 14, 2014 Order on Rate Design Issues (Part II) that optional demand rates should be developed for the residential and SGS customer classes, subject to a review of billing system costs. As such, while focused on enabling EVs and heat pumps, customers may desire to take delivery under this rate for other purposes that result in more efficient utilization of the grid, such as for the installation of distributed storage technology that would shift load outside of the peak demand window, reducing demand and thus infrastructure investments on the grid and saving the customer on delivery costs.

Q. Please describe the savings potential a customer could receive by taking service under an optional EV or heat pump rate.

A. The Company estimates a residential customer that drives an EV a typical distance everyday taking service under the optional EV rate would save about $20/month on their

[18] Elizabeth V. Hobman, Elisha R. Frederiks, Karen Stenner, Sarah Meikle, "Uptake and usage of cost-reflective electricity pricing: Insights from psychology and behavioural economics," *Renewable and Sustainable Energy Reviews*, Volume 57, 2016, Pages 455-467, ISSN 1364-0321, https://doi.org/10.1016/j.rser.2015.12.144.

delivery costs versus taking delivery under Rate A. Exhibit RD-3, Schedule 5 provides a summary comparison of customer costs under the two rates.

Q. When would the Company be able to offer these optional EV or heat pump rates?

A. CMP is targeting July 1, 2024 for implementation of these new optional residential and SGS rates. More details on the system requirements, costs, and timeline for changing CMP's TOU periods to facilitate implementation of new rate designs are discussed below in Section IX of this testimony.

Q. How will customers be aware of these optional rate offerings, if approved?

A. A robust public communication plan will accompany the launch of these new rates to raise awareness and encourage enrollment. Communication will be coordinated with other EV customer awareness communications, including incorporation into a potential electricity rate cost calculator on CMP's website.

Q. Please describe other factors that will influence uptake of these optional EV or heat pump rates.

A. Potential enrollment rates are highly contingent on the availability of a TOU supply for residential and SGS customers. About half the cost of electricity for customers is supply. More customers will be encouraged to enroll if there is an available time-differentiated supply product that they can combine with the time-differentiated delivery rate. As such, the Company suggests the Commission, as recommended by the MURRDI Report, consider a TOU supply product for residential and SGS standard offer. The Company can work with the Commission as desired to help shape such a product as, for instance, time-differentiated periods between delivery and supply should be aligned for customer ease of understanding and reaction. The Commission should explore ways to procure such an offering that enables higher customer uptake and better bid pricing than what was observed when the Commission first procured but then discontinued a TOU standard offer small class supply product in the early 2010s.

B. Expansion of Dynamic Demand Delivery Rate Option

Q. Is the Company proposing optional rates for customers taking service under rates with demand charges?

A. Yes. The Company anticipates expanding eligibility for the B-DCFC rate design to all demand-bill customers in their respective classes, thus offering a dynamic delivery rate for customers, meeting recommendation #3 of the MURRDI stakeholders on Load Flexibility Enabled by Dynamic Rate Designs.[19] Note that this new optional rate, B-CPT, has been proposed in Docket No. 2021-00325.

The two-part demand charge design of this rate accounts for differences in (a) distribution costs that are largely driven by customer maximum demands and (b) transmission costs that are largely driven by the temporal coincidence of those demands with system peaks. Specifically, the two-part demand rate contains two separate measures of customer demand: (a) the customer's non-coincident peak ("NCP") demand, which is the customer's maximum demand during each billing period; and (b) the customer's coincident peak ("CP") demand, which is a customer's maximum demand during the monthly system peak.

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[19] MURRDI Report at 20 ("**Recommendation:** Maine should move toward a more dynamic grid with more granular load flexibility capabilities in a concerted manner. As a first step, the Maine PUC should immediately look more closely at time of use rates and/or other dynamic rate structures that more accurately reflect the cost of producing and delivering power. It should also take into account how time-varying rate designs could help to meet the state's climate and energy requirements."), available at https://www.nature.org/en-us/newsroom/maine-modernizing-electric-grid/.

The NCP demand charge reflects a customer's contribution to costs associated with distribution facilities. The NCP demand charge recovers local delivery costs, which are generally: (a) any portion of the rate class customer-related costs that is not recovered in the customer charge; (b) secondary distribution demand-related costs; and (c) any portion of primary distribution costs not included in local transmission costs. The NCP demand charge is calculated the same way as CMP's traditional demand charges.

The CP demand charge is designed to align price signals received by customers with their responsibility for those costs incurred in serving CMP's system peak load. The CP demand charge recovers upstream delivery costs, which are generally: (a) local transmission costs (*e.g.*, non-pooled transmission facilities); and (b) regional transmission costs (*e.g.*, pooled transmission facilities). A customer's CP billing demand is calculated monthly, in the same manner as an existing sub-transmission and transmission ("ST&T") customer's CP demand is calculated.

Q. What are the benefits of the B-DCFC/B-CPT optional rates described above?

A. This two-part demand rate aligns with the costs incurred by CMP, thereby better reflecting cost causation. Existing participants on the B-DCFC rate have realized over 40% savings on delivery costs,[20] and future participants are expected to achieve about 45% savings,[21] given the charging load characteristics experienced at light-duty vehicle Level 3 fast charging stations.

[20] See the Company's Interim Report Update on CMP's EV Pilots filed on May 30, 2021 in Docket No. 2019-00217, a copy of which is provided as Exhibit GM-5.

[21] See the Maine Clean Transportation Roadmap, Figure 17 at 37 (December 2021), available at: https://www.maine.gov/future/initiatives/climate/cleantransportation.

The Company believes other customers, such as those seeking to deploy distributed storage solutions, should have the opportunity to achieve cost savings that might be realized under this cost-based two-part demand rate. For certain customers, this dynamic delivery rate, where the CP demand is incurred in a short window, may result in savings without any change in behavior. For others, this dynamic peak pricing delivery rate – which has a shorter peak window than the existing fixed and NCP measured TOU demand rate – may help enable behavioral or technological solutions, such as distributed storage, that can save customers costs while at the same time shifting load and reducing stress on the system at peak times.

Such a rate helps enable more efficient utilization of CMP's delivery network. This two-part demand rate avoids transmission peak investments via a more direct price signal; the same signal already utilized by ST&T customers. Benefits include a time variant CP that is inherently adaptable over time to changes in system peaks.

Q. How will the Company promote these optional rates to customers?

A. This new rate option for demand-billed customers will be included in the customer education and awareness campaign for CMP's rate changes and new options.

C. Customer/Employee Communication Plans to Support New Pricing Plans

Q. Please provide the details of the Company's communication plan.

A. A robust customer communication plan will accompany the launch of the new rates to raise awareness and encourage enrollment among customers who might benefit from one of the new pricing options.

J.D. Power and Associates identifies several factors that contribute to overall customer satisfaction, including the availability of pricing options that meet customers' needs. Customers are also more satisfied if they perceive that the utility is making an effort to help them manage monthly electricity costs.[22]

The Company will develop a plan to raise awareness of the pricing options and engage customers who may benefit as follows:

- **Raise Awareness and educate:** The Company will broadly communicate the availability of options and offer tools to help customers assess the benefits of participating in an optional pricing plan. The Company anticipates content and tools will be available on the website and that all customers will be made aware of these options through bill inserts, bill messages, and social media.
- **Create interest and engage:** The Company will identify and directly communicate with customers who exhibit behaviors and usage patterns that may benefit from an optional pricing plan. Targeted emails and usage conversations in the Customer Care Center will include information about the availability and potential benefits of the pricing options, including customized savings calculations based on current usage and usage management assumptions. These communications will direct customers to the tools for analyzing and enrolling in plan options. The cost for the communication plan is approximately $120,000 - $150,000, which includes approximately $20,000 per year for the EV website rate cost calculator.
- **Opt-in enrollment:** Those customers across all residential and SGS classes identified as clearly benefiting under the new TOU periods based on historic usage will receive detailed information through a one-time opt-in enrollment campaign.

[22] J.D. Power and Associates' Residential Electric Customer Satisfaction Model, 2021.

Customers will be provided an estimate of their delivery savings and given the option to opt in to the new TOU rates.

- **Integrated messaging:** Communications will be integrated with other EV customer awareness communications, including incorporation into an electricity rate cost calculator on CMP's EV website. The Company will present these options within the Energy Manager.

D. Residential Service Charges

Q. Why is the Company proposing changes to the residential service charges?

A. The MCOS study supports collecting both customer-related (services, meters, customer-related functions) and local facilities (transformers, secondary lines, local primary lines) costs through the service charge.

Q. What are the proposed changes to the Rate A and A-TOU service charges?

A. For residential all hours and TOU rates, CMP proposes for Rate Year 1 to raise the base distribution service charge by $5/month to $15.80 per month[23] and collect the remaining revenue requirement though per kWh charges. This increase in the service charge is supported by the MCOS study which indicates an efficient monthly service charge of $30.92 for Rate A and $36.44 for the current Rate A-TOU. Although the increase does not raise the service charge to the level indicated by the MCOS study, it moves the service charge in the right direction while considering bill impacts. The current base distribution service charge of $10.48 per month for each of these classes essentially recovers the costs associated with customer-related functions. The increase to $15.80

[23] The Company proposes that the monthly service charge for the redesigned residential TOU rate also be set at $15.80.

begins to recover a greater portion of local facilities costs in the service charge that are currently recovered in the per kWh distribution charge.

For Rate Year 2, CMP proposes to increase the residential service charge by $2/month and for Rate Year 3, CMP proposes to increase the residential service by an additional $2/month. As with the Rate Year 1 increases, the Rate Year 2 and Rate Year 3 increases are supported by the MCOS study.

Q. Please describe the proposed changes to the A-LM service charges.

A. CMP is proposing to set the A-LM base distribution service charge at marginal cost for all three rate years, which is lower than the current A-LM service charge.

E. Non-Residential Service Charges

Q. What are the proposed changes to non-residential service charges?

A. The monthly service charges for all non-residential service classes (*i.e.*, SGS and above) are collecting at least the customer-related costs, and also collecting a portion of costs associated with local facilities. For the SGS all hours class, CMP proposes to increase service charges by $5/month for Rate Year 1, $2/month for Rate Year 2, and an additional $2/month for Rate Year 3.

For demand classes (MGS, IGS, and LGS secondary and primary), CMP proposes to increase the service charge by 25% in Rate Year 1, 3.5% in Rate Year 2, and 2.5% in Rate Year 3. For most classes, over 80% of customers see base distribution increases equal to or below the overall increase of CMP's base distribution revenue requirement and over 70% of customers see delivery increases equal to or below the increase of CMP's delivery revenue requirement.

CMP proposes to align the monthly service charge for the SGS-TOU service class with the SGS all-hours service class. Similarly, the Company proposes to align the monthly service charges for the MGS-S-TOU service class with the all-hours MGS-S service class, and the MGS-P-TOU service class with the all-hours MGS-P service class.

F. Demand Charge for MGS, IGS, and LGS Distribution Customers

Q. What are the proposed changes to demand charges for the MGS, IGS, and LGS rate classes?

A. The Company plans to continue measuring non-transmission demands for MGS, IGS, and LGS customers on an integrated 15-minute basis.

For MGS-S and MGS-P all hours rate classes, CMP will include three seasonal periods for the demand structure. Since the demand charge for customers in these classes is based on the maximum measured customer demand occurring during the billing period, these classes are unaffected by the change in TOU hours.

CMP also plans to apply demand charges to the highest integrated 15-minute demands occurring during the peak, shoulder, and off-peak periods. Today, for each pricing season, the Company applies the same demand charge to the highest demands registered in the on-peak and in the shoulder periods and applies no demand charges to demands registered during the off-peak period. The MCOS study supports applying demand charges to off-peak periods.

For demand rates for the MGS-TOU, IGS, and LGS distribution level service classes, CMP is proposing to increase the service charges as described above and allocate the remaining revenues to the other TOU periods based on the MCOS study results. This rate design balances the results of the MCOS study with mitigating bill impacts for customers for whom TOU rates are mandatory. Please see Exhibit RD-5 and Exhibit RD-6 for the bill impacts by rate class.

VII. RESIDENTIAL SERVICE CHARGES AND LOW-INCOME CUSTOMERS

Q. Will CMP's proposed changes to residential service charges have a negative effect on low-income customers?

A. In Docket No. 2018-00194, the OPA's consultant asserted that an increase to residential service charges will have a disproportionate effect on low-income customers because these customers are likely to use less electricity than higher-income households.[24] The consultant also asserted that usage associated with CMP's measure of low-income customers (*i.e.*, customers participating in the Home Energy Assistance Program ("HEAP") and the Company's Electricity Lifeline Program ("ELP")) may not be indicative of the usage of the larger low-income population.

While CMP does not dispute that usage levels among low-income customers can vary, CMP's position that low income does not necessarily equate to low-usage is supported by studies analyzing low-income usage levels in several countries. For example, Drs. Hethie Parmesano and Sarah Potts Voll note in their paper, *Rethinking Rate Design for Electricity Distribution Service in the US*,[25] that studies in several countries have found that low-income customers are not necessarily low-usage

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[24] April 25, 2019 Rebuttal Testimony of Scott Rubin filed on behalf of the Office of the Public Advocate in Docket No. 2018-00194, at page 6, lines 11-12.

[26] Dr. Hethie Parmesano and Dr. Sarah Potts Voll, *Rethinking Rate Design for Electricity Distribution Service in the US ("Rethinking Rate Design")*, filed by the Company on February 4, 2014 as CMP Rate Design Rebuttal Testimony, Exhibit REB-RARD-01, in Docket No. 2013-00168.

customers.[26] These findings are consistent with CMP's analysis of the usage patterns of its ELP customers.

Q. Does the Company have any analysis that supports that its low-usage customers are not necessarily low-income customers?

A. As described in CMP's Rebuttal Testimony in Docket No. 2013-00168[27] and as updated using customer information for 2021, a significant portion of the Company's low-use customers are not low-income. An analysis of CMP customer data showed conservatively that about 30 - 35% of CMP's low-use customers – *i.e.*, those using under 400 kWh per month – are seasonal or vacation homes.[28] By any measure, the ability to own a second property is not indicative of a low-income customer.

CMP's analysis of customers with usage equal to or below 400 kWh in 2021 shows that approximately 14% of CMP's total customer base falls into this usage group. Of these customers, approximately 3.3% received HEAP benefits.

Q. Has the Panel drawn any conclusions regarding low-income customers and increased service charges?

A. Yes. CMP continues to assert that the analyses showing the impact of increased service charges to ELP customers are relevant. As the Company has demonstrated, these lowest income customers tend to use significantly more electricity than the average and, as a whole, would benefit from a rate structure with an increased service charge. CMP also

[26] *Rethinking Rate Design* at 11 of 16.

[27] CMP Rate Design Rebuttal Testimony at page 9, lines 8-11 (Feb. 4, 2014), filed in Docket No. 2013-00168.

[28] CMP compiled all accounts using the following criteria: (1) the account had a code indicating the customer noted their property is a seasonal residence; or (2) CMP sends the monthly bill to an out-of-state address. This method likely understates the number of seasonal customers as many seasonal properties do not contain the above-referenced code and many in-state customers also have vacation homes within CMP's service territory.

notes that outside of knowing which customers participate in HEAP and ELP programs, CMP collects no other income-related information on its customers.

VIII. REVENUE DECOUPLING MECHANISM

Q. Please describe the Company's proposal regarding its revenue decoupling mechanism.

A. CMP proposes that the structure of the distribution revenue decoupling mechanism ("RDM") remain unchanged from the structure approved in Docket Nos. 2013-00168 and 2018-00194, and 2020-00159 with the following minor exception. The Company proposes adjusting RDM revenue targets prospectively rather than retroactively. CMP proposes no change to the current adjustment calculation, which is 75% of the average annual year over year customer growth rate (positive or negative). CMP will update base target levels to reflect the product of the rates designed to recover the proposed revenue requirement and the January 2023 rate year sales forecast. Revenues resulting from the optional and re-designed rate classes under the January 2023 rates would be included in the RDM and incorporated into the appropriate residential or non-residential classes for reconciliation purposes. The new TOU and beneficial electrification rates were developed based on current usage patterns. The revenue resulting from these rates will likely differ from the RDM targets because customers' uptake, retention, and responses to these rates structures have yet to be determined. The RDM is important to ensure appropriate revenue collection from each service class.

IX. PROPOSED CHANGES TO METERING SYSTEMS

A. Approach and Methodology

Q. Why is CMP proposing a change to its metering systems?

A. CMP needs to make changes to its metering systems to accommodate the Company's TOU proposal, particularly if adopted at scale.

Q. What is CMP's current methodology to calculate a customer's energy consumption for billing?

A. Currently, CMP's SAP Customer Relationship Management and Billing ("CRM&B") system calculates electric energy consumption based on meter register reads (*i.e.*, point in time values of the kW and/or kWh units measured by the meter) obtained from the Itron Enterprise Edition Meter Data Management System ("IEE MDMS"), MV-90 or FCS.

Q. Is CMP proposing any changes?

A. CMP has determined that using interval-based, not register-based, billing by leveraging Rate Modeler, a component of the IEE MDMS, is an efficient systems-based approach to accommodate changes to TOU schedules and rates particularly if adopted at-scale. Physical meter exchanges or reprogramming are not required with this approach. Although the meter's display will not show a change to the TOU periods originally programmed into the meter, customers will be able to see their hourly interval consumption on the Energy Manager portal and total consumption per updated TOU period on their electric bill.

Q. Will the Company's Rate Modeler tool facilitate the implementation of new TOU and demand-based rates?

A. Yes. For customers opting for a TOU rate, CMP would use Rate Modeler to configure the TOU schedules. When SAP CRM&B requests it, Rate Modeler would perform a time series calculation, which means summing each meter's hourly intervals within each TOU period during the billing period to produce one consumption value in kWh per TOU period. Rate Modeler would then transmit these consumption values to SAP CRM&B in what is called a time of use bucket. For residential or SGS customers opting for the demand rate, Rate Modeler would send a demand kW value based on the hourly interval with the highest consumption during the billing period as well as a total consumption value for the billing period. For customers opting for both TOU and demand rates, Rate Modeler would send a set of demand kW values based on the highest hourly interval within each TOU period during the billing period in addition to a set of total consumption values for each TOU period.

B. Summary of Expected System Changes

Q. Please describe the changes to IEE MDMS.

A. This system contains the register and interval data for AMI meters. Rate Modeler is already available in IEE MDMS, but new rates and TOU schedules will need to be setup.

Q. Please describe the changes to the Company's MV-90 system.

A. The MV-90 system contains the meter data transmitted via dial-up or IP communications from customers with complex metering and/or daily ISO-NE reporting requirements. There are approximately 470 MV-90 meters as of this filing, of which approximately 340 are used specifically for billing purposes via a register generated by a custom module and the remaining 130 are for measuring non-billing generation and tie lines. Since this system already leverages hourly interval data, only a change to the TOU schedule in the application settings is required.

Q. Please describe the changes to the Company's Field Collection System ("FCS").

A. The FCS system receives manually read meter data uploaded from handheld devices. As of this filing, approximately 53 TOU customers participate in CMP's Smart Meter Opt-Out program, including 49 residential TOU, 3 residential TOU Super Saver, and one SGS. Since consumption will be calculated in Rate Modeler, a custom interface to support the flow of meter interval data from FCS to MDMS will need to be developed.

Q. Please describe the changes to SAP CRM&B.

A. The SAP CRM&B system is used for customer service business functions including customer billing, which currently uses register values from IEE MDMS, MV-90, and FCS as billing determinants. Billing and meter configuration would need to be modified to use the consumption values provided by Rate Modeler as billing determinants to produce the bill.

C. Estimated Costs and Implementation Timeline

Q. What are the estimated implementation costs for the changes described above?

A. CMP provides the estimated costs for the various systems in Table 1 below.

Table 1: Estimated Implementation Costs

Cost Component	**Estimated Cost (USD)**
Rate Modeler Implementation including: Vendor implementation of Rate Modeler setup includes the following: o Management of the project plan and all activities. o Perform full technical implementation through all Sandbox, development, quality, and production environments, including up to four (4) interval billed Rate Modeler configurations and integration with SAP CRM&B. o Perform functional testing and assist with integration testing. o Thirty (30) days of enhanced support for go-live	$1,843,509
SAP CRM&B Modifications including: Includes changes to billing configuration, register groups, and a conversion effort for existing TOU and demand meters to utilize the consumption values from Rate Modeler.	$320,000
Meter Probing including: This includes meter field technician labor and installing a replacement meter cover with a magnet necessary to manually probe (with a handheld device) interval data from the meters of a fraction of the approximately 6,000 customers enrolled in TOU rates as of this filing.	$14,760
FCS Transfer Process includes: A new custom interface to transfer any manually read meter interval data from FCS to IEE MDMS so that Rate Modeler can calculate the consumption values.	$25,000
Allowance for Funds Used During Construction (AFUDC): This is the cost accrued in recognition that the Company has expended capital that has not yet been placed into service and thus included in rate base. The funding source of that capital results in costs (interest for the debt and shareholder return for the equity).	$148,324
Total:	**$2,351,593**

Q. How does the Company propose to recover these implementation costs?

A. The implementation costs listed in Table 1 above are not included in CMP's Capital Investment Plan used to calculate the revenue requirement. Instead, the Company proposes that these costs be recovered through a capital adjustment mechanism. In the event the Commission approves the Company's TOU proposal, CMP would execute the necessary implementation activities discussed above, and these costs would be recovered as part of the capital adjustment mechanism based on a showing of actual prudent expenditures in the year after they are placed into service. The actual plant additions and other expenses arising from these investments will be used to calculate the necessary revenue adjustment, which will be made to rates as part of the annual compliance filing process.

Q. What is the timeline for implementing meter system changes?

A. Table 2 below estimates an implementation timeline of fifteen (15) months followed by two (2) months of post go-live support. Project activities would commence upon regulatory approval.

Table 2: Estimated Implementation Timeline

Phase	Description	Duration
Preparation	Finalize project team and complete the procurement process for external services.	Two months
Design	Create IT functional and technical specifications for system changes according to business requirements	Three months
Build	Perform configuration and development activities on identified systems and initial IT unit testing	Five months
Test	Perform systems' integration testing to meet requirements	Four months
Production	Move all system configuration and development changes to production, including migrating customers prior to the start of their next bill cycle	One month
Monitor	Post go-live support and monitoring	Two months

Q. Does this conclude the Panel's testimony at this time?

A. Yes.