NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities Corp. d/b/a Liberty Change in Distribution Rates	Docket No. DE 23-039

DIRECT TESTIMONY

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EBEN PERKINS AND DR. RICHARD SILKMAN

I. INTRODUCTION

Q. Please state your names, positions, and business addresses.

A. Eben Perkins, Vice President, and Dr. Richard Silkman, Founder and Chief Executive Officer, both of Competitive Energy Services, LLC, 148 Middle Street, Portland, ME 04101.

Q. Please describe Competitive Energy Services, LLC.

A. Competitive Energy Services, LLC ("CES") is an energy consulting company founded in 2000 and based in Portland, Maine. CES manages the strategic procurement of more than $2 billion of annual energy purchasing on behalf of over 750 customers across 16 states and provinces. We assist our customers in evaluating and developing onsite electricity generation opportunities, including cogeneration, fuel cells, and solar photovoltaic systems, and implementing energy efficiency and demand management measures including participation in utility and Independent System Operator demand response programs. We also help customers navigate the journey to reduce their greenhouse gas emissions and develop long-term strategic plans to invest in low-carbon energy systems.

Q. Mr. Perkins, please describe your educational and professional experience.

A. I received my B.A. in environmental analysis from Pomona College. I have worked in the energy industry in a variety of roles, holding positions in regulated and deregulated areas of the electric sector. Prior to joining CES, I served as Manager of Smart Grid Planning and Programs for Iberdrola USA (now Avangrid) from 2014 to 2016. For the last seven years, I have worked with Dr. Silkman and CES' management team first as Director of Special Projects and currently as a Vice President. I manage CES' consulting practice, providing clients across North America with specialized electric, gas, and fuel market assessment, utility tariff evaluation and negotiation support, strategic planning for investment in energy infrastructure, and competitive solicitation for behind-the-meter distributed energy resources including but not limited to battery storage, solar photovoltaics, and fuel cells.

Recent focus areas of CES' consulting work include helping colleges and universities throughout New England develop energy master plans to convert district steam production and distribution systems to low-temperature hot water networks that enable the phased electrification of campus heating, and helping numerous clients across New England evaluate and deploy behind-the-meter battery storage systems to enhance their electric demand management capabilities and address rising electricity costs. In addition, I have spearheaded CES' participation in recent regulatory proceedings in Maine where CES has successfully advocated for significant improvements in electric rate design with the aim to help advance the state's beneficial electrification efforts, including in Docket No. 2021-00325 and Docket No. 2022-00152. My resume is included in Exhibit CES-1.

Q. Dr. Silkman, please describe your educational and professional experience.

A. I received my B.A. in economics from Purdue University (with distinction) and my Ph.D. in economics from Yale University. I was the Director of the Maine State Planning Office (1987-1992), a cabinet level agency with broad policy and planning responsibilities, including economic development, energy, telecommunications, taxation, budgetary, land-use management and health care. I have served as a consultant on energy matters for a variety of clients across the country, including a trade association of Maine's largest industrial consumers of energy, a Fortune 500 multi-state retail grocery company, a consortium of consumer organizations, and a variety of municipal governments and agencies. In representing these clients and others, I have testified before the Maine, Massachusetts, New Hampshire, Vermont, California, and Pennsylvania public utilities commissions on matters of rate design, the justness and reasonableness of rates, and electric utility industry restructuring. Over the past two decades, I have been the Chief Executive Officer of CES. My resume is included in Exhibit CES-1.

Q. Have you previously testified before the New Hampshire Public Utilities Commission or other regulatory bodies?

A. Dr. Silkman has testified before the New Hampshire Public Utilities Commission (the "Commission"), and in electric utility regulatory proceedings in numerous other states, including California, Pennsylvania, Vermont, and Massachusetts, as well as in cases before the Federal Energy Regulatory Commission. Mr. Perkins has not previously testified before the Commission. Mr. Perkins has testified before the Maine Public Utilities Commission in *Request for Approval of a Rate Change Pertaining to Central Maine Power Company,* Docket No. 2022-00152, *Commission Initiated Investigation into Stranded Cost Rate Design*, Docket No. 2022-00160, *Commission Initiated Inquiry Into Rate Design Issues Associated with 2021 Legislation*, Docket No. 2021-00198, and *Commission Initiated Investigation Into Transmission and Utility Rate Design To Promote State Policies*, Docket No. 2021-00325. Mr. Perkins has also testified before the Massachusetts Department of Public Utilities in *Petition of NSTAR Electric Company for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan*, D.P.U. 22-22.

Q. On whose behalf are you submitting testimony in this proceeding?

A. We are jointly submitting testimony on behalf of Dartmouth College.

Q. Please summarize your testimony.

A. Our Testimony is organized into eight sections, as described below:

- Section I provides an introduction.
- Section II gives an overview of Dartmouth College.
- Section III describes Liberty's current rate design for General Service Time-of-Use ("Rate G-1") customers including Dartmouth.
- Section IV summarizes the concerns we have with Liberty's rate design proposal and presents our recommendations on how to improve the G-1 rate design to fully support the Company's rate modernization objectives and to empower large customers to adopt and utilize distributed energy resources ("DERs").
- Section V compares Liberty's existing time-of-use ("TOU") periods for Rate G-1 to the updated TOU periods the Company has proposed for Rate D-TOU, Rate D-11, Rate D-12, Rate G-3-TOU, Rate EV-L, Rate EV-M, Rate EV-L-E, and Rate EV-M-E.
- Section VI discusses Liberty's existing ratchet for monthly distribution demand charges and why we disagree with the Company's proposal to continue applying the demand ratchet to Rate G-1, Rate G-2, Rate EV-L, and Rate EV-M. In this section we address Liberty's argument that distribution costs are fixed in nature and do not vary by time of day or year and provide examples of how the demand ratchet disincentivizes Liberty's larger customers from installing and operating behind-the-meter DERs such as energy storage.
- Section VII reviews Liberty's proposal to implement seasonal differentiation in its distribution rates for residential and small commercial TOU classes and why the

Company's proposed six-month summer rate season is too broad. In this section we discuss why seasonal rate differentiation should be extended to all TOU customers.

- Section VIII summarizes Liberty's transmission rate design for G-1 customers and how the rate structure is completely disconnected from Liberty's underlying cost of transmission service. In this section we detail how the Company's current transmission charges, which are assessed to G-1 customers using a flat around-the-clock price per kilowatt-hour ("kWh"), disincentivize G-1 customers from installing behind-the-meter DERs.

Q. Are you sponsoring any exhibits in addition to your testimony?

A. Yes, in addition to this testimony, we are sponsoring the following exhibits:

- Exhibit CES-1, Mr. Perkins' and Dr. Silkman's Resumes
- Exhibit CES-2, CES Analysis of Liberty's 2022 Distribution Substation Hourly Load Data & Peak Load by Month
- Exhibit CES-3, Seasonal Rate Differentiation Approved by Maine Public Utilities Commission for Central Maine Power Company in Docket No. 2022-00152
- Exhibit CES-4, Eversource Energy Western Massachusetts Extra Large General Service: Rate T-5 Tariff
- Exhibit CES-5, Eversource Energy Eastern Massachusetts Greater Boston Service Area Large General Service: Rate G-3 Tariff
- Exhibit CES-6, Central Maine Power Company Optional Targeted Service Rate: B-CPT Coincident Peak Transmission Tariff
- Exhibit CES-7, Sample of Versant Power and Central Maine Power Company Regional Network Service Hourly System Loads, Calendar Year 2022

II. OVERVIEW OF DARTMOUTH

Q. Please provide an overview of Dartmouth College.

A. Dartmouth College is a private, co-educational, residential college located in Hanover, New Hampshire. Dartmouth enrolls approximately 4,400 undergraduates and 2,100 graduate students and currently has approximately 950 faculty members and 3,300 administrative staff. The College maintains and operates approximately 300 buildings in the area, including lecture halls, dorms, and other facilities. Liberty provides electric service to Dartmouth's main campus and local facilities across approximately 175 different electric accounts.

In 2017, Dartmouth established an institutional goal to reduce greenhouse gas emissions from campus operations. Dartmouth is undertaking a significant campus decarbonization plan to realize these goals, including a campuswide conversion of building-level and district utilities infrastructure to enable the electrification of high-efficiency heating and cooling operations across the College's facilities.

Q. What does Dartmouth's campus decarbonization plan entail?

A. Over the past 15 years, Dartmouth has been implementing energy efficiency improvements to existing facilities and designing new high-performance buildings, with the aim to manage the College's energy costs and reduce campus greenhouse gas emissions. Dartmouth's current and ongoing priorities are to continue with energy efficiency improvements to existing and new facilities, and to convert the campus' district heating system from steam to low-temperature hot water, which the College anticipates will improve the efficiency of the campus' heating distribution system by roughly 20%. Unlike steam, a district hot water system can utilize non-combustion, low-carbon thermal energy sources for heating such as geo-exchange (geothermal borefields and water-source heat pumps), solar thermal, and air-source heat pumps. These highly efficient heating and cooling technologies are powered by electricity and provide a viable pathway to significantly cut onsite emissions associated with Dartmouth's heating fuel use today.

Dartmouth recently completed construction of the first portion, about 10%, of the campus' new district hot water network, which serves the heating systems in the Arthur L. Irving Institute for Energy and Society and the Class of 1982 Engineering and Computer Science Center buildings. New low-temperature hot-water heating systems have been completed in Dartmouth Hall, Rollins Chapel, Webster-Rauner Library, Reed, Thornton, and Anonymous Halls. Design and construction is underway for installation of low-temperature hot-water heating systems and energy efficiency improvements in other buildings on campus. Dartmouth is also in the advanced stage of finalizing geo-exchange system siting, which will determine the locations for several large-scale geothermal borefields. Geo-exchange heating and cooling is expected to serve as the backbone of the campus' non-combustion energy future.

Q. How do you expect Dartmouth's campus decarbonization efforts will change the College's electricity usage over time?

A. The campus decarbonization plan will significantly increase Dartmouth's grid electricity consumption and demand as the campus' district steam system is phased out in the coming years. The main campus' two primary electric accounts served by Liberty consume approximately 50 million kWh of grid electricity today and have a combined maximum grid demand of roughly 10 MW in the summer and 6.5 MW in the winter. Dartmouth estimates the campus' annual grid electricity purchases will increase to over 75 million kWh by 2030. Unless DERs are installed on campus and operated to shift grid demand, the College's demand on Liberty's system during peak hours is expected to substantially increase as the decarbonization plan is implemented.

Q. Is Dartmouth evaluating strategies and technologies to manage the campus' increasing grid demand?

A. Yes. Dartmouth is evaluating a range of behind-the-meter DERs that could be operated to reduce the campus' grid demand during periods when Liberty is experiencing peak demand conditions on its local distribution system and on the transmission system serving its territory. Dartmouth appreciates the potential impact that campus electrification could have on Liberty's system. DERs, however, can provide an effective tool to mitigate this impact.

Potential DER solutions for the campus include onsite thermal energy storage, battery storage, and active load management for controllable electric loads such as electric vehicle charging. For example, Dartmouth has conducted a preliminary feasibility analysis for installing two chilled water storage tanks on campus that would have a combined storage capacity of 2.2 million gallons and 16,000 ton-hours of cooling potential. A thermal energy storage system like these storage tanks would operate as a "water battery", allowing Dartmouth to produce and store chilled water overnight and to discharge that chilled water the following afternoon and evening for space cooling in lieu of consuming grid power. Operating the chilled water storage tanks would enable significant reductions in Dartmouth's grid demand during hot, humid summer afternoons and evenings when Liberty's system is at its lowest carrying capacity, benefitting all Liberty ratepayers by helping shift load outside of peak hours that drive marginal capacity investment.

III. CURRENT RATE DESIGN FOR G-1 CUSTOMERS

Q. Please summarize how Liberty charges G-1 customers like Dartmouth for electricity delivery (i.e., transmission and distribution).

A. Dartmouth's main campus in Hanover is served by two primary electric accounts. Both accounts take service from Liberty under Rate G-1. Liberty's G-1 rate design includes a fixed monthly charge, various unit-based energy charges that are assessed per kWh of consumption, and a demand charge based on the greater of a customer's maximum 15-minute grid demand registered in a billing cycle during on-peak hours or 80% of the customer's maximum 15-minute grid registered during on-peak hours in the prior 11 months.

In July 2023, Liberty assessed G-1 customers a fixed monthly service charge of $493.50, a distribution demand charge of $10.45 per kilowatt ("kW") with a demand ratchet provision, a distribution energy charge of $0.00298 per kWh during Liberty's off-peak hours, a distribution energy charge of $0.00770 per kWh during Liberty's on-peak hours, and a flat energy charge of $0.02367 per kWh during all hours. This flat, around-the-clock energy rate includes Liberty's transmission charge, stranded cost charge, system benefits charge, and storm recovery adjustment.

Liberty's current delivery rates for G-1 customers have no seasonal differentiation. The distribution demand charge is the same rate in all 12 months, as are the rates for the Company's various energy charges that are assessed per kWh of usage. Examining the TOU periods for G-1 customers, Liberty's on-peak period for Rate G-1 includes the hours of 8:00 a.m. to 9:00 p.m. daily Monday through Friday excluding holidays. Liberty's off-peak period for Rate G-1 includes all other hours, spanning 9:00 p.m. to 8:00 a.m. daily Monday through Friday, and all day on Saturdays, Sundays, and holidays.

Q. When was the last time Liberty updated its rate design for G-1 customers?

A. According to Liberty, the Company has not modified the definition of its on-peak hours for Rate G-1 for more than a decade and is unaware of any changes made by Liberty's predecessor prior to the acquisition in 2012.[1]

Q. Is Liberty proposing to make any updates or changes to its distribution rate design or transmission rate design for Rate G-1 in this proceeding?

A. No. Liberty seeks to maintain its status quo rate design for Rate G-1.

Q. Did Liberty evaluate how the Company's current rate design affects G-1 customers' ability to use DERs to reduce grid demand in a way that benefits other ratepayers?

A. No.[2] While Liberty has invested substantial time and effort evaluating how to increase DER adoption among its residential customers, including developing a full proposal to expand the Company's residential battery storage program, Liberty has made no effort to evaluate whether its rate design incentivizes or disincentivizes DER adoption among its non-residential customers.

Q. Did Liberty meet with any G-1 customers to solicit feedback on its current rate design as part of its effort to review and modernize its retail rates in New Hampshire?

A. No. According to Liberty, no meetings were held with, or feedback solicited from any of Liberty's G-1 customers during the development of the rate proposals included in this case. Effective rate modernization for Liberty's New Hampshire service territory, however, cannot be achieved in a vacuum without input from or engagement with its largest customers.

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[1] DAR 1-11
[2] DAR 1-20

IV. PURPOSE OF TESTIMONY: CONCLUSIONS & RECOMMENDATIONS

Q. What is the purpose of your testimony?

A. Liberty does not propose to modernize its G-1 rate design, contrary to the intentions of its Advanced Rate Design Roadmap. Liberty's current rate design discourages large customer investment in DERs for targeted load shifting to minimize their contribution to peak demand on Liberty's system, promotes the inefficient use of resources, perpetuates the application of the outdated and unjustified demand ratchet, and constitutes a lost opportunity for customers as a whole. The purpose of this testimony, therefore, is to explain why all rate classes should be modernized in this proceeding.

Throughout its initial filing, Liberty emphasizes the importance of rate modernization. According to Liberty, there are three pillars to the Company's rate modernization strategy and process: 1) create strong connections to the underlying costs of providing electric service; 2) incentivize efficient customer behavior that creates downward pressure on prices and advances affordability; and 3) provide customers with a choice in pricing products.

For its largest customers that take distribution service under Rate G-1, however, Liberty is proposing to maintain its existing distribution and transmission rate designs without changes. Despite G-1 customers' electricity usage making up roughly 40% of the Company's total sales during the 2022 test year, Liberty chooses not to update how electric delivery charges are structured and assessed to its large customers. At the same time, Liberty proposes to implement significant TOU rate design updates and improvements in this proceeding for residential and small commercial customers.

We agree with Liberty that incentivizing efficient customer behavior through effective rate structures is crucial to create downward pressure on prices and advance electricity affordability, especially at this early stage of beneficial electrification in New Hampshire when customer adoption of DERs and load management actions can have a real impact on the need for marginal capacity investment in Liberty's system. However, as we discuss in the coming sections, the existing G-1 rate design discourages DER adoption.

Q. How does Liberty's rate design proposal for Rate G-1 discourage large customer investment in DERs such as behind-the-meter energy storage?

A. To answer this question, one must review each component of Liberty's delivery charges and ask whether shifting a customer's grid demand using a DER can produce electric cost savings for that customer in practice. As we detail in the coming sections, Liberty's distribution and transmission rates are structured in a way that pose significant challenges and limitations for a customer to reduce its electric costs even if the customer effectively shifts its grid demand out of Liberty's on-peak hours.

Liberty's distribution rate design is problematic in a number of regards for a G-1 customer using a DER. Liberty's monthly distribution demand charge accounts for most of a G-1 customer's annual electric distribution cost. Liberty's broad 13-hour daily on-peak period forces a customer to significantly oversize a DER's capacity to have any chance of reducing the customer's grid demand across all on-peak hours in a month. Furthermore, Liberty's demand ratchet forces a DER to be operated on every business day of the year for the customer to see distribution demand cost savings, eliminating the opportunity for seasonal thermal energy storage technologies to be used to produce distribution cost savings for the host customer. Finally, even though Liberty's distribution costs are driven by peak load conditions in the summer months when the system is at its lowest carrying capacity relative to the load on the system, Liberty's G-1 rates have no seasonal differentiation. To properly incentivize DERs that target peak summer load reduction, summer rates must be higher than non-summer rates.

Transmission charges account for a large share of a G-1 customer's annual electric delivery cost. Under ISO New England's Open Access Transmission Tariff, Liberty's cost obligations for transmission service are determined each month by the utility's peak demand. However, Liberty assesses G-1 customers a flat energy charge per kWh that has no connection to Liberty's monthly peak load hour. If a G-1 customer operates a DER to reduce its grid demand during Liberty's monthly peak load hour, the customer will see no transmission cost savings even though Liberty's other customers will benefit from a lower transmission cost allocation from ISO New England resulting from the DER's load shifting. Due to round-trip charging losses for energy storage technologies, G-1 customers that install and operate behind-the-meter battery systems or thermal energy storage systems will actually see a <u>net cost increase</u> in their monthly electric delivery bill from Liberty.

As detailed in the testimony of Mr. Balashov, Liberty's Senior Director of Grid Modernization, a primary purpose of Liberty's residential battery storage pilot program was to evaluate the potential to use batteries to reduce customer costs by reducing the regional and local network service transmission charges through targeted and coordinated discharging of customer-sited batteries during the times of forecasted system peaks.[3] Due to Liberty's rate design for G-1

[3] Direct Testimony of Dmitry Balashov, Battery Storage, page 4, lines 1-5.

customers, if these same batteries were sited and operated behind-the-meter at a G-1 customer's facility, then this same objective becomes impossible to achieve.

Q. Please state your primary conclusions and recommendations.

A. Our primary conclusions and recommendations are as follows:

1. __Conclusion__ – Liberty's proposal to maintain its existing TOU periods for Rate G-1 but to implement new, updated TOU periods for Rate D-TOU, Rate D-11, Rate D-12, Rate G-3-TOU, Rate EV-L, Rate EV-M, Rate EV-L-E, and Rate EV-M-E violates basic ratemaking principles and the core goals of Liberty's rate modernization plan.

__Recommendation__ – Liberty should revise the peak period for all TOU customers to 3 P.M. to 8 P.M. daily Monday through Friday excluding holidays. Liberty's proposal to implement a new mid-peak period should be rejected, with these hours (8 A.M. to 3 P.M. daily Monday through Friday excluding holidays) treated as off-peak hours.

2. __Conclusion__ – Liberty's proposal to maintain a distribution demand ratchet for Rate G-1, Rate G-2, Rate EV-L, and Rate EV-M customers does not reflect Liberty's underlying cost of providing distribution service and poses a significant barrier to DER adoption.

__Recommendation__ – Liberty should eliminate the demand ratchet for all TOU customers' monthly distribution demand charges. A customer's billed demand for each month should be the greater of the following: 1) the greatest fifteen-minute peak during the peak hours which occurs during such month as measured in kilowatts or 2) 90% of the greatest fifteen-minute peak during the peak hours occurring during such month as measured in kilovolt-amperes.

3. __Conclusion__ – Liberty's proposal to maintain a flat distribution demand rate for G-1 customers without seasonal differentiation does not send customers accurate price signals regarding the cost of utilizing Liberty's distribution system. Liberty's proposed summer season (May to October) for Rate D-TOU, Rate D-11, Rate D-12, Rate G-3-TOU, Rate EV-L, Rate EV-M, Rate EV-L-E, and Rate EV-M-E is too broad and includes several months that have much lower distribution loads compared to peak summer conditions.

Recommendation – First, Liberty should revise the two TOU seasons to a two-month summer season (July and August) and a ten-month non-summer season (September to June). Second, Liberty should implement seasonal differentiation in distribution rates for all TOU customers, with the distribution demand rate in July and August set significantly higher than the distribution demand rate in the other non-summer months.

4. Conclusion – Liberty's proposal to maintain a flat, around-the-clock energy rate for assessing transmission charges to G-1 customers that does not vary by time of day contradicts cost causation principles and disincentivizes DER adoption. For G-1 customers that want to install behind-the-meter battery storage or thermal storage systems, Liberty's current transmission rate design would cause the customer's monthly electric cost to increase even if the customer operates the storage system effectively.

Recommendation – Liberty should create a new voluntary transmission rate design option that enables G-1 customers to opt into having their transmission charges assessed based on a customer's average 60-minute grid demand during Liberty's monthly peak load hour. This rate structure would align a large customer's monthly transmission charges to how ISO New England assesses transmission costs to Liberty. This optional rate would follow the template of Eversource Energy's and Central Maine Power Company's coincident peak demand transmission tariffs in Massachusetts and Maine for large distribution customers.

V. DISTRIBUTION RATE DESIGN: TIME OF USE PERIODS

Q. Please explain your concern with Liberty's proposed TOU periods.

A. As proposed by Liberty, Rate G-1 would have significantly different TOU periods than Liberty's other TOU rate classes. Liberty's on-peak period for G-1 customers includes the hours of 8 A.M. to 9 P.M. daily Monday through Friday, excluding holidays. Assuming there are 21 business days in the average 30-day month, the on-peak hours for Rate G-1 cover nearly 33% of total hours in a monthly billing cycle. Liberty's proposed on-peak period for its other TOU rate classes, shown in Table 1, would only cover 15% of total hours in a month. The five-hour daily on-peak period (3 P.M. to 8 P.M. each business day) proposed for these rate classes is substantially smaller than the 13-hour daily on-peak period Liberty proposes maintaining for Rate G-1.

Table 1. Proposed TOU Periods by Rate Class

TOU Rate Class	Peak Hours	Off-Peak Hours	Mid-Peak Hours
Rate G-1 Rate G-2	8 A.M. to 9 P.M. daily Monday through Friday, excluding holidays.	9 P.M. to 8 A.M. daily Monday through Friday, and all hours on Saturday, Sunday, and holidays.	Not applicable
Rate D-TOU Rate D-11 Rate D-12 Rate G-3-TOU Rate EV-L Rate EV-M Rate EV-L-E Rate EV-M-E	3 P.M. to 8 P.M. daily Monday through Friday, excluding holidays.	12 A.M. to 8 A.M. and 8 P.M. to 12 A.M. daily	8 A.M. to 3 P.M. daily Monday through Friday, excluding holidays. 8 A.M. to 8 P.M. Saturday, Sunday, and holidays.

CES works with clients across New England and the U.S. We are not aware of any electric utility in North America that has proposed or implemented TOU periods that differ by customer class in the same territory. This is because the cost to serve a customer depends on the customer's load shape and not on the rate class the customer is in. In our experience, Liberty's proposed TOU approach is unprecedented.

Q. Does Liberty explain why it proposes different TOU periods for Rate G-1 compared to the other TOU classes?

A. No. In his direct testimony, Mr. Tillman, Liberty's Senior Manager of Rate Design, points to four characteristics of effective TOU rates that were used to guide development of Liberty's rate design proposal: 1) a short peak period, 2) a strong price signal and opportunity for significant bill savings, and 3) rates should reflect system costs, and 4) simplicity.[4] Liberty's proposal to maintain a 13-hour daily on-peak period for Rate G-1, while implementing a much shorter five-hour daily on-peak period for the other TOU classes in Table 1 is inconsistent with these purported characteristics of effective TOU rates.

Mr. Tillman goes on to state that TOU rates should be defined by the same underlying principles and methodologies across the entire portfolio of TOU rates available to its customers.[5] Liberty's proposal to have different TOU periods for Rate G-1 compared to Rate D-TOU, Rate D-11, Rate D-12, Rate G-3-TOU, Rate EV-L, Rate EV-M, Rate EV-L-E, and Rate EV-M-E contradicts this statement. There is an evident disconnect between Liberty's stated rate design objectives and its actual rate design proposal for G-1 customers.

Q. Did Liberty perform any analysis to support its decision to maintain a 13-hour daily on-peak period for Rate G-1?

[4] Direct Testimony of Greg Tillman, Advanced Rate Design, page 8, lines 5-14.
[5] Direct Testimony of Greg Tillman, Advanced Rate Design, page 33, lines 3-4.

A. No. Mr. Tillman's direct testimony only mentions Rate G-1 twice and only in the context of the proposed electric vehicle charging rates. Liberty has provided no evidence or analysis to justify why G-1 customers should be subject to different TOU periods than other customer classes.

Q. Has Liberty confirmed when the Company will update its TOU periods for Rate G-1?

A. No. Liberty merely states that it intends to align the remaining TOU rate structures in future proceedings.[6] Liberty's Advanced Rate Design Roadmap provides no clear timing or specific commitment for the Company to update its TOU periods for Rate G-1.[7]

Q. If Liberty agrees to update the TOU periods for Rate G-1 to align with the other TOU classes, would that change in their rate design proposal be sufficient?

A. No. As shown in Table 1, Liberty is proposing to implement a new mid-peak period for TOU classes other than Rate G-1. Liberty's proposed mid-peak hours include 8 A.M. to 3 P.M. on business days and 8 A.M. to 8 P.M. on Saturday, Sunday, and holidays.

Q. Why do you disagree with Liberty's proposal to add a new mid-peak TOU period?

A. The Company has provided no analysis to confirm that capacity-related investment in primary distribution plan is being driven by peak demand that is occurring during any specific time period.[8] The existence of a mid-peak is not supported by any evidence or analysis presented by the Company in its initial filing. Liberty's distribution planners do not size the capacity of the distribution system based on "mid-peak" conditions. Implementing a mid-peak period dilutes the price signal that should be sent to customers during on-peak hours.

[6] DAR 1-12
[7] DAR 2-2
[8] DAR 1-21

VI. DISTRIBUTION RATE DESIGN: DEMAND RATCHET

Q. In its initial filing, Liberty consistently emphasizes that TOU rates should create strong connections to the underlying costs of providing electric service. Do you agree?

A. Absolutely. Utility planners design and make investments in the distribution and transmission systems to meet peak demand conditions. Customers' grid demands during these targeted periods dictate whether a utility needs to invest capital to expand the carrying capacity of the system. By leveraging rate design to structure rates in a way that follows cost causation principles, utilities can send effective price signals to customers that incentivize customer behavior and DER adoption to reduce customers' contribution to grid demand during these peak demand periods that drive incremental investment and higher rates for all ratepayers.

Q. Please explain what you mean by cost causation principles.

A. The principle of cost causation states that each customer should bear the responsibility for those costs the utility incurs to serve that customer. For some costs such as the cost of a meter, the cost to send a monthly bill, the cost of a transformer that serves a single customer, or the cost of extending a line to provide electric service to a single customer, it is relatively easy to associate the cost incurred by the utility with the customer responsible for that cost.

When a component of the electric grid serves multiple customers, separating the responsibility for the cost of that component among the various customers it serves can be very difficult, if not impossible. In these instances, certain conventions are adopted and incorporated into methodologies such as embedded cost of service studies, in which the utility allocates components of its costs to different customer classes. The conventions that underlie allocations of costs related to system components that serve multiple customers attempt to define the cause of the costs – for example, system coincident peak demand, non-coincident peak demand by customer, annual energy flows – and then allocate those costs to each customer or customer class based on its relative contribution to the cost driver.

Q. Please explain how Liberty assesses its monthly distribution demand charge to Dartmouth and other G-1 customers.

A. Liberty determines a G-1 customer's billed demand each month as the greatest of the following: 1) the greatest fifteen-minute peak during the peak hours which occurs during such month as measured in kilowatts; 2) 90% of the greatest fifteen-minute peak during the peak hours occurring during such month as measured in kilovolt-amperes; or 3) 80% of the customer's greatest demand as determined above during the preceding eleven months. This billed demand unit is then multiplied by the distribution demand rate, currently $10.45 per kW, with discounts for certain customers based on voltage service and transformer ownership.

We refer to the third component of Liberty's billed demand calculation as a demand ratchet, because a customer's maximum 15-minute grid demand registered during on-peak hours in a month can dictate the customer's monthly distribution demand charge for the next 11 months. In practice, a demand ratchet sets a floor for a customer's distribution demand charges throughout the year, reflecting 80% of the customer's maximum on-peak demand registered in a year.

Q. What is Liberty's reasoning for maintaining its distribution demand ratchet?

A. Liberty states that the costs of the distribution function are primarily fixed in nature and do not vary based on the time of day in which the distribution service is used. [9] Liberty claims that as

[9] DAR 1-7

a customer changes consumption patterns throughout the day, there is no direct impact on the costs to provide distribution service to the customer.

Q. Do you agree with Liberty's position?

A. Liberty is conflating costs in the short-run with costs in the long-run. If a customer permanently modifies its load on Tuesday, Liberty's costs of providing distribution service on Wednesday will not change. Costs will not change on Thursday or next week, or even next month. Over the short-term, Liberty is correct – its costs are fixed. In fact, economists define the short-run as the length of time during which a company's costs are fixed with respect to a specific aspect of its production process or equipment used.

However, as Liberty evaluates the adequacy of its distribution system to meet future loads, it looks at a longer planning horizon during which it is able to modify its physical plant to meet those future loads. This is the long-run – and over the long-run, Liberty's costs to serve loads are not fixed. Liberty's grid is not and has never been static; and looking to the future as beneficial electrification of transportation and space heating expand across its service territory, the grid promises to become even more dynamic.

Q. Does Liberty's position with respect to the fixed nature of its costs align with the Company's initial testimony on rate design?

A. No. In his initial testimony, Mr. Tillman states "since the costs of electric service are different during these defined time periods, it follows that the prices during the on peak period higher than the prices during the off-peak period. As customers respond to the price signals by reducing or shifting load away from the on-peak period, they reduce peak demands on the system resulting in more efficient use of system resources and lower overall costs for all customers."[10] Clearly, Mr. Tillman is referring to the long-run, where system resources and overall costs are capable of adjusting to meet customer loads.

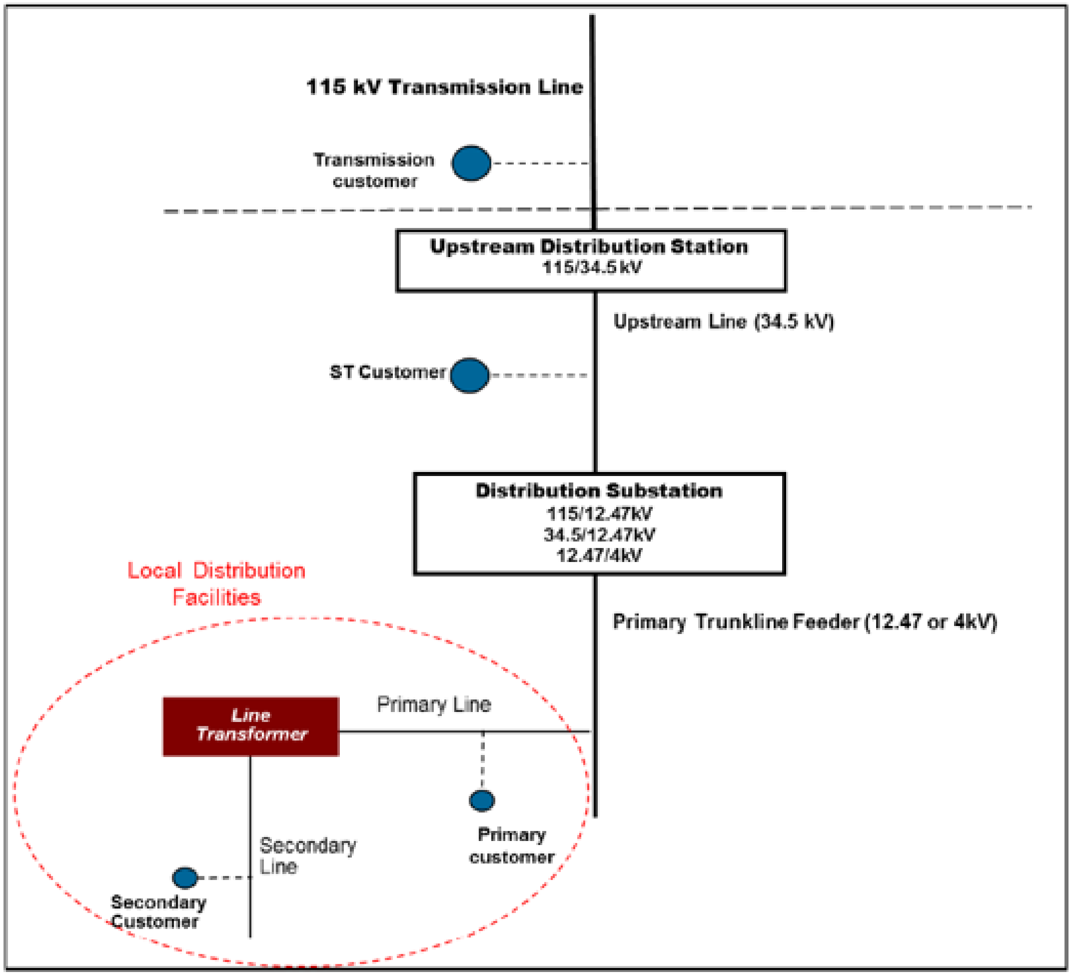
Q. Do you agree with Liberty's reasoning to maintain the demand ratchet?

A. No. Liberty's argument ignores the fact that there are multiple components of the distribution system, some of which are sized based on a customer's maximum design demand whereas other distribution components are shared among customers and are sized based on the coincident peak demand that customers collectively place on Liberty's local distribution substation and primary distribution feeders.

The distribution system consists of two primary categories of plant: growth-related distribution facilities and local distribution facilities. As shown in Figure 1 below, growth-related distribution facilities include shared distribution system infrastructure such as distribution substations and primary trunkline feeders that connect to a substation. For growth-related facilities, increases in customers' grid demand during coincident peak demand periods drive expansion of the local substation and primary feeders. As local peak load grows, the trunkline feeders that start at the substation and end at the point where the line branches to create a local primary line may need to be upgraded or rerouted. Changes in a customer's load pattern, specifically reductions in the customer's grid demand during periods of coincident peak demand measured at the local distribution substation, will result in direct impacts to Liberty's costs to provide distribution service to customers served by that substation.

[10] Direct Testimony of Greg Tillman, Advanced Rate Design, page 7 lines 8-13

Figure 1. Simplified Diagram of Distribution and Transmission System



Local distribution facilities include line transformers, secondary lines, and the local portion of primary lines. Local distribution facilities are typically less shared across customers and thus are incurred based on individual customer design demand rather than the coincident peak loads of all customers served. For these local distribution facilities, we agree with Liberty that as a customer changes consumption patterns throughout the day or across different seasons, there is likely to be no direct impact on the costs Liberty incurs for these facilities. However, over the long run even these facilities may need to be replaced and upsized if a customer's load increases beyond the capacity of these facilities. Accordingly, utility rates should send correct price signals to customers.

Q. How would you recommend Liberty design distribution rates to reflect the differing cost causation for growth-related distribution facilities and local distribution facilities?

A. Since the cost of local distribution facilities are generally fixed in nature, it is appropriate for Liberty to collect these costs through a customer's fixed monthly service charge based on the marginal costs of providing such facilities. However, since the cost of growth-related distribution facilities is driven by aggregate customer demand during select periods of coincident peak demand, it is appropriate for Liberty to collect these costs through a demand charge that is based on a customer's maximum demand registered each month during the on-peak period.

Q. What do you recommend is modified in Liberty's rate design to reflect this?

A. The distribution demand ratchet should be eliminated for all TOU customers. Liberty should determine a G-1 customer's billed demand each month under ordinary load conditions as the greater of 1) the greatest fifteen-minute peak during the peak hours which occurs during such month as measured in kilowatts, or 2) 90% of the greatest fifteen-minute peak during the peak hours occurring during such month as measured in kilovolt-amperes. As discussed in Section 3, Liberty's peak hours for Rate G-1 and Rate G-2 should be updated to cover 3 P.M. to 8 P.M. daily Monday through Friday, excluding holidays.

Q. Does Liberty's distribution demand ratchet discourage investment in DERs for targeted load management?

A. Yes. While Liberty claims the Company is moving towards modernized rates that promote efficient customer behavior to create downward pressure on prices and advance affordability goals, the demand ratchet discourages large customer investment in DERs to achieve this objective. According to Liberty, the over-arching goal of TOU rates is to provide a tool for customers to have more control over their electricity bill.[11] In his initial testimony, Mr. Tillman states "if a customer shifts load from the higher-priced on-peak period to the lower-priced off-peak period, they will create a direct reduction to their electric bill."[12] This is simply not true for G-1 customers that want to install DERs like behind-the-meter energy storage.

Q. Please provide an example of how the demand ratchet discourages DER investments.

A. Let's consider a G-1 customer like Dartmouth that is evaluating whether to install a behind-the-meter battery storage system. One of the potential values for a G-1 customer to install a behind-the-meter battery system is to discharge the battery during Liberty's peak hours to reduce the customer's grid demand and associated delivery charges during the on-peak period.

Table 2 below shows the maximum 15-minute demand Liberty registered for Dartmouth's North Campus account during peak hours in each month throughout 2022. The second column of the table shows that North Campus registered its highest monthly on-peak max demand of 5,292 kW in September 2022 and its lowest monthly on-peak max demand of 3,582 kW in April 2022. In the third column of the table, the max 15-minute demand readings recorded in each month of 2022 are multiplied by 80% to reflect how Liberty examines its ratchet calculation. For example, North Campus' maximum on-peak demand of 5,292 kW registered in 2022 was recorded in September 2022. 80% of 5,292 kW equals 4,234 kW, the demand figure that Liberty uses in subsequent months to determine whether to apply the ratchet.

[11] Direct Testimony of Greg Tillman, Advanced Rate Design, page 4 lines 15-16
[12] Direct Testimony of Greg Tillman, Advanced Rate Design, page 4 lines 17-18

Table 2. Dartmouth North Campus Account: 2022 Max Grid Demand by Month

Month	Max 15-Minute Demand 2022 Actuals	Max 15-Minute Demand 80% Ratchet Calculation	Does the Demand Ratchet Apply?
January	3,940	3,152	Yes
February	3,916	3,133	Yes
March	3,883	3,106	Yes
April	3,582	2,866	Yes
May	5,232	4,186	No
June	5,071	4,057	No
July	4,952	3,962	No
August	4,997	3,998	No
September	5,292	4,234	No
October	5,024	4,019	No
November	4,540	3,632	No
December	3,824	3,059	Yes

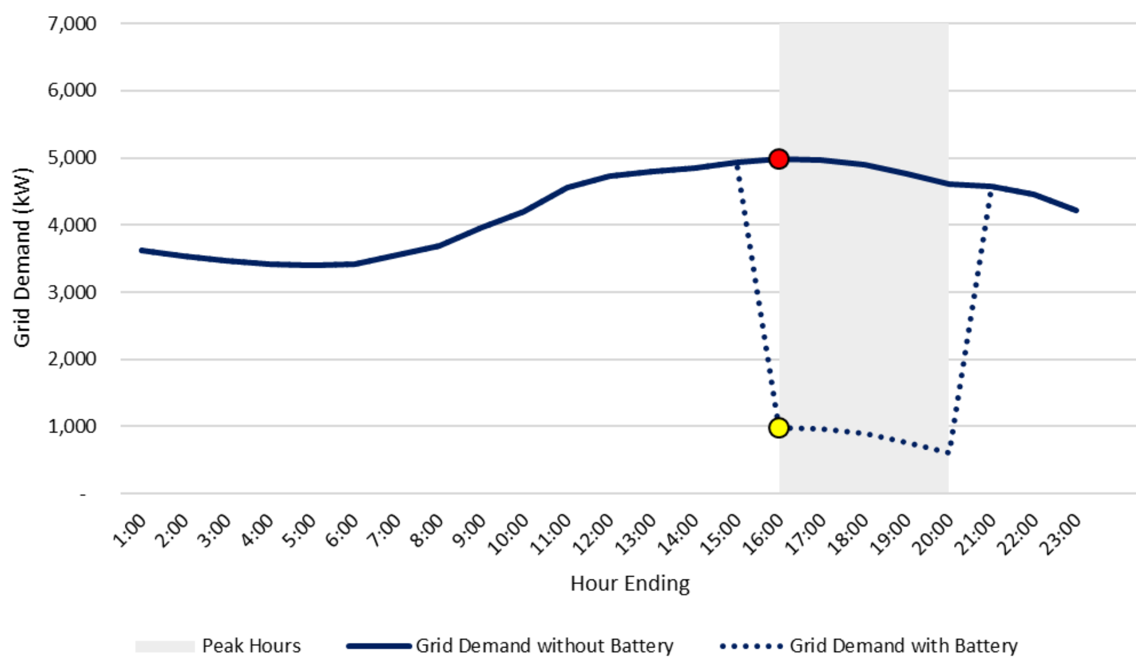
The fourth column of Table 2 shows that Liberty's demand ratchet applied to the North Campus' distribution demand charge in five of the twelve months in 2022. 80% of 5,500 kW, the maximum on-peak demand registered by North Campus in September 2021, is 4,400 kW. This 4,440 kW established the basis for the demand ratchet for the next 11 months. As shown in the third column of the table, the maximum on-peak demands registered in January 2022 through April 2022 were all less than 4,400 kW, so the demand ratchet of 4,400 kW applied in all four months.[13] The maximum on-peak demand registered by North Campus in May 2022 through August 2022 exceeded 4,400 kW in all four months, so the demand ratchet did not apply in these months. North Campus' maximum on-peak demand of 5,292 kW registered in September 2022 reset the demand ratchet, which applied in December 2022 when the account's maximum on-peak demand of 3,824 kW was less than 4,324 kW, 80% of 5,292 kW.

[13] The North Campus account's maximum 15-minute load in 2021 was registered at 5,500 kW in September 2021. 4,400 kW is 80% of 5,500 kW.

Now let's assume that a 5 MW / 20 MWh battery system is installed behind-the-meter on North Campus. This sizing means that Dartmouth could discharge the battery system at a maximum rate of 5 MW for up to four hours. Alternatively, Dartmouth could operate the system to discharge less power depending on load conditions on campus and avoid exporting excess power to Liberty's distribution system. For example, Dartmouth could discharge the battery at 4 MW for five hours, 2 MW for 10 hours, or could schedule varying discharge rates so long as the total energy sent to campus during the discharge does not exceed 20 megawatt-hours ("MWh").

Assuming Liberty's on-peak hours are updated to cover 3 P.M. to 8 P.M. across all business days, Figure 2 below shows how a behind-the-meter battery system's discharged energy could reduce North Campus' grid demand during the five-hour peak period.

Figure 2. Behind-the-Meter Battery Discharging Impact on North Campus Grid Demand

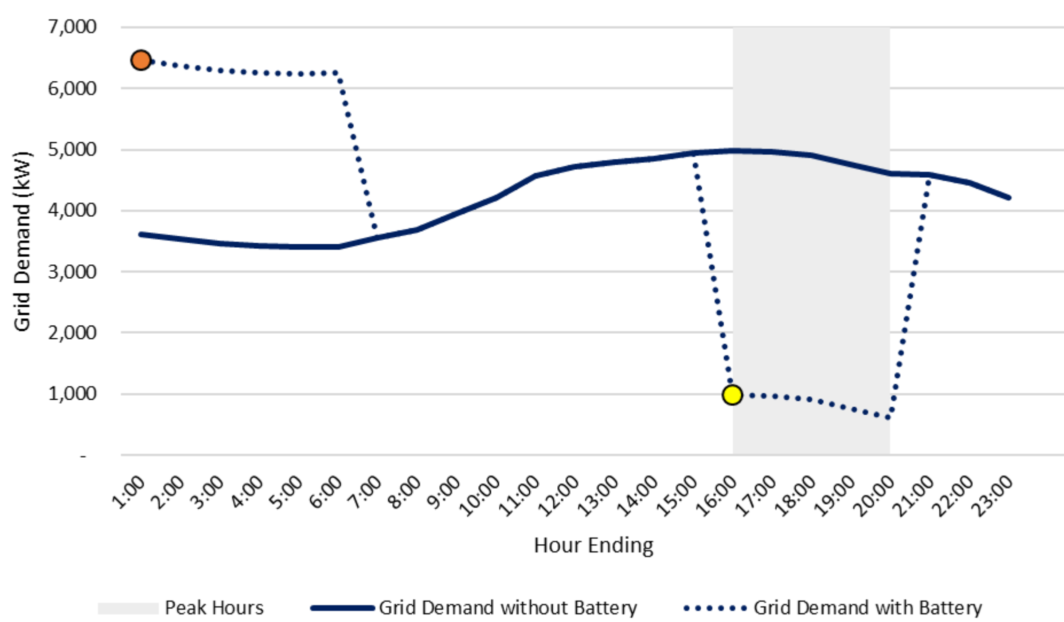


The grid demand data included in Figure 2 is Liberty's hourly readings for North Campus on September 12, 2022, the day on which Dartmouth registered its highest load for the year (5,292 kW) at this account. Figure 2 shows that without a battery, North Campus' maximum 15-minute grid demand during Liberty's updated on-peak hours would have been approximately 5 MW, as noted by the red marker. If the battery was discharged at 4 MW over five hours to span the on-peak period between 3 P.M. and 8 P.M., the account's maximum on-peak grid demand on this day would be reduced to roughly 1 MW, as noted by the yellow marker.

Q. What about the impact of battery charging? Wouldn't Dartmouth need to charge the battery from the grid after each discharge to be able to use the battery again?

A. That's correct. Dartmouth would need to charge the battery from the grid to recharge the system after each discharge event. Figure 3 shows that on September 12, 2022, North Campus' overnight grid demand ranged between 3 MW and 4 MW, as shown by the sold blue line.

Figure 3. Behind-the-Meter Battery Charging Impact on North Campus Grid Demand



With the new added load from charging a battery, the account's overnight grid demand would increase, as shown by the dashed blue line in Figure 3. Assuming the battery is charged from the grid between 10 P.M. and 6 A.M. at a rate of 2.85 MW, Figure 3 shows that the account would have registered a maximum off-peak grid demand of nearly 6.5 MW overnight, noted by the orange marker. Since this increased overnight grid demand occurs during Liberty's off-peak hours, the increased electric load caused by battery charging would not impact North Campus' monthly distribution demand charge and would not be considered by Liberty when determining whether to apply the demand ratchet to the account's demand charge for this month.

Q. How does Liberty's demand ratchet impact discourage a G-1 customer from installing a behind-the-meter battery storage system?

A. The existence of the demand ratchet makes it nearly impossible for the host customer to use an energy storage system to effectively manage the customer's distribution demand charges. The demand ratchet requires that a battery system be successfully discharged on every business day throughout the year, which 1) shortens a battery's useful life by accelerating degradation of the system's energy capacity and 2) takes away the customer's ability to choose when to strategically discharge the battery system.

If the host customer does not discharge the battery on a business day, whether it be for planned maintenance of the system, an unplanned outage or malfunction that forces the system offline, or for strategic management of the battery's energy degradation to prolong the system's useful life, the host customer's potential to reduce its billed distribution demand over the next 11 months will be cut by nearly two-thirds due to the effect of the demand ratchet. A single 15-

minute interval grid demand during peak hours will negate the impact of battery operations on the host customer over the next year.

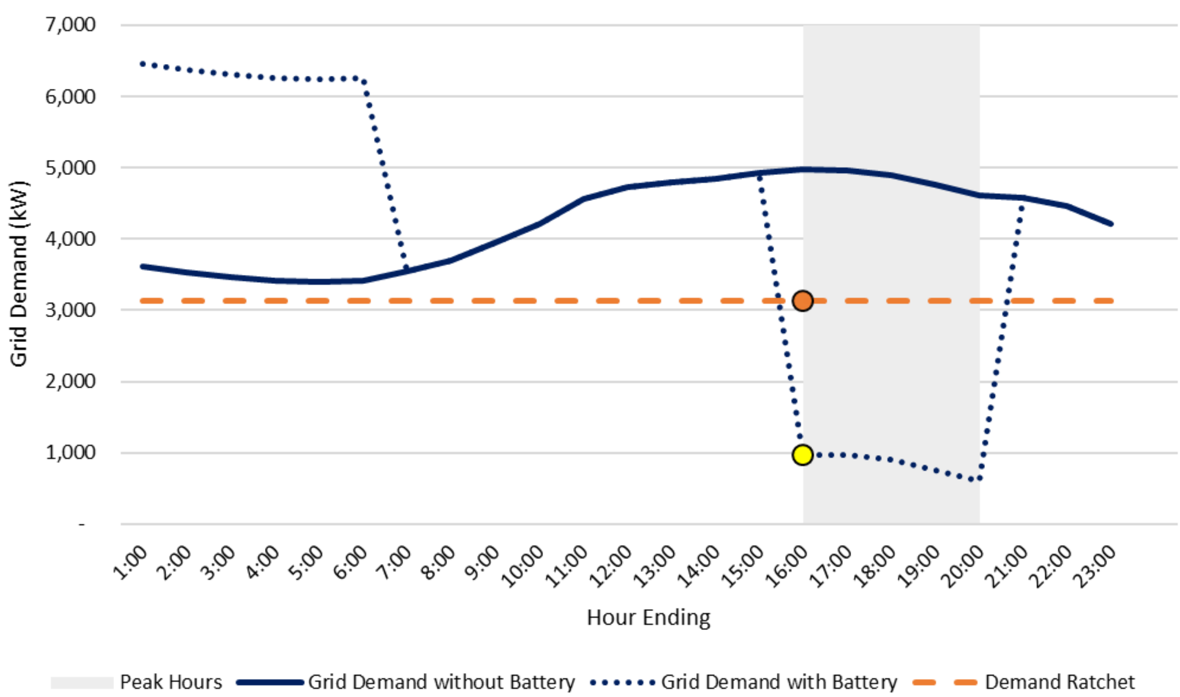
To understand this issue, let's revisit the definition of the demand ratchet. Liberty determines a G-1 customer's billed demand each month as the greatest of the following: 1) the greatest fifteen-minute peak during the peak hours which occurs during such month as measured in kilowatts; 2) 90% of the greatest fifteen-minute peak during the peak hours occurring during such month as measured in kilovolt-amperes; or 3) 80% of the customer's greatest demand as so determined above during the preceding eleven months.

Let's assume a behind-the-meter battery system on Dartmouth's North Campus is not discharged during a business day in October due to downtime for normal system maintenance. Even though that October day may have mild temperatures producing lower loads on the local distribution system, meaning Dartmouth's grid demand has no bearing on the cost of Liberty's growth-related distribution facilities, Dartmouth will be penalized for this grid demand for the next 11 months through the demand ratchet.

This issue is illustrated in Figure 4 below. The North Campus account's average grid demand in October is approximately 4 MW during our proposed updated on-peak hours (3 P.M. to 8 P.M. on business days), which are highlighted in gray. If battery downtime occurs during updated on-peak hours in October, the demand ratchet for North Campus would be set at an estimated 3 MW (80% of 4 MW). Using the same hourly load data for the North Campus account from September 12, 2022 that is presented in Figures 2 and 3, Figure 4 shows that the demand ratchet of roughly 3 MW would cut a battery's demand charge reduction potential by

50%. Even though the account's grid demand during the on-peak hours on this day is reduced from roughly 5 MW to 1 MW, the account's demand charge would be 3 MW due to the ratchet.

Figure 4. Demand Ratchet Impact on Demand Charge Reduction Potential



Even though the 4 MW battery discharge on this day would cause Dartmouth's maximum grid demand to be limited to 1 MW between 3 P.M. and 8 P.M., as shown by the dashed blue line in Figure 4 and the hours highlighted in gray, Liberty would assess Dartmouth a monthly demand charge of 3 MW due to the application of the demand ratchet using the maximum on-peak demand registered in the prior October. By significantly diluting the potential for DERs like battery storage to help the host customer reduce its monthly distribution demand charge, the demand ratchet prevents a customer that shifts load from the on-peak period to the off-peak period from realizing a full reduction to their electric bill.

Q. You noted the demand ratchet's impact on battery degradation. Please explain why daily cycling of a battery would reduce a battery storage system's useful life.

A. A lithium-ion battery system's energy capacity degrades with each operations cycle. Based on CES' work with other end users in New England that have installed behind-the-meter battery systems, there is a notable difference in battery degradation between 120 cycles per year and 250 cycles per year. The increased degradation compounds over years of operations.

Liberty's demand ratchet would force a host customer to pursue 250+ cycles per year (i.e., every business day) if the host wants to see a direct reduction in their monthly distribution demand charges. This operations requirement shortens a battery's life and would lead customers to operate their systems on mild days that have no bearing on the utility's decision whether marginal investment is needed to expand growth-related distribution and transmission plant.

Q. Does the demand ratchet have a similar impact in discouraging a G-1 customer to install a behind-the-meter thermal energy storage system?

A. Yes. A chilled water storage tank could produce significant reductions in Dartmouth's grid demand during hot summer afternoons and evenings when the grid is at its lowest carrying capacity. However, since the system is designed to provide space cooling, the chilled water tanks would have little to no operations outside of the summer months and therefore would not reduce Dartmouth's grid demand in the shoulder season or the winter months. Dartmouth's ability to reduce its distribution demand charges in the summer months would be undercut in the same way as we illustrated in Figure 4, removing a key financial incentive to install the system.

Q. What do you recommend as the solution to address this issue?

A. Liberty should eliminate the demand ratchet for all TOU customers.

VII. DISTRIBUTION RATE DESIGN: SEASONAL RATE DIFFERENTIATION

Q. What is Liberty's reasoning for not differentiating its distribution rates by season for Rate G-1?

A. Liberty contends that distribution costs are generally fixed in nature and do not vary with the time of day or year. [14] This is the same short-run conflation noted above. Liberty states, however, that to the extent that some distribution costs are deemed to vary by time of day or year, rates should reflect such variation in costs.

Q. Is Liberty's rate design proposal consistent with this reasoning?

A. No. Liberty's distribution demand and energy rates for G-1 customers remain the same across all 12 months, even though Liberty's system has significantly different carrying capacities in the summer compared to the winter months, and therefore different long-run costs to serve loads in the different seasons. For distribution system components that are shared among customers, such as substations and primary trunkline feeders, the carrying capacities of these grid components differ substantially, depending on temperature and wind conditions.

Therefore, when Liberty's grid planners examine whether marginal capacity needs to be added to the distribution system, the team should be examining not only the peak load registered at a distribution substation or on a trunkline feeder but also the carrying capacities of these components at that time. Given Liberty's current and expected load hourly loads over the next ten to twenty years, the distribution demand rate should be much higher in the summer months than in the other months of the year to reflect the grid's lower carrying capacity in hot conditions.

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[14] DAR 1-17

Q. Please explain what you mean by grid carrying capacity and why this should be reflected by varying rates across seasons.

A. Carrying capacity refers to the maximum amount of electrical current that power lines, transformers, and other grid equipment can physically handle without experiencing thermal overloading. The grid's carrying capacity is not static; it varies depending on ambient air temperature and wind speed, among other factors. Distribution and transmission systems in New England have very different carrying capacities during the summer and winter months. The grid can handle significantly more load during coincident peak demand hours in the winter months, which typically occur on frigid, windy nights when grid carrying capacities are at their maximums. These conditions are the opposite of temperature and wind speed during coincident peak demand hours in the summer months, which typically occur during hot, humid, and stagnant conditions in the late afternoon and early evening when grid carrying capacities are at their minimums.

It is not only the peak load that matters in terms of driving growth-related investments in Liberty's distribution system capacity. Grid equipment ratings are substantially different between summer and winter conditions, meaning that the grid has different carrying capacities even if the peak load on a distribution substation in the winter exceeds the peak load in the summer. It is the relationship between the actual load and the carrying capacity of the grid each hour that matters.

Over the last three decades, this relationship has been most strained during the hour of summer peak when the grid's carrying capacity is at its lowest. As a result, we have come to think that the only critical factor is the annual system peak load. It is not. The incremental kilowatt of demand added during the summer months will continue to drive marginal investment in new grid capacity for Liberty for the foreseeable future and therefore should be the focus of price signals in distribution rate design. Even as heat pumps increase customers' electricity consumption and demand during the winter months, we expect that for the foreseeable future this increased demand will be offset by the grid's higher carrying capacity during cold, windy conditions when heat pumps incur maximum draw from the grid.

Q. If Liberty updates its distribution demand rate to follow the seasonal differentiation template it has proposed for its other TOU classes, would that change be sufficient?

A. No. Liberty is proposing to implement two rate seasons for distribution charges assessed to Rate D-TOU, Rate D-11, Rate D-12, Rate G-3-TOU, Rate EV-L, Rate EV-M, Rate EV-L-E, and Rate EV-M-E. The proposed summer season includes six months, May through October, and the proposed winter season includes six months, November through April. As shown in Table 3, Liberty is proposing minimal seasonal differentiation between the summer and winter rates.

Table 3. Liberty's Proposed Distribution Rate Design for Non-G1 TOU Classes

Rate Class		Summer (May - October)			Winter (November - April)		
		Off Peak	Mid Peak	Peak	Off Peak	Mid Peak	Peak
Rate D-TOU	$/kWh	$0.0673	$0.0819	$0.1019	$0.0641	$0.0728	$0.0864
Rate D-11	$/kWh	$0.0673	$0.0819	$0.1019	$0.0641	$0.0728	$0.0864
Rate D-12	$/kWh	$0.0673	$0.0819	$0.1019	$0.0641	$0.0728	$0.0864
Rate G-3-TOU	$/kWh	$0.0617	$0.0851	$0.0835	$0.0644	$0.0774	$0.0762
Rate EV-L	$/kWh	$0.0184	$0.0224	$0.0228	$0.0188	$0.0214	$0.0216
Rate EV-L-E	$/kWh	$0.0184	$0.0224	$0.0228	$0.0188	$0.0214	$0.0216
Rate EV-M	$/kWh	$0.0228	$0.0285	$0.0305	$0.0234	$0.0252	$0.0270
Rate EV-M-E	$/kWh	$0.0228	$0.0285	$0.0305	$0.0234	$0.0252	$0.0270

Rate Class		Summer (May - October)			Winter (November - April)		
		Off Peak	Mid Peak	Peak	Off Peak	Mid Peak	Peak
Rate D-TOU	% of Summer Rate				95.2%	88.9%	84.8%
Rate D-11	% of Summer Rate				95.2%	88.9%	84.8%
Rate D-12	% of Summer Rate				95.2%	88.9%	84.8%
Rate G-3-TOU	% of Summer Rate				104.4%	91.0%	91.3%
Rate EV-L	% of Summer Rate				102.2%	95.5%	94.7%
Rate EV-L-E	% of Summer Rate				102.2%	95.5%	94.7%
Rate EV-M	% of Summer Rate				102.6%	88.4%	88.5%
Rate EV-M-E	% of Summer Rate				102.6%	88.4%	88.5%

Table 3 shows that under Liberty's proposal, there is a roughly 10% difference on average between its distribution energy charges in the summer season and its distribution charges in the winter season for the selected TOU rate classes.

Q. How do you recommend improving this seasonal rate differentiation?

A. First, Liberty's summer rate season should be narrowed to only include July and August. As shown in Table 4 and Table 5 below, the peak annual demand currently being recorded at Liberty's distribution substations is heavily concentrated in July and August. Tables 4 and 5 are color coded such that the highest load readings are shown in red and the lowest load readings are shown in green by substation.

The peak load measured at each substation in May, June, September, and October is notably lower than the peak load measured by Liberty in July and August. For example, as shown in Table 5 Liberty's Mount Support substation recorded a peak monthly load of 38,695 kW in July 2022 and 39,161 kW in August 2022. Mount Support recorded a peak monthly load of 35,267 kW in May 2022, 33,541 kW in June 2022, and 35,217 kW in September 2022. This roughly 10% difference in peak monthly load between July/August and the other months is significant.

Having an extended summer rate season that spans six months from May to October, as proposed by Liberty, dilutes the price signal that customers should receive in July and August when Liberty's distribution system is most constrained.[15] Liberty's distribution demand rates for G-1 customers should be higher in July and August compared to the other months of the year.

[15] A copy of CES' analysis and the hourly load data used to develop Table 4 and Table 5 is provided in Exhibit CES-2. These tables have several blank cells due to missing or seemingly erroneous data in Liberty's response to DAR 1-3. CES organized the hourly load data provided in Liberty's response to DAR 1-3 by distribution substation based on the Company's response to DAR TS 1-1.

Table 4. Maximum Monthly Loads by Liberty Distribution Substation Metering Point: January 2022 – December 2022

	Liberty Distribution Substations Max Monthly Load (kW)													
	Mount Support		Golden Rock		Spicket River	Pelham		Rockingham	Slayton Hill		Wilder (NGRID)	Michael Ave	Vilas Bridge (NGRID)	
Month	6218282	6218283	7220335	7220336	2208265	7220077	7220078	228263	2031083	4213019	5217399	3210687	2208270	2208264
Jan	15,019	15,926		24,998	15,513	10,597	9,992		13,180	10,193	13,801	6,458	4,617	3,393
Feb	14,402	17,060		24,163	14,109	9,500	9,185		11,907	10,067	13,087	6,411	4,274	3,133
Mar	14,112	15,876		25,920	12,506	13,747	8,757		10,962	9,626	12,338	6,108	3,951	2,915
Apr	13,520	16,481		17,251	10,588	7,018	7,321	9,374	9,097	8,644	10,080	5,940	3,228	2,428
May	15,712	20,160			19,500	11,164	11,504	13,219	10,294	11,920	11,658	7,143	3,692	2,935
Jun	14,830	19,051	11,256	15,638	19,928	11,806	12,373	15,271	10,231	11,542	12,096	6,942	3,744	2,917
Jul	32,395	21,319	13,272	19,526	22,766	14,654	14,918	20,563	11,365	13,003	13,582	9,368	4,308	3,465
Aug	18,396	37,145	13,826	20,419	22,706	15,082	22,592	20,542	12,083	13,520	14,308	8,205	4,346	3,537
Sep	15,939	21,496	9,744	15,091	13,664	9,526	10,156	16,524	9,248	10,924	11,255	6,539	3,154	2,655
Oct		20,236	10,080	15,552	11,448	7,081	8,644	14,515	9,689	9,614	10,840	5,954	3,275	2,339
Nov	27,077	16,934	7,358	11,894	12,606	7,825	9,526	10,519	10,269	8,581	11,209	5,759	3,741	2,673
Dec	26,246	26,258	7,879	12,067	14,113	8,984	9,034	10,930	16,506	8,996	11,739	5,732	3,937	2,995

	Liberty Distribution Substations Max Monthly Load (% of May-Oct Peak Load)													
	Mount Support		Golden Rock		Spicket River	Pelham		Rockingham	Slayton Hill		Wilder (NGRID)	Michael Ave	Vilas Bridge (NGRID)	
Month	6218282	6218283	7220335	7220336	2208265	7220077	7220078	228263	2031083	4213019	5217399	3210687	2208270	2208264
Jan														
Feb														
Mar														
Apr														
May	49%	54%			86%	74%	51%	64%	62%	88%	81%	76%	80%	83%
Jun	46%	51%	81%	60%	88%	78%	55%	74%	62%	85%	85%	74%	81%	82%
Jul	100%	57%	96%	75%	100%	97%	66%	100%	69%	96%	95%	100%	93%	98%
Aug	57%	100%	100%	79%	100%	100%	100%	100%	73%	100%	100%	88%	94%	100%
Sep	49%	58%	70%	58%	60%	63%	45%	80%	56%	81%	79%	70%	68%	75%
Oct		54%	73%	60%	50%	47%	38%	71%	59%	71%	76%	64%	71%	66%
Nov														
Dec														

Table 5. Maximum Monthly Loads by Liberty Distribution Substation: January 2022 – December 2022

Liberty Distribution Substations Max Monthly Load (kW)									
Month	Mount Support	Golden Rock	Spicket River	Pelham	Rockingham	Slayton Hill	Wilder (NGRID)	Michael Ave	Vilas Bridge (NGRID)
Jan	30,001		15,513	20,588		22,365	13,801	6,458	8,009
Feb	30,971		14,109	18,686		21,017	13,087	6,411	7,350
Mar	28,350		12,506	17,098		19,492	12,338	6,108	6,849
Apr	27,985		10,588	13,999	9,374	16,695	10,080	5,940	5,527
May	35,267		19,500	22,617	13,219	20,752	11,658	7,143	6,612
Jun	33,541	26,664	19,928	24,179	15,271	21,395	12,096	6,942	6,569
Jul	38,695	32,328	22,766	29,459	20,563	23,839	13,582	9,368	7,744
Aug	39,161	33,830	22,706	30,631	20,542	25,351	14,308	8,205	7,767
Sep	35,217	24,262	13,664	19,404	16,524	20,173	11,255	6,539	5,734
Oct		18,053	11,448	15,007	14,515	17,539	10,840	5,954	5,558
Nov	29,786	18,475	12,606	16,519	10,519	18,068	11,209	5,759	6,385
Dec	32,080	19,370	14,113	17,917	10,930	24,608	11,739	5,732	6,932

Liberty Distribution Substations Max Monthly Load (% of May-Oct Peak Load)									
Month	Mount Support	Golden Rock	Spicket River	Pelham	Rockingham	Slayton Hill	Wilder (NGRID)	Michael Ave	Vilas Bridge (NGRID)
Jan									
Feb									
Mar									
Apr									
May	90%		86%	74%	64%	82%	81%	76%	83%
Jun	86%	79%	88%	79%	74%	84%	85%	74%	82%
Jul	99%	96%	100%	96%	100%	94%	95%	100%	97%
Aug	100%	100%	100%	100%	100%	100%	100%	88%	97%
Sep	90%	72%	60%	63%	80%	80%	79%	70%	72%
Oct		53%	50%	49%	71%	69%	76%	64%	69%
Nov									
Dec									

Second, the differential between Liberty's summer distribution rates and winter distribution rates should be much higher than the roughly 10% difference proposed by Liberty. We recommend that the G-1 distribution demand rate in July and August be set at least five times higher than the G-1 distribution demand rate in the other 10 months of the year.

This proposed rate differential is modeled on Central Maine Power Company's upcoming rate design overhaul stemming from its recent rate case settlement in Maine Public Utilities Commission Docket No. 2022-00152. In this proceeding CMP conducted an updated marginal cost of service study with a full-blown distribution probability of peak analysis. CMP concluded the Company's marginal investments in distribution capacity are being driven by summer peak load conditions and that the prior differential between its summer (July and August) and non-summer (September through June) demand rates of roughly 20% was insufficient.

As shown in Exhibit CES-3, in January 2025 CMP will be implementing a significant increase in its seasonal demand rate differential for larger non-residential customers. For Large General Service customers,[16] the on-peak demand rate in July and August is currently \$3.13 per kW, roughly 20% higher than the on-peak demand rate of \$2.61 per kW from September to June. In 2025, CMP's on-peak demand rate in July and August will increase to \$19.92 per kW and will be nearly 15 times higher than the on-peak demand rate of \$1.36 per kW from December to March and \$1.04 per kW in the shoulder months. We have proposed a lower seasonal differential increase for Liberty in this case, at least 500%, to enable a gradual transition process for customers.

[16] CMP's Large General Service customers have a maximum monthly measured demand during an on-peak period that exceeds 1,000 kW.

VIII. TRANSMISSION RATE DESIGN

Q. How does Liberty currently charge its G-1 customers for transmission?

A. Liberty charges G-1 customers a flat rate per kWh for transmission. In July 2023, Liberty's transmission rate for G-1 customers was $0.01900 per kWh. This rate does not vary by time of day and does not vary by season.

Q. Does the transmission rate design that Liberty has proposed in this proceeding for G-1 customers meet Liberty's rate modernization goals?

A. No. If properly designed, Liberty's transmission charges should create strong connections to the Company's underlying costs of providing transmission service and should send customers a clear price signal to incentivize grid demand reductions during coincident peak demand periods when Liberty is assessed transmission costs from ISO New England. Liberty's proposal to continue using a flat per kWh rate sends no such price signal.

Q. Please explain Liberty's underlying cost of providing transmission service and how that comports with Liberty's rate design for G-1 customers.

A. Under ISO New England's Open Access Transmission Tariff, Liberty's cost obligations for transmission service are determined each month by its peak hourly load. Specifically, the total costs for transmission service are allocated to each transmission owner in New England based on a formula that computes the utility's share of the sum of the non-coincident peak loads of all transmission utilities each month. As a result, if a transmission utility's coincident monthly peak load falls for any reason, the share of its transmission costs fall. This means that, if a customer does not impose any grid demand during the hour of Liberty's monthly peak load, Liberty incurs no transmission costs to serve that customer. Since the customer imposes no transmission related costs on Liberty that month, it should not be allocated any of the costs incurred by the Company for transmission service that month.

Q. Is there any reason for Liberty continuing to assess transmission charges to G-1 customers based on monthly kilowatt-hour consumption?

A. We are not aware of any sound argument that Liberty has put forward in support of its current rate design. In its initial filing, Liberty clearly recognizes the shortcomings in its current transmission rate design. In presenting the proposed rate design updates for residential and small commercial TOU customers, the Company states that changes in a customer's load pattern throughout the day will result in direct impacts to the cost of transmission service required to serve that customer.[17] Furthermore, Liberty proposes to assign transmission costs to these customers based on the utility's contribution to the ISO-NE's monthly coincident peak load for Regional Network Service and Local Network Service.

Q. How is Liberty proposing to assess transmission charges to its other TOU customers?

A. Table 6 below presents Liberty's proposed transmission rates for Rate D-TOU, Rate D-11, Rate D-12, Rate G-3-TOU, Rate EV-L, Rate EV-M, Rate EV-L-E, and Rate EV-M-E. Table 6 highlights how significantly these proposed transmission rates would vary by TOU period. During Liberty's proposed summer season, from May to October, transmission rates during Liberty's off-peak hours would be less than 1% of on-peak transmission rates and transmission rates during Liberty's proposed mid-peak hours would be roughly 30% of on-peak transmission rates. During Liberty's proposed winter season, November to April, transmission rates during

[17] Direct Testimony of Greg Tillman, Advanced Rate Design, page 21 lines 1-2

Liberty's off-peak hours would be roughly 2% of its on-peak transmission rates and transmission rates during Liberty's proposed mid-peak hours would be roughly 10% of its on-peak transmission rates.

Table 6. Liberty's Proposed Transmission Rate Design for Other TOU Classes

Rate Class		Summer (May - October)			Winter (November - April)		
		Off Peak	Mid Peak	Peak	Off Peak	Mid Peak	Peak
Rate D-TOU	$/kWh	$0.0000	$0.0411	$0.1266	$0.0032	$0.0128	$0.1497
Rate D-11	$/kWh	$0.0000	$0.0411	$0.1266	$0.0032	$0.0128	$0.1497
Rate D-12	$/kWh	$0.0000	$0.0411	$0.1266	$0.0032	$0.0128	$0.1497
Rate G-3-TOU	$/kWh	$0.0007	$0.0309	$0.1126	$0.0029	$0.0146	$0.1401
Rate EV-L	$/kWh	$0.0006	$0.0308	$0.0985	$0.0022	$0.0114	$0.1034
Rate EV-L-E	$/kWh	$0.0006	$0.0308	$0.0985	$0.0022	$0.0114	$0.1034
Rate EV-M	$/kWh	$0.0006	$0.0283	$0.0926	$0.0023	$0.0120	$0.1138
Rate EV-M-E	$/kWh	$0.0006	$0.0283	$0.0926	$0.0023	$0.0120	$0.1138

Rate Class		Summer (May - October)			Winter (November - April)		
		Off Peak	Mid Peak	Peak	Off Peak	Mid Peak	Peak
Rate D-TOU	% of On-Peak Rate	0.0%	32.5%		2.1%	8.6%	
Rate D-11	% of On-Peak Rate	0.0%	32.5%		2.1%	8.6%	
Rate D-12	% of On-Peak Rate	0.0%	32.5%		2.1%	8.6%	
Rate G-3-TOU	% of On-Peak Rate	0.6%	27.4%		2.1%	10.4%	
Rate EV-L	% of On-Peak Rate	0.6%	31.3%		2.1%	11.0%	
Rate EV-L-E	% of On-Peak Rate	0.6%	31.3%		2.1%	11.0%	
Rate EV-M	% of On-Peak Rate	0.6%	30.6%		2.0%	10.5%	
Rate EV-M-E	% of On-Peak Rate	0.6%	30.6%		2.0%	10.5%	

Q. Does Liberty explain why it updated the transmission rate design for other TOU customers but left G-1 customers' transmission rate structure unchanged?

A. Liberty provides no good explanation. In response to DAR 1-15, however, Liberty does acknowledge that its existing transmission rate design does not reflect the time differentiation of the underlying costs that are assessed based on the Company's proportional share of the regional transmission system requirements.

Q. Does Liberty believe that its current rate design provides an appropriate price signal to incentivize G-1 customers to adopt DERs?

A. It appears so. According to Liberty, the differential between the on-peak rate and off-peak rate should be large enough to give the customer a significant incentive to reduce consumption when the price is high and provide an opportunity for meaningful bill savings.[18]

Liberty argues that the existing on-peak to off-peak differential in its distribution energy charge for G-1 customers 1) promotes changes in usage patterns and 2) promotes investments in any DERs and decarbonization measures that assist in either reducing demands and energy consumption during the on-peak period.[19] In response to DAR 1-1, Liberty notes that the existing (and proposed) on-peak distribution rate is about 3.4 times the off-peak distribution rate. This is not correct; Liberty's existing on-peak distribution rate of $0.00770 per kWh is 2.6 times the off-peak rate of $0.00298 per kWh. Regardless of this TOU differential, the rates themselves are minimal compared to the other delivery charges assessed by Liberty.

Q. Without engaging G-1 customers or conducting any actual evaluation of its rate design, how could Liberty know that its existing rate design promotes investment in DERs?

A. We do not know. It appears that Liberty does not recognize that DERs using energy storage technology, such as battery storage or thermal energy storage, experience round-trip charging losses each time a system is cycled and recharged. For example, current lithium-ion battery technology typically has a round-trip efficiency of around 88%. Chilled water storage tanks, which allow a customer like Dartmouth to produce chilled water overnight and to discharge that chilled

[18] Direct Testimony of Greg Tillman, Advanced Rate Design, page 8, lines 8-11.
[19] DAR 1-1

water the following afternoon and evening in lieu of consuming grid power to operate electric chillers during higher loads on Liberty's system, have roughly the same round-trip efficiency when one considers off-peak chilled water production and pumping load.

This means that for every 1,000 kWh of energy that is discharged from a behind-the-meter storage system, roughly 140 kWh of charging energy is lost during the charging process. Assuming this battery is charged from the grid overnight, these round-trip efficiency losses create a financial cost for the host customer if there is an off-peak energy charge assessed per kWh. In July 2023, Liberty's total off-peak energy charge was $0.02665 per kWh and the total on-peak energy charge was $0.03137 per kWh, which incorporates Liberty's distribution charge, the transmission charge, the system benefits charge, the stranded cost charge, and the storm recovery adjustment.

This means for every 1,000 kWh of that is discharged by a battery to the host customer, the customer avoids $31.37 in total on-peak energy charges. To fully recharge the battery after the discharge, the host customer would incur a cost of $30.28 in total off-peak energy charges, which includes round-trip losses during charging. It is difficult to see how the resulting $1 in energy savings per battery cycle supports Liberty's argument that the differential between peak and off-peak delivery rates should be large enough to give the customer a significant incentive to reduce consumption when the price is high and provide an opportunity for meaningful bill savings.

Q. This comparison of the total off-peak energy rate to the total on-peak energy rate includes all per kWh rate components. What if we just focus on the transmission rate?

A. Liberty's flat, around-the-clock energy charge <u>increases</u> the host customer's total annual transmission cost if a customer operates a behind-the-meter energy storage system to shift the customer's grid demand outside of Liberty's peak hours. Even if the storage system's discharge successfully coincides with Liberty's monthly peak demand hour, reducing the transmission cost ISO New England assesses to Liberty and producing savings for other ratepayers, the customer hosting the energy storage technology would see none of the benefit.

Let's revisit the 5 MW / 20 MWh behind-the-meter battery storage example for Dartmouth's North Campus. Assuming the battery system has a round-trip efficiency of 88%, Dartmouth would need to charge the battery system with 22.7 MWh to fully recharge the system after a complete discharge. The 2.7 MWh difference reflects the battery's round-trip charging losses and is energy that Dartmouth cannot later discharge to avoid a future grid purchase. With Liberty's flat transmission rate of $19 per MWh applying around-the-clock, including during off-peak hours when the battery would be charging from the grid, Dartmouth would incur a net transmission cost of roughly $50 per cycle. Dartmouth's annual transmission cost could increase more than **$12,000** due to the battery if the system is cycled 250 times (i.e., every business day) to address the restrictions posed by Liberty's distribution demand ratchet.

This issue of round-trip charging losses has a similar impact of increasing Dartmouth's annual transmission costs if a thermal energy storage system is installed on campus. Consider the example of the two chilled water storage tanks that Dartmouth has studied for the campus. If Dartmouth fully discharges the two chilled water tanks, the system could help Dartmouth avoid an estimated 12.6 MWh of on-peak electric usage during the discharge period on a hot summer day. For Dartmouth to fully recharge the tanks, an estimated 14.3 MWh of grid electricity would need to be purchased from the grid to run electric chillers overnight during off-peak hours and to pump chilled water back into the storage tanks.

This operations cycle would produce an estimated 1.7 MWh of round-trip charging losses. Based on Liberty's current flat transmission rate of $19 per MWh, the round-trip charging losses would cost Dartmouth $32 for each cycle of the thermal energy storage system, even though a discharge during Liberty's monthly peak load hour would reduce ISO New England's transmission cost assessment to Liberty.

Q. What do you propose as an updated transmission rate design for Rate G-1 to address these issues with Liberty's existing rate design?

A. We recommend that Liberty create a new voluntary transmission rate design option that enables G-1 customers to opt into having their transmission charges assessed based on a customer's average 60-minute grid demand during Liberty's monthly peak demand hour.

This demand-based coincident peak ("CP") rate design strongly supports the Company's three rate modernization objectives: 1) the CP option creates strong connections to the underlying costs of Liberty providing transmission service to its large customers; 2) the CP rate structure incentivizes efficient customer behavior to create downward pressure on prices and advance affordability; and 3) the CP option provides G-1 customers with a choice in pricing products.

Q. Is there precedent for this recommended solution being implemented in New England?

A. Yes. This CP rate design has been approved and implemented in Maine and Massachusetts. In Western Massachusetts, Eversource Energy has used a CP rate design to assess transmission charges to its large distribution customers since 2012. These customers, which take service under the Company's T-5 rate class[20], are assessed a transmission demand charge each month based on a customer's average 60-minute grid demand during Eversource's monthly peak load hour as measured across the Company's legacy Northeast Utilities service territory.[21] The CP rate design was approved by the Massachusetts Department of Public Utilities ("DPU") for all T-5 customers in D.P.U. 10-70-B. A copy of Eversource's Rate T-5 is provided in Exhibit CES-4.

In November 2022, the DPU approved an expansion of the CP rate design to Eversource's service territory in Eastern Massachusetts. This expansion was driven by Eversource's large distribution customers in Eastern Massachusetts, who strongly advocated for a CP transmission rate design in D.P.U. 22-22 despite firm opposition by Eversource in the case. Starting in January 2023, Eversource's Rate G-3 customers in Eastern Massachusetts and in Western Massachusetts can opt into the CP transmission rate design. Participating customers are assessed a transmission demand charge each month based on a customer's average 60-minute grid demand during Eversource's monthly peak load hour as measured across the Company's legacy NSTAR Electric system[22]. A copy of Eversource's Rate G-3 tariff is provided in Exhibit CES-5.

In September 2022, the Maine Public Utilities Commission ("MPUC") approved a voluntary CP transmission rate design for Central Maine Power Company's non-residential rate classes. This decision was made in Docket No. 2021-00325, a rate design proceeding called for by the Maine Legislature to examine whether transmission and distribution rate designs in Maine fully

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[20] Following Docket No. 22-22, Rate T-5 was reclassified as Rate G-3 as part of Eversource's rate consolidation effort across its Massachusetts service territories.

[21] The legacy Northeast Utilities service territory includes Eversource's service territories in Western Massachusetts (Western Massachusetts Electric Company), New Hampshire (Public Service Company of NH), and Connecticut (Connecticut Light & Power).

[22] The legacy NSTAR Electric system includes Eversource's service territories in Greater Boston, Cambridge, and the South Shore.

support the state's beneficial electrification goals. Specifically, the Legislature directed the MPUC to consider rate structures for energy storage technologies, electric vehicle charging, and heat pumps. Starting in July 2023, any non-residential CMP customer[23] can opt into Rate B-CPT; participating customers will be assessed a transmission demand charge each month based on their average 60-minute grid demand during CMP's monthly peak load hour. A copy of CMP's Rate B-CPT tariff is provided in Exhibit CES-6.

Q. In approving these rate options, did the DPU or MPUC opine on the benefits of utilizing a CP rate design to assess transmission charges to customers?

A. Yes. In its order approving the CP rate option for T-5 customers in Western Massachusetts, the D.P.U. recognized that a CP rate design clearly follows cost causation principles, would incentivize efficient customer behavior that benefits all ratepayers by reducing customer contributions to grid demand during periods of coincident peak demand on the system, and would not be unduly burdensome for Eversource to administer:

> The Department finds that introduction of a new transmission rate redesign, mandatory for the 20 Rate T-5 customers only, would provide an opportunity for those customers to achieve lower transmission costs, would result in minimal, if any, shifting of transmission costs to other electric utilities, would not be unduly burdensome for the Company to administer, and would provide useful data for the Department to evaluate whether implementing a rate redesign for all interval-metered customers statewide is in the public interest. Further, this transmission rate design would be consistent with the ratemaking principle of cost causation (i.e., rates for service reflect the costs that are actually "caused" or imposed by the customers who must pay the rates).[24]
>
> Transmission costs are incurred based on peak demands on the system and are priced at the wholesale level based on peak demand. Recovering transmission costs through the demand

[23] CMP's non-residential customers with maximum demand over 20 kW fall into one of three rate classes: Medium General Service (maximum demand between 20 kW and 400 kW), Intermediate General Service (maximum demand between 400 kW and 1,000 kW), or Large General Service (maximum demand over 1,000 kW).
[24] Order on Western Massachusetts Electric Company's Compliance Filing on Transmission Service Pricing; September 19, 2012; D.P.U. 10-70-B, page 7.

> charge should provide customers with an incentive to reduce monthly peak demand, thereby potentially reducing transmission costs for all customers. [25]

In D.P.U. 22-22, the D.P.U. made a similar finding that a CP rate design for transmission charges creates a price signal that meets rate design goals of efficiency, simplicity, and fairness:

> The Department has previously stated that pricing transmission service based on a customer's use at the time of system peak rather than based on the customer's peak, which may not coincide with the system peak, provides a more equitable assignment of cost responsibility. The 12 CP billing for Rate T-5 is one method of efficiently assigning accurate costs to those customers who utilize the transmission system during peak periods. While customer behavior benefits from 12 CP may not result in lower system costs immediately, lower system peak usage will eventually be reflected in transmission system peak forecasts, lowering costs for all customers.
>
> In the Company's last base distribution rate case, the Department directed the Company to evaluate the further expansion of coincident peak transmission billing to NSTAR Electric customers; however, the Company did not undertake any such evaluation that could assist the Department in weighing the merits of the proposed use of 12 CP transmission billing for all large customers As the Company has made and continues to make efforts toward rate alignment, and as 12 CP billing supports numerous rate-making goals such as simplicity and efficiency, the Department finds that it is reasonable and appropriate for the Company to expand optional 12 CP transmission billing to all large general service customers.[26]

Q. Why do you recommend that Liberty implement the CP rate design for G-1 customers on a voluntary, opt in basis?

A. Implementing the CP rate option on a voluntary, opt in basis is a prudent, measured first step in moving Liberty's transmission rate design for larger customers towards the Company's actual cost of providing transmission service. To our knowledge, this case is the first time in recent memory that Liberty has shared its hourly regional network service ("RNS") load data[27], which is

[25] Order on Western Massachusetts Electric Company's Petition for Approval of a General Increase in Electric Distribution Rates and a Revenue Decoupling Mechanism; January 31, 2011; D.P.U. 10-70, page 328.
[26] Order on NSTAR Electric Company's Petition for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan; November 30, 2022, D.P.U. 22-22, pages 460-461.
[27] Liberty provided this data in response to DAR 1-4.

necessary for G-1 customers to evaluate the effectiveness of various DER solutions to help reduce CP demand during Liberty's monthly peak load hour.

By allowing G-1 customers to opt into the CP rate design, Liberty would be removing a key obstacle for customers interested in proceeding with DER measures immediately, while providing its other G-1 customers time to review the rate impact of CP transmission charges and DER feasibility before the rate option may be considered mandatory in Liberty's next rate case. Furthermore, we expect voluntary enrollment will limit Liberty's need for manual billing and will provide time for the Company to assess and implement an automated billing solution for CP demand charges.

Q. Is it unduly burdensome for Liberty to administer billing for a CP rate design?

A. No. According to Liberty, the Company would need to manually bill a CP rate option.[28] Liberty states its current billing system and meter data systems are not currently configured to accommodate a change in the transmission demand data validation and calculation.

Liberty claims that this rate design change poses an administrative burden to the Company. We recommend that the Commission consider such a statement in the context of Liberty's request for substantial ratepayer investment in advanced metering infrastructure ("AMI"). The primary benefit of AMI is that it enables utilities to implement TOU rate structures for all customer classes that send effective and efficient price signals. Upgrading billing systems to enable this billing functionality is a basic requirement to maximize the benefits

[28] DAR 1-22

of AMI. Liberty should not be able to reap the benefits of adding AMI to its rate base while avoiding reasonable updates and improvements to its billing capabilities over time.

In Western Massachusetts, Eversource has been billing its T-5 customers for over a decade without major issues. Eversource has not assessed an incremental fee for billing these customers. In a similar vein, in approving Rate B-CPT for CMP customers, the MPUC did not approve an incremental fee for manual billing. In D.P.U. 22-22, the D.P.U. allowed Eversource to assess a monthly $500 bill preparation fee for customers who choose to opt in to 12 CP transmission service. The $500 fee will remain in place until Eversource has transitioned to its new billing system at the end of 2024 that allows automated billing of the CP rate option.

Q. Are there any other changes the Commission should require Liberty to make associated with implementing a voluntary CP rate design option for G-1 customers?

A. Because Liberty does not make public its real-time load on which its RNS cost obligations are based, it is difficult for any customer to make informed predictions of what hour will be the hour in which Liberty's peak load occurs each month. While predicting the hour is always an uncertain exercise, having access to RNS load information in near real-time and shortly after each operating day would reduce this uncertainty substantially for G-1 customers on the CP rate option.

The Commission should require Liberty to report its RNS data to interested customers on an ongoing basis 1) in near-real time (i.e., every five minutes) and 2) following each operating day in line with the timeline that Liberty's settlement team follows in reporting data to ISO New England. This data could either be posted publicly on Liberty's website or could be posted to a secure one-way FTP site by Liberty that is accessible to interested customers. We do not believe that this would be difficult for Liberty to do, nor do we believe that this would violate any provisions of its OASIS requirements if the load data is made available to all users of its system in the same manner. In any case, it should be made clear that Liberty is not liable for the accuracy of any data it posts or the timeliness of these posts, absent a clear showing of willful negligence.

CMP provides a model template for this type of RNS data sharing with its customers. CMP currently posts its instantaneous RNS load publicly on the company's website every five minutes and posts hourly RNS data after each operating day in line ISO New England's settlement timeline.[29] Implementing this capability was not costly or unduly burdensome for CMP. Versant Power similarly posts its hourly RNS data publicly on the Company's website[30] and Eversource has established a one-way FTP site to share its hourly RNS data with certain T-5 customers covering the legacy Northeast Utilities service footprint. A sample of CMP's and Versant's hourly RNS data that is reported publicly is provided in Exhibit CES-7.

Q. Does that conclude your testimony?

A. Yes.

[29] https://www.cmpco.com/w/rns-downloads?p_l_back_url=%2Fsearch%3Fq%3Dhourly%2520rns%2520load

[30] https://www.versantpower.com/suppliers-and-partners/load-profiling-settlement/