COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and Approval of a Performance Based Ratemaking Mechanism.	)	**D.P.U. 17-05**

Supplemental Direct Testimony of

Tim Woolf and Melissa Whited

On behalf of

Sunrun Inc. and The Energy Freedom Coalition of America, LLC

Regarding Eversource's Revised Rate Design Filing

August 15, 2017

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1. INTRODUCTION AND SUMMARY

Q. Please state your name, title, and employer.

A. Woolf: My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A. Whited: My name is Melissa Whited. I am a Principal Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Are you the same Tim Woolf and Melissa Whited that provided direct testimony in this docket?

A. Yes.

Q. On whose behalf are you testifying in this case?

A. We are providing evidence on behalf of Sunrun Inc. and the Energy Freedom Coalition of America, LLC.

Q. What is the purpose of your supplemental testimony?

A. The purpose of our supplemental testimony is to respond to Eversource's (Eversource's, or, the Company's) initial and revised rate design proposal submitted to the Department on June 1, 2017, and supplemented on July 25, 2017, and July 26, 2017.

Q. Please summarize your primary findings.

A. We find that Eversource's proposed monthly minimum reliability charge (MMRC) does not meet the Department's criteria for justifying and designing an MMRC. We also find that applying an MMRC to customers that have already installed distributed generation technologies is inconsistent with the Department's long-standing ratemaking principles, would be grossly unfair to those customers, would have a chilling effect on the development of new distributed generation resources, and would be inconsistent with the Commonwealth's statutes, regulations, and energy policy goals. In addition, according to a July 25, 2017 letter from State Representative Thomas Golden to Secretary Beaton (filed in this docket on August 1, 2017), failure to allow for grandfathering of existing customers would be contrary to the intent of the statute authorizing the establishment of an MMRC.

In addition, we find that Eversource's proposals for consolidating rates results in several rate designs that are inconsistent with the Department's long-standing ratemaking principles and represent a big step backwards from many efforts that the Department and the Commonwealth have taken to promote the implementation of clean, efficient, cost-effective distributed energy resources. While we generally agree that rates should be consolidated to provide more consistency across the service territory, Eversource has chosen to reject some rate designs that are consistent with Department principles and precedent and in the public interest, and maintain those that are not. Further, Eversource's proposed elimination of certain rate designs would have substantial negative consequences for customers who have invested or would invest in distributed generation.

Q. Please comment on the Company's June and July submittals regarding consolidated rates.

A. We do not believe the mitigation strategies the Company included in its late submittals will cure the defects with its rate design proposals, as we discuss herein, particularly since the Company's proposed mitigation discount is short-lived (only five years).[1]

Q. Please summarize your primary recommendations.

A. We recommend that the Department reject Eversource's proposed MMRC. There is no justification for any form of an MMRC at this time. If the Department finds that the Company has demonstrated that some form an MMRC is warranted at this time, the MMRC should be in the form of a minimum bill equal to the customer charge, as suggested by the Department with the Straw Proposal it offered in D.P.U. 16-64. If the Department allows for any form of an MMRC, it should exempt customers who have already installed distributed generation (DG), as well as low-income customers, and customers in publicly-supported housing.

We also recommend that if rates are consolidated, the Company should identify those rate design elements that are most consistent with Department principles and precedent, and

[1] DPU-63-6 (Supplemental 1) at 5.

with the public interest; and apply those throughout its service territory. In particular, we recommend that the Department:

- Reject the Company's proposal to apply a demand charge to all small C&I customers that have or install suitable meters.
- Require the Company to offer all residential and small C&I customers well-designed optional TOU rates that do not have a demand charge.

2. THE MONTHLY MINIMUM RELIABILITY CHARGE

<u>Eversource Has Not Met the Requirements for an MMRC</u>

Q. What requirements must be met in order to establish an MMRC?

A. At least 14 criteria have been mandated by the Massachusetts Legislature or the Department for the Department's approval of rate designs for net metering customers. First, the 2016 Act Relative to Solar Energy (the "Act") established four criteria that must be met in order for the DPU to approve an MMRC. These criteria are that the MMRC must:

1) equitably allocate the fixed costs of the electric distribution system not caused by volumetric consumption;
2) not excessively burden ratepayers;
3) not unreasonably inhibit the development of Net Metering Facilities; and
4) be dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system. St. 2016, c. 75, § 9; G.L. c. 164, §139(j).

In its Order 16-64-E, the Department directed the Companies to consider additional data when developing an MMRC. These data include:[2]

5) the impact of market net metering credits,

6) bill impact analysis,

7) cost of service studies supporting the allocation between fixed and variable charges, and

8) justification for an MMRC, to the extent necessary, to support a proposed MMRC.

Further, the Department encouraged the Distribution Companies "to continue discussing MMRC proposals and data requests with interested stakeholders in advance of an adjudicatory proceeding."[3]

The Department established additional criteria for rates applicable to DG customers in D.P.U. 15-155. In that proceeding, National Grid proposed a new rate design that it claimed was necessary to mitigate cost shifting from DG customers to non-DG customers. The Department ultimately rejected National Grid's proposal for failure to meet several criteria. Specifically, the Department found that National Grid had failed to:

9) quantify the amount of costs attributable specifically to DG customers;

10) quantify the distribution system benefits associated with DG customers in its service territory; or

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[2] *Investigation of the Department of Public Utilities, on its own Motion, Instituting an Emergency Rulemaking pursuant to G.L. c. 164, §§ 138 and 139; G.L. c. 30A, § 2; 220 C.M.R. §§ 2.00 et seq.; and Executive Order 562, to Amend 220 C.M.R. § 18.00 et seq.*, D.P.U. 16-64, 16-64-E at 20-21 (Jan. 13, 2017) ("D.P.U. 16-64-E").

[3] D.P.U. 16-64-E at 20-21.

11) substantiate its cost-shift assumption with a reasonable analysis and quantitative record evidence, other than quantifying net metering credits and citing to current rate design.[4]

In addition, the Department noted that G.L. c. 164, § 141 requires the Department to consider the impacts of rate design decisions "on the successful development of energy efficiency and on-site generation." Accordingly, the Department found that that National Grid had failed to provide evidence regarding:

12) the impact of its rate design on energy efficiency,

13) compliance with the three-year energy efficiency plan, and

14) incentives to lower demand.[5]

Q. Has Eversource met these criteria?

A. No. While the Company claims that cost-shifting is occurring, it has not quantified the benefits associated with DG customers (criterion 10) or substantiated its cost-shift assumption with reasonable analysis and quantitative record evidence (criterion 11). Instead, the Company refers only to cost-shifting from displaced revenues to substantiate its claim.[6] Without adequate quantitative evidence, the Company cannot adequately justify the MMRC (criterion 8), and the MMRC cannot be said to equitably allocate costs

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4 *Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on November 6, 2015, to be effective December 1, 2015*. D.P.U. 15-155, Order at 458 (Sept. 30, 2016) ("Order 15-155").

5 Order 15-155 at 458.

6 Exh. ES-RDP-1 at 96.

(criterion 1), and would excessively burden ratepayers with Distributed Generation (criterion 2).

In addition, the Company's proposed MMRC is based on a demand charge, which would result in a substantial decrease in the volumetric charge. Because net metering customers' bill savings are based on the volumetric charge, this could unreasonably inhibit the development of net metering facilities (criterion 3). Further, the Company has not quantified the impacts that its proposed rate design could have on energy efficiency (criterion 12) or compliance with the Company's three-year energy efficiency plan (criterion 13).

Finally, although it is not a requirement in the strict sense, we note that Company did not follow the Department's recommendation to continue to discuss MMRC proposals with interested stakeholders in advance of filing its proposal.[7]

<u>Eversource has not demonstrated that there is a need for an MMRC</u>

Q. You state that Eversource refers only to cost-shifting from displaced revenues as justification for an MMRC. Why are displaced revenues inadequate evidence of the need for an MMRC?

A. Displaced revenues are simply revenues that would have been collected from the net metering customers were it not for their self-generation. However, displaced revenues alone cannot be used as an indicator of a cost-shift. While the need to recover displaced revenues results in upward pressure on rates, the benefits provided by distributed

[7] D.P.U. 16-64-E at 20-21.

generation exert a countervailing effect by reducing utility costs and rates, thereby offsetting some or all of the impact created by the need to recover displaced revenues. Both the upward pressure associated with recovery of displaced revenues and the downward pressure of distributed generation benefits must be accounted for in order to determine any cost shift.

Q. Please explain how the benefits of distributed generation will offset cost-shifting.

A. As the Commonwealth has found, distributed generation can provide a wide range of benefits to the entire electric system by reducing distribution costs, transmission costs, purchases from wholesale electricity markets, and environmental compliance costs.[8] The reductions in utility system costs as a result of distributed generation will offset the increase in rates to recover displaced revenues, thereby mitigating, or even eliminating any cost-shifting that might occur as a result of distributed generation.[9]

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8 *See* 225 CMR 20.01 (filed Aug.11 2017) (stating that "[t]he continued use and development of these [solar photovoltaic] generating units have the potential to: reduce peak demand, system losses, the need for investment in new infrastructure, and distribution congestion; increase grid reliability; and diversify the Commonwealth's energy supply. Further, it will also contribute to the Commonwealth's environmental protection goals concerning air emissions . . .").

9 For example, in our recent analysis of the value of solar in Washington, DC, we found that cost-shifting was largely mitigated by the benefits provided by distributed solar. Our analysis found that utility system benefits amounted to more than $0.13/kWh, which was approximately equal to the average residential retail rate. Thus the resulting impact on non-net metered residential customers was only $0.02 on average. *See* Melissa Whited et al., *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting* Synapse Energy Economics, prepared for the Office of the People's Counsel for the District of Columbia (Apr. 12, 2017), http://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.

The MMRC Conflicts with State Solar Policies

Q. Please describe the Commonwealth's energy policy goals regarding solar as articulated in the Act.

A. As stated in the Act Relative to Solar Energy, the Commonwealth endeavors to provide "continued support of solar power generation and a transition to a stable and equitable solar market at a reasonable cost to ratepayers."

Q. How does the Commonwealth intend to achieve this goal?

A. Historically, the Commonwealth has sought to support distributed solar through a combination of programs, including net metering and solar renewable energy certificates (SRECs). Currently, the SREC program is being replaced by a new program, referred to as the Solar Massachusetts Renewable Target (SMART) Program.

Q. Please describe the SMART program.

A. Under 225 CMR 20.00,[10] the SMART program would provide incentives designed to stimulate 1,600 MW of additional solar development in Massachusetts. Incentives would be set using a declining block auction model, with the Initial Base Compensation Rates established through a competitive solicitation for large projects. Smaller projects[11] will receive an incentive in one of two ways: a fixed "Performance-Based" incentive for

[10] On August 11, 2017, the Department of Energy Resources ("DOER") filed its proposed final version of the 225 CMR 20.00 Solar Massachusetts Renewable Target (SMART) Program regulation with the Secretary of State's Office. DOER expects that version to be published in the State Register on August 25, 2017 with minimal to no changes. This testimony cites to the unofficial version available at Development of the Solar Renewable Target (SMART) Program.

[11] Defined as Solar Tariff Generation Units with capacities equal to or less than one MW AC. 225 CMR § 20.07(3)(c).

behind-the-meter systems;[12] or a Contract-for-Differences for standalone systems.[13] The SMART program will offer these incentives for 10 or 20 years depending on the size of the project.[14]

Q. How is the incentive for residential and small commercial systems structured?[15]

A. For residential and small commercial systems serving an onsite load (behind-the-meter), the Initial Base Compensation Rate would be indexed to the auction clearing price;[16] and the system would receive a fixed Performance Based Incentive calculated off of the Base Compensation Rate for a period of 10 or 20 years depending on the size.

Q. Should the MMRC work in concert with the SMART program?

A. Yes, it is important that it does. While the Act allows the distribution utilities to propose a Monthly Minimum Reliability Contribution for approval by the DPU, the Act also directs the Department of Energy Resources to develop a statewide solar incentive program (i.e., the SMART program) "to encourage the continued development of solar renewable energy generating sources" by electricity customers in Massachusetts. Thus, while the Act does not specify how an MMRC should interact with the SMART program, the two items should work in concert to meet state solar policy goals.

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[12] 225 CMR 20.08(2).

[13] 225 CMR 20.08(1).

[14] 225 CMR 20.07(a).

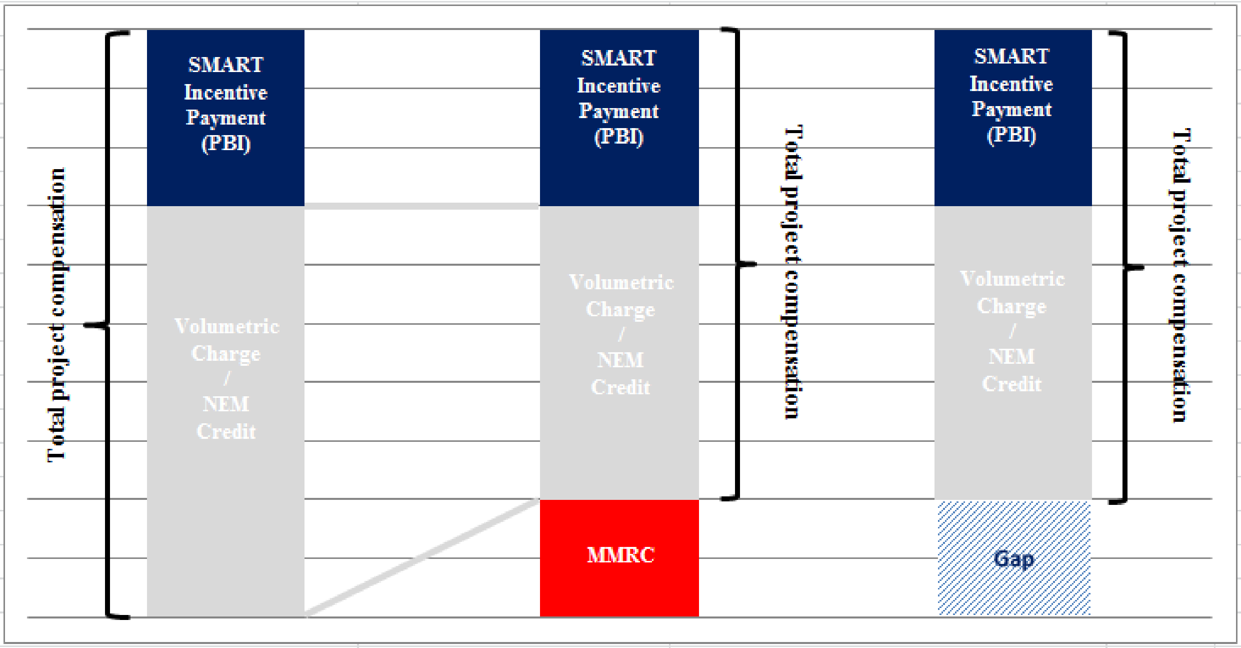
[15] The Company has proposed applying an MMRC to residential and small commercial customers. *See supra*, n. 20.

[16] *See* 225 CMR 20.07(3)(c), specifying the method for determining the Initial Base Compensation Rates for Solar Tariff Generation Units with capacities equal to or less than one MW AC.

Q. Would Eversource's proposed MMRC conflict with the SMART program?

A. Yes. As noted above, the SMART program is designed to provide a financial incentive to encourage the development of 1,600 MW of additional solar generation. However, Eversource's proposed MMRC would undermine the success of the program since it would erode the economics of the very same projects the program and the Administration seek to encourage. As depicted in Figure 1 below, for behind-the-meter systems, the fixed incentive payment "sits" on top of whatever net metering credit a customer is eligible to receive in lieu of the customer's volumetric charge.

FIGURE 1. SMART Program Incentive Payment Illustration



However, the MMRC would decrease, or diminish, the amount of the bill (the volumetric charge) a customer can offset with net metering. As the MMRC erodes the volumetric charge a customer can offset (or reduces the amount a customer can manage by the net metering) it creates a gap in the economics of a project, thereby undermining the intent of the SMART program.

Unfortunately, this is precisely what Eversource is currently proposing with its MMRC. If the MMRC were implemented, the distribution rate would decrease and the value of net metering credits would be reduced. Since the incentive payment calculation of the SMART incentive is fixed, this would result in an unintended reduction (or "gap") in the total compensation a net metering customer would expect to receive.

Q. Is this impact on solar customers consistent with the goals of the Act?

A. No, such a sudden reduction in savings for solar customers is not consistent with the Act's intent to promote stable support for continued solar development and works in opposition to what the SMART Incentive is designed to achieve.

Demand Charges

Q. If it were demonstrated that cost shifting is occurring, would the Company's MMRC be an appropriate mechanism for mitigating it?

A. No. The Company's proposed MMRC is fundamentally flawed from a rate design perspective. In particular, the MMRC fails to comport with the principles of efficient price signals, simplicity, continuity, and fairness.

Q. Please describe how the MMRC fails to provide an efficient price signal.

A. Rate design can provide customers with price signals that can help encourage customers to optimize their electricity consumption patterns and reduce demand on the system when it is stressed. However, the Company's proposed MMRC increases the fixed customer charge and imposes a demand charge on customers. The customer charge and demand charge are difficult or impossible for customers to avoid, and both of these charges reduce the volumetric rate. A lower volumetric rate sends customers the price signal that their usage does not affect distribution system costs, and provides less of an incentive for customers to reduce their energy consumption. In fact, a lower volumetric rate may even induce customers to increase their energy consumption, which is particularly problematic if such consumption coincides with system peak periods.

Q. Why does a demand charge not provide an efficient price signal?

A. First, the Company's proposed demand charge does little to encourage customers to reduce consumption when it matters most – during peak demand hours. Because most of the distribution system is sized to meet the system's local coincident peak demands,[17] it is not the individual residential or small commercial customer's peak demand that drives additional system costs, but the timing of that demand and its coincidence with other demands on the system.[18] For residential and small commercial customers, Eversource allocates between 80 and 87 percent of demand-and reliability-related costs on the basis of the *class* maximum demand, not individual customers' maximum demands.[19] Only transformer costs are allocated based on customer non-coincident demand.[20]

Second, the price signal to reduce demand is concentrated into a single hour of the month – the hour of the customer's individual maximum demand. During other hours, the price signal is limited, since reducing demand below the customer's monthly peak will have no financial benefit for the customer. Thus the price signal sent by the demand charge is that

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[17] The system coincident peak demands may vary at different levels of the system. For example, a distribution system feeder may experience its peak demand at a different time than the bulk transmission system. The NARUC 1992 Cost Allocation Manual, Appendix 6-A, discusses methods for calculating equipment peaks for each distribution component, and then comparing these to various class peaks to determine the allocator that best matches the equipment peaks. Currently, distribution demand- and reliability-related costs are primarily allocated to Eversource residential and small commercial customers on the basis of the class peak, and not on the basis of individual peak demand (SREF-3-015, SREF-3-15(a) and SREF-3-15(b)).

[18] A small non-coincident demand charge may be appropriate for large commercial and industrial customers, where certain components of the system must be sized to meet that individual customer's demand, where an increase in the customer's demand would require an equipment upgrade. But most utility system costs are not driven by an individual residential customer's non-coincident maximum demand – instead, they are driven by coincident demands during peak hours. *See* Jim Lazar, *Use Great Caution in Design of Residential Demand Charges*, Natural Gas & Electricity, at 19 (Feb. 2016) available at https://www.raponline.org/document/download/id/7844 ("NCP [Non-Coincident Peak] demand is not relevant to any system design or investment criteria above the final line transformer, and only there if the transformer serves just a single customer.").

[19] Response to Q-SREF-3-015.

[20] *Id*.

reducing electricity consumption outside of the customer's single peak hour is of little value.

Finally, the demand charge reduces the distribution rate ($/kWh), thereby reducing incentives for energy efficiency, as discussed above, and contrary to G.L. c. 164, § 141. In fact, the MMRC would lower the distribution rate by 44% for R-1 customers and 74% for G-1 customers in Eastern Massachusetts.[21] Holding all else equal, a reduction in the price of electricity will lead to an increase in electricity consumption, and incentives for energy efficiency and conservation will be reduced.

Q. How does the MMRC fail to comport with the principle of simplicity?

A. Demand charges represent a much more complex rate design than residential customers and many small commercial customers are accustomed to. Surveys and focus groups have found that the concept of demand charges is not well-understood and frequently raise concerns from customers.[22] Not only are demand charges conceptually new, customers generally lack the tools needed to manage their demand, and Eversource's proposal contains no plans to provide customers with such tools. Without investing in automating technology, residential customers have little ability to monitor and quickly

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[21] Based on MMRC rates listed on Exhibit ES-RDP-6 (ALT1), Schedule RDP-1 and *Electric Rates for Greater Boston Service Area*, Eversource (effective January 1, 2017) available at https://www.eversource.com/Content/docs/default-source/rates-tariffs/ema-greater-boston-rates.pdf?sfvrsn=12.

[22] Recent surveys indicate that approximately 50% of residential customers do not understand the terms "kW" and "kWh." *See* LeBlanc, Bill, *Do Customers Understand Their Power Bill? Do They Care? What Utilities Need to Know*, E Source Survey Blog (Jan. 21, 2016) available at: https://www.esource.com/email/ENEWS/2016/Billing. Further, focus groups in Ontario found that the concept of maximum use during peak hours "is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU." Customers also expressed concerns regarding fairness, specifically that "that small lapses in their conservation efforts will mean they will have to pay a high price". *See* Gandalf Group, *Ontario Energy Board Distribution Charge Focus Groups Final Report*, at 9 (Oct. 9, 2013) ("Gandalf Report") available at: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0410/Appendix%20B%20-%20Gandalf%20Distribution%20Focus%20Groups.pdf.

adjust their demand levels.[23] Further, where residential demand charges have been implemented, enrollment tends to be very low, indicating low levels of customer acceptance. Of the 24 other examples of demand charges that have been applied to residential customers in the US on an opt-in basis, most have enrollment below 1%,[24] despite existing for multiple years and customer marketing efforts.

Q. Have any investor-owned utilities made demand-based rates mandatory for residential customers?

A. No. In fact, demand charges have been routinely rejected for mandatory application to residential customers.[25] Several recent examples include California, Arizona, Nevada, and Oklahoma. In addition, parties to a rate case in Texas recently proposed a stipulation under which Oncor would withdraw its proposal for a DER tariff that would have included a residential demand charge. [26] A decision on the proposed stipulation is pending.

In California, the Commission explicitly rejected demand charges as a component of a net metering successor tariff. The Commission's rationale was that "demand charges can be complex and hard for residential customers to understand. Since the vast majority of NEM customers are residential customers, it is reasonable to consider the NEM successor

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[23] For example, a widely held concern of participants in focus groups in Ontario regarding demand charges is that they do not have the tools to manage their demand. *See* Gandalf Report at 6, 11.

[24] Rocky Mountain Institute, *A Review of Alternative Rate Designs*, at 72 (May 2016) ("RMI Review").

[25] Salt River Project is the only utility that we are aware of that has implemented a mandatory demand charge for residential net metered customers. Salt River Project is a political subdivision of the state of Arizona, and as such is not subject to regulation by the Arizona Corporation Commission. We are not aware of any utilities subject to commission regulation that have implemented a mandatory demand charge for residential customers (including net metered customers).

[26] Public Utility Commission of Texas, *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, PUC Docket No. 46957, SOAH Docket No. 473-17-3196, Stipulation, ¶ P. (Aug. 2, 2017), available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/46957_420_949886.PDF.

tariff in light of the needs of residential customers. From that perspective, the NEM successor tariff should not incorporate a demand charge…"[27]

In Oklahoma, the Commission rejected the proposed demand charge and implemented two requirements that the utility must fulfill if it wishes to propose a demand charge in the future:

1) The utility must first conduct a study and pilot program on demand charges to evaluate customer acceptance, understanding, and ability to respond to a demand charge; and

2) For any demand charge for customers with distributed generation, the utility must "include as part of its case [DG] cost effectiveness tests, such as those performed for the company's demand programs, and make available to the parties detailed cost and benefit data."[28]

In Arizona, the Commission recognized that there was significant "public distrust or antipathy to the [demand charge] proposal" and stated that "In order for customers to understand how demand charges work and how they can manage their energy consumption to save money, or at least not incur a bill increase, requires education and tools available to monitor their load," which have not "been made available."[29] Nevada's rationale for declining to implement a mandatory demand charge for net metered

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[27] California Public Utilities Commission, Decision 16-01-044, Decision Adopting Successor to Net Energy Metering Tariff, Rulemaking 14-07-002 (Jan. 28, 2016).
[28] Oklahoma Corporation Commission, Cause No. PUD 201500273, Final Order, at 13 (Mar. 20, 2017).
[29] Arizona Corporation Commission, Decision No. 75697, Docket No. E-04204A-15-0142, at 65 (Aug. 18, 2016).

customers similarly hinged on customer education needs and uncertainty regarding customer acceptance.[30]

Despite this, Eversource proposes to make demand charges mandatory for new residential net metering customers through the MMRC.[31]

Q. Is the MMRC consistent with the principle of continuity?

A. No. The Department notes that rate continuity means that "changes to rate structure should be gradual to allow customers to adjust their consumption patterns in response to a change in structure."[32] Professor Bonbright defines this goal as the "stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."[33]

In contrast to a gradual approach, the MMRC would significantly alter the rate structure for many net metered customers, particularly residential and non-demand small commercial customers. In addition to introducing an entirely new charge in the form of a demand charge, the MMRC would more than double or even triple the fixed charge for many customers compared with current rates. This fixed charge, in combination with a demand charge, further limits a customer's ability to control his or her electricity bill.

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[30] Nevada Public Utilities Commission, Docket No. 15-07041 & Docket No. 15-07042, Modified Final Order, at 147 (Feb.18, 2016).

[31] The Company proposes to apply the MMRC to new residential net metered customers with an in-service date on or after January 1, 2018, and new general service rate customers with an in-service date on or after January 1, 2019. Exh. ES-RDP-1, at 91. In DPU-56-9 (Supp.), the Company proposes to delay the start date of the MMRC for residential customers to 2019.

[32] *Petition of Massachusetts Electric Company and Nantucket Electric Company, pursuant to G. L. c. 164, § 94, and 220 C.M.R. § 5.00 et seq., for a General Increase in Electric Rates and Approval of a Revenue Decoupling Mechanism*, D.P.U. 09-39, Order at 402 (Nov. 30, 2009).

[33] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, at 291 (1961) ("Bonbright").

As shown in the table below, proposed customer charge increase would range from 58% to 192% for residential customers, and 139% to 321% for certain small commercial customers. Such a massive increase cannot be described as "gradual," and clearly violates the principle of continuity.

TABLE 1. Customer Charge under MMRC Compared to Current Rates[34]

		Current Customer Charge	MMRC Customer Charge	Change
R-1	South Shore	$3.73	$10.88	192%
	Cape Cod/Martha's Vineyard	$3.73	$10.88	192%
	Cambridge	$6.87	$10.88	58%
	Greater Boston	$6.43	$10.88	69%
	WMECO	$6.00	$10.88	81%
G-1 (Non-Demand)	Cambridge	$4.62	$19.43	321%
	Greater Boston	$8.14	$19.43	139%

Q. Does the MMRC promote fairness between rate classes?

A. Eversource asserts that the MMRC promotes fairness by reducing the potential for costs to be shifted to other rate classes.[35] However, as described above, customers who install distributed generation or other demand resources, such as storage, provide benefits to the utility system.[36] These reduced costs then translate into lower revenue requirements for

[34] Exh. ES-RDP-6 (ALT1), Schedule RDP-1, and Summary of Electric Delivery Service Rates for Cambridge, Boston, South Shore, Cape Cod/Martha's Vineyard, and WMECO, available at https://www.eversource.com/Content/ema-c/residential/my-account/billing-payment/rates-tariffs/electric-tariffs-rules and https://www.eversource.com/Content/wma/business/my-account/billing-payment/rates-tariffs/electric-tariffs-rules.

[35] Exh. ES-RDP-1 at 43.

[36] *See*, *for example*, SolarCity, *A Pathway to the Distributed Grid*, (2016) available at http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf. *See also* Julia Pyper, *Californians Just Saved $192 Million Thanks to Efficiency and Rooftop Solar*, Greentech Media (May 31, 2016) available at https://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar (reporting on CAISO's finding that load reduction attributable to energy efficiency and rooftop solar allowed it to cancel 13 transmission projects in the PG&E service area).

distribution utilities and lower costs of generation for all customers. To determine whether customers employing demand resources are paying their "fair share" of distribution system costs, one cannot look at the reductions in the customer's bill alone. One must also consider the system benefits provided by that customer.

Q. Please summarize your conclusions regarding the MMRC and the Department's rate design principles.

A. The demand charge and customer charge in the proposed MMRC are in direct contravention to the Department's goals of efficiency, simplicity, and continuity. The MMRC's proposed demand charge and higher customer charge will fail to achieve the goals of equity and efficiency, and in fact would reduce customer control, distort price signals, and lead to significant customer confusion. Further, the MMRC's mandatory demand charge for residential customers would create a dangerous precedent, and could lead to future proposals aimed at expanding the breadth and magnitude of residential demand charges.

3. GRANDFATHERING AND THE MMRC

Q. If the Department determined that an MMRC should be implemented, would it be reasonable to apply the MMRC to existing DG customers, who have already invested in DG?

A. No, absolutely not. Failure to grandfather customers would violate two important principles of rate design: (1) continuity of rates, also referred to as "gradualism," and

(2) the "practical" attributes of public acceptability by being perceived as unfair. In addition, failure to grandfather customers would be inconsistent with the intent of the statute authorizing the establishment of an MMRC, as discussed by State Representative Thomas Golden in his July 25, 2017 letter to Secretary Beaton.

Q. Please describe how failure to grandfather existing customers would violate the principle of gradualism.

A. The principle of gradualism requires that rate changes be made gradually, "with a minimum of unexpected changes seriously adverse to existing customers."[37] Customers make rational decisions assuming that their electric rates will be reasonably stable and predictable. Again, according to Professor Bonbright, "unless rate-making policies are sufficiently stable to permit a consumer to predict with reasonable confidence what his charges will be . . . a cost-price system of rate making will be self-defeating when viewed as a means of securing a rational control of demand."[38]

In contrast, application of an MMRC to customers that have already installed DG (and in some cases, moving existing customers, some of which have existing long-term contractual obligations) to an entirely new "consolidated" rate, as discussed below) would represent a dramatic change to the rates that customers expected to pay at the time they chose to install the DG. While customers might have expected their variable rates to increase (or decrease) over time as a result of rate cases and changing industry

[37] Bonbright at 291.
[38] Bonbright at 297.

conditions, they could not have expected their *rate structure* to change, or the economics of their investment to change so dramatically.

Q. **Please explain how failure to grandfather existing customers would violate the principle of public acceptability.**

A. DG customers have invested significant financial resources in on-site generation capabilities based on the current NEM tariff, which was previously approved by the Commission. Significant changes to the tariff would simply be unfair to existing customers. Massachusetts families and businesses who decided to invest their personal financial resources based on an economic calculation that was sensible and affordable under a particular Commission-approved tariff ought to be able to rely on the continuity of that tariff.

Q. **How have other states addressed grandfathering in the context of net energy metering tariffs?**

A. States typically allow grandfathering in one form or another vis-à-vis net energy metering tariffs. As recently reported in *Fortune*: "while solar rates around the U.S. are being reexamined by state agencies, few regulators have actually changed the rates for existing solar customers."[39] Existing customers are typically grandfathered for at least 15 to 20 years. Examples of grandfathering for existing net energy metering customers include

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[39] Fehrenbacher, Katie, *Why Nevada Brought Back Favorable Rates for Existing Solar Customers*, Fortune (Sept. 16, 2016), available at <http://fortune.com/2016/09/16/nevada-solar-grandfathering/>.

California (20 year grandfathering),[40] Arizona (20 year grandfathering),[41] Hawaii (indefinite grandfathering),[42] and Arkansas (20 year grandfathering).[43]

Q. Why do states typically allow grandfathering for net energy metering tariffs?

A. One chief reason grandfathering is done is because failure to grandfather existing customers is widely viewed as economically unfair to the customers who already installed on-site generation.

For instance, when California ruled in favor of grandfathering, the Public Utilities Commission of California stated that it was

> persuaded that customers who invest in renewable distributed generation systems and participate in existing [net energy metering] tariffs should at least have an opportunity to recoup their initial investment in distributed renewable generation. In addition, we find that adopting a transition period that denies customer-generators the opportunity to realize their expected benefits would not be in the public interest, to the extent that it could undermine regulatory certainty and discourage future investment in renewable distributed generation.[44]

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[40] Public Utilities Commission of the State of California, Decision Establishing a Transition Period Pursuant to Assembly Bill 327 for Customers Enrolled in Net Energy Metering Tariffs, Rulemaking 12-11-005, Decision 14-03-041, at 20 (Mar. 27, 2014) available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K386/89386131.PDF>.

[41] Arizona Corporation Commission, *In the Matter of the Commission's Investigation Value and Cost of Distributed Generation*, Docket No. E-00000J-14-0023, Decision No. 75859, at 156 (Jan. 3, 2017) available at <http://docket.images.azcc.gov/0000176114.pdf>.

[42] Public Utilities Commission of the State of Hawaii, *In the Matter of Public Utilities Commission Instituting a Proceeding to Investigate Distributed Energy Resource Policies*, Docket No. 2014-0192, Decision and Order No. 33258, at 164 (Oct. 12, 2015) available at <http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464>.

[43] Arkansas Public Service Commission, *In the Matter of Net Metering and the Implementation of Act 827 of 2015*, Order No. 10, Docket 15-027-R at 142 (Mar. 8, 2017) available at < http://www.apscservices.info/pdf/16/16-027-R_212_1.pdf >.

[44] *See* Public Utilities Commission of the State of California, *Decision Establishing a Transition Period Pursuant to Assembly Bill 327 for Customers Enrolled in Net Energy Metering Tariffs*, Rulemaking 12-11-005, Decision 14-03-041, at 20 (Mar. 27, 2014) available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K386/89386131.PDF>.

To the same end, the Arizona Corporation Commission clarified that its decision to grandfather existing customers was

> not intended to shield customers with DG systems from generally applicable rate design changes, such as changes for the basic service charge. It is, instead, intended to preserve the expectations that customers with DG systems may have relied upon when they chose to adopt DG technology.[45]

Q. Has any state prohibited grandfathering for net energy metering tariffs?

A. No, not to my knowledge. When a utility or regulatory body has proposed to require existing customers with distributed generation to move to a new rate without any allowance for grandfathering, it has generated significant controversy and negative press. A prominent example is Nevada.

Q. Please briefly explain the history of net metering in Nevada.

A. In July 2015, NV Energy[46] filed an application for approval of new net energy metering tariffs with the Public Utilities Commission of Nevada ("Nevada PUC").[47] On December 22, 2015, the Nevada PUC issued an order that approved the application with

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45 Arizona Corporation Commission, *In the Matter of the Commission's Investigation Value and Cost of Distributed Generation*, Docket No. E-00000J-14-0023, Decision No. 75859, at 156 (Jan. 3, 2017) available at <http://docket.images.azcc.gov/0000176114.pdf>.

46 Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy.

47 *See* Public Utilities Commission of Nevada, *Application of Nevada Power Company D/B/A NV Energy for Approval of a Cost-Of-Service Study and Net Metering Tariffs*, Docket No. 15-07041, Original Filing, (Jul. 31, 2015), available at < http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/4399.pdf>, and Public Utilities Commission of Nevada, *Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of a Cost-of-Service Study and Net Metering Tariffs*, Docket No. 15-07042, Original Filing, (Jul. 31, 2015), available at <http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/4402.pdf>.

modifications, and specifically did not allow grandfathering for existing net energy metering customers.[48]

Q. How was the Nevada PUC's decision received by stakeholders and the public?

A. Following the Nevada PUC's December 2015 order, customers, politicians, and others widely criticized the decision and advocated for grandfathering. The case gained publicity nationwide, and was extensively reported on by high-profile publications including articles in *Fortune, USA Today*, and others. As part of the backlash,

- customers organized protests,[49] and
- solar developers exited the state and many local companies went out of business, causing substantial job losses.[50]

In addition, politicians ranging from Senate Minority Leader Harry Reid to Governor Sandoval became involved in the debate. Senator Reid stated, "Left unchanged, the repercussions of this decision will continue to be a black mark on Nevada's reputation

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[48] Public Public Utilities Commission of Nevada, *Application of Nevada Power Company D/B/A NV Energy for Approval of a Cost-Of-Service Study and Net Metering Tariffs*, Docket No. 15-07041, Order at 52-64 (Dec. 22, 2015) & *Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of a Cost-of-Service Study and Net Metering Tariffs*, Docket No. 15-07042, Order at 52-64 (Dec. 22, 2015) both available at < http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/8412.pdf>. See also Public Utilities Commission of Nevada, *Application of Nevada Power Company D/B/A NV Energy for Approval of a Cost-Of-Service Study and Net Metering Tariffs*, Docket No. 15-07041, Modified Order, at 152-64 (Feb. 2, 2016) & *Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of a Cost-of-Service Study and Net Metering Tariffs*, Docket No. 15-07042, Modified Final Order at 152-64 (Feb. 2, 2016) both available at < http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/9692.pdf>.

[49] Fehrenbacher, Katie, *Nevada's New Solar Feed Have People Furious*, Fortune (Jan. 14, 2016) available at <http://fortune.com/2016/01/14/nevada-solar-battleground/>.

[50] Shallenberger, Krysti, *Sunrun exists Nevada after net metering decision*, Utility Dive (Jan. 7, 2016), available at <http://www.utilitydive.com/news/sunrun-exits-nevada-after-net-metering-decision/411728/>, and Noon, Allison *Lawmakers Advance Bills to Revive Solar Industry in Nevada*, U.S. News and World Report (Apr 5, 2017) available at <https://www.usnews.com/news/best-states/nevada/articles/2017-04-05/lawmakers-advance-bills-to-revive-nevada-solar-industry>.

and will imperil job creation and innovation in the Silver State…. The need for Nevada to get this policy correct is more pressing than ever."[51]

Governor Sandoval's chief strategy officer said that the Nevada decision damaged the state's international clean energy reputation.[52] In view of the backlash over the unfairness to existing DG customers, Governor Brian Sandoval of Nevada issued Executive Order 2016-04, initiating the New Energy Industry Task Force to come to a resolution.[53]

Q. What was the result of the Governor's Task Force?

A. The task force ultimately recommended grandfathering for 20 years, stating that such an approach "will provide a reasonable amount of time to recoup the investment of these systems."[54]

Q. How was the grandfathering debate finally resolved?

A. In July 2016, NV Energy, Nevada PUC staff, the state's consumer advocate, and SolarCity submitted a settlement agreement to the Nevada PUC for review and approval that established separate rates for grandfathered private generation customers through November 30, 2036 (approximately 20 years). The Nevada PUC approved the settlement

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[51] Hidalgo, Jason, *Nevada regulators unanimously approve rooftop solar grandfathering deal*, USA Today (Sept. 13, 2016, updated Sept. 16, 2016) available at <https://www.usatoday.com/story/money/business/2016/09/13/nv-energy-solarcity-deal-grandfather-residential-rooftop-solar-customers/90306788/>.

[52] Whaley, Sean, *Official: Fallout from PUC Ruling Tarnished Nevada's Clean Energy Image,* Las Vegas Review-Journal (Mar 22, 2016) available at <https://www.reviewjournal.com/business/energy/official-fallout-from-puc-ruling-tarnished-nevadas-clean-energy-image/ >.

[53] Nevada Governor Brian Sandoval, Executive Order 2016-04 (2014) available at <http://gov.nv.gov/News-and-Media/Executive-Orders/2016/EO_-2016-04-New-Energy-Task-Force/>.

[54] New Energy Industry Task Force, Final Recommendations (Sept. 30, 2016) available at <http://energy.nv.gov/uploadedFiles/energynvgov/content/Programs/NEITF%20Final%20Recommendations(1).pdf>.

in September 2016, thereby instituting grandfathering for NEM customers in the state of Nevada, putting an end to a year of heated debate on grandfathering.[55]

Further, the Nevada Legislature passed legislation in 2017 to address the rate structure for future net metering customers, which requires that all future net metering customers be grandfathered under the rate structure outlined in the legislation for 20 years.

Q. Is the Nevada experience relevant to Massachusetts?

A. Yes. The Nevada experience demonstrates that failure to grandfather existing customers is widely regarded as unfair to customers, in contravention of accepted rate design principles, inconsistent with state policy goals, and would likely generate additional public and political concerns, beyond those already filed in this docket. For example, see the July 25th letter from Senator Golden.

Q. Do your points about grandfathering apply to residential, commercial, and industrial customers?

A. Yes. The issues of continuity or rates, public acceptability, and fairness regarding grandfathering all apply to all types of customers.

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[55] Public Utilities Commission of Nevada, *Application of Nevada Power Company d/b/a NV Energy filed under Advice Letter No. 466 to revise Tariff No. 1-B to modify Net Metering Rider-A Schedule NMR-A to establish separate rates for grandfathered private generation customers*, Docket No. 16-07028, Order (Sept. 16, 2016) & *Application of Sierra Pacific Power Company d/b/a NV Energy filed under Advice Letter No. 585-E to revise Tariff No. 1 to modify Net Metering Rider-A Schedule NMR-A to establish separate rates for grandfathered private generation customers*, Docket No. 16-07029, Order (Sept. 16, 2016) both available at <http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-7/15119.pdf>.

Q. Are these grandfathering issues important for cities and towns?

A. Yes. Many cities and towns have installed distributed generation technologies, many of which are supported by long-term contracts and power purchase agreements that cannot be modified to account for changes to rate design. Applying the MMRC to these customers would be grossly unfair to those towns, causing them to lose millions of dollars from their distributed solar investments.[56] In addition, it would have a chilling effect on any towns or cities that consider adopting distributed generation technologies in the future. This outcome would clearly be inconsistent with the Solar Act, as well as the Green Communities Act, which was particularly focused on encouraging cities and towns to implement clean distributed generation resources.

Q. Are these grandfathering issues important for stand-alone generators?

A. Yes. Stand-alone generators represent an important part of the Commonwealth's clean energy policies and goals ever since they were first enabled in the Green Communities Act.[57] These facilities allow a broad range of customers to participate in the development of, and the benefits available from, distributed solar generation, beyond those customers who have a suitable roof or other location on their property. They make it much easier for cities and towns to adopt distributed solar resources, and they allow for "community solar" projects that can be made available to a range of customer types, including low-

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[56] *See, for example*, the town of Newton's testimony that it would lose "about $400,000 per year and $7 million over 20 years." D.P.U. 17-05, Public Hearing, Tr. at 22 (Jul. 26, 2017). In addition, see the comments of the Town of Bourne, filed on August 2, 2017; the comments of the Town of Tisbury, filed on July 24, 2017; the comments of the Town of Orleans, filed on July 24, 2017; and the comments of the Town of Chatham, filed on August 1, 2017.

[57] An Act Relative to Green Communities, St. 2008, c. §169.

income customers. Stand-alone generation projects already represent a large portion of the distributed solar resources developed in the Commonwealth.

Applying the MMRC retroactively to these projects would be grossly unfair to the project developers, the project participants, or both. It would also have a chilling effect on any customers or developers thinking of investing in new stand-alone generation projects. This outcome would clearly be inconsistent with the Solar Act, the Green Communities Act, and Commonwealth energy goals in general.

4. ALTERNATIVES TO EVERSOURCE'S PROPOSED MMRC

Q. If the Department were to find that some form of MMRC is warranted, how you would you recommend it be designed?

A. Any MMRC approved by the Department should meet all the 14 criteria identified by the Department and listed above in Section 2. First and foremost, the MMRC must be justified (criterion 8), supported by an analysis of cost-shifting expected from distributed generation (criterion 11), which properly accounts for the benefits of distributed generation (criterion 10). The MMRC must not inhibit the development of distributed generation resources (criterion 3), and must be consistent with the Commonwealth's energy policy goals and statutes, especially the GCA, the Solar Act, and the SMART program.

We recommend that the Department's straw proposal for an MMRC in D.P.U. 16-164 be used as guidance for any MMRC that the Department finds to be warranted. In particular, the MMRC should be based on Phase I of the Department's straw proposal, which requires that the customer charge would act as a "minimum bill."[58] In other words, DG customers would not be able to avoid paying their customer charge, regardless of how much DG generation or how many net metering credits they produced. Furthermore, all low-income customers and customers in publicly assisted housing should be exempt from the MMRC, consistent with the recommendations of the Low-Income Network and the Clean Energy Stakeholders in that docket. This minimum bill approach would meet the ultimate objective of the MMRC, without creating new rate designs that are inconsistent with the Departments' rate design principles, are a significant deviation from historic rate design precedent, and pose grave risks for customers.

Q. Acadia Center has proposed a distribution reliability charge as an alternative to Eversource's proposed MMRC.[59] Do you support its proposal?

A. No. While we applaud Acadia Center's creativity in developing the distribution reliability charge, and we agree that its proposal is significantly better than the MMRC proposed by Eversource, we do not support the application of a distribution reliability charge for Eversource. First, there has been no evidence provided in this docket suggesting that the cost-shifting from DG resources is significant enough to warrant any kind of an MMRC, or any action to mitigate against cost-shifting from DG. Second, the distribution reliability credit is relatively complex and may be difficult for many residential and small commercial and industrial customers to understand and take full advantage of. Third, we believe that a simple minimum bill, based upon the customer charge, is a much better mechanism to address concerns about cost-shifting from DG.

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[58] D.P.U. 16-164-E at 5.
[59] Exh. AC-ML-1, at. 35 and Exh. AC-ML-7.

5. CONSOLIDATED RATES

Q. Do you have any concerns with the Company's proposal to consolidate rates across its territory?

A. Yes. The Company currently offers a variety of rate designs across the different parts of its service territory. While we generally agree that rates should be consolidated to provide more consistency across the service territory, Eversource has chosen to eliminate some rate designs that are consistent with Department principles and are in the public interest, but maintain some that are not. We are particularly concerned with Eversource's proposals to:

- Eliminate certain small C&I rate schedules (such as T-1) that apply to municipal and stand-alone distributed generators, and transition small C&I customers with distributed generation to rate schedules that contain a demand charge.
- Eliminate the optional TOU rates available to residential and small C&I customers.
- Eliminate the seasonal rates offered to residential and small C&I customers.

We address each of these items below.

<u>Small C&I Rates that Contain a Demand Charge</u>

Q. What rate design changes is Eversource proposing for small C&I customers that have installed distributed generation?

A. The Company is proposing to eliminate certain time-of-use rates (T-1, G-4, and G-6) and move small C&I customers with distributed generation onto flat rates with a demand charge. For example, the Company is proposing to move all stand-alone net metered generators to the G-1 Demand rate, even though these customers have no on-site load.[60]

Q. Is the Company proposing an alternative TOU rate to replace the ones that it is eliminating?

A. The Company is proposing to introduce an optional time-of-use rate (G-5), but this rate would have a demand charge component. The current rates that the Company seeks to eliminate do not have a demand charge component.

Q. Would moving customers with no on-site load to a rate with a demand charge better reflect cost causation?

A. Eversource's demand charge is designed to recover demand-related costs based on a customer's maximum consumption during a specified time interval (e.g., maximum demand in a 15-minute period), and to provide a price signal for customers to reduce their contribution to peak demand. Stand-alone generators do not contribute to consumptive demand on the system, but can provide demand-related benefits (such as relieving local capacity constraints). Applying a demand-related charge to stand-alone generators with no demand is illogical. Moreover, it drastically reduces the net metering compensation that such facilities receive, which, again, conflicts with the objectives of the SMART program and other Commonwealth policies.

[60] Attachment SREF-8-2.

Q. How would moving these customers to a rate with a demand charge impact the economics of distributed generation?

A. Forcing current DG facilities to switch to an optional TOU rate with a demand charge would significantly reduce the economics of those facilities.[61] This would likely have a disastrous effect on many solar projects, including municipal projects, stand-alone projects, and community solar projects. Such an outcome would clearly be inconsistent with the Green Communities Act, the Solar Act, and Commonwealth energy policies.

Q. What do you recommend regarding rate design for small C&I customers with distributed generation?

A. At a minimum, we recommend that existing customers be grandfathered, by providing these customers with the opportunity to remain on their current rate structure. However, a better approach would be to simply make the current TOU rates *without* demand charges the optional TOU rate for small C&I customers across the Company's service territory.

Q. Is there another aspect of Eversource's small C&I rate consolidation that you have concerns about?

A. Yes. Eversource is proposing to apply the G-1 rate with a demand charge to all small C&I customers that have installed or will install a demand meter. We are opposed to demand charges for small C&I customers, for all the reasons described in Section 2 above. Even if this proposal applies to only a small portion of small C&I customers at this time, it is a bad precedent. Also, this approach might eventually require all small C&I

[61] *See supra*, Section 2.

customers who install DG to take service under a demand charge. This would likely have a chilling effect on the economics and customer adoption of DG facilities.

Q. Is there a better way to offer demand charges to small C&I customers?

A. Yes. We recommend that Eversource offer small C&I customers the *option* to choose a rate structure with a demand charge in it. Combined with our recommendation above on TOU rates, this means that Eversource would offer small C&I customers three rate design options: (a) a flat energy rate with no demand charge (which would be the default rate), (b) an optional TOU rate with no demand charge, and (c) an optional three-part rate with a demand charge.[62] This way, customers can choose which rates that best enable them to manage their electricity bills while using the system efficiently, without posing significant risks to these customers or undermining the development of DG resources.

Time-of-Use Rates for Residential and Small C&I Customers

Q. Please describe what Eversource is proposing to do with optional TOU rates for residential and small C&I customers.

A. The Company currently offers optional TOU rates for residential and small C&I rates in Boston, Cambridge, and South Shore territories, but not the WMECO territory. It is proposing to eliminate all optional TOU rates for residential and small C&I customers.

[62] A three-part rate consists of a customer charge, an energy charge, and a demand charge.

Q. Do you have any concerns with the Company's proposal to eliminate optional TOU rates for residential and small C&I customers throughout its territories?

A. Yes. TOU rates can provide much more efficient prices signals than flat rates. While it may be premature to apply *opt-out* TOU rates for all residential and small C&I customers, due to metering limitations and concerns about customer impacts, there is no reason that the Company cannot offer *opt-in* TOU rates. In fact, these rates have been very influential in supporting the development of municipal and stand-alone DG facilities.

Q. The Company asserts that the low adoption rate for its current TOU rates suggests that customers are not interested in TOU rates. Do you agree?

A. No. First, it is important to note that some small C&I customers, particularly cities, towns, and stand-alone DG developers, have shown great interest in the optional TOU rates.[63] Second, there may be many reasons why there has been little residential customer uptake of the current TOU offering. The specific design of the offering can have a large impact on customer interest, because the design will determine how economic the TOU rate is to customers, and what types of actions customers must take to benefit from the rate. There may be ways to design the optional residential TOU rates to send better price signals, be more economic to customers, and be more appealing to customers.

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[63] Response to SREF-8-2.

Q. The Company asserts that TOU rates are not appropriate for distribution costs, because "distribution system costs are primarily demand related."[64] Do you agree?

A. No. It is increasingly recognized that many distribution costs have a temporal component. For example, in California, Southern California Edison is proposing to reduce its demand charges for commercial customers because its "recent cost studies determined that distribution-related costs *do* vary by time of day."[65] This is a critical concept that should be considered when deciding upon the relevance of TOU rates for distribution services.[66] Further, in January, the CPUC directed that TOU rate periods consider the time profile of marginal distribution and transmission costs. *See* Decision 17-01-006, January 19, 2017, Rulemaking 15-12-012, p. 27, [67]where the CPU stated: "We also conclude that the time sensitivity of all elements of a utility's hourly marginal costs is relevant and, ideally, should be considered in assessing TOU periods."

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64 ES-RDP-1, at 16: 8-12.

65 California Public Utilities Commission, T*estimony of Southern California Edison Company in Support of its Application for Approval of its 2017 Transportation Electrification Proposals*, A.17-01-021 at 76 (January 20, 2017).

66 Order 15-155 at 444. Relatedly, National Grid noted in D.P.U. 15-155 that "Encouraging customers to shift load from high use, peak periods into off-peak periods through demand management results in a better utilization of the existing distribution system [which] reduces the need to build additional system capacity to meet peak loads…." *See* Prefiled Testimony of Pricing Panel, Exhibit NG-PP-1, D.P.U. 15-155, November 6, 2015, Page 30, lines 9-21.

67 California Public Utilities Commission, *Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments*, Rulemaking 15-12-012, Decision 17-01-006, Decision Adopting Policy Guidelines to Assess Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payment (Jan. 19, 2017) available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M172/K782/172782737.PDF.

6. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. We recommend that the Department reject Eversource's proposed MMRC. If the Department finds that the Company has demonstrated that some form an MMRC is warranted at this time, the MMRC should be in the form of a minimum bill equal to the customer charge, from which customers who have already installed distributed generation (DG), as well as low-income customers, and customers in publicly-supported housing, are exempt.

We also recommend that if rates are consolidated, that the Department:

- Reject the Company's proposal to apply a demand charge to all small C&I customers that have or install suitable meters.
- Require the Company to offer all residential and small C&I customers well-designed optional TOU rates that do not have a demand charge.

Q. Does this conclude your supplemental testimony?

A. Yes.