

**COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES**

Petition of NSTAR Electric Company)
d/b/a Eversource Energy for Approval of) **D.P.U. 21-90**
Phase II Electric Vehicle Infrastructure Program)

Petition of Massachusetts Electric Company)
and Nantucket Electric Company each) **D.P.U. 21-91**
d/b/a National Grid for Approval of)
Phase III Electric Vehicle Market Development Program)

TRACK 2

DIRECT TESTIMONY OF

JOSHUA R. CASTIGLIEGO

ON BEHALF OF

INTERVENOR GREEN ENERGY CONSUMERS ALLIANCE

EXHIBIT GECA-JRC-1

May 27, 2022

Table of Contents

I. INTRODUCTION 1

II. PURPOSE OF TESTIMONY 2

III. BACKGROUND ON DEMAND CHARGES 3

IV. IMPACTS OF DEMAND CHARGES ON ELECTRIC VEHICLE CHARGING..... 6

V. OVERVIEW OF PROPOSED DEMAND CHARGE ALTERNATIVES 7

VI. BENEFITS OF CO-LOCATION 12

VII. ILLUSTRATIVE EXAMPLE OF CO-LOCATION..... 17

VIII.RECOMMENDATIONS AND CONCLUSIONS 31

1 **I. INTRODUCTION**

2 **Q. Mr. Castiglione, please state your full name, business name and address.**

3 **A.**My name is Joshua R. Castiglione. I am a Researcher and Assistant Director at the Applied
4 Economics Clinic. Our offices are located at 1012 Massachusetts Avenue, Arlington MA,
5 02476.

6 **Q. What is your educational background?**

7 **A.**I received a Master of Arts in Energy & Environment from Boston University and a Bachelor of
8 Science in both Mathematics and Physics from Roger Williams University.

9 **Q. Please describe your professional experience.**

10 **A.**I have more than four years of professional experience in energy and climate research and
11 analysis, with a focus on decarbonization and pollution mitigation. I have authored more than
12 20 reports and have been published in *Waste Management*. Prior to joining the Applied
13 Economics Clinic, I worked as a Research Fellow at Boston University's Institute for
14 Sustainable Energy, where I led the analysis in the *Carbon Free Boston* report on the emissions
15 impacts associated with Boston's waste management system to inform the City's
16 decarbonization efforts as it works to achieve carbon neutrality by 2050.

17 My recent work includes investigating the value of winter grid reliability, examining the net
18 emissions savings benefit of a battery storage facility, and critiquing the over-procurement of
19 PJM's capacity market. My Curriculum Vitae is attached as Exhibit GECA-JRC-2.

20 **Q. Have you ever testified before the Massachusetts Department of Public Utilities (DPU)?**

21 **A.**Yes. I submitted direct testimony in Track 1 of DPU Docket Nos. 21-90 and 21-91.

1 **Q. On whose behalf are you submitting this testimony?**

2 **A.** I am submitting this testimony on behalf of the Green Energy Consumers Alliance.

3 **Q. Are you sponsoring any exhibits?**

4 **A.** Yes. I am sponsoring the following exhibits:

- 5 • Exhibit GECA-JRC-2 – Curriculum Vitae of Mr. Joshua R. Castigliego
- 6 • Exhibit GECA-JRC-3 – Workpapers

7 **Q. What materials did you review in preparing this testimony?**

8 **A.** Any document upon which I relied directly is cited in my testimony.

9 **II. PURPOSE OF TESTIMONY**

10 **Q. What is the purpose of your testimony?**

11 **A.** The purpose of my testimony is to investigate co-locating renewable power generation (e.g.,
12 solar PV) and/or energy storage at electric vehicle (EV) charging stations as a technology-based
13 approach to alleviating the financial barrier that utility demand charges pose to the widespread
14 deployment of direct current fast charging (DCFC) stations across the Commonwealth. Based
15 on that investigation, I provide recommendations to the Department on the current proposals
16 concerning demand charges to EV charging stations.

17 **Q. Please summarize your conclusions.**

18 **A.** I find that co-location with renewables and/or energy storage has the potential to lower the
19 average cost per EV charge (depending, in part, on the utility's rate structure), which would
20 alleviate the financial barrier for EV charging stations due to demand charges. I demonstrate
21 that utility demand charges can work hand in hand with the co-location of renewables and
22 energy storage to synergistically combat the financial barrier and increase overall deployment

1 of DCFC stations in the Commonwealth. To obtain those benefits, the electric distribution
2 companies and the Department must take the impact of co-location into consideration when
3 constructing and approving demand charge rate structures.

4 **III. BACKGROUND ON DEMAND CHARGES**

5 **Q. What is a demand charge?**

6 **A.** According to the Massachusetts Office of Technical Assistance and Technology (OTA), a
7 demand charge is a fee based on the highest amount of energy used in a specific interval
8 (typically 15, 30, or 60-minutes long) throughout a billing period (typically, one month).¹ The
9 higher the peak consumption over the demand interval the greater the demand charge, which is
10 charged on monthly electric bills in dollars per kilowatt (\$ per kW).²

11 Electric distribution companies in Massachusetts collect demand charges from all commercial
12 and industrial customers that have a demand meter. Different rate schedules are created to
13 differentiate customer classes based on a variety of factors, including the customer's monthly
14 peak demand.

15 **Q. Why do electric distribution companies use demand charges?**

16 **A.** Demand charges allow electric distribution companies to recover costs associated with building
17 a distribution system that has the capacity to meet peak customer demand. Demand charges also
18 serve as price signals to customers:

¹ Massachusetts Office of Technical Assistance and Technology (OTA). N.d. "Understanding Your Electric Bill: Saving Money on Demand Charges and Power Factor." *Executive Office of Energy and Environmental Affairs (EEA)*. Available at: <https://www.mass.gov/doc/understanding-your-electric-bill-saving-money-on-demand-charges-and-power-factor-0/download>. p.1.

² Ibid.

1 *Demand represents the amount of power required by the customer at a moment in*
2 *time and is a necessary element in determining the size of the distribution system*
3 *required to serve a customer. Energy is the amount of power used over time. Energy*
4 *is most directly related to supply where the customer requires a specific volume to*
5 *be delivered. As an energy delivery company, customer demand is highly correlated*
6 *with transmission and distribution costs. Therefore, demand charges send price*
7 *signals to customers regarding the cost they place on the electric grid.³*

8 According to a 2019 Vermont Public Service Department report, the intent of demand charges
9 is to allow utilities to recover the high expenses associated with providing electric services
10 during peak times:

11 *Demand charges exist to cover the utility's fixed costs of providing a certain level of*
12 *energy to their customers at the utility's peak periods. At the utility system level, and*
13 *at the regional level, utilities have to maintain enough capacity in power plants,*
14 *substations and wires to deliver energy at the utility system peak. This capacity is*
15 *expensive, and the utility needs to cover these costs. In addition to allowing the*
16 *utility to recover these costs, demand charges, when well designed, can provide a*
17 *price signal to encourage sound conservation and/or to shift peak during periods of*
18 *high demand.⁴*

³ D.P.U. 21-90, Exhibit ES-RDC-1 at 6, lines 10-17.

⁴ Vermont Public Service Department. 2019. *Demand Charges: Analysis and Recommendations*. Vermont State Legislature. Available at: <https://legislature.vermont.gov/Documents/2020/WorkGroups/SenateAgriculture/ReportsandResources/W~none~DemandChargesReport2019~2-1-2019.pdf>, p.3.

1 **Q. Are there any downsides associated with demand charges?**

2 **A.** Yes. Demand charges can pose a cost burden for customers with relatively flat loads—or,
3 alternatively, for customers that are unable to control the shape of their load—who nevertheless
4 have difficulty reducing their peak demand.

5 Moreover, the Vermont Public Service Department’s 2019 report on demand charges explains
6 that individual customer peak demand may share little overlap with overall system peak
7 demand, making demand charges ineffective price signals:

8 *From the utility perspective, there is typically limited alignment between the utility's*
9 *system costs and customer peaks. Demand charges can assess higher-demand*
10 *customers with higher charges, regardless of their contribution as a cost causer to*
11 *the utility system... As a general case, the large user with higher peak demands will*
12 *contribute more to the system peak than the smaller user. Management of customer-*
13 *specific peak loads corresponds to little change in the system costs unless the*
14 *customer peaks coincide with that of the system. This sometimes means that a*
15 *significant reduction in peak load from the perspective of individual customers can*
16 *correspond to a significant loss in revenue to the system without a commensurate*
17 *reduction in costs.*⁵

⁵ Vermont Public Service Department. 2019. *Demand Charges: Analysis and Recommendations*. Vermont State Legislature. Available at: <https://legislature.vermont.gov/Documents/2020/WorkGroups/SenateAgriculture/ReportsandResources/W~none~DemandChargesReport2019~2-1-2019.pdf>, p.5.

1 **IV. IMPACTS OF DEMAND CHARGES ON ELECTRIC VEHICLE CHARGING**

2 **Q. Do operators of EV charging stations pay demand charges in Massachusetts?**

3 **A.** Yes. Currently, operators of EV charging stations, including DCFC and Level II charging
4 stations, are subject to demand charges in Massachusetts.

5 **Q. Are demand charges an obstacle to operators of EV charging stations?**

6 **A.** Yes. Demand charges are a substantial financial barrier to the deployment of public EV
7 charging stations, especially DCFC stations. DPU Order 20-69-A explains that demand charges
8 are particularly burdensome for public charging sites with low utilization rates, at least initially:

9 *The combination of low energy use and high charging power can cause demand*
10 *charges to comprise the majority of a charging site host's monthly [electric] bill.⁶*

11 **Q. How do demand charges pose a financial barrier to operators of EV chargers?**

12 **A.** EV charging station operators with low utilization rates tend to experience a financial barrier
13 due to high demand charge costs relative to the potential revenue from EV charging. The
14 National Association of State Energy Officials' (NASEO) 2021 report *Demand Charges &*
15 *Electric Vehicle Fast-Charging* finds that DCFC infrastructure is unique in that it requires large
16 instantaneous draw (i.e., high kW) for fast charging but experiences relatively infrequent
17 utilization; these characteristics prevent most DCFC stations from being cost-competitive with
18 gas stations, and some from being profitable at all.⁷ The NASEO report finds that demand
19 charges are by far the largest portion of the overall cost of DCFC charging, on average

⁶ D.P.U. Order 20-69-A at 42.

⁷ Tucker, D., et al. 2021. *Demand Charges & Electric Vehicle Fast-Charging: An Intermountain West Assessment*. National Association of State Energy Officials (NASEO). Available at: <https://www.naseo.org/data/sites/1/documents/publications/Demand%20Charges%20and%20EV%20Charging%20-%20Final.pdf>. p.13-14.

1 amounting to 74 percent of DCFC station host electric bills.⁸ Research from Georgetown
2 Climate Center finds that some meters supporting only DCFC stations have demand charges
3 comprising upwards of 80 percent of their monthly electric bills.⁹

4 As utilization of EV charging infrastructure increases, the overall cost burden of electric bills
5 (including demand and other electric charges) is anticipated to decrease. The 2021 NASEO
6 report estimates that a utility-owned 50-kW DCFC station is expected to incur electric costs of:

- 7 • **\$146** per EV charge (or \$5.14 per kWh) under **low utilization** (meaning one charge per
8 week), compared to
- 9 • **\$3** per EV charge (or \$0.12 per kWh) under **high utilization** (meaning 100 charges per
10 week).¹⁰

11 **V. OVERVIEW OF PROPOSED DEMAND CHARGE ALTERNATIVES**

12 **Q. Has the Commonwealth of Massachusetts taken any action to alleviate the financial**
13 **barrier posed by demand charges?**

14 **A.** Yes. Section 29 of the Commonwealth’s January 2021 Transportation Act specifically directs
15 each electric utility to propose at least one alternative to standard demand charges:

16 *Notwithstanding any general or special law to the contrary, not later than 180 days*
17 *after the effective date of this act, each distribution company as defined in section 1*
18 *of chapter 164 of the General Laws shall file at least 1 commercial tariff or program*

⁸ Tucker, D., et al. 2021. p.5.

⁹ Zyla, K.A. 2014. *Charging Ahead—Options for Policymakers Regarding the Regulation of Electric Vehicle Charging Markets*. Georgetown Climate Center. Available at: <https://www.georgetownclimate.org/files/report/GCC%20-%20Charging%20Ahead%20-%20June%202014.pdf>

¹⁰ Tucker, D., et al. 2021. p.13-14.

1 *utilizing alternatives to traditional demand-based rate structures to facilitate faster*
2 *charging for light-duty vehicles, heavier-duty vehicles and fleet vehicles.*¹¹

3 **Q. Has the Massachusetts DPU provided guidance to electric distribution companies to**
4 **ensure compliance with Section 29 of the Transportation Act?**

5 **A.** Yes. In May 2021, the Department issued DPU Order 20-69-A providing guidance for
6 compliance with Section 29 of the Commonwealth’s January 2021 Transportation Act, which
7 directs electric distribution companies to follow three guidelines in constructing their proposed
8 demand charge alternatives:

9 *In developing the demand charge alternative proposals, the Companies shall*
10 *consider the following: (1) converting kW-based charges to kilowatt-hour-based*
11 *charges; (2) off-peak charging demand charge rebates or discounts; and (3) sliding*
12 *scale demand charges based on the load factor of the electric vehicle charging site.*¹²

13 **Q. What is a load factor?**

14 **A.** A load factor is the ratio between a customer’s average net energy usage (in kWh) and
15 maximum energy usage (i.e., peak demand multiplied by number of hours) over a time
16 period, commonly a month.

17 **Q. Have any electric distribution companies in Massachusetts submitted their demand**
18 **charge alternative proposals following the DPU’s guidance?**

19 **A.** Yes. Eversource and National Grid have submitted testimony in DPU Docket Nos. 21-90 and
20 21-91, respectively, that outlines their proposed demand charge alternatives.

¹¹ Massachusetts Session Laws Chapter 383 (Transportation Act), Section 29 (2021). *An Act Authorizing and Accelerating Transportation Investment*. Available at: <https://malegislature.gov/Laws/SessionLaws/Acts/2020/Chapter383>

¹² D.P.U. Order 20-69-A at 42.

1 **Q. Please summarize the demand charge alternatives proposed by Eversource in DPU**
2 **Docket No. 21-90.**

3 **A. In its direct testimony in DPU Docket No. 21-90, Eversource proposes the introduction of two**
4 new rate schedules, EV-1 and EV-2, which would be applied to all separately metered, EV
5 charging sites.¹³

6 **Rate EV-1** consists of a monthly customer charge of \$15.03 and an energy-based rate of
7 \$0.03138 per kWh.

8 **Rate EV-2** consists of a monthly customer charge of \$222.03, along with energy- and demand-
9 based rates that operate on a sliding scale depending on customer load factor over the prior 12
10 months.¹⁴

- 11 • For customers with an annual site load factor **exceeding 15 percent**, the energy-based rate
12 is \$0.00203 per kWh and the demand-based rate is \$11.08 per kW;
- 13 • load factors **greater than 10 and less than or equal to 15 percent**, the energy- and
14 demand-based rates are \$0.01499 per kWh and \$5.54 per kW, respectively;
- 15 • load factors **greater than 5 and less than or equal to 10 percent**, the energy- and
16 demand-based rates are \$0.02148 per kWh and \$2.77 per kW, respectively; and
- 17 • load factors **less than or equal to 5 percent**, the energy rate is \$0.02796 per kWh and
18 demand rate is zero.¹⁵

¹³ D.P.U. Docket No. 21-90, Exhibit ES-RDC-1 at 5.

¹⁴ D.P.U. Docket No 21-90, Exhibit ES-RDC-1 at 5.

¹⁵ D.P.U. Docket No 21-90, Exhibit ES-RDC-1 at 9-10.

1 **Q. Please describe how Eversource’s proposed rate schedules are structured among EV**
2 **charging station operators?**

3 **A.** Operators of EV charging stations with a monthly peak demand of less than or equal to 200
4 kW for twelve consecutive billing months qualify for Eversource’s proposed Rate EV-1,
5 while those with a monthly peak demand greater than 200 kW qualify for proposed Rate EV-
6 2. Eversource believes that its EV-1 offering would largely be utilized by Level II charging
7 sites and EV-2 would apply to DCFC sites.¹⁶ Eversource also notes that the purpose of the
8 distinction between its two proposed rate schedules is to align with National Grid’s offerings:

9 *The Company established 200 kW as the breakpoint between Rate EV-1 and EV-2*
10 *to better align the applicability of its rate offerings with those of National Grid.*¹⁷

11 **Q. Please summarize the demand charge alternatives proposed by National Grid in DPU**
12 **Docket No. 21-91.**

13 **A.** In its direct testimony in DPU Docket No. 21-91, National Grid proposes the introduction of
14 “EV Pricing” under two of its existing rate schedules for general service: Rate G-2 (a demand
15 tariff) and Rate G-3 (a time-of-use tariff). These new rate schedules would be available to all
16 separately metered EV charging stations.¹⁸

17 **Rate G-2** consists of a monthly customer charge of \$30, along with energy- and demand-based
18 rates that operate on a sliding scale depending on customer load factor over a 12-month
19 period.¹⁹

¹⁶ D.P.U. Docket No 21-90, Exhibit ES-RDC-1 at 10, lines 6-13.

¹⁷ D.P.U. Docket No 21-90, Exhibit ES-RDC-1 at 10, lines 13-15.

¹⁸ D.P.U. Docket No 21-91, Exhibit NG-DCA-1 at 10.

¹⁹ D.P.U. Docket No 21-91, Exhibit NG-DCA-2 at 1.

- 1 • For customers with an annual site load factor **exceeding 15 percent**, the energy-based rate
2 is \$0.00213 per kWh and the demand-based rate is \$11.21 per kW;
- 3 • load factors **greater than 10 and less than or equal to 15 percent**, the energy- and
4 demand-based rates are \$0.01928 per kWh and \$5.60 per kW, respectively;
- 5 • load factors **greater than 5 and less than or equal to 10 percent**, the energy- and
6 demand-based rates are \$0.02784 per kWh and \$2.80 per kW, respectively; and
- 7 • load factors **less than or equal to 5 percent**, the energy rate is \$0.03460 per kWh and
8 demand rate is zero.

9 **Rate G-3** consists of a monthly customer charge of \$223, along with energy- and demand-
10 based rates that operate on a sliding scale depending on customer load factor over a 12-month
11 period. (National Grid’s Rate G-3 applies different energy-based rates for “On-Peak” and “Off-
12 Peak” energy usage, where the off-peak (i.e., hours between 9PM and 8AM daily Monday
13 through Friday, and all day on weekends and holidays) energy-based rate is \$0 per kWh. On-
14 peak (i.e., hours between 8AM and 9PM daily Monday through Friday, excluding holidays)
15 energy-based rates are provided below.):²⁰

- 16 • For customers with an annual site load factor **exceeding 15 percent**, the energy-based rate
17 is \$0.00175 per kWh and the demand-based rate is \$8.05 per kW;
- 18 • load factors **greater than 10 and less than or equal to 15 percent**, the energy- and
19 demand-based rates are \$0.02410 per kWh and \$4.02 per kW, respectively;

²⁰ D.P.U. Docket No 21-91, Exhibit NG-DCA-2 at 1.

- 1 • load factors **greater than 5 and less than or equal to 10 percent**, the energy- and
2 demand-based rates are \$0.03524 per kWh and \$2.01 per kW, respectively; and
- 3 • load factors **less than or equal to 5 percent**, the energy rate is \$0.04639 per kWh and
4 demand rate is zero.

5 **Q. Please describe how National Grid’s proposed rate schedules are structured among EV**
6 **charging station operators?**

7 **A.** Operators of EV charging stations with a monthly peak demand of less than or equal to 200
8 kW and a monthly energy usage greater than 10,000 kWh qualify for National Grid’s
9 proposed Rate G-2, while those with a monthly peak demand greater than 200 kW qualify for
10 proposed Rate G-3. Similar to Eversource, National Grid believes that its G-2 offering would
11 be primarily used by Level II charging sites, while its G-3 offering would apply to DCFC
12 sites.²¹

13 **VI. BENEFITS OF CO-LOCATION**

14 **Q. Aside from the rate-based demand charge alternatives outlined by the Department in**
15 **DPU Order 20-69-A and proposed by Eversource and National Grid, do any other**
16 **alternatives exist to alleviate the financial barrier posed by demand charges on EV**
17 **charging stations?**

18 **A.** Yes. Co-location of renewable energy and/or energy storage resources with EV charging
19 stations was raised by Green Energy Consumers Alliance and Unitil in their comments
20 submitted in DPU Docket No. 20-69.²²

²¹ D.P.U. Docket No 21-91, Exhibit NG-DCA-1 at 13, lines 12-17.

²² D.P.U. Order No. 20-69-A at 22.

1 **Q. Has Eversource evaluated or formed an opinion on the potential impacts co-locating**
2 **renewables and/or energy storage resources at EV charging stations would have on**
3 **demand and demand charges?**

4 **A.** No. According to Eversource’s Response to Information Request GECA-ES-4-1(f)-(g), the
5 utility has not evaluated or formed an opinion on the potential impacts that co-location of
6 renewables and/or energy storage would have on demand and demand charges at EV charging
7 stations.²³

8 **Q. Has National Grid evaluated or formed an opinion on the potential impacts co-locating**
9 **renewables and/or energy storage resources at EV charging stations would have on**
10 **demand and demand charges?**

11 **A.** Yes. According to National Grid’s Response to Information Request GECA-NG-1-5, the utility
12 has considered co-location as an approach to demand charge management. Further, it
13 acknowledges the potential benefits of co-location with respect to demand charges: “Energy
14 storage can be leveraged to limit demand charges by using the battery to limit the power
15 demand on the grid.”²⁴

16 However, National Grid notes that “the lack of incentives for energy storage limits the ability
17 for co-location of energy storage to be used to mitigate demand charges.”²⁵

²³ D.P.U. 21-90, Eversource’s Response to Information Request GECA-ES-4-1(f)-(g)

²⁴ D.P.U. 21-91, National Grid’s Response to Information Request GECA-NG-1-5

²⁵ D.P.U. 21-91, National Grid’s Response to Information Request GECA-NG-1-5

1 **Q. How does co-location with renewables and/or energy storage at EV charging stations**
2 **alleviate the financial barrier posed by demand charges?**

3 **A.** The co-location of renewables with EV charging infrastructure provides on-site energy
4 generation, which reduces the charging stations’ reliance on the larger electric grid. Renewable
5 generation, like solar PV, can reduce the net energy usage from the grid through directly
6 supplying energy for EV charging (thus reducing the energy needed from the grid) and by net
7 metering energy back to the grid (delivering energy onto the grid during daylight hours)—both
8 of which contribute to a lower load factor for the EV charging station and, therefore, a lower
9 bracket of demand charge rates under Massachusetts utilities’ proposals.

10 The co-location of energy storage with EV charging infrastructure and solar allows operators of
11 EV charging stations to shave peak demand, which can lead to additional reductions in monthly
12 demand charges as described below.

13 A 2019 study in the journal *Applied Energy*, titled “Technology solutions to mitigate electricity
14 cost for electric vehicle DC fast charging,” finds that the use of battery storage can benefit both
15 customers and utilities by shaving peak demand:

16 *Previous studies have shown that energy storage can be used to effectively reduce*
17 *electricity cost for both consumers and utilities, especially by providing energy*
18 *arbitrage and peak shaving. That is, using energy storage to align electricity*
19 *demand with supply can provide significant system benefits. Several studies have*
20 *shown that for an industrial customer with a properly-sized battery, an energy*

1 *storage system can reduce electricity cost by shaving peak demand and reducing*
2 *demand charges.*²⁶

3 A 2020 study in the journal *Energy Policy*, titled “Demand charge savings from solar PV and
4 energy storage,” finds that co-location with solar PV is most effective in providing demand
5 charge savings in buildings where peak usage occurs during daylight hours when solar
6 production is greatest. Co-location with energy storage can yield cost savings even when peak
7 usage occurs outside of solar generation hours. The cost savings from combined solar PV and
8 energy storage are greater than the sum of savings from PV alone and energy storage alone.²⁷

9 The 2019 study published in the *Applied Energy* finds that co-locating energy storage at EV
10 charging stations helps mitigate high electricity demand charges, while co-location with solar
11 PV helps mitigate energy-based charges and are most effective for loads that correlate with
12 hours of solar production. The study also finds that co-locating solar PV and energy storage
13 together can lead to synergies:

14 *Moreover, batteries and PV can be deployed synergistically to provide cost*
15 *reductions for DCFC, leveraging their ability to mitigate demand and energy*
16 *charges. For most sites, co-location is economically preferable, as it reduces fixed*
17 *cost and cost related to demand charges. The median savings from co-location*
18 *increase as DCFC utilization increases, but relative savings decrease as fixed and*
19 *demand charges become a smaller portion of total costs.*²⁸

²⁶ Muratori, M., et al. 2019. “Technology solutions to mitigate electricity cost for electric vehicle DC fast Charging,” *Applied Energy*, 242. Available at: <https://doi.org/10.1016/j.apenergy.2019.03.061> p.416.

²⁷ Darghouth, N.R., et al. 2020. “Demand charge savings from solar PV and energy storage.” *Energy Policy*, 146. Available at: <https://www.sciencedirect.com/science/article/pii/S0301421520304882>

²⁸ Muratori, M., et al. 2019. p.416.

1 A 2017 National Renewable Energy Laboratory (NREL) study, titled “How to Estimate
2 Demand Charge Savings from PV on Commercial Buildings,” concludes that co-locating solar
3 PV with EV charging stations will most likely reduce demand charges at sites where peak
4 energy usage currently occurs towards the middle of the day when solar generation is most
5 abundant. Such sites are often schools or office buildings and tend not to be apartments or
6 hotels.²⁹

7 **Q. By how much can co-location with renewables and/or energy storage reduce demand**
8 **charges for EV charging stations?**

9 **A.** The 2019 study published in the *Applied Energy* on the co-location of EV charging
10 infrastructure with solar and/or energy storage reveals that, for an infrequently utilized 50-kW
11 DCFC station, co-location of solar PV and energy storage technologies results in a 34 percent
12 reduction in median energy charges, and a 60 percent reduction in median demand charges.³⁰
13 Under high utilization, co-location at the same 50-kW DCFC station results in a 64 percent
14 reduction in both energy and demand charges.³¹

15 A joint 2017 study conducted by Lawrence Berkeley National Laboratory (LBL) and NREL
16 finds that co-locating solar PV with EV charging stations can reduce demand charges by 7
17 percent at commercial buildings and 18 percent at schools and offices, while hotels and
18 apartments see no reduction on average.³²

²⁹ National Renewable Energy Laboratory (NREL). 2017. *How to Estimate Demand Charge Savings from PV on Commercial Buildings*. NREL. Available at: <https://www.nrel.gov/docs/fy17osti/69016.pdf>

³⁰ Muratori, M., et al. 2019. p.420.

³¹ Muratori, M., et al. 2019. p.420.

³² Darghouth, N.R., et al. 2017. *Exploring Demand Charge Savings from Commercial Solar*. LBL and NREL. Available at: <https://emp.lbl.gov/publications/exploring-demand-charge-savings-0>, pp.13-14.

1 **VII. ILLUSTRATIVE EXAMPLE OF CO-LOCATION**

2 **Q. Have you examined the electric distribution companies' proposed demand charge**
3 **alternatives?**

4 **A.** Yes. As discussed above, Eversource and National Grid are proposing demand charge
5 alternatives for EV charging stations that differ depending on: (1) monthly peak demand (i.e.,
6 above or below 200 kW); (2) load factors; and (3) time of day (i.e., on-peak versus off-peak
7 hours).

8 **Q. Are Eversource and National Grid's proposed demand charge alternatives different**
9 **from one another?**

10 **A.** Yes. Although both utilities impose a threshold of a 200 kW monthly peak demand between
11 the proposed rate classes, the resulting rate structures are different from one another.
12 Eversource's Rate EV-1—which applies to EV charging stations with a monthly peak
13 demand of no more than 200 kW—only applies an energy-based rate to all customers
14 regardless of load factor, while National Grid's Rate G-2 applies both energy- and demand-
15 based rates on a sliding scale depending on the customer's load factor.
16 Eversource's EV-2 and National Grid's Rate G-3—which apply to EV charging stations with
17 a monthly peak demand in excess of 200 kW—both impose energy- and demand-based rates
18 on a sliding scale depending on the customer's load factor. Unlike Eversource, National Grid
19 also differentiates its energy-based rates for on-peak and off-peak hours.

1 **Q. Have you estimated the cost impacts to charging station operators of the utilities’**
2 **proposed demand charge schedules?**

3 **A.** Yes. I constructed a simplified, illustrative spreadsheet model (provided as Exhibit GECA-
4 JRC-2) to demonstrate the cost impacts of the utilities’ proposed demand charge schedules
5 using two sample system sizes: a six port, 300-kW charging station and a four port, 200-kW
6 charging station. Both charging stations were assessed during a typical Winter month under
7 moderate and high utilization cases.³³ These two sample utilization levels result in load
8 factors that are dependent on the other energy infrastructure (i.e., solar PV and battery
9 storage) with which the charging apparatus is co-located.

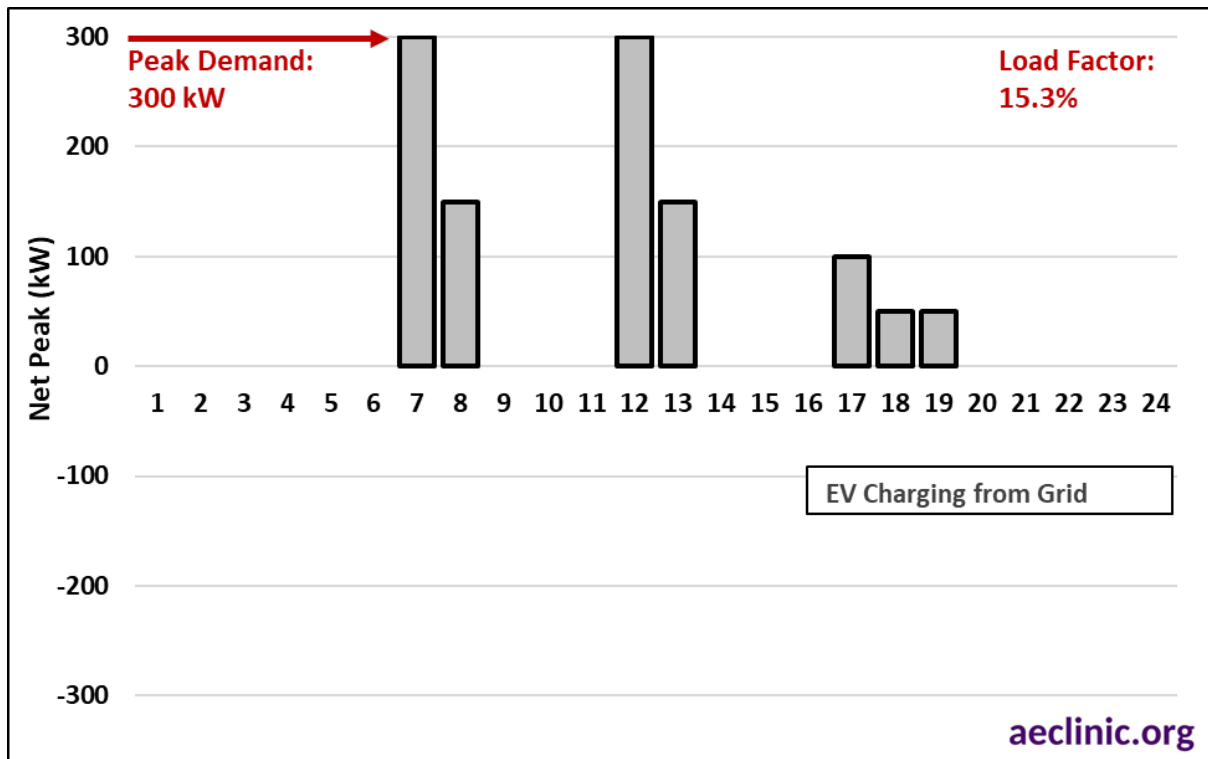
10 The moderate and high utilization cases represent the frequency of EV charges throughout a
11 typical Winter day (which is assumed to have daylight hours between 8AM and 5PM). The
12 utilization cases were constructed to provide insight into the load factor and peak demand of
13 the sample system, but also to assess the financial burden on the EV charging station from
14 monthly customer and demand charges. Daily load curves for the utilization cases are
15 provided here for illustrative purposes and are not meant to represent the load curve of an EV
16 charging station in any particular location or day. (To estimate monthly costs imposed by
17 customer and demand charges, I assume that a typical Winter month consists of 30 days, 20
18 of which are non-holiday weekdays.)

³³ The illustrative example of co-location described in this testimony is modeled during a typical Winter month, which has fewer daylight hours (i.e., less solar production) than Summer months. This conservative assumption shows the minimum impact of co-location on reducing monthly costs for EV charging stations due to customer and demand charges.

1 **Q. Which of the proposed rate schedules apply to the illustrative 300-kW EV charging**
2 **station (without co-location) under the moderate and high utilization cases that you**
3 **analyzed?**

4 **A.** The moderate utilization case (without co-location) results a peak load of 300 kW and a load
5 factor of 15.3 percent, which places it into Eversource’s Rate EV-2 and National Grid’s Rate
6 G-3 (see Figure 1 below). The high utilization case increases the load factor to 44.4 percent,
7 which does not change the applicable rate schedules from either of the utilities (see Figure 2
8 below).

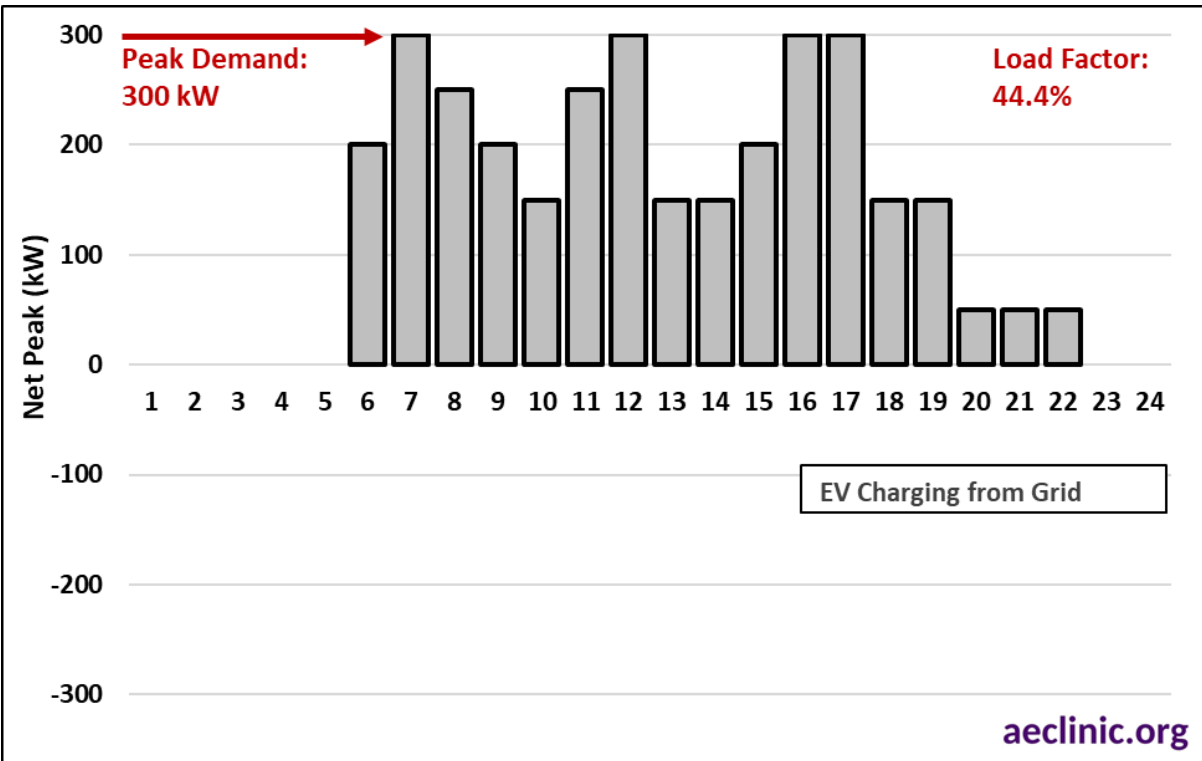
9 **Figure 1. Illustrative load curve for a six port, 300-kW charging station with moderate utilization**



10
11

Source: Exhibit GECA-JRC-3

1 **Figure 2. Illustrative load curve for a six port, 300-kW charging station with high utilization**



2
3 *Source: Exhibit GECA-JRC-3*

4 **Q. Without co-location, what is the resulting financial burden of monthly customer and**
5 **demand charges between the two utilization cases?**

6 **A.** Without colocation, under the moderate utilization case (22 EV charges per day), the EV
7 charging station is responsible for monthly customer and demand charges equivalent to **\$4.04**
8 **and \$5.47 per EV charge** for National Grid and Eversource, respectively. In contrast, the
9 high utilization case (64 EV charges per day) results in monthly customer and demand
10 charges equivalent to **\$1.42 and \$1.95 per EV charge** for National Grid and Eversource,
11 respectively. Under the moderate utilization case, the per EV charge costs are nearly three
12 times greater than those of the high utilization case.

1 In addition, based on the number of EV charges per day, the likely revenue received from EV
2 charging customers in the moderate utilization case is approximately one-third of what would
3 be received the high utilization case.

4 For context, residential customers (including those with EV charging infrastructure) are not
5 required to pay the high costs associated with customer and demand charges as their
6 commercial and industrial counterparts (including EV charging station operators). This
7 difference in rate schedules results in EV charging station operators facing higher costs than
8 residential customers.

9 Furthermore, lower utilization rates result in meager revenues from EV charging customers
10 to offset the high fixed costs of installing and operating EV charging stations. This financial
11 burden is a hindrance to widespread deployment of EV charging stations (especially DCFC
12 stations) throughout the Commonwealth.

13 **Q. What are the customer and demand charges of the utilities' proposed demand charge**
14 **alternatives that apply in the illustrative 300-kW charging station without co-location**
15 **of renewables or energy storage under the high utilization case?**

16 **A.** For a typical Winter month, and without co-location, the illustrative 300-kW charging station
17 with a load factor of 44.4 percent and a peak load of 300 kW would be responsible for a
18 monthly customer and demand charge cost of \$2,729 for National Grid and \$3,741 for
19 Eversource under the high utilization case (see Table 1 at p.28, *infra*).

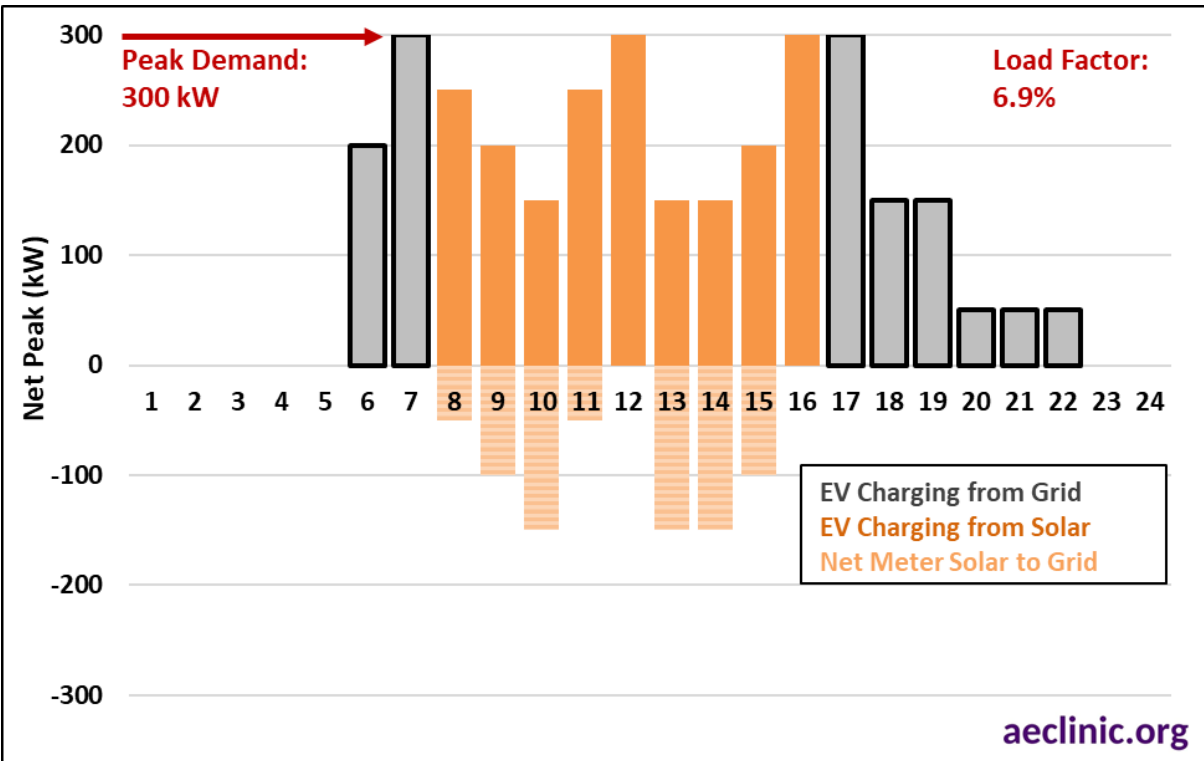
1 **Q. Did you analyze the effects of co-locating renewables and/or energy storage with EV**
2 **charging infrastructure as part of your illustrative example?**

3 **A.** Yes. I analyzed the effects of co-locating renewables and/or energy storage with EV charging
4 stations on the cost impacts of the utilities' proposed demand charge alternatives. For this
5 illustrative example, I chose to co-locate a solar PV system that is equivalent to the size of
6 the EV charging station (i.e., 300-kW solar PV for the 300-kW charging station) and a
7 battery storage system that is sized slightly larger to account for any efficiency losses (i.e.,
8 330-kW battery storage for the 300-kW charging station to account for an assumed efficiency
9 loss of 10 percent).

10 **Q. What impact does co-locating solar PV have on the illustrative 300-kW charging station**
11 **under the high utilization case?**

12 **A.** By co-locating solar PV with the 300-kW charging station, solar generation is able to replace
13 the need for grid-supplied electricity during daylight hours, which I assumed to be between
14 8AM and 5PM for a typical Winter day. In addition, any solar generation that is not used
15 directly for EV charging is assumed to be net metered back to the grid. Under the high
16 utilization case, the co-location of solar PV with the EV charging station reduces the net
17 energy usage from the grid, which decreases the load factor from 44.4 percent to 6.9 percent
18 (see Figure 3 below).

1 **Figure 3. Illustrative load curve for a 300-kW station co-located with solar PV under high utilization**



2
3 Source: Exhibit GECA-JRC-3

4 **Q. What are the customer and demand charges that apply with co-locating of solar PV at**
5 **the illustrative 300-kW charging station under the high utilization case?**

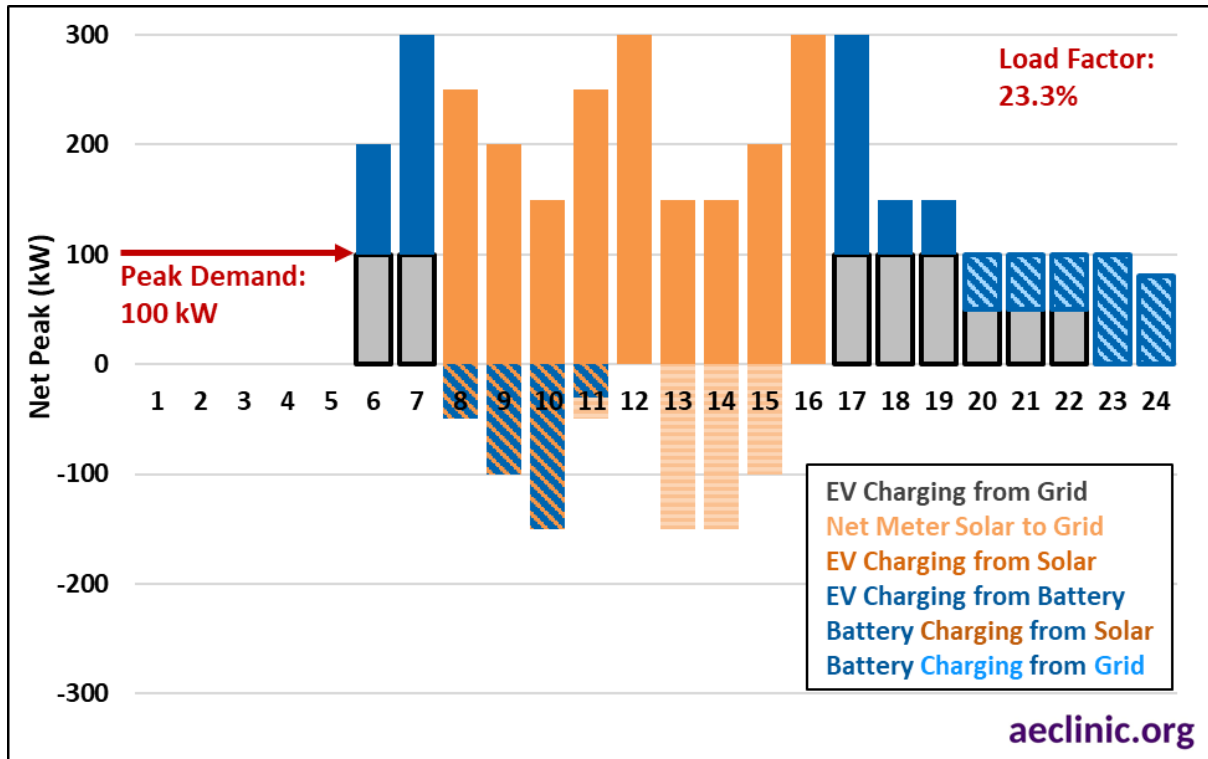
6 **A.** Under the high utilization case, the illustrative 300-kW charging station remains in
7 Eversource’s Rate EV-2 and National Grid’s Rate G-3 when co-located with solar PV;
8 however, lowering the load factor from 44.4 percent to 6.9 percent changes the applicable
9 energy- and demand-based rates to those that apply to customers with load factors greater
10 than 5 percent and less than or equal to 10 percent. Co-locating solar PV with the 300-kW
11 charging station reduces the monthly customer and demand charge costs by nearly half for
12 National Grid (\$1,284) and two-thirds for Eversource (\$1,375) under the high utilization

1 case (see Table 1 at p.28, *infra*), which is equivalent to **\$0.67 and \$0.72 per EV charge**,
2 respectively (see Table 2 at p.29, *infra*).

3 **Q. What impact does co-locating both solar PV and battery storage have on the illustrative**
4 **300-kW charging station under the high utilization case?**

5 **A.** By co-locating both solar PV and battery storage with the 300-kW charging station, the
6 battery storage system is able to reduce the overall peak demand for hours of the day with
7 low or no solar production. In my illustrative example, I chose to use battery storage to limit
8 peak demand at 100 kW for the 300-kW EV charging station example with the goal of
9 lowering the amount of kW applicable for electric utility demand charges (see Figure 4
10 below). (Peak demand is limited to 75 kW in the 200-kW charging station example.)
11 The co-location of solar PV and battery storage with the EV charging station reduces the
12 peak demand from the grid, which results in a load factor of 23.3 percent (see Figure 4
13 below). The load factor is higher with co-location of solar PV and battery storage compared
14 to co-location with solar PV alone since the maximum potential energy usage from the grid is
15 reduced from 7,200 kWh per day (which is equivalent to the peak demand of 300 kW
16 multiplied by 24 hours) to 2,400 kWh per day (which is equivalent to the peak demand of
17 100 kW multiplied by 24 hours).

1 **Figure 4. Illustrative load curve for a 300-kW station co-located with solar and storage under high**
 2 **utilization**



3
 4 *Source: Exhibit GECA-JRC-3*

5 **Q. What are the customer and demand charges that apply to co-locating of solar PV and**
 6 **battery storage at the illustrative 300-kW charging station under the high utilization**
 7 **case?**

8 **A.** Since battery storage is able to reduce peak demand to 100 kW, the illustrative 300-kW
 9 charging station co-located with solar PV and battery storage moves down to Eversource's
 10 Rate EV-1 and National Grid's Rate G-2 in the high utilization case.

11 For Eversource, this co-location scenario results in a monthly customer and demand charge
 12 cost of \$542 (or **\$0.28 per EV charge**) under the high utilization case, which is a 61 percent

1 decrease from the solar only co-location scenario and an overall 86 percent decrease from the
2 no co-location scenario (see Table 1 at p.28 and Table 2 at p.29, *infra*).

3 For National Grid, this co-location scenario results in a monthly customer and demand
4 charge cost of \$1,187 (or **\$0.62 per EV charge**) under the high utilization case, which is an 8
5 percent decrease from the solar only co-location scenario and an overall 57 percent decrease
6 from the no co-location scenario (see Table 1 at p.28 and Table 2 at p.29, *infra*).

7 **Q. Overall, what load factors, peak demands, and customer and demand charges are**
8 **incurred in the moderate and high utilization cases in Winter?**

9 **A.** Table 1 below shows the monthly costs incurred by the 300-kW and 200-kW charging
10 station examples for each of the co-location scenarios under moderate (i.e., 22 EV charges
11 per day for the 300-kW charging station) and high (i.e., 64 EV charges per day for the 300-
12 kW charging station) utilization cases.

13 The 300-kW system under high utilization results in a substantial decrease in the monthly
14 customer and demand charge costs from both National Grid and Eversource. However, each
15 electric distribution company, due to their individual rate structures, have different monthly
16 charges when energy storage is added to the system. Here battery storage moves customers
17 between the proposed rate schedules from Rate G-3 to Rate G-2 for National Grid and from
18 Rate EV-2 to Rate EV-1 for Eversource. Although energy- and demand-based rates are
19 higher in National Grid's Rate G-2 compared to its Rate G-3, the lower monthly customer
20 charge (\$223 falls to \$30) combined with a lower monthly peak demand (from 300 kW to
21 100 kW for the 300-kW charging station) leads to a decrease in customer and demand

1 charges. For Eversource, the lower monthly customer charge (\$222 falls to \$15) and lower
2 monthly peak demand also result in a decrease in customer and demand charges. In addition,
3 Eversource's Rate EV-1 does not have a demand-based rate like Rate EV-2 does, and
4 therefore has lower costs.

5 In the 200-kW system, there is a much larger benefit from co-locating with solar, however,
6 the case for adding storage is not strong for either utility. Again, this is due to the electric
7 distribution companies' rate structures.

8 In the moderate utilization case, there is a strong argument for both co-location scenarios.
9 Solar PV generation that is not used for EV charging can be net metered, thus the abundance
10 of unused solar generation in the moderate utilization case results in a load factor of zero and
11 only monthly customer charges apply to customer bills.

1 **Table 1. Illustrative customer and demand charge estimates (\$ per month) under moderate and high**
 2 **utilization**

Moderate Utilization during Winter				
300 kW EV Charging Site (22 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per month)	
			National Grid	Eversource
EV Charger Only	15.3%	300	\$2,666	\$3,613
EV Charger plus Solar	0.0%	300	\$223	\$222
EV Charger plus Solar and Storage	0.0%	100	\$30	\$15
200 kW EV Charging Site (15 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per month)	
			National Grid	Eversource
EV Charger Only	15.6%	200	\$2,320	\$721
EV Charger plus Solar	0.0%	200	\$30	\$15
EV Charger plus Solar and Storage	0.0%	75	\$30	\$15
High Utilization during Winter				
300 kW EV Charging Site (64 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per month)	
			National Grid	Eversource
EV Charger Only	44.4%	300	\$2,729	\$3,741
EV Charger plus Solar	6.9%	300	\$1,284	\$1,375
EV Charger plus Solar and Storage	23.3%	100	\$1,187	\$542
200 kW EV Charging Site (44 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per month)	
			National Grid	Eversource
EV Charger Only	45.8%	200	\$2,413	\$2,086
EV Charger plus Solar	8.3%	200	\$924	\$392
EV Charger plus Solar and Storage	24.4%	75	\$899	\$429

3
 4 *Note: See Exhibit GECA-JRC-3 for calculations.*

1 **Table 2. Illustrative customer and demand charge estimates (\$ per EV charge) under moderate and high**
 2 **utilization**

Moderate Utilization during Winter				
300 kW EV Charging Site (22 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per EV charge)	
			National Grid	Eversource
EV Charger Only	15.3%	300	\$4.04	\$5.47
EV Charger plus Solar	0.0%	300	\$0.34	\$0.34
EV Charger plus Solar and Storage	0.0%	100	\$0.05	\$0.02
200 kW EV Charging Site (15 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per EV charge)	
			National Grid	Eversource
EV Charger Only	15.6%	200	\$3.52	\$1.09
EV Charger plus Solar	0.0%	200	\$0.05	\$0.02
EV Charger plus Solar and Storage	0.0%	75	\$0.05	\$0.02
High Utilization during Winter				
300 kW EV Charging Site (64 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per EV charge)	
			National Grid	Eversource
EV Charger Only	44.4%	300	\$1.42	\$1.95
EV Charger plus Solar	6.9%	300	\$0.67	\$0.72
EV Charger plus Solar and Storage	23.3%	100	\$0.62	\$0.28
200 kW EV Charging Site (44 EV charges per day)	Load Factor (%)	Peak Demand (kW)	Customer and Demand Charge (\$ per EV charge)	
			National Grid	Eversource
EV Charger Only	45.8%	200	\$1.26	\$1.09
EV Charger plus Solar	8.3%	200	\$0.48	\$0.20
EV Charger plus Solar and Storage	24.4%	75	\$0.47	\$0.22

3
 4 *Note: See Exhibit GECA-JRC-3 for calculations.*

1 **Q. Overall, what per EV charge costs are incurred by EV charging stations in each of the**
2 **scenarios examined?**

3 **A.** Table 2 above presents the per EV charge costs incurred by the 300-kW and 200-kW
4 charging station examples for each of the co-location scenarios under the moderate (i.e., 22
5 EV charges per day for the 300-kW charging station) and high (i.e., 64 EV charges per day
6 for the 300-kW charging station) utilization cases. For the “EV Charger Only” scenarios,
7 moderate utilization results in a per EV charge cost that is three times higher than under the
8 high utilization case. However, the co-location of renewables and/or energy storage leads to
9 substantial cost reductions in both utilization cases compared to the “EV Charger Only”
10 scenario. These results show both the financial burden (on a per EV charge basis) between
11 utilization cases as well as the capability of co-location as a technology-based solution to
12 reduce customer and demand charge costs.

13 **Q. Would the conclusions of this analysis differ if the co-location scenarios were assessed**
14 **for Summer rather than Winter?**

15 **A.** No. The conclusions of this analysis would remain the same, although the specific rates and
16 per EV charge costs would change. The Summer season allows for more hours of solar
17 production over the course of a day, which would allow the co-location of solar PV to further
18 offset the amount of energy required from the grid—thus, lowering the load factor and
19 resulting in a larger decrease in per EV charge costs.

1 **Q. Can co-location with solar and/or energy storage reduce financial burdens to EV**
2 **charging stations and, if so, under what circumstances?**

3 **A.** Yes. Co-location with solar PV and/or energy storage have the potential to reduce the
4 financial burdens to EV charging stations. However, the extent of the reduction of financial
5 burden depends on the rate structure approved by the Department.

6 **VIII. RECOMMENDATIONS AND CONCLUSIONS**

7 **Q. Would co-location of renewables and energy storage with DCFC stations lower costs**
8 **per EV charge improving these stations financial viability and increasing their chances**
9 **of securing investment?**

10 **A.** Yes. Co-location with renewables and energy storage lowers per EV charge costs
11 (depending, in part, on the utility’s rate structure), which would alleviate the financial barrier
12 that stands in the way of widespread deployment of DCFC stations across the
13 Commonwealth.

14 **Q. What can the Department do to facilitate the use of co-location to increase investment**
15 **in DCFC stations in the Commonwealth?**

16 **A.** Massachusetts DPU should require the electric distribution companies to revisit their demand
17 charge alternative proposals to create rate structures that can work hand in hand with the co-
18 location of renewables and energy storage to synergistically combat financial barriers and
19 increase overall deployment of DCFC stations in the Commonwealth. Specific incentives for

1 co-location might also be considered, similar to the manner in which the SMART solar
2 program offers adders for co-location with storage.³⁴

3 **Q. Does this conclude your testimony?**

4 **A. Yes.**

³⁴ Massachusetts Department of Energy Resources. "Solar Massachusetts Renewable Target (SMART)." Available at: <https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program>