April 9, 2021

Michelle Turner
Administrative Secretary
Efficiency Maine Trust
168 Capitol Street, Suite 1
Augusta, ME 04330-6856

Re: Request for Information on Efficiency Maine Trust Triennial Plan V (Fiscal Years 2023-2025), Response of Sunrun Inc.

Ms. Turner,

Pursuant to the Efficiency Maine Trust Request for Information ("RFI") for the Triennial Plan V ("Plan"), Sunrun Inc. respectfully submits the enclosed preliminary comments along with supporting reports and materials in response to RFI question number 8.

Sunrun is the nation's leading home solar, battery storage and energy services provider with over 500,000 customers in 22 states, the District of Columbia and Puerto Rico. Sunrun is pleased to offer these preliminary comments and looks forward to further engagement throughout the development of the Plan.

Respectfully submitted,

/s/ Christopher Rauscher

Christopher Rauscher
Director, Policy & Storage Market Strategy
Sunrun Inc.
225 Bush Street, Suite 1400
San Francisco, CA 94104
Phone: (207) 400-1150
Email: chris.rauscher@sunrun.com

Sunrun Inc. Response to RFI Question #8

Question 8:

The Trust has spent the last two years testing various load management strategies through its Innovation Program and intends to offer a new program to deploy demand response, load shifting, and load management in the next plan. Examples of these pilot projects include load shifting in commercial freezers using phase-change material; a residential "Bring-Your-Own-Device" pilot; and incentives for off-peak EV charging. Please share examples of successful load management initiatives from other jurisdictions that the Plan could draw from, as well as any reports, studies or evaluations that would aid the Trust in designing or prioritizing these strategies.

Response:

Sunrun commends Efficiency Maine Trust for its work and proposal for a residential "Bring-Your-Own-Device" ("BYOD") program as part of the Triennial Plan V ("Plan"). Recognizing the ratepayer savings and other benefits of leveraging customer-sited battery storage resources to provide peak load reduction and other grid benefits, each of the ISO-New England states with the exception of Maine has now adopted a residential BYOD program (or programs) on a statewide basis or in at least one of its utility service territories.[1] A statewide BYOD program in Maine can provide the market framework necessary to leverage customer-owned battery storage for load management and other grid services that will allow Maine ratepayers to capture the savings and other benefits that BYOD programs bring to ratepayers in other states. Such a program can also help increase access to clean, resilient backup energy that battery storage provides.

As described further in the attached appendices, BYOD programs are part of the natural evolution of energy efficiency programs. For instance, in Massachusetts, the Department of Public Utilities found programs that allow residential (and in some instances commercial) customers with battery storage to provide capacity and peak demand reduction services through the BYOD program, titled *ConnectedSolutions*, to be cost-effective for ratepayers.[2] As demonstrated by the studies and materials appended to these comments, incorporating residential battery storage programs as part of energy efficiency programs allows program administrators to leverage significant private capital investment to help meet energy efficiency goals and drive deeper ratepayer savings.

Residential BYOD programs are a proven model to support a cleaner, more efficient, and more cost-effective electric grid. The following supporting materials are included in the Appendix to these comments as a resource for developing a residential BYOD program in Maine.

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[1] *See* Appendix A: *New England Residential BYOD Program Examples*.

[2] *See* D.P.U. 18-110 through 18-119, *2019-2021 Three-Year Plans Order* at p. 30 (Jan. 29, 2019) *available at* https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom /10317061; DPU 20-33 though 20-36 *Energy Efficiency Order*, at pp. 10-11 (July 28, 2020) *available at* https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12489899.

- Clean Energy Group, *Energy Storage the New Efficiency: How States can use Energy Efficiency Funds to Support Battery Storage and Flatten Costly Demand Peaks*[3]
- Clean Energy Group, *Connected Solutions: A New State Funding Mechanism to Make Battery Storage Accessible to All*[4]
- Clean Energy Group, *ConnectedSolutions: The New Economics of Solar + Storage for Affordable Housing in Massachusetts*[5]
- Sunrun: *Meeting Utility Needs with Customer Solar + Storage to Reduce Costs for All*[6]
- Massachusetts Department of Public Utilities, Docket Nos. 18-110 though 18-119, *2019-2021 Three-Year Plans Order*[7]
- Massachusetts Department of Public Utilities, Docket Nos. 20-33 though 20-36, *Energy Efficiency Order*[8]

Sunrun offers these resources as a guide to Efficiency Maine Trust to inform its work toward developing a residential BYOD program for inclusion in the draft Plan. Sunrun appreciates the opportunity to provide these comments and supporting resources and looks forward to further engagement throughout the development of the Plan.

Respectfully submitted,

/s/ Christopher Rauscher
Christopher Rauscher
Director, Policy & Storage Market Strategy
Sunrun Inc.
225 Bush Street, Suite 1400
San Francisco, CA 94104
Phone: (207) 400-1150
Email: chris.rauscher@sunrun.com

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[3] Clean Energy Group, *Energy Storage the New Efficiency: How States can use Energy Efficiency Funds to Support Battery Storage and Flatten Costly Demand* (Apr. 2019) *available at* https://www.cleanegroup.org/ceg-resources/resource/energy-storage-the-new-efficiency/ (Appendix B).

[4] Clean Energy Group, *Connected Solutions: A new State Funding Mechanism to Make Battery Storage Accessible to All* (Feb. 2021) *available at* https://www.cleanegroup.org/wp-content/uploads/connected-solutions-policy.pdf (Appendix C).

[5] Clean Energy Group, *ConnectedSolutions: The New Economics of Solar+Storage for Affordable Housing in Massachusetts* (Feb. 2021) *available at* https://www.cleanegroup.org/wp-content/uploads/connected-solutions-affordable-housing.pdf (Appendix D).

[6] Sunrun, *Meeting Utility Needs with Customer Solar + Storage to Reduce Costs for All* (Appendix E).

[7] D.P.U. 18-110 through 18-119, *2019-2021 Three-Year Plans Order* (Jan. 29, 2019) *available at* https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10317061 (Appendix F).

[8] D.P.U. 20-33 though 20-36, *Energy Efficiency Order* (July 28, 2020) *available at* https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12489899 (Appendix G).

Appendix A

New England Residential BYOD Program Examples

New England Residential BYOD Program Examples

State	Utility	Program	Compensation	Use Case
Connecticut[1]	Eversource	Connected Solutions – Targeted Seasonal	$225/kW-summer & $50/kW-winter (avg. per peak event), locked in for five years.	Reduction in ISO-NE capacity charges.
Connecticut[2]	United Illuminating	ConnectSun	$0.05/kWh from June – Sept. on-peak energy, locked in for five years, plus $500 rebate for additional metering.	Distribution deferral on two circuits.
Massachusetts[3]	National Grid	Connected Solutions – Targeted Seasonal	$225/kW-summer & $50/kW-winter (avg. per peak event), locked in for five years.	Reduction in ISO-NE capacity charges.
Massachusetts[4]	Eversource	Connected Solutions – Targeted Seasonal	$225/kW-summer & $50/kW-winter (avg. per peak event), locked in for five years.	Reduction in ISO-NE capacity charges.
Massachusetts[5]	National Grid, Unitil, Eversource	Connected Solutions – Daily Dispatch	$/kW for dispatch on a daily basis. Further details of permanent program forthcoming.	Reduction in ISO-NE capacity charges.
New Hampshire[6]	Liberty Utilities	Residential Battery Storage Pilot	Phase 1 (Utility-Owned): Arbitrage via new TOU rate. Phase 2 (BYOD): TBD	Reduction in ISO-NE transmission and potentially capacity charges.

[1] Eversource Connecticut. Application for ConnectedSolutions: Small Scale Batteries, available at: https://www.eversource.com/content/ct-c/residential/save-money-energy/manage-energy-costs-usage/demand-response/battery-storage-demand-response

[2] Energize Connecticut. ConnectSun, available at: https://www.energizect.com/connectsun-home

[3] National Grid Massachusetts. Program Materials for Connected Solutions for Small Scale Batteries, available at: https://www.nationalgridus.com/media/pdfs/resi-ways-to-save/program-materials-for-connectedsolutions-for-small-scale-batteries-ma.pdf

[4] Eversource Massachusetts East. Application for ConnectedSolutions: Small Scale Batteries, available at: https://www.eversource.com/content/docs/default-source/save-money-energy/battery-demand-response-application.pdf?sfvrsn=3e03d362_4

[5] Massachusetts Department of Public Utilities. Docket Nos. 20-33, 20-34, 20-35, and 20-36. Order dated July 28, 2020 at p. 6, available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12489986

[6] New Hampshire Public Utilities Commission ("NH PUC"). Docket No. DE 17-189. Order No. 26,209. January 17, 2019. A BYOD version of the currently active utility-owned battery storage program is slated to be developed upon the successful demonstration of the current program. New Hampshire is also pursuing the development of a statewide BYOD program via its 2021-2023 energy efficiency and demand response program development process. *See* NH PUC Docket No. DE 20-092, available at: https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092.html

New England Residential BYOD Program Examples

State	Utility	Program	Compensation	Use Case
Rhode Island[7]	National Grid	Connected Solutions – Targeted Seasonal	$400/kW-summer season (avg. per peak event), locked in for five years.	Reduction in ISO-NE capacity charges.
Vermont[8]	Green Mountain Power	Bring Your Own Device	Up-front payment of $850/kW for 3-hour storage discharge capability or $950/kW for 4-hour discharge capability (10% event performance tolerance subject to clawback), plus $850 for systems installed under solar self- consumption option. Adder of $100/kW for standalone systems and additions to existing solar in certain locations. 10-year program commitment.	Reduction in ISO-NE transmission and capacity charges; solar production shifting.

[7] National Grid Rhode Island Program Materials for Connected Solutions for Small Scale Batteries, available at: https://www.nationalgridus.com/media/pdfs/resi-ways-to-save/ri-program-materials-for_-connectedsolutions-for-small-scale-batteries-v16.pdf

[8] Green Mountain Power. BYOD – Terms and Conditions, available at: https://greenmountainpower.com/bring-your-own-device/battery-systems/

Appendix B

Clean Energy Group

Energy Storage the New Efficiency: How States can use Energy Efficiency Funds to Support Battery Storage and Flatten Costly Demand Peaks

Energy Storage: The New Efficiency

HOW STATES CAN USE ENERGY EFFICIENCY FUNDS TO SUPPORT BATTERY STORAGE AND FLATTEN COSTLY DEMAND PEAKS

Todd Olinsky-Paul | Clean Energy Group | April 2019

ABOUT THIS REPORT

This report, which describes how states can use energy efficiency funds to provide incentives for energy storage, is a publication of Clean Energy Group (CEG), with appendices containing several white papers prepared by the Applied Economics Clinic under contract to CEG. This report explains the steps Massachusetts took to become the first state to integrate energy storage technologies into its energy efficiency plan, including actions to 1) expand the goals and definition of energy efficiency to include peak demand reduction, and 2) show that customer-sited battery storage can pass the required cost-effectiveness test. The report summarizes the economics of battery cost/benefit calculations, examines key elements of incentive design, and shows how battery storage would have been found to be even more cost-effective had the non-energy benefits of batteries been included in the calculations. The report also introduces seven non-energy benefits of batteries, and for the first time, assigns values to them. Finally, the report provides recommendations to other states for how to incentivize energy storage within their own energy efficiency plans. Four appendices provide detailed economics analysis, along with recommendations to Massachusetts on improving its demand reduction incentive program in future iterations of the energy efficiency plan.

The report and accompanying analyses were generously supported by grants from the Barr Foundation and Merck Family Fund. It is available online at *www.cleanegroup.org/ceg-resources/resource/energy-storage-the-new-efficiency*.

ACKNOWLEDGMENTS

Clean Energy Group wishes to express its sincere thanks to Barr Foundation and the Merck Family Fund for their generous support of this work; to Liz Stanton and staff of the Applied Economics Clinic, who produced the economic analyses that serve as the basis for many findings of this report; and to the following organizations with whom CEG collaborated to advocate for Massachusetts battery storage incentives: Northeast Clean Energy Council, Acadia Center, Conservation Law Foundation, and Local Initiatives Support Corporation (LISC) Boston. Thanks also to Liz Stanton of the Applied Economics Clinic, Rachel Gold of the American Council for an Energy-Efficient Economy (ACEEE), and Jamie Dickerson of the New England Clean Energy Council (NECEC), for their review comments. Todd Olinsky-Paul wishes to thank Lewis Milford, Maria Blais Costello, Meghan Monahan, and Samantha Donalds of Clean Energy Group for their invaluable contributions.

DISCLAIMER

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HOW TO READ THIS REPORT

This report comprises two parts, which may appeal to different audiences.

The main body of this report explains how a groundbreaking new energy efficiency policy came about in Massachusetts; summarizes original economic analyses that supported this policy change; identifies key barriers and issues confronting states in this making this policy change; and makes recommendations for policy and program development in other states. This portion of the report is intended for a general audience and should be of interest to state policymakers and regulators.

Following the main body of the report are three appendices that contain the original white papers prepared for Clean Energy Group by economist Liz Stanton and the staff of the Applied Economics Clinic. These white papers 1) present an independent cost/benefit analysis of customer-sited battery storage, 2) review the economic underpinnings of the new Massachusetts performance-based incentive for battery storage within the efficiency plan, and 3) present new analysis valuing seven non-energy benefits of battery storage. They are intended for readers who wish to delve more deeply into the economics of battery storage and should be of interest to economists and regulators.

The AEC white paper presented here as Appendix 1 was published in July 2018. The two additional white papers from AEC, presented here as Appendix 2 and Appendix 3, are being published and released simultaneously with this report.

A fourth appendix contains recommendations, prepared by Clean Energy Group, for improving the Massachusetts Energy Efficiency Plan, as it pertains to battery storage.

Executive Summary

INTRODUCTION

Energy storage is perhaps the most revolutionary new energy technology since the electric grid was invented over a century ago. It can transport electricity over time, as well as distance; it can act as a generator or as a load; it can integrate renewables into the grid or enable customers to disconnect from the grid entirely.

But states have yet to figure out how to move storage aggressively into various market segments with dedicated incentive programs. Typically, states have supported new clean energy technologies, such as wind and solar, through public benefit funds or utility incentives, which bring down the up-front capital costs and jump-start markets. So far, only a few states have developed incentives that would support energy storage. But that is beginning to change.

This report shows how a new energy storage incentive has been created through the innovative use of state energy efficiency funds. With technical support from Clean Energy Group (CEG), a national nonprofit advocacy organization, Massachusetts, a national leader in energy efficiency, has incorporated energy storage as an active demand reduction measure in its 2019-2021 Three-Year Energy Efficiency Plan.[1] This groundbreaking action was supported with original economic analysis by the Applied Economics Clinic (AEC), under contract to CEG.[2]

This report explains how, for the first time, distributed energy storage has been included in a state energy efficiency plan, and what the implications are for states and the storage industry. It covers the following topics:

- How behind-the-meter battery storage provides efficiencies, both for the customer and for the energy system.
- Why and how Massachusetts included storage in its energy efficiency plan.[3]
- Why this is important to move storage into many markets, including low-income markets where early stage technologies might not otherwise penetrate until years from now.
- Why expanding energy efficiency to include demand reduction measures like energy storage is in keeping with the historical evolution of such funds, to bring new technologies into their programs over time.
- What actions are necessary to enable more states to incorporate storage into their efficiency plans, and to use efficiency funds to jumpstart battery storage markets in those states.
- How to value both energy and non-energy benefits of battery storage, and why this is important if storage is to be incorporated into state policy and programs.

This report shows how a new energy storage incentive has been created through the innovative use of state energy efficiency funds.

KEY FINDINGS

Distributed battery storage can deliver valuable energy efficiencies, both behind the meter and on the grid. This report presents economic analysis showing that peak demand reduction, an emerging energy service for which battery storage is well suited, provides cost savings to both storage customers and the energy system as a whole. Peak demand reduction, or peak shifting, is a valuable efficiency that cannot be effectively achieved with traditional, passive efficiency measures, but it can be cost-effectively achieved with battery storage. As more renewables come onto the electric grid, the ability to shift peak loads becomes more important and valuable.

States can open energy efficiency programs to battery storage with one simple step. As shown in Massachusetts, states can redefine energy efficiency to include the peak demand reduction concept. Electricity demand peaks are costly, leading to huge inefficiencies across the energy system. While some states have demand reduction programs, these are not typically as well funded as are energy efficiency programs. Bringing demand programs under the umbrella of energy efficiency makes more resources available to support battery storage deployment and allows consumption-reduction and demand-reduction measures to be installed together, to achieve optimal results.

Battery storage can pass required cost-effectiveness screens, justifying the investment of public dollars. As shown in the CEG/AEC July 2018 report (Appendix 1), battery storage passes the Total Resource Cost (TRC) test in Massachusetts, meaning it returns savings to consumers that are greater than its cost. This is the threshold requirement for efficiency measures to be eligible for incentives under the Massachusetts Energy Efficiency Plan. Since most state rebate and incentive programs include cost-effectiveness screens, it is important that states develop methods to fairly and thoroughly evaluate the costs and benefits of battery storage.

Battery storage offers more than just energy benefits—and its non-energy benefits are both valuable and important. As shown in the CEG/AEC report on the non-energy benefits of storage (Appendix 3), battery storage offers many non-energy benefits, including resiliency, reduced outages, increased property values, job creation, and reduced land use. The non-energy benefits of storage must be assigned an economic value, or by default they will be valued at zero in cost/benefit analyses. In this report, we present economic analysis showing the value of seven non-energy benefits of battery storage.

Numerous program design issues should be addressed when states contemplate creating battery storage incentives. These include: Incentive design, Financing, Low-income provisions, Defining peak, Duration of discharge, Measuring benefits, Ownership issues, Stacking incentives, and Transparency.

More work is needed to continue to refine and expand the value of battery storage, including the identification and valuation of more non-energy benefits. Establishing a more accurate benefit-cost ratio (BCR) for distributed battery storage will support its inclusion in state energy efficiency programs and other incentive programs (such as rebates) that require measures to pass a cost-effectiveness screen. If this is not done, storage will continue to be at a disadvantage relative to other technologies, and it may not qualify for state incentive programs.

State energy efficiency programs represent an important potential source of incentive funding for distributed battery storage. Most states have energy efficiency programs, and these programs collectively represent an investment of nearly $9 billion in public funds annually. Qualifying energy storage as an efficiency measure in these state programs would make storage eligible for vastly greater incentive support than it currently enjoys in any state—even early adopter states like California, Massachusetts and New York. Bringing new technologies like storage into state energy efficiency programs is in keeping with the history of these programs and is cited as a best practice in EPA guides.[4]

Battery storage offers many non-energy benefits, including resiliency, reduced outages, increased property values, job creation, and reduced land use.

RECOMMENDATIONS

In the main body of this report, we discuss policy issues and present recommendations for a national audience of state policymakers and regulators. Recommendations and discussion directed specifically toward improving the Massachusetts demand reduction program can be found in Appendix 4.

Key Recommendations

- Other states should learn from the experience of Massachusetts and incorporate demand reduction measures, including storage, into their own energy efficiency plans.
- State energy storage incentives, in general, should include three basic elements: an up-front rebate, a performance incentive, and access to financing.
- State energy storage incentives should include adders and/or carve-outs for low-income customers. These customers need the cost savings and other benefits of new clean energy technologies the most but are typically the last to gain access to them.
- Researchers should build on the economics analyses presented here. Specifically, cost/benefit analyses of storage should be conducted using not only the TRC but also other cost-effectiveness tests commonly in use among states, such as the Societal Cost Test and the Utility/PACT test.
- Non-energy benefits of storage should be identified, analyzed, and valued.

How Massachusetts brought energy storage into its efficiency plan

In January 2019, the Massachusetts Department of Public Utilities (DPU) approved the Commonwealth's new Three-Year Energy Efficiency Plan, which for the first time includes incentives that could be used for behind-the-meter energy storage. This DPU order[5] demonstrates a bold new direction for energy storage funding at the state level, while expanding the opportunities for behind-the-meter battery storage applications.

In Massachusetts, two barriers needed to be overcome before energy storage could be included in the efficiency plan:

1. **Redefining efficiency.** In order to include storage within the energy efficiency plan, Massachusetts first had to include *demand reduction*, a major application of battery storage, within the efficiency plan. This underlying expansion of the Commonwealth's efficiency efforts to include demand reduction was formalized as early as 2008 with the Massachusetts *Green Communities Act*.[6]

2. **Showing that storage is cost-effective.** In order for battery storage to qualify for the efficiency plan, it first had to be shown to be *cost-effective*. This meant that batteries had to be able to pass a Total Resource Cost (TRC) test with a benefit-cost ratio (BCR) equal to or greater than 1. This was demonstrated in the CEG/AEC July 2018 white paper, *Massachusetts Battery Storage Measures: Benefits and Costs*, in Appendix 1.

These two barriers will likely be faced by every state that seeks to incorporate energy storage into its energy efficiency plan. We discuss these two barriers, and how they can be overcome, in more detail below.

REDEFINING EFFICIENCY

The first barrier to the inclusion of energy storage in energy efficiency programs is the traditional definition of electrical efficiency as "using fewer electrons." If efficiency is defined solely in terms of reduced electricity consumption, efforts to include battery storage as an efficiency measure will face high barriers due to the round-trip losses associated with battery cycling. Therefore, any effort to incorporate battery storage into an efficiency program first requires that the definition of efficiency be expanded to include energy services other than reduced consumption.

Any effort to incorporate battery storage into an efficiency program first requires that the definition of efficiency be expanded to include energy services other than reduced consumption.

In Massachusetts, the inclusion of energy storage as an efficiency measure was preceded by the recognition that in addition to reducing consumption, there is also value in shifting consumption from times of high electricity demand to times of lower demand. This peak load shifting is an increasingly important application for which batteries are well suited, and which cannot be accomplished with traditional, passive efficiency measures. Massachusetts recognized the high cost of high electricity demand (peak demand) to utility customers and to the grid and, to better address the problem, brought demand reduction measures into its efficiency program, see **Figures 1** and **2** (p. 8).

Massachusetts formally associated demand reduction with energy efficiency in the *Green Communities Act of 2008.*[7] *The Green Communities Act* requires that efficiency program administrators seek ". . . all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." Demand reduction, in this context, includes the notion of shifting demand from peak to off-peak hours.

FIGURE 1

Traditional Efficiency Reduces Net Consumption, but Does Not Shift Peaks

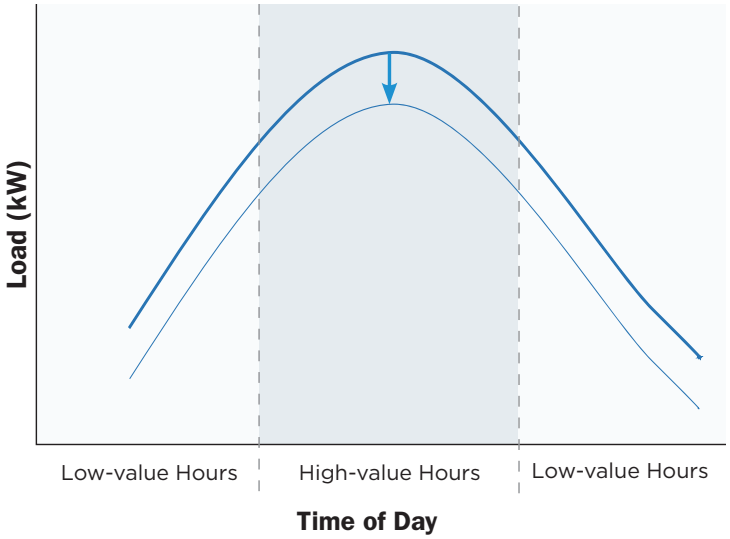
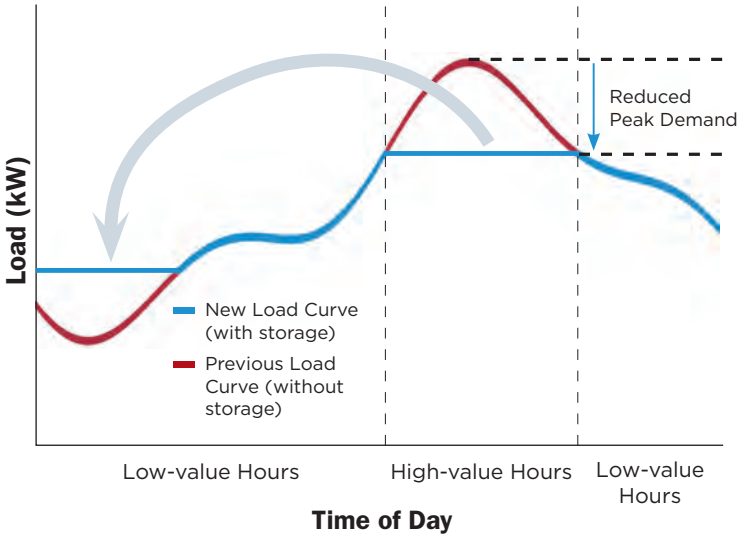


FIGURE 2

Peak Demand Reduction Shifts Peaks, but Does Not Reduce Net Consumption



Redefining efficiency—Not all load hours should be valued the same!

That this was the intent of the *Green Communities Act* was confirmed and reinforced in the *State of Charge* report, published jointly by Massachusetts Clean Energy Center (MA CEC) and Massachusetts Department of Energy Resources (MA DOER) as part of the Massachusetts Energy Storage Initiative in 2016. *State of Charge* (p. xix) notes that "Storage and other measures that shift load are firmly covered by the intent of the [Green Communities] Act" and adds, "The 2016–2018 Statewide Energy Efficiency Investment Plan ("Three Year Plan") identifies peak demand reduction as an area of particular interest in the term sheet and in the EEAC resolution supporting the Three Year Plan. . . . Energy storage, used to shift and manage load as part of peak demand reduction programs, can be deployed through this existing process." This was further reinforced by the state legislature in the 2018 "Act to Advance Clean Energy," Section 2, which specifically added active demand management technologies and called out energy storage as an allowable investment in the energy efficiency plan.

Among its many recommendations, the *State of Charge* report called for "Storage as Peak Demand Savings tool in Energy Efficiency Investment Plans" and notes on p. 162, "The [Green Communities] Act establishes the framework for developing, implementing and funding energy efficiency and demand-side management programs. The Act treats demand management (either peak load reduction or peak load shifting) the same way as energy efficiency (load reduction)."

Beyond reinforcing the legal basis for storage to be included as an efficiency measure, the *State of Charge* report also took a first step toward assessing the value of storage as a demand reduction technology. The report concluded that 40 percent of the Commonwealth's annual electricity dollars spent was attributable to just 10 percent of the top demand hours. That is, the top 10 percent demand hours in each year cost Massachusetts *nearly half* its overall electricity budget. Shifting load away from these very costly peak hours, while it does not reduce net electricity consumption, can significantly reduce costs to ratepayers and increase efficiencies across the electric system (see **Figure 3)**.

Shifting load away from these very costly peak hours, while it does not reduce net electricity consumption, can significantly reduce costs to ratepayers, and increase efficiencies across the electric system.

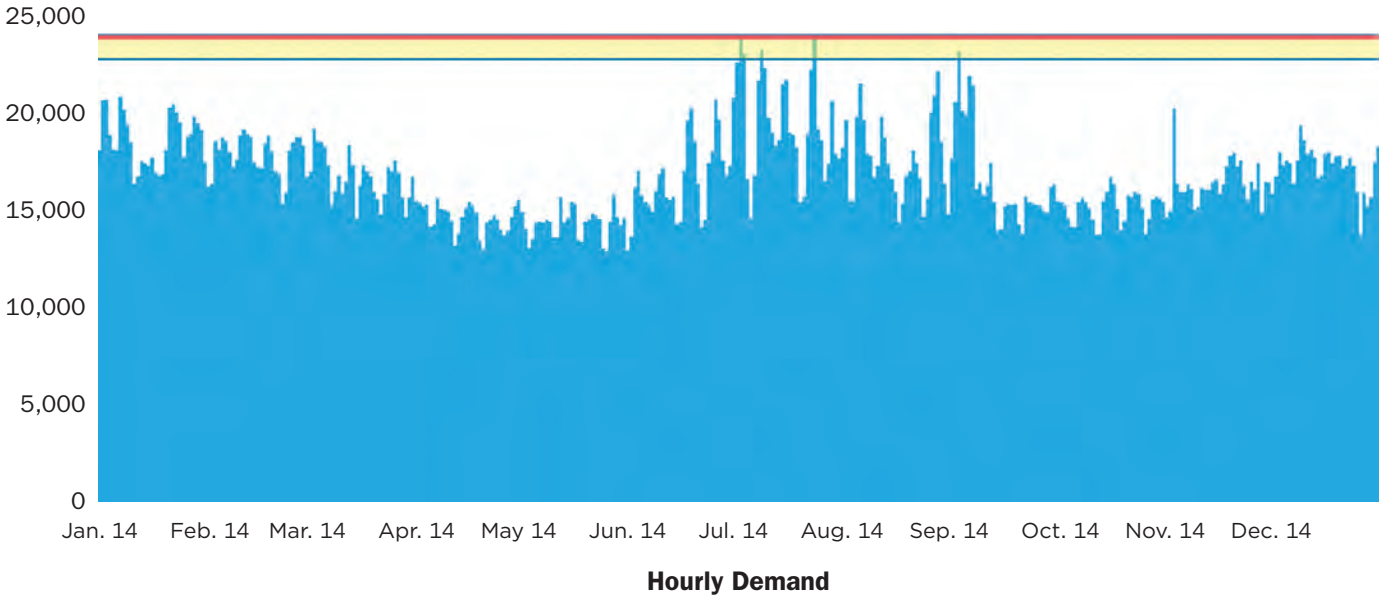
The net value of peak load reduction using behind-the-meter battery storage in Massachusetts was more specifically established in CEG's cost/benefit valuation of storage, with analysis from the Applied Economics Clinic (see Appendix 1) and, subsequently, by the Massachusetts utility program administrators' own BCRs for energy storage.

SHOWING THAT STORAGE IS COST-EFFECTIVE

Once peak demand reduction measures became eligible for inclusion in the energy efficiency plan, it remained to show that battery storage would also pass the Commonwealth's cost effectiveness test, the Total Resource Cost test (TRC).[8]

FIGURE 3

Peak-hour Demand for 2014—Whole Energy System Sized to Meet This Peak



The white area indicates inefficiencies in a system sized to meet occasional peaks.

Source: The Massachusetts *State of Charge* report

In recommending battery storage as an energy efficiency measure, the *State of Charge* report notes the importance of showing that storage can pass the TRC cost-effectiveness test. The report states,

> "In order to incorporate storage and demand reduction as full-scale programs in future Three Year Plans, the DPU must approve them as cost-effective as defined in the DPU Guidelines.... This cost effectiveness test relies on years of precedent and has been rigorously defined to support robust energy efficiency and passive demand reduction programs, but are [sic] untested for active demand response programs. It is possible that active demand reduction programs might require modification to the current cost effectiveness methodology."[9]

In 2018, CEG contracted with Liz Stanton of the Applied Economics Clinic (AEC) to produce original economic analysis[10] of distributed battery storage, using the same data and methods employed by utility program administrators in the Massachusetts energy efficiency program. AEC's initial white paper, "Massachusetts Battery Storage Measures: Benefits and Costs"[11] showed that battery storage passes the cost/benefit test required by the Commonwealth's energy efficiency program, with BCRs of 2.8 in the low-income category, and 3.4 in the commercial/industrial category. In other words, for every dollar of public money spent on battery storage, the Commonwealth would see benefits in the range of $2.80–$3.40. Therefore, according to the Massachusetts Green Communities Act,[12] battery storage should qualify for inclusion in the Massachusetts Energy Efficiency Plan.[13] These results are shown in **Table 1**. Clean Energy Group presented the findings from AEC's analysis

TABLE 1

Total Benefits and Costs by Customer Class

Parameter for 2019	Low-Income	C&I
Total Electric Benefits ($)	$36,296	$155,782
Total Resource Costs ($)	$13,163	$46,322
Benefit-Cost Ratio	**2.8**	**3.4**

Source: Applied Economics Clinic calculations

to the DOER, the Massachusetts Energy Efficiency Advisory Council (EEAC), and the utility program administrators. These positive BCRs provided a basis for inclusion of a performance incentive that could be applied to battery storage as a demand reduction measure in the proposed new energy efficiency plan.

Following the release of the white paper, the utility program administrators revised their draft energy efficiency plan to include a new calculation of the cost/benefits of storage. This final plan was presented by the program administrators in October, and ultimately approved by the DPU. In this version of the energy efficiency plan, the Massachusetts utilities, using only the energy benefits of battery storage, came up with BCRs in the range of 0–6.2, as shown in **Table 2** (p. 10).

Note that the program administrators' calculated BCRs for energy storage are different depending on where storage measures are to be installed and how they are to be dispatched. For example, in **Table 2**, storage in the targeted dispatch program in the Eversource service territory is shown to have a BCR of 3.2 when installed behind a commercial/industrial

TABLE 2

Energy Benefits of Storage by Utility

BCRs	Cape Light			Eversource			National Grid			Unitil		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Residential Advanced Demand Management Program (A2e)												
Program BCRs	1.6	2.4	2.4	1.0	1.4	1.6	1.5	2.4	2.5	0.7	1.1	1.2
Direct Load Control	4.9	6.6	7.4	5.0	5.0	5.0	5.3	5.5	5.3	5.2	9.6	9.6
Behavior DR												
Storage System & Performance		3.0	3.0									
Storage Daily Dispatch				1.5	1.5	1.5	4.9	4.9	5.0			
Storage Targeted Dispatch				0.0	0.0	0.0	0.1	0.1	0.1			
EV Load Management								0.8	0.8			
Income-Eligible Advanced Demand Management Program (B1b)												
Program BCRs		2.3	2.4					2.4	2.4			
Direct Load Control												
Behavior DR												
Storage System & Performance		3.0	3.0									
Storage Daily Dispatch												
Storage Targeted Dispatch												
EV Load Management												
Commercial/Industrial Advanced Demand Management Program (C2c)												
Program BCRs	7.5	4.6	4.7	2.9	2.9	2.8	7.9	4.8	4.9	2.7	2.9	3.1
Interruptible Load	9.7	9.8	9.8	7.9	7.9	7.9	7.5	7.5	7.5	4.2	4.2	4.2
Winter Interruptible Load												
Storage System & Performance		3.0	3.0									
Storage Daily Dispatch				1.7	1.7	1.7	4.9	4.9	5.0	6.2	6.2	6.2
Storage Targeted Dispatch				3.2	3.2	3.2	0.1	0.1	0.1	0.1	0.1	0.1
Custom	8.3	8.3	8.3		2.0	2.0	1.3	1.3	1.3			

Source: AEC

This table shows the BCRs of behind-the-meter energy storage as calculated by the program administrators (i.e., utilities) in Massachusetts. Note that these BCRs are based on energy benefits, which include emissions reductions, but they do not take into account non-energy benefits in their calculations. The circled numbers show how results can vary based on sector.

meter, but a BCR of zero when installed behind a residential meter. However, overall, the program administrators' results were similar the CEG-commissioned analysis performed by AEC, showing that in most cases, battery storage is cost-effective.

The proposed new energy efficiency plan was approved by the Massachusetts DPU in January 2019. The plan is expected to provide approximately $13 million in customer-sited performance incentives for demand reduction, which could result in the installation of approximately 34 MW of new behind-the-meter battery storage over three years.

Following the energy efficiency plan's approval, CEG again contracted with AEC to produce additional analysis of battery storage BCRs, as included in the final energy efficiency plan (attached in Appendix 2 of this report).

The plan is expected to provide approximately $13 million in customer-sited performance incentives for demand reduction, which could result in the installation of approximately 34 MW of new behind-the-meter battery storage over three years.

Valuing the non-energy benefits of storage

Although energy storage passed the required cost/benefit test for most applications in the Massachusetts energy efficiency plan, it did so based solely on its energy benefits. It is important to note that storage also provides non-energy benefits, which were not included in the storage BCRs calculated for the Massachusetts energy efficiency plan. CEG therefore contracted with AEC to conduct new analysis valuing the non-energy benefits of battery storage (attached in Appendix 3 of this report).

Establishing the value of non-energy benefits of battery storage is important because unless dollar values can be assigned to these benefits, their value in state cost/benefit analyses is effectively zero. Had the value of the non-energy benefits been included in the cost/benefit calculations for energy storage in Massachusetts, the resulting BCRs would likely have been higher. When other states conduct their own cost/benefit calculations for energy storage, it is important that the non-energy benefits of storage be included; otherwise, storage may be undervalued and may not qualify for energy efficiency incentive funds.

In the "Non-Energy Benefits of Battery Storage" white paper, AEC has identified seven non-energy benefits of battery storage and calculated their values. Though this is not a comprehensive list, it shows that storage has significant non-energy benefits, which should be included in future BCR calculations.

The seven non-energy benefits of battery storage analyzed in AEC's white paper are the following:

1. Avoided power outages
   a. Energy system reliability benefit (the system-wide benefit of fewer grid outages)
   b. Non-energy reliability benefit to consumers (customer's value of backup power)
2. Higher property values (after storage is installed)
3. Avoided fines to utilities for outages
4. Avoided cost to utilities of collections and terminations
5. Avoided cost to utilities of emergency calls during outages
6. Job creation
7. Reduced land use due to peaker replacement (using distributed storage as a peaking resource to avoid investments in new fossil fueled peaker plants, which require more land)[14]

It is important that the non-energy benefits of storage be included; otherwise, storage may be undervalued and may not qualify for energy efficiency incentive funds.

These non-energy benefits are valued by AEC as shown in **Table 3** (p. 12).

Inclusion of these non-energy benefit values in future storage cost/benefit analyses should result in an even greater BCR for battery storage as a demand reduction measure, and it could justify more aggressive investment goals by the Commonwealth of Massachusetts and its utilities.

TABLE 3

Values for Additional Non-Energy Benefits of Battery Storage

	Non-Energy Benefit (2018$)
Avoided Power Outages	
Battery storage measure participants avoid outages, and all of the costs that come with outages for both families and businesses	• Residential: **$172**/kWh • Commercial/Industrial: **$15.64**/kWh
Higher Property Values	
Installing battery storage in buildings increases property values for storage measure participants by increasing leasable space, increasing thermal comfort, increasing marketability of leasable space, and reducing energy costs.	• **$5,325**/housing unit for low-income single family participants • **$510**/housing unit for owners of multi-family housing
Avoided Fines	
Increasing battery storage will result in fewer power outages and fewer potential fines for utilities	• **$24.8 million** in 2012
Avoided Collections and Terminations	
More battery storage reduces the need for costly new power plants, thereby lowering ratepayer bills, and making it easier for ratepayers to consistently pay their bills on time. This reduces the need for utilities to inititate collections and terminations.	• Terminations and Reconnections: **$1.85**/year/participant • Customer Calls: **$0.77**/year/participant
Avoided Safety-Related Emergency Calls	
Increasing battery storage results in fewer power outages, which reduces the risk of emergencies and the need for utilities to make safety-related emergency calls	• **$10.11**/year/participant
Job Creation	
More battery storage benefits society at large by creating jobs in manufacturing, research and development, engineering, and installation.	• **3.3 jobs**/MW • **$310,000**/MW
Less Land Used for Power Plants	
More battery storage reduces the need for peaker plants, which are more land-intensive than storage installations—benefiting society by allowing more land to be used for other purposes.	• **12.4 acres**/MW

Source: AEC

This table shows the values calculated by AEC for seven non-energy benefits of battery storage. These non-energy benefits should be considered by policy makers when calculating the cost/benefit for battery storage. The non-energy benefits are in addition to the energy benefits.

How the Massachusetts program incentivizes battery storage

It is important to understand that the Massachusetts Active Demand Reduction program within the Energy Efficiency Plan *incentivizes peak demand reduction, not the installation of demand-reducing technologies.* This means that customers can qualify for battery performance incentives, but there is no rebate for installing batteries. Customers must shoulder the initial investment (unless developers offer leasing or power purchase agreement options).[15]

Customers installing batteries or other peak demand reduction devices will be able to sign up for a five-year performance contract with their utility. At the end of each season (twice a year) they will be paid an incentive payment based on how much they reduced their load (use of electricity) *on average* in response to utility signals for that season. This program will be offered both to commercial and to residential customers (although a critical mass of residential customers from each area will have to sign up before the utilities issue contracts).

It is anticipated that the program will be marketed to customers by third-party developers. HEAT loans (zero-interest loans) will be available to Massachusetts customers purchasing storage equipment, but developers may also offer their own financing plans, which may include leasing as well as purchasing options.

At this writing, the program performance incentive rates were still being developed by the program administrators. For the "targeted" dispatch program, the summer rate is anticipated to be $100/kWh average load reduction, and the winter rate is anticipated to be $25/kWh average load reduction. Payouts would be calculated seasonally based on the customer's average load reduction in each season.[16]

For a commercial customer signed up for targeted dispatch, this program could provide a modest but significant incentive. For example, a commercial customer installing a 60-kWh battery system might be able to earn $2,500/year or $12,500 over the five-year contract period (for details on how this is calculated, see *duration of discharge* below).

Utility filings indicate that the Massachusetts utilities anticipate spending approximately $13 million over three years on demand reduction incentives (exclusive of the administrative costs of the program). The incentives are expected to result in about 34 MW of new behind-the-meter battery storage being installed in the Commonwealth. If the program is successful, it is reasonable to assume that these levels of investment and the resulting deployment will increase in future energy efficiency plans.

It is important to understand that the Massachusetts Active Demand Reduction program within the Energy Efficiency Plan incentivizes peak demand reduction, not the installation of demand-reducing technologies.

Only new battery installations would be eligible for an incentive. There is no requirement that batteries be paired with renewable generation, but solar+storage customers could take advantage of both the efficiency incentive and the state's SMART solar program, which includes a storage adder. Commercial customers may also be able to engage in demand charge management behind the meter, for additional savings; and solar customers can net-meter excess solar. Other upcoming state programs, such as a clean peak standard now in development, may present additional revenue opportunities for storage customers.

What this means for other states and for the battery storage industry

Clean Energy Group views the inclusion of battery storage as a demand reduction measure in the Massachusetts energy efficiency program as critically important to the development of a robust and competitive battery storage market in the Commonwealth. But beyond that, we see this as an important precedent for other states across the nation.

The larger context for this work is that battery storage has not, to date, enjoyed the kind of broad support from public clean energy funds that other clean energy technologies, such as wind and solar, have relied on. Only a few early adopter states—California, Massachusetts, New York, New Jersey, and Oregon—have established battery storage procurement mandates or portfolios; and even fewer states offer incentives for behind-the-meter battery storage deployment. Thus, there is very little material support in state policy for distributed storage.

Due to competition for public funds, it is difficult for any emerging clean energy technology to attract new dollars for the creation of a new state incentive program. On the other hand, battery storage may fit into existing incentive programs with dedicated funding. Among such programs, energy efficiency is nearly ubiquitous, and a leader in terms of committed funds. With nearly $9 billion spent nationwide in 2017, state efficiency budgets constitute an enormous resource. Equally important to the size of these budgets is their relative permanence and reliability when compared to one-off grant programs and time-limited bridge incentive funding.

The 2018 ACEEE State Scorecard[17] shows that out of the 50 states and the District of Columbia, only Alaska, Kansas and North Dakota spent no money on electric efficiency in 2017. Top annual spenders included California ($1.4 billion/year), Massachusetts ($620 million/year), and New York ($450 million/year). For the third in a row, Massachusetts is ranked first on the 2018 scorecard, which considers policy and program efforts in terms of performance, best practices, and leadership.

These state energy efficiency budgets constitute a large potential new source of support for behind-the-meter storage deployment going forward. If other states follow Massachusetts' lead, bringing demand reduction technologies like battery storage into their energy efficiency programs, battery storage could gain access to many more state incentive dollars than are currently available to it. Conversely, if peak demand-reducing measures remain segregated from mainstream efficiency measures, they will likely continue to receive a fraction of the support given to efficiency measures.

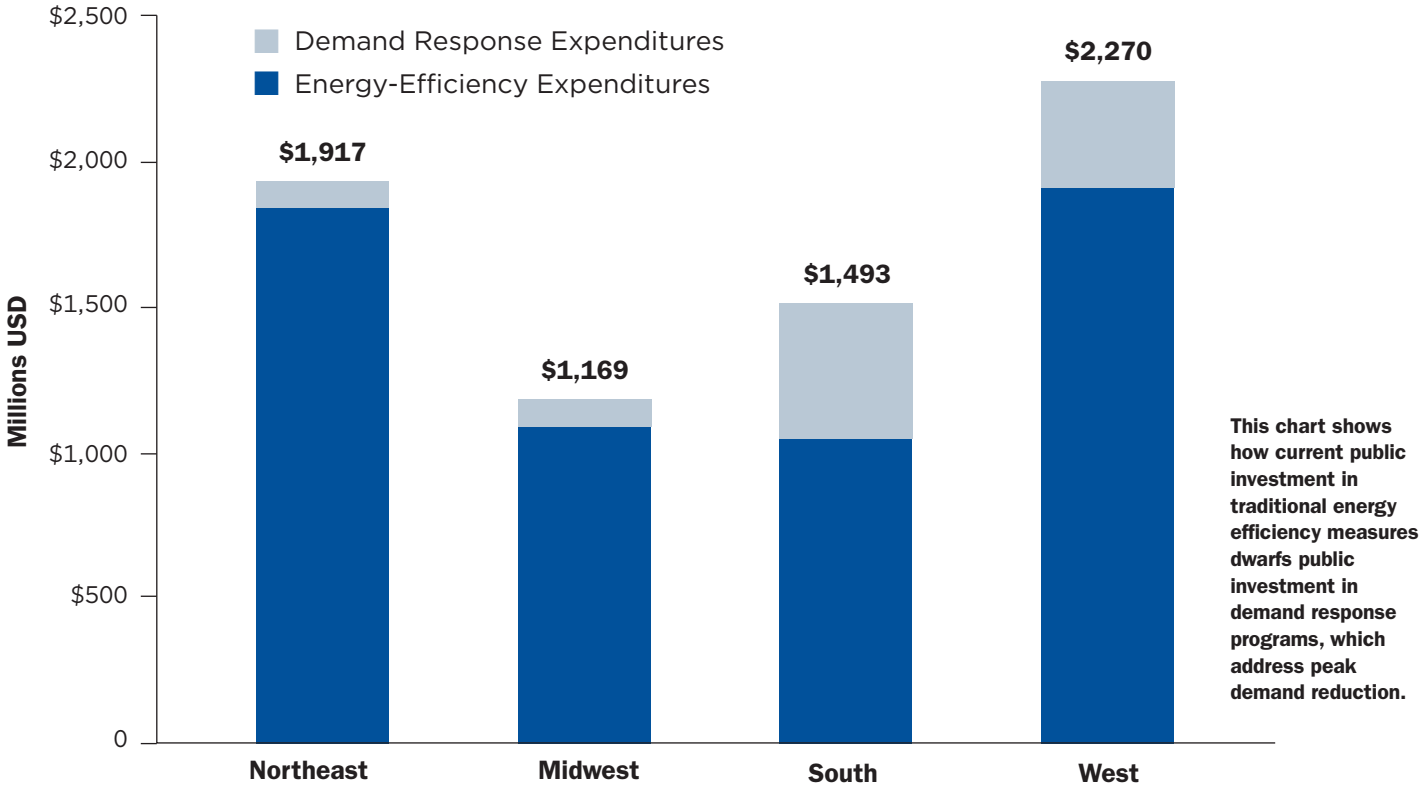
The disparity between public dollars spent on traditional energy efficiency measures versus demand reduction measures is stark. Nationally, demand reduction program budgets account for only about 16 percent of the combined energy efficiency-demand response spend in the US (see **Figure 4**).[18]

Adding battery storage to efficiency programs makes sense for several reasons. First, distributed battery storage is a good fit for efficiency programs. It works well behind the meter, delivers significant cost savings and other benefits to customers, and provides needed services not provided by traditional, passive efficiency measures. Notably, at a time when electricity demand is increasing faster than volumetric electricity sales, battery storage is capable of targeted peak demand reductions—unlike traditional measures, such as low-energy lighting and weatherization measures, which reduce net consumption but do nothing to shift demand peaks.[19] As shown by the "duck curve" phenomenon,[20] which was first noted in California but has now become evident in New England as well, the ability to shift peak loads becomes more important as more solar generation is added to the grid.

Second, it is noteworthy that the rise of battery storage comes at an opportune time, coinciding with the decline of state investment in efficient lighting programs. Long a mainstay of efficiency programs, lighting investments are now declining due to federal standards, which require light bulbs reach higher efficiencies. Unless these federal lighting regulations are rescinded,[21]

FIGURE 4

US Electric Energy Efficiency and Demand Response Expenditures by Region, 2016



Source: Consortium for Energy Efficiency 2017 Annual Industry Report

no incandescent bulb currently on the market will be able to be sold in the US by 2020, and the market will have completed its transition to fluorescent and LED bulbs.[22] Thus, state efficiency dollars currently dedicated to increased lighting efficiency will be freed up, and could be reallocated to support emerging demand reducing resources, including battery storage.

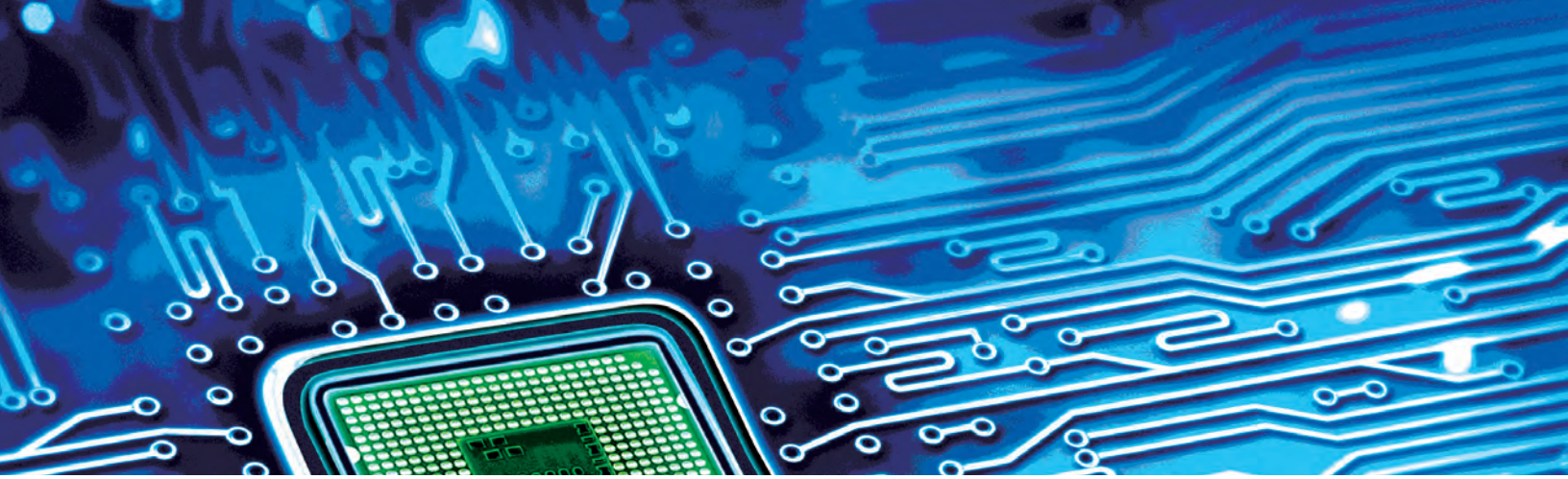
Third, customer and grid benefits are greatest when both kinds of efficiency—consumption reduction and demand reduction—are applied together. For some customers, potential reductions in electricity consumption are limited, and once these limits are reached, only demand management can provide further gains.

Commercial utility customers, in particular, frequently face steep electricity demand charges based on the highest 15-minute demand period each month. These customers need and deserve the ability to reduce demand peaks by employing battery storage behind the meter.[23] Doing so not only saves money for the storage owner—it also saves money across the electric system, by reducing the need to run costly "peaker" power plants and easing congestion on electric lines and substations.

It is also important to recognize that the integration of new technologies like battery storage is well within the history of state energy efficiency programs. In fact, the US EPA cites adding new technologies as a best practice in energy efficiency programs. In its 2008 National Action Plan for Energy Efficiency, EPA explains the importance of introducing new technologies as a best practice for efficiency programs:

> Many of the organizations reviewed have a history of providing programs that change over time to accommodate changes in the market and the introduction of new technologies . . . technology innovation that targets improved energy efficiency and energy management will enable society to advance and sustain energy efficiency in the absence of government-sponsored or regulatory-mandated programs. Robust and competitive consumer-driven markets are needed for energy efficient devices and energy efficiency service. . . . Programs must be able to incorporate new technologies over time. As new technologies are considered, the programs must develop strategies to overcome the barriers specific to these technologies to increase their acceptance.[24]

Massachusetts' groundbreaking inclusion of battery storage in its energy efficiency program is a change that should have significant and far-reaching impacts. Massachusetts is at the cutting edge in the electric efficiency sphere, and the work that has been done to incorporate and value distributed battery storage as an efficiency measure in Massachusetts should inform similar efforts in other states.



Program design considerations

The Massachusetts Three-Year Energy Efficiency Plan was shaped through a collaborative process that included state agencies, utilities, and non-governmental organizations. As the plan evolved, numerous program design considerations arose. We discuss some of these here. States looking to incorporate battery storage into their own efficiency plans will likely need to consider similar program design elements.

INCENTIVE DESIGN

In designing incentives for battery storage deployment, it is important to recognize both the unique operational and economic attributes of batteries, and the barriers they face as an emerging technology.

As discussed above, battery storage operates differently from traditional energy efficiency measures in that it does not usually reduce the net consumption of electricity, but instead, can redistribute consumption to non-peak times. In addition to this peak shifting service, battery storage can often provide other services to both the customer (such as resiliency) and the grid (such as ancillary services).

Battery storage operates differently from traditional energy efficiency measures in that it does not usually reduce the net consumption of electricity, but instead, can redistribute consumption to non-peak times.

Battery storage developers and customers may need to stack several such applications to achieve favorable battery storage project economics (see "Stacking incentives" below). Furthermore, unlike passive efficiency measures, batteries must be discharged at the right times to provide the desired demand reduction benefit; and in some cases must be charged at specific times, or from specific sources, to achieve economies and satisfy regulations and tax rules. These unique attributes should be taken into account when states design battery storage incentives, so that participation in the incentive program does not preclude the use of storage for other revenue-generating or cost-saving applications.

As an emerging technology, battery storage also faces cost and risk barriers. Installed costs of battery storage have declined rapidly in recent years but still present a barrier for customers, especially for low-income customers. Customers also shoulder the burden of economic risk, which is exacerbated when incentives come only in the form of performance incentives. Both these barriers could be addressed by an up-front rebate for battery storage systems.

Massachusetts regulators and efficiency program administrators chose to offer performance incentives for peak demand reduction in response to a utility signal, rather than a straightforward energy storage rebate upon installation. This makes sense from a program administrator's point of view, because it incentivizes only those uses of storage that achieve the desired load reductions during demand peaks. However, it puts the burden of capital investment entirely on the customer or developer. A more traditional up-front rebate would have shifted this burden in part to the state, but that would not have provided any guarantee that the resulting installed storage capacity would provide the peak load reduction services envisioned in the plan.

Ideally, states would offer both an up-front rebate and performance incentives. This would help to make storage more affordable and accessible, especially to underserved communities, while also incentivizing peak demand reductions.

FINANCING

Another important element of a successful incentive program is financing. The Massachusetts energy efficiency plan makes energy storage eligible for the HEAT loan program, an interest-

free loan offered to support the installation of efficiency measures. Unfortunately, the seven-year HEAT loan payback period exceeds the five-year incentive contract the utility program administrators will offer customers.[25] With no assurance that a second five-year contract will be offered after the initial contract period, and with incentive rates subject to change after contracts expire, HEAT loan recipients may have no way to offset the final two years of loan payments. Even during the initial five years, annual incentive payments to battery customers are unlikely to fully offset HEAT loan debt incurred as a result of battery purchases.

In practice, third-party developers may offer their own financing packages when marketing the battery incentive program. This industry financing, if offered, would provide an alternative to some customers. However, customers outside territories targeted by developers may have no recourse other than the Commonwealth's HEAT loan program.

States looking to support customer-owned battery storage deployment should consider providing low- or zero-interest financing with paybacks calibrated to coincide with performance incentive payments. Alternately, a customer rebate would help to offset equipment costs and could reduce the loan burden carried by the customer.

LOW-INCOME PROVISIONS

As noted above, battery storage is a relatively new technology that faces cost and financing barriers. These are particularly problematic when it comes to deploying the technology in low-income communities. To avoid leaving low-income customers behind, it is important that states include provisions for participation by underserved communities in storage incentive programs.

One major shortcoming of the Massachusetts plan is that it lacks any special provisions to support participation by low-income customers, referred to in the Massachusetts energy efficiency plan as "income eligible" customers (see **Table 4**).[26]

TABLE 4

Lack of Income-Eligible Programs by Utility

	Cape Light			Eversource			National Grid			Unitil		
Summer kW Savings	**2019**	**2020**	**2021**	**2019**	**2020**	**2021**	**2019**	**2020**	**2021**	**2019**	**2020**	**2021**
Residential Advanced Demand Management Program												
Program Summer kW Savings	1,055	2,869	3,400	2,050	3,150	4,250	6,099	8,597	11,033	94	112	135
Direct Load Control	1,055	1,618	1,861	2,000	3,000	4,000	5,156	6,785	8,278	94	112	135
Behavioral DR												
Storage System & Performance		1,250	1,539									
Storage Daily Dispatch				50	150	250	903	1,763	2,696			
Storage Targeted Dispatch												
EV Load Management							39	49	60			
Income-Eligible Advanced Demand Management Program												
Program Summer kW Savings		289	385									
Direct Load Control												
Behavioral DR												
Storage System & Performance		289	385									
Storage Daily Dispatch												
Storage Targeted Dispatch												
EV Load Management												
Commercial/Industrial Advanced Demand Management Program												
Program Summer kW Savings	5,798	6,053	6,080	28,000	57,500	96,000	69,500	79,000	90,000	300	500	500
Interruptible Load	5,395	5,458	5,485	27,000	47,000	75,000	66,000	72,000	79,000	200	400	400
Winter Interruptible Load												
Storage System & Performance		192	192									
Storage Daily Dispatch				500	5,000	10,000	2,500	5,000	7,000	100	100	100
Storage Targeted Dispatch				500	5,000	10,000						
Custom	403	403	403		500	1,000	1,000	2,000	4,000			

Source: Applied Economics Clinic

This table shows the program offerings in the Active Demand Reduction program, including battery storage. Note that none of the Commonwealth's utilities provided an income-eligible offering (the blank space indicated by the red oval). Cape Light Compact did propose income-eligible investment, but Cape Light's proposed program was not approved by the DPU.

The result is that while low-income customers can participate through the commercial and residential offerings, there is no dedicated, additional support targeted to low-income communities.

Typically, it is more difficult to provide clean energy options to low-income communities, which need clean, resilient and low-cost energy the most. States looking to incorporate storage into energy efficiency plans should include specific low-income provisions, such as an added incentive, more favorable financing, a carve-out guaranteeing a certain percentage of low-income participation, an up-front rebate, or (preferably) a combination of these.

DEFINING PEAK

Because the value of peak load shifting is tied to the value of energy at peak demand hours, it is important to ensure that these peak hours are defined in a way that 1) allows for battery storage to meaningfully shift peak loads and 2) allows these shifted peak loads to be appropriately valued.

In Massachusetts, peak hours are defined in "Avoided Energy Supply Components in New England: 2018 Report" (AESC) as being from 9 a.m. to 11 p.m. weekdays, excluding holidays, both summer (four months) and winter (eight months). As noted in AEC's July 2018 report, "This broad definition of 'peak' is not useful in representing the strategic use of batteries to relieve tight energy markets in periods of high energy demand or high energy prices."

TABLE 5
Peak/Off-Peak Hours, 2019

	Total Count	Highest 10% by	
		Energy Price	MWh
Summer Peak	1,260	0	317
Summer Off-Peak	1,668	1	313
Winter Peak	2,565	502	128
Winter Off-Peak	3,267	373	118

Source: Applied Economics Clinic calculations

From the perspective of a battery storage provider, the problem with such a broad definition of peak is twofold. First, shifting so many hours (1,260 hours in summer and 2,565 hours in winter) is not feasible (see **Table 5**). Second, the average value of any given peak hour is lowered by the sheer number of hours considered to be "peak." In other words, the more hours defined as "peak," the less valuable any given peak hour is, on average. In Massachusetts, for example, the average value of a peak MWh under this overly broad definition falls into a range of $31–$47. These prices would be significantly higher, however, if the definition of "peak" hours were restricted to the top 10 percent of hours in the year, either by price or by volumetric sales, as suggested in the *State of Charge* report.

TABLE 6
Peak/Off-Peak Hours, 2019

	Total Count	Highest 10% by	
		Energy Price	MWh
Summer Peak	$31	N/A	$37
Summer Off-Peak	$27	$69	$36
Winter Peak	$47	$80	$73
Winter Off-Peak	$42	$78	$75

Source: Applied Economics Clinic calculations

To illustrate the significance of the pricing difference, AEC showed in its July 2018 report that under the AESC definition of peak, the average avoided energy price for a winter peak hour is $47 (see **Table 6**). If defined as the top 10 percent of hours by peak pricing, the same winter peak hour is worth $80. If defined as the top 10 percent of hours by MWh sales, the same hour is worth $73.

States interested in integrating storage into an energy efficiency program should make sure to adopt a definition of "peak" that is narrow enough to allow storage measures to make a meaningful and valuable contribution.

These differences in peak load shifting values are very important for battery storage. Under an extremely broad definition of peak, such as is used in AESC 2018, storage measures represent a net cost to the electric system. Under a more restricted definition of peak as the top 10 percent of hours by price, storage provides a net benefit. Although there are other benefits of storage to be calculated (such as non-energy benefits), this fundamental definition of peak hours provides the basis of the positive BCR for battery storage.

It is important to understand that "peak" may be defined differently for different purposes, and by different entities. For example, ISO-New England recognizes a 2- and 4-hour peaks, while PJM recognizes a 10-hour peak, for their respective demand response programs. These definitions may have a great impact on how battery storage can play in wholesale markets in these regions. However, there is nothing preventing a state from using a different definition of peak within an energy efficiency program.

States interested in integrating storage into an energy efficiency program should make sure to adopt a definition of "peak" that is narrow enough to allow storage measures to make a meaningful and valuable contribution.

DURATION OF DISCHARGE

Related to the above discussion of how peak hours are defined is the issue of the duration of discharge (of the batteries) required for demand reduction measures. Where performance incentives are used, the duration of discharge can have a significant impact on the economic viability of battery storage. The Massachusetts program administrators have indicated that they will call for demand reduction in three-hour blocks. For example, a customer might be called upon to reduce their load from 2 p.m. until 5 p.m. Because the incentive payment is based on the average hourly load reduction across all the hours called in a season, this three-hour signal effectively reduces battery capacity to one-third its nameplate capacity, for purposes of calculating the seasonal incentive payment.[27]

As an example, consider a customer who has a 60-kW battery. When responding to a three-hour call by the utility, the maximum average load reduction possible across those three hours is 20 kW. This average is then multiplied by the incentive rate to arrive at the incentive payment. If the utilities instead employed a two-hour load-reduction call, the same battery would be capable of an average reduction of 30 kW per hour, resulting in a higher incentive payment at season's end. Given a 100/kW incentive rate (the targeted dispatch program's summer rate), the difference in annual incentive payments is significant:

Three-hour call: 20 kW x $100 = $2,000 seasonal payment

Two-hour call: 30 kW x $100 = $3,000 seasonal payment

Note that under the targeted dispatch program, the winter rate is only $25/kWh, so signing up for the winter season does not add much to the customer's annual payout.

Assuming a 60 kW battery (maximum 20 kW load reduction average):

Summer payout = 20 kW x $100 = $2,000

Winter payout = 20 kW x $25 = $500

Annual revenue = $2,500

States that design an incentive based on this average load-reduction model should be aware that the longer the duration of load-reduction calls by the utility, the lower the incentive payment will be to the customer.[28]

MEASURING BENEFITS

The need to show that battery storage passes a cost-effectiveness screen is not unique to Massachusetts. Most states require some sort of cost-effectiveness screening, not only for energy efficiency plans, but also for other types of clean energy incentive programs. Where a benefit/cost test is required, a full accounting of the benefits of battery storage should include both energy benefits and non-energy benefits.

The Massachusetts program administrators' BCR calculations for the 2019–2021 efficiency plan, as shown in **Table 2** (p. 10), are based on the energy benefits of storage, but they do not take into account its many non-energy benefits. These non-energy benefits were omitted despite the fact that they are commonly used in calculating the BCR of traditional efficiency measures in Massachusetts. The current Massachusetts energy efficiency plan describes non-energy benefits, here referred to as non-energy impacts (NEIs), thus:

> "A NEI is a benefit (positive or negative) for participants in energy efficiency beyond the energy savings gained from installing energy efficient measures. NEIs include benefits such as reduced costs for operation and maintenance associated with efficient equipment or practices, or reduced environmental and safety costs. The Department has stated that NEIs are 'a well-established component of the program cost-effectiveness analyses conducted by the Program Administrators' and found that the benefits of the NEIs are quantifiable and flow to Massachusetts ratepayers. 2013-2015 Order at 61. The Department has specifically stated that non-resource benefits (NEIs) should be included in cost-effectiveness. Guidelines at §§ 3.4.4.1, 3.4.4.2."[29]

The plan goes on to state that the program administrators have included benefits associated with NEIs in the current plan's cost-effectiveness calculations for a number of measures, including low-income, health- and safety-related NEIs, C&I new construction NEIs, residential multi-family common area lighting NEIs, residential heat pump NEIs, and others. However, the non-energy benefits of energy storage were not included, meaning that energy storage technologies were likely undervalued compared to other measures included in the plan. A more accurate accounting of the BCR of energy storage would have included its non-energy benefits.

Most states require some sort of cost-effectiveness screening, not only for energy efficiency plans, but also for other types of clean energy incentive programs.

When states omit non-energy benefits from cost/benefit calculations, the value of those non-energy benefits defaults to zero for purposes of finding the BCR of the measure. The result is that the measure being considered will be undervalued, and it may not pass the cost-effectiveness screen. Therefore, it is important for states to begin to assign values to the non-energy benefits of battery storage.

In addition to the omission of non-energy benefits, there are a number of other omissions and errors in the valuation of battery storage in the 2019–2021 Massachusetts energy

efficiency plan. The most important of these are discussed in more detail in the Appendices. Future work may focus on further analysis of some of these issues.

It should be noted that calculating the BCR of battery storage is a complicated task that relies on previously established values for services such as avoided emissions and avoided energy demand reduction induced price effects (DRIPE). Many of these underlying values may not be the same for all states. For example, the values associated with avoided emissions and increased capacity will vary from state to state and market to market. Therefore, while the values of various storage benefits presented in this report may serve as a good baseline for other states, additional work may be needed to fully adapt these values to the needs of other states' policymakers.

OWNERSHIP ISSUES

Issues around the ownership and control of battery storage resources are important, and they should be considered carefully when states design storage incentive plans or incorporate storage into existing programs, such as energy efficiency plans. In order to advance battery storage deployment, it is important that customers retain rights of ownership and control of storage resources behind their electric meters.

This is important due to the need to stack benefits, as described below (see "Stacking Incentives").

In order to advance battery storage deployment, it is important that customers retain rights of ownership and control of storage resources behind their electric meters.

Though it does not address issues of battery ownership directly, the Massachusetts energy efficiency plan assumes customer and third-party ownership of battery resources behind the meter. However, Massachusetts law places no restrictions on utility ownership of storage, meaning that utilities could have opted to offer customers utility-owned batteries, as Green Mountain Power has done in Vermont, and Liberty Utilities is doing in New Hampshire.[29] Such a move could have had a negative effect on the nascent distributed, customer-sited battery storage industry in the Commonwealth rather than supporting its development; and future customers could have faced a potential utility monopoly when pursuing battery storage options.

Similar to issues of battery ownership are issues of the ownership and control of battery attributes that have their own market values, such as capacity. This was the subject of a recent Massachusetts DPU docket. In January 2019, the DPU issued a ruling[31] allowing customers to buy back the capacity assets of behind-the-meter, solar+battery storage systems, to which the utilities had previously claimed rights of ownership. This is an important issue not only because battery capacity is a monetizable asset, but also because control over it can determine when and whether customers control the dispatch (use) of their own battery systems. This in turn has significant implications for project economics, particularly for commercial customers who wish to use batteries for demand charge management. If utilities are allowed to own the capacity rights to behind-the-meter battery storage and bid this capacity into markets, as they do in the case of net-metered solar, this can prevent customers from using batteries to reduce demand charges, because the utilities may leave batteries depleted at times when customers need to use them to reduce their own electricity demand.

In the case of the Massachusetts energy efficiency plan, the program administrators will not directly dispatch behind-the-meter storage resources, but instead will compensate customers based on their average load reduction in response to a utility signal. This means customers retain the ability to use their batteries for other purposes if they judge those purposes to be more valuable than the efficiency performance incentive. There is no penalty for failing to respond to a utility dispatch signal, but it does lower the yearly average load reduction, which is used to calculate the customer's incentive payment.

States looking to incorporate batteries into an efficiency program should be aware of this aspect of incentive design. If customers lose control of their battery storage equipment (e.g., utilities can remotely discharge batteries without customer consent), their ability to stack benefits decreases (see "Stacking Incentives," below). In this case, incentive rates may need to be higher to make customer participation worthwhile. The same logic applies to cases where failure to respond to a dispatch call can result in a fine.

STACKING INCENTIVES

Battery storage owners and developers often configure battery systems in such a way as to allow "benefit stacking." This refers to the ability of a single battery system to provide numerous benefits, often generating savings from several incentive or revenue streams. The ability to stack incentives and applications is important, because it gives customers flexibility; and it can help to further defray the cost of investing in a battery system. It follows the principle of allowing battery storage owners to be compensated fairly for all the services that the batteries are able to provide.

For example, a commercial customer who installs a new solar+storage system in Massachusetts may qualify for a SMART solar incentive (rebate) with a storage adder, as well as an energy efficiency demand-reduction incentive.

The customer may be able to net meter solar generation and may also engage in demand charge management (reducing the monthly demand charge that is part of commercial utility bills). Being able to stack values in this way allows the customer greater flexibility and helps to offset the cost of installing the solar+storage system.

Other states interested in developing battery storage policy should consider how various state programs and storage markets may interact, to avoid unduly limiting how the storage resource can be used. Opportunities for combining incentives and market programs should be clearly spelled out to reduce confusion and give consumers and developers a clear understanding of potential project economics, which is important to obtain financing.

TRANSPARENCY

During the development of the Massachusetts energy efficiency plan, numerous stakeholders noted a lack of transparency which made it difficult to provide meaningful stakeholder input. Lack of transparency has also been noted as a shortcoming of the final plan, which leaves significant design elements vague.

For example, the program administrators have stated in docket filings that they intend to offer residential contracts for load reduction performance incentives (for which storage would be eligible) only after a critical mass of applications has been received.[32] However, there is nothing in the plan identifying how many applications are needed to trigger the offer. This creates uncertainty and hinders the efforts of developers in marketing the program to their customers.

Vague, inconsistent, and opaque program language should be avoided when states design battery storage incentive programs.

Similarly, in their white papers, AEC notes that such fundamental terms as "measure" are used to mean different things by different program administrators in different parts of the plan. This kind of internal inconsistency makes it difficult to understand what incentives are available to customers.

Vague, inconsistent, and opaque program language should be avoided when states design battery storage incentive programs. States looking to adapt portions of the Massachusetts energy efficiency plan to support their own policy development for battery storage should be aware of these internal inconsistencies and avoid replicating them. For example, a state could require utilities to agree on the definition of important terms such as "measure," which are necessary to understand how an efficiency program works and what various incentives are worth to customers.

What states should do to promote battery storage

While Massachusetts' integration of battery storage into its energy efficiency plan as a demand reduction measure is not perfect, it does provide a model for other states to follow, along with some lessons learned as identified below.

Other states that are leaders in clean energy programs and policy should consider following the example of Massachusetts. These states should understand that the changing electricity system presents a need and opportunity to identify new types of efficiency. Among these, peak demand reduction will be increasingly important. It is critical that technologies capable of reducing peak demand, such as battery storage, be incorporated fully into state energy efficiency programs, so that behind-the-meter storage markets can come to scale, with incentives commensurate to those offered other clean energy and efficiency measures.

Other states that are leaders in clean energy programs and policy should consider following the example of Massachusetts.

Here are some lessons learned from Massachusetts for states to consider:

- Expand the definition of energy efficiency to include peak demand reduction. This means that state energy efficiency goals would include peak demand reduction goals, and that peak demand reduction measures would be made eligible for efficiency incentives.
- Fully integrate demand reduction measures, including battery storage, into state energy efficiency plans.
  - In some states with separate demand reduction targets and budgets, this might mean merging the efficiency and demand reduction budgets into a single program that encompasses both energy efficiency and demand reduction goals.
- Establish battery storage or demand reduction incentives within the energy efficiency program.
  - These should, in general, include three basic elements: an up-front rebate, a performance incentive, and access to financing.
  - These should also include adders and/or carve-outs for low-income customers. These customers need the cost savings and other benefits of new clean energy technologies the most but are typically the last to gain access.
  - Utility ownership should be limited, so that some substantial portion of the storage deployed will be owned by customers and/or third parties.
  - Third-party developers should be allowed to market the program to customers, provide private financing, offer lease and PPA models, and aggregate capacity to meet program goals.
- Adopt, adapt and build on the economics analysis presented here.
  - Cost/benefit analyses of storage should be conducted using whatever cost-effectiveness tests states apply to other energy efficiency measures. These might include the Total Resource Cost Test, the Societal Cost Test or the Utility/PACT test.
  - BCRs should be calculated based on both the energy and the non-energy benefits of storage.
  - Additional non-energy benefits of storage should be identified and valued.

Key Findings and Conclusion

Many studies have concluded that battery storage offers immense value to the electric grid as well as to consumers. The benefits of storage include not just renewables integration and peak shifting, but other services such as increased resiliency, reduced transmission and distribution investment, ancillary services provision, arbitrage and black start capability. The challenge has been that markets do not yet exist for most of these services; and without markets, it has been very difficult for policymakers to assign values to these benefits of storage, or for storage providers to sell and be compensated for these benefits.

This market failure is a major finding of the Massachusetts *State of Charge* report, which concludes, "The biggest challenge to achieving more storage deployment in Massachusetts is the lack of clear market mechanisms to transfer some portion of the system benefits (e.g., cost savings to ratepayers) created to the storage project developer."[33]

The same problem is discussed in the Massachusetts energy efficiency plan itself, which notes, "There is no beneficial value proposition for individual residential customers to participate in active demand offerings [including battery storage] absent Program Administrator incentives. However, peak demand reductions through active demand management can have a system benefit that reduces overall capacity and temporal-energy costs for all customers."[34]

This basic market failure is a familiar one, and it is one reason why many states invest public funds to support development and deployment of new advanced clean energy resources. However, the investment of public funds, in itself, often requires states to show that this investment will result in a positive return. To do this, it is necessary to attribute dollar values to the many benefits of behind-the-meter battery storage.

This report begins to address the challenges of valuing battery storage by showing that it can and does pass a Total Resource Cost test in Massachusetts; and furthermore, that storage provides many additional non-energy benefits that have definable monetary value in Massachusetts, and that could (and should) be incorporated into future cost/benefit analyses, both in Massachusetts and in other states.

The biggest challenge to achieving more storage deployment in Massachusetts is the lack of clear market mechanisms to transfer some portion of the system benefits (e.g., cost savings to ratepayers) created to the storage project developer.

This report also documents incentive design issues arising from this first-ever inclusion of energy storage in a state energy efficiency plan. These design issues will need to be considered by other policy makers that wish to follow the lead of Massachusetts. The lessons learned from Massachusetts, as discussed in this report, should inform similar efforts in other states.

More work remains to be done to more accurately define the value of storage, including expanding on the non-energy benefits of storage—analyzed for the first time in this report—as well as to further refine program design for storage within state energy efficiency plans. However, this report should provide valuable information to state policymakers and regulators working to incorporate storage in efficiency and other incentive programs.

Key take-aways from this report:

1. At least two major barriers had to be overcome in order to incorporate energy storage into the Massachusetts energy efficiency plan: first, peak demand reduction had to be incorporated into the energy efficiency program; and second, storage had to be shown to pass cost-effectiveness screens. Other states will likely have to confront these barriers when incorporating storage into their own energy efficiency plans.

   a. Peak demand reduction is an important new kind of electric efficiency that offers benefits both to customers and to the grid. Battery storage is a critical technology for shifting peaks when installed behind the customer's meter.

   b. Battery storage passes the Massachusetts cost/benefit test and has been incorporated into the Massachusetts energy efficiency plan for 2019–2021. About 34 MW of behind-the-meter battery storage is expected to be installed in MA over three years under load reduction performance contracts worth about $13 million in customer incentives. Other states should follow the example of Massachusetts and conduct their own cost/benefit analysis of behind-the-meter energy storage.

2. The non-energy benefits of energy storage have significant value and should be included in cost/benefit analyses. This was not done in the 2019–2021 Massachusetts Energy Efficiency Plan but should be included in future iterations of the plan and should be considered by other states when developing energy storage incentives.

3. Numerous program design issues should be addressed when states contemplate creating battery storage incentives, whether within an efficiency plan, or as a free-standing rebate. These include: Incentive design, Defining peak, Dispatch duration, Measuring benefits, Ownership issues, Low-income provisions, Stacking incentives, and Transparency.

4. More work is needed to continue to refine and expand the value of battery storage, including the identification and valuation of more non-energy benefits. Establishing a more accurate BCR for distributed storage will support its inclusion in state energy efficiency programs and other incentive programs (such as rebates) that require measures pass a cost-effectiveness screen. If this is not done, storage will continue to be at a disadvantage relative to other technologies and may not qualify for state incentive programs.

5. State energy efficiency programs represent an important potential source of incentive funding for distributed battery storage. Most states have energy efficiency programs, and these programs collectively represent an investment of nearly $9 billion in public funds annually. Bringing new technologies like storage into state energy efficiency programs is a recommended "best practice."

At least two major barriers had to be overcome in order to incorporate energy storage into the Massachusetts energy efficiency plan: first, peak demand reduction had to be incorporated into the energy efficiency program; and second, storage had to be shown to pass cost-effectiveness screens.

ENDNOTES

1 The Commonwealth of Massachusetts. "Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan 2019–2021." *Department of Public Utilities.* October 31, 2018. *http://ma-eeac.org/wordpress/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf*.

2 In addition to conducting the economic analysis presented here, CEG advocated for program design elements in the Massachusetts Energy Efficiency plan that would support customer choice, allow the participation of third-party installers and aggregators, provide significant financing and incentives—with an emphasis on the needs of low-income customers and underserved communities—and ensure a competitive and diverse market for behind-the-meter battery storage in Massachusetts.

3 Although it is the first to fully incorporate energy storage into its energy efficiency program, Massachusetts is not the first state to recognize the importance of storage for peak demand reduction. Arizona Corporation Commission (ACC) has included peak demand reduction in its state energy efficiency resource standard, although it caps the contribution of peak demand reductions at 2% (the overall goal is 22% cumulative energy savings by 2020). ACC also ordered Arizona Public Service, the state's largest utility, to develop a residential demand response or load management program that facilitates energy storage technology. APS developed the Demand Response, Energy Storage and Load Management (DRESLM) initiative, which was approved by the ACC in 2016 and offered to customers in 2017. In 2018 APS expanded the DRESLM initiative to include both residential and non-residential customers. ACC has also ordered all regulated Arizona utilities to include energy storage in their integrated resource plans, or explain why it is omitted. For more information on the APS Demand Side Management plan, see *https://www.aps.com/en/ourcompany/aboutus/energyefficiency/Pages/home.aspx*.

4 United States Environmental Protection Agency. "National Action Plan for Energy Efficiency, Chapter 6: Energy Efficiency Program Best Practices." 2015. *https://www.epa.gov/energy/energy-efficiency-program-best-practices.*

5 The Commonwealth of Massachusetts, Department of Public Utilities. *Three Year Energy Efficiency Plans Order.* D.P.U. 18-110 through D.P.U. 18–119. January 29, 2019. *https://www.mass.gov/files/documents/2019/01/31/2019-2021%20Three-Year%20Energy%20Efficiency%20Plans%20Order_1.29.19.pdf*.

6 An Act Relative to Green Communities. The Commonwealth of Massachusetts, Chapter 169. July 2, 2008. Retrieved March 13, 2019. *https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169*.

7 The Commonwealth of Massachusetts. M.G.L. c.25, §21. Retrieved March 12, 2019. https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter25/Section21.

8 At the time of this analysis, Massachusetts required individual efficiency measures to pass the TRC cost-effectiveness test. The 2018 Act to Advance Clean Energy amended this requirement so that it now applies to entire sectors rather than individual measures. Note that although the total resource cost test (TRC) is the most commonly used, many states use other cost-effectiveness tests such as the participant cost test (PCT), the utility/program administrator cost test (PACT), the ratepayer impact measure test (RIM), and the societal cost test (SCT). This report does not address how battery storage would fare in tests other than the TRC. For more information on the differences between different types of cost-effectiveness tests, see: National Action Plan for Energy Efficiency. "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers." *United States Environmental Protection Agency and United States Department of Energy.* November 2018. *https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf*, and Daykin, Elizabeth et al. "Whose Perspective? The Impact of the Utility Cost Test." *Cadmus Group.* December 2011. *https://www.cadmusgroup.com/wp-content/uploads/2012/11/TRC_UCT-Paper_12DEC11.pdf*.

9 Massachusetts Department of Energy Resources and Mass Clean Energy Center. "State of Charge: A Comprehensive Study of Energy Storage in Massachusetts." September 27, 2016. *https://www.mass.gov/service-details/energy-storage-study*.

10 Stanton, Elizabeth A. "Massachusetts Battery Storage Measures: Benefits and Costs." *Clean Energy Group.* July 2018. *https://www.cleanegroup.org/ceg-resources/resource/massachusetts-battery-storage-measures-benefits-and-costs*.

11 Ibid.

12 An Act Relative to Green Communities. The Commonwealth of Massachusetts, Chapter 169. July 2, 2008. Retrieved March 13, 2019. *https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169*.

13 Ibid. The Green Communities act states that "Every three years. . . the electric distribution companies and municipal aggregators with certified efficiency plans shall jointly prepare an electric efficiency investment plan…. Each plan shall provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply."

14 Note that the land use benefit is presented in acres rather than dollars. This is because it is difficult to know the value of the land required for a prospective new peaker plant. However, this benefit could be quite valuable. For example, the average value of land in Boston is $600,000 per acre according to a recent report: Albouy, David et al. "Metropolitan Land Values." *The Review of Economics and Statistics.* July 2018, 100(3): 454–466. *http://davidalbouy.net/landvalue_index.pdf*. Based on this average, the formula to find the value of land saved through use of distributed storage to replace a peaker plant planned for Boston would be $600,000 x 12.4 x MW capacity of peaker. For example, avoiding development of a 60 MW peaker in Boston could save $446.4 million in avoided land use

value. Of course, all land value is highly locational; and this only provides a very rough estimate, which would be different for different cities.

15 Clean Energy Group (CEG) had originally proposed a stand-alone battery storage rebate plan for Massachusetts. Due to a lack of available funds for such a rebate, this proposal was put on hold temporarily, in favor of incorporating storage into the energy efficiency budget. CEG supported this effort, but also continues to advocate for a battery storage rebate, which could be provided within the Commonwealth's energy efficiency plan or as a stand-alone program.

16 There is also a daily dispatch program, which may offer higher incentive rates in exchange for more frequent battery cycling, but this is being offered initially as a pilot program, and may be expanded to a full program offering in coming years.

17 Berg, Weston, et al. "The 2018 State Energy Efficiency Scorecard." *American Council for an Energy-Efficient Economy.* Research Report U1808. October 2018. *https://aceee.org/research-report/u1808*.

18 Consortium for Energy Efficiency. "State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts 2017." March 2018. *https://www.cee1.org/annual-industry-reports*.

19 In this regard, storage is part of an emerging field of smart and grid interactive energy efficiency measures which address, to varying degrees, load shifting and reduced consumption behind the meter. These include wireless thermostats, remotely controlled HVAC and water heater systems, and the like.

20 Spector, Julian. "Massachusetts Is Staring Down a Duck Curve of Its Own. Storage Could Help." *GTM²*. April 23, 2018. *https://www.greentechmedia.com/articles/read/massachusetts-is-staring-down-a-duck-curve-of-its-own-storage-could-help#gs.3388ma*.

21 deLaski, Andrew and Steve Nadel. "Rollback of light bulb standards would cost consumers billions—$100 per household each year." *The Appliance Standards Awareness Project (ASAP)* and *The American Council for an Energy-Efficient Economy (ACEEE).* February 6, 2019. *https://aceee.org/press/2019/02/rollback-light-bulb-standards-would*.

22 Granda, Chris. "Impacts of the 2020 Federal Light Bulb Efficiency Standard." *Strategies.* February 2018. *https://appliance-standards.org/sites/default/files/AESP2020LightingStandards.pdf*.

23 Commercial/industrial customers in Massachusetts face some of the highest demand charges in the nation, but a recent study conducted by CEG and NREL shows that high demand charges can be found in many parts of the country. See: McLaren, Joyce and Seth Mullendore. "Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges." *National Renewable Energy Laboratory* and *Clean Energy Group.* August 24, 2017. *https://www.cleanegroup.org/ceg-resources/resource/nrel-demand-charges-storage-market*.

24 Environmental Protection Agency. "National Action Plan for Energy Efficiency, Chapter 6: Energy Efficiency Program Best Practices." August 2015. *https://www.epa.gov/energy/energy-efficiency-program-best-practices*.

25 The Massachusetts energy efficiency plan provides for contractual battery storage performance payments to customers over a five-year term. This is an unusual offering in that the incentive term is longer than the term of the three-year energy efficiency plan.

26 In the efficiency plan proposed by the PAs to the DPU, only Cape Light Compact proposed any batteries for income eligible customers. The Cape Light Compact plan was opposed by Eversource and the DPU did not approve it. At this writing it is uncertain whether the Cape Light Compact plan will eventually go forward as proposed.

27 This is because a battery would not have time to discharge, recharge and discharge again during a period of three consecutive hours.

28 Technically, this type of performance incentive can be considered a "payment for performance," rather than a traditional incentive.

29 The Commonwealth of Massachusetts. "Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan 2019–2021" (page 119–120). *Department of Public Utilities.* October 31, 2018. *http://ma-eeac.org/wordpress/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf*.

30 The Liberty and GMP programs offer residential customers a utility-owned battery in exchange for a monthly fee. The customer can use the battery for backup power in case of a grid outage; during normal operations, the utility draws on the battery to reduce peak demand.

31 The Commonwealth of Massachusetts, Department of Public Utilities. *Net Metering, Smart Provision, And the Forward Capacity Market.* D.P.U. 17-146-B. February 1, 2019. *https://d12v9rtnomnebu.cloudfront.net/library-page/D.P.U._17-146-B_Order_02.01.19.pdf*.

32 The program adminstrators' response to the DPU's Information Request DPU-Electric 2-3, wherein the program administrators state that they "may not offer the statewide storage offerings if they cannot achieve cost-effectiveness, i.e., if there are not enough storage devices already deployed and willing to enroll to be able to overcome any fixed costs necessary to offer the program."

33 Massachusetts Energy Storage Initiative. "State of Charge." *Massachusetts Department of Energy Resources (DOER)* and *Massachusetts Clean Energy Center (MassCEC)* (page xiii). July 2017. *https://www.mass.gov/files/2017-07/state-of-charge-report.pdf*.

34 The Commonwealth of Massachusetts. "Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan 2019–

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Appendix 1

MASSACHUSETTS BATTERY STORAGE MEASURES: BENEFITS AND COSTS

Massachusetts Battery Storage Measures: Benefits and Costs

July 2018 – White Paper

Applied Economics Clinic

Prepared for:

Clean Energy Group

Author:

Elizabeth A. Stanton, PhD

www.aeclinic.org

July 31, 2018

[AEC-2018-07-WP-02]

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Acknowledgements

This report was commissioned by Clean Energy Group in support of its efforts to expand the benefits of energy storage and clean energy technologies. This work is generously funded by Barr Foundation and The Merck Family Fund. CEG wishes to thank the following organizations and individuals for their input and comments: Janet Besser and Jamie Dickerson of Northeast Clean Energy Council, and Michael Kleinberg and Chandler Miller of DNVGL.

About Clean Energy Group

Clean Energy Group (CEG) is a leading national, nonprofit advocacy organization working on innovative policy, technology, and finance strategies in the areas of clean energy and climate change. CEG promotes effective clean energy policies, develops new finance tools, and fosters public-private partnerships to advance clean energy markets that will benefit all sectors of society for a just transition. CEG assists states and local governments to create and implement innovative practices and public funding programs for clean energy and resilient power technologies. CEG manages the Clean Energy States Alliance (CESA), a national nonprofit consortium of public funders and agencies working together to accelerate clean energy deployment. Learn more at www.cleanegroup.org.

About Applied Economics Clinic

The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University's Global Development and Environment Institute. The Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

1. Introduction

Lithium-ion batteries for electric storage are considered in Massachusetts' energy efficiency program administrator's 2019-2021 draft plan, released April 30, 2018,[1] and addressed, partially, in the "BCR Model" spreadsheets (publicly released in June 2018) used to calculate cost-effectiveness in the April draft plan. Massachusetts' assessment of the cost-effectiveness of electric demand and peak-reducing measures' depends on the "BCRs"—or benefit-cost ratios—estimated in these spreadsheets. For measures to be included in the funding allocation and program implementation described in the 2019-2021 plan they must receive a benefit-cost ratio of 1.0 or higher; that is, a measure's benefits must have a higher value than its costs.

This Applied Economic Clinic white paper provides the calculations and assumptions necessary to estimate complete 2019 benefit-cost ratios for battery storage measures in Massachusetts, using a methodology identical to that of the program administrator's own "BCR Model" spreadsheets for the 2019-2021 and previous three-year efficiency plans. The resulting Massachusetts benefit-cost ratios for battery storage in 2019 are:

- 2.8 for a single-family home battery under the low-income efficiency program
- 3.4 for a multi-family apartment complex battery under the commercial and industrial efficiency programs

The benefits of electric battery storage outweigh their costs, and, therefore, must be offered by Massachusetts electric program administrators to their customers, in accordance with the Green Communities Act.[2] This white paper reviews the calculation of a value for battery storage of the cost and each type of benefit included in Massachusetts' cost-effectiveness assessment: avoided energy, avoided energy demand reduction induced price effects (DRIPE), summer generation capacity, winter generation capacity, electric capacity DRIPE, transmission, distribution, and reliability, non-energy benefits, and non-embedded environmental costs. Of these benefits, avoided capacity costs are by far the most substantial.

[1] Massachusetts Program Administrators. 2018. "Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan: 2019-2021". http://ma-eeac.org/wordpress/wp-content/uploads/2019-2021-Three-Year-Energy-Efficiency-Plan-April-2018.pdf

[2] The General Court of the Commonwealth of Massachusetts. 2008. Acts 308-80: An Act Relative to Green Communities. Chapter 169. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.

2. Engineering Assumptions

Lazard's *Levelized Cost of Storage 3.0* report outlines two behind-the-meter energy storage use cases: Case 4, commercial, and Case 5, residential.[3] Case 4, commercial, represents storage "designed for behind-the-meter peak shaving and demand charge reduction services for commercial energy users" while Case 5, residential, represents storage "designed for behind-the-meter residential home use," that "provide backup power, power quality improvements and extend the usefulness of self-generation".[4] This analysis adopts the lithium-ion assumptions for both Cases.

Figure 1 presents the technical parameters of all cases, with Cases 4 and 5 highlighted.

Figure 1. Energy storage use cases—operational parameters

		Project Life (Years)	MW(1)	MWh of Capacity(2)	100% DOD Cycles/Day(3)	Days/ Year(4)	Annual MWh	Project MWh
In-Front-of-the-Meter	1 Peaker Replacement	20	100	400	1	350	140,000	2,800,000
In-Front-of-the-Meter	2 Distribution	20	10	60	1	350	21,000	420,000
In-Front-of-the-Meter	3 Microgrid	10	1	4	2	350	2,800	28,000
Behind-the-Meter	4 Commercial	10	0.125	0.25	1	250	62.5	625
Behind-the-Meter	5 Residential	10	0.005	0.01	1	250	2.5	25

= "Usable Energy"(5)

Source: Reproduced from Lazard's Levelized Cost of Storage Analysis – Version 3.0, page 9. https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf. *Emphasis added by Applied Economics Clinic.*

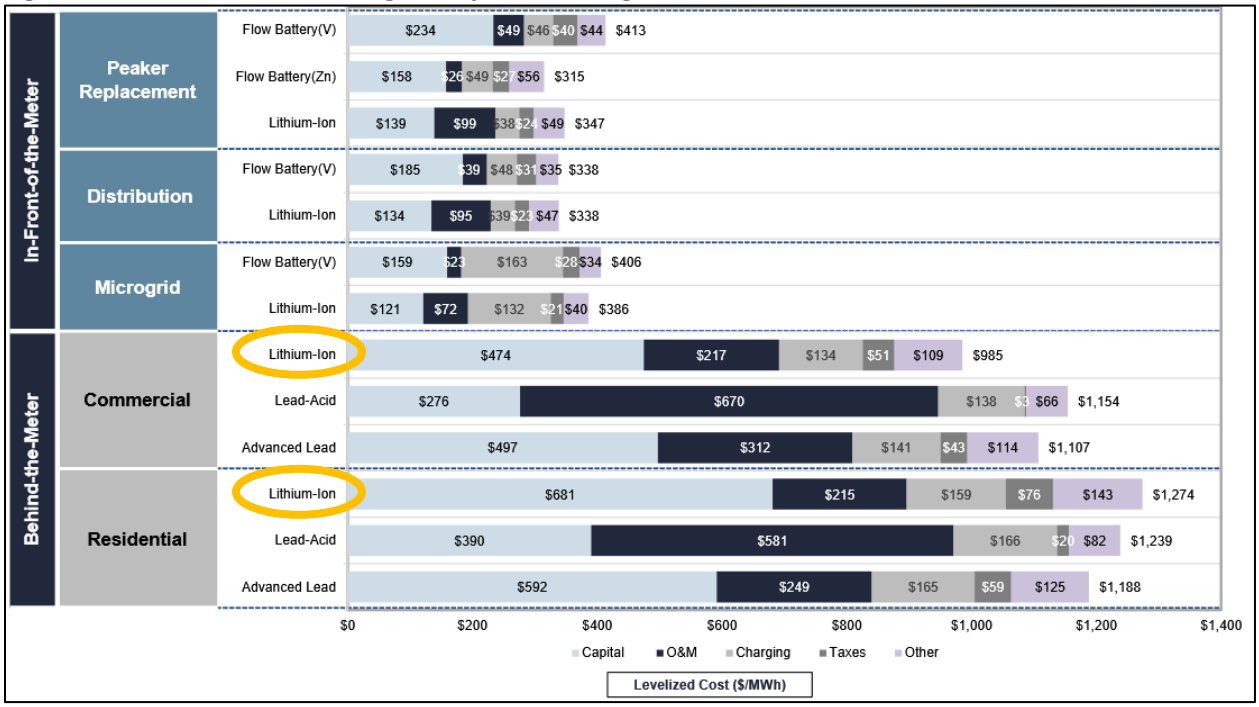
Figure 2 below presents Lazard's levelized cost of storage for Cases 4 and 5 according to their "high" component costs: capital, operations and maintenance (O&M), charging, taxes and other costs. In the calculations presented in this white paper, the following changes are made to Lazard's treatment of the components:

- Capital costs are de-escalated by 20 percent from the 2017 cost, following Lazard's assumption, to estimate the 2019 capital cost.

[3] Lazard. November 2017. *Lazard's Levelized Cost of Storage Analysis – Version 3.0*, page 8. https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf
[4] Ibid.

- Capital costs per MWh of battery capacity are adjusted to instead reflect capacity costs per MWh of use based on 52 days of use per year (that is, 52 full cycles per year—on average, one cycle per week) instead of the frequency of use shown in Figure 1.
- Charging costs are removed because, in Massachusetts, costs and savings related to the use of electricity are included in the benefits calculations of benefit-cost ratios. For measures—like storage—where on an annual basis megawatt-hours (MWhs) are lost instead of saved the net costs of charging are considered negative benefits. To include charging in these measures' levelized cost would be double counting.

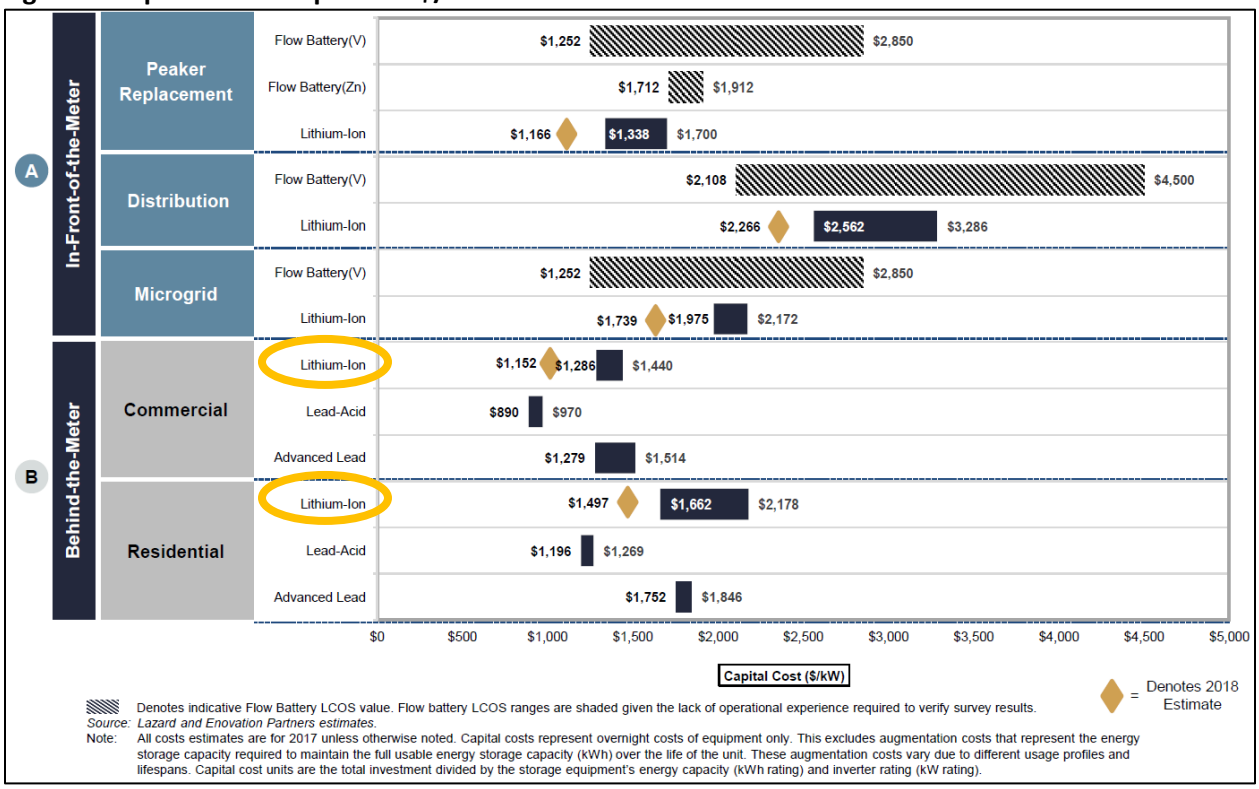
Figure 2. Levelized cost of storage components—high



Source: Reproduced from Lazard's Levelized Cost of Storage Analysis – Version 3.0, page 29. https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf. *Emphasis added by Applied Economics Clinic.*

Figure 2 and Figure 3 together show that Lazard's levelized capital costs of $474/MWh for commercial multi-family and $681/MWh for low-income single-family represent 1,440/kW for commercial and $2,178/kW for residential. When we reduce these costs by 20 percent for 2019, the per kW capital costs are $1,152/kW for multi-family and $1,742/kW for single-family.

Figure 3. Capital cost comparison: $/kW



Source: Reproduced from Lazard's Levelized Cost of Storage Analysis – Version 3.0, page 15. https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf. *Emphasis added by Applied Economics Clinic.*

3. Total Resource Cost

The total resource cost is calculated as the product of the measure or system life in years, the annual production in MWh, and the levelized cost in dollars per MWh, scaled proportionately to the kW size of the system being analyzed. These kW system sizes used in this report are: 6 kW for a single-family battery in the low-income efficiency program, and 30 kW for multi-family battery in the commercial and industrial efficiency program. In their "BCR Model" spreadsheets, National Grid assumes 2.5 kW for residential batteries, and Cape Light Compact assumes 5 kW for residential and 5 kW for commercial and industrial batteries. Eversource and Unitil do not include any system size measures in their "BCR Model" spreadsheets. Because technical assumptions regarding battery performance and cost are proportional to system size throughout these calculations, system size does not impact on cost-effectiveness.

For simplicity, a single system of each kind of measure (residential and commercial) is assumed for the calculations presented in this white paper. This should not be interpreted as a recommendation for how many measures the program administrators should strive to provide.

Using this method, total resource costs for each measure are $13,163 for low-income measures and $46,322 for commercial and industrial measures (see Table 1 below). It is important to note that these total resource costs represent levelized costs per MWh of battery discharge, not capital costs, and are estimated for the 10-year lifetime of the measures.

Table 1. Total resource cost

Parameter for 2019	Low-Income	C&I	Source
Quantity	1	1	
Measure Life	10	10	Lazard's Levelized Cost of Storage Analysis v.3.0 November 2017, p.9
Maximum Load Reduction (kW)	6	30	
Annual kWh Production (kWh)	624	3,120	Lazard's Levelized Cost of Storage Analysis v.3.0 November 2017, p.9
2019 Levelized Cost ($/MWh) without capital costs	$434	$377	Lazard's Levelized Cost of Storage Analysis v.3.0 November 2017, p.12, 14, 29; "high" cost of storage components; 2017 total cost per MWh less capital and charging costs
2019 capital cost ($/kW)	$1,742	$1,152	Lazard's Levelized Cost of Storage Analysis v.3.0 November 2017, p.15, "high" cost of storage components; 2017 capital cost less 10% per year per Lazard
Total Resource Cost ($)	**$13,163**	**$46,322**	**Calculation; multiplied by measure life**

Source: Applied Economics Clinic calculation

4. Energy Use by Time Period

The program administrators' "BCR Model" methodology has traditionally been used to estimate the benefits and costs of energy efficiency measures that reduce annual energy demand. While the methodology includes the apparatus and assumptions necessary to estimate benefits from peak shifting measures—such as batteries—that change the pattern of energy demand but do not lower the annual total, this is not the way these spreadsheets have typically been used. For a typical energy efficiency measure, the gross annual kWh savings would be a positive value, but for the battery storage measures shown here, they are negative, due to round-trip efficiency losses inherent in batteries. Batteries are typically charged at times of low demand or low energy price and discharged at times of high demand or high energy prices. If batteries had perfect round-trip efficiency (no energy was lost in storing and

discharging the battery), then gross annual kWh savings would equal zero. Energy out would equal energy in. However, Lazard assumes 15 percent efficiency losses for commercial batteries and 14 percent efficiency losses for residential batteries.[5] For this reason, gross annual kWh saved shows a loss, or negative value: negative 87.4 kWh for low-income and negative 468 kWh for commercial and industrial (see Table 2 below).

Table 2. Energy use by time period

Parameter for 2019	Low-Income	C&I	Source
EE: Gross Annual kWh Saved	(87.4)	(468.0)	Assume 15% efficiency loss for commercial; 14% for residential Lazard's Levelized Cost of Storage Analysis v.3.0 November 2017, p.31
Summer Peak Energy (%)	33.3%	33.3%	By assumption: representing a peak shifting measure
Summer Off-Peak Energy (%)	-33.3%	-33.3%	
Winter Peak Energy (%)	66.7%	66.7%	
Winter Off-Peak Energy (%)	-66.7%	-66.7%	
Summer Coincident (%)	100.0%	100.0%	MA PAs assumption
Winter Coincident (%)	100.0%	100.0%	By assumption
Summer Peak Energy MWh Net Lifetime	2.1	10.4	Changed PA calculation to refer to total peak MWh instead of total annual MWh savings/losses
Summer Off-Peak Energy MWh Net Lifetime	-2.4	-12.2	Changed PA calculation to refer to total off-peak MWh instead of total annual MWh savings/losses; off peak calculated as 100%/(1-efficiency rate)
Winter Peak Energy MWh Net Lifetime	4.2	20.8	Changed PA calculation to refer to total peak MWh instead of total annual MWh savings/losses
Winter Off-Peak Energy MWh Net Lifetime	-4.8	-24.5	Changed PA calculation to refer to total off-peak MWh instead of total annual MWh savings/losses; off peak calculated as 100%/(1-efficiency rate)

Source: Applied Economics Clinic calculations

[5] Lazard. November 2017. *Lazard's Levelized Cost of Storage Analysis – Version 3.0*, page 31. https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf

The program administrators' "BCR Model" takes the annual kWh saved and divides it into four time-periods—summer peak, summer off-peak, winter peak, winter off-peak—totaling 100 percent. For example, National Grid's new residential buildings high-rise lighting measure is assumed to have annual savings allocated as follows: 12.9 percent summer peak, 15.2 percent summer off-peak, 36.3 percent winter peak, and 35.6 percent winter off-peak.

Alternatively, for a storage measure, the assumption used in this white paper is that energy is subtracted from energy demand during summer and winter peak (a negative percentage) and added on to demand during summer and winter off-peak (a positive percentage), adding up to zero across the four time-periods. (Efficiency losses are included in the calculation of gross annual kWh saved and are therefore not included in these shares to avoid double counting.) The values use in these calculations (shown in Table 2) are 33.3 percent summer peak and 66.7 percent winter peak, negative 33.3 percent summer off-peak and negative 66.7 percent winter off-peak, and 100 percent summer and winter coincident.[6] This is equivalent to assumption an equal use of the battery in every month of the year (where summer is assumed to last for four months, and winter for eight months).

Based on these assumptions, the avoided energy over a ten-year system life from a 6 kW low-income single-family battery is: 2.1 MWh of summer peak energy and 4.2 MWh of winter peak energy, and negative 2.4 MWh of summer off-peak energy and negative 4.8 MWh of winter off-peak energy. The avoided energy over a ten-year system life from a 30 kW commercial multi-family battery is: 10.4 MWh of summer peak energy and 20.8 MWh of winter peak energy, and negative 12.2 MWh of summer off-peak energy and negative 24.5 MWh of winter off-peak energy (see Table 2 above).

5. Avoided-Energy Benefits

Avoided-energy benefits are the product of avoided energy (in MWh) and avoided energy prices, as calculated in the *Avoided Energy Supply Components in New England: 2018 Report* (AESC 2018).[7] Avoided energy prices are calculated on an hourly basis in AESC 2018 and then aggregated to summer peak, summer off-peak, winter peak, winter off-peak. The average energy prices for these time periods, by year, are very sensitive to changes in the assignment of hours as peak or off-peak. AESC 2018 follows the definition of peak as 9 am to 11 pm each weekday (excluded holidays) for both summer (four months) and winter (eight months). This broad definition of "peak" is not useful in representing the strategic use of batteries to relieve tight energy markets in periods of high energy demand or high energy prices.

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[6] Program administrators hard-code a winter coincidence to peak of 0 percent (see "BCR Model" spreadsheets, 'ADMYr1 tab, AE4:AE123).

[7] Synapse Energy Economics. June 1, 2018. Avoided Energy Supply Components in New England: 2018 Report. http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf

As shown in Table 3, redefining peak as those hours with the highest energy prices or highest MWh sales results in a very different allocation of hours between summer peak, summer off-peak, winter peak, winter off-peak. By energy price, all but one of the highest priced hours are in the winter months, and 43 percent of these are off-peak. By demand, 28 percent are in winter and 48 percent of these are off-peak.

Table 3. Peak/Off-peak hours for 2019

		Highest 10% by	
	Total Count	Energy Price	MWh
Summer peak	1,260	0	317
Summer offpeak	1,668	1	313
Winter peak	2,565	502	128
Winter offpeak	3,267	373	118

Source: Applied Economics Clinic calculations

Table 4 demonstrates how average energy prices change based on each of these definitions. The average avoided energy price for winter peak is $47 under the AESC 2018 definition of peak, $80 under the definition of peak as those hours with the highest energy prices, and $73 under the definition of peak as those hours with the highest MWh sales. The average avoided energy price for winter off-peak is $42 under the AESC 2018 definition of peak, $78 under the definition of peak as those hours with the highest energy prices, and $75 under the definition of peak as those hours with the highest MWh sales.

The average avoided energy price for summer peak is $31 under the AESC 2018 definition of peak and $37 under the definition of peak as those hours with the highest MWh sales. The average avoided energy price for summer off-peak is $27 under the AESC 2018 definition of peak, $69 under the definition of peak as those hours with the highest energy prices, and $36 under the definition of peak as those hours with the highest MWh sales.

Table 4. Peak/Off-peak energy prices for 2019

		Highest 10% by	
	Total Count	Energy Price	MWh
Summer peak	$31	n/a	$37
Summer offpeak	$27	$69	$36
Winter peak	$47	$80	$73
Winter offpeak	$42	$78	$75

Source: Applied Economics Clinic calculation

Table 5 and Table 6 below present avoided-energy benefits using two different definitions.

Table 5 presents avoided-energy benefits using the AESC 2018 definition of peak; benefits are negative for both storage measures, meaning a cost to the electric system: -$22 for low-income single-family and -$138 for commercial multi-family.

Table 5. Avoided energy benefits: AESC 2018 definition of peak

Parameter for 2019	Low-Income	C&I	Source
Summer Peak Energy Benefits ($)	$113	$563	Changed PA calculation to refer to total peak MWh instead of total annual MWh; corrected erroneous cell reference to wrong avoided costs
Summer Off-Peak Energy Benefits ($)	(113.0)	(572.0)	Changed PA calculation to refer to total off-peak MWh instead of total annual MWh; off peak calculated as 100%/(1-efficiency rate); corrected erroneous cell reference to wrong avoided costs
Winter Peak Energy Benefits ($)	$288	$1,440	Changed PA calculation to refer to total peak MWh instead of total annual MWh; corrected erroneous cell reference to wrong avoided costs
Winter Off-Peak Energy Benefits ($)	($310)	($1,569)	Changed PA calculation to refer to total off-peak MWh instead of total annual MWh; off peak calculated as 100%/(1-efficiency rate); corrected erroneous cell reference to wrong avoided costs
Total Avoided Energy Benefits ($)	**($22)**	**($138)**	**Sum**

Source: Applied Economics Clinic calculation; cell references corrected in "BCR Model" spreadsheets, 'ADMStrategies' tab.

Table 6 presents avoided-energy benefits using the percent of hours by energy price definition that is consistent with discharging an average of one time per week: the highest 2.2 percent of hours by energy price in winter and the highest 5.0 percent of hours by energy price in summer. Following this method, batteries would have time to charge in between each discharge. In addition, discharges occur during times of highest energy prices. With just 52 discharges per year, it is possible to select times of very high energy prices, and still have time to charge between each discharge. Using this definition, benefits are positive for both storage measures—meaning a positive benefit to the system: $162 for low-income single-family and $787 for commercial multi-family.

Table 6. Avoided energy benefits: Discharging 52 times per year

Parameter for 2019	Low-Income	C&I	Source
Summer Peak Energy Benefits ($)	$136	$682	With peak definition adjusted to match 52 discharges per year
Summer Off-Peak Energy Benefits ($)	($119)	($602)	
Winter Peak Energy Benefits ($)	$461	$2,305	
Winter Off-Peak Energy Benefits ($)	($316)	($1,598)	
Total Avoided Energy Benefits ($)	**$162**	**$787**	**Sum**

Source: Applied Economics Clinic calculation

6. Avoided-Energy DRIPE Benefits

Demand reduction induced price effects (DRIPE) are defined in AESC 2018 as "the reduction in prices in the wholesale markets for capacity and energy, relative to the prices forecast in the Reference case, resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period."[8] Avoided-energy DRIPE benefits are the product of avoided energy and avoided-energy DRIPE as presented in AESC 2018.

The avoided-energy DRIPE benefits presented in Table 7 have been adapted to the definition of peak as the highest 10 percent by energy price, although this change makes relatively little difference to the resulting benefits. Benefits are positive for both storage measures, meaning a positive benefit to the system: $38 for low-income single-family and $185 for commercial multi-family.

[8] Synapse Energy Economics. June 1, 2018. "Avoided Energy Supply Components in New England: 2018 Report". Page 13. http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf.

Table 7. Avoided-energy DRIPE benefits

Parameter for 2019	Low-Income	C&I	Source
Summer Peak Energy DRIPE Benefits ($)	$41	$206	Changed PA calculation to refer to total peak MWh instead of total annual MWh saved/lost; corrected erroneous cell reference to wrong avoided costs
Summer Off-Peak Energy DRIPE Benefits ($)	($33)	($165)	Changed PA calulation to refer to total off-peak MWH instead of total annual MWh saved/lost; off-peak calculated as 100$/(1-efficiency rate); corrected erroneous cell reference to wrong avoided costs
Winter Peak Energy DRIPE Benefits ($)	$126	$631	Changed PA calculation to refer to total peak MWH instead of total annual MWh saved/lost; corrected erroneous cell reference to wrong avoided costs
Winter Off-Peak Energy DRIPE Benefits ($)	($85)	($429)	Changed PA calculation to refer to total off-peak MWH instead of total annual MWh saved/lost; off-peak calculated as 100$/(1-efficiency rate); corrected erroneous cell reference to wrong avoided costs
Energy Electric Cross DRIPE Benefits ($)	($11)	($58)	
Total Energy DRIPE Benefits ($)	**$38**	**$185**	**Sum**

Source: Applied Economics Clinic calculations

7. Avoided-Capacity Benefits

The program administrator's "BCR Model" awards measures with benefits based on avoided costs of summer generation capacity, winter generation capacity, electric capacity DRIPE, transmission, distribution, and reliability—together referred to as "avoided-capacity benefits." The benefits shown in Table 8 are calculated following the program administrator's methodology exactly with one important change: the program administrator's assumption of a winter capacity value of $0/kW for storage measure has been adjusted to the AESC 2018 un-cleared capacity value by year.[9] The sum of all avoided-

[9] Un-cleared capacity chosen as a proxy to replace zero values. Program administrators hard-code a winter capacity value of $0/kW (see "BCR Model" spreadsheets, 'Avoided Cost' tab, O9:O40), which applies to both energy efficiency and advanced demand management measures.

capacity benefits for the two storage measures is positive, $30,861 for low-income single-family and $154,300 for commercial multi-family.

Table 8. Avoided-capacity benefits

Parameter for 2019	Low-Income	C&I	Source
Summer Generation Capacity Benefits ($)	$2,586	$12,928	
Winter Generation Capacity Benefits ($)	$2,586	$12,928	Changed PA calculation to use uncleared capacity value per kW instead of $0. Note that PAs assign winter generation a value of $0/kW for all measures.
Electric Capacity DRIPE Benefits ($)	$14,362	$71,810	
Transmission Benefits ($)	$2,491	$12,454	
Distribution Benefits ($)	$8,342	$41,708	
Reliability Benefits ($)	$494	$2,472	
Total Electric Capacity Benefits ($)	**$30,861**	**$154,300**	**Sum**

Source: Applied Economics Clinic calculations

8. Avoided-Non-Energy Benefits

The program administrators' "BCR Model" assigns non-energy benefits to numerous energy efficiency measures based on the *Massachusetts Program Administrators' Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts Evaluation*.[10] Table 9 lists non-energy benefits for which monetary values were provided in the 2011 Evaluation; marked in green are the subset of these benefits assigned to measures in the program administrator's 2019-2021 April draft plan.

[10] Massachusetts Program Administrators. 2011. *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation*. http://ma-eeac.org/wordpress/wp-content/uploads/Special-and-Cross-Sector-Studies-Area-Residential-and-Low-Income-Non-Energy-Impacts-Evaluation-Final-Report.pdf

Table 9. Avoided-non-energy benefits

NEI	Duration
UTILITY PERSPECTIVE	
Arrearages	Annual
Bad debt write-offs	Annual
Terminations and reconnections	Annual
Rate discounts	Annual
Customer calls	Annual
Collections notices	Annual
Safety-related emergency calls	Annual
Insurance savings	—
SOCIETAL PERSPECTIVE	
National Security	Annual
NON-RESOURCE BENEFITS	
Appliance Recycling – Avoided landfill space	One time
Appliance Recycling – Reduced emissions due to recycling plastic and glass, reduced emissions	One time
Appliance Recycling – Reduced emissions due to incineration of insulating foam	One time
PARTICIPANT PERSPECTIVE (OWNERS OF LOW-INCOME RENTAL HOUSING), PER HOUSING UNIT	
Marketability/ease of finding renters	Annual
Reduced tenant turnover	Annual
Property value	One time
Equipment maintenance (heating and cooling systems)	Annual
Reduced maintenance (lighting)	Annual
Durability of property	Annual
Tenant complaints	Annual
PARTICIPANT PESPECTIVE (OCCUPANT)	
Higher comfort levels	Annual
Quieter interior environment	Annual
Lighting quality & lifetime	One time
Increased housing property value	One time (Annual for NLI RNC)
Reduced water usage and sewer costs (dishwashers)	Annual
Reduced water usage and sewer costs (faucet aerators)	Annual
Reduced water usage and sewer costs (low flow showerheads)	Annual
More durable home and less maintenance	Annual
Equipment and appliance maintenance requirements	Annual
Health related NEIs	Annual
Improved safety (heating system, ventilation, carbon monoxide, fires)	Annual
Window AC NEIs	Annual

**** Green cells showing the Benefits in April Draft of 2019-2021 Plan**

Source: Massachusetts Program Administrators. 2011. Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation. *Emphasis added by Applied Economics Clinic.*

While storage may provide many non-energy benefits, our literature review did not turn up any valuations of these benefits (see Table 10).

Table 10. Non-energy benefits sources reviewed

Eichman et al. December 2015. "Operational Benefits of Meeting California's Energy Storage Targets." National Renewable Energy Laboratory.
Edmunds et al. February 2017. "The Value of Energy Storage and Demand Response for Renewable Integration in California." Lawrence Livermore National Laboratory.
Edmunds et al. June 2013. "The Value of Energy Storage and Demand Response for Renewable Integration in California." Prepared for the California Energy Commission by Lawrence Livermore National Laboratory.
Energy Storage Association. 2018. "Incidental and Other Benefits." http://energystorage.org/energy-storage/energy-storage-benefits/benefit-categories/incidental-and-other-benefits
Hledik, et al. 2017. "Stacked Benefits: Comprehensively Valuing Battery Storage in California." Prepared for Eos Energy Storage.
Lazard. 2017. "Lazard's Levelized Cost of Storage Analysis – Version 3.0."
Massachusetts Department of Energy Resources and Massachusetts Clean Energy Center. 2016. "State of Charge: Massachusetts Energy Storage Initiative."
Massachusetts Program Administrators. 2011. "Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation." NMR Group, Inc.
Medina et al. 2014. "Electrical Energy Storage Systems: Technologies' State-of-the-Art, Techo-Economic Benefits and Applications Analysis." 47th Hawaii International Conference on System Sciences.
New York Department of Public Service. July 2015. "Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding." Paper No. 14-M-0101.
NMR Group, Inc. August 2011. "Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation." Prepared for Massachusetts Program Administrators.
ReOpt Web Tool User Manual. https://reopt.nrel.gov/tool/REopt%20Lite%20Web%20Tool%20User%20Manual.pdf
Stark et al. February 2015. "Renewable Electricity: Insights for the Coming Decade." Prepared by Joint Institute for Strategic Energy Analysis for the National Renewable Energy Laboratory.
U.S. Energy Information Administration. 2018. "U.S. Battery Storage Market Trends." U.S. Department of Energy.
Woolf et al. September 2014. "Benefit-Cost Analysis for Distributed Energy Resources." Advanced Energy Economy Institute and Synapse Energy Economics.

Therefore, the calculations presented in this white paper include only one non-energy benefit: a one-time increase to property values of adding a storage system. These values are calculated using the "low-income" benefit from the 2011 Evaluation for a heating retrofit: which was reported to be $949 in the *Massachusetts Program Administrators' Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts Evaluation*. The sum of all avoided-non-energy benefits for the two storage measures is positive, $5,235 for low-income single-family and $510 for commercial multi-family (see Table 11).

Table 11. Avoided-non-energy benefits

Parameter for 2019	Low-Income	C&I	Source
One time per Unit (Net)	**$5,235**	**$510**	Massachusetts' Program Administrators' Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts Evaluation August 15, 2011; p.1-6, 1-8: Increased housing property value is $949 for LI; for multi-family property owners (marketability/ease of finding renters, property value; equipment maintenance) is $17.03 per unit Electric State-wide Cost and Savings Table for 2011: LI 1-4 family heating retrofit TRC for one measure is $1,895; for multi-family $1,155 Resulting assumption: LI housing property value increase by 1/2 of measure capital cost for single-family and 1% for owners of multi-family

Source: Applied Economics Clinic calculations

Avoided-non-energy benefits are the only benefit category in this cost-effectiveness assessment that would change if these batteries were offered in a residential efficiency program, and not in a "low-income" or means-tested program.

9. Avoided Non-Embedded Environmental Costs

Avoided non-embedded-costs are the product of avoided emissions and the avoided cost of emissions from AESC 2018. These avoided costs are "non-embedded" in the sense that they are externality costs: costs that are not included in market prices but have value to Massachusetts. In the program administrators' "BCR Model" spreadsheets' non-embedded costs are set to zero; the benefit-cost ratios present below adopt this same assumption of zero non-embedded environmental costs.

The section presents the benefits that would occur if non-embedded costs instead included a $100 per metric ton cost of carbon dioxide (CO_2), the lower of two non-embedded CO_2 costs provided in AESC 2018. Here, AESC 2018's definition of peak is important in two ways.

First, AESC 2018 assumes (as a result of its modeling of the hourly dispatch of New England electric generation resources) that CO_2 emissions rates (lbs/MWh) are higher in off-peak hours than they are in peak hours (see Table 12).

Table 12. Electric-sector CO_2 and NO_x emissions rate (lbs/MWh)

	Winter		Summer	
	On Peak	*Off Peak*	*On Peak*	*Off Peak*
CO_2	978	999	952	959
NO_X	0.212	0.241	0.173	0.180

Note: Emissions rates do not vary substantially across years.
Source: EnCompass modeling outputs for main 2018 AESC case

Source: Avoided Energy Supply Components in New England: 2018 Report by Synapse Energy, Inc. Table 150. http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf.

This finding runs counter to the more common assumption that, in New England, CO_2 emissions rates are lower in off-peak hours and higher in peak hours. ISO-New England reported higher peak than off-peak emissions in is its 2016 annual emissions report (see Table 13), which has held true in the last two years (see Figure 4).

Table 13. 2016 LMU Marginal Emission Rates—All LMUs (lb/MWh)

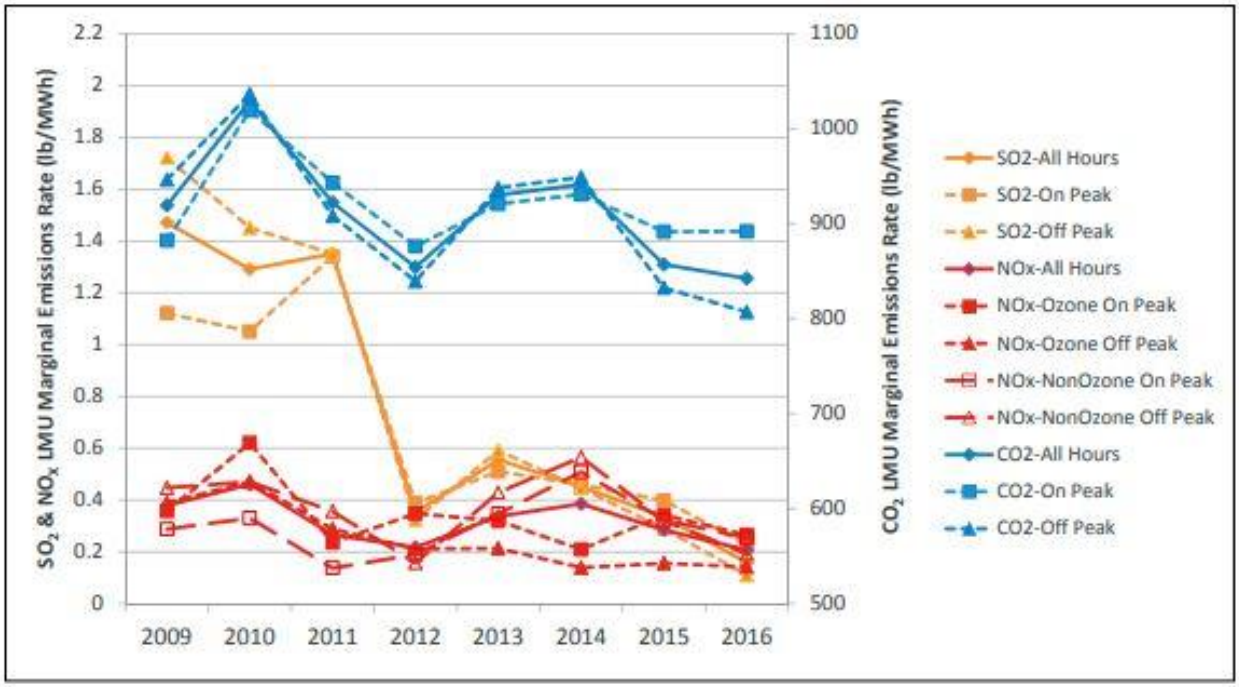
Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.26	0.14	0.25	0.19	0.21
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.22	0.11		0.16
CO_2		892	807		842

(a) The ozone season occurs between May 1 and September 30, while the non-ozone season occurs from January 1 to April 30 and from October 1 to December 31.

(b) On-peak hours consist of all weekdays between 8:00 a.m. and 10:00 p.m. Off-peak hours consist of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours.

Source: ISO-NE 2016 Emissions Report, Table 5-3. https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf.

Figure 4. 2009-2016 Marginal Emissions Rates, all LMUs (lb/MWh)



Source: ISO-NE 2016 Emissions Report, Table 5-9. https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf.

Second, the definition of peak impacts not only energy prices (see Table 3 and Table 4 above) but also the average emissions rates for these periods. The calculations presented in this white paper do not include any correction or revised definition with regards to emission rates. The necessary data are not available in the AESC 2018 report or user interface.

Both Table 14 and Table 15 present avoided non-energy-costs using AESC 2018's definition of peak. Table 14 presents avoided non-embedded costs using the AESC 2018 peak and off-peak emission rates; benefits are negative for both storage measures—meaning a cost to the system: -$51 for low-income single-family and -$270 for commercial multi-family.

Table 14. Avoided-non-embedded costs: AESC 2018 peak and off-peak emissions rates

Parameter for 2019	Low-Income	C&I	Source
Summer Peak Energy Benefits ($)	$90	$452	Changed PA calculation to refer to total peak MWh instead of total annual MWh; changed peak and off-peak CO2 emissions rates
Summer Off-Peak Energy Benefits ($)	($106)	($535)	Changed PA calculation to refer to total off-peak MWh instead of total annual MWh; off peak calculated as 100%/(1-efficiency rate); changed peak and off-peak CO2 emissions rates
Winter Peak Energy Benefits ($)	$186	$930	Changed PA calculation to refer to total peak MWh instead of total annual MWh; changed peak and off-peak CO2 emissions rates
Winter Off-Peak Energy Benefits ($)	($221)	($1,117)	Changed PA calculation to refer to total off-peak MWh instead of total annual MWh; off peak calculated as 100%/(1-efficiency rate); changed peak and off-peak CO2 emissions rates
Total Avoided Non-Embedded Benefits ($)	**($51)**	**($270)**	**Sum**

Source: Applied Economics Clinic calculations

Table 15 presents avoided non-energy-costs using the peak and off-peak emission rates for ISO-New England's 2018 emissions report; benefits are negative (but smaller) for both storage measures, meaning a cost to the system: -$12 low-income single-family and -$83 for commercial multi-family.

Table 15. Avoided-non-embedded costs: ISO-New England peak and off-peak emissions rates

Parameter for 2019	Low-Income	C&I	Source
Summer Peak Energy Benefits ($)	$85	$423	With peak / offpeak emission rates changed to 2016 ISO-NE values: 2016 ISO New England Generator Air Emissions Report, January 2018, Table 5-3, https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf
Summer Off-Peak Energy Benefits ($)	($89)	($451)	
Winter Peak Energy Benefits ($)	$170	$848	
Winter Off-Peak Energy Benefits ($)	($178)	($903)	
Total Avoided Non-Embedded Benefits ($)	**($12)**	**($83)**	**Sum**

Source: Applied Economics Clinic calculations

In the total benefits and benefit-cost ratios presented below, non-embedded environmental costs are set to zero, following the program administrators' "BCR Model" assumption.

10. Total Benefits

Table 16 sums up total benefits for these two storage measures assuming the peak definite of highest 10 percent of hours by energy price for energy benefits, non-energy impacts for low-income households, and zero non-embedded environmental costs. For low-income single-family measure, $36,296; for commercial multi-family measure, $155,782.

Table 16. Total benefits

Parameter for 2019	Low-Income	C&I
Total Avoided Energy Benefits ($)	$162	$787
Total Energy DRIPE Benefits ($)	$38	$185
Total Electric Capacity Benefits ($)	$30,861	$154,300
Total Non-Energy Impacts ($)	$5,235	$510
Total Avoided Non-Embedded Benefits ($)	$0	$0
Total Electric Benefits ($)	**$36,296**	**$155,782**

Source: Applied Economics Clinic calculations

11. Benefit-Cost Ratio

Based on the assumptions and methodology presented in this white paper, the benefit-cost ratio for the low-income single-family measure is 2.8 (that is, the value of benefits is nearly three times that of the costs, see Table 17) and the benefit-cost ratio for the commercial multi-family measure is 3.4. Both measures pass the cost-effectiveness test for Massachusetts.

Table 17. Total benefits and costs

Parameter for 2019	Low-Income	C&I
Total Electric Benefits ($)	$36,296	$155,782
Total Resource Cost ($)	$13,163	$46,322
Benefit-Cost Ratio	**2.8**	**3.4**

Source: Applied Economics Clinic calculations

If avoided-non-energy benefits were removed from these calculations, their benefit-cost ratios would be reduced to 2.4 for the single-family battery and 3.4 for the multi-family battery.

Appendix 2

MASSACHUSETTS BATTERY STORAGE MEASURES: BENEFITS AND COSTS, UPDATED APRIL 2019

Massachusetts Battery Storage Measures: Benefits and Costs

Updated April 2, 2018 – White Paper

Applied Economics Clinic

Prepared for:

Clean Energy Group

Author:

Elizabeth A. Stanton, PhD

www.aeclinic.org

April 2, 2019

[AEC-2019-04-WP-01]

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Acknowledgements

This report was commissioned by Clean Energy Group in support of its efforts to expand the benefits of energy storage and clean energy technologies. The Applied Economics Clinic would like to thank Todd Olinsky-Paul, Project Director at the Clean Energy Group, for comments and input that greatly improved this report.

Executive Summary

On January 29, 2019, the Massachusetts Department of Public Utilities (DPU) approved—with some exceptions and limitations—program administrators' 2019-2021 three-year energy efficiency plan. The program administrators' plan includes incentives for battery storage along with cost-effectiveness assessment of these storage measures. This Applied Economics Clinic white paper updates the July 2018 white paper[1] of the same name: The July 2018 white paper reviewed the program administrators' April 2018 cost-effectiveness assessment and provided an independent cost-effectiveness analysis whereas this white paper reviews program administrators' final assessment submitted October 31, 2018. The October assessment of battery storage measures' specifications, associated programs, and related costs differ substantially from the plans submitted in April.[2]

This white paper reviews the methodology, assumptions, and results of the cost-effectiveness assessment of storage measures presented in the approved 2019-2021 plan and the assessment of battery measures that was submitted to DPU by Cape Light Compact but not approved, including discussion of:

- ***Measure specification:*** Program administrators' storage measures differ, and these differences impact on cost-effectiveness. Nonetheless, almost all of the included active demand response programs are cost effective.
- ***Inclusion of measures in the final plan:*** Program administrators' way of presenting storage measure adoption is inconsistent and sometimes difficult to interpret. With that limitation in mind, the approved 2019-2021 plan appears to include battery storage equivalent to 0.1 to 0.5 percent of peak load, depending on electric distributor (for a total of about 34 megawatts of storage statewide).
- ***Improvements to April draft plan:*** Corrections to program administrators' April draft cost-effectiveness assessments include the treatment of storage measures' charging and discharging periods, and the inclusion of a Massachusetts-specific cost of Global Warming Solutions Act compliance. These needed corrections were discussed in the July 2018 white paper.
- ***Critical omissions:*** Despite improvements and corrections, the final plan still includes several critical omissions in the program administrators' calculations of the benefit-cost ratios of

[1] Stanton, E.A. July 2018. *Massachusetts Battery Storage Measures: Benefits and Costs*. Applied Economics Clinic White Paper. AEC-2018-07-WP-02. https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs

[2] The July 2018 white paper does not apply to the final (October 31, 2018) version of Massachusetts' program administrator efficiency and storage plan.

storage, including the omission of any value related to non-energy benefits, the omission of any value related to winter reliability, and the undervaluing of summer capacity benefits.

The findings of this white paper are limited by the extent of information made available by the program administrators at the time of this writing.[3]While several of these issues likely have the effect of undervaluing benefits in storage measures' cost-effectiveness analysis, all program administrators have assessed the programs that include storage measures as cost-effective in all years (with the exception of Unitil in 2019).

The total Massachusetts summer peak capacity addition three-year plan offering for behind-the-meter storage was 34 MW, or two-fifths of the Commonwealth's assessed storage potential (84 MW). Nevertheless, these omissions should be corrected in future energy efficiency planning, to more completely and fairly evaluate the cost-effectiveness of behind-the-meter energy storage.

[3] Somewhat more detailed descriptions of Massachusetts' storage measures have been made available in two March 2019 presentations to the Energy Efficiency Advisory Council: Schlegel, J. March 20, 2019. *Active Demand Management: Where Are We Now Plus A Look Ahead.* Slide presentation by the EEAC Consultant Team to the Massachusetts Energy Efficiency Advisory Council. Available at: http://ma-eeac.org/march-20-eeac-meeting/; Massachusetts Energy Efficiency Program Administrators. March 20, 2019. *Active Demand Reduction Demonstration & Initiative Update.* Slide presentation by the EEAC Consultant Team to the Massachusetts Energy Efficiency Advisory Council. Available at: http://ma-eeac.org/march-20-eeac-meeting/;

1. Introduction

Lithium-ion batteries for electric storage are considered in Massachusetts' energy efficiency program administrator's 2019-2021 plan, last updated October 31, 2018,[4] and addressed in the "BCR Model" spreadsheets (provided in November 2018) used to calculate the values in the approved plan and in the assessment of battery measures submitted by Cape Light Compact but not approved. Massachusetts' assessment of electric demand and peak-reducing measures' cost-effectiveness depends on the "BCRs"—or benefit-cost ratios—estimated in these spreadsheets. For measures to be included in the funding allocation and program implementation described in the 2019-2021 plan, they must receive a benefit-cost ratio of 1.0 or higher; that is, a measure's benefits must have a higher value than its costs.[5]

This Applied Economic Clinic white paper reviews the calculations and assumptions used by program administrators to estimate complete 2019-2021 benefit-cost ratios for battery storage measures in Massachusetts, according to the methodology shown in program administrator's own "BCR Model" spreadsheets for the October 31, 2018 plan.[6]

Massachusetts program administrators' benefit-cost ratios for 2019 range from 0.0 to 6.2 for individual storage measures (benefit-cost ratios of 1.0 and higher indicate cost-effectiveness) and from 0.7 to 7.9 for the advanced demand management programs (called "active demand reduction" or ADR in the approved three-year plan) that include storage measures. Only one ADR program (that is, the group of measures considered jointly) for one utility in one year (Unitil's residential ADR program for 2019) failed to achieve cost-effectiveness. All other utility storage-related programs for all years were found to be cost effective.

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[4] Massachusetts Department of Public Utilities. Docket Nos. 18-116, 18-117, 18-118, 18-119. *Three Year Energy Efficiency Plan for 2019 through 2021.* October 31, 2018. "Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan: 2019-2021". Available at: http://ma-eeac.org/wordpress/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf

[5] The General Court of the Commonwealth of Massachusetts. 2008. Acts 308-80: *An Act Relative to Green Communities.* Chapter 169. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.

[6] This February 2019 AEC white paper updates a July 2018 white paper of the same name: Stanton. July 2018. *Massachusetts Battery Storage Measures: Benefits and Costs.* Applied Economics Clinic White Paper. AEC-2018-07-WP-02. https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs

Because the benefits of electric battery storage outweigh their costs, as shown in this report, these cost-effective measures must be offered by Massachusetts electric distributors to their customers, in accordance with the Green Communities Act.[7]

Each program administrator may offer three ADR programs—residential, income-eligible, and commercial/industrial. The Massachusetts program administrators have developed different battery measures (along with other ADR measures) to offer to their customers: System and Performance, Daily Dispatch, and Targeted Performance (discussed below). Storage cost effectiveness depends on measure specification.

Massachusetts energy efficiency program administrators' benefit-cost ratios for the ADR programs that include battery storage show cost-effectiveness (i.e., are greater than 1.0), with the exception of Unitil's residential program in 2019. Cost-effectiveness can be measured either at the program or the measure level. Massachusetts program administrators have three storage-related programs in parallel to the three programs offered for energy efficiency: residential, income-eligible, and commercial and industrial ADR (see Table 1). Each of these three programs can include three types of measures (described in more detail below): storage system and performance, storage daily dispatch, and storage targeted performance. Not every program administrator offers every measure type.

Table 1. MA program administrators' storage-related programs and measures

Programs	Measures
Residential Advanced Demand Management Program (A2e)	A2e Storage System and Performance
	A2e Storage Daily Dispatch
	A2e Storage Targeted Dispatch
Income-Eligible Advanced Demand Management Program (B1b)	B1b Storage System and Performance
	B1b Storage Daily Dispatch
	B1b Storage Targeted Dispatch
Commercial/Industrial Advanced Demand Management Program (C2c)	C2c Storage System and Performance
	C2c Storage Daily Dispatch
	C2c Storage Targeted Dispatch

Program cost-effectiveness is calculated as the summed benefits of measures in the program divided by the summed costs of these measures plus the costs of the program's administration. Storage program cost-effectiveness depends, therefore, on three factors: (1) the cost-effectiveness of the measures in the programs; (2) the composition of those measures (how many of each measure is included); and (3) the expected costs to administer the program.

[7] The General Court of the Commonwealth of Massachusetts. 2008. Acts 308-80: *An Act Relative to Green Communities*. Chapter 169. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169

Storage ***measure*** cost-effectiveness depends on the specification of these measures, and Massachusetts' program administrators have designed very different storage measures for inclusion in their final 2019-2021 plan.

Programs and measures not achieving cost-effectiveness are shown in orange text in Table 2.

Table 2. MA program administrators' benefit-cost ratios for ADR measures

BCRs	Cape Light			Eversource			National Grid			Unitil		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Residential Advanced Demand Management Program (A2e)												
Program BCRs	*1.6*	*2.4*	*2.4*	*1.0*	*1.4*	*1.6*	*1.5*	*2.4*	*2.5*	*0.7*	*1.1*	*1.2*
Direct Load Control	4.9	6.6	7.4	5.0	5.0	5.0	5.3	5.5	5.3	5.2	9.6	9.6
Behavioral DR												
Storage System and Performance		3.0	3.0									
Storage Daily Dispatch				1.5	1.5	1.5	4.9	4.9	5.0			
Storage Targeted Dispatch				0.0	0.0	0.0	0.1	0.1	0.1			
EV Load Management								0.8	0.8			
Income-Eligible Advanced Demand Management Program (B1b)												
Program BCRs		*2.3*	*2.4*					*2.4*	*2.4*			
Direct Load Control												
Behavioral DR												
Storage System and Performance		3.0	3.0									
Storage Daily Dispatch												
Storage Targeted Dispatch												
EV Load Management												
Commercial/Industrial Advanced Demand Management Program (C2c)												
Program BCRs	*7.5*	*4.6*	*4.7*	*2.9*	*2.9*	*2.8*	*7.9*	*4.8*	*4.9*	*2.7*	*2.9*	*3.1*
Interruptible Load	9.7	9.8	9.8	7.9	7.9	7.9	7.5	7.5	7.5	4.2	4.2	4.2
Winter Interruptible Load												
Storage System and Performance		3.0	3.0									
Storage Daily Dispatch				1.7	1.7	1.7	4.9	4.9	5.0	6.2	6.2	6.2
Storage Targeted Dispatch				3.2	3.2	3.2	0.1	0.1	0.1	0.1	0.1	0.1
Custom	8.3	8.3	8.3		2.0	2.0	1.3	1.3	1.3			

Note: Blank cells indicate that no measures were offered.

Among the battery storage measures offered by program administrators in their final 2019-2021 plan, only Eversource and National Grid's residential Storage Targeted Dispatch measures, and National Grid's commercial and industrial Storage Targeted Dispatch measure do not meet cost-effectiveness in all three years.

"Storage System and Performance" measures: Cape Light Compact's proposed storage measures differ from those of other program administrators and from the description of storage measures approved in the 2019-2021 plan. The Cape Light Compact proposed storage measures would provide 1,000 participants with free 4-kilowatt (kW) batteries and then manage the batteries' charging and discharge to reduce system peak demand without an additional incentive. (In contrast, the other program administrators' approved storage measures do not provide batteries to participants.) Cape Light Compact's proposed measures have a 10-year measure life.

"Storage Daily and Targeted Dispatch" measures: Eversource, National Grid, and Unitil's proposed storage measures use a "bring your own battery" structure: participants provide their own batteries and receive financial incentives for allowing the program administrators to send dispatch signals (to which either the customer or a third-party aggregator then respond):

> *The 2019-2021 Plan includes new statewide Active Demand Reduction Offerings for residential and commercial and industrial sectors designed to reduce summer and winter peak demand. Customers will earn an incentive for verifiably shedding load in response to events called by Program Administrators…The Program Administrators will offer a technology agnostic approach in order to encourage innovations and capture all cost-effective demand reductions. (2019-2021 3YP, p.9)*

> *[A] new bring-your-own device active demand reduction initiative that allows residential and income eligible customers to expand the use of controllable efficiency equipment that can provide demand reduction during peak hours;…a new specialized storage performance offering will provide enhanced incentives to customers to dispatch energy storage during daily peak hours in the summer and winter months. (2019-2021 3YP, p.14)*

The Eversource, National Grid, and Unitil "measures" are an incentive, not a battery. These incentives have a 1-year measure life.

While the System and Performance, and Daily Dispatch measures are cost-effective in all years, some Targeted Dispatch measures are not. Of program administrators' residential (Eversource and National Grid) and commercial and industrial (Eversource, National Grid, and Unitil) Targeted Dispatch measures, only one—Eversource's commercial and industrial measure—is cost-effective. Among Targeted Dispatch measures, Eversource's cost-effective commercial and industrial measure differs from the measures that are not cost-effective in one important regard: The cost-effective measure includes summer discharge and benefits, the others do not. The absence of summer discharge for certain measures raises questions regarding measure design that cannot be answer given current public materials. Greater transparency in providing detailed descriptions of each storage measure would facilitate third-party reviewers in offering useful critique and analysis, and could lead to improvements in measure design and selection.

The Targeted Dispatch measures, which (according to program administrators' BCR spreadsheets) are not dispatched in summer months, are assigned no benefit for their kW savings and cannot achieve cost-effectiveness.

2. Storage is included only minimally for some program administrators

The number of storage measures included in the final 2019-2021 plan is difficult to interpret and is not comparable among the program administrators (see Table 3).

Table 3. MA program administrators' number of measures for ADR measures

Number of Measrues	Cape Light			Eversource			National Grid			Unitil		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Residential Advanced Demand Management Program (A2e)												
Program Number of Measures	*1,918*	*4,242*	*4,984*	*5*	*5*	*5*	*10,609*	*14,464*	*18,154*	*170*	*204*	*245*
Direct Load Control	1,918	2,942	3,384	1	1	1	9,375	12,336	15,050	170	204	245
Behavioral DR												
Storage System and Performance		1,300	1,600									
Storage Daily Dispatch				2	2	2	420	820	1,254			
Storage Targeted Dispatch				2	2	2	420	820	1,254			
EV Load Management							393	488	596			
Income-Eligible Advanced Demand Management Program (B1b)												
Program Number of Measures		*300*	*400*									
Direct Load Control												
Behavioral DR												
Storage System and Performance		300	400									
Storage Daily Dispatch												
Storage Targeted Dispatch												
EV Load Management												
Commercial/Industrial Advanced Demand Management Program (C2c)												
Program Number of Measures	*215*	*529*	*578*	*8*	*9*	*9*	*7*	*7*	*7*	*6*	*8*	*8*
Interruptible Load	214	328	377	1	1	1	1	1	1	1	2	2
Winter Interruptible Load				1	1	1	1	1	1	1	2	2
Storage System and Performance		200	200									
Storage Daily Dispatch				2	2	2	2	2	2	2	2	2
Storage Targeted Dispatch				4	4	4	2	2	2	2	2	2
Custom	1	1	1		1	1	1	1	1			

Different program administrators appear to be using different definitions of a "storage measure" and may even be defining a "measure" differently for different sectors. Cape Light Compact's System and Performance measure is a single 4-kW battery provided to a participant together with the Compact's managed discharge of that battery. For Eversource, National Grid, and Unitil's commercial and industrial Daily and Targeted Dispatch measures, and for Eversource's residential Daily and Targeted Dispatch measures, the measure appears to be the aggregated managed discharge of all batteries signed up with the program. For National Grid and Unitil's residential Daily and Targeted Dispatch measures, however, the measure appears to be each battery signed up for the program (see Table 4). (That there is a difference between Cape Light Compact and National Grid's residential storage measures can be observed in their measures lives: 10 years for Cape Light Compact's battery provision measure and 1 year for National Grid's bring-your-own battery measure.)

Table 4. Definition of measure

	Cape Light	Eversource	National Grid	Unitil
Residential Advanced Demand Management Program (A2e)	Single battery provided	Aggregate of BYO batteries	Single BYO battery	Single BYO battery
Income-Eligible Advanced Demand Management Program (B1b)	Single battery provided	N/A	N/A	N/A
Commercial/Industrial Advanced Demand Management Program (C2c)	Single battery provided	Aggregate of BYO batteries	Aggregate of BYO batteries	Aggregate of BYO batteries

The Massachusetts Energy Efficiency Advisory Council's consultant team identified the potential for including 84.3 megawatts (MW) of summer peak behind-the-meter storage capacity in the 2019-2021 plan, and a total of 250 MW for all ADR programs. Table 5 presents the programs administrators' ADR offering in summer peak kW, from their October 31, 2018 filing. (Massachusetts' program administrators' winter storage offering is not the same as that for summer.) Here, again, the information provided is difficult to interpret and is not comparable among the program administrators. Eversource, National Grid, and Unitil's Daily and Targeted Dispatch measures have a one-year measure life and therefore the capacity additions do not accumulate. Cape Light Compact's System and Performance measures have a 10-year measure life and the summer peak capacity presented likely refers to annual incremental additions to storage capacity (i.e. new batteries given to participants in each year). Assuming that Cape Light Compact's summer capacity accumulates but the other program administrators' does not, the total Massachusetts summer peak capacity addition offering for behind-the-meter storage was 33.9 MW, or two-fifths of the consulting team's estimate of storage potential.

Table 5. MA program administrators' summer kW savings for ADR measures

Summer kW Savings	Cape Light			Eversource			National Grid			Unitil		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Residential Advanced Demand Management Program												
Program Summer kW Savings	*1,055*	*2,869*	*3,400*	*2,050*	*3,150*	*4,250*	*6,099*	*8,597*	*11,033*	*94*	*112*	*135*
Direct Load Control	1,055	1,618	1,861	2,000	3,000	4,000	5,156	6,785	8,278	94	112	135
Behavioral DR												
Storage System and Performance		1,250	1,539									
Storage Daily Dispatch				50	150	250	903	1,763	2,696			
Storage Targeted Dispatch												
EV Load Management							39	49	60			
Income-Eligible Advanced Demand Management Program												
Program Summer kW Savings		*289*	*385*									
Direct Load Control												
Behavioral DR												
Storage System and Performance		289	385									
Storage Daily Dispatch												
Storage Targeted Dispatch												
EV Load Management												
Commercial/Industrial Advanced Demand Management Program												
Program Summer kW Savings	*5,798*	*6,053*	*6,080*	*28,000*	*57,500*	*96,000*	*69,500*	*79,000*	*90,000*	*300*	*500*	*500*
Interruptible Load	5,395	5,458	5,485	27,000	47,000	75,000	66,000	72,000	79,000	200	400	400
Winter Interruptible Load												
Storage System and Performance		192	192									
Storage Daily Dispatch				500	5,000	10,000	2,500	5,000	7,000	100	100	100
Storage Targeted Dispatch				500	5,000	10,000						
Custom	403	403	403		500	1,000	1,000	2,000	4,000			

By program administrator, total summer capacity for storage measures is as follows:

- Cape Light Compact (adding together 2020 and 2021 as discussed above): 3.8 MW (not approved)
- Eversource: 20.3 MW
- National Grid: 9.7 MW
- Unitil: 0.1 MW
- **Total: 33.9 MW including Cape Light Compact; 30.1 MW without Cape Light Compact**

Eversource and Cape Light Compact's combined proposed storage measures amounted to 0.5 percent of Eversource's peak load (or 0.4 percent after removing Cape Light Compact's peak savings), National Grid's measures amount to 0.2 percent of its peak load, and Unitil's measures amount to 0.1 percent of its peak load.[8] For comparison, the Energy Efficiency Advisory Council's consultant team's estimated

[8] ISO-NE Regional Network Load data. August 2018. https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/reg-net-load-costs

potential storage capacity of 84.3 MW is 0.9 percent of Eversource, National Grid, and Unitil's combined summer peak load.

3. Improvements from the April draft storage benefit-cost analysis

Massachusetts' program administrators' approved cost-effectiveness analysis of storage measures offered in their final 2019-2021 plan includes several improvements over their April 2018 draft.[9]

Peak shifting

The April draft represented peak shifting by allocating peak energy (MWh) savings across four seasons (summer peak and off-peak, winter peak and off-peak), rather than explicitly showing charging and discharging in its calculations. The approved 2019-2021 plan instead treats both winter and summer, and charging and discharging as separate "measures."[10] This new method allows for a clearer accounting of what is and is not valued. It should be noted, however, that storage measures' benefit-cost ratios only have meaning for the aggregate of these four "measures" (summer charging, summer discharging, winter charging, winter discharging). The four "measures" together make up the storage measure as one would normally understand it.

Avoided non-embedded costs

The April draft assumes a $0 per metric ton non-embedded cost of carbon dioxide (CO_2). The final 2019-2021 plan includes the Massachusetts-specific avoid cost of Global Warming Solutions Act compliance as developed in the August 2018 supplement[11] to the *Avoided Energy Supply Components in New England: 2018 Report* (AESC 2018)[12]: $35 per short ton of CO_2. This adds to the measured benefits of storage.

[9] For a complete review of Massachusetts program administrators April 2018 draft 2019-2021 benefit-cost analysis for storage measures see: Stanton. July 2018. Massachusetts Battery Storage Measures: Benefits and Costs. Applied Economics Clinic White Paper. AEC-2018-07-WP-02. https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs

[10] Some program administrators' storage programs do not have savings in every season. The framework for calculating benefits reported in the three-year plans, however, is consistent across program administators.

[11] Knight, Pat, et al. August 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act: Supplement to 2018 AESC Study*. Prepared for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection. http://ma-eeac.org/wordpress/wp-content/uploads/MA-GWSA-Supplement-to-2018-AESC-Study.pdf

[12] Synapse. June 2018. *Avoided Energy Supply Components in New England: 2018 Report.* http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf

4. Remaining concerns from the April draft storage benefit-cost analysis

Some other issues presented in the July 2018 version[13] of this critique have not been addressed and remain concerns in the approved 2019-2021 plan:

Non-energy benefits are omitted

Program administrators did not include non-energy benefits (such as avoided utility costs, national security, benefits to landlords, increased property values, improved comfort levels, safety, and health, and reduced home maintenance) in their cost-effectiveness assessment of battery measures, although non-energy benefits such as these are included in the cost-effectiveness assessments of energy efficiency measures. This omission is discussed in Section 6.

Summer capacity values are undervalued

Program administrators include only one-tenth of the capacity prices associated with summer peak reductions from batteries in their cost-effectiveness assessment. This largely unexplained assumption is discussed in Section 6.

Winter reliability values are omitted

Program administrators assign a value of $0 to the reliability of Massachusetts' winter electric service in their cost-effectiveness assessment of battery measures. This omission is discussed in Section 6.

Peak versus off-peak emissions

Avoided non-embedded-costs are the product of avoided emissions and the avoided cost of emissions from AESC 2018. These avoided costs are "non-embedded" in the sense that they are externality costs: costs are that are not included in market prices but have value to Massachusetts. AESC 2018 assumes (as a result of its modeling of the hourly dispatch of New England electric generation resources) that CO_2 emissions rates (lbs/MWh) are higher in off-peak hours than they are in peak hours (see Table 6).

[13] Stanton. July 2018. Massachusetts Battery Storage Measures: Benefits and Costs. Applied Economics Clinic White Paper. AEC-2018-07-WP-02. https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs

Table 6. Electric-sector CO_2 and NO_x emissions rate (lbs/MWh)

	Winter		Summer	
	On Peak	*Off Peak*	*On Peak*	*Off Peak*
CO_2	978	999	952	959
NO_X	0.212	0.241	0.173	0.180

Note: Emissions rates do not vary substantially across years.
Source: EnCompass modeling outputs for main 2018 AESC case

Source: Avoided Energy Supply Components in New England: 2018 Report by Synapse Energy, Inc. Table 150. Available online at http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf.

This assumption runs counter to the more commonly used assumption that, in New England, CO_2 emissions rates are lower in off-peak hours, and higher in peak hours. Higher peak emissions are reported by ISO-New England is its 2016 annual emissions report (see Table 7) and have been so in the last two years as shown in Figure 1. The definition of peak impacts not only on energy prices but also on the average emissions rates for these periods.

Table 7. 2016 LMU Marginal Emission Rates—All LMUs (lb/MWh)

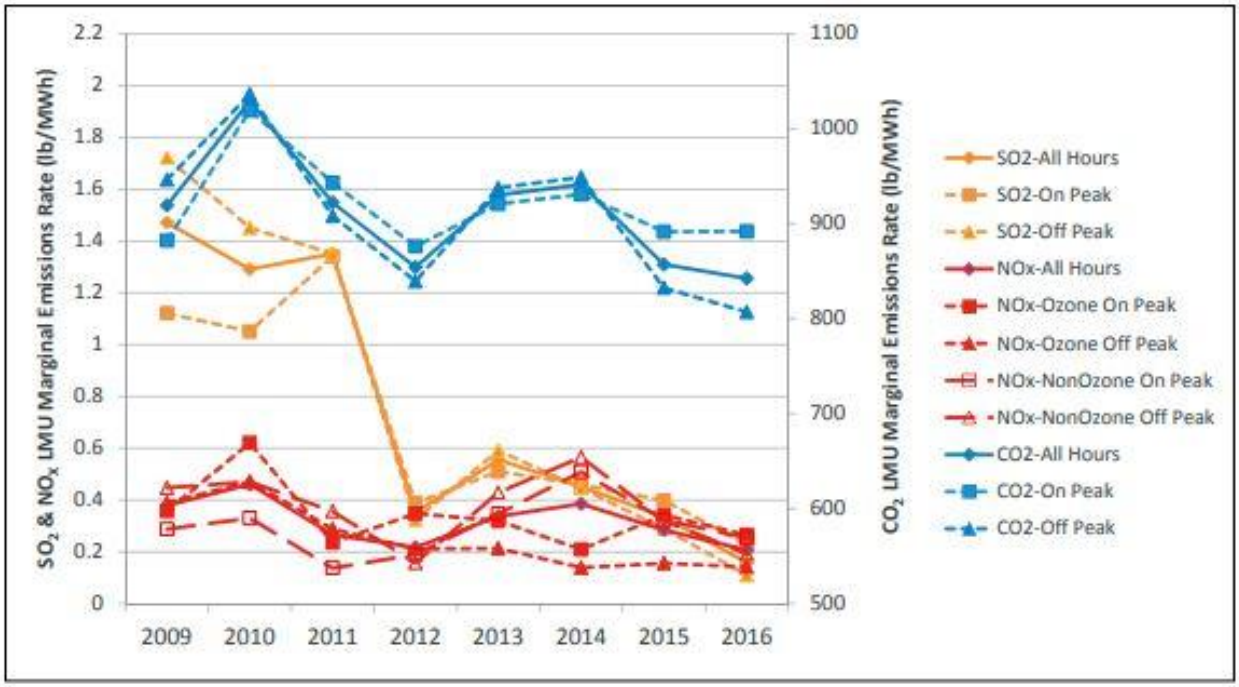
Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.26	0.14	0.25	0.19	0.21
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.22	0.11		0.16
CO_2		892	807		842

(a) The ozone season occurs between May 1 and September 30, while the non-ozone season occurs from January 1 to April 30 and from October 1 to December 31.

(b) On-peak hours consist of all weekdays between 8:00 a.m. and 10:00 p.m. Off-peak hours consist of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours.

Source: ISO-NE 2016 Emissions Report. Table 5-3. Available online at: https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf.

Figure 1. 2009-2016 Marginal Emissions Rates, all LMUs (lb/MWh)



Source: ISO-NE 2016 Emissions Report, Table 5-9. Available online at: https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf.

Program administrators' final plan continues to follow the AESC 2018 assumption that (contrary to ISO-New England historical data) New England generator's CO_2 emission rates are higher off-peak than on. The adoption of this unfounded assumption in program administrators' plan means that storage energy benefits, which include emissions benefits, are likely lower than they would otherwise be.

Average energy price by time period

Battery measures' avoided-energy benefits are the product of avoided energy (in MWh) and avoided energy prices, as calculated in AESC 2018. Avoided energy prices are calculated on an hourly basis in AESC 2018 and then aggregated to summer peak, summer off-peak, winter peak, winter off-peak. The average energy prices for these time periods, by year, are very sensitive to changes in the assignment of hours as peak or off-peak. AESC 2018 follows the definition of peak as from 9 am to 11 pm each weekday (excluded holidays) for both summer (four months) and winter (eight months).

As shown in

Table 8, redefining peak as those hours with the highest energy prices or highest MWh sales results in a very different allocation of hours between summer peak, summer off-peak, winter peak, winter off-peak. By energy price, all but one of the highest priced hours are in the winter months, and 43 percent of these are off peak. By demand, 28 percent are in winter and 50 percent of these are off peak.

Table 8. Peak/Off-peak hours for 2019

	Total Count	Highest 10% by	
		Energy Price	MWh
Summer peak	1,260	0	317
Summer offpeak	1,668	1	313
Winter peak	2,565	502	128
Winter offpeak	3,267	373	118

Source: Stanton. July 2018. Massachusetts Battery Storage Measures: Benefits and Costs. Applied Economics Clinic White Paper. AEC-2018-07-WP-02. https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs

The program administrators continue to assume average summer and winter, peak and off-peak, energy prices instead of using hourly data from AESC 2018 modeling to better identify energy prices during expected periods of charging and discharging for storage measures. The approved 2019-2021 plan continues this practice with the likely result that energy prices during periods of discharge are being undervalued in storage measures' cost-effectiveness assessments.

5. Critical omissions in October methodology

Three key methodological choices stand out as areas of particular concern in the cost-effectiveness assessments for storage measures presented in the final 2019-2021 plans: no value is assigned to non-energy benefits, summer capacity is undervalued, and no value is assigned to winter reliability.

Non-energy benefits valued at $0

In addition to energy benefits (avoided cost of: energy, generation capacity, transmission and distribution infrastructure, and emission permits), storage-related measures also provide non-energy benefits to both consumers and utilities. The program administrators' "BCR Model" assigns non-energy benefits to numerous energy efficiency measures based on the *Massachusetts Program Administrators' Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts Evaluation*[14], including: avoided utility costs, national security, benefits to landlords, increased property values, improved comfort levels, safety, and health, and reduced home maintenance.

The Massachusetts' program administrators have omitted the value of the non-energy benefits of storage in their 2018 cost-effectiveness assessments. A March 2019 Applied Economics Clinic white paper, *Massachusetts Non-Energy Benefits of Battery Storage*, addresses this issue in detail and provides evidence of the following benefits: avoided power outages, higher property values, avoided fines, avoided collections and terminations, avoided safety-related emergency calls, job creation, and reduced

[14] Massachusetts Program Administrators. 2011. *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation*. http://ma-eeac.org/wordpress/wp-content/uploads/Special-and-Cross-Sector-Studies-Area-Residential-and-Low-Income-Non-Energy-Impacts-Evaluation-Final-Report.pdf

power plant land usage.[15] The program administrators' failure to include these non-energy benefit values in their benefit-cost ratio calculations for energy storage likely resulted in their undervaluing storage in the three-year energy efficiency plan.

Summer capacity is undervalued

Program administrators' approved cost-effectiveness assessments reduce the summer capacity and electric capacity price sensitivity (called "DRIPE") to 10 percent of its calculated value for almost all storage measures. The BCR spreadsheets refer to this 90 percent reduction as the "Limited Demand Response Scaling Factor," but neither explain nor cite the source of this modeling choice. AESC 2018 includes two oblique references that may refer to this benefit reduction:

> *The PJM load forecasters ran sensitivities on their generally similar regression-based forecasts at the request of the Maryland Office of Peoples Counsel. Those sensitivities showed that an equal-percentage load reduction on all hours for three years resulted in a reduction in the forecast by 10 to 30 percent of the load reduction starting by the seventh year (four years after the end of the modeled load reduction).* (p.104)

> *The PJM load forecasters ran sensitivities on their econometric forecasting model and found that load reductions on a few high-load days each summer would reduce the load forecast by only about 10 percent of that from an energy efficiency reduction in all hours. Program administrators should model the effect of selective high-hour reductions on the ISO New England load forecast before claiming any avoided capacity costs from those resources. For initial screening, program administrators may wish to credit those measures with 10 percent of the values in Table 41.[107] (Footnote 107: On the other hand, a PA may theoretically claim additional savings if it can demonstrate that its summer DR program reduces load every day during the July/August summer peak forecast period.)* (p.105)

Massachusetts' program administrators appear to have chosen to take a sensitivity analysis conducted for Maryland on electric peak demand forecasts for the PJM region as evidence that not only demand response but most advanced demand or storage measures only operate during 10 percent of peak hours. With this assumption in place, storage BCRs are approximately one-third lower than they would otherwise be (e.g. a BCR of 0.5 with this scaling factor would otherwise be 1.5 without it). Only 10 percent of peak hours are assigned a value, and the value assigned is that of the average across all peak hours defined as 9am to 11pm on weekdays. This method neither captures the high value of avoiding the small number of hours with very high energy costs, nor the smaller per hour value of other "peak hours" (as defined by the program administrators).

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[15] Woods, B. and Stanton, E.A. March 2019. *Massachusetts Non-Energy Benefits of Battery Storage*. Applied Economics Clinic White Paper. AEC-2019-03-WP-01. Available online: https://aeclinic.org/publicationpages/2019/3/15/massachusetts-non-energy-benefits-of-battery-storage.

Winter reliability values at $0

Because New England's peak times for electric consumption occur in summer months, it is this "summer peak" that is used to calibrate markets for generation capacity. Avoided capacity costs are, therefore, the savings from reduced needs to capacity investments vis-à-vis summer peak.

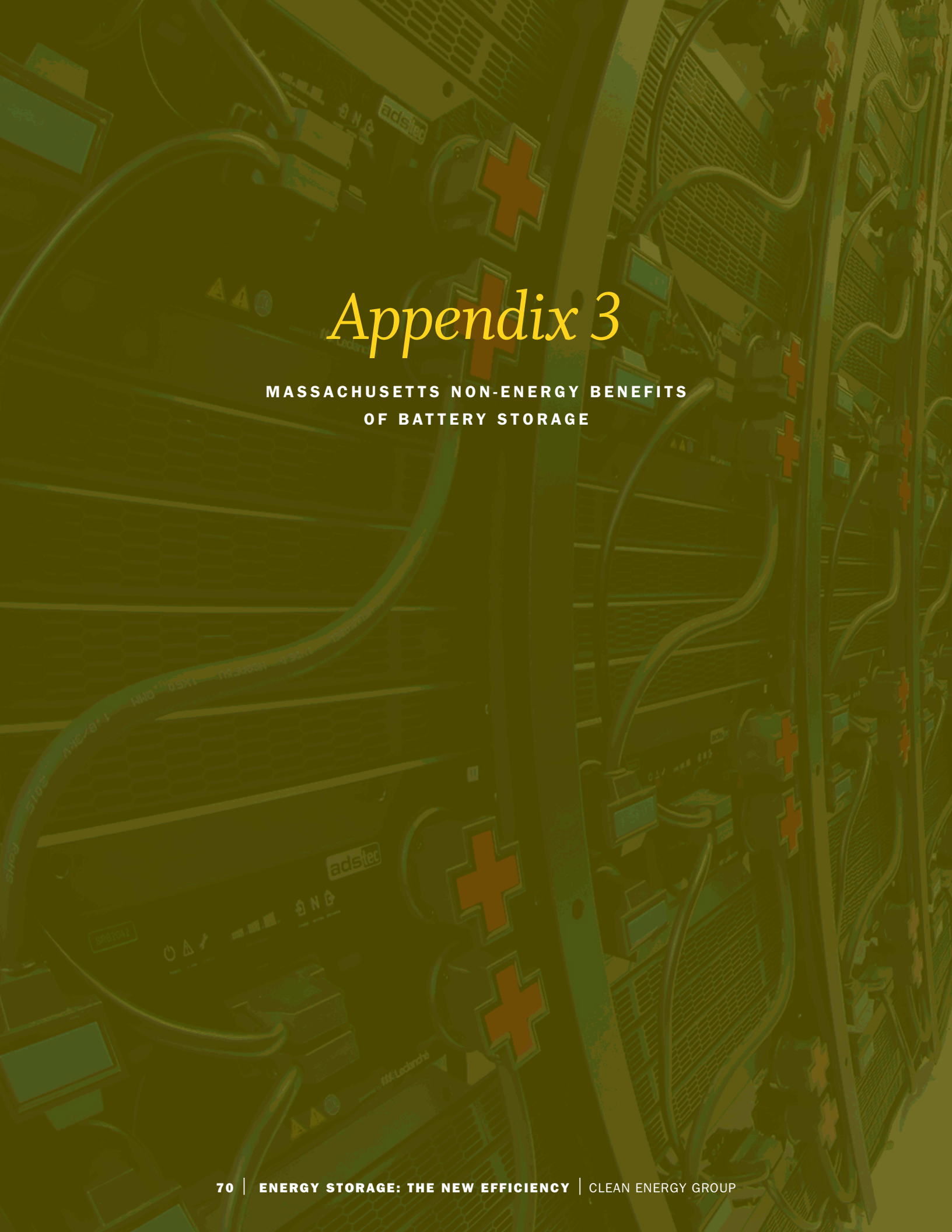
Reduced demand for peak generation capacity in winter does not avoid New England capacity market purchases and is called "winter reliability" in reference to this difference. Nonetheless, reduced winter peak capacity demands (increased winter reliability) holds a substantial value for Massachusetts as the Commonwealth works to balance coincident demands for natural gas used for heating and for electric generation.

Program administrators' final 2019-2021 plan acknowledges storage measures' impact on winter reliability:

> *The innovations in this Plan include new active demand reduction efforts that will have an impact on summer peak demand and winter reliability, while strongly supporting the Commonwealth's greenhouse gas reduction goals. (p.29-30)*

but omits a value for winter reliability. The approved 2019-2021 plan explains that a winter reliability benefit is under development:

> *The Program Administrators have agreed with DOER and the Attorney General to conduct a study to be commenced in Q1 of 2019 to quantify any benefits associated with winter peak capacity reduction. The PAs will issue an RFP and conduct this study in collaboration with the DOER, the Attorney General and the Council consultants. Study results will be aligned with and compatible with the 2018 AESC. If new benefits are identified as a result of this study, the Program Administrators will apply those benefits to reported values. (p.169)*



Appendix 3

MASSACHUSETTS NON-ENERGY BENEFITS OF BATTERY STORAGE

Massachusetts Non-Energy Benefits of Battery Storage

April 2019 – White Paper

Applied Economics Clinic

Prepared for:
Clean Energy Group

Authors:
Bryndis Woods
Elizabeth A. Stanton, PhD

www.aeclinic.org
April 2, 2019
[AEC-2019-04-WP-01]

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Acknowledgements

This report was commissioned by Clean Energy Group in support of its efforts to expand the benefits of energy storage and clean energy technologies. The Applied Economics Clinic would like to thank Todd Olinsky-Paul, Project Director at the Clean Energy Group, for comments and input that greatly improved this report.

Executive Summary

Behind the meter battery storage in Massachusetts benefits the energy system itself—lowering costs—and also affords "non-energy benefits" to the participants of storage programs, to electric distributors, and to society. To date, these non-energy benefits have not been included in efforts by utility program administrators to calculate energy storage benefit-cost ratios. For an energy efficiency measure to be included in a program administrator's energy efficiency program, that measure must have a benefit-cost ratio that is greater than 1—that is, the benefits must be found to outweigh the costs. Leaving non-energy benefits out of cost-benefit calculations may lead to energy efficiency programs that are not offering all the cost-effective efficiency measures that are available. Some of non-energy benefits may be more difficult to quantify than energy system benefits, but leaving non-energy benefits out of programmatic cost-effectiveness assessments has the same effect as assuming they have no value. Omitting these important values may lead to decisions regarding battery investments that are not strategic or economic for the Commonwealth, and puts battery storage measures at a disadvantage vis-à-vis demand response measures and efficiency measures that do include non-energy benefits in their cost-benefit calculations. In this white paper, we present the results of a preliminary assessment of seven non-energy benefits of battery storage, as summarized in Table ES-1.

Table ES-1. Non-energy benefits of battery storage in Massachusetts

	Non-Energy Benefit (2018$)
1) Avoided power outages	
Battery storage helps avoid outages, and all of the costs that come with outages for families, businesses, generators and distribution companies	Residential: **$1.72**/kWh Commercial/Industrial: **$15.64**/kWh
2) Higher property values	
Installing battery storage in buildings increases property values for storage measure participants by: (1) increasing leasable space; (2) increasing thermal comfort; (3) increasing marketability of leasable space; and (4) reducing energy costs	**$5,325/**housing unit for low-income single family participants **$510/**housing unit for owners of multi-family housing
3) Avoided fines	
Increasing battery storage will result in fewer power outages and fewer potential fines for utilities	**$24.8 million** in 2012
4) Avoided collections and terminations	
More battery storage reduces the need for costly new power plants, thereby lowering ratepayer bills, and making it easier for ratepayers to consistently pay their bills on time. This reduces the need for utilities to initiate collections and terminations	Terminations and Reconnections: **$1.85**/year/participant Customer calls: **$0.77**/year/participant
5) Avoided safety-related emergency calls	
Increasing battery storage results in fewer power outages, which reduces the risk of emergencies and the need for utilities to make safety-related	**$10.11**/year/participant
6) Job creation	
More battery storage benefits society at large by creating jobs in manufacturing, research and development, engineering, and installation	**3.3 jobs**/MW **$310,000**/MW
7) Less land used for power plants	
More battery storage reduces the need for peaker plants, which are more land-intensive than storage installations—benefitting society by allowing more land to be used for other purposes	**12.4 acres**/MW

Background

Battery storage accounts for a small but growing share of U.S. electric capacity.[1] According to the U.S. Energy Information Administration (EIA), as of July 2018, the United States has a total electric capacity of 1.2 million megawatts (MW), of which 763 MW is battery storage, accounting for 0.06 percent of all electric capacity in the nation. Massachusetts' 4 MW of battery storage capacity amounts to just 0.03 percent of electric capacity in the Commonwealth.

In 2008, Massachusetts passed into law the Green Communities Act (GCA)[2] and the Global Warming Solutions Act (GWSA)[3]. GCA required electric distributors to pursue all cost-effective energy efficiency opportunities for their customers, created the state's Energy Efficiency Advisory Council, increased the state's renewable energy portfolio requirements, and set aside $10 million per year to assist municipalities seeking to build renewable and alternative energy facilities. GWSA set statewide greenhouse gas emission reduction requirements, including an 80 percent reduction by 2050 (from a 1990 baseline).[4]

GCA and GWSA laid the groundwork for the Baker Administration, in 2015, to set aside $10 million—a figure that doubled to $20 million in 2017[5]—to explore and promote energy storage technology, develop the state's storage market, and recommend policy for the adoption of energy storage to help the state meet its clean energy and climate goals. Following this initiative, the *State of Charge* report, published by the Massachusetts Clean Energy Center (CEC) and Department of Energy Resources (DOER), found that "[t]here is great potential in Massachusetts for new advanced energy storage to enhance the efficiency, affordability, resiliency and cleanliness of the entire electric grid by modernizing the way we generate and deliver electricity."[6] The study found that the electric grid in Massachusetts could cost effectively utilize 1,766 MW of battery storage by 2020.[7] In 2018, Massachusetts passed *An*

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[1] U.S. Department of Energy. February 22, 2012. *Energy Storage: The Key to a Reliable, Clean Electricity Supply*. Available online: https://www.energy.gov/articles/energy-storage-key-reliable-clean-electricity-supply.

[2] The 190th General Court of the Commonwealth of Massachusetts. 2008. Chapter 169: An Act Relative to Green Communities. Available online: https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.

[3] The 190th General Court of the Commonwealth of Massachusetts. 2008. Chapter 298: An Act Establishing the Global Warming Solutions Act. Available online: https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter298.

[4] For a fuller accounting of the GCA, GWSA, and Massachusetts' clean energy policy history, see: Woods, Schlegel and Stanton. May 2018. *Massachusetts' Clean Energy Policy Overview*. Available online: https://aeclinic.org/publicationpages/2018/6/18/history-of-ma-energy-sector-policy-brief.

[5] Mass.gov. December 7, 2017. Baker-Polito Administration Awards $20 Million for Energy Storage Projects. Available online: https://www.mass.gov/news/baker-polito-administration-awards-20-million-for-energy-storage-projects.

[6] Massachusetts Clean Energy Center and Department of Energy Resources. 2017. *State of Charge: Massachusetts Energy Storage Initiative Study*. Available online: https://www.mass.gov/files/2017-07/state-of-charge-report.pdf. p.i.

[7] MA CEC/DOER 2017. *State of Charge.* p. 77.

Act to Advance Clean Energy, which sets an target of 1,000 megawatt-hours of energy storage in service by 2026.[8]

Massachusetts' 2019-2021 energy efficiency plans, approved January 29, 2019,[9] include a proposed new active demand management program with electric battery storage measures. Active demand management is a comprehensive set of actions intended to shift energy demand away from peak times to avoid building new, expensive generating plants, and includes: battery storage, exploiting flexibility on both the supply-side and demand-side, and coordinating demand-side measures with energy efficiency opportunities to more cheaply and efficiently supply energy. For battery storage to receive funding under GCA—in the same way that energy efficiency measures have historically—each program administrator's active demand management program offering for the three-year plan must be found to be cost effective. (Each electric distribution company or utility has a "program administrator" responsible for running their energy efficiency program.) The 2018 *Act to Advance Clean Energy* states:

> *There shall be an energy storage target of 1,000 megawatt hours to be achieved by December 31, 2025. To achieve this target, the department of energy resources may consider a variety of policies to encourage the cost-effective deployment of energy storage systems, including the refinement of existing procurement methods to properly value energy storage systems, inclusion in energy portfolio standards, the use of alternative compliance payments to develop pilot programs and the use of energy efficiency funds under section 19 of chapter 25 of the General Laws if the department determines that the energy storage system installed at a customer's premises provides sustainable peak load reductions on either the electric or gas distribution systems and is otherwise consistent with section 11G of chapter 25A of the General Laws.*[10]

For storage measures to be included in the funding allocation and program implementation described in the Massachusetts' program administrators 2019-2021 plans,[11] each group of measures' benefits must have a higher value than that group's costs.[12] Although the program administrators did find storage measures to be cost effective, their benefit-cost calculations were based only on the energy benefits of storage, not taking into account the non-energy benefits explored in this paper. This likely resulted in an undervaluing of energy storage, and therefore a lower benefit-cost ratio than would have been calculated had all benefits of storage measures been evaluated. As noted in CEC/DOER's *State of Charge*

[8] The 190th General Court of the Commonwealth of Massachusetts. 2018. Chapter 227: An Act to Advance Clean Energy. Available online: https://malegislature.gov/Bills/190/H4857/BillHistory. Lines 148-9.
[9] MA DPU 18-116, 18-117, 18-118, 18-119. *Three Year Energy Efficiency Plan for 2019 through 2021.*
[10] An Act to Advance Clean Energy. Lines 148-157.
[11] Massachusetts Department of Public Utilities. Docket Nos. 18-116, 18-117, 18-118, 18-119. *Three Year Energy Efficiency Plan for 2019 through 2021.* Available online: http://ma-eeac.org/wordpress/wp-content/uploads/2019-2021-Three-YearEnergy-Efficiency-Plan-April-2018.pdf.
[12] Cost-effectiveness is currently assessed at the program level in Massachusetts.

report, while the ability to monetize all the benefits associated with increased battery storage deployment may be limited, non-monetizable benefits have value nonetheless.[13]

In Massachusetts' 2019-2021 energy efficiency plans include a new active demand management program with electric battery storage measures. Massachusetts program administrators' assessment of energy efficiency measures' cost effectiveness includes two main categories of benefits: 1) energy system benefits (or energy avoided costs), and 2) non-energy benefits (see text box below for a brief explanation of energy versus non-energy benefits). In the 2019-2021 plan, active demand management measures have been assigned values for the former category but not the latter: In other words, non-energy benefits of storage are given no value in assessing these measures' cost effectiveness.

	Benefits of Battery Storage	
	Energy Benefits	**Non-Energy Benefits**
Who benefits?	Benefits to the energy system	Benefits to participants in battery storage programs, electric distribution companies and/or society at large
How does benefit manifest?	Benefit conferred through reductions in the cost of supplying energy	Benefit conferred directly to beneficiary
Examples	▪ Reduced peak energy demand ▪ Reduced need for new generating capacity ▪ Transmission and distribution cost reductions ▪ Increased grid resiliency ▪ Facilitates renewable energy integration	▪ Avoided value losses to cusomters and utilities from power outages ▪ Enhanced value to customers from reduced incidence of power outages ▪ Enhanced property values ▪ Enhanced ability to pay less expensive electric bills ▪ Job creation

While many states use cost-benefit analyses to determine which traditional energy efficiency measures to pursue, Massachusetts is the first state in the country to apply a similar methodological approach for battery storage. To achieve the best decision making, it is critical that Massachusetts recognize the full value of these benefits. To this end, this white paper explores the non-energy benefits of electric storage measures in Massachusetts.

What are the benefits of battery storage?

GCA requires that all cost-effective actions be taken regarding energy efficiency and renewable energy. Massachusetts program administrators perform benefit-cost analyses to determine which energy efficiency and active demand management programs to include in their three-year plans. Capturing a full range of benefits and costs is essential to ensure the most strategic program implementation in the

[13] MA CEC/DOER 2017. *State of Charge.*

Commonwealth.[14] CEC/DOER's *State of Charge* report found that installing 1,766 MW of advanced energy storage in Massachusetts could save electric consumers $2.3 billion through 2020 (see Table 1 below).

Table 1. *State of Charge* total system benefits from Massachusetts energy storage

Benefit	Ratepayer Savings (billions $)
Energy Cost Reduction	$0.3
Reduced Peak Capacity	$1.1
Ancillary Services Cost Reduction	$0.2
Wholesale Market Cost Reduction	$0.2
Transmission and Distribution Cost Reduction	$0.3
Integrating Distributed Renewable Generation Cost Reduction	$0.2
Total System Benefits	**$2.3**

Source: MA CEC/DOER 2017. State of Charge. p.xii.

State of Charge highlights many commonly discussed energy system benefits from battery storage. An electric grid that has built-in backup in the form of storage can more reliably supply energy on demand and is more resilient to disruptions. Improving the grid's ability to store energy produced at one time and dispatch it at another time would facilitate the increased use of intermittent renewable energy sources. Increasing the grid's share of renewable energy would also result in fewer greenhouse gas emissions from fossil fuel energy generation and associated environmental disruptions like gas leaks or pipeline spills. Increasing the share of renewable energy in New England's electric grid will boost the economy by increasing the value of those resources and by creating jobs associated with an increased need to produce, transport, install and maintain new energy infrastructure.[15]

Perhaps battery storage's most critical energy system benefit, however, is its use in reducing New England's peak energy demand and the substantial costs associated with peak. As battery storage reduces the need for generation at peak, it lowers costs by shrinking the amount of capacity that electric distributors must possess to meet peak demand, and lowers required capacity reserve margins as well. For example, for every 1 MW of reduced peak demand in New England, there is an associated reduced capacity need of approximately 1.15 MW.[16]

[14] Stanton, E.A. July 2018. *Massachusetts Battery Storage Measures: Benefits and Costs.* Applied Economics Clinic White Paper. AEC-2018-07-WP-02. Available online: https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs; and Stanton, E.A. March 2019. *Updated Massachusetts Battery Storage Measures: Benefits and Costs.* Applied Economics Clinic White Paper. AEC-2019-03-WP-02. Available online: https://aeclinic.org/publicationpages/2019/3/15/updated-massachusetts-battery-storage-measures-benefits-and-costs.

[15] Accounts for 15 percent operating reserve margin. Source: MA CEC/DOER 2017. *State of Charge*.

[16] Kotha, M. June 13, 2018. *Future Representative Installed Capacity Requirements for CCP 2023-2024 through CCP 2027-2028*. Slide 8. Available online: https://www.iso-ne.com/static-assets/documents/2018/06/a9_representative_icr_values_for_ccp_2023_2024_through_2027_2028.pdf.

These types of energy system benefits (often referred to as avoided energy costs) are estimated in more detail by the *Avoided Energy Supply Components in New England* (AESC) reports, most recently released in March 2018 and updated in June 2018 (hereafter referred to as AESC 2018).[17] The energy system benefits estimated in that report include avoided fuel costs, avoided electric generating capacity costs, and avoided costs of complying with GWSA.

In addition to energy system benefits, however, storage measures confer several "non-energy benefits" that are separate from those directly applicable to the cost of energy supply. Battery storage provides benefits to electric distributors and to ratepayers, including both families and businesses, and to society at large. These non-energy benefits of storage are the topic of this white paper.

What are non-energy benefits?

Non-energy benefits of battery storage are conferred not through changes to the cost of electric services (energy system benefits), but directly to participants in storage programs, the electric distribution companies themselves, or to society as a whole. For example, during a power outage, storage systems can enable businesses to stay open, residents to stay in their homes, and hospitals to continue to operate—resulting in clear benefits that are unrelated to the cost of electricity, such as: avoided loss of customers and revenue; avoided equipment damage; avoided loss of perishable materials and goods; and avoided data losses. Some of these non-energy benefits may be more difficult to quantify than energy system benefits, or may require new and different measurement tools.[18] To leave these critical benefits unmeasured, however, is equivalent to assuming that they have no value in a benefit-cost analysis, which has the result of lowering benefit-cost metrics and reducing the likelihood that storage measures and programs will achieve cost effectiveness and be included in program administrators' three-year energy efficiency plans.

Massachusetts energy efficiency program administrators have a long history of assigning values to the non-energy benefits of weatherization, insulation, heating and cooling upgrades, retrofits, lighting and appliance upgrades and other efficiency measures. Program administrators prepare—and periodically update and expand upon—*Non-Energy Impact (NEI) Evaluation* studies that estimate the non-energy benefits of energy efficiency measures for residential and low-income ratepayers in the state, including, for example: reduced asthma, reduced thermal stress on occupants, fewer missed days of work, reduced risk of fire, and reduced noise. The MA NEI Evaluation 2011 study considered utility and societal non-energy impacts in addition to residential and low-income ratepayer non-energy impacts.[19] The MA

[17] Synapse Energy Economics. June 1, 2018. *Avoided Energy Supply Components in New England: 2018 Report* . Prepared for AESC 2018 Study Group. Available online: https://www.ct.gov/deep/lib/deep/energy/aesc-2018-17-080-june-1-release.pdf.

[18] Energy Storage Association (ESA). November 2017. *35x25: A Vision for Energy Storage*. Available online: http://energystorage.org/system/files/attachments/esa_vision_2025_final.pdf.

[19] Massachusetts Program Administrators. August 15, 2011. *Massachusetts Special and Cross-Sector Studies Area, Residential and Low-Income Non-Energy Impacts (NEI) Evaluation*. Prepared by NMR. Available online: http://ma-eeac.org/wordpress/wp-content/uploads/Special-and-Cross-Sector-Studies-Area-Residential-and-Low-Income-Non-Energy-Impacts-Evaluation-Final-Report.pdf.

NEI Evaluation 2016 study focused exclusively on residential and low-income ratepayer non-energy impacts.[20] Table 2 (on the following page) lists the non-energy benefits for which monetary values were provided in the MA NEI Evaluation 2011; rows marked in green indicate the subset of these benefits assigned to measures in the program administrator's 2019-2021 plan.

Currently, the non-energy benefits of battery storage are not included in Massachusetts active demand management program planning. Omitting these non-energy benefits introduces a downward bias on storage measures' benefit-cost assessments. Without a full consideration of all benefits, Massachusetts is unlikely to make the best strategic decisions regarding these important cost-saving measures.

[20] Massachusetts Program Administrators. August 5, 2016. *Massachusetts Special and Cross-Cutting Research Area: Low-Income Single-Family Health-and Safety-Related Non-Energy Impacts (NEIs) Study*. Prepared by Three, Inc. and NMR. Available online: http://ma-eeac.org/wordpress/wp-content/uploads/Low-Income-Single-Family-Health-and-Safety-Related-Non-Energy-Impacts-Study.pdf.

Table 2. Massachusetts non-energy benefits of energy efficiency

NEI	Duration
UTILITY PERSPECTIVE	
Arrearages	Annual
Bad debt write-offs	Annual
Terminations and reconnections	Annual
Rate discounts	Annual
Customer calls	Annual
Collections notices	Annual
Safety-related emergency calls	Annual
Insurance savings	—
SOCIETAL PERSPECTIVE	
National Security	Annual
NON-RESOURCE BENEFITS	
Appliance Recycling – Avoided landfill space	One time
Appliance Recycling – Reduced emissions due to recycling plastic and glass, reduced emissions	One time
Appliance Recycling – Reduced emissions due to incineration of insulating foam	One time
NEI	**Duration**
PARTICIPANT PERSPECTIVE (OWNERS OF LOW-INCOME RENTAL HOUSING), PER HOUSING UNIT	
Marketability/ease of finding renters	Annual
Reduced tenant turnover	Annual
Property value	One time
Equipment maintenance (heating and cooling systems)	Annual
Reduced maintenance (lighting)	Annual
Durability of property	Annual
Tenant complaints	Annual
PARTICIPANT PESPECTIVE (OCCUPANT)	
Higher comfort levels	Annual
Quieter interior environment	Annual
Lighting quality & lifetime	One time
Increased housing property value	One time (Annual for NLI RNC)
Reduced water usage and sewer costs (dishwashers)	Annual
Reduced water usage and sewer costs (faucet aerators)	Annual
Reduced water usage and sewer costs (low flow showerheads)	Annual
More durable home and less maintenance	Annual
Equipment and appliance maintenance requirements	Annual
Health related NEIs	Annual
Improved safety (heating system, ventilation, carbon monoxide, fires)	Annual
Window AC NEIs	Annual
**** Green cells showing the Benefits in April Draft of 2019-2021 Plan**	

Source: MA NEI Evaluation 2011. Reproduced from: Stanton, E.A. July 2018. Massachusetts Battery Storage Measures: Benefits and Costs. Applied Economics Clinic White Paper. AEC-2018-07-WP-02. Available online: https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs.

Non-Energy Benefits of Battery Storage

This white paper presents seven non-energy benefits of electric storage measures in Massachusetts: 1) avoided power outages; 2) higher property values; 3) avoided fines; 4) avoided collections and terminations; 5) avoided safety-related emergency calls; 6) job creation; and 7) less land used for power plants. In the following sections, we discuss each non-energy benefit in terms of how it works, how it is valued, and how and why it applies to Massachusetts. (Energy and emission-reduction benefits of storage are evaluated in AESC 2018 and, therefore, including in battery measures' cost-effectiveness assessment.)

The seven storage non-energy benefits presented here do not represent a comprehensive set of all such benefits. Rather, this list and the monetized benefits that we have assembled are a starting point for a discussion of how best to fully measure the advantages to Massachusetts of battery storage. The measures selected for inclusion in this white paper are drawn from our review of the literature and are recurring benefits, with one exception: an increase in property value is a one-time benefit.

1. Avoided power outages

Power outages entail costs to generators, distribution companies, and consumers. Battery storage, if charged and discharged at appropriate times, reduces peak load, thereby increasing reserve margins and enhancing grid reliability; it also reduces the incidence and duration of power outages. Avoiding power outages is beneficial for electric distributors and for ratepayers. From an energy system point of view, the benefit of avoided power outages is lower total system costs. From the storage measure participants' point of view, the benefit of avoided power outages is the reduction of costly—and potentially dangerous—disruptions to life and work.

AESC 2018 introduces estimation of a new energy system reliability benefit: the avoided costs of power outages to the electric system. As we describe in this section, this energy system reliability benefit is distinct from the non-energy benefits to consumers of avoided outages. Some understandable confusion between these two kinds of benefits may, nonetheless, arise: the non-energy benefits of avoided outages to families and businesses is often called the "value of lost load" (VoLL). AESC 2018 follows—but does not explain—the common practice of using ratepayers' VoLL as a proxy to estimate the energy system costs of outages. This use of ratepayers' VoLL as a proxy for system costs should not, however, suggest that system costs are in fact the VoLL.

1. ***Energy system reliability benefit:*** Greater reliability lowers system costs. This avoided cost is typically measured indirectly by assuming—based on economic theory—that system reliability costs are equal to the benefits to consumers of avoided outages. AESC 2018 uses ratepayers' VoLL as a proxy to estimate the avoided system costs of enhanced reliability.

2. ***Non-energy reliability benefit to consumers:*** VoLL is a measure of the value to families and businesses of lost load (outages). Storage measure participants' non-energy VoLL benefit is distinct from the energy system reliability benefit estimated by AESC 2018.

Energy system reliability benefit

Reliable electric service is a benefit for both electric distributors and consumers, but valuing the benefit is made difficult by the fact that there is no market for the reliability of energy, or for energy interruptions. As a result, most valuation exercises seek to determine the reverse; according to an overview of VoLL studies and their use: "It proves often easier to estimate the costs of the effects of supply interruptions for energy consumers."[21] VoLL accomplishes that by expressing what a *Frontiers in Energy Research* article called the "monetary evaluation of uninterruptedness of power supply."[22] VoLL estimates the cost per kilowatt-hour (kWh) of a power outage. According to economic theory, energy system reliability can be assumed to have a value equal to the costs to customers in the event of power outages. (Power suppliers would pay up to, but not beyond, this value in order to avoid losses.[23])

AESC 2018 follows the practice of using VoLL as a proxy for energy system reliability benefits, and presents four values for U.S. VoLL taken from the literature (see Table 3).

Table 3. AESC 2018 results of reported values of lost load literature review (2018$/kWh)

Report year	Author	Region	Small C&I	Large C&I	Residential	Average across sectors
2015	LBNL[a]	US	$280	$16	$2	$37[d]
2014	London Economics[b]	ERCOT	$7	$4	--	$12[d]
2014	London Economics[b]	US	$46	$31	$2	--
2010	Centolella[c]	Midwest	$56	$28	$5	--

[a] Sullivan et al. 2015. Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States. Prepared for Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. Lawrence Berkeley National Laboratory (LBNL). [b] London Economics International LLC. 2013. Estimating the Value of Lost Load. Prepared for the Electric Reliability Council of Texas, Inc. [c] Centolella, P. 2010. Estimates of the Value of Uninterrupted Service for The Mid-West Independent System Operator. Harvard Electricity Policy Group. [d] AESC 2018.

AESC 2018 presents $25 per kWh—the average of the first two U.S. VoLL estimates from Table 3—as the New England VoLL and, by proxy, as the New England system reliability avoided cost. The other two VoLL results in Table 3 were not included in AESC 2018's VoLL estimate. The second London Economics result (Row 3 in Table 3) is taken from the same study as the ERCOT VoLL and reports the results of an

[21] van der Welle, A. and van der Zwaan, B. 2007. *An Overview of Selected Studies on the Value of Lost Load (VoLL).* Energy Research Centre of the Netherlands. p.2.

[22] Schröder and Kuckshinrichs. December 24, 2015. "Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review", *Frontiers in Energy Research*. Available online: https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full. p.2

[23] "In the optimum cases, the level of supply security should be defined in such a way that the marginal damage costs, expressed by VoLL, are equal to the marginal costs for ensuring uninterrupted electricity supply. Accordingly, the calculation of the economic indicator VoLL represents, on the one hand, an opportunity to determine the level of damange caused by a power interruption, the results of which, on the other hand, describes the value of power supply security." Schröder and Kuckshinrichs, 2015. p.4.

older version of the Centolella 2010 study[24] (Row 4 in Table 3). In the Centolella 2010 study, Paul Centolella and coauthors, on behalf of SAIC, estimate U.S. Midwest VoLL, based on the methodology and data used in an earlier version of the LBNL 2015 study[25] (Row 1 in Table 3).

AESC 2018 accepts the LBNL 2015's "willingness-to-pay" survey results as presented, changing only their dollar year and calculating an average value appropriate to the relevant distribution of outage durations in New England. For the London Economics 2014 study, however, AESC 2018 re-calculates New England-specific results following London Economics' production function methodology, citing a U.S. AID study on the Republic of Georgia[26] in substantiating this methodology.

Cleveland State University's 2017 report on valuing resiliency from microgrids describes the VoLL production function methodology in detail and provides U.S.-wide results, with results ranging up to $110 per kWh across different industries.[27] We replicated the production function methodology used in AESC 2018 for New England states but got somewhat different results, as shown in Table 4.

Table 4. Ratio of 2016 GDP to energy usage: AESC 2018 and AEC (2018$/kWh)

State	AESC 2018 GDP/kWh	AEC GDP/kWh
MA	**$15.15**	**$15.64**
CT	$8.98	$16.54
RI	$7.60	$13.47
VT	$5.70	$9.35
NH	$7.05	$12.45
ME	$5.00	$8.96
New England	**$11.63**	**$14.46**

Source: AESC 2018, Table 95, p.224. Data for AEC calculations: GDP—Bureau of Economic Analysis, Regional Data, Gross Domestic Product by State, NACIS All GDP components, available online: https://apps.bea.gov/regional/downloadzip.cfm. Energy usage—EIA-861, Retail Sales of Electricity by State by Sector by Provider, available online: https://www.eia.gov/electricity/data/state/. GDP and sales values originally provided in 2016 dollars have been updated to 2018 dollars using the CPI-U index.

[24] Centolella et al. (2006). *Estimates of the Value of Uninterrupted Service for The Midwest Independent System Operator*. Science Applications International Corporation (SAIC).

[25] Sullivan et al. (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States. Prepared for Office of Electricity Delivery and Energy Reliability*. U.S. Department of Energy. Lawrence Berkeley National Laboratory (LBNL). Available online: http://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf.

[26] Khujadze, S. May 2014. *A Study of the Value of Lost Load (VoLL) for Georgia*. Prepared by Deloitte Consulting for the United States Agency for International Development's Hydro Power and Energy Planning Project (USAID-HPEP).

[27] Thomas, A.R. and Henning, M. December 1, 2017. *Valuing Resiliency from Microgrids: How End Users can Estimate the Marginal Value of Resilient Power*. Cleveland State University, Urban Publications. Available online: https://engagedscholarship.csuohio.edu/urban_facpub/1516/. Values originally provided in 2012 dollars have been updated to 2018 dollars using the CPI-U index.

While our Massachusetts production function-based VoLL matched that of AESC 2018 very closely, results for the other New England states differ. Our New England average, using this method, was $14 per kWh, compared to $12 per kWh reported in AESC 2018. Replacing AESC 2018 with our correction raises the final cross-methodology average VoLL only slightly: from $25 per kWh to $26 per kWh.

Non-energy reliability benefit to consumers

Whereas AESC 2018's estimate of energy system reliability benefits uses ratepayer VoLL only as a proxy for avoided system costs, our estimate of Massachusetts' non-energy reliability benefit to storage measure participants is the VoLL itself. Reliability can and does provide many distinct benefits and it is important to note that VoLL accounts for some, but not all of these benefits. For example, more resilient power enables providers of safety and health services—like hospitals or community health centers—to continue to provide services that are highly valuable to society during outages associated with natural disasters, a distinct non-energy benefit that may not be adequately accounted for in VoLL. There is additional value of avoided power outages for customers who are elderly, disabled or have serious health conditions and rely on electronic devices and are more vulnerable to power outages than the average customer. Research has found that in the United States—among the 175 million people covered by employer-sponsored health insurance—approximately 218 per 100,000 people are "electricity-dependent residing at home".[28] Investor-owned utilities in Massachusetts and other states are required to maintain lists of health critical customers (called "life support customers" in Massachusetts) who cannot have their power shut off, and are prioritized in power restoration efforts, because they are reliant on electrical medical devices, and to be without power would be harmful or life threatening.[29]

Including multiple benefits from increased reliability does not represent double counting. Increased reliability is a benefit to *both* to the energy system as a whole and to ratepayers participating in storage programs. A 2015 study in the journal *Frontiers in Energy Research* (see Figure 1 below) provides an overview of multiple, distinct benefits from battery storage including both "investments in grid construction via charges (network tariffs)" (or energy system benefits) and various non-energy ratepayer benefits discussed in this white paper, including the value of lost load to residential, commercial and industrial ratepayers, and effects on property values.

[28] Molinari, N.A.M., Chen, B., Krishna, N., and Morris, T. March 2017. "Who's at Risk When the Power Goes Out? The At-home Electricity-Dependent Population in the United States, 2012." *Journal of Public Health Management and Practice*, 23(2), 152-159. Available online: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5007208/.

[29] See: Code of Massachusetts Regulations Title 220. January 27, 2017. 220 CMR 19.00: Standards of Performance for Emergency Preparation and Restoration of Service for Electric Distribution and Gas Companies. Available online: https://www.mass.gov/files/documents/2016/08/rr/220cmr1900.pdf for Massachusetts law governing utility responsibilities towards health-critical customers.

Figure 1. Avoided costs from battery storage

Economy (industry, commercial users)			Private Individuals		
Damage costs		Mitigation costs	Damage costs		Mitigation costs
Direct	Indirect		Direct	Indirect	
(a) Opportunity costs of idle resources • Labor • Country • Capital • Profits	(a) Delayed deliveries along the value chain	Procurement of standby generators, batteries, etc.	(a) Restrictions on activities, lost leisure, stress	Restrictions on acquisition of goods	Procurement of standby generators, batteries, etc.
	(b) Damage for consumers if the company produces an end product	Investments in grid construction via charges (network tariffs)	(b) Financial costs • Damage to premises and real estate • Food spoilage • Data loss	Costs for other private individuals and companies	Investments in grid construction via charges (network tariffs)
(b) Production holdups and restart times	(c) Costs/benefits for some manufacturers		(c) Health and safety aspects		
(c) Adverse effects and damage to capital goods, data loss	(d) Health and safety aspects				
(d) Health and safety aspects					

Source: Reproduced from Schröder and Kuckshinrichs, 2015. Table 2, p. 3.

For use in Massachusetts non-energy benefits of storage, residential VoLL can be estimated using the LBNL 2015 willingness-to-pay survey results for residential customers as cited in AESC 2018. EIA data indicates that 4 hours is the average duration of power outages in the United States across all utility types.[30] LBLN's 4-hour outage VoLL estimate for residential customers is $1.72 per kWh.[31]

Table 5. Estimated cost per event, average kW and unserved kWh, residential (2018$)

	Momentary	30 Minutes	1 hour	4 hours	8 hours	16 hours
Cost per Event	$4.19	$4.83	$5.47	$10.20	$18.46	$34.77
Cost per Average kW	$2.79	$3.11	$3.54	$6.65	$12.13	$22.75
Cost per Unserved kWh	$33.16	$6.33	$3.54	$1.72	$1.50	$1.40

Source: LNBL, 2015. Values originally provided in 2013 dollars have been updated to 2018 dollars using the CPI-U index. Cost per event refers to the "cost for an individual interruption for a typical customer". Cost per average kW refers to the "cost per event

[30] U.S. Energy Information Administration. April 5, 2018. *Average frequency and duration of electric distribution outages vary by states*. Available online: https://www.eia.gov/todayinenergy/detail.php?id=35652.

[31] Clean Energy Group and Greenlink have a series of forthcoming publications that presents outage estimates for the Southeast: Clean Energy Group, "Resilient Southeast Report Series", pending publication, 2019.

normalized by average demand". Cost per unserved kWh refers to the "cost per event normalized by the expected amount of unserved kWh for each interruption duration".

While the cost of power outages to residential customers may seem small on a per kWh basis, power outages are highly disruptive. As the Energy Storage Association points out in their *Vision for Energy* Storage report:

> *For a homeowner, the economic cost may seem minimal, but the cost to quality of life is high: medication and food refrigeration, shelter and access to water are among those critical losses.*[32]

Power outages also have the potential to cause disruptions for commercial and industrial customers:

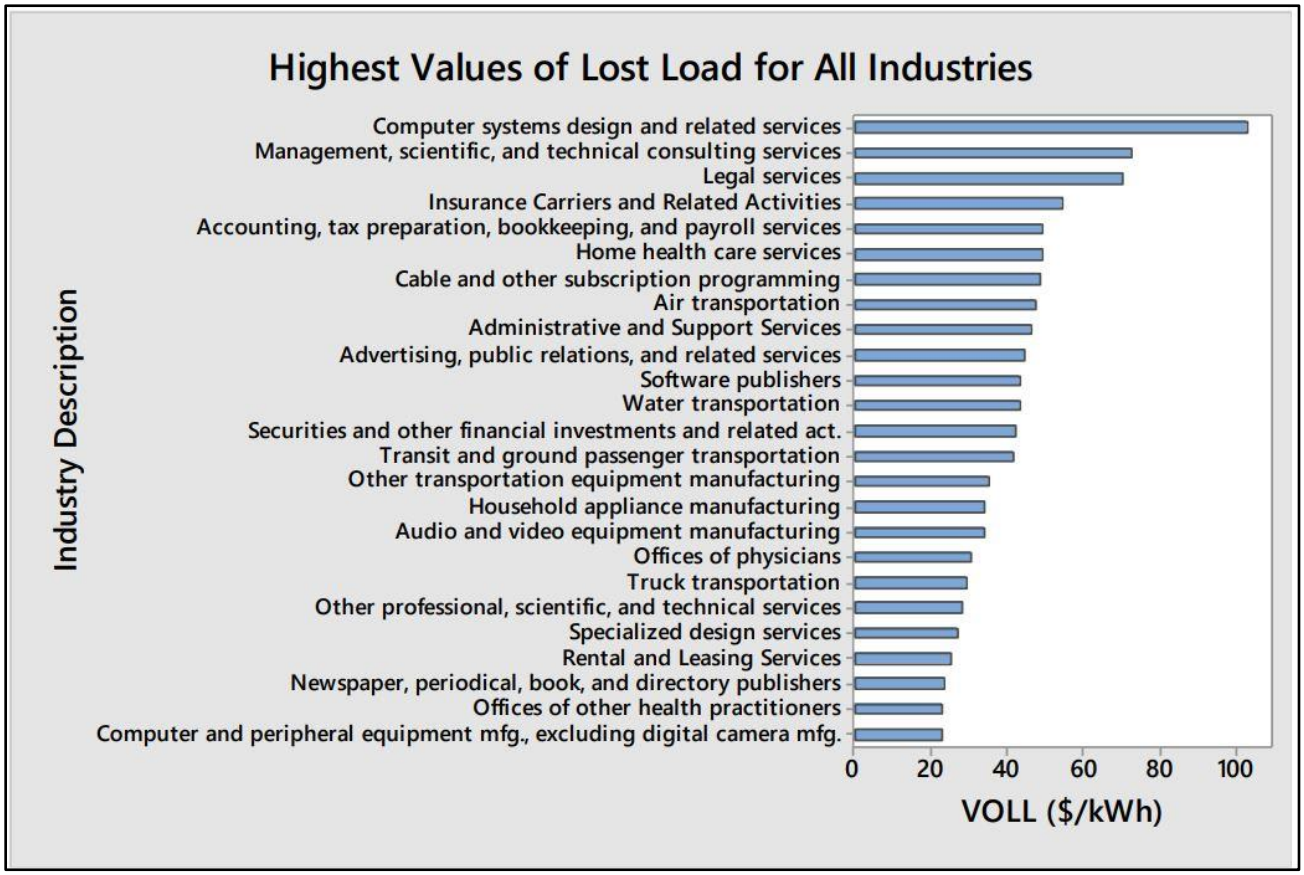
> *As enhanced connectivity drives increases in computing capability and economic value in the same footprint, every server that loses power will only have a greater economic cost to it—rippling even further throughout society. The higher VOLL extends to almost all commercial enterprises. Grocers lose perishable products, stores are unable to sell their wares, and credit card systems lose capability to process payments at data centers and points of sale.*[33]

For commercial and industrial non-energy benefits of storage, AESC 2018's Massachusetts-specific production function-based VoLL is $15.64 per kWh. However, it should be noted that the Cleveland State University 2017 analysis of U.S. VoLL suggests a very wide range of values by business sector (see Figure 2). The VoLL values in Figure 2 are not Massachusetts-specific (and are, therefore, not included in this analysis); the wide range of U.S. VoLL values points to a need for additional analysis in New England to fully capture variation in VoLL by industry.

The application of these per kWh non-energy benefits values should follow that of current non-energy benefits for energy efficiency measures. To this end, moving forward, it will be important to consider the extent to which battery storage measures can prevent power outages and the total kWhs of expected outages (absent these measures) in a given year.

[32] ESA 2017. p.4.
[33] ESA 2017. p.4.

Figure 2. Cleveland State University (2017) VoLL per kWh by industry



Source: Reproduced from Thomas and Henning, 2017. Figure 2, p. 13.

2. Higher property values

Installing storage in buildings can increase property values in several ways. Battery storage systems can keep heating and cooling systems running during a power outage, contributing to the increased thermal comfort of buildings and increasing their value.[34] Energy backup systems also serve to increase the marketability of units for landlords, again, increasing the value of the property.[35] Battery storage systems can also reduce maintenance costs by providing energy use data that allows building operators to assess and optimize real-time energy usage.

This non-energy benefit has a value to ratepayers as a one-time increase to property values from adding a storage system. These values can be calculated using the "low-income" single and multi-families benefits for a heating retrofit from the MA NEI Evaluation 2011: one-half of measure capital cost for single family, and 1 percent of measure capital cost for owners of multi-family housing. The Applied Economic Clinic's July 2018 White Paper, *Massachusetts Battery Storage Measures: Benefit and Costs*,

[34] ACEEE. 2012. *Measuring Participant Perspective Non-Energy Impacts (NEIs)*. Available online: https://aceee.org/files/proceedings/2012/data/papers/0193-000046.pdf.
[35] MA NEI Evaluation 2011.

assigned values of $5,325 per housing unit for low-income single-family participants and $510 per unit for owners of multi-family housing based on the MA NEI Evaluation 2011 benefit to capital cost ratios.[36,37] An increase in property values would also accrue to residential storage-measure participants who are not income eligible, and to commercial and industrial storage-measure participants.

It is important to note that installing solar arrays can increase a building's value. Evidence shows that home buyers across the United States are willing to pay a premium of about $15,000 for a home with solar panels.[38] Massachusetts offers solar property tax exemptions for both residential and non-residential solar customers; under current law (M.G.L. c. 59, sec. 59) "[a] solar or wind powered system or device which is being utilized as a primary or auxiliary power system for the purpose of heating or otherwise supplying the energy needs of property taxable under this chapter; provided, however, that the exemption under this clause shall be allowed only for a period of twenty years from the date of the installation of such system or device."[39] That means, even when the value of a building increases after a solar system is installed, property taxes still reflect the pre-solar value of the building. While such policies do not currently exist for battery storage in the Commonwealth, tax exemptions are an important tool to incentivize the uptake of storage in homes and businesses.

3. Avoided outage fines

As installed battery storage increases, the risk of power outages falls[40]—which means that utilities may avoid costly fines associated with severe power outage events.

In 2012, the Massachusetts Department of Public Utilities (DPU) levied penalties totaling $24.8 million against National Grid, NSTAR, and Western Massachusetts Electric Company (WEMCO) related to their response to power outages caused by Tropical Storm Irene and the Halloween Blizzard of 2011.The fines were levied after customer complaints prompted state officials to launch an investigation into the utilities' preparedness and response to the 2011 storms. The investigation was extensive with 16 public hearings, a dozen evidentiary hearings, and over one thousand exhibits. National Grid, NSTAR and WEMCO were required submit their plans to pay the fines to the DPU within 30 days. The penalties were applied as a credit for ratepayers per a law passed in 2012 that made it illegal for utilities to change rates in order to pay fines for subpar performance.[41] The constitutionality of this law was challenged in

[36] Stanton, E.A. July 31, 2018. Massachusetts Battery Storage Measures: Benefits and Costs. Prepared for Clean Energy Group. AEC-2018-07-WP-02. Available online: https://aeclinic.org/publicationpages/2018/7/30/massachusetts-battery-storage-measures-benefits-and-costs. p.17.
[37] Note that these values do not include any associated increase in property taxes.
[38] Energy.gov. No Date. Solar Homes Sell for a Premium. Available online: https://www.energy.gov/eere/solar/downloads/solar-homes-sell-premium.
[39] The 191st General Court of the Commonwealth of Massachusetts. General Laws, Chapter 59, Section 59. Available online: https://malegislature.gov/Laws/GeneralLaws/PartI/TitleIX/Chapter59.
[40] Zhang, T., Cialdea, S., Orr, J.A., and Emanuel, A.E. 2014. Outage Avoidance and Amelioration using Battery Energy Storage Systems. *IEEE*. Available online: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6808127.
[41] Howard, Z. December 11, 2012. *Massachusetts slaps utilities with record fines for 2011 outages*. Reuters. Available online: https://www.reuters.com/article/us-usa-massachusetts-power/massachusetts-slaps-utilities-with-

Fitchburg Gas and Electric Light Company v. DPU, but was ultimately upheld by the Massachusetts Supreme Judicial Court.[42]

Together, National Grid, NSTAR, and WEMCO were fined a total of $24.8 million[43] for violating various storm response obligations from their respective emergency response plans, such as: failing to adequately communicate with customers and municipalities; failing to provide damage assessments in a timely fashion; failing to respond to public safety calls; failing to effectively assess the severity of the storms; and failing to directly contact customers with medical needs.[44] Costs paid in fines do not include the legal and procedural expenses from fighting the fines. While the fines were levied due to the inadequate response of various utilities to power outages rather than due to the outages themselves, it is important to reiterate that increased deployment of battery storage makes power outages—and, by extension, the fines that may accompany them—less likely.[45]

With detailed outage data—outage duration, number of affected customers and total lost load—it would be possible to calculate a dollar per kWh estimate of fines and legal costs that Massachusetts utilities could avoid through battery storage programs and avoided severe power outages.

4. Avoided collections and terminations

Battery storage provides electric supply during times of peak demand, reducing the need for costly new peaker plants and the resulting capacity costs that are passed on to ratepayers through their rates and bills. When ratepayers face lower costs they are better able to pay their bills. Electric distributors benefit by avoiding costs associated with collections and terminations.

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record-fines-for-2011-outages-idUSBRE8BA19420121211. Ring, D. December 11, 2012. Massachusetts utility regulators: National Grid and Western Massachusetts Electric Company face multimillion dollar fines for Irene, October snowstorm responses. MassLive. Available online: https://www.masslive.com/news/index.ssf/2012/12/national_grid_to_be_fined_1872.html.

[42] Supreme Judicial Court and Appeals Court of Massachusetts. April 14, 2014. Fitchburg Gas and Electric Light Company vs. Department of Public Utilities. Case Docket SJC-11397. Online: http://www.ma-appellatecourts.org/display_docket.php?dno=SJC-11397.

[43] National Grid was fined $18.7 million, NSTAR $4.1 million and WEMCO $2 million.

[44] Mass.gov. July 26, 2012. AG Seeks More Than $16 Million in Penalties for Inadequate Storm Response by National Grid. Available online: http://www.mass.gov/ago/news-and-updates/press-releases/2012/2012-07-26-natl-grid-dpu.html?_ga=2.175198242.1077349657.1539625103-207293685.1523300621. Mass.gov. July 12, 2012. AG Seeks $4 Million in Penalties for Inadequate Storm Response by Western Massachusetts Electric Company. Available online: http://www.mass.gov/ago/news-and-updates/press-releases/2012/2012-07-12-wmeco-dpu-recommendation.html. Mass.gov. August 7, 2012. AG Seeks Close to $10 Million in Penalties for Inadequate Storm Response by NSTAR. Available online: http://www.mass.gov/ago/news-and-updates/press-releases/2012/2012-08-07-nstar-dpu.html.

[45] Zhang, T., Cialdea, S., Orr, J.A., and Emanuel, A.E. 2014. Outage Avoidance and Amelioration using Battery Energy Storage Systems. *IEEE*. Available online: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6808127.

MA NEI Evaluation 2011 presents non-energy benefits of avoided collections and terminations for energy efficiency measures, explaining that:

> *Utilities can realize a number of NEIs from their energy efficiency programs in the form of financial savings. Energy-efficient technologies installed by PA programs often result in reduced energy bills for participants, which can decrease the likelihood that customers experience difficulties with paying their utility bills. In turn, utilities realize financial savings through reduced costs associated with arrearages and late payments, uncollectible bills and bad debt write-offs, service terminations and reconnections, bill-related customer calls, and the bill collections process.*[46]

Battery storage—like energy efficiency—can reduce the need for expensive peaker plants and provide electricity at peak more cheaply (assuming that battery storage is appropriately charged at times of inexpensive supply and discharged at times of peak, expensive demand). When rates and bills are lowered and customers are better able to consistently pay their bills, electric distributors need to make fewer collection calls, terminations and reconnections.[47]

Table 6 presents the MA NEI Evaluation 2011 values recommended for these avoided collections and terminations costs for energy efficiency. Because battery storage also lowers peak energy use and ratepayer costs, with the same result—that customers are better able to pay their bills on time—these same benefits are equally applicable to battery storage program participants. The program administrator-recommended value for these avoided costs for terminations and reconnections and customer calls are, respectively: $1.85 and $0.77 per year per participant.

[46] MA NEI Evaluation 2011. p. 1-2.

[47] Woolf et al. September 22, 2014. *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits*. Prepared for the Advanced Energy Economy Institute. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf. p.25.

Table 6. Benefits of avoided terminations, reconnections, and customer calls

Study	$/year/participant (Adjusted 2018$)
Terminations and Reconnections	
WI Low-Income Weatherization (Skumatz and Gardner, 2005)	$0.17
National Low-Income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	$0.75
CT Low-Income Weatherization (Skumatz and Nordeen, 2002)	$0.14
CA Low-Income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc., and Megdal Associates, 2001)	$0.10
VT Low-Income Weatherization (Riggert et al., 1999)	$10.33
CA Low-Income Weatherization (Skumatz and Dickerson, 1999)	$0.48
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$0.97
Average of 2018$ Adjusted Values	**$1.85**
Customer Calls	
WI Low-Income Weatherization (Skumatz and Gardner, 2005)	$0.55
MA Low-Income Weatherization (Skumatz Economic Research Associates, 2002)	$0.81
CT Low-Income Weatherization (Skumatz and Nordeen, 2002)	$0.75
CA Low-Income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc., and Megdal Associates, 2001)	$2.22
CA Low-Income Weatherization (Skumatz and Dickerson, 1999)	$0.10
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$0.19
Average of 2018$ Adjusted Values	**$0.77**

Source: MA NEI Evaluation 2011. p. D-5 and D-6. MA NEI Evaluation provided values in 2010$. Values originally provided in 2010 dollars have been updated to 2018 dollars using the CPI-U index.

5. Avoided safety-related emergency calls

As the amount of battery storage connected to the electric grid increases, the frequency and duration of power outages is reduced.[48] Power outages entail risks and can and do result in safety-related emergency calls to customers. When families and businesses experience fewer power outages, electric distributors avoid making some safety-related emergency calls and the expenses associated with those calls.

MA NEI Evaluation 2011 presents non-energy benefits of avoided safety related emergency calls, and describes the related savings to electric distributors: as electric load during peak periods is reduced, "utilities may realize financial savings due to a reduction in safety-related emergency calls and insurance

[48] (1) Nexight Group. December 2010. *Electric Power Industry Needs for Grid-Scale Storage Applications*. Prepared on behalf of the U.S. Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability and the DOE's Office of Energy Efficiency and Renewable Energy Solar Technologies Program. Available online: https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Utility_12-30-10_FINAL_lowres.pdf. (2) Zhang, T., Cialdea, S., Orr, J.A., and Emanuel, A.E. 2014. Outage Avoidance and Amelioration using Battery Energy Storage Systems. *IEEE*. Available online: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6808127.

costs, due to reduced fires and other emergencies."[49] This benefit may be particularly applicable for electric distributors that offer efficiency programs that repair or replace appliances to low-income households, who may be more likely to have old or damaged space and water heating appliances, gas appliances, and gas connectors.[50]

Non-energy benefits of battery storage reducing emergency calls may exist as well, to the extent that outages and related safety risks are avoided. Table 7 shows the program administrator-recommended value for this avoided cost in the context of energy efficiency: $10.11 per year per participant.

Table 7. Benefits of avoided safety-related emergency calls

Study	$/year/participant (Adjusted 2018$)
Safety-Related Emergency Calls	
National Low-Income Weatherization NEBs Study (Schweitzer and Tonn, 2002)	$9.48
MA Low-Income Weatherization (Skumatz Economic Research Associates, 2002)	$0.55
CT Low-Income Weatherization (Skumatz and Nordeen, 2002)	$0.29
CA Low-Income Public Purpose Test (TecMarket Works, Skumatz Economic Research Inc., and Megdal Associates, 2001)	$0.10
VT Low-Income Weatherization (Riggert et al., 1999)	$25.38
CA Low-Income Weatherization (Skumatz and Dickerson, 1999)	$11.67
Venture Partners Pilot Program (Skumatz and Dickerson, 1997)	$23.27
Average of 2018$ Adjusted Values	**$10.11**

Source: Adapted from MA NEI Evaluation 2011. p. D-8. MA NEI Evaluation provided values in 2010$. Values originally provided in 2010 dollars have been updated to 2018 dollars using the CPI-U index.

6. Job Creation

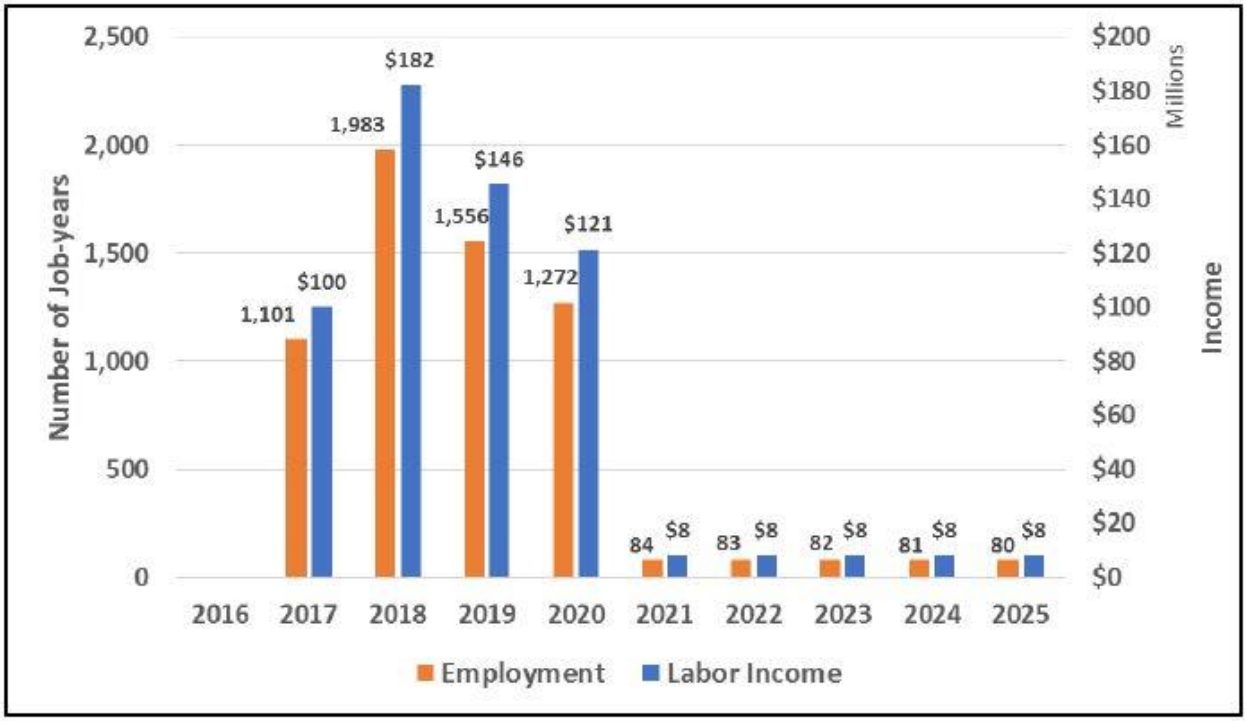
As investment in storage grows in Massachusetts, related jobs will be created along the entire supply chain, including in: battery manufacturing, research and development, engineering, construction, operations and maintenance, sales, marketing, management, and administration. While job creation is not considered in Massachusetts program administrators benefit-cost ratios for energy efficiency, increasing employment is clearly a benefit to the Commonwealth.

CEC/DOER's 2017 *State of Charge* report addresses job creation as a non-energy benefit of increased investment in energy storage, noting that "growing [the] energy storage industry can expand on the success of the clean energy industry, bringing in new business to Massachusetts and creating new jobs."[51] The report found that deploying 1,766 MW of energy storage in the Commonwealth could create 6,322 job-years (where 1 job-year is defined as one job for one year) and $591 million in labor

[49] MA NEI Evaluation 2011. p. 1-4.
[50] MA NEI Evaluation 2011. p. 4-16; Woolf et al., 2014. p.25
[51] MA CEC/DOER 2017. *State of Charge*. p.23.

income over the ten-year study period (2016-2025) (see Figure 3 below).[52] Per year, these benefits are equivalent to an average of approximately 700 jobs and $66 million; equivalent to 3.3 jobs per MW and $310,000 per MW over the battery storage deployment period (2017-2020) and 0.05 jobs per MW and $4,500 per MW over the storage maintenance period (2021-2025).[53] For context, according to a Massachusetts Clean Energy Center employment report, in 2017, clean energy industry employment in the Commonwealth grew by 4,014 jobs.[54]

Figure 3. *State of Charge* Massachusetts employment and labor income impacts, 2016-2025



Source: Reproduced from MA CEC/DOER 2017, State of Charge. Available online: https://www.mass.gov/files/2017-07/state-of-charge-report.pdf. Figure Appendix B-3, p.222.

CEC and DOER note that the employment and labor income impacts shown in Figure 3 are the result of anticipated levels of spending. Currently, Massachusetts has allocated $10 million in spending on energy storage initiatives from 2017 through 2020 only, resulting in a sharp decrease in employment and labor income impacts in 2021. In order for employment and labor income impacts in 2021 and beyond to be at the levels expected between 2017 and 2020, more spending would need to be allocated to additional storage deployment in those years.[55]

[52] MA CEC/DOER 2017. *State of Charge*. p.103.
[53] MA CEC/DOER 2017. *State of Charge.* p.222-3.
[54] Massachusetts Clean Energy Center (CEC). 2017. *Massachusetts Clean Energy Industry Report*. Available online: https://www.masscec.com/2017-massachusetts-clean-energy-industry-report.
[55] MA CEC/DOER 2017. *State of Charge.* p.223.

The *State of Charge* report finds that investing in energy storage systems in Massachusetts will provide: 1) direct benefits from employment created from activities such as planning, developing, constructing, installing and maintaining battery storage;[56] 2) indirect benefits created in industries that support battery storage, such as necessary inputs to manufacture batteries—like lithium ion—or facilities needed to facilitate the manufacture, maintenance or operation of battery storage;[57] and 3) induced benefits (that is, ripple effects through the economy) from, for example, battery storage employees spending money near their place of work in restaurants and shops, signing up for health care services, signing up for retirement accounts, etc.[58]

To estimate a value to this non-energy benefit, we used the results of the *State of Charge* report, presented in Figure 3 above, calculating the number of job years created per MW of battery storage and the associated labor income generation per MW. During the construction period between 2017 and 2020, for each MW of installed battery storage capacity, CEC and DOER expect approximately 3.3 job years and $310,000 of labor income. *State of Charge* projects an average annual income plus benefits of approximately $93,000 per job year.

Increasing battery storage in Massachusetts holds the promise of job creation, which will serve to strengthen local communities by providing Massachusetts families will valuable sources of family income.

7. Less land used for power plants

More battery storage reduces capacity reserve margins and the need for power plants that supply energy exclusively at times of peak demand. Reducing the number of peaker plants needed to maintain reliability (which is an energy system benefit) results in an additional non-energy benefit for society as a whole: less land need be devoted to power plants and instead could be used for other purposes such as recreation, conservation, commercial or residential buildings, cropland or pasture.

State of Charge explains, "[A]dvanced energy storage projects require a much smaller footprint than conventional power plants."[59] The report goes on to discuss the comparative land requirements of storage measures and new power plants:

> *With impending power plant retirements in local load pockets, building new power plants or transmission lines is an extensive undertaking with large land requirements. Advanced energy storage, in contrast, can easily be added to local areas to provide grid stability, eliminating the need for new gas-fired generation or transmission to solve these local reliability needs.* [60]

[56] MA CEC/DOER 2017. *State of Charge.* p.223.
[57] MA CEC/DOER 2017. *State of Charge.* p.223.
[58] MA CEC/DOER 2017. *State of Charge.* p.223-4.
[59] MA CEC/DOER 2017. *State of Charge.* p. 9.
[60] MA CEC/DOER 2017. *State of Charge.* p. 9.

According to a report commissioned by the U.S. Department of Energy's Storage Systems Program, "society at large has a significant stake in the storage opportunity because some of the key benefits accrue, in part or in whole, to society at large (e.g., reduced air emissions and reduced land use impacts from reduced need for new infrastructure)".[61] Increasing battery storage capacity in Massachusetts provides benefits beyond those directly experienced by electric distributors or ratepayers; there are broader societal benefits including making more land available for alternative uses.

Neither the MA NEI Evaluation 2011[62] nor the MA NEI Evaluation 2016 address reduced land use as a non-energy benefit, although many energy efficiency measures lessen the need for new power plants in the same way that battery storage does, shrinking the electric sector's land use footprint.

As a preliminary estimate of this non-energy benefit based we compare the land use footprints of conventional natural gas combustion turbines and utility-scale battery storage (see Table 8). The vast majority of storage measures offered to ratepayers by the program administrators, however, can be expected to have much smaller per MW land footprints than would a utility-scale battery storage facility. Many behind-the-meter battery storage installations have no land-use footprint whatsoever. (For example, Tesla's Powerwall 2 battery is 45"x30"x6" and is typically installed within an existing building.[63])

[61] Eyer, J. and Corey, G. February 2010. *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide: A Study for the DOE Energy Storage Systems Program*. Prepared by Sandia National Laboratories, SAND2010-0815. Available online: https://www.smartgrid.gov/files/sandia_energy_storage_report_sand2010-0815.pdf. p. 152.

[62] MA NEI Evaluation 2011 does include a consideration of a related non-energy benefit, namely, avoided landfill space due to appliance recycling programs.

[63] Energy Matters. "Buy Tesla Powerwall 2 Home Battery." Available online: https://www.energymatters.com.au/residential-solar/tesla-powerwall-battery/.

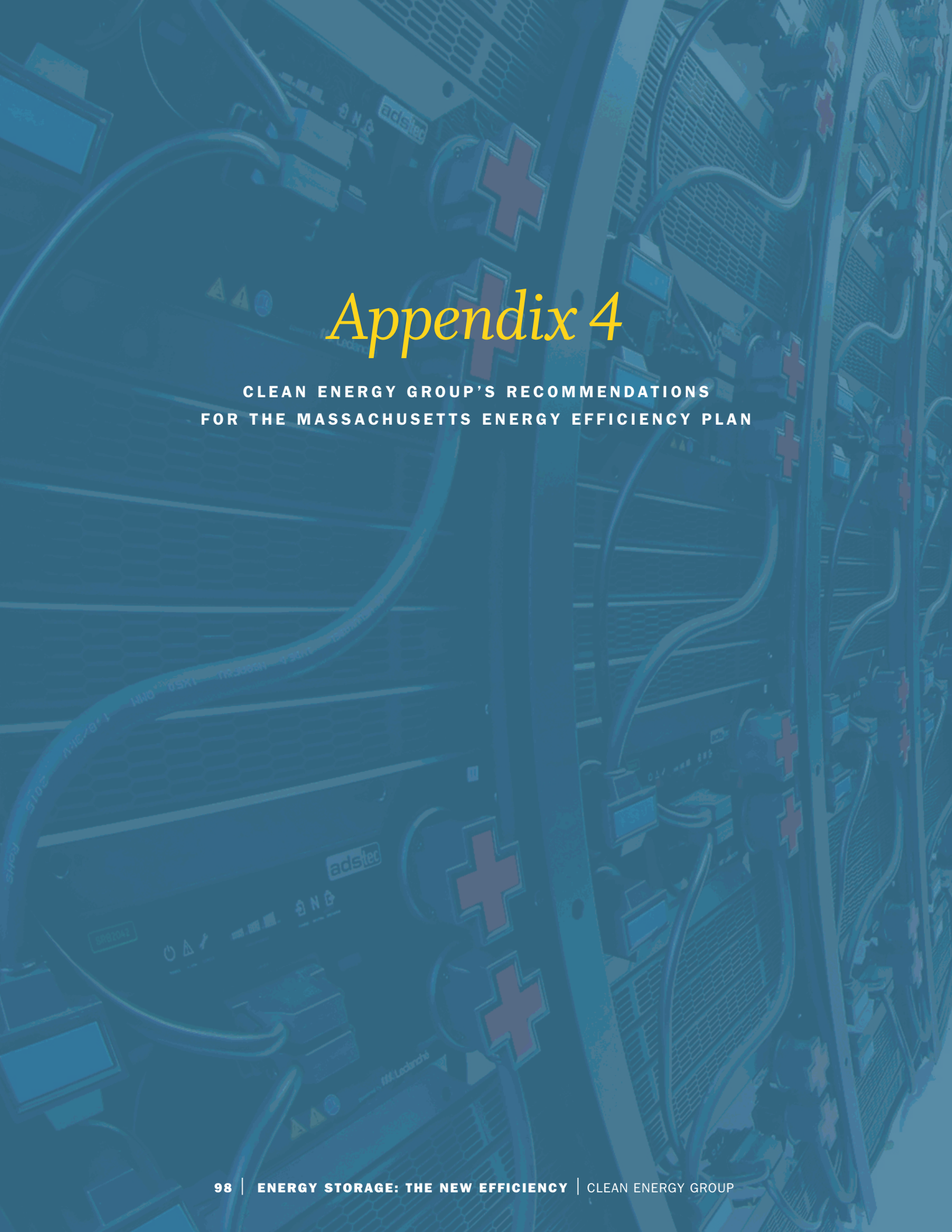
Table 8. Average land use of U.S. natural gas plants and utility-scale battery storage installations

Energy Type	Land Use Footprint (Acres/MW)	Location	Source
Natural gas	**12.4**	U.S.-wide estimate	Eyer, J. and Corey, G. February 2010. Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide: A Study for the DOE Energy Storage Systems Program. Prepared by Sandia National Laboratories, SAND2010-0815. Available online: https://www.smartgrid.gov/files/sandia_energy_storage_report_sand2010-0815.pdf.
Utility-scale battery storage	**0.017**	Average of three cases provided below	AEC calculation
Utility-scale battery storage	0.004	Duke Energy wind and battery storage project (TX)	International Renewable Energy Agency (IRENA). 2015. Case Studies: Battery Storage. Available online: http://www.irena.org/documentdownloads/publications/irena_battery_storage_case_studies_2015.pdf
Utility-scale battery storage	0.007	Solar Grid Storage solar and battery storage project (MD)	International Renewable Energy Agency (IRENA). 2015. Case Studies: Battery Storage. Available online: http://www.irena.org/documentdownloads/publications/irena_battery_storage_case_studies_2015.pdf
Utility-scale battery storage	0.04	AES Energy Storage 50 MW lithium-ion configuration	Leslie, P. 2014. Battery Storage Projects. Puget Sound Energy Presentation. UW Energy and Environment Seminar. Available online: https://class.ece.uw.edu/500/2014aut-e/11-13-14%20Pres%20(PSE%20Storage).pdf

While natural gas plants use a substantial amount of land, residential battery storage typically involves little or no additional use of land. The difference between the land use footprint of a typical natural gas combustion turbine and behind-the-meter battery storage is approximately 12.4 acres per MW of capacity—meaning that for each MW of battery storage installed, 12.4 acres of land is available to be utilized for non-energy purposes. While we do not have access to data on the land value of existing gas plants, nor are we able to predict the land value of plants yet to be built, recent research has found that the average value of urban land in Boston is $600,000 per acre.[64] If, for example, a 60 MW gas peaker plant in urban Boston were avoided by installing battery storage instead—the total value of land available for other uses would be approximately $446 million. It is important to conclude with a caveat: land values are highly location-dependent, and the numbers presented above should be interpreted with care as an illustration only.

[64] Albouy, D., Ehrlich, G. and Shin, M. 2018. Metropolitan Land Values. *The Review of Economics and Statistics, MIT Press*, 100(3), 454-466. Available online: http://davidalbouy.net/landvalue_index.pdf. p.460.

Full valuation of an energy project that was 12 acres of land per MW more efficient than its alternative would include benefits to the utility—for example, reduced operations, maintenance, and property taxes—as well as benefits to society—for example, land that might have been designated for a power plant could be used for mixed-use development instead.



Appendix 4

CLEAN ENERGY GROUP'S RECOMMENDATIONS FOR THE MASSACHUSETTS ENERGY EFFICIENCY PLAN

Appendix 4

CLEAN ENERGY GROUP'S RECOMMENDATIONS FOR THE MASSACHUSETTS ENERGY EFFICIENCY PLAN

The Massachusetts 2019–2021 Energy Efficiency Plan included some important advances in the inclusion of energy storage as a peak demand reducing technology. However, there are several ways to improve the plan to make it more proactive in supporting energy storage and clean energy equity. We offer the following suggested improvements for Massachusetts' 2022–2024 Three-Year Energy Efficiency Plan:

- **Low-income provisions.** Typically, it is more difficult to provide clean energy options to low-income communities, which need clean, resilient and low-cost energy the most. This is why the Commonwealth of Massachusetts has established a multi-agency initiative to ensure that low-income communities do receive clean energy services and programs.[1] The Commonwealth's energy efficiency plan includes "income-eligible" measures for these underserved communities, however, the program administrators did not include any storage incentives in the income-eligible category for the 2019–2021 plan. To correct this omission, Massachusetts should focus on developing specific low-income provisions as it begins the process to develop the next three-year energy efficiency plan, which will commence in 2022. These could include an added low-income incentive, more favorable financing, a carve-out guaranteeing a certain percentage of low-income participation, an up-front rebate, or (preferably) a combination of these.

- **Lack of transparency.** Numerous stakeholders have noted a lack of transparency in the way the energy efficiency plan was developed, as well as in the resulting plan. The plan as approved by the DPU still includes vague and undefined elements that make it difficult to understand exactly what is being offered to storage customers by the program administrators. Improved transparency is essential, both to enable stakeholder participation in the process, and to enable developers to effectively market the plan.

- **Stacking incentives/applications.** Stacking applications and incentives (such as net metering, SMART incentives, and efficiency incentives) can be important to allow customers to defray battery storage system costs. Because the Massachusetts energy efficiency plan does not prohibit the stacking of incentives and applications, it is assumed that this practice will be allowed. However, it would be preferable to make this clear in the language of the energy efficiency plan itself.

- **Size of investment.** The investment in incentives that could be applied to energy storage is small ($13 million/34 MW) relative to both the size of the state's peak load, and to the size of the efficiency budget. Future plans should expand the energy storage offering.

- **Daily Dispatch program.** The Massachusetts Department of Public Utilities (DPU) should allow the utilities to go forward with their proposed Daily Dispatch energy storage incentive as a full program offering, rather than a pilot program.

- **Energy Storage System and Performance program.** The MA DPU should allow Cape Light Compact (CLC) to go forward with its proposed Storage System and Performance program, which would, if approved, provide free batteries to 1,000 residential and commercial customers of CLC, including low-income customers. CLC's proposed program was the only part of the plan that included income-eligible customers in any way. It also set forth a different approach to incentivizing battery deployment, that would have provided the state with an alternative model to compare with the statewide offering.

1 The MA governor announced the Affordable Access to Clean and Efficient Energy Initiative in 2016. For more information, see *https://www.mass.gov/service-details/affordable-access-to-clean-and-efficient-energy-initiative*.

- **Energy storage benefits omitted/undervalued.** Due to numerous omissions, notably the absence of any consideration of non-energy benefits, energy storage was likely undervalued in the utility program administrators' benefit/cost ratios (BCRs). In addition to the omission of non-energy benefits, there are a number of other omissions and errors in the valuation of energy storage in the 2019–2021 Massachusetts energy efficiency plan. The most important of these are listed below (these issues are discussed in more detail in Applied Economics Clinic's reports in Appendices 1–3):
  - Non-energy benefits valued at zero
  - Summer discharge generally not included in targeted discharge
  - Winter reliability benefits valued at zero. The MA Energy Efficiency Advisory Council (EEAC) and the program administrators should together work to value the winter reliability benefits of energy storage, as called for by the EEAC and DOER.
  - Emissions benefit under-counted (CO_2 emissions assumed higher in off-peak hours than on-peak hours, contrary to ISO-New England data)
  - Energy prices use assumed averages rather than actual, granular prices by time period
  - Summer capacity undervalued—assumption that storage only operates during 10 percent of peak hours (based on Maryland study)

In addressing the above issues, additional analytical work may be needed. Recommended future analytical work in Massachusetts includes:

- Analysis of additional non-energy benefits of energy storage (beyond the seven included in this report)
- Evaluation of the value of winter reliability benefits of energy storage (as called for by DOER and the EEAC)
- Analysis of assumptions that New England generators' CO_2 emission rates are higher during off-peak than peak hours (contrary to ISO-New England historical data), and the impact of this on storage BCRs Revision of storage BCRs using hourly price data rather than average seasonal on- and off-peak prices, as the program administrators did for the 2019 MA energy efficiency plan
- Analysis of the value of shaving peak demand in New England
- Analysis of the value of health benefits resulting from replacing fossil fuel generation with renewables and energy storage

ABOUT THE AUTHOR

Todd Olinsky-Paul is a project director for Clean Energy Group (CEG) and Clean Energy States Alliance (CESA). He conducts policy work for Clean Energy Group's Resilient Power Project, supporting state policymakers and regulators in integrating behind-the-meter battery storage into state policy and programs. He also directs CESA's Energy Storage and Technology Advancement Partnership (ESTAP), a federal-state funding and information sharing project that aims to accelerate the deployment of electrical energy storage technologies in the United States. Todd's recent work has focused on energy storage policy and economics, including work with federal and state energy agencies, utilities, non-governmental organizations and national laboratories. He holds a Master of Science in Environmental Policy from Bard College and a Bachelor of Arts from Brown University.
Todd@cleanegroup.org

ABOUT CLEAN ENERGY GROUP

Clean Energy Group (CEG) is a national, nonprofit organization that promotes effective clean energy policies, develops low-carbon technology innovation strategies, and works on new financial tools to advance clean energy markets that will benefit all sectors of society for a just transition. CEG works at the state, national, and international levels with stakeholders from government, the private sector, and nonprofit organizations. CEG promotes clean energy technologies in several different market segments, including resilient power, energy storage, solar, and offshore wind. CEG created and now manages a sister organization, the Clean Energy States Alliance, a national nonprofit coalition of public agencies and organizations working together to advance clean energy through public funding initiatives. Neither organization accepts corporate contributions. *www.cleanegroup.org*

Energy Storage: The New Efficiency

HOW STATES CAN USE ENERGY EFFICIENCY FUNDS TO SUPPORT BATTERY STORAGE AND FLATTEN COSTLY DEMAND PEAKS

Clean Energy Group (CEG) is a leading national, nonprofit advocacy organization working on innovative policy, technology, and finance strategies in the areas of clean energy and climate change.

CEG's energy storage policy work is focused on the advancement of state, federal, and local policies that support increased deployment of energy storage technologies. Battery storage technologies are critical to accelerate the clean energy transition, to enable a more reliable and efficient electric power system, to promote greater energy equity, health, and resilience for all communities.

Learn more about Clean Energy Group and its Energy Storage Project at *www.cleanegroup.org/ceg-projects/energy-storage-policy*.

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50 State Street, Suite 1 • Montpelier, VT 05602
802.223.2554 | www.cleanegroup.org | info@cleanegroup.org

Appendix C

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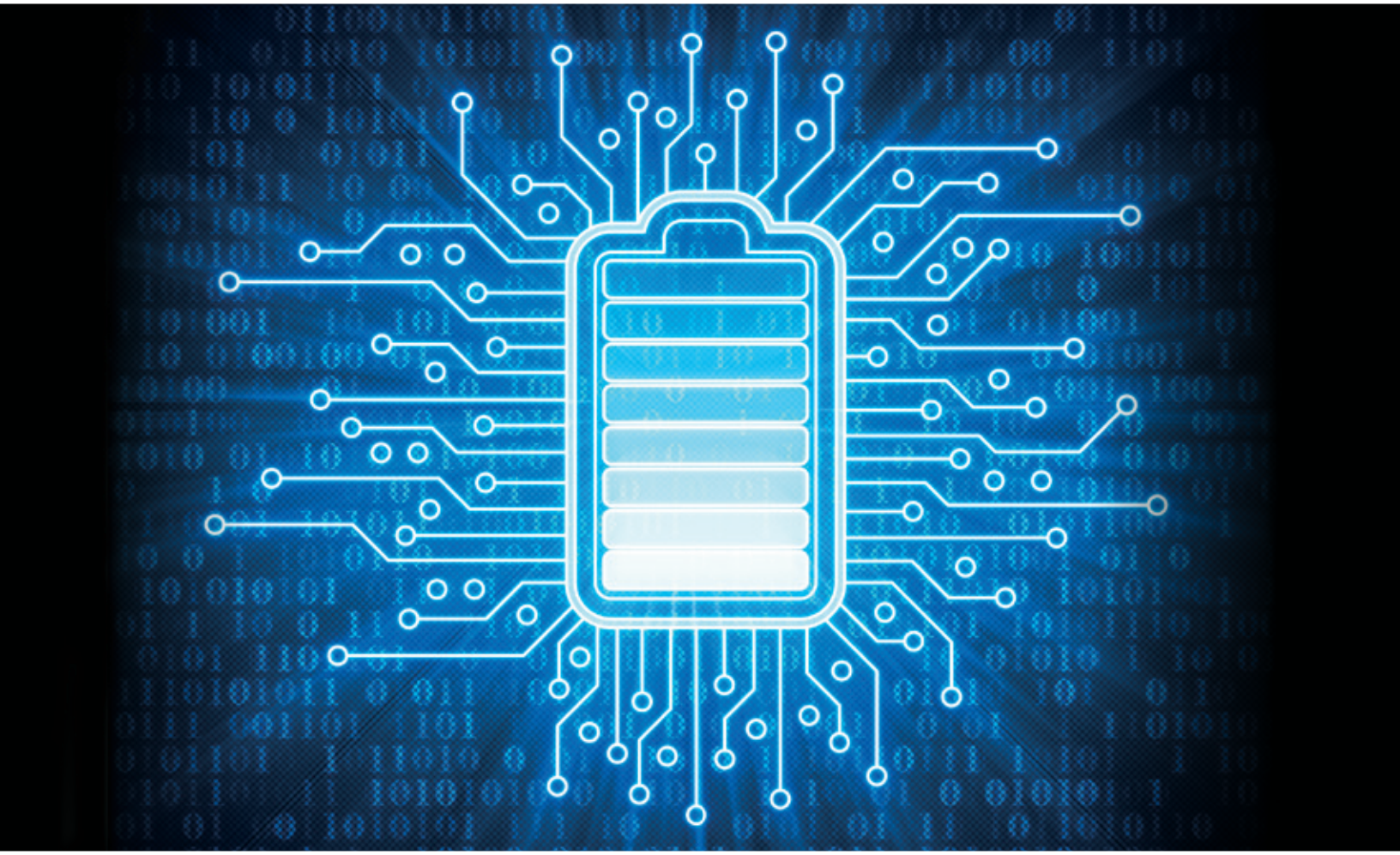
Connected Solutions: A New State Funding Mechanism to Make Battery Storage Accessible to All

ConnectedSolutions

A NEW STATE FUNDING MECHANISM TO MAKE BATTERY STORAGE ACCESSIBLE TO ALL



CleanEnergyGroup

Todd Olinsky-Paul | February 2021

ABOUT THIS REPORT

This report, prepared by Clean Energy Group (CEG), explains the policy advantages and opportunities represented by the ConnectedSolutions customer battery storage incentive program, developed (with technical support from CEG) as part of the 2019–2021 Three-Year Energy Efficiency Plan in the Commonwealth of Massachusetts. The report summarizes the barriers to scaling up distributed battery storage, explains how the ConnectedSolutions model addresses these barriers, and provides recommendations to other states for how to incentivize battery storage within their own energy efficiency plans. The report was generously supported by funding from Barr Foundation, The John Merck Fund, and Merck Family Fund. It is available online at www.cleanegroup.org/ceg-resources/resource/connected-solutions-policy.

"ConnectedSolutions" is a customer load reduction program developed by utilities in Massachusetts. The term "ConnectedSolutions" is used in this report as a generic term for any utility program, funded through a state energy efficiency program, that pays performance-based incentives to electricity customers in exchange for aggregated battery dispatch on peaks.

ABOUT THE AUTHOR

Todd Olinsky-Paul is a senior project director for Clean Energy Group and Clean Energy States Alliance (CESA). He directs CESA's Energy Storage and Technology Advancement Partnership (ESTAP), a federal-state funding and information sharing project that aims to accelerate the deployment of electrical energy storage technologies in the United States. Todd also works on CEG's Resilient Power Project, supporting solar+storage behind the meter for critical infrastructure energy resiliency. Todd's recent focus has been on the development of energy storage policy and programs at the state level. Todd has a M.S. in Environmental Policy from Bard College and a B.A. from Brown University.

ACKNOWLEDGMENTS

Clean Energy Group wishes to express its sincere thanks to Barr Foundation and the Merck Family Fund for their generous support of this work; to Geoff Oxnam at American Microgrid Solutions (AMS) and Liz Stanton from the Applied Economics Clinic (AEC), who produced the economic analyses that underly some of the findings of this report; and to those who made this a better report through their insightful review comments, including Liz Stanton of AEC, Geoff Oxnam of AMS, Bryan Garcia at the Connecticut Green Bank, Chris Rauscher and colleagues at Sunrun, Lew Milford, Seth Mullendore and Maria Blais Costello at Clean Energy Group, and Warren Leon at Clean Energy States Alliance. The author also wishes to thank Rob Sanders, Meghan Monahan, Samantha Donalds and Marriele Mango of Clean Energy Group and Clean Energy States Alliance for their invaluable contributions.

DISCLAIMER

ConnectedSolutions

A NEW STATE FUNDING MECHANISM TO MAKE BATTERY STORAGE ACCESSIBLE TO ALL

Todd Olinsky-Paul
Clean Energy Group

FEBRUARY 2021

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Courtesy of Sunrun

Executive Summary

When a new clean energy technology emerges, its benefits are often more evident than the mechanisms to monetize those benefits. This is the situation we now find ourselves in with distributed energy storage. Markets and market regulation have not kept up with advances in battery technology and its applications, meaning battery storage owners are frequently unable to monetize their investment. And, despite the fact that bringing behind-the-meter (BTM) energy storage to scale is key to achieving numerous state clean energy goals, state policy also has not kept pace with advances in the technology, with the result that most states have few (if any) incentives or other funding mechanisms in place to support the growth and development of distributed storage markets.

This policy gap represents a significant missed opportunity to harness the myriad benefits battery storage can provide to communities, grid operators, and utilities. Distributed, privately owned storage can reduce peak demand, enhance renewables integration, increase community resilience, defer distribution system investments, and reduce local emissions—all valuable services that support policy goals in many states.

Ideally, in the absence of developed markets for these services, state energy storage incentives would compensate battery owners for delivering these benefits. States could step in with programs to connect storage providers with off-takers of these services, much as states developed net metering programs to connect distributed solar generators to the electric grid. Yet until very recently, nobody had designed such a program for battery storage. And because it remains difficult to monetize the many benefits of distributed storage, funding and financing for these systems remains difficult to secure, even in states that are committed to a clean energy future.

Now a new, performance-driven incentive program called ConnectedSolutions, developed in the Commonwealth of Massachusetts with technical support from Clean Energy Group (CEG), supplies the missing funding link to accelerate customer-side uptake of battery technology, while simultaneously delivering the many important public benefits of storage, and providing a way for storage owners to monetize these benefits. The fundamental innovation of ConnectedSolutions is to integrate customer batteries into the state energy efficiency program, making them eligible for performance payments as peak demand reducing resources. Properly implemented, the ConnectedSolutions model could become for distributed battery storage what net metering has been for distributed solar—a vital link allowing benefits to flow from private system owners to public electric grids, and a key funding tool to scale up a vital emerging clean energy technology.

The fundamental innovation of ConnectedSolutions is to integrate customer batteries into the state energy efficiency program, making them eligible for performance payments as peak demand reducing resources.

This report explains how the ConnectedSolutions program was developed in the Northeast, why it is successful, and how states can adopt it to transform battery storage markets nationwide. It also explains the many economic, social and policy benefits of ConnectedSolutions. And it recommends federal initiatives that could support the adoption of this program across the nation, through national storage initiatives and technical assistance to states.

POLICY ADVANTAGES OF THE CONNECTEDSOLUTIONS MODEL

Through working with state policymakers, regulators, developers, and utilities, CEG has found that the ConnectedSolutions program model offers numerous policy advantages, because it:

- **Makes funds available for distributed storage incentives** by drawing on existing efficiency budgets

- **Addresses costly and polluting demand peaks** through the formation of clean virtual power plants
- **Uses private battery systems to produce public benefits** through the use of multi-year customer/utility contracts
- **Reduces investment risk** for battery owners, developers, and lenders by improving project economics and making revenues more consistent and predictable
- **Improves battery system economics** through regular performance payments and heightened system financeability
- **Encourages system and program standardization** by setting state-wide program eligibility standards
- **Democratizes storage ownership and benefits** by making storage accessible to all, and generating widespread ratepayer benefits
- **Improves energy resilience** by supporting and encouraging larger batteries
- **Addresses utility ownership issues** by providing a distributed procurement mechanism

Courtesy of Sunrun

Key Elements of the ConnectedSolutions Model

As developed in Massachusetts, the ConnectedSolutions program model incorporates a few simple but innovative elements to provide economic, efficiency, and policy benefits to customers, utilities, policymakers, and the storage industry.

Although each state and utility will need to adapt the basic model to meet specific needs and accommodate local regulations, certain key elements are essential to an effective ConnectedSolutions program:

- **Battery funding through state energy efficiency programs** provides a stable source of incentive funding for BTM battery systems
- **Customer and third-party ownership** of batteries ensure diverse and competitive battery markets
- **Pay-for-performance on a utility signal** aggregates private batteries for the public good, and ensures utilities pay only for services received
- **Up-front rebates (recommended)** help overcome cost barriers, especially for LMI customers
- **Financing mechanisms such as low- or no-cost financing and on-bill payment** further reduce cost barriers and make the program accessible in underserved communities
- **Stackable rate adders (recommended)** encourages the provision of multiple social benefits
  - Equity/Low-Income rate adder
  - Resilient systems rate adder
- **Payment for energy export** as well as load reduction encourages larger batteries, makes residential systems cost-effective, and provides greater grid benefits
- **Multi-year customer contracts with utilities** make systems financeable and encourage project pipelines
- **Inclusion of third-party aggregators** diversifies the market and makes more financing and ownership models available to customers
- **Stackability with other incentive programs** maximizes customer returns on investment and supports related state clean energy programs
- **Customer opt-out without penalty** safeguards customer resilience benefits

Bigstock/holbox

- **Gives state policymakers a new tool to address related energy policy goals** such as increasing and integrating renewable generation, reducing peak demand, enhancing electric resilience, and increasing clean energy access for underserved communities

These policy advantages should make the ConnectedSolutions model attractive to state policymakers and provide a solid basis for incorporating energy storage into state energy efficiency plans as a peak demand reducing measure.

The ability to address related state energy policy goals through the ConnectedSolutions program model is particularly important when considering how to address issues of energy equity. Too often, state clean energy incentive programs struggle to achieve significant levels of LMI enrollment. It is important that the emerging energy storage market not leave underserved communities behind. The ConnectedSolutions model, if properly designed and implemented, can help to address this equity gap.

THE IMPORTANCE OF STORAGE EQUITY

Underserved and low- to moderate-income (LMI) communities need energy storage more than others, both to reduce energy costs and to provide resilient backup power during grid outages. At the same time, these communities face higher barriers that must be overcome if they are to access the benefits of energy storage. ConnectedSolutions, as originally implemented in Massachusetts, did not include sufficient provisions to overcome these barriers. Now, proposals in other New England states have shown how the program can be improved to make it more equitable and accessible.

Numerous studies have shown that underserved communities pay a higher-than-average portion of income to cover energy costs. This is partly because lower income customers tend to live in older, less energy-efficiency houses, and are less able to make efficiency investments to improve these houses. Also, energy expenses are to some degree inflexible, meaning they don't vary as much as the customer's ability to pay. According to the National Conference of State Legislatures, "A review of energy expenses in metropolitan areas shows that customers who earn at or below 80 percent of an area's median income contribute, relative to their income, more than twice that of median-income customers and more than three times that of high-income customers."[1]

At the same time, underserved communities are more vulnerable to natural disasters and the accompanying power outages. For example, Brookings reports that "Hurricanes hit the poor the hardest"[2] while *The Atlantic* notes the same dynamic in the California Camp Fire.[3]

For these reasons, as well as for basic equity considerations, it is important that LMI and underserved communities not be left behind in the energy storage revolution.

In order to address energy storage equity issues, certain barriers must be overcome. These barriers include low rates of home ownership in LMI communities, the high up-front cost of energy storage, the lack of information about incentive programs and the benefits of energy storage, and the difficulty of obtaining financing in these communities.

These barriers can be addressed through some simple improvements to the basic structure of ConnectedSolutions, to make it more accessible:

- **Addition of an up-front rebate** as proposed by the Connecticut Green Bank and included in the current Connecticut Public Utilities Regulatory Authority (PURA) straw proposal, with a higher rebate rate or adder for LMI participants

Underserved and low- to moderate-income (LMI) communities need energy storage more than others, both to reduce energy costs and to provide resilient backup power during grid outages. At the same time, these communities face higher barriers that must be overcome if they are to access the benefits of energy storage.

- **Pay-for-performance rate adders** for LMI participants
- **Health incentive adders** for critical home health customers
- **More financing options** including on-bill financing, as proposed by the Connecticut Green Bank
- **Affordable housing developer outreach, marketing, and technical support** to help owners and developers of multifamily affordable housing facilities integrate solar+storage solutions
- **Virtual storage/community storage** as piloted by the Sacramento Municipal Utility District (SMUD). This variation on the community solar model allows the utility to install large scale battery storage at a central location (typically at a utility substation) and then sell "shares" in the storage to customers who may not be able to site a battery in their own home or business. The utility then uses the storage to reduce costs associated with peak demand and shares the benefits with shareholders through bill credits. ConnectedSolutions could allow for similar arrangements with municipalities, schools or community buildings hosting the baterries and contracting with utilities on behalf of community "shareholders" who would share in the benefits. Resiliency benefits to a school, municipal or community building would also benefit the community, as the facility could serve as a public shelter in case of a grid outage.

LESSONS LEARNED AND RECOMMENDATIONS FOR STATE POLICYMAKERS

Although ConnectedSolutions is a very new program, CEG has compiled some lessons learned from early adopters and developed recommendations for state policymakers looking to adopt a ConnectedSolutions model program:

1. **Follow the steps taken in other states, with appropriate adaptations.** These include:
   - **Integrate peak demand reduction** into the state's energy efficiency plan
   - **Specify that BTM batteries are eligible** as a peak-reducing or active demand response measure
   - **Show that batteries pass the cost/benefit test** required for inclusion in the efficiency plan
   - **Require efficiency plan administrators to develop a customer battery program** within the efficiency plan
   - **Ensure that the state's related policy goals are supported** by the battery program
   - **Review existing regulations and program rules for needed updates** to accommodate BTM batteries and allow benefit stacking.
   - **Address distribution systsem** hosting capacity shortfalls as necessary
2. **Provide incentives and financing to help cover up-front costs.** The ConnectedSolutions model can provide a customer payback through utility pay-for-performance contracts, but the customer still has to pay the up-front costs of purchasing and installing a battery. The addition of an up-front rebate and/or low- or no-cost financing to this model can help customers overcome the initial cost barrier, especially in the case of low- and moderate-income customers.
3. **Offer long-duration customer contracts.** The duration of customer pay-for-performance contracts is critically important for risk reduction and financing—the longer the better.
4. **Allow power export to the grid.** Allowing power export in addition to load reduction, and counting exported power toward customer performance payments, prevents regional peak demand reduction contributions from being limited by the size of the customer's load. This is important for project economics, especially for residential and small commercial customers, and allows the full grid benefits of BTM batteries to be realized.
5. **Avoid excessive metering requirements.** Simple solutions, such as using inverter readings, are recommended over more complicated and costly solutions, such as requiring customers to install multiple electric meters to monitor battery charging and discharging.
6. **Coordinate between clean energy incentive programs.** BTM battery storage customers may need to stack multiple incentives and revenue streams to make their investment pay off; for that to happen, the state's suite of clean energy regulations and programs must work together.
7. **Recognize the value of customer resilience.** To make pay-for-performance battery programs work, state policy makers and utility program administrators need to acknowledge and support the resilience needs of individuals and communities.
8. **Predict and address interconnection barriers early.** Numerous BTM storage projects have been delayed or cancelled due to unexpected high costs of interconnection when line upgrades are required. When developing BTM solar and storage programs, states should assess utility hosting capacity

A battery storage system at one of the 14 rental units at the McKnight Lane Redevelopment in Waltham, VT. Each of the affordable housing units is equipped with a solar and battery storage system.

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ahead of time, and plan for distribution system upgrades where they are needed, to avoid high upgrade costs falling on individual customers.

CONCLUSION

The electric grid is at an inflection point. States are taking on big, new, clean energy challenges, such as increasing RPS targets, setting 100 percent clean energy goals, developing clean peak standards, increasing electric efficiency, advancing electrification, and tackling grid modernization. At the same time, states need to find ways to increase electric system resilience, reduce reliance on dirty fossil fuel peaker plants, lower the high costs of peak demand, and democratize the clean energy revolution to ensure that low-income and underserved communities share in the benefits of emerging, clean, distributed energy technologies.

To accomplish all this, states need to expand and scale up the deployment of distributed, BTM energy storage. Distributed battery storage is the key enabling technology that can integrate renewables onto the grid, provide clean backup power during grid outages, reduce demand peaks and the associated high costs and emissions, enable electrification, and retire dirty peaker plants.

ConnectedSolutions gives states a way to support and scale up battery storage without developing new incentive programs or establishing new budgets: the model simply requires states to integrate energy storage into their existing energy efficiency programs. Utilities and third parties then market and administer the program, which is highly cost-effective, since utilities purchase only the grid services that they need from customer batteries, and do not incur the added costs of capital investment, operations and maintenance, or decommissioning. This gives utilities the ability to benefit from energy storage services, without incurring the costs and responsibilities of energy storage ownership.

For utility customers, the ConnectedSolutions incentives can leverage low- or no-cost financing for the batteries, which can be paid off well within the lifespan of the equipment through a simple, low-risk, multi-year, pay-for-performance contract. For investors, the program lowers risk, increases standardization, and allows pipelines of BTM energy storage projects to be developed.

By enabling the deployment of more battery storage capacity, and by focusing the aggregated dispatch of this capacity on peak demand periods, this new model can help states begin to replace dirty fossil fuel power plants with clean, distributed solar+storage systems that provide real benefits to individuals, businesses, and communities. The result will be a cleaner, more resilient, more equitable power system for all.

Courtesy of Sunrun

Introduction

In 2019, the Commonwealth of Massachusetts commenced a nation-leading experiment. With technical support from Clean Energy Group (CEG), Massachusetts approved a three-year energy efficiency plan[4] that, for the first time, included behind-the-meter (BTM) energy storage as a peak demand reducing measure, allowing incentives to be made available from the state's energy efficiency budget.

For nearly a decade, Massachusetts had led the nation in energy efficiency, winning top marks from the American Council for an Energy Efficient Economy (ACEEE).[5] But this was something different: energy storage, in the form of residential and commercial-scale batteries, represented a new type of efficiency. Battery performance incentives from the efficiency budget represented a new way to fund distributed energy storage. And the aggregation of customer-owned batteries through utilities and third parties, to reduce costly regional demand peaks, represented the nation's first state-supported virtual power plant (VPP), a new business model that harnesses private storage resources to create public ratepayer savings.

Clean Energy Group had already helped to create one of the first small-scale VPPs in Vermont, where Green Mountain Power (GMP), the state's largest utility, was facing similar peak-related expenses. In 2016, GMP, CEG and the Clean Energy States Alliance (CEG's sister nonprofit) worked with the US Department of Energy (DOE) Office of Electricity, Sandia National Laboratories and foundation funders to install a pilot project in rural Waltham, VT, placing batteries in 14 modular, high-efficiency solar-equipped homes at the new McKnight Lane affordable housing development.[7] Through this pilot, GMP learned to aggregate and coordinate BTM batteries to meet regional grid needs.

Based on the success of McKnight Lane, GMP launched a residential Powerwall program[8] in partnership with Tesla, followed by a Bring Your Own Device (BYOD) battery program[9] that allowed GMP customers to choose between several home battery manufacturers. GMP's most recent program, called Resilient Home,[10] allows customers to install two Powerwall batteries for longer duration backup power. Like Connected-Solutions, the GMP programs allow the utility to partner with customers to install BTM batteries to meet larger grid needs. GMP has saved millions of dollars for its ratepayers by using customer-sited batteries to control demand peaks, thereby lowering capacity and transmission costs.[11]

In 2019, Massachusetts approved a three-year energy efficiency plan that, for the first time, included behind-the-meter energy storage as a peak demand reducing measure, allowing incentives to be made available from the state's energy efficiency budget.

However, few utilities have pursued distributed energy storage as aggressively as GMP; in fact, many are resistant to the idea of scaling up a new BTM energy resource. This can create a challenging landscape for forward-looking state energy policymakers tasked with meeting numerous clean energy goals and targets, such as integrating more renewable generation, modernizing the grid and making it more resilient, reducing air emissions, increasing efficiency and promoting the adoption of new distributed energy technologies.

In Massachusetts, the Department of Energy Resources (DOER) had been tasked with meeting aggressive new state energy storage procurement targets. After supporting the adoption of these targets, CEG proposed a customer energy storage rebate program to scale up deployment of the technology—but the state didn't have funds budgeted to support a new rebate. What it did have was a well-funded energy efficiency program.

From a regulatory standpoint, there was little need to amend the existing energy efficiency program rules to accommodate energy storage. The state had already included peak demand reduction in the enabling legislation as a goal of the efficiency

program, and batteries are a peak-shifting technology. The problem was that nobody had conducted the necessary analysis to show that behind-the-meter battery storage could pass the state's required cost/benefit test, in order to be funded under the efficiency program. With deadlines to complete the Commonwealth's energy efficiency plan looming, CEG contracted with Applied Economics Clinic to perform the needed analysis. The results, published in 2018,[12] showed that customer batteries would pass the test.

The Massachusetts efficiency program administrators (utilities) subsequently conducted their own cost/benefit analysis for BTM storage, with remarkably similar results.[13] Under state law, the efficiency program was required to "provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective." With its cost-effectiveness established, energy storage was in.

Once the ConnectedSolutions battery program was developed and implemented in Massachusetts, the two biggest investor-owned utilities in the Commonwealth, Eversource and National Grid, began working with regulators to offer similar battery programs to their customers in neighboring states. At this writing, the program has been adopted in Massachusetts, Rhode Island and Connecticut, and piloted in New Hampshire.[14] Meanwhile, BYOD programs similar to GMP's have been launched by utilities in New Hampshire, New York, California, and Oregon, and are under discussion by utilities and regulators in other states.

ConnectedSolutions and BYOD programs are important not simply because they are new, but because they solve numerous problems in bringing distributed battery storage to scale. Compared to other funding mechanisms, this new aggregated distributed storage model, sometimes called a "virtual power plant (VPP)," solves key challenges that battery storage often presents for developers, lenders, battery owners, utilities, policymakers, and regulators:

- **For developers** it improves battery project bankability and internal rates of return while unlocking grid service value that may be inaccessible through other programs

Once the ConnectedSolutions battery program was developed and implemented in Massachusetts, the two biggest investor-owned utilities in the Commonwealth, Eversource and National Grid, began to offer similar battery programs to their customers in neighboring states.

- **For lenders** it reduces risk
- **For battery owners** it shortens payback periods, makes batteries accessible to all, and provides backup power for free
- **For utilities** it makes behind-the-meter batteries controllable and predictable, and reduces the cost and risk inherent in storage capital investment
- **For policymakers and regulators** it democratizes storage and benefits all ratepayers, improving the case for investing public funds

Perhaps most importantly, it makes large and established energy efficiency budgets available to support distributed battery storage, making it possible for states to scale up this essential new technology. This serves numerous state policy interests, such as increasing renewable energy deployment, reducing fossil fuel dependency, reducing emissions, flattening regional demand peaks, lowering system-wide energy costs, and increasing grid resilience.

This report takes a first look at this new aggregated battery storage model from a policy perspective. It examines existing customer battery storage programs, exploring their benefits and challenges; reports on lessons learned; and makes recommendations for states wishing to replicate and improve upon these programs.

How the ConnectedSolutions Model Works

As developed in Massachusetts, the ConnectedSolutions program is based on a pay-for-performance model of customer battery funding. The program is part of the Commonwealth's Three-Year Energy Efficiency Plan, and it achieves efficiencies by reducing peak demand on the regional grid. To achieve peak demand reductions, the utility contracts for use of the customer's battery during regional demand peaks; the customer owns the batteries, and the utility pays only for services actually delivered.

Customers sign a five-year contract with their utility to participate in up to two of three different program offerings: a winter seasonal program, a summer daily dispatch program, and a summer targeted dispatch program. Customers can participate in one summer program, but not both, along with the winter program. Each of the three programs has its own performance payment rate. Payments are based on seasonal average hourly dispatch during the hours signaled by the utility. Dispatch events are usually three hours in duration, meaning battery capacity is de-rated by two-thirds when calculating payments.

For example, a commercial customer in Massachusetts installs a 60-kWh battery and signs up for the summer daily dispatch program, which offers a pay rate of $200/kW. If the customer responds to every utility signal over the season, and fully dispatches their battery each time, their maximum possible payment for one summer season is 20 kW x $200/kW = $4,000 (because a 60 kWh battery can, at best, deliver 20 kW/hr for three hours). Assuming the same customer also signs up for the winter program, their maximum payout for a year would be $4,500 (the winter program rate is $25/kW). Over a five-year contract period, this commercial customer could earn a maximum of $22,500 from participating in ConnectedSolutions.

There is no guarantee at this point that the utility program administrators will offer customers a second five-year contract, or that the rates would remain the same, but assuming a second contract was available at the same rates, the customer would be able to earn a maximum of $45,000 over ten years. This income is additional to other available incentives, such as the value of any Clean Peak Standard credits generated, the SMART solar rebate, net metering revenues, and the federal Investment Tax Credit (the last three assume the customer has a solar PV system as well as a battery). Together, these incentives and performance payments make it possible for the battery storage system to pay for itself—even for low-income and residential customers, who might not be able to reduce demand charges or take advantage of other significant energy cost savings in the absence of such incentives.

In the Massachusetts ConnectedSolutions program, customers are credited not only for reducing their load, but also for any excess power they export to the grid during dispatch calls. This means that customer revenues are not limited by the size of the customer's load.

It is important to note that customers who sign up for the program are not required to participate in every dispatch event called by their utility. Customers can opt out if they do not wish to respond to the utility signal, for example if they wish to reserve battery capacity for their own use during the dispatch window. There is no penalty for failing to respond, but this will reduce the customer's average response rate (and therefore payment) for the season.[15]

It is also important to understand that in the Massachusetts ConnectedSolutions program, customers are credited not only for reducing their load, but also for any excess power they export to the grid during dispatch calls. This means that customer revenues are not limited by the size of the customer's load. For example, if the commercial customer discussed above happened to have a facility load of only 10 kW during a battery dispatch call, the excess 10 kW left in the battery after reducing the customer's load to zero could be exported to the grid, and it would be credited as part of the customer's performance payment.[16]

Courtesy of Sunrun

The Barriers to Distributed Storage Scale-Up

Distributed energy storage (behind customer meters) offers numerous benefits—so many that it is frequently referred to as the "holy grail" needed to unlock a clean, renewable energy future. Unfortunately, there are many barriers to bringing distributed energy storage to scale. These problems must be overcome if communities, states, and regional electric grids are to realize the promised benefits.

The primary barriers to bringing distributed storage to scale at present include cost and related financing and market barriers:

- **High capital costs.** Despite significant decreases in manufacturing costs, batteries remain too expensive relative to their monetizable benefits in many parts of the country, and for many applications. This also means that for state policymakers, it may be costly to provide effective incentives for battery storage.
- **Economic risk/lack of financing.** Some of the monetizable benefits of storage, such as demand charge management, may be viewed as risky by lenders. This means that even where storage can achieve payback through cost reductions and revenues, favorable financing for storage investment may not be available, and pipelines of projects can be difficult to develop. Where too few financing vehicles exist to help address high capital costs, policymakers and developers struggle to provide battery ownership opportunities, especially in low- to middle-income (LMI) communities.
- **Lack of markets/barriers to market entry.** Many benefits of storage cannot be monetized due to the lack of markets for energy storage services, or because of the barriers to market access. This makes it challenging for storage to provide all the benefits of which it is capable, and it can prevent storage from passing cost/benefit analyses.
- **Lack of standardization.** A lack of standardization at all levels of the storage ecosystem, including in system components and communications/controls, regulatory codes and standards, market rules, and state policies and programs, translates to added costs to developers, including system design/build costs and administrative costs.

Other problems with distributed storage stem from these cost, financing, and market barriers:

- **Barriers to provision of social benefits.** Battery storage can offer many social benefits, such as reduced regional electric peak demand, improved integration of renewable generation, and increased energy resilience. But without developed markets for these benefits, it is difficult for storage owners to provide them.[17] This in turn makes it difficult for policymakers to justify distributed storage incentives, because it may appear that public funds are paying only for private end-user benefits.
- **Unequal access.** For the reasons enumerated above, energy storage remains a niche commodity. This means that utilities, high-wealth individuals, and big corporations may have access to the benefits of energy storage, while LMI communities and customers may not. This energy justice problem is typical of new clean energy technologies such as solar PV, but with the right state policies, it could be avoided in the scale-up of distributed energy storage.

Distributed energy storage (behind customer meters) offers numerous benefits—so many that it is frequently referred to as the "holy grail" needed to unlock a clean, renewable energy future. Unfortunately, there are many barriers to bringing distributed energy storage to scale.

Courtesy of Sunrun

How ConnectedSolutions Addresses Energy Storage Barriers

ConnectedSolutions directly addresses these barriers by providing a reliable, performance-based incentives for BTM battery storage, thereby reducing economic risk and enabling financing for BTM battery projects. This also enables customer-owned storage to benefit the regional grid, allows for diversification of storage ownership, and provides state policymakers with a way to incentivize the additional societal benefits of energy storage. In short, the ConnectedSolutions model solves challenges faced by many parties—customers, utilities, developers, lenders, regulators, and policymakers—who want to support or install battery storage.

Program benefits fall roughly into two categories: economic benefits and social benefits.

ECONOMIC BENEFITS

ConnectedSolutions addresses battery cost barriers by offering utility performance payments to participating battery owners. These payments are guaranteed through multi-year contracts and backed by state energy efficiency program budgets. Predictable revenues offset battery costs, reduce economic risk, and make it easier for lenders to provide favorable financing to storage owners and developers.

Funding through energy efficiency programs

The first and most obvious policy benefit of the ConnectedSolutions program is that it makes existing energy efficiency funds available to support BTM battery storage deployment—or, put another way, it provides state policymakers with a way to offer battery storage incentives using an existing program that is typically well-established and well-funded. Incorporating storage into an existing energy efficiency program can be easier and more effective than starting a new storage incentive program with new sources of funding.

A significant advantage of moving energy storage into state efficiency programs is that these programs tend to be better funded than many other state clean energy initiatives. In 2019, states invested more than $6.8 billion in electric efficiency programs annually (see Table 1, p.16), with investment levels growing steadily since 1998 (see Figure 1, p.17).[18] The median investment in electric efficiency is $64 million annually per state. Allowing batteries to qualify for these funds could add significantly to the effort to bring distributed energy storage to scale.

It is also important to note that some existing, traditional efficiency measures are now returning fewer benefits than they have in the past. For example, in many markets, most available lighting upgrades have already been accomplished. In addition, the lighting industry has already moved on to more efficient technologies, with incandescent bulbs hardly available any longer, and even compact fluorescent bulbs quickly losing market share to LEDs. This being the case, continuing to pump public dollars into lighting rebates makes less economic sense. As older efficiency measures begin to offer diminishing returns, state programs should shift funding to support new and emerging technologies, like energy storage. In fact, incorporating new technologies is a well-established best practice for energy efficiency programs.[19]

Improving project economics

Prior to the development of the ConnectedSolutions/BYOD model, the main economic model for BTM battery economics was commercial demand charge management (DCM).[20] The DCM model relies on the ability of BTM batteries to lower onsite peak demand for commercial facilities operating under utility rate tariffs with a demand charge component, a process known as "peak shaving." By discharging batteries to lower their facility's 15-minute peak demand each month, commercial customers paying high demand rates can reduce their energy costs. For some commercial customers, this peak demand reduction results in significant cost savings.[21]

The Federal Role in Advancing Battery Storage

To date, there has been too little federal support for energy storage program development at the state level. Although the Federal Energy Regulatory Commission (FERC) has ordered wholesale energy markets opened to storage participation, it remains for state policymakers and regulators, together with regional grid operators and utilities, to create the mechanisms for that participation. The federal government, under a new administration, could do much to support state efforts to develop programs like ConnectedSolutions, which create the mechanisms to link private, BTM batteries with public energy grids and markets. Here we list some actions that should be taken at the federal level to provide this support. For a more detailed discussion of these points, see Appendix A.

- **Establish a federal energy storage tax credit.**
- **Establish national storage capacity targets.**
- **Set national storage pricing and technology improvement goals.**
- **Support development of storage applications, valuation and markets, and industry benchmarking and tracking.**
- **Establish storage codes and standards/best practices.**
- **Support LMI access to energy storage.**
- **Support battery storage for resilient power.**
- **Develop federal/state partnerships and provide technical support.**
- **Provide federal support for state storage analysts.**
- **Provide municipal utility and rural electric cooperative storage support.**
- **Support battery storage for home health.**
- **Support batteries for peaker plant replacement.**
- **Provide low-cost storage financing to reduce risk.**

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TABLE 1

2019 Electric Efficiency Program Spending by State

State	2019 Electric Efficiency Spending ($ million)	$ Per Capita	State	2019 Electric Efficiency Spending ($ million)	$ Per Capita
Rhode Island	104.1	98.24	**Nevada**	45.3	14.71
Massachusetts	620.4	90.02	**Utah**	47.1	14.69
Vermont	55.2	88.46	**Missouri**	85.8	13.98
Maryland	275.6	45.58	**North Carolina**	145.8	13.90
Connecticut	161.4	45.28	**New Jersey**	123.0	13.85
California	1516.4	38.38	**Wisconsin**	79.0	13.57
Oregon	161.5	38.28	**Montana**	14.4	13.44
New Hampshire	48.6	35.74	**South Carolina**	64.0	12.43
Idaho	61.4	34.37	**Arizona**	82.4	11.32
Illinois	433.8	34.23	**Texas**	196.2	6.77
Maine	45.9	34.12	**Kentucky**	27.2	6.09
New York	645.2	33.17	**Mississippi**	17.1	5.74
Hawaii	42.0	29.66	**Georgia**	57.0	5.37
Minnesota	157.0	27.84	**South Dakota**	4.7	5.31
Michigan	250.7	25.10	**Louisiana**	24.6	5.29
Washington	190.7	25.05	**Florida**	105.4	4.91
Iowa	75.6	23.95	**West Virginia**	7.6	4.24
Arkansas	68.0	22.52	**Virginia**	31.7	3.72
District of Columbia	15.4	21.79	**Nebraska**	7.1	3.65
Colorado	108.0	18.75	**Tennessee**	19.2	2.81
Delaware	17.9	18.41	**Alabama**	7.7	1.57
Wyoming	10.2	17.66	**North Dakota**	0.2	0.20
Oklahoma	68.6	17.34	**Kansas**	0.3	0.11
Pennsylvania	197.5	15.43	**Alaska**	0.0	0.03
Indiana	101.8	15.12			
New Mexico	31.7	15.12	**U.S. total**	**6,832.4**	
Ohio	175.0	14.97	**Median**	**64.0**	**15.12**

Source: ACEEE, "The 2020 State Energy Efficiency Scorecard." *https://www.aceee.org/research-report/u2011*

Analysis by CEG has shown that participating in ConnectedSolutions can significantly improve battery economics as compared to the DCM model.[22] Modeling battery storage at six multifamily affordable housing facilities in Massachusetts demonstrated that participating in ConnectedSolutions offers significantly better project economics for the facilities studied, compared to the results for the same facilities under a DCM model. This is shown in improved internal rates of return (IRRs), which increased by 26-36 percent under ConnectedSolutions, and reduced simple payback periods (SPPs) as shown in Figure 2 (p.17).

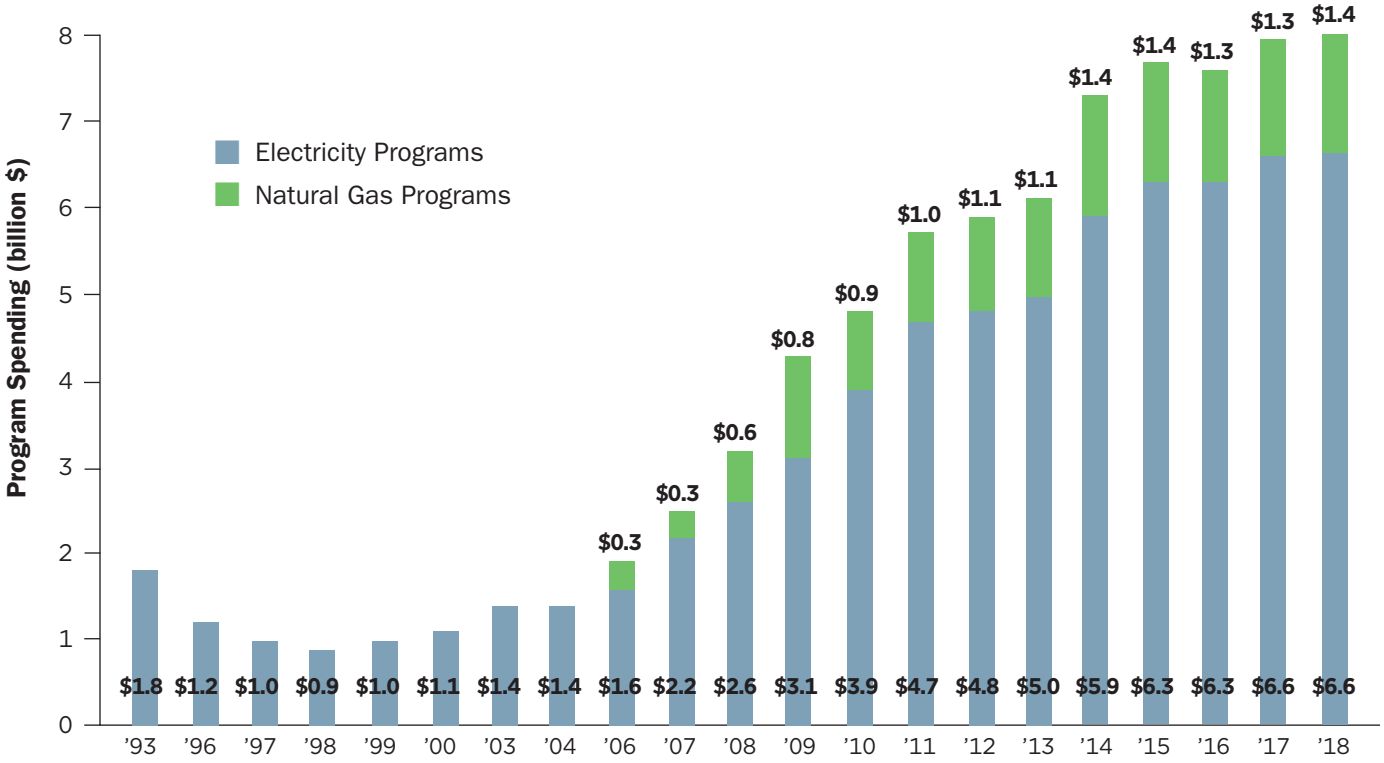
The improved economic performance of batteries under the ConnectedSolutions model is important because it makes possible numerous other benefits, as explained below. For more information about CEG's economic analysis, see *ConnectedSolutions: The New Economics of Solar+Storage for Affordable Housing in Massachusetts.*[23]

Reducing economic risk and improving project financeability

ConnectedSolutions reduces economic risk for battery projects, as compared with the DCM model, by eliminating battery owner guesswork and guaranteeing cash flow through multi-year utility contracts. This in turn reduces investment risk and improves battery project bankability, which is important for bringing distributed storage to scale.

FIGURE 1

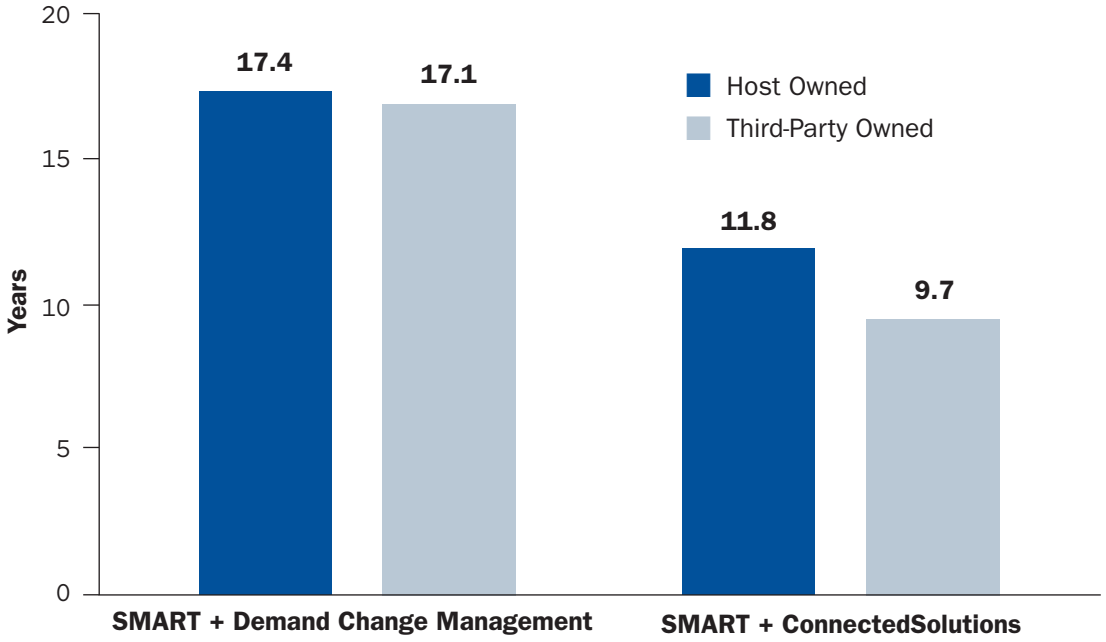
The Growth of State Electric Efficiency Funding



Source: ACEEE, "The 2020 State Energy Efficiency Scorecard." *https://www.aceee.org/research-report/u2011*

FIGURE 2

Simple Payback Period for Commercial Multifamily Housing in Massachusetts



This chart shows average SPP for several projects in Massachusetts Eversource territory. Battery projects are 25-year projects with battery replacement at year 10.

Source: American Microgrid Solutions

Until now, recouping the significant investment required to purchase and install a battery system behind the customer's meter required a lot of time and effort, as well as some luck. The most promising model, demand charge management for commercial customers, assumes that the customer can correctly and consistently predict their peak electrical usage and manage the battery effectively, so that it is fully charged and ready for use to shave each peak. This can be more difficult than it sounds, especially if the facility has multiple peaks in a day or even in a week. Missing just one peak during a month can mean missing out on that month's projected cost savings. If there are two peaks in one day, recharging the battery in between could be impossible. Similarly, if a customer's load curve is relatively flat, achieving significant cost savings through peak shaving may not be feasible.

Demand charge management is also subject to risks beyond the customer's control. For example, if the utility changes its tariff, or the customer experiences changes in their electricity usage due to evolving energy needs or changes in operational patterns, the savings available through demand charge management could be permanently affected.

These risks can make it harder for energy storage project developers to get financing at favorable rates.

By contrast, the ConnectedSolutions model ties battery revenues to a utility contract, and battery operations to utility signals. Rather than predicting their own facility's peaks, the customer merely allows their battery to respond to utility signals, which are announced the day before to give ample time for battery charging. Customer payments are guaranteed through the contract, so long as they participate in the peak events when signaled to do so.[24] This removes the guesswork and uncertainty from customer battery operations, allowing revenues to be more confidently predicted.

Risk reduction is important for project financing; and favorable project financing is important to bring storage to scale. In order to advance the battery storage industry from a series of one-off, unique projects to pipelines of standardized projects, it is necessary to develop replicable, low-risk products that can be marketed to a wide audience. ConnectedSolutions takes a significant step in this direction by lowering risk, and another by making energy storage projects standardized and widely replicable across a broad range of customers. It also lowers administrative costs for developers by making it easier to identify potential project sites. Under the ConnectedSolutions model, developers no longer need to waste time and analysis resources locating the few commercial customers with the right type of load profile for DCM projects.

Increasing standardization

If the deployment model for battery energy storage remains the purchase and installation of one-off, unique, designed-to-order systems, then distributed storage will continue to be expensive, difficult to finance and insure, and primarily available only to wealthy early adopters. If storage is to be scaled up to meet state clean energy and grid modernization goals, it will need to become standardized around requirements for installation, interconnection, performance, maintenance, decommissioning, and recycling, while still encouraging a diverse and competitive market.

In order to advance the battery storage industry from a series of one-off, unique projects to pipelines of standardized projects, it is necessary to develop replicable, low-risk products that can be marketed to a wide audience.

The importance of standardization is evident if one considers other common consumer appliances. For example, consider the personal computer (PC). When shopping for a computer, one may be able to choose between dozens if not hundreds of competing products. However, whichever product is selected, the consumer can be assured that it will conform to numerous industry standards and will be able to perform a suite of expected applications.

Though different PCs may have different chargers, all will plug into a standard wall outlet. They may have different processors, but all will be able to run standard software packages, including many offered by third parties. Most accessory devices, such as keyboards, monitors, printers, etc. will work with whatever PC the customer has purchased. Furthermore, all PCs conform to a much larger ecosystem of codes and standards, including fire codes, electrical codes, consumer protection laws, and the like, and benefit from supporting industries that offer insurance, warrantees, financing, maintenance, and replacement plans.

In other words, a certain amount of standardization in competitive markets is important; without it, personal computers (and thousands of other products) would be far less useful and beneficial, and far fewer people would buy them.

Stationary battery storage has not yet reached this level of standardization. Codes and standards are still being developed, and critical services such as communication and control between different devices can still be problematic. Support services such as financing, insurance and recycling are just beginning to develop. Increased standardization is necessary if batteries are to come to scale and provide all the benefits of which they are capable.

The ConnectedSolutions/BYOD model encourages standardization in that participating customers must own batteries that meet minimum program standards. Some of these standards

have been established by program administrators (utilities), in order to facilitate signaling customer batteries and measuring battery discharge. Others may be established by state regulators or policymakers, who will want to ensure that participating batteries meet minimum standards for safety, round trip efficiency, and cost-effectiveness.

Currently, some of these standards take the form of pre-approved equipment lists. As an example, Green Mountain Power has identified five batteries that are eligible for participation in its BYOD program, while National Grid has identified four qualifying inverter manufacturers for participants in its ConnectedSolutions program. As these programs become more sophisticated, standards will likely be increasingly expressed in terms of performance metrics and certifications rather than lists of approved equipment.

Furthermore, ConnectedSolutions programs support standard system offerings because batteries no longer need to be sized to specific customer loads. In part, this is because batteries are credited for exporting power to the grid under ConnectedSolutions—as opposed to economic models, like DCM and demand response, that limit benefits to customer load reductions.[25] Allowing power export frees customers to economically install larger batteries and enables developers to offer a few standard battery systems designed to work well under the Connected-Solutions program terms, rather than having to design systems to meet individual customer needs based solely on facility loads.

And as ConnectedSolutions and similar program models are adopted by more states, developers and aggregators will increasingly be able to standardize their program offerings, thereby reducing administrative costs.

While it is important not to limit competition between battery manufacturers, it is also important to begin to establish standards for the industry. As ConnectedSolutions/BYOD programs spread to other states and utility territories, they will encourage increased standardization at both the system and the program levels.

EFFICIENCY VS. DEMAND RESPONSE

Where Do Batteries Belong?

Currently, customer energy storage aggregation programs come in two basic flavors: the ConnectedSolutions model in New England, which supports customer-owned batteries through state energy efficiency plans; and BYOD programs in several utility territories, which treat storage as part of utility demand response programs. One could see these as competing models, although customers generally will not have a choice as to which of the two models they prefer. From a policymaking perspective, however, it is worth considering the relative merits of each, and whether there is an advantage in choosing one model over the other.

Although both models represent a significant step forward in distributed storage funding, CEG suggests policymakers consider adopting the ConnectedSolutions, efficiency-based model wherever it is feasible. There are five main reasons for this recommendation:

- **The availability of larger energy efficiency budgets compared to demand response budgets.** According to the US Energy Information Administration, state electric energy efficiency budgets currently amount to about $6 billion nationwide (another $2 billion is allocated to gas efficiency programs). By contrast, utility budgets for demand response programs cumulatively amount to about $1.5 billion.
- **The opportunity for greater policy input into efficiency program development.** Efficiency programs tend to be more transparent and open to input from state policymakers, NGOs, and the general public.
- **The ability of states to incentivize utility efficiency gains through performance payments.** The use of utility performance incentive mechanisms (PIMs) enables states to reward utilities for successfully meeting efficiency program goals.
- **The ability of the customer to export power to the grid in the ConnectedSolutions model.** By comparison, demand response programs are typically designed for load reduction only, which limits the benefits and revenue potential of BTM batteries.
- **The statewide nature of energy efficiency programs, which supports equitable access to energy storage technology.** By comparison, demand response programs are frequently available only to customers within a single utility territory, and in many cases residential customers have no opportunity to participate.

For more information on the advantages of Connected-Solutions over demand response programs for scaling up distributed energy storage, see Appendix C.

SOCIAL BENEFITS

In addition to the economics benefits discussed above, the ConnectedSolutions model offers new ways to expand the social benefits of distributed energy storage. These social benefits include reducing expensive and polluting demand peaks, expanding electric system resilience, democratizing and expanding the storage market (including LMI communities), and addressing numerous related state energy policy goals.

Addressing costly and polluting demand peaks

When electricity demand is at its highest, the cost of grid energy is also very high. Currently, billions of ratepayer dollars are paid each year to fossil fuel peaker plants that charge a premium to operate during these peak demand hours.[26] These peaker plants are also associated with high levels of harmful air pollution emissions, and they are often sited in urban environments, resulting in local pollution-related health issues in predominately low-income communities and communities of color.

The high costs and emissions associated with peak demand are increasingly recognized as a problem by state policymakers. For example, in 2016 the Massachusetts *State of Charge* report found that 40 percent of the state's overall cost of electric service was attributed to just 10 percent of highest demand hours each year (see Figure 3).

Distributed energy storage, properly managed, provides a policy solution to high costs and pollution associated with fossil fuel peaker plants. Storage can compete with these peaker plants (and replace them) by providing lower-cost, cleaner peaking power[27] along with other community benefits, such as resilience and energy cost savings. But to do so, it must be scaled up and aggregated through utility- or third-party battery programs. That is, there must be sufficient BTM storage capacity available to provide clean power on peak; and there must be a mechanism to ensure that these BTM systems will all discharge at the right time to provide the needed service to the grid.

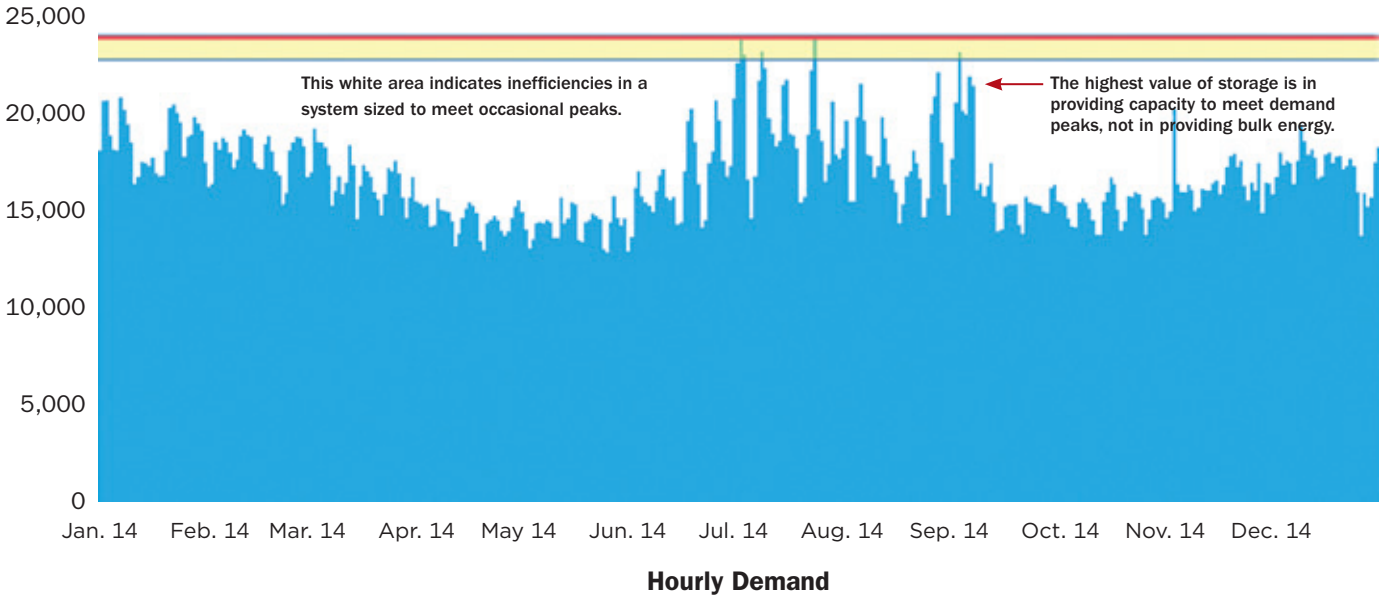
There must be sufficient BTM storage capacity available to provide clean power on peak; and there must be a mechanism to ensure that these BTM systems will all discharge at the right time, to provide the needed service to the grid.

ConnectedSolutions provides both the funding mechanism to scale-up BTM storage, and the aggregation/dispatch mechanism to harness BTM storage for regional grid needs. It is a one-stop policy solution for states to begin to tackle the problem of peak demand in a targeted way, whether through vertically integrated or deregulated utilities.

It is important to note that peak demand cannot be effectively reduced using only traditional, passive efficiency measures (which lower overall electricity consumption, but do not shift demand peaks) or through stand-alone renewable generators

FIGURE 3

Sizing the Entire Grid to Meet Occasional Peaks Causes Inefficiencies

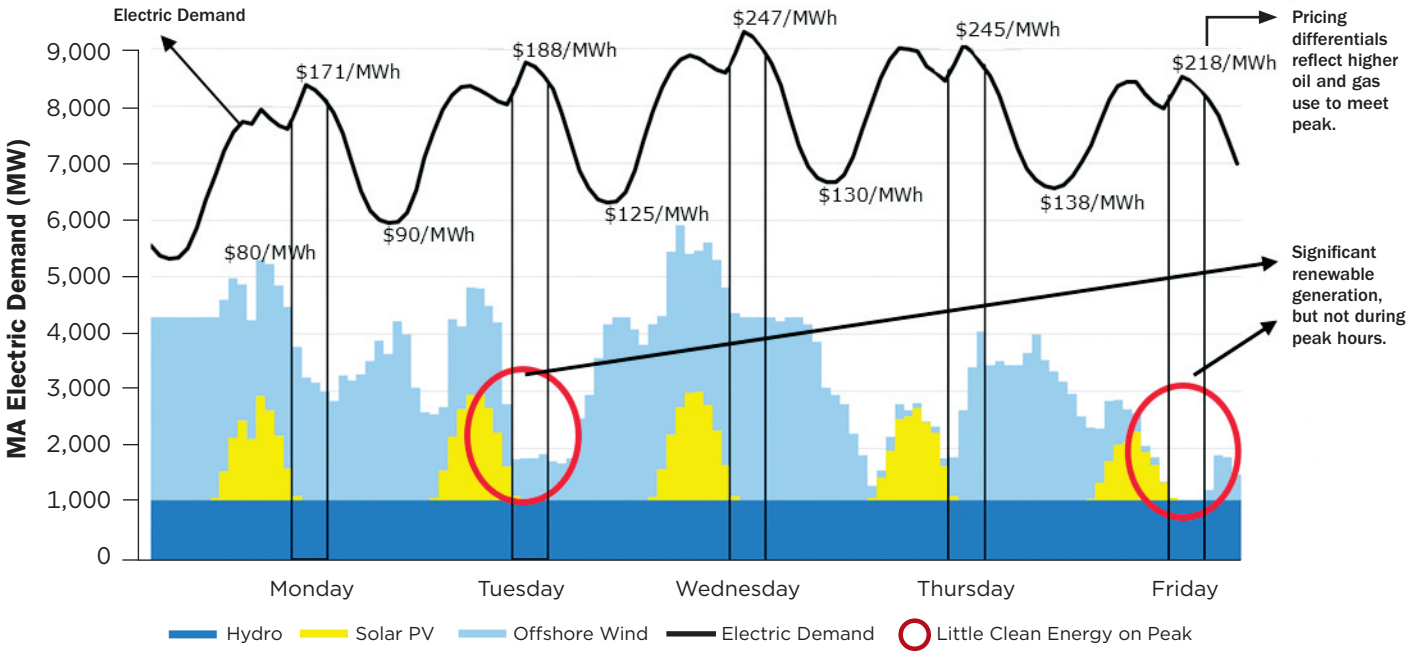


The monetizable value of storage is partly due to the high costs of our oversized grid.

Source: Adapted by the author from Massachusetts *State of Charge* report.

FIGURE 4

Renewables Do Not Reliably Produce During Demand Peaks



Production profile for 1,090 MW Hydro, 3,200 MW Offshore Wind, 5,000 MW Solar PV

Without significant amounts of energy storage, anticipated increased amounts of solar PV, hydroelectric power and offshore wind to be installed by 2030 will not reliably address peak electricity demand hours in the winter (note that many states do not have the option of increasing generation from offshore wind and hydro).

Source: Massachusetts DOER.

like solar and wind (because these renewables cannot be dispatched on-demand, and peak generation hours for wind and solar often do not align with peak demand from customers [see Figure 4]).

In fact, some studies have indicated that as more distributed solar PV is added to the grid, overproduction of solar electricity at midday can result in lower demand for grid power during these times and higher demand during evening peaks, requiring dispatchable generators to meet steeper ramping requirements.[28] And in general, more renewables on the grid can mean more unpredictable variation in generation, resulting in greater potential for mis-matches between supply and demand for electricity.[29]

Energy storage is the key clean energy technology to effectively target regional demand peaks. To achieve this, ConnectedSolutions provides for utility or third-party dispatch of distributed battery systems on peaks, thereby directing the peak-reducing benefits of BTM batteries toward the regional demand peak rather than individual customer peaks. This coordinated, aggregated use of distributed energy storage, sometimes called a "virtual power plant" (VPP), saves money for all ratepayers and increases efficiency across the regional grid.[30]

The ability to provide widespread ratepayer benefits gives the ConnectedSolutions model a distinct advantage over the demand charge management (DCM) model. While both models provide benefits to the storage owner, only ConnectedSolutions guarantees benefits to all ratepayers.

Improving resilience

Resilience in the face of increasingly frequent and severe power outages is an important benefit offered by BTM battery storage. Whether utility customers are facing outages due to hurricanes on the East Coast, ice storms in the Midwest, or wildfires on the West Coast, the ability to continue to support critical loads when the grid is down is increasingly important to both policymakers and ratepayers.[31] However, the duration of the resilience benefit that energy storage can provide is determined by the size of the battery relative to the customer's load, with larger capacity batteries providing more resilience than smaller ones (all else being equal). Due to the design of its pay-for-performance rate structure, ConnectedSolutions supports larger BTM batteries than customers might otherwise be able to economically install, and thereby supports greater resilience in the event of grid outages.

Batteries for Peaker Plant Replacement

Utilities sometimes refer to aggregated, distributed solar plus battery storage systems (solar+storage) as "virtual power plants," but they could as easily be called "virtual peaker plants." That is because the main service these aggregated solar+storage systems provide is one that has traditionally been provided by fossil-fuel peaker plants—small generators that seldom run but command a premium price for standing ready in case of a demand spike or unexpected drop in generation.

There are more than 1,000 fossil-fuel peaker plants operating in the US, amounting to about 120 GW capacity in total (see Figure 5). Of this total peaking capacity, 84 percent of the plants run only ten percent of the year or less, usually for only a few hours at a time. They burn natural gas, fuel oil, or even kerosene, and they are frequently sited in low-income urban environments. Because they are relatively small, many under 25 MW in capacity, they are frequently not regulated as stringently as larger power plants. And although some peakers are slated to retire, there are many proposed new peakers in interconnection queues across the country.

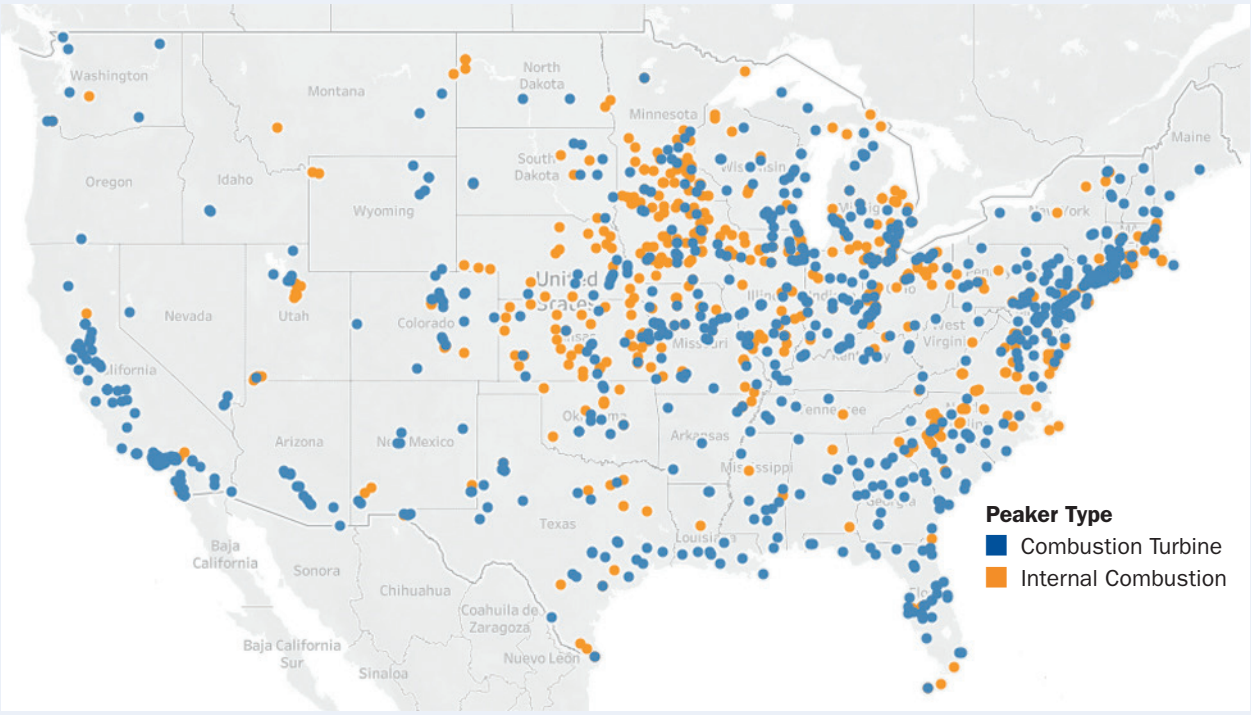
In short, peakers are inefficient, highly polluting, and expensive, earning billions of dollars each year. This means that the few peak demand hours each year are disproportionately expensive for electric customers.

Distributed battery storage provides the key to replacing dirty, costly peakers with clean, dispatchable generation that provides additional benefits, like backup power and customer cost savings, that fossil fuel peakers do not offer. And the ConnectedSolutions/BYOD models provide the key to bringing distributed storage to scale and aggregating multiple BTM systems into a dispatchable peaking resource.

For more information on peaker plant replacement with renewables and energy storage, see CEG's *Phase Out Peakers* project at *www.cleanegroup.org/ceg-projects/phase-out-peakers* and a recent report, *Dirty Energy, Big Money,* produced by the PEAK Coalition at *www.cleanegroup.org/ceg-resources/resource/dirty-energy-big-money*.

FIGURE 5

Peaker Plants in the US



Source: U.S. Energy Information Administration Form 923 Schedule 3B (2016)

FIGURE 6

ConnectedSolutions Larger Batteries

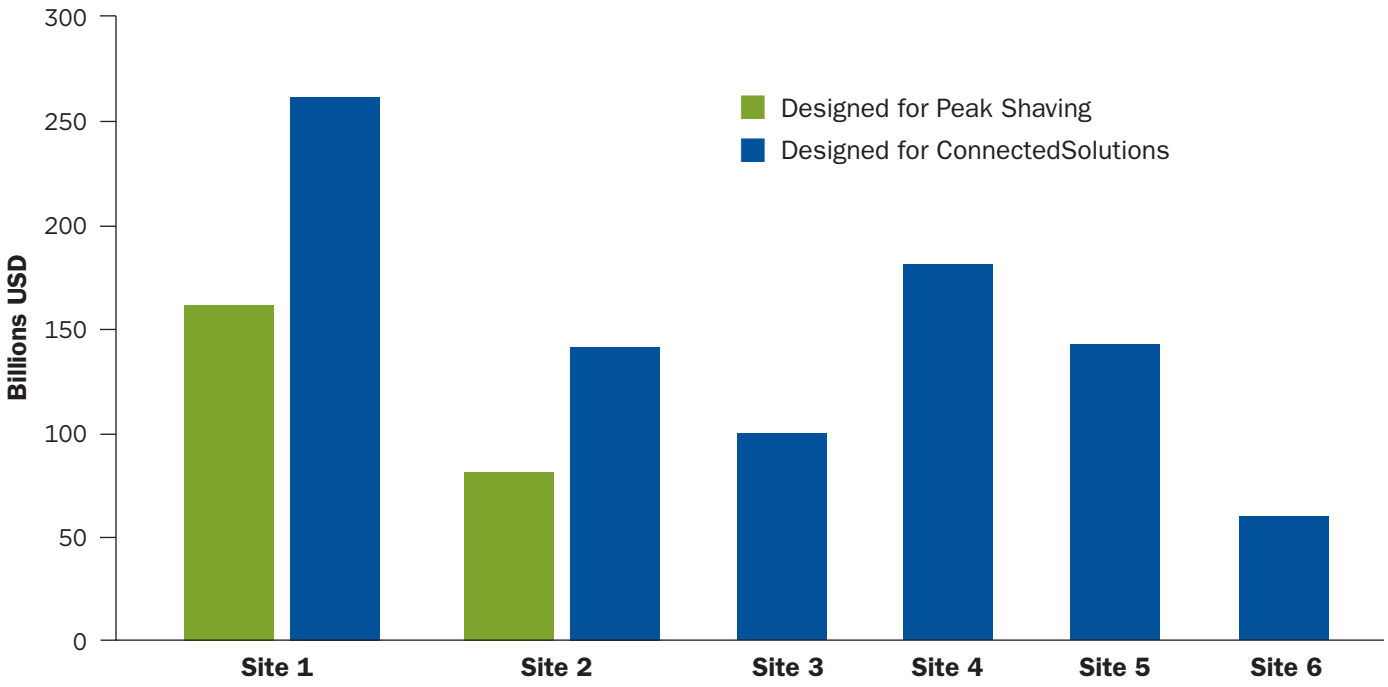


Chart comparing the size (in kWh) of two multifamily affordable housing facility batteries, as optimized for DCM (green) vs ConnectedSolutions (blue).

Source: American Microgrid Solutions, analysis conducted for CEG report *ConnectedSolutions: The New Economics of Solar+Storage for Affordable Housing in Massachusetts.*

This finding resulted from CEG's analysis of six multifamily affordable housing facilities in Massachusetts, comparing optimally sized resilient solar+storage systems under the ConnectedSolutions program versus a DCM model. The analysis found that when systems were designed to optimize financial performance under ConnectedSolutions, the result was larger, longer duration batteries as compared with systems designed for optimal DCM performance (see Figure 6).[32]

The reason for this phenomenon is that DCM savings are based on shaving facility peak loads during the highest 15-minute demand period each month (because utilities assess commercial customer demand charges based on monthly 15-minute demand peaks). Therefore, systems optimized for DCM applications typically favor less expensive, shorter duration batteries. By contrast, participation in the ConnectedSolutions program rewards participating customers based on their average battery discharge over three hours (to best address longer regional peak demand events). In addition, customers who sign up for ConnectedSolutions are paid not just for reducing their load, but also for exporting excess power to the grid, meaning that larger batteries can earn revenues that are not limited to facility load reduction. Optimizing system design economically to participate in ConnectedSolutions therefore tends to result in larger, longer-duration batteries that can provide greater backup power during a grid outage.

It's important to note that although the larger batteries favored by the ConnectedSolutions model are more costly, they also enable the battery owner to capture greater and more reliable revenues through the customer's pay-for-performance contract with their utility, improving paybacks and internal rates of return (IRR), in addition to providing greater resilience benefits.

Adopting an incentive program like ConnectedSolutions that supports larger battery systems also creates an opportunity for state policymakers to improve the energy resilience of critical facilities.[33] CEG has long advocated that states should offer an adder or rebate to support deployment of resilient solar+storage at these facilities. With the adoption of ConnectedSolutions, states gain a pay-for-performance program that—with the addition of an adder or carve-out for resilient battery projects serving critical community needs—could help direct efficiency program funds to strengthen community resilience.

Democratizing storage

The short history of BTM energy storage has so far followed the pattern set by other emerging clean energy technologies, such as solar PV; that is, wealthy early adopters and corporations purchase batteries for their own benefit, while low- and moderate-income customers are left behind. Not only is this bad public policy, it also relegates energy storage to a niche

position. If battery storage is to be effectively scaled up, significant democratization must be achieved to bridge this equity gap.

The ConnectedSolutions model democratizes distributed battery storage in two ways. First, *it creates a storage program open to all investor-owned utility customers in states that adopt it*, democratizing and enlarging the potential customer base for battery ownership. And second, *it spreads the resulting cost savings to all ratepayers*, democratizing the benefits of distributed energy storage.

Both of these democratization effects are important policy benefits, because state policymakers will want to be able to show that public money invested in distributed storage incentives is equitably available to a wide and diverse customer base, and that benefits accrue to the ratepaying public at large. We address these effects below.

Democratizing the customer base

Unlike demand charge management, which is a viable option only for a subset of commercial customers, or demand response programs, which are only available to customers of the utility offering the program, ConnectedSolutions is implemented through a state's energy efficiency program, meaning it is available to all customers of any regulated utility operating in the state. This greatly expands the number and type of customers that can economically install battery storage, and it creates opportunities for the development of high-volume project pipelines. This, in turn, makes it possible for developers to realize economies of scale and offer favorable financing (and in addition, battery customers can access low- or no-interest state loan programs in some states, such as the HEAT loan program in Massachusetts). With simple equity provisions, such as an equity rate adder and a rebate for low-income customers, ConnectedSolutions can be made more accessible to underserved communities,[34] supporting the adoption of solar generation and the deployment of resilient power systems in communities where these benefits are needed the most.[35]

Democratizing the benefits

One of the drawbacks of traditional BTM storage funding models, such as grants or rebates, is that in the absence of operational requirements, they do not guarantee widespread ratepayer benefits. This can make it difficult for policymakers to justify providing public funds for them. Similar arguments can be made for other clean energy and efficiency measures, but the problem is exacerbated for battery storage, because batteries do not generate clean energy, nor do they reduce net consumption of energy. If battery customers operate their systems in ways that benefit only themselves—for example, to reduce their electricity demand during periods that are non-coincident with systemwide peaks, or for resilience benefits at non-critical or non-public facilities—it may appear that battery incentives benefit only the recipients and not the public at large.

ConnectedSolutions solves this problem by aligning the operation of customer batteries with regional grid needs, so that by participating in the program, private battery owners generate energy cost savings for all ratepayers in the region. Once the Connected-Solutions program is adopted, utilities and third-party aggregators can build networks of battery customers aggregated into VPPs—and because utilities pay only for the battery services they receive, there is no question of public money funding private benefits.

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Addressing utility ownership issues

Related to the issue of storage democratization is the issue of utility ownership of energy storage assets. In some states, electric utilities are allowed to own storage, while in others, they are not (or such ownership is allowed only to meet specific needs such as distribution system resilience). In either case, a ConnectedSolutions or BYOD program can be beneficial in helping to expand distributed storage deployment while encouraging a diverse storage marketplace.

- In states where utilities **cannot own storage** (or where utility ownership is restricted), the ConnectedSolutions model provides a ready way for utilities to procure storage services. The use of efficiency funds to provide customer incentives allows for fast scale-up of distributed storage, while customer contracts and the pay-for-performance incentive structure help to control private battery operations, reducing the utility's perception of risk from storage customers who might otherwise discharge BTM batteries in unpredictable ways or at times that are counterproductive from the standpoint of grid needs.
- In states where utilities **can own storage**, the Connected-Solutions model helps to ensure a diverse and competitive storage marketplace where customers, developers and aggregators can participate. This helps to counterbalance the inherent risk that, where utilities can own storage, a utility storage monopoly could develop.

The concept of utility monopoly risk may require a bit more discussion. Historically, many utilities have viewed customer-owned storage as a problem rather than a solution. One reason for this is that utilities normally cannot control when a customer-owned battery charges and discharges. While solar+storage advocates have long argued that pairing batteries with solar makes solar dispatchable and should help to alleviate problems caused by the variable nature of the solar resource, utilities may worry that customers could operate their batteries in ways that are not helpful to the grid (for example, a customer might discharge their battery at midday during peak solar production, potentially exacerbating rather than alleviating the "duck curve" problem).[36]

Furthermore, when distributed solar+storage scales up, the market for utility electricity sales declines.[37] Thus, utilities may see customer- and third-party-owned solar+storage as competing with their core business. And they may argue that distributed energy resources (DERs) shift fixed costs unfairly to other ratepayers.[38]

For these and other reasons, utilities may prefer to own storage (in states where they are allowed to do so) rather than having to deal with third party- or customer-owned BTM storage systems. However, this can create the risk of a utility storage monopoly because utilities that can own storage possess inherent competitive advantages over customers and third parties in terms of storage investment, siting, and interconnection.

For example, it can be difficult or expensive for customers and third parties to interconnect new storage (and renewable generation) projects. When a new DER interconnection request threatens to overwhelm distribution grid capacity, utilities often require the customer requesting the interconnection to pay for line upgrades. These line upgrades can be prohibitively expensive. Some customers in Massachusetts have been asked to pay $1 million or more for distribution line upgrades before they can interconnect a new solar+storage project (one group of 12 projects totaling 45.8 megawatts was told the cost to interconnect would be $75 million for line upgrades, which would take five to seven years to complete before interconnection could take place.)[39] In addition to added costs, interconnection requests can be delayed while utility hosting capacity studies are conducted, resulting in significant barriers to program subscription.[40]

By contrast, utilities can rate-base capital expenditures for storage assets as well as distribution system upgrades, receiving a guaranteed rate of return. They know where non-wires alternatives opportunities exist and can monetize these opportunities, while third-party developers have neither the opportunity nor a mechanism to monetize it. They can site storage at substations and other utility property where interconnections are readily available and grid services can be conveniently provided.

For all these reasons, where utilities are allowed to own storage, they may be able to out-compete third-party storage developers.

While there is nothing inherently wrong with utility-owned energy storage, it can be argued that ratepayers benefit more from a competitive storage market. The ConnectedSolutions model can help ensure diverse and competitive storage ownership, while providing utilities some assurance that participating customers will discharge their batteries at appropriate times for regional peak load reduction, benefiting utilities and the grid. While the program does not penalize customers for failing to participate in peak "events" called by the utility, doing so reduces customer payments for the season. Thus, customers who sign up for ConnectedSolutions tend to discharge their batteries during paid, utility-defined events rather than at other times.[41]

Meeting other energy policy goals

In addition to supporting peak demand reductions (the main goal of battery storage within a state energy efficiency plan), incorporating storage into efficiency programs gives state policymakers a new and potent tool to help achieve other, related state clean energy goals, such as increased renewable generation, increased resilience for grids and critical infrastructure, energy cost reductions for low-income communities, and reduced need for fossil fuel peaker plants (for example, through emerging clean peak programs and the creation of distributed solar+storage "virtual peakers"). Such policy objectives can be achieved through the use of adders, carve-outs, and other incentives, either within an efficiency program or in related programs such as solar and storage rebates and utility procurement targets.[42]

These related policy benefits are sometimes referred to within energy efficiency programs as non-energy benefits (NEBs) or non-energy impacts (NEIs). NEBs should be included when conducting the cost/benefit analyses required to make battery storage eligible for state energy efficiency funds, in order to provide a more comprehensive accounting of the benefits storage provides. However, some cost/benefit analyses omit NEBs simply because not enough work has been done to assign a value to these benefits.

Although valuing NEBs can be difficult, it is important that such values are established and included in cost/benefit calculations. Otherwise, many important benefits provided by energy storage will default to zero in these calculations, with the result that energy storage may appear to be less cost-effective than it actually is. CEG has previously published analysis valuing seven non-energy benefits of BTM energy storage, such as job creation, reduced grid outages, and reduced land use, that are frequently left out of cost/benefit analyses.[43] This is an area where more work should be done.

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Batteries for Home Health Care

Resilience has long been a prime motivator for both residential and commercial customers installing solar+storage systems. Now, with extreme weather and wildfires on the rise and a global pandemic putting increasing pressure on health networks, the importance of resilient power systems to support critical home health equipment is coming to the fore.

At least 2.5 million individuals in the U.S. rely on electricity to power critical in-home medical equipment, such as oxygen concentrators, nebulizers, and other powered home health devices.[44] Millions more depend on powered devices and services to aid in tasks of daily living, such as climbing stairs, bathing, or making a meal. For these households, in the absence of a reliable backup power system, even a short-term grid outage can quickly become life-threatening.

The importance of backup power for home health care has been underlined recently by a series of devastating events. Hurricane Maria decimated Puerto Rico's energy infrastructure in 2017 (health care complications, including outage-related issues like medical device failure, accounted for almost one-third of the estimated 4,645 additional deaths in the three months following the hurricane); seasonal wildfires in California have prompted utilities to preemptively and repeatedly cut power to millions of people; and the Covid-19 pandemic has overwhelmed hospitals, increased social isolation and exposed the vulnerabilities of home health patients worldwide.

Solar+storage is the clean, renewable resilient power solution. Behind-the-meter solar+storage can support critical loads during grid outages and also provide energy cost savings and revenues during normal operating conditions. By comparison, diesel and gas generators are polluting, rely on fuel deliveries (which may not be reliable during a natural disaster), and sit idle 99 percent of the time, thus representing a sunk cost that provides no benefits except during an outage. A side effect of all this idle time is that fossil fuel backup generators tend not to be properly maintained, and therefore frequently fail when called upon. They also produce carbon monoxide when running—an unfortunate side effect of fossil fuel combustion that can be deadly in enclosed environments.[45]

Until now, the primary barrier to solar+storage deployment for critical infrastructure and home health resilience has been cost. ConnectedSolutions and similar programs represent new and effective ways to manage these costs and scale up BTM resilient solar+storage deployment, making clean resilient power available to many more people with critical home health needs.

For more information on the nexus between battery storage and home health care, see CEG's report, *Home Health Care in the Dark: Why Climate, Wildfires and Other Risks Call for New Resilient Energy Storage Solutions to Protect Medically Vulnerable Households from Power Outages.*[46]

Courtesy of Sunrun

Key Program Elements and Lessons Learned

KEY ELEMENTS OF THE CONNECTEDSOLUTIONS MODEL

Although every state and utility will need to adapt the basic ConnectedSolutions model to meet specific needs and accommodate local regulations, certain key elements of the program outlined below are essential to an effective state level, behind the meter (BTM) incentive program.

Funding through state energy efficiency programs. Incorporating BTM storage as a peak demand reducing measure in utility energy efficiency programs ensures that a significant and predictable budget will be available for the program, allows policy input and makes utility Performance Incentive Mechanisms (PIMs) possible.

Customer or third-party ownership. It is important that customers can own batteries and decide how best to operate them for energy cost savings, revenues, resilience, and other applications. It is also important to allow third-party ownership in order to achieve a diversity of business models (owner/operator, lease, or PPA) and financing available to the customer. The best programs will avoid exclusive utility ownership of systems so that a diverse, competitive, and inclusive market is created.

Pay-for-performance on a utility signal. This ties BTM battery performance to regional grid needs and allows for the creation of a fleet of distributed storage resources that can be aggregated and dispatched in a coordinated way. It also allows utilities to procure only those services they need.

Up-front rebate (recommended). A rebate (not included in the program as originally implemented in Massachusetts) would reduce the initial cost barrier, while the performance payment provides predictable revenues and directs battery services to times when they provide the most benefit to ratepayers. Rebate rates can be increased for LMI customers, to support storage deployment in underserved communities.

Low- or no-cost financing, on-bill payment, PACE (recommended). These related financing mechanisms can work in tandem with a rebate and utility pay-for-performance incentive to further lower cost barriers, especially for LMI participants.

Stackable Rate adders. These allow the program to target battery deployment for specific purposes, for example in underserved communities (equity/LMI adders) and for added community services (resilient systems adders).

- **Equity/LMI rate adder.** This is important to allow LMI communities to participate in the program. Set-asides, while helpful, may not be sufficient to overcome the added financing and development barriers faced by LMI communities.
- **Resilient systems rate adder.** This acknowledges the added cost of making BTM storage systems islandable, and the added social benefits of resilient systems, especially when they support critical facilities such as emergency shelters, first responders, water treatment/pumping and multifamily housing.

Payment for energy export as well as load reduction on peaks. This allows the monetization of battery capacity that exceeds load and provides an economics basis for households and small commercial customers to participate in the program; it also allows the grid to benefit from the full scope of distributed battery services.

Multi-year customer contracts. Multi-year contracts reduce investment risk by making project economics more certain; this enables low-cost financing and supports the development of project pipelines, including in low-income communities.

Inclusion of third-party aggregators. This allows developers and aggregators to market the program to their customers, provide financing, and bundle products such as solar+storage.

Stackable incentive programs. Allowing customers to stack incentives from multiple programs improves project economics and maximizes social benefits. Programs such as pay-for-performance battery incentives, solar net metering, tax incentives, clean peak credits and rebates can be made stackable. Program guides should clearly define which incentives may be stacked and where limitations exist.

Opt-out without penalty. Allowing customers to opt-out of discharge calls without penalty recognizes their need to reserve battery capacity for resilience or business purposes. Guidance should be provided regarding recommendations for battery reserves.

LESSONS LEARNED

Although the ConnectedSolutions program and similar BYOD programs are still relatively new, there is some experience from early adopter states that should inform state efforts to develop new programs.

Improving Equity/Low-Income Participation

The Massachusetts ConnectedSolutions program is groundbreaking, but there are nevertheless ways in which it could be improved. One significant omission is an equity budget with adders or incentives for LMI customers. Without these features, LMI customers and developers serving underserved communities may find it difficult to overcome the additional barriers they face to access the program.

To address this, some alternative versions of the model proposed in other states incorporate an up-front rebate, with an LMI adder, in addition to pay-for-performance incentives and no- or low-cost financing. A good example of this is provided by the Connecticut Green Bank's proposed program, "Solarize Storage."[47] This proposal also includes an on-bill financing option.

Providing a rebate is particularly important if policymakers wish to include underserved communities in a distributed energy storage program. A budget set-aside (equity carve-out) alone is unlikely to work, because it does not address the higher cost and financing barriers in these communities.[48]

Duration of Customer Contracts

The duration of customer pay-for-performance contracts is critically important, as these contracts define how many years of revenues the system owner can rely on. Contracts vary in duration from program to program. For example, the Massachusetts ConnectedSolutions program offers five-year contracts;[49] by contrast, New York demand response contracts are three years,[50] while the Green Mountain Power BYOD program features ten-year customer contracts.[51]

Generally, longer contracts are better for both customers and lenders, because they provide a longer predictable revenue stream and thereby contribute more to reducing investment risk. If the utility or regulator does not feel comfortable guaranteeing pay-for-performance rates for more than a few years, there are other options. For example, the utility could issue

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customers a 10-year contract with an option to revise rates after five years. This approach would at least give customers some certainty that the utility would not walk away from the program after five years.

Ideally, the customer contract and rates will allow the customer to realize a payback of the installed cost of the battery within the expected lifespan of the equipment. For example, in Massachusetts, residential customers participating in the ConnectedSolutions program should be able to break even on their battery investment in year six, on average, assuming their contract is renewed at the same rate after it expires in year five, and that they participate fully in every dispatch call.[52]

Exporting Power to the Grid

One important feature of ConnectedSolutions model programs that sets them apart from typical utility demand response programs is that they not only reward customers for reducing loads behind the meter, but also for exporting power to the grid.[53] By contrast, most demand response programs are designed for load reduction only, and do not allow the export of excess power from a battery.

Allowing power export prevents battery contributions and customer payments from being limited by the size of the customer's load. This is important for project economics, because otherwise, residential customers and those with small loads might be unable to economically participate in the program (developers would view these customers as having limited revenue potential relative to capital and administrative costs). It can also be important to the electric grid, which otherwise cannot realize the full benefit of BTM storage resources.[54]

Metering

The issue of metering may arise in some states due to concerns about solar+storage customers participating in net metering programs. Different states have resolved this issue in different ways. Simpler solutions requiring fewer meters, such as the policy adopted by utility Green Mountain Power in Vermont, are recommended over more complicated and costly solutions requiring multiple meters, such as adopted by utilities in Massachusetts.[55]

Requiring customers to install multiple meters generally adds cost to solar+storage systems and makes it less likely that these systems will pencil out economically. In addition, requiring additional meters can present installation or system design challenges in certain situations; therefore, added metering requirements should be avoided whenever possible.

Interactions Between Related Incentive Programs

Due to high capital costs and under-developed markets, energy storage owners will generally seek to stack multiple program benefits wherever possible, in order to make their investment pay off. Therefore it is important for state agencies and utility program administrators to clearly define how and under what circumstances different clean energy program benefits work together (or don't). Failure to do this can increase customer and developer uncertainty and deter investment.

The ConnectedSolutions model allows customers to monetize the full value of their batteries, regardless of their home or commercial facility load. By contrast, most demand response programs are designed for load reduction only, and do not allow the export of excess power from a battery.

For example, it was initially unclear in Massachusetts whether battery owners participating in ConnectedSolutions could also earn Clean Peak Standard credits, or whether the clean peak credits would be considered an environmental attribute purchased by the utility under the ConnectedSolutions pay-for-performance contract. Some national storage developers had assumed the two programs were not compatible. Eventually, the Massachusetts Department of Energy Resources (DOER) issued a statement clarifying that the programs are, in fact, stackable.[56] Ideally, questions such as these should be addressed with stakeholder input when programs are designed, and rules about stacking benefits should be included in program guidance documents, so that developers and customers are not left to draw their own conclusions.

Supporting Community and Customer Resilience

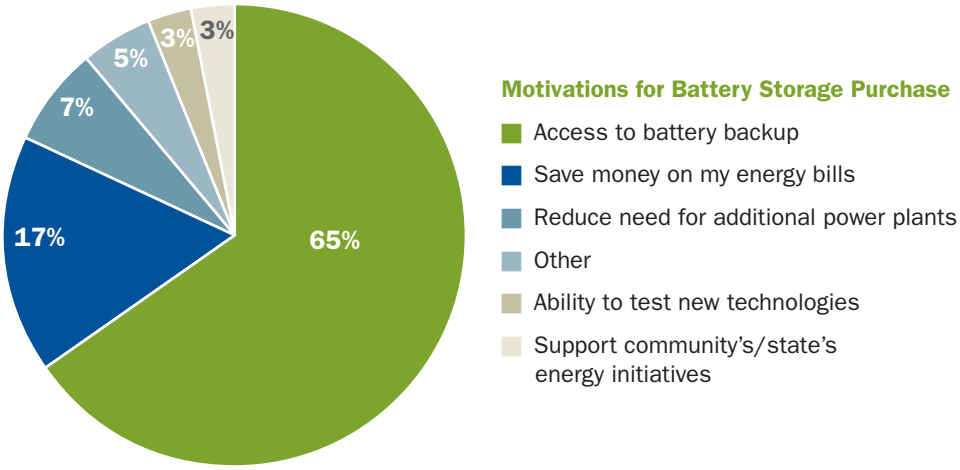
In a recent report, Navigant Consulting (now Guidehouse) found that resilience was the single biggest motivator for Massachusetts residential utility customers participating in the ConnectedSolutions program through National Grid. In that study, 65 percent of residential program participants said that resilient power was their top reason for purchasing a battery (see Figure 7, p.30).[57]

Though it is common to install BTM batteries for resilient power benefits, such batteries do not provide these benefits by default—the system must be configured to do so, and this adds cost. Given the increasing importance of resilient power, both to customers and to policymakers and energy regulators, state energy storage programs should provide additional funding for resilient systems.[58]

Furthermore, program administrators should take customer resilient power concerns into account when designing program mechanics and ensure that customers are aware of safeguards built into the program. According to the Navigant Consulting

FIGURE 7

Resilience is the Number One Motivation for Residential Battery Purchase in Massachusetts



Other Highlights

94% never opted out of an event

97% would recommend the program to other customers

97% are likely or very likely to continue with the program

Source: Navigant Consulting (Guidehouse) report and presentation to Massachusetts Energy Efficiency Advisory Council
https://ma-eeac.org/wp-content/uploads/January-Demand-Presentation_EEAC_Final_1-16-20.pdf

report cited above, "Of those participants who reported their primary motivation was access to battery backup or rated the importance of access to battery backup highly, 74 percent were at least a little concerned that the program might drain their battery system when they were counting on it to provide backup power.... National Grid designed the program so that events are not called if a storm is predicted in the near future, but it is unclear how aware participants were of this aspect of the program design."[59] Program administrators should inform customers of these safeguards; they should also identify a recommended battery reserve level and publicize this to program participants, as recommended in the Navigant report.[60]

Anticipating Interconnection Costs and Hosting Capacity Needs

Numerous BTM storage projects have been delayed or cancelled altogether due to unexpected high costs of interconnection when line upgrades are required. In most cases, when proposed BTM projects threaten to exceed the existing distribution grid hosting capacity in the area, the cost of equipment upgrades to remedy the problem is the responsibility of the customer proposing to add the new BTM resources. These upgrades can cost millions of dollars—an insurmountable barrier for the first customer in the queue.

Utility hosting capacity studies can also cause delays and result in numerous proposed projects being cancelled. In Massachusetts, some 900 MW of SMART program capacity was delayed for months due to National Grid "cluster studies," prompting an investigation of the utility by the state Department of Public Utilities.[61,62]

The adequacy of utility distribution system hosting capacity to support BTM energy storage deployment should be assessed and made public before or during the development of new distributed battery incentive programs.

In general, the adequacy of utility distribution system hosting capacity to support BTM energy storage deployment should be assessed and made public before or during the development of new distributed battery incentive programs. To the extent possible, distribution system upgrades necessary for the success of such programs should be undertaken in a way that spreads costs broadly, so they do not overburden a few customers who happen to be first in the queue. And maps showing areas where hosting capacity upgrades are needed should be made public, along with anticipated dates of completion, so that developers and customers can plan future projects. If distribution investment deferral is a monetizable benefit for BTM energy storage in some areas, this should also be public information, and a mechanism to procure and compensate such projects should be developed as part of the program.[63] Some states have already begun to investigate such mechanisms.[64]

It is also helpful if storage systems below a predetermined size threshold, as well as those configured to prohibit energy export to the grid, can be exempted from requirements for studies and upgrade costs.

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Recommendations for State Policymakers

States that wish to increase distributed energy storage deployment should consider using the ConnectedSolutions program model. Although each state's program will be slightly different, we provide here the basic steps to adopt the program, along with sample language from enabling legislation and other key documents.

1. INTEGRATE PEAK DEMAND REDUCTION INTO THE STATE'S ENERGY EFFICIENCY PLAN

In order to include storage within the energy efficiency plan, states typically will first need to define peak demand reduction, a major application of battery storage, as a type of efficiency. This enables peak demand reducing measures to be incorporated into the efficiency program and funded through the program budget.

This can involve a paradigm shift for efficiency program administrators, advisory council members and other stakeholders. Traditionally, electric efficiency has referred to reducing the net consumption of electricity. Reducing peak demand by shifting it to off-peak times does not entail a net reduction in consumption, but instead achieves efficiencies across the grid by flattening load curves, easing grid congestion, reducing the need for grid overbuild, and reducing dependence on fast-ramping generation resources such as fossil fuel peaker plants (see Figures 8A and 8B). Although net consumption is not reduced, ratepayer costs can be reduced significantly.

FIGURE 8A

Traditional Efficiency Reduces Net Consumption, but Does Not Shift Peaks

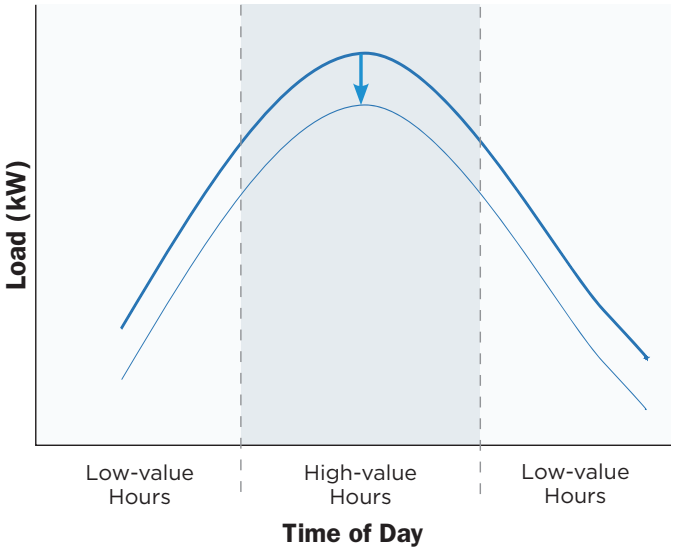
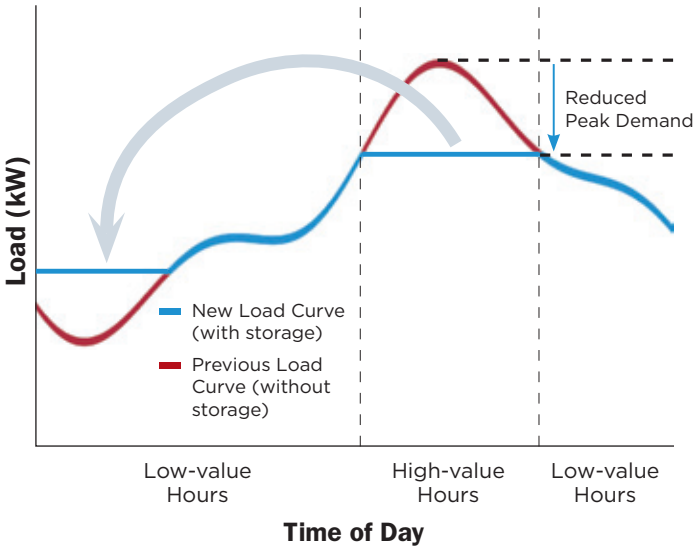


FIGURE 8B

Peak Demand Reduction Shifts Peaks, but Does Not Reduce Net Consumption



Redefining efficiency—Not all load hours should be valued the same!

Source: Clean Energy Group

In order to achieve this new type of efficiency, the definition of "efficiency" in state statutes and other documents may need to be expanded. Terms used to express this concept within an efficiency plan may include "demand reduction," "peak demand reduction," "peak shifting" and "active (or advanced) demand response."

Sample efficiency language from New England states

Numerous examples of language exist for states to follow when expanding the definition of efficiency to include peak demand reduction:

- The 2008 Massachusetts *Green Communities Act* states that the state shall "develop a plan to reduce total energy consumption in the commonwealth by at least 10 per cent by 2017 through the development and implementation of the green communities program, established by section 10 of chapter 25A of the General Laws, that utilizes renewable energy, **demand reduction**, conservation and energy efficiency" and requires that efficiency program administrators seek "…all available energy efficiency and **demand reduction** resources that are cost effective or less expensive than supply."[65]

- Connecticut's 2020 energy efficiency plan includes as a priority "Implement Effective Demand Reduction Strategies" and has a section on **Active Demand Reduction**[66] that states, "Battery storage technology is envisioned as an optimal strategy, as it would allow customers to provide load reduction in several ways, as the technology can provide capacity in daily, targeted, and winter periods."[67]

- Rhode Island's 2020 energy efficiency plan includes active demand response as a key priority: "Innovate to capture savings from new technologies and strategies to position energy efficiency programs for the future including the integration of energy efficiency with **active demand response**, electrification of heat and hot water, renewable energy, and smart grid technologies." The plan further defines active demand response: "Active demand response relies on a connected device or customer receiving a signal to change how they typically use energy for a defined period of time. The most common example is a signal to reduce electric energy use during time of high electrical system load." The plan further explains, "Initially, the active demand response programs focused on customer-initiated active demand response for commercial and industrial customers and thermostat-based active demand response for residential customers. Using this as a base, the Company has expanded this to include battery storage on the residential side and is proposing to further expand the program to battery storage on the commercial and industrial side."[68]

  In its section devoted to definitions and terms, the Rhode Island 2020 energy efficiency plan defines active vs passive demand response:

  "Active Demand Response: The reduction or shifting of energy use by customers during peak periods, (peak event) when the load on the electric grid or gas distribution system is high. Passive Demand Response: Energy efficiency measures that permanently shift or reduce electricity use. Examples include energy efficient appliances, lighting, advanced cooling and heating systems and equipment."[69]

- The New Hampshire 2018-2020 Statewide Energy Efficiency Plan states: "In addition to achieving significant reductions in demand for electricity (kWh) as part of the EERS goals, the energy efficiency programs also result in significant reductions in demand, or connected load (kW), during both off-peak and on-peak hours. Peak demand reductions from standard energy efficiency measures are typically referred to as "passive" demand reductions, given that they are achieved as a result of higher efficiency equipment that is primarily intended to reduce demand across many hours, including peak periods. **"Active" demand reduction** measures, in contrast, reduce demand at specific times when called upon. For the 2020 program year, the NHSaves Residential and C&I programs are expected to result in passive demand reductions of 15.7 MW during the ISO-NE summer on-peak hours and 18.9 MW during the ISO-NE winter on-peak hours. Eversource and Unitil Electric's C&I and Residential Active Demand Reduction Initiatives are projected to result in an additional 10.7 MW reduction during the ISO-NE summer peak."[70]

2. SPECIFY THAT BEHIND-THE-METER BATTERIES ARE ELIGIBLE IN THE PLAN AS PEAK-REDUCING OR ACTIVE DEMAND REDUCTION MEASURES

Once peak demand reduction is incorporated into the state's energy efficiency plan as a goal, it is helpful to add language that specifically names energy storage as an eligible demand-reducing measure.

For example, the 2016 Massachusetts *State of Charge* report notes that "Storage and other measures that shift load are firmly covered by the intent of the [Green Communities] Act" and adds, "The 2016–2018 Statewide Energy Efficiency Investment Plan ("Three Year Plan") identifies peak demand reduction as an area of particular interest…. Energy storage, used to shift and manage load as part of peak demand reduction programs, can be deployed through this existing process." And the 2018 Massachusetts *Act to Advance Clean Energy* specifically allows the use of energy efficiency funds to support the deployment of cost-effective energy storage "if the department determines that the energy storage system installed at a customer's premises provides sustainable peak load reductions."

3. SHOW THAT BATTERIES PASS THE STATE'S COST/BENEFIT TEST

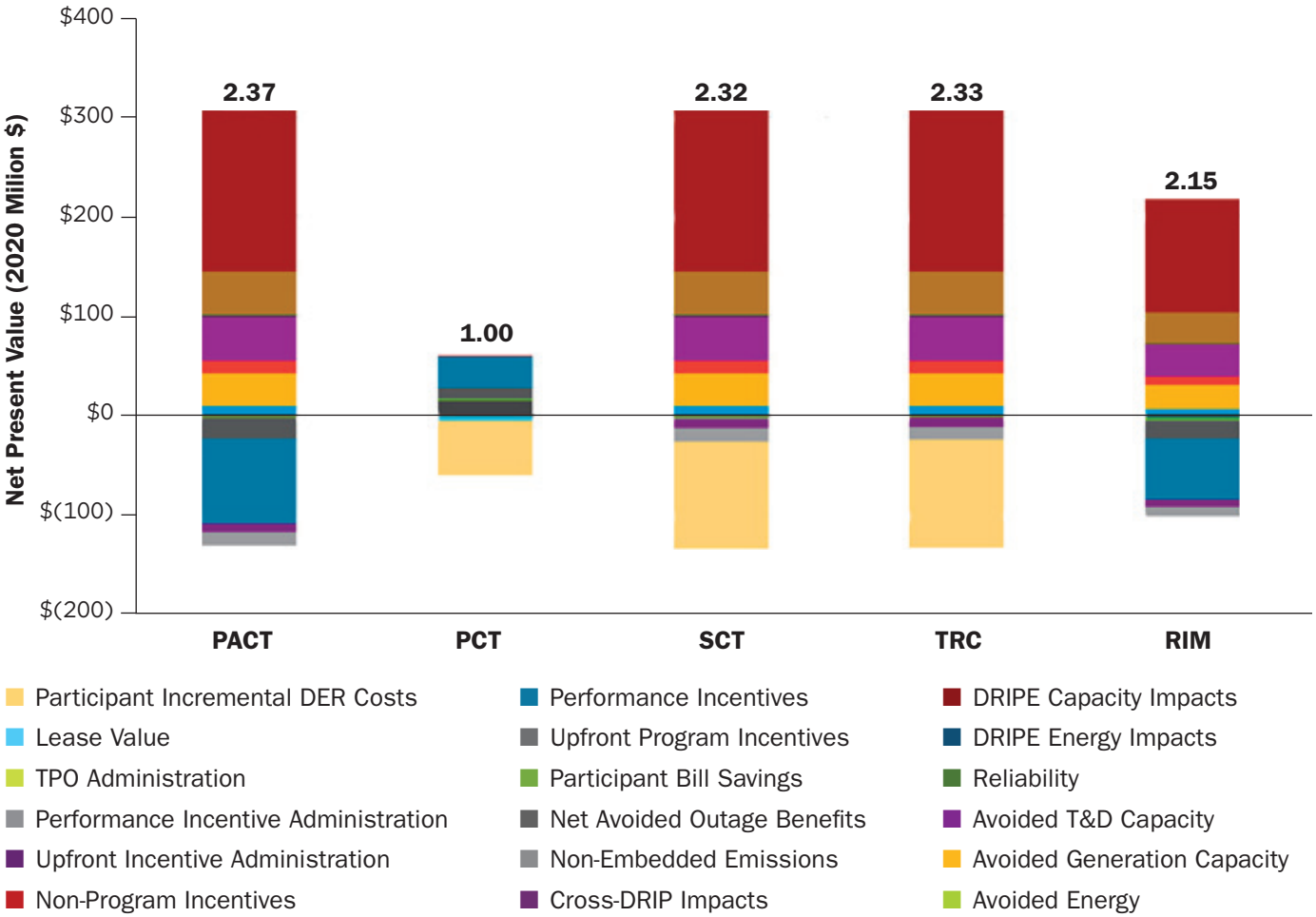
Generally, new technologies or measures proposed for a state energy efficiency program will be required to pass a cost/benefit test. This is necessary to demonstrate that public money allocated to support the program is well-spent, and that ratepayers will receive positive value for their investment.

In Massachusetts, Clean Energy Group contracted with the Applied Economics Clinic (AEC) to conduct an independent cost/benefit analysis for BTM battery storage, which was useful because it showed that a positive result could be obtained[71] (the utilities subsequently performed their own cost/benefit analysis—see Table 2, p.34). This was key to getting BTM storage included in the energy efficiency program.

Although the requirement for a cost/benefit test is common, different states use different tests. Some of the most commonly used are the Total Resource Cost Test, the Societal Cost Test, the Utility Cost Test, the Participant Cost Test, and the Rate Impact Measure (see Figure 9). The tests vary in their methodology and will also typically include different benefits in the cost/benefit equation. For example, the Societal Cost Test tends to include more non-energy benefits, such as environmental and health benefits, while others, like the Utility Cost Test, may not take these societal benefits into account. Beyond these basic differences in approach, different states will modify and apply these tests in different ways. Also, some states will test individual efficiency measures, while others will test programs that could include numerous measures.

FIGURE 9

Multiple Cost/Benefit Tests of BTM Battery Storage



Cost/benefit test results from Connecticut Green Bank Solarize Storage proposal, showing the program's cost effectiveness under various tests including the Program Administrator Cost Test (PACT), the Participant Cost Test (PCT), the Societal Cost Test (SCT), the Total Resource Cost Test (TRC) and the Ratepayer Impact Measure (RIM). Scores above 1 indicate that returns exceed investments. Note that a score >1 on the RIM test, sometimes called the "no losers test," indicates that implementation of this measure will not raise costs for non-participants. Battery storage scores well above 1 here, a rare result for an energy efficiency measure.

Source: PURA-Docket-No.-17-12-03RE03—Solarize-Storage-Proposal-from-the-Green-Bank.pdf (*ctgreenbank.com*)

TABLE 2

Summary of Daily Dispatch Incentive Costs, Demand Reductions, and Benefit Projections from Planned Benefit-Cost Model

	2020			2021		
	Incentive Costs	Planned KW Reductions	Planned Benefits	Incentive Costs	Planned KW Reductions	Planned Benefits
Residential Daily Dispatch Offer Incentive costs, Demand Reduction, and Benefits Projections from Planned Benefit-Cost Models						
Eversource	$41,250	150	$178,241	$68,750	250	$297,351
National Grid	$396,880	1,763	$1,923,750	$606,936	2,696	$2,944,976
Unitil	$1,125	5	$6,066	$1,125	5	$6,072
Cape Light Compact	$35,475	120	$142,593	$59.125	200	$237,881
C & I Dispatch Offer Incentive Costs, Demand Reducation, and Benefits Projections from Planned Benefit-Cost Models						
Eversource	$1,250,000	5,000	$5,941,363	$2,500,000	10,000	$11,894,038
National Grid	$1,125,000	5,000	$5,455,988	$1,575,000	7,000	$7,646,301
Unitil	$20,000	100	$121,323	$20,000	100	$121,437
Cape Light Compact	$350,000	1,400	$1,663,582	$350,000	1,400	$1,665,165

Tables from the Massachusetts ConnectedSolutions program, showing anticipated incentive costs and benefits from the first two years of the program.

Source: Massachusetts EEAC

In order to show that battery storage passes the state's cost/benefit test, it is helpful to be able to count as many benefits as possible. Typically, energy benefits are included, but other benefits, sometimes known as "non-energy benefits" (NEBs) or "non-energy impacts" (NEIs), may not be. These non-energy benefits can include things like job creation, reduced land use, and increased grid resiliency. There are precedents for counting non-energy benefits in efficiency program cost/benefit analyses,[72] although which ones are included varies from state to state; it is worthwhile, when considering a new technology like energy storage, to discuss including new NEBs, because storage may produce different NEBs than traditional, passive efficiency measures.

Unfortunately, many NEBs offered by BTM battery storage, such as resilience, do not have an established value or formula for establishing their value. In these cases, their value will default to zero in cost/benefit analyses, meaning they will not be considered on the value side of the equation. For other NEBs, such as health-related savings, jobs creation and reduced land use, states may have established values, but may not include them in battery cost/benefit tests despite the fact that batteries can provide these benefits.

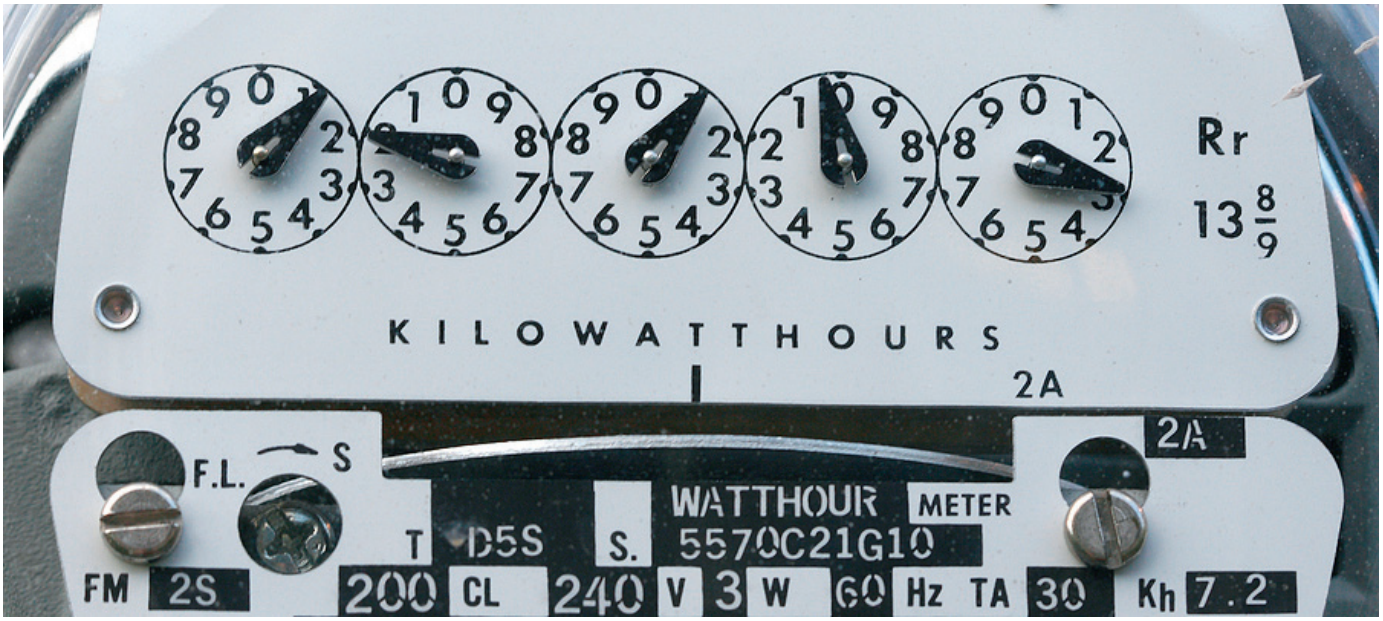
In Massachusetts, CEG contracted with AEC to calculate the value of seven NEBs that were not included in the Massachusetts energy storage cost/benefit test but should have been.[73] This analysis showed that storage is capable of providing many important and valuable benefits beyond those considered by the state in its cost/benefit analysis, and points to areas where the state's test may be expanded to create a more fair and thorough cost/benefit picture for energy storage.

4. REQUIRE PLAN ADMINISTRATORS OR UTILITIES TO INTRODUCE A BATTERY PROGRAM INTO THE PROPOSED ENERGY EFFICIENCY PLAN

Once peak demand reduction is a goal of the efficiency plan and batteries are shown to pass the cost/benefit test, the plan administrators should develop a battery program within their efficiency offerings. Stakeholders, regulators and energy efficiency advisory bodies should work with utilities on developing and marketing customer battery offerings.

It is helpful if state statutes require the inclusion of all cost-effective measures. For example, Massachusetts *Green Communities Act* states that efficiency program administrators shall seek "…all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply."[74] Such language requires the program administrators to include battery storage once a positive cost/benefit test has been obtained. However, not all states have such a requirement in law. In these cases advocacy for development of a battery program may be needed.

Often, distributed storage offerings are initially established as small-scale pilots and later expanded. This can be useful, as a pilot program can allow the utilities an opportunity to work out any problems and gather information helpful in expanding the program. However, pilots by design are limited to a small subset of ratepayers and are often less cost-effective than full-scale programs due to their small size. Utilities should be required to move successful pilot programs into full program status in a timely manner.



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5. ENSURE THAT THE STATE'S RELATED POLICY GOALS ARE SUPPORTED; REVIEW EXISTING REGULATIONS AND RULES FOR NEEDED UPDATES TO ACCOMMODATE BTM BATTERIES

One of the advantages of funding distributed storage through a state energy efficiency plan is that other state policy goals can be supported. For example, the state may want to use energy storage to help ensure low-income communities have access to clean energy, increase deployment and integration of renewable generation, direct clean energy toward peak demand hours, or improve electric system resilience.

In order to support these policy goals, incentives and carve-outs can be built into the state's energy storage incentive structure, either within the ConnectedSolutions/BYOD program, or outside of it in a related program. For example, a proposed program based on the ConnectedSolutions model from the Connecticut Green Bank, called "Solarize Storage," incorporates an up-front rebate in combination with pay-for-performance, and it offers higher rebate rates for LMI participants.[75] The Massachusetts SMART solar program, which has a battery adder that can be stacked with the state's ConnectedSolutions program incentives, offers adders for solar systems that support various state policy goals, such as projects that redevelop brownfields, or are located in low income eligible areas.[76]

In addition to incentivizing battery deployment that supports state policy goals, it is important to remove regulatory or administrative barriers that may hinder battery developers from supporting these goals. Toward this end, policy makers should review the state's suite of renewable and energy storage policies, programs and regulation to ensure that all the parts work together toward the desired goals. This may sometimes require regulatory adjustments.

For example, in Massachusetts, the addition of BTM batteries to customer solar PV required changes to the state's net metering regulations in order to allow net metering customers to install batteries, and to ensure customers were not charging batteries from the grid and then discharging them to the grid for net metering credit. Utilities in Massachusetts worked with the state regulator to update net metering rules, requiring customers to configure solar+storage systems such that batteries cannot discharge to the grid, or to install multiple meters to monitor the flow of power.[77] Another regulatory change in Massachusetts addressed the question of whether utilities or customers own the capacity rights to BTM batteries, and established a mechanism through which customers can retain those rights, thus safeguarding an important asset that can be monetized by battery owners.

In Rhode Island, the program administrators reported that commercial customer participation was limited due to state program rules that restricted the size of solar+storage systems. According to the Rhode Island 2020 Energy Efficiency Plan, "Adoption of the C&I storage incentive initiative was limited in 2019 due to cost barriers. Energy storage systems are only cost-effective at the current incentive rates when coupled with solar, as this allows the asset owner to earn the Federal Investment Tax Credit for the energy storage system, however the RI Net Metering and Renewable Energy (RE) Growth programs do not currently allow for paired solar + storage facilities greater than 25 kW. The Company is . . . evaluating if and how the Net Metering and RE Growth programs could be adapted to allow paired solar + storage facilities greater than 25 kW."

It may be inevitable that such adjustments will need to be made, but many problems can be avoided if the state reviews its suite of clean energy policies, programs and regulations ahead of time and approaches needed changes in a coordinated way.

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Conclusion

Storage is a ubiquitous feature of our modern world. We store everything that is important to life: food, in granaries and warehouses; water, in reservoirs and tanks; oil—4.1 billion barrels of it—in the national strategic reserve. The Strategic National Stockpile, a national repository of antibiotics, vaccines, antidotes and other critical medical supplies, is kept in 12 secret warehouses in undisclosed locations across the US. In our homes, we have smaller storage facilities for fuels, hot water, and food. Our businesses stockpile all sorts of supplies on site—paper, pens, printer ink, cleaning supplies. We even keep stores of many things we could easily live without: chocolate, road salt, sticky notes, liquor, and cosmetics.

It is ironic, then, that the one thing we store very little of is one of the most important commodities we produce: electricity. Currently, the total electric storage capacity of the United States is just a little over two percent of its generating capacity, and the vast majority of that is provided by pumped hydroelectric storage facilities built in the 1970s. Stationary battery storage, although it has become a popular topic in the press, represents only 0.03 percent of our national generating capacity. In other words, from the perspective of the electric grid, it hardly exists.

This means that the US electric grid, something we rely on every moment of every day, is the world's largest just-in-time delivery system, in which power is generated at the very moment and in the exact amount demanded by consumers. As demand fluctuates, generation must likewise rise and fall. If generation gets out of step with demand, blackouts ensue.

This system, delicate as it sounds, has worked tolerably well for more than a century. However, the world is changing. The rise of renewables has added variability to the generation side of the grid equation, where previously only the demand side was expected to be variable. The spread of distributed generation means that two-way flows of power are now not only possible, but necessary. And the increase in frequency and severity of natural disasters, with their accompanying grid failures, means customer-owned resilient power is no longer just a nice idea—it is critical.

For these reasons and many others, battery storage has been called the "holy grail" for renewable energy and a modern grid. It is surprising, then, that so little has been done at the federal level to encourage and support the scale-up of battery storage. Outside of a few FERC orders, important for opening wholesale markets to this new technology, there is almost no federal policy on storage. Even at the state level, where so much has been done to spur the adoption of renewable generation, only a handful of states have set an energy storage procurement target; even fewer have storage incentives in place. After all, it's easy to say storage is important, but much harder to actually find the resources to support it while markets develop.

ConnectedSolutions gives states a new tool. It allows them to use existing energy efficiency budgets to support the scale-up of distributed energy storage. This one simple step—including distributed battery storage as an efficiency measure—answers the question of how states can find the resources to support the needed widespread deployment of energy storage to meet the needs of the electric grid.

In this report, we have shown how ConnectedSolutions has been implemented in New England, and how it could be replicated in other regions. We have explained how the ConnectedSolutions model benefits all ratepayers, democratizing the energy storage landscape and creating virtual power plants to meet real grid needs. We have explored the economic and policy benefits of this new model funding program. In an accompanying report, *ConnectedSolutions: The New Economics of Solar+Storage for Affordable Housing in Massachusetts,* we show how the model improves solar+storage project economics and makes projects more financeable. (The report can be found at www.cleanegroup.org/ceg-resources/resource/connected-solutions-affordable-housing.)

The ConnectedSolutions model has been shown to work in New England. What remains is for the energy agencies, regulators and efficiency program administrators of other states to adopt it, improve it, and put it into action.

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Appendix A: Recommendations for Federal Policymakers

At this writing, there is little federal support for states working to advance energy storage policy and programs. This is a significant policy gap that should be addressed by the new federal administration.[78]

Currently, the distributed battery storage market in the US is about where the distributed solar market was before states implemented net metering to allow export of BTM solar generation to the grid. With ConnectedSolutions, states now have a tool to allow export of BTM battery storage capacity to the grid. If widely adopted, the ConnectedSolutions model could do for the US distributed battery market what net metering has done for distributed solar.

Although the ConnectedSolutions program model is administered at the state and utility levels, federal support could speed its adoption across the nation. Recent FERC orders, notably FERC orders 841 and 2222, have paved the way for distributed energy storage to participate in wholesale energy markets—but the FERC orders do not create the necessary mechanisms to fund and finance distributed systems, connect them to wholesale markets, and allow monetization by system owners. Grid operators under FERC jurisdiction (ISOs and RTOs) will lower barriers to allow distributed storage to participate in energy markets, but states and utilities must ultimately adopt policies and programs that will bring distributed storage to scale and organize it into an effective tool to provide market services where and when they are needed. ConnectedSolutions and BYOD programs are ideal for this purpose.

What is needed now is a suite of federal programs to support widespread adoption of the ConnectedSolutions model at the state level. Federal support for state policy and program development will be key to bringing energy storage to scale, as it has been for solar PV.

What is needed now is a suite of federal programs to support widespread adoption of the ConnectedSolutions model at the state level. Federal support for state policy and program development will be key to bringing energy storage to scale, as it has been for solar PV.

Here are some federal roles and initiatives that would support the expansion, adaptation, and development of ConnectedSolutions programs:

Federal energy storage tax credit: A standalone federal storage tax credit is important to support storage deployment while the industry is in its early growth phase. Such a tax credit would work in tandem with the ConnectedSolutions pay-for-performance model to support BTM storage economics; this in turn would help distributed battery storage scale up faster, access new markets, and gain economies of scale. Currently, energy storage paired with solar can share the federal Investment Tax Credit (ITC), but only if the storage is charged from solar at least 75% of the time; and the ITC is sunsetting over the coming few years.

National storage capacity targets: The federal government should set a national energy storage capacity goal, or a series of targets, and support these targets with incentives and technical and policy support resources. Ideally this national goal would not be monolithic but would separately address distributed (BTM) storage as distinct from utility- or merchant-owned bulk storage.

National storage pricing and technology improvement goals: To improve battery storage technology while driving prices down, national storage pricing targets should be established, and technical goals, such as increased energy density and round-trip efficiency, should be set. This will expand the number of applications for which storage can provide cost-effective services and thereby grow markets for programs such as ConnectedSolutions. It would also help battery storage meet state program requirements for cost-effectiveness and energy efficiency.

Storage applications, valuation and markets, and industry benchmarking and tracking: A federal effort, led by national energy laboratories, could help to advance understanding of battery storage economics, particularly in the areas of quantitative valuation of storage applications, stacking of applications, and needed market reforms to enable monetization of these applications. This would then inform recommendations on market rules, regulation, and policy. This information would provide a needed underpinning for the development of state programs such as ConnectedSolutions, which depends, for example, on understanding the regional cost of peak demand and the cost/benefit value of storage as a peak demand reducing measure.

Storage codes and standards/best practices: The national energy labs should continue and expand their present efforts to help develop codes and standards for battery storage. Currently, BTM storage programs are hampered by permitting and siting barriers (for example, it is still very difficult to install batteries inside buildings in New York City) and the battery storage industry is hampered by a lack of coherent and consistent performance and safety standards. Without federal guidance and the promulgation of best practices, local ordinances are likely to default to the most conservative siting standards, while state and utility programs will continue to have to develop their own performance standards for program eligibility. This could slow storage adoption and prevent BTM storage from coming to scale.

LMI engagement. States have demonstrated a concern that underserved communities not be left behind in clean energy transitions, but methods to address barriers to LMI participation are still being developed. Federal support is particularly needed to help states target new, emerging and challenging LMI energy storage markets. These markets can be supported by helping states to value and incentivize battery storage in settings such as affordable housing, critical community facilities, peaker plant replacement, and home health care. Targeted federal support for LMI engagement could include tax incentives targeted to low-income communities, goal-setting, knowledge sharing and policy support to states.

Battery storage for resilient power: A national program focused on the role and value of battery storage for resilient power applications should be launched within the national labs. As part of this effort, the role of aggregated, distributed storage should be explored, along with methods for storage owners

The Clean Energy States Alliance hosted a full-day workshop in Atlanta in January 2019 with 14 representatives of frontline community-based organizations to learn of their perspectives on clean energy equity.

Clean Energy States Alliance

and aggregators to monetize resiliency services. This effort could include formation of a new federal "Resilient Power Initiative" that would provide federal grants, technical assistance support, and other measures to advance resilient energy storage markets across the country.

More targeted assistance could also be provided for resilience in specific sectors: for example, US DOE could work with HUD to create an "Office of Housing Resiliency" to provide grants to housing developers and owners, as well as information and analytical support, to encourage the installation of solar and battery storage in affordable housing units across the country, to allow residents to shelter in place during natural disasters and the associated grid power outages. Similarly, US DOE should work with Department of Health and Human Services (HHS) and other relevant federal agencies to institute a new program to ensure its thousands of federally qualified community health centers have 24/7 reliable electricity with solar and battery storage technologies. National energy labs could also play a foundational role in helping to determine metrics and tools to calculate the value of resilience services.

Federal/state partnerships and support: An existing federal-state partnership program run out of the DOE Office of Electricity has allowed Sandia National Laboratories and Pacific Northwest National Laboratories to support state needs in the area of energy storage, but this current program tends to focus largely on utility- or large commercial-scale storage. Nevertheless, it provides a model that could be expanded (with increased funding) to support states and municipalities developing policy and regulation addressing behind-the-meter storage, and to assist them in developing demonstrations and pilot projects.[79] To support the inclusion of BTM storage in state energy efficiency programs, DOE and the national labs should create a national clearinghouse of model legislation, regulation and policy best practices; provide policy best practices reports, training for state policymakers and regulators, and technical support for state energy storage program development; and offer other assistance to local, state, and regional entities.

Federal support for state storage analysts: Many states do not have in-house expertise on energy storage technology, policy and program development. The U.S. Department of *Energy's State Energy Program* (SEP) should provide *funding* and technical assistance to states for the purpose of hiring energy storage analysts within state energy agencies.

Municipal utility and rural electric cooperative storage adoption: A federal effort to support energy storage deployment should include technical assistance and knowledge resources for municipal utilities and rural electric co-ops. Although they are not typically engaged in administering state energy efficiency programs, municipal utilities and co-ops can develop their own BYOD programs. The national labs should build on their existing relationships with the National Rural Electric Cooperative Association (NRECA) and regional municipal utility organizations to provide technical support for the development of such programs.

Battery storage for home health: US DOE should work with the HHS to consider how to provide coverage through Medicare or Medicaid for battery storage as an eligible technology to protect vulnerable populations dependent on powered home health care equipment. HHS should create a new "Office of Resilient Home Health Care" that could administer such a program and offer incentives to companies to offer new technology innovations in this market. Such a program could work in tandem with state and utility ConnectedSolutions/BYOD programs, with the result that millions of people could gain access to life saving, clean energy technology.[80]

Batteries for peaker plant replacement. By aggregating BTM batteries to provide peak demand reduction, the ConnectedSolutions program model allows distributed battery storage to compete with fossil fueled peaker plants. To support the expansion of this emerging alternative, US DOE, in partnership with other agencies such as the Environmental Protection Agency (EPA), should create a "Peaker Replacement Program" that would offer an array of federal support to phase out the more than 1,000 fossil-fuel peaker plants currently in operation, and replace them with renewable energy and battery storage alternatives. Such an effort would support distributed, aggregated energy storage programs such as ConnectedSolutions by offering targeted incentives for phased peaker replacement and retirement.

Lowering financial risk. The ConnectedSolutions program model goes a long way toward lowering investment risks for BTM storage, but its impact could be enhanced with federal support. This could include establishment of a dedicated federal "Energy Storage Financing" program that would support the development of new initiatives to overcome financial risk, especially in LMI clean energy markets. The program could offer federal credit enhancement and loan guarantee funds, work with green banks and other financial entities to develop storage financing mechanisms and extend favorable loans to housing developers and others working to bring the benefits of energy storage to the LMI space.

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Appendix B: Where ConnectedSolutions Is Being Adopted

The ConnectedSolutions program began in Massachusetts and has already been expanded there. Similar programs have been implemented in Rhode Island and Connecticut (see Appendix Table 1), and a program is proposed in New Hampshire following a pilot. Several utilities have also launched "Bring Your Own Device" (BYOD) customer battery initiatives that operate outside of state energy efficiency programs. Below are summaries of some of these programs. Links to program documents may be found in Appendix D.

CONNECTEDSOLUTIONS MODEL PROGRAMS (ALPHABETICAL BY STATE)

Connecticut: The state Energy Efficiency Board approved ConnectedSolutions as a mid-course program update, and it is currently being rolled out by Eversource and United Illuminating Company, the state's two big utilities. There's a brief description of this program in the 2020 update Eversource filed in their Conservation and Load Management plan, which states: "In 2018 and 2019, Eversource began deploying residential battery storage projects in Massachusetts and is actively pursuing cost-effective ways to integrate residential battery storage into an ADR [Active Demand Response] program in 2020. Eversource has issued a three-state Request for Proposal ("RFP") for demand reduction vendors for targeted technologies, including battery storage. Battery storage technology is envisioned as an optimal strategy, as it would allow customers to provide load reduction in several ways, as the technology can provide capacity in daily, targeted, and winter periods. The key findings from Massachusetts deployments will be used to inform the Connecticut program as it is rolled out in 2020."

APPENDIX TABLE 1

Summary Table for ConnectedSolutions Program Rates

State	Massachusetts	Mssachusetts	Rhode Island	Connecticut
Utility	National Grid	Eversource	National Grid	Eversource
Summer Rebate	$225	$225	$400	$225
Winter Rebate	$50	$50	$0	$50
Max # of Events per Summer	60	60	60	60
Max # of Events per Winter	5	5	0	5
Max Duration of Events	3 hours	3 hours	3 hours	3 hours
Estimated 5-year incentive for major solar batteries				
LG Chem RESU 10H	$4,300	$4,300	$6,200	$4,300
Telsa Powerwall 2	$6,200	$6,200	$9,000	$6,200
Generac PWRcell 17	$7,800	$7,800	$11,400	$7,800
Sonnen ecol.inx 20	$9,200	$9,200	$13,300	$9,200
Panasonic EVDC Plus	$7,800	$7,800	$11,400	$7,800
ElectriQ PowerPod 20.2	$7,600	$7,600	$11,000	$7,600

This table shows estimated five-year economics of ConnectedSolutions for residential customers in three states.

Source: EnergySage. This table shows estimated five-year economics of ConnectedSolutions for residential customers in three states. See https://news.energysage.com/the-connectedsolutions-program-what-you-need-to-know.

Although details have not been supplied to date, the program appears very similar to the one developed in Massachusetts, including a pay-for-performance revenue model with customer ownership of BTM batteries.

In addition, PURA, the CT state energy regulator, has issued a straw proposal for distributed battery program designs. The proposal includes a pay-for-performance feature combined with a customer rebate, on-bill and low-cost financing, and LMI adders.[81]

Massachusetts: Starting with the 2019-2021 three-year energy efficiency plan, Massachusetts offered two different program plans to customers: a summer targeted dispatch program, and a winter program. A third program, summer daily dispatch, was delayed by the state utility regulator, but is now being added to the program offerings.

Rates vary depending on the season and type of participation, and rates are different for commercial and residential participants. Payments are based on the average load reduction per hour over a three-hour dispatch event and are paid seasonally. Participating customers get a day-ahead notice of dispatch and can opt out if they wish. There is no penalty for opting out but doing so does reduce the customer's average load reduction for the season, on which payments are based.

The program in Massachusetts is being administered by National Grid, Eversource, Until, and Cape Light Compact (CLC). In addition, CLC is also offering a separate battery program for its customers, that is quite different from the other utilities' programs and is the only one in the state that includes specific LMI incentives (CEG pointed to this as a major shortfall in the statewide programs approved for the 2019–2021 efficiency plan).

The basic outline of the Cape Light program is this: CLC will offer targeted and (pending DPU approval) daily dispatch options to their BYOD customers, similar to the statewide program offered by other utilities; but, in addition, they will also offer solar+battery+heat pump systems to 250 low- and moderate-income residential customers. These 250 LMI customers are broken down into two categories:

- 150 low-income customers receive all three technologies at no cost
- 100 moderate income customers pay 25 percent of cost up to a cap of $5,000 (for PV and battery system)

This LMI program will use a third-party ownership structure for the solar+storage to take advantage of the federal investment tax credit. It will also monetize the SMART solar incentive, ConnectedSolutions payments and Clean Peak Standard credits for the solar+storage, and Alternate Energy Portfolio Standard credits for the heat pumps. A third party will install the systems and provide financing.

New Hampshire: The state's major utilities, Eversource and Unitil, have filed a proposal to expand their active customer demand response pilot into a regular program offering for the 2021-2023 energy efficiency plan. The program would be similar to the ones being run in Massachusetts and Rhode Island.[82] The utilities have stated that customer demand is strong and have proposed a higher incentive for batteries than for other direct load control technologies such as wi-fi thermostats.

APPENDIX TABLE 2

Performance Payment Rate Details for National Grid's ConnectedSolution Battery Program in Massachusetts and Rhode Island

		MASSACHUSETTS	RHODE ISLAND
Commercial	Daily Dispatch	• 20–30 events per summer • 2–3 hours per event • Technology/Vendor Agnostic • **$200/kW-performed-summer** • **$25/kW-performed-winter** • **Plus SMART Battery Adder**	• 30–60 events per summer • 2–3 hours per event • Technology/Vendor Agnostic • **$300/kW-summer**
Residential	Residential Batteries	• 30–60 events per summer • 2–3 hours per event • 4 Approved Battery Vendors • **$225/kW-performed-summer** • **$50/kW-performed-winter** • **Plus SMART Battery Adder**	• 3–60 events per summer • 2–3 hours per event • 4 Approved Battery Vendors • **4400/kW-summer**

Source: National Grid

Rhode Island: In 2019, Rhode Island utility National Grid implemented ConnectedSolutions along the same lines as its Massachusetts program, including residential and commercial battery offerings as part of its active demand reduction program within the state's energy efficiency plan. The RI program is structured similarly to the Massachusetts program, although performance compensation rates are higher in Rhode Island. Participation in the commercial program was hindered by state Net Metering and Renewable Energy Growth programs that do not allow paired solar+storage facilities greater than 25 kW. National Grid is seeking to amend these programs.[83] Despite this setback, the Rhode Island ConnectedSolutions program has been successful overall, and National Grid has already expanded it for subsequent plan years.

UTILITY BYOD PROGRAMS (ALPHABETICAL BY STATE)

California: Sacramento Municipal Utility District (SMUD), Southern California Edison (SCE) and Pacific Gas and Electric Company (PG&E)

California customers have experienced numerous power outages related to wildfires, and the state, along with its electric utilities, is encouraging the deployment of resilient power systems through several pilots and proposed new regulations. Two California utilities already offer customer battery storage programs, while a third has recently announced procurement of aggregated BTM systems. Additionally, California Public Utility Commission (CPUC) staff have proposed a pilot program that would allow customer resources, including energy storage, to be aggregated to provide distribution system deferral services. And a proposed CPUC rulemaking would change regulations to allow for emergency power export from BTM batteries.

SMUD offers its commercial customers a set incentive in return for the customer's commitment to operate batteries in such a way as to reduce peak demand. Solar+storage customers who net meter commit that at least 51 percent of battery capacity will be used to shift energy generated from solar to offsetting loads during peak periods. Battery-only customers commit that at least 51 percent of battery capacity will be used to shift energy usage from on-peak periods to off-peak periods. Compensation rates vary based on battery capacity, from $600 for a 15-kW battery to $5,000 for batteries larger than 150 kW. Commercial Energy Storage Program details are available at *www.smud.org/en/Going-Green/Battery-storage/Business*.

SMUD is also developing a first-of-its-kind community storage program, Energy StorageShares, that offers virtual demand management services to non-connected commercial customers who purchase shares.[84] In return for their investment, participating customers receive a monthly on-bill credit commensurate with the savings they would have realized by installing an on-site battery for demand charge reduction. The credit continues over a 10-year term. In turn, SMUD uses customer investments to procure a battery in a location that maximizes grid benefits. Through this program, commercial customers can receive guaranteed savings regardless of their load shape or their ability to site or maintain a battery at their facility.

For its residential customers, SMUD offers the Smart Energy Optimizer (*https://www.smud.org/en/Going-Green/Battery-storage/Homeowner*), a residential battery energy storage program that makes use of day ahead price signals to direct battery dispatch to specific times of day that enhance grid benefits beyond what a traditional time of use rate can do.

What is needed now is a suite of federal programs to support widespread adoption of the ConnectedSolutions model at the state level. Federal support for state policy and program development will be key to bringing energy storage to scale, as it has been for solar PV.

SCE has announced a one-year pilot program in partnership with Sunrun, under which 300 customers will be able to install solar+storage systems that will be aggregated by SCE in a virtual peaker arrangement.[85] The utility has stated that it would like to expand the pilot to include other developers. The initial phase of the program does not include a pay-for-performance tariff, although participating customers will receive a $250 incentive for participating. It is worth noting that California also offers the Self-Generation Incentive Program (SGIP) storage rebate, which includes enhanced incentives for low income and resilient systems.

PG&E has announced procurement of 27 MW of aggregated BTM energy storage, pursuant to a November 2019 decision by the CPUC that identified potential electric system reliability issues beginning in summer of 2021. In that decision, the CPUC authorized PG&E to procure at least 716.9 MW of system reliability resources. See *www.power-grid.com/der-grid-edge/pge-seeks-approval-for-six-storage-projects-totaling-387-mw*.

There is also a CPUC Energy Division Staff Proposal for a BYOD Deferral Tariff, that would allow customers who own battery storage to enroll their devices to provide dispatchable grid services that could defer distribution system investments.[86] And a proposed CPUC rulemaking contemplates allowing BTM batteries to export power to the grid during emergencies.[87]

New York: ConEd and PSEG

There are two emerging BYOD programs in New York state—one on Long Island, and one in the Orange/Rockland area. Public Service Enterprise Group (PSEG) Long Island offers a BYOD pay-for-performance program to its residential and commercial customers. The program is like those developed by Green Mountain Power in Vermont and Liberty Utilities in

New Hampshire. Battery customers can sign a 10-year performance contract, under which they will be paid in return for load reductions behind the meter at peak demand times as signaled by the utility. Customer batteries will be dispatched a maximum of 10 times between May 1 and September 30 each year, for a maximum of four hours each time. The program is marketed to customers by third-party aggregators who enroll customers and manage their participation and define payment terms. The utility notifies the aggregators a day in advance of an event, and the aggregators notify their customers. Customers may opt out of participating in an event but doing so reduces their seasonal compensation.

Orange & Rockland Utilities (O&R), a subsidiary of Consolidated Edison, has partnered with Sunrun to offer combined solar+storage systems to 300 residential customers, forming a virtual power plant that can be dispatched to ease congestion on the distribution grid.[88] Sunrun will earn compensation from O&R for managing and dispatching the networked home systems; O&R will benefit by leveraging the aggregated, BTM resource to reduce electricity load on heavily used distribution lines. Participating customers will receive a home solar+storage system at a discounted rate, as well as a resilience benefit in case of a grid outage.

Sunrun has been very active in developing aggregated residential solar+storage systems. In 2019, Sunrun became the first distributed storage developer to successfully bid 20 MW of aggregated residential solar and battery power into the ISO New England capacity market.[89] Also in 2019, Sunrun won a contract to help replace the retiring jet fueled Oakland Power Plant in Oakland, California with power from home solar and battery systems installed on low-income housing in West Oakland and Alameda County.[90] Sunrun is also partnering with Southern California Edison on a 300-customer, residential solar+storage pilot (see below). And in Hawaii, Sunrun is delivering electricity from home solar and batteries to the Hawaiian Electric Company as part of an innovative Grid Services Purchase Agreement.[91]

Oregon: Portland General Electric

Portland General Electric (PGE) has announced a pilot program to incentivize the installation and connection of 525 residential batteries in their Portland, OR territory.[92] The customer batteries will contribute about 4 MW to the grid when aggregated into a virtual power plant. In exchange, participating customers will receive an on-bill credit of $40 or $20 per month, depending on whether the batteries are charged from the grid or from solar PV. Customers may also be eligible for a rebate of $5,000 if they participate in a solar program offered by Energy Trust of Oregon, which manages the state's energy efficiency program. Customers living within the PGE Smart Grid Test Bed will also be eligible for a rebate when they purchase a battery.

Courtesy of Sunrun

Vermont: Green Mountain Power

GMP offers two battery programs to customers: a utility-owned battery program in partnership with Tesla, and a customer-owned, BYOD program.

GMP's programs began with a 14-unit low-income pilot program in Waltham, VT that was supported by CEG/CESA, Sandia National Laboratories and US DOE Office of Electricity.[93] That program involved the aggregation and dispatch of 14 individual residential solar+storage systems for utility peak demand reduction. Following the development of this pilot in 2016, GMP rolled out a Tesla Powerwall program, in which the utility owned and dispatched batteries placed behind customer meters, and customers paid a monthly fee in exchange for which they received resilience benefits in the event of a grid outage. This program evolved into GMP's current Resilient Home program, in which customers receive two Powerwalls for complete home resilience. GMP has also launched a separate BYOD program that offers performance payments to customers that own batteries.[94] Batteries from six different manufacturers are eligible. GMP also received a grant allowing it to provide free batteries to 100 low-income Vermont residents.[95] Through these programs, GMP has procured or contracted with thousands of residential customer batteries, as well as installing a number of larger, utility-scale batteries at its substations; the company recently announced its battery resources had saved ratepayers $3 million in 2020 alone.[96]

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Appendix C: Efficiency vs. Demand Response—Where do batteries belong?

Currently, customer energy storage aggregation programs come in two basic flavors: the ConnectedSolutions model in New England, which supports customer-owned batteries through state energy efficiency plans; and BYOD programs in several utility territories, which treat storage as part of utility demand response programs. One could see these as competing models, although customers generally will not have a choice as to which of the two models they prefer. From a policymaking perspective, however, it is worth considering the relative merits of each and whether there is an advantage in choosing one model over the other.

Although both models represent a significant step forward in distributed storage funding, CEG suggests policymakers consider adopting the ConnectedSolutions, efficiency-based model wherever it is feasible. There are five main reasons for this recommendation:

1. **The availability of larger energy efficiency budgets compared to demand response budgets.** According to the US Energy Information Administration, state electric energy efficiency budgets currently amount to about $6 billion nationwide (another $2 billion is allocated to gas efficiency programs). By contrast, utility budgets for demand response programs cumulatively amount to about $1.5 billion.

2. **The opportunity for greater policy input into efficiency program development.** Efficiency programs tend to be more transparent and open to input from state policymakers, NGOs and the general public.

3. **The ability of states to incentivize utility efficiency gains through performance payments.** The use of utility performance incentive mechanisms (PIMs) enables states to reward utilities for successfully meeting efficiency program goals.

4. **The ability of the customer to export power to the grid in the ConnectedSolutions model.** By comparison, demand response programs are typically designed for load reduction only, which limits the benefits and revenue potential of BTM batteries.

5. **The statewide nature of energy efficiency programs, which supports equitable access to energy storage technology.** By comparison, demand response programs are frequently available only to customers within a single utility territory, and in many cases residential customers have no opportunity to participate.

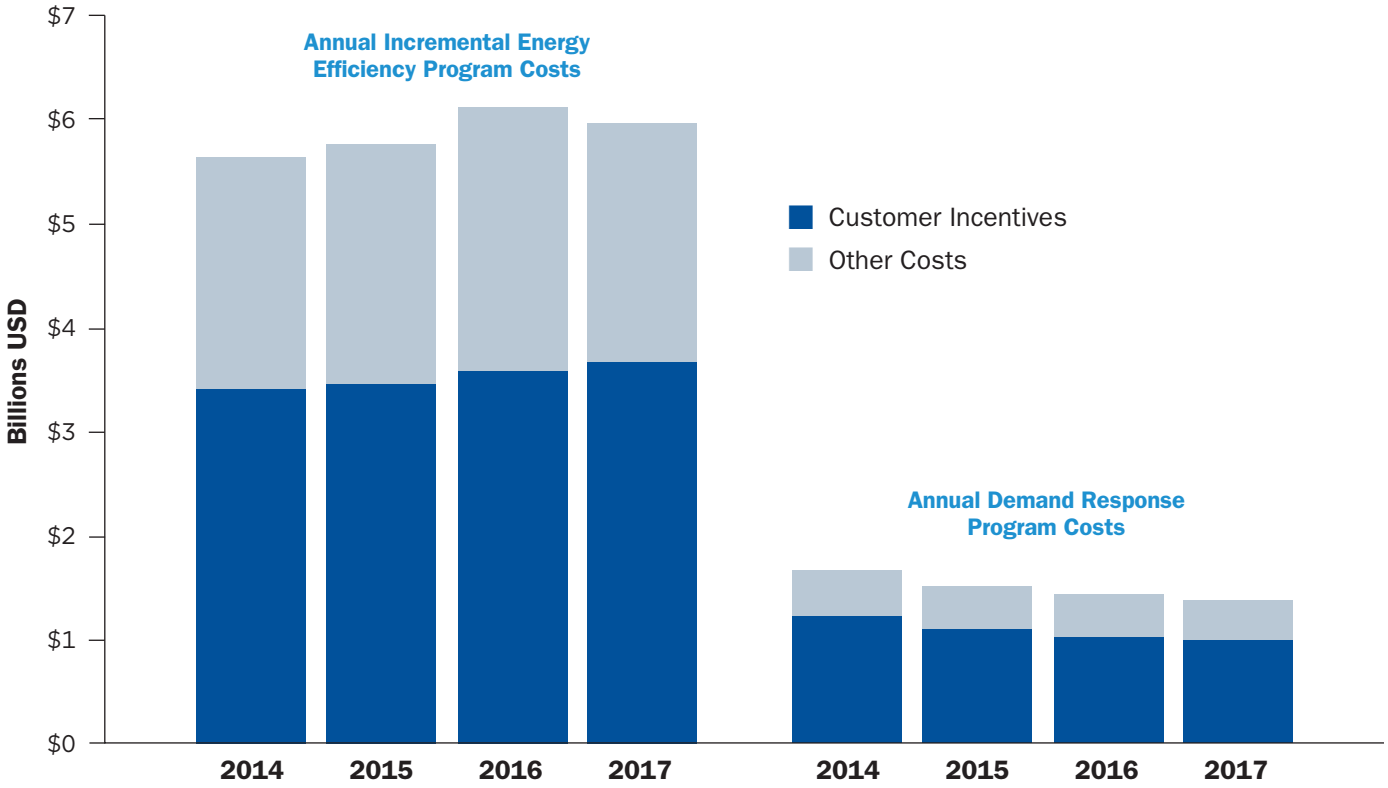
More money in efficiency budgets. According to the US Energy Information Administration, state electric energy efficiency budgets currently amount to about $6 billion nationwide (another $2 billion is allocated to gas efficiency programs). By contrast, utility budgets for demand response programs cumulatively amount to about $1.5 billion (see Appendix Figure 1, p.45).

If policymakers wish to bring distributed storage to scale, it makes sense to look to the best funded programs for support. As Appendix Figure 1 (p.45) makes clear, energy efficiency programs simply command more funds than demand response programs.

More policy control over efficiency programs. Energy efficiency programs tend to be more proactive and more responsive to state policy goals than demand response programs. Typically, demand response programs are developed by utilities and approved by utility regulators. With a few exceptions, utilities and utility regulators do not view themselves as responsible for promulgating policy advances, but rather see themselves as providers and defenders of basic ratepayer interests such as reasonable rates and equitable service.[97] So long as a utility program proposal does not unduly burden ratepayers,

APPENDIX FIGURE 1

State Energy Efficiency Spending Vs. Utility Demand Response Spending



Source: US EIA "Today in Energy," March 29, 2019. *https://www.eia.gov/todayinenergy/detail.php?id=38872*

it is likely to be approved by regulators.[98] It is still relatively rare for regulators to require utilities to make more aggressive investments in new technology in order to advance policy goals; and in many states, policymakers have little input into the development of utility demand response programs.

Energy efficiency programs, by contrast, are usually developed by utilities in collaboration with an efficiency advisory board or council. These advisory boards typically represent a broad selection of stakeholder interests including environmental organizations and state energy agencies. Often, they contract outside experts to provide independent analysis, and they are far more likely to push utilities to pilot new technologies and advance state policy goals. These processes are also typically more transparent to the public, and often include formal public comment periods, public meetings, and other opportunities for stakeholders to provide input.

Ability to incentivize efficiency battery program gains. Utilities, which typically administer both energy efficiency and demand response programs, may have little intrinsic motivation to make gains in these areas. Demand response is often viewed as a "passthrough" payment from the utilities' perspective, meaning that payments made to customers for demand response services simply offset payments that would otherwise be made to the grid operator or another service provider. Even worse from the utilities' perspective, demand reduction and increases in customer efficiency can have a negative impact on the utilities' bottom line. As pointed out by the American Council for an Energy-Efficient Economy (ACEEE) in a 2018 report, "regulated utilities traditionally face disincentives to implementing and scaling up energy efficiency within their territories. Efficiency reduces electricity sales and revenues, resulting in financial losses compared to traditional supply-side infrastructure investments." Specifically, ACEEE identifies three main concerns utilities may have about advancing energy efficiency: program cost recovery, decreased energy sales, and lack of earnings opportunities for shareholders compared to other utility investments.[99]

To combat these disincentives, states have increasingly turned to utility performance incentive mechanisms (PIMs). While a few states incentivize utilities to engage in demand response offerings, many more incentivize utilities to expand and effectively administer energy efficiency programs. According to ACEEE, 29 states have adopted utility performance incentives within their efficiency programs – essentially, payments for utilities to reward them for achieving efficiency goals. This provides a way to encourage utilities to support the scale-up of battery storage through ConnectedSolutions-type programs.

The use of PIMs has proven to be very effective. In Massachusetts, for example, ACEEE reports, "The incentive structure in place has resulted in energy efficiency programs being viewed as a core business unit capable of contributing to the overall business objectives of [National Grid]."[100]

Ability to export to the grid. Traditionally, demand response programs are load-reducing only; they are not designed to allow customers to export power to the grid. This makes sense because demand response programs have generally been available only to industrial and large commercial customers, who get compensated for turning down large facility loads during demand peaks. Because these programs compensate customers for load reductions, they rely on baselining—that is, they require customers to establish a baseline load, against which load reductions can be measured. In theory, there is no reason customers with generators or storage behind their meters could not export power through a demand response program, but that would likely require significant changes in program rules and in the utility's tariff.

By contrast, ConnectedSolutions does allow power export. This means that customer earnings (and battery sizes) are not limited by the facility's load. It also makes it easier for residential customers to participate. Residential loads are typically quite modest, so a solar+storage residential customer would not see significant revenues if their ConnectedSolutions contract allowed for load reductions only.

A state-wide solution. If state policymakers want to promote and support widespread deployment of distributed energy storage, adding it into an existing energy efficiency plan is a viable way to establish such support across the state, without the burden of standing up a new program with a new budget. Once added to the state's energy efficiency program, the battery offering will be marketed to customers of all the regulated utilities in the state. By contrast, leaving distributed storage to be developed by utilities through demand response programs is likely to result, at best, in scattered battery pilot programs advanced by a few progressive utilities, but not in comprehensive state-wide programs made available to all customers equally.

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Appendix D: Program Documents and Resources

Below are links to resources for state policymakers and regulators who are considering adopting a ConnectedSolutions model program.

STATE POLICIES AND ORDERS

Arizona Corporation Commission battery rebate and BYOD program (proposed): https://www.azcc.gov/news/2020/10/01/commissioner-lea-m%C3%A1rquez-peterson-leads-second-chance-for-az-homeowners-to-install-new-rooftop-solar-in-2020-2021-provides-one-more-year-at-current-export-rate and https://docket.images.azcc.gov/E000009162.pdf

California PUC staff proposal to allow BTM batteries to export power during grid emergencies: https://drive.google.com/file/d/1NCEL5mONMkeELDG6XphWsdk6p0I5Gle1/view

California Southern California Edison customer battery program: https://www.solarpowerworldonline.com/2020/06/sunrun-partners-with-southern-california-edison

California SMUD StorageShares program: https://www.cleanegroup.org/smuds-energy-storageshares-program/

California SMUD residential solar+storage system estimator: https://www.smud.org/en/Going-Green/Battery-storage/Homeowner

Connecticut Green Bank battery program proposal (Solarize Storage): PURA-Docket-No.-17-12-03RE03—Solarize-Storage-Proposal-from-the-Green-Bank.pdf (ctgreenbank.com)

Connecticut Eversource battery program proposal: http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/03e85be2e5c42978852585b600530c53?OpenDocument

Connecticut PURA Straw Electric Storage Program Design: http://www.dpuc.state.ct.us/DOCKCURR.NSF/0/f8eea3048fcb4ace8525865400707a2c/$FILE/RE03%20Straw%20Proposal.pdf

Connecticut energy efficiency plan: https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/FINAL-2021-Plan-Update-Filed-10302020.pdf

New Hampshire energy efficiency plan proposal: https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092/INITIAL%20FILING%20-%20PETITION/20-092_2020-09-01_NHUTILITIES_EE_PLAN.PDF

New Hampshire Liberty Utilities battery storage pilot program: https://new-hampshire.libertyutilities.com/acworth/residential/smart-energy-use/electric/battery-storage.html

Massachusetts energy efficiency statewide plan: https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf

Massachusetts ConnectedSolutions program materials: https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-ciprogrammaterials.pdf

Massachusetts Cape Light Compact program (including LMI solar+storage+heat pump systems, and previous free battery proposal): https://www.capelightcompact.org/eeplan

Massachusetts National Grid Navigant Consulting (Guidehouse) report: This report is no longer available online, but results are included in a presentation to the Massachusetts Energy Efficiency Advisory Council: https://ma-eeac.org/wp-content/uploads/January-Demand-Presentation_EEAC_Final_1-16-20.pdf

Massachusetts SMART Program Guideline Regarding Low Income Generation Units: https://www.mass.gov/doc/low-income-generation-units-guideline-october-2020/download

Rhode Island ConnectedSolutions program materials: https://www.nationalgridus.com/media/pdfs/resi-ways-to-save/connected-solutions-ri-program-materials.pdf

Rhode Island energy efficiency plan: http://rieermc.ri.gov/wp-content/uploads/2019/11/ngrid-ri-2020-annual-ee-plan.pdf

Vermont GMP Tesla program: https://greenmountainpower.com/rebates-programs/home-energy-storage/powerwall

Vermont GMP BYOD program: https://greenmountainpower.com/rebates-programs/home-energy-storage/bring-your-own-device

Vermont GMP Resilient Home program: https://greenmountainpower.com/rebates-programs/home-energy-storage/resilient-home

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CLEAN ENERGY GROUP REPORTS

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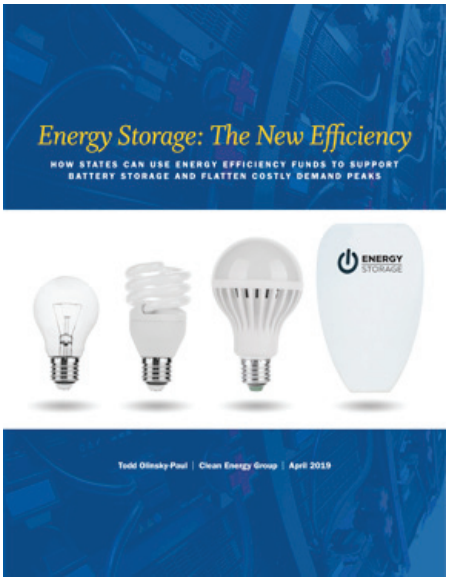
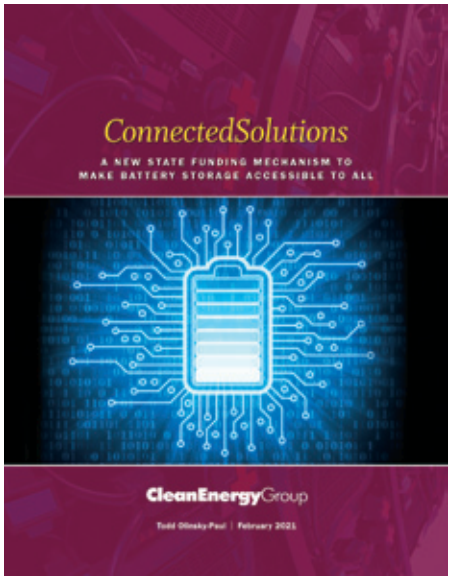
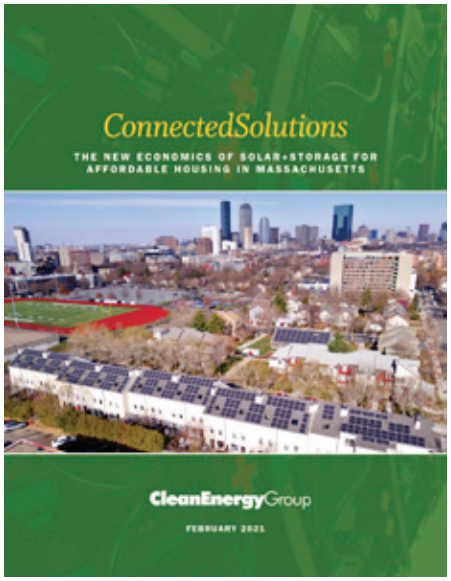
To link to the reports in this series on ConnectedSolutions, click on the covers below.







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ConnectedSolutions

A NEW STATE FUNDING MECHANISM TO MAKE BATTERY STORAGE ACCESSIBLE TO ALL

Clean Energy Group (CEG) is a leading national, nonprofit advocacy organization working on innovative policy, technology, and finance strategies in the areas of clean energy and climate change.

CEG's energy storage policy work is focused on the advancement of state, federal, and local policies that support increased deployment of energy storage technologies. Battery storage technologies are critical to accelerate the clean energy transition, to enable a more reliable and efficient electric power system, and to promote greater energy equity, health, and resilience for all communities.

Learn more about Clean Energy Group and its Energy Storage Project at *www.cleanegroup.org/ceg-projects/energy-storage-policy*.

CleanEnergyGroup
Innovation in Finance, Technology & Policy
50 State Street, Suite 1 • Montpelier, VT 05602
802.223.2554 | www.cleanegroup.org | info@cleanegroup.org

Appendix D

Clean Energy Group

ConnectedSolutions: The New Economics of Solar + Storage for Affordable Housing in Massachusetts

ConnectedSolutions

THE NEW ECONOMICS OF SOLAR+STORAGE FOR AFFORDABLE HOUSING IN MASSACHUSETTS

CleanEnergyGroup

FEBRUARY 2021

ABOUT THIS REPORT

ConnectedSolutions: The New Economics of Solar+Storage for Affordable Housing in Massachusetts presents the results of an analysis to evaluate the impact of the Massachusetts ConnectedSolutions customer-sited battery program on the economics of pairing solar PV with battery storage (solar+storage) at multifamily affordable housing properties. The economics of solar and storage were assessed for six Massachusetts affordable housing properties under two scenarios—one with ConnectedSolutions and one without the program. The analysis found that, compared with other business cases, participation in ConnectedSolutions significantly improves the economic viability of solar+storage for these multifamily housing properties.

The report was produced for the Resilient Power Project (*www.resilientpower.org*), a joint project of Clean Energy Group and Meridian Institute. The Resilient Power Project works to accelerate market development of resilient, clean energy solutions in low-income and underserved communities to further clean energy equity by ensuring that all communities have access to the economic, health, and resiliency benefits that solar+storage can provide. The Resilient Power Project is supported by The JPB Foundation, The Kresge Foundation, Surdna Foundation, Nathan Cummings Foundation, The New York Community Trust, Barr Foundation, The John Merck Fund, and Merck Family Fund.

The report is also based upon work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under the Solar Energy Technology Office (SETO) Award Number DE EE0008758. This award is managed by the Clean Energy States Alliance (CESA). The views expressed herein do not necessarily represent the views of the U.S. Department of Energy or the United States Government.

ACKNOWLEDGEMENTS

The authors would like to thank WinnCompanies, 2Life Communities, and Homeowners Rehab Inc. for their valuable contributions to this report, and to Marriele Mango at Clean Energy Group and Nate Mills at American Microgrid Solutions for reviewing the report and providing input. Maria Blais Costello of Clean Energy Group was responsible for report production, working with David Gerratt of DG Communications on the report design. Much appreciation also for the generous support of the foundations and organizations funding this work. Many of the photos used in this report were graciously provided by SunBug Solar and by Resonant Energy.

DISCLAIMER

ConnectedSolutions

THE NEW ECONOMICS OF SOLAR+STORAGE FOR AFFORDABLE HOUSING IN MASSACHUSETTS

Seth Mullendore and Todd Olinsky-Paul
Clean Energy Group

Geoff Oxnam
American Microgrid Solutions

Dr. Travis Simpkins and Amy Simpkins
muGrid Analytics

FEBRUARY 2021

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Cover Photo: 70-kilowatt solar system developed by Resonant Energy and installed by ACE Solar at Beryl Gardens in Roxbury, MA, a Madison Park Development Corporation property. Source: Resonant Energy

142-kilowatt solar system developed and installed by Sunbug Solar across nine buildings at The Residences at Melpet Farm in Dennis, MA, a Preservation of Affordable Housing (POAH) and Housing Assistance Corporation property. Source: Sunbug Solar

Executive Summary

Despite the economic benefits that solar PV paired with battery storage (solar+storage) and the importance of reliable resilient power for multifamily affordable housing properties—and at housing properties serving elderly populations and individuals with electricity-dependent medical needs—few affordable housing properties have installed solar+storage systems. Those that have succeeded in installing solar+storage have often depended on significant grant support to make the projects financially viable.

This report explores a new battery storage program that is beginning to change this narrative. When the ConnectedSolutions program was initially launched in Massachusetts in 2019, it became the first program in the country to use state energy efficiency funds to support the development of customer-sited battery storage as a demand reduction measure. The design of the program makes it accessible to nonprofit entities—like many affordable housing providers—and creates an opportunity for any type of facility to generate an economic return through battery storage investments, regardless of how the property uses energy or how it is billed for electricity. Because ConnectedSolutions pays for performance based on a multi-year contract between the customer and their electric utility, the program makes battery storage revenues more predictable and reduces project investment risk.

To evaluate the impact of the ConnectedSolutions program on affordable housing properties, the economics of solar+storage was assessed for six multifamily affordable housing properties in Massachusetts. The financial feasibility of solar+storage for each property was explored under two scenarios: one with participation in the ConnectedSolutions program and one where ConnectedSolutions was not available. Nonprofit and for-profit ownership scenarios were also explored. While the results detailed in this report are specific to multifamily affordable housing properties, they are widely applicable to all types of facilities where the ConnectedSolutions program is available.

These analyses produced several important findings, including the following:

- Without ConnectedSolutions, most of the properties would not have been able to economically install a solar+storage system.
- With ConnectedSolutions, solar+storage project internal rates of return (IRR) improved by an average of more than 30 percent, net present values (NPV) increased an average of more than $80,000, and simple payback periods (SPP) for projects decreased by one to three years.
- ConnectedSolutions resulted in larger, longer duration battery systems able to deliver greater utility bill savings to housing providers and greater energy resilience to protect vulnerable residents during power outages.
- ConnectedSolutions improves the financeability of solar+storage projects by reducing uncertainty with the provision of five-year contracts between the utility and participating battery system owners, resulting in consistent revenue opportunities based on utility signals. This represents a significant reduction of economic risk compared to dependence on savings through reducing utility demand charges, which relies on the battery owner to successfully manage variable, difficult-to-predict onsite peaks in energy demand.
- Because ConnectedSolutions results in customer battery systems being dispatched at more beneficial times for the grid, the program helps to democratize the benefits of battery storage by delivering savings to all ratepayers.

Based on the findings, it is strongly recommended that policymakers interested in expanding solar+storage access in difficult-to-reach sectors, such as affordable housing and community-serving facilities, should pursue the design and implementation of a customer-sited battery program with elements similar to the ConnectedSolutions model.

84-kilowatt solar system developed by Resonant Energy and installed by ACE Solar at Dewitt Community Center in Boston, MA, a Madison Park Development Corporation property.
Source: Resonant Energy

Introduction

Over the past several years, Clean Energy Group (CEG), a national nonprofit organization, has assisted affordable housing providers in exploring the technical and financial feasibility of developing solar PV paired with battery storage (solar+storage) at properties across their portfolios.[1] Much of this work has been focused on the Northeast, where CEG first launched its Resilient Power Project in the wake of Superstorm Sandy, with the goal of helping low-income and climate-vulnerable communities strengthen the energy resilience of essential facilities, such as community centers, health clinics, and multifamily affordable housing properties. Affordable housing has always been a key focus for the work as many facilities serve aging populations, individuals with electricity-dependent medical needs, and residents with limited resources to relocate during climate emergencies.

When this effort first began, solar+storage installations were often developed as demonstration projects, which were only economically viable due to significant grant support provided by states, foundations, and federal agencies. However, the economics of solar+storage have changed over time as technology costs have fallen and new market opportunities have emerged. This report explores one of the most promising of these market opportunities, a utility battery storage program in Massachusetts called ConnectedSolutions, and how the program has transformed the economics of solar+storage for affordable housing properties.[2]

With ConnectedSolutions, which was developed based on analysis supported by CEG[3], the Commonwealth of Massachusetts became the first state to incorporate customer-sited, behind-the-meter battery storage into its energy efficiency plan, as a tool to reduce peak energy demand on the grid.[4] Essentially, ConnectedSolutions rewards participating utility customers for discharging stored energy during times of high demand for electricity across all customers within the utility's service territory. This helps the utility avoid using other, higher-cost ways of meeting peak demand needs, such as calling on expensive, inefficient peaker power plants to operate.[5] To learn more about how ConnectedSolutions works, see the box below.

This report explores one of the most promising of these market opportunities, a utility battery storage program in Massachusetts called ConnectedSolutions, and how the program has transformed the economics of solar+storage for affordable housing properties.

This report represents the first independent, public analysis of the impact of ConnectedSolutions on the economics of solar+storage systems at multifamily affordable housing properties. As detailed in the following sections, the structure of Connected Solutions significantly improves the economic viability of solar+storage for multifamily properties across the state, whereas, without ConnectedSolutions, the development of solar+storage would not be economical for the majority of properties analyzed. While this analysis was limited to multifamily affordable housing properties in Massachusetts, the results and key findings are broadly applicable to all types of facilities where the ConnectedSolutions program is available.

MASSACHUSETTS CONNECTEDSOLUTIONS PROGRAM

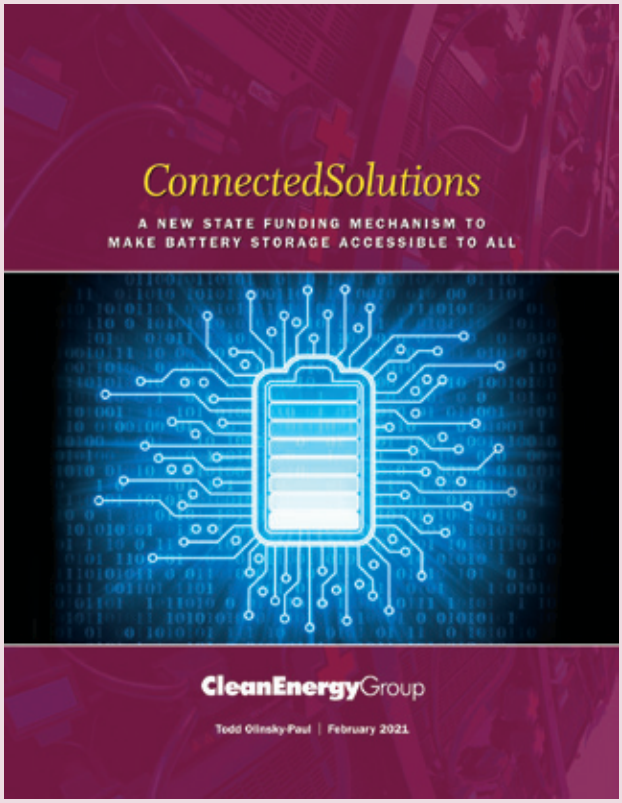
How It Works

The ConnectedSolutions customer battery storage program was launched in 2019 with the goal of reducing utility peak demand expenses in Massachusetts. The program provides payments to customer-sited battery systems that discharge stored energy during specific times throughout the year. ConnectedSolutions is based on a pay-for-performance model, meaning that utility customers, or third-party energy storage providers, own the battery systems, and utilities pay only for the demand reduction services delivered.

ConnectedSolutions is part of the Massachusetts three-year energy efficiency plan. Instead of reducing energy consumption (kilowatt-hours) like most energy efficiency measures, batteries reduce the maximum level of demand for energy (kilowatts). Instead of calling on expensive, seldom used fossil-fuel power plants, known as peakers, during times of high energy demand, utilities can call on customer-sited batteries to discharge stored energy when needed.

The three largest Massachusetts utilities, Eversource, National Grid, and Until, all participate in the Connected-Solutions program, though each implements the program with slight variations. To participate in the program, customers with battery systems enter into a five-year contract with their utility. The contract does not sign over control of the battery system or commit the customer to discharge the battery at any given time, it merely guarantees that the customer can participate in Connected-Solutions for at least the five-year term of the contract.

Participating utility customers can choose to include their batteries in one or two of three different programs: a winter seasonal program, a summer daily dispatch program, and a summer targeted dispatch program. Customers can participate in one summer program, but not both, along with the winter program. Each of the three programs has its own rate for customer performance payments. Customers receive compensation when their battery system successfully discharges energy during a peak demand event. Most events are three hours in duration, and battery owners are typically notified 24 hours before an event occurs. Batteries participating in the program will typically be managed either by software that can respond to the utility signals or through an agreement with a third party that manages the battery



performance. There is no penalty for failing to respond to an event, but this will reduce the customer's average response rate (and lower the performance payment) for the season.

As an example: If a commercial customer with a 60-kilowatt-hour battery system were to sign up for the summer daily dispatch program, which offers a compensation rate of $200 per kilowatt, and responded perfectly to each three-hour event, their maximum payment for the season would be $4,000 (60 kilowatt-hours/3 hours X $200 per kilowatt). Over the five-year term of a contract, the customer could earn up to $20,000 just for participating in the summer portion of the program.

For more information about the policy implications of ConnectedSolutions and how such a program could be implemented in other states, see *Connected Solutions: A New State Funding Mechanism to make Battery Storage Accessible to All* at https://www.cleanegroup.org/ceg-resources/resource/connected-solutions-policy.

A 48-kilowatt solar system developed by Resonant Energy and installed by ACE Solar at Hibernian Hall in Boston, MA, a Madison Park Development Corporation property.
Credit: Resonant Energy

Analysis Methodology

To evaluate the potential impact of the ConnectedSolutions program on the economics of solar+storage for affordable housing, Clean Energy Group, American Microgrid Solutions, and muGrid Analytics conducted techno-economic analyses, using property details and electricity consumption data from six multifamily affordable housing properties in Massachusetts, shown in Table 1 as Sites 1–6.[6]

The techno-economic feasibility analysis for each site evaluated solar PV and battery storage solutions in terms of both their operational and financial performance over the life of the project. From the technical side, the analysis considered solutions that could be engineered, installed, and operated under the requirements and constraints of both the site and the electric utility. To find the most economical energy solution, the analysis selected system sizes that would produce the greatest value to the owner over time.

The analyses were performed using muGrid Analytics' Redcloud tool—a design and dispatch optimization platform that models the performance of a combination of distributed generation and energy storage assets within the specific conditions of the site and its utility. Redcloud identifies the optimal mix of assets, sizes, and operating characteristics to meet the host site's goals, and accounts for capital costs (equipment, installation, replacement), operating costs (fuel, maintenance, service), utility bill savings, and revenue from programs and incentives. Redcloud determines optimal sizing and dispatching of energy assets that maximizes the value of solar+storage over time for the system owner.

The economic impact of ConnectedSolutions was determined by modeling two scenarios: one scenario where the ConnectedSolutions program does exist and one where the program does not. For the scenario without ConnectedSolutions, the main economic driver for battery storage is to reduce utility demand charges. These are charges based on the highest level of demand for electricity during a billing period, measured in kilowatts.[7] Some utilities, like Eversource, tend to have relatively high demand charges for certain commercial customers. Other utilities, such as National Grid, have lower demand charges, making it challenging to offset the cost of battery storage through demand charge bill savings alone. Both scenarios

The economic impact of ConnectedSolutions was determined by modeling two scenarios: one scenario where the ConnectedSolutions program does exist and one where the program does not.

TABLE 1
Multifamily Affordable Housing Property Details

Property	Units	Age	Utility	Rate Tariff
Site 1	209	1978 (Renovated 2018)	Eversource	B7
Site 2	146	1984 (Renovated 1998)	Eversource	B7
Site 3	98	Under construction	Eversource	Cambridge G2
Site 4	150	2010	Eversource	Boston G2
Site 5	154	2002	National Grid	G2
Site 6	134	2012	National Grid	G2

include economic benefits from avoided energy costs due to solar generation offsetting grid usage and net metering credits, as well as incentives available through the Solar Massachusetts Renewable Target (SMART) program (see Box).

Two ownership scenarios were also evaluated: one where the solar+storage system is owned by a nonprofit, *tax exempt* entity and a second scenario where the system is owned by a for-profit, *taxable* entity. In both scenarios, it is assumed that the solar+storage system owner is the same entity that pays the electricity bills for the property. Many affordable housing providers are nonprofit organizations, which cannot directly take advantage of tax credit incentives for solar and energy storage. There are ways that a nonprofit can realize some of the benefits from incentives like the federal investment tax credit (ITC) for solar, such as working with a third-party provider or tax-equity investor.[8] These options were not fully explored in this analysis, though the results for taxable entities show the total benefits a nonprofit housing provider and a for-profit third party could realize through a partnership arrangement. Under this type of arrangement, a third party that qualifies for the tax incentives would pay for the construction, installation, operation, and maintenance of the solar+storage system. The nonprofit entity would either purchase electricity from the system at a negotiated rate through a power purchase agreement (PPA) or lease the system.

To compare the results evenly between the sites, many site conditions and development considerations—such as roof conditions, installation costs, and interconnection constraints—were normalized across all properties. Solar sizing was held constant for each individual site through all scenarios. This was done to assess the impact of ConnectedSolutions on the economics of battery storage without the complexity of varying solar system sizing as well. Solar sizing for each site was determined either by referencing existing solar design specifications for the property or maximizing available space for solar siting, up to a production cap of 100 percent of annual electricity consumption. While the analyses do not evaluate the sites for specific solar or battery storage products, system sizing, costs, and configurations are based on products widely available in the market today. This means that the model adjusts the optimized results to fit the closest inverter and battery storage system sizing that is commercially available.

Developers, investors, and property owners use a range of financial metrics to evaluate the economic feasibility of a project. The results for each site and ownership scenario in this analysis were compared using three common metrics: internal rate of return (IRR), net present value (NPV), and simple payback period (SPP). IRR is a measure of how profitable an investment will be. The higher the IRR, the more attractive the investment opportunity. NPV is the sum of future cash flows, anticipated revenue, and savings versus expenses, in today's dollars. In general, a positive NPV suggests that a project is worth pursuing. SPP is the time it takes for a project's benefits (revenue, savings, incentives) to offset its costs.

Solar Massachusetts Renewable Target (SMART)

142-kilowatt solar system developed and installed by Sunbug Solar across nine buildings at The Residences at Melpet Farm in Dennis, MA, a Preservation of Affordable Housing (POAH) and Housing Assistance Corporation property. Source: Sunbug Solar

The Solar Massachusetts Renewable Target (SMART) program was established as a long-term incentive to catalyze the development of 1,600 megawatts of new solar capacity in Massachusetts. The program offers 10-year or 20-year fixed-price incentives that set compensation rates for solar generation based on project size, along with incentive adders for specific project attributes.

On November 26, 2018, the SMART incentives became available to solar projects of all types and sizes, up to five megawatts. SMART is designed as a declining block program, which means that the program's per kilowatt-hour incentive levels decline over time as more solar capacity is installed in the state. Each block of solar capacity includes carveouts for small projects (25 kilowatts or less) to encourage projects of all sizes to participate. The program also features stackable adders that increase the incentive rate for projects that include certain features, such as energy storage systems and community solar. SMART solar installations of 500 kilowatts or larger are now required to include battery storage.

To receive compensation, solar system owners register with the program and receive payments directly from their distribution utility for each kilowatt-hour of solar energy produced. For more information about the Solar Massachusetts Renewable Target (SMART) program, see https://www.mass.gov/solar-massachusetts-renewable-target-smart.

A 32-kilowatt solar system developed by Resonant Energy and installed by ACE Solar at Dudley Greenville in Boston, MA, a Madison Park Development Corporation property. Source: Resonant Energy

Analysis Results

As shown in the following table and figures, the availability of the ConnectedSolutions program significantly improved the economic feasibility of solar+storage for all multifamily affordable housing properties analyzed in this study. In fact, without ConnectedSolutions, even a small battery storage system was not found to be an economically optimal solution for four of the six sites analyzed. Overall, ConnectedSolutions boosted IRRs by an average of about 30 percent, increased NPVs by tens of thousands of dollars, and reduced project payback periods by one to three years.

Participating in ConnectedSolutions differs from engaging in demand charge management in several ways that affect the optimum battery size for the systems studied. One major difference is that ConnectedSolutions is designed to reduce systemwide demand for electricity, as opposed to site-specific demand. This means that battery systems participating in ConnectedSolutions are rewarded for their performance during three-hour dispatch windows, achieving greater economic returns by delivering more power for a longer duration than systems optimized for managing onsite demand to reduce utility demand charges, which typically targets much shorter peak periods. Also, under ConnectedSolutions, battery owners are credited not just for onsite load reduction, but also for

Overall, ConnectedSolutions boosted IRRs by an average of about 30 percent, increased NPVs by tens of thousands of dollars, and reduced project payback periods by one to three years.

any power discharged to the grid during regional peaks, meaning that batteries participating in ConnectedSolutions are not limited in their revenue potential by the size of the load of the host facility. For these reasons, ConnectedSolutions favors the development of bigger battery systems, with higher power and energy ratings than those designed for demand charge management alone, as shown in Table 2.

It is worth noting that ConnectedSolutions offers a distinct economic advantage over demand charge management for many types of facilities that have relatively flat load profiles (few spikes in demand) and therefore are not able to reduce costs much by lowering their own peak demand. The multifamily properties studied in this report provide a good example of this phenomenon. Because these types of facilities tend to

TABLE 2
Solar+Storage System Sizing Results for Six Multifamily Affordable Housing Properties

Property	Solar (kW)	Battery (No ConnectedSoultions)		Battery (With ConnectedSoultions)	
		Power (kW)	Energy (kWh)	Power (kW)	Energy (kWh)
Site 1	116	40	80	70	140
Site 2	250	80	160	130	260
Site 3	105	—	—	50	100
Site 4	222	—	—	60	180
Site 5	120	—	—	70	140
Site 6	40	—	—	30	60

have rather flat loads, with broad peaks sometimes lasting hours, significant onsite peak load reduction to lower utility demand charge expenses would be difficult to achieve. For these sites, and many other facilities with similarly shaped load profiles, reducing demand charges simply would not offset the cost of a battery. This is doubly true for the sites located in National Grid's service territory (Sites 5 and 6), which are subject to fairly low demand charge rates. With ConnectedSolutions, utility demand charge rates and facility load profiles are no longer essential for battery storage to make economic sense. In fact, utility rates and onsite energy consumption pattern have no bearing on the economic potential for ConnectedSolutions participation.

For facilities that do have demand charges that can be managed and reduced with battery storage, the larger battery systems supported by ConnectedSolutions participation are more likely to be able to reliably reduce a site's peak demand and related demand charges. Although demand charge reduction was not prioritized in modeling systems optimized for participation in ConnectedSolutions, the sites did realize additional demand charge savings. With larger battery systems, the sites achieved about 20 percent greater electric utility bill savings versus smaller batteries optimized for demand charge management without the ConnectedSolutions program.

INTERNAL RATE OF RETURN (IRR)

IRRs for solar+storage systems optimized with the ConnectedSolutions program were found to average 26 percent greater for nonprofit, tax exempt entities and 36 percent greater for taxable entities, as compared to scenarios without ConnectedSolutions. With ConnectedSolutions, IRRs ranged from 7.8 percent to 12.1 percent for nonprofit entities (Figure 1A, p.12) and from 10.7 percent to 15.2 percent for for-profit entities (Figure 1B, p. 12). For reference, an IRR of around 8 percent is sometimes viewed as the minimum threshold for an attractive investment. Nearly all the projects evaluated would exceed that threshold with ConnectedSolutions.

NET PRESENT VALUE (NPV)

As with IRR, all scenarios with ConnectedSolutions outperformed demand charge management optimized systems without ConnectedSolutions when comparing NPVs. For nonprofit entities, NPVs increased by $19,000 to $189,000 with ConnectedSolutions, depending on the size of the project (see Figure 2A, p.13). Taxable entities realized NPV gains ranging from $23,000 to $149,000 with ConnectedSolutions (Figure 2B, p.13).

In several cases, the introduction of ConnectedSolutions turned projects that appeared to be poor or marginal investments with negative NPVs into promising investment opportunities with positive NPVs. This was the case for Site 3 under a nonprofit ownership scenario and Sites 4, 5, and 6 under a for-profit ownership structure.

For all sites, NPVs and IRRs were higher in ownership structures with a taxable entity that could take advantage of the ITC. As shown in Figure 2A (p.13), nonprofit owned solar+storage systems for three of the sites still resulted in negative NPVs even with ConnectedSolutions. This is a reflection of the poor economics of solar at these properties; it was not an indication that battery storage or ConnectedSolutions are ineffective for these sites. In all cases, adding batteries participating in ConnectedSolutions to solar resulted in improved NPV outcomes. It is also important to note that NPV results are highly dependent on the discount rate used in the analysis, which is specific to individual entities based on their target rate of return on investments. For these analyses, a discount rate of 9 percent was used. Using a lower discount rate would improve NPV results.

IRRs for solar+storage systems optimized with the ConnectedSolutions program were found to average 26 percent greater for nonprofit, tax exempt entities.

SIMPLE PAYBACK PERIOD (SPP)

SPP is one of the most straightforward metrics to assess the economic differences between two scenarios. The value represents the number of years it would take for the economic benefits of a project to pay for the initial investment. As the name implies, it's a simplified approach; however, it is useful for quick comparisons that do not depend on project life and discount rate assumptions as do IRR and NPV.

Again, the existence of ConnectedSolutions improved values across all scenarios. For both ownership arrangements, systems optimized with ConnectedSolutions had SPPs that averaged 17 percent shorter than without the program, ranging from one to three years shorter. In the case of nonprofit entities (Figure 3A, p.14), SPPs decreased by an average of nearly two years, dropping from an average SPP of 10.8 years to 8.9 with Connected-Solutions. Taxable ownership scenarios (Figure 3B, p.14) dropped from an average SPP of 8.0 years without ConnectedSolutions to 6.6 years with the program.

These results are even more significant when considering the increased upfront investment for projects participating in ConnectedSolutions, which included much larger, more expensive battery systems. This means that the financial returns with ConnectedSolutions were high enough to pay off the greater investment in battery storage over a shorter period of time. In fact, projects that would not include batteries without participation in ConnectedSolutions (Sites 3–6) saw the biggest reductions in SPP years when program participation was included, up to a 2.9 year decrease in SPP for the Site 6 nonprofit ownership scenario.

FIGURE 1A

Internal Rate of Return (Tax Exempt Entity)

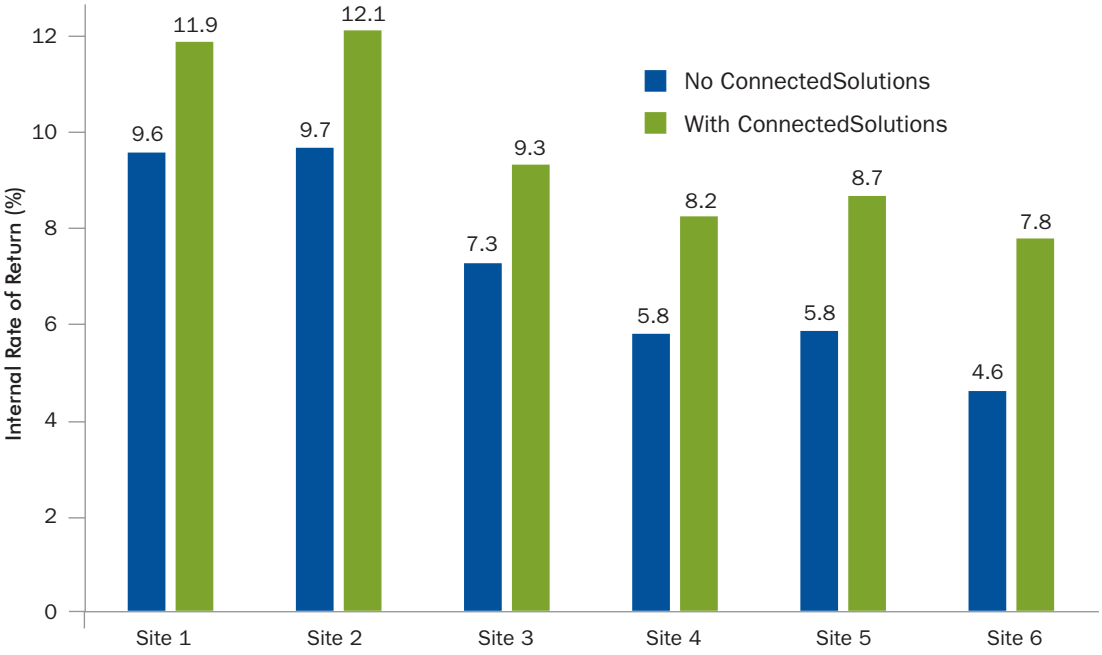
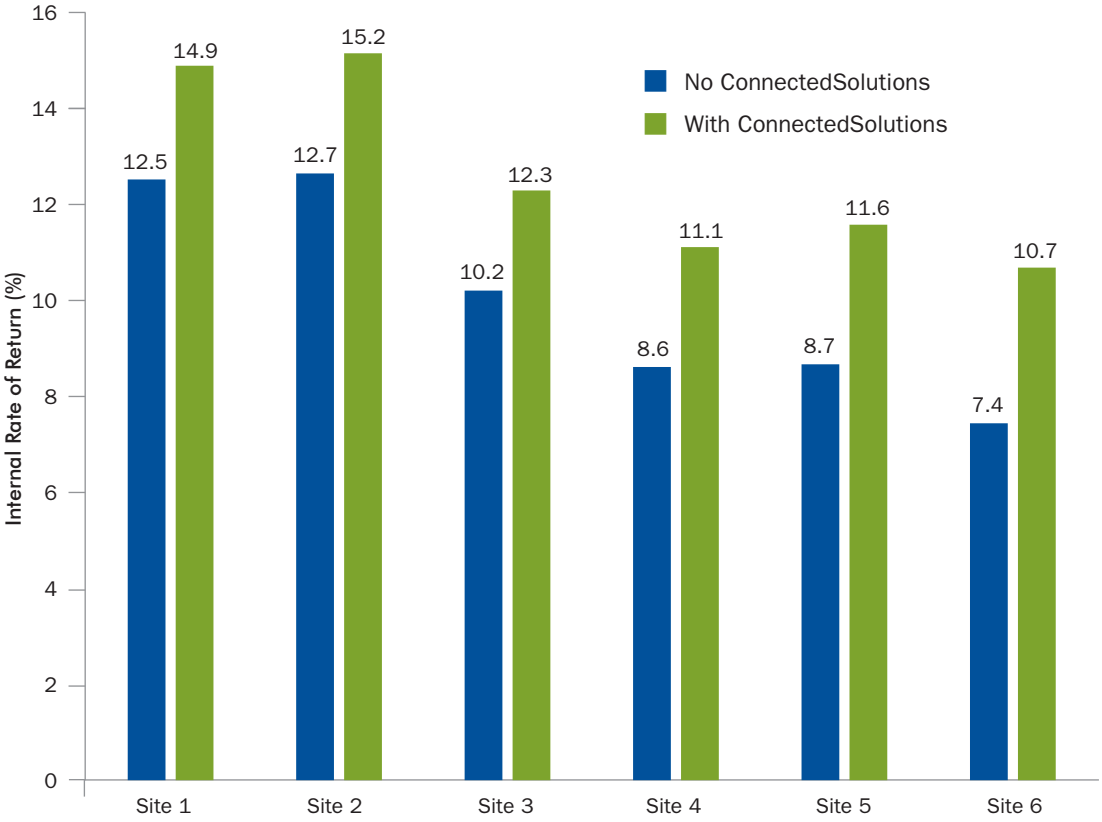


FIGURE 1B

Internal Rate of Return (Taxable Entity)



Internal rate of return (IRR) results for solar+storage systems at six Massachusetts multifamily affordable housing properties over a 25-year project period. The solar+storage systems at each site were optimized for two economic scenarios, either with the ConnectedSolutions program (green bars) or without ConnectedSolutions (blue bars), and two ownership scenarios: ownership by a nonprofit, tax exempt entity (Figure 1A) and ownership by a for-profit, taxable entity able to take advantage of federal tax credits (Figure 1B).

FIGURE 2A

Net Present Value (Tax Exempt Entity)

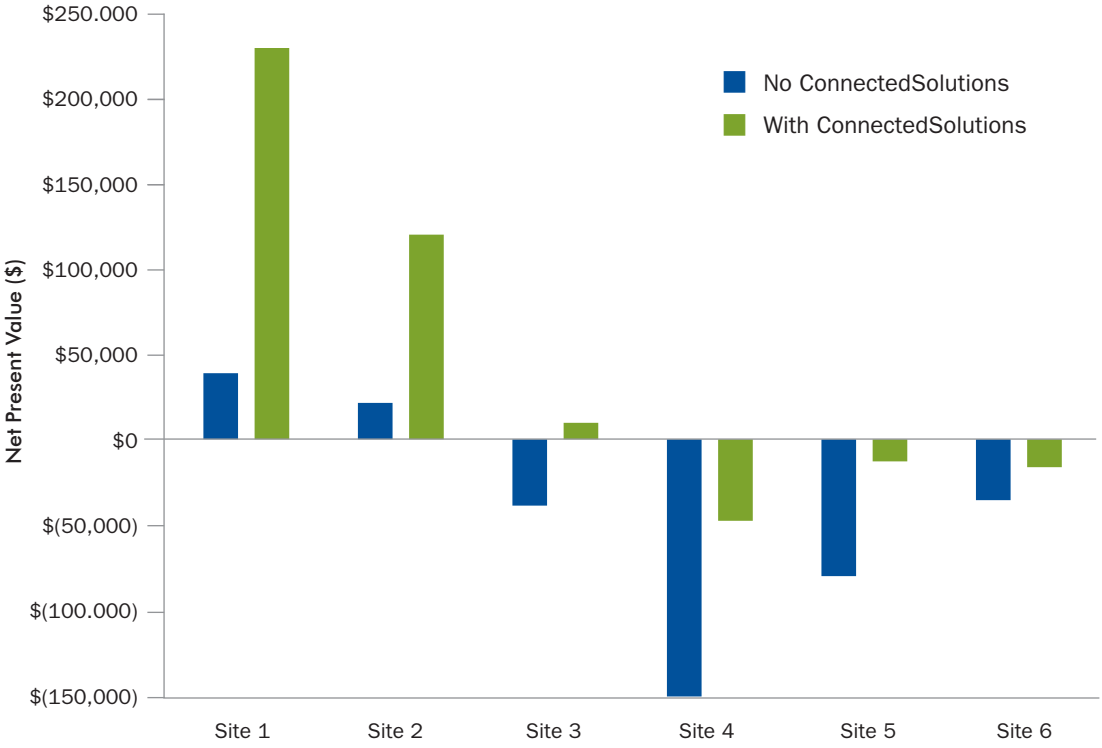
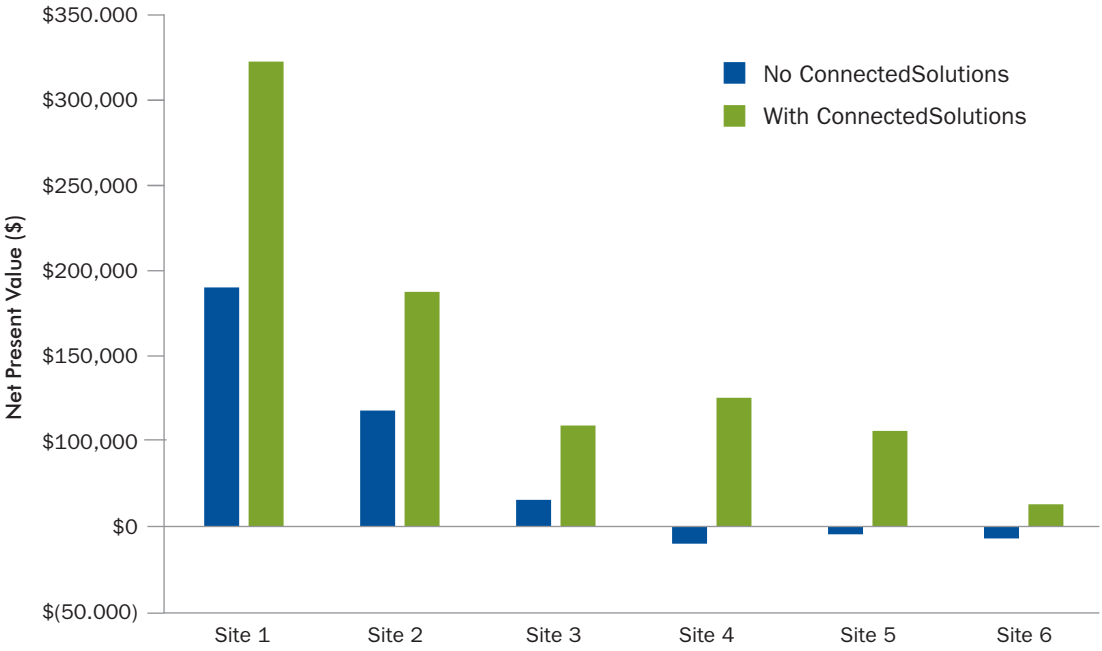


FIGURE 2B

Net Present Value (Taxable Entity)



Net present value (NPV) results for solar+storage systems at six Massachusetts multifamily affordable housing properties over a 25-year project period at a discount rate of 9 percent. The solar+storage systems at each site were optimized for two economic scenarios, either with the ConnectedSolutions program (green bars) or without ConnectedSolutions (blue bars), and two ownership scenarios: ownership by a nonprofit, tax exempt entity (Figure 2A) and ownership by a for-profit, taxable entity able to take advantage of federal tax credits (Figure 2B).

FIGURE 3A

Simple Payback Period (Tax Exempt Entity)

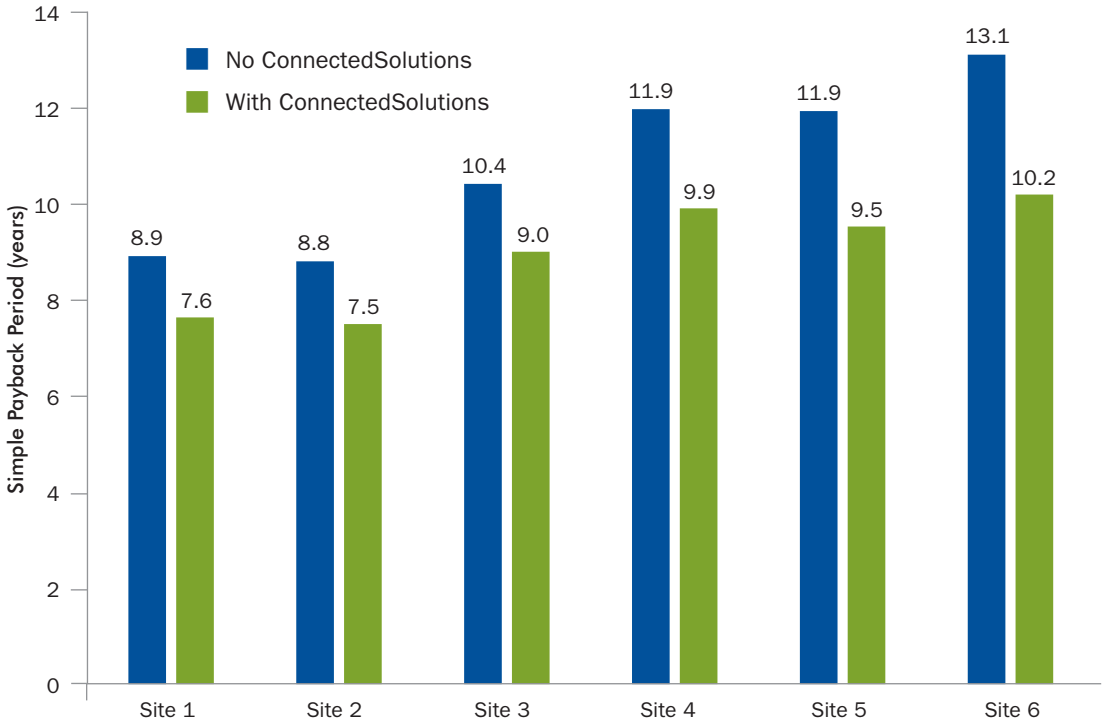
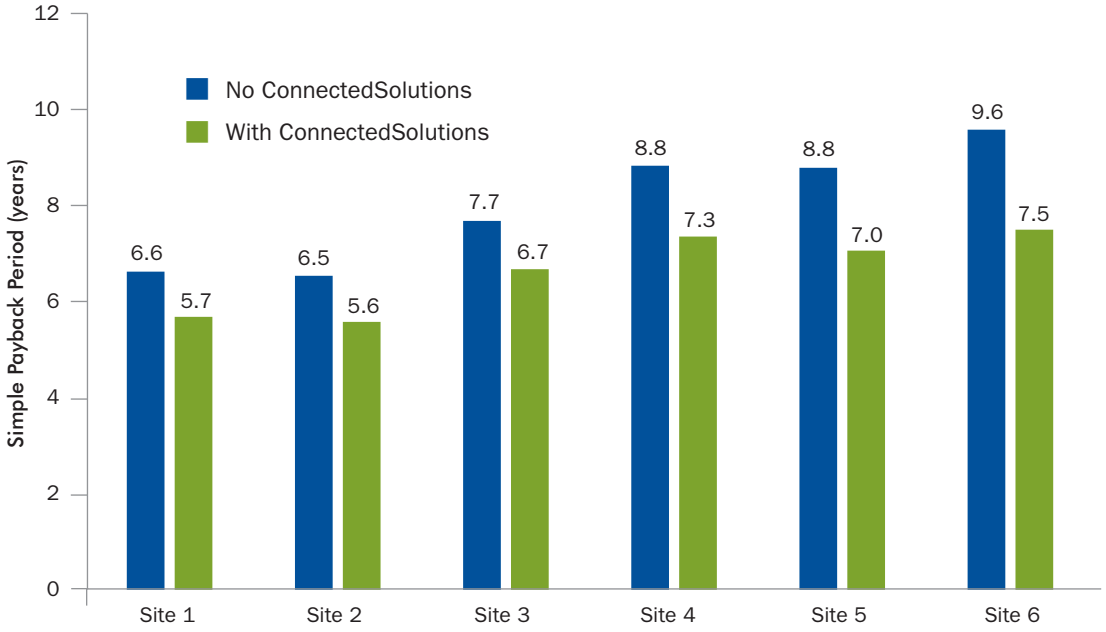


FIGURE 3B

Simple Payback Period (Taxable Entity)



Simple payback period (SPP) results for solar+storage systems at six Massachusetts multifamily affordable housing properties. The solar+storage systems at each site were optimized for two economic scenarios, either with the ConnectedSolutions program (green bars) or without ConnectedSolutions (blue bars), and two ownership scenarios: ownership by a nonprofit, tax exempt entity (Figure 3A) and ownership by a for-profit, taxable entity able to take advantage of federal tax incentives (Figure 3B).

iStockphoto/Denis Tangney, Jr.

Conclusion

The results of this study clearly demonstrate that the Massachusetts ConnectedSolutions program improves the financial feasibility of developing solar+storage projects at multifamily affordable housing properties, regardless of the size of the property, how it uses energy, the utility providing its electricity, or the structure of its electric rate tariff. The findings provide important evidence for how a program can be designed to help support the more equitable deployment of battery storage resources to serve all populations. This is particularly true for properties like affordable housing that may want to realize the resilience benefits of solar+storage to protect vulnerable populations but may not have energy consumption patterns that favor demand charge management, which has historically been the most widely available economic benefit from battery storage.

The analysis results point to several key aspects of ConnectedSolutions that could boost solar+storage deployment in affordable housing and similar types of community-serving facilities:

- ConnectedSolutions resulted in stronger economics for all sites analyzed, in several cases making battery storage economical at properties where it would not otherwise be financially viable.
- By providing five-year contracts and demand periods based on utility signals rather than customer predictions, ConnectedSolutions improves the financeability of solar+storage projects. While financial entities may be hesitant to invest in projects where the economics depend on varying and often unpredictable site-specific demand charge savings, the multi-year certainty of ConnectedSolutions and security of a utility-backed revenue stream make a project a much more bankable opportunity.
- Because the program is tied to regional demand, not site-specific demand, and because it rewards customers for power exported to the grid as well as for onsite load reduction, ConnectedSolutions allows for the development of larger battery systems. In addition to greater financial benefits, these larger battery systems could be used to power more critical loads over a longer period of time to keep essential services running during a power outage.[9]
- Unlike tax incentives, the benefits of ConnectedSolutions are accessible to tax exempt entities, which is pivotal for catalyzing greater battery storage investments by nonprofit entities, such as affordable housing providers, community-based organizations, and local governments.
- ConnectedSolutions results in customer battery systems being dispatched at more beneficial times for the grid as a whole, thereby benefiting all ratepayers and not simply the sites at which they are hosted, democratizing the benefits of energy storage.

The program's focus on regional demand and predictable, stable returns helps to reduce the risk of battery storage investment for system owners and shares the benefits of those investments across many parties. In addition to the grid benefits and economic returns ConnectedSolutions can deliver, it is critically important for the financial viability of solar+storage projects designed for energy resilience, which are often not financially supported by battery savings achievable through demand charge management alone.

None of these factors will guarantee that the introduction of a program like ConnectedSolutions will suddenly make solar+storage an attractive investment for all multifamily affordable housing properties or other types of facilities. However, it strongly suggests that a program with similar elements could radically improve the economic viability of solar+storage projects across a wide spectrum of facility types by freeing property owners from a dependence on site-specific conditions. Because of this, it is recommended that state policymakers interested in accelerating the deployment of customer-sited solar+storage, while also improving the equitable distribution of battery storage resources, explore the implementation of a program like ConnectedSolutions. For more detailed information about how to implement such a program, see *ConnectedSolutions: A New State Funding Mechanism to make Battery Storage Accessible to All* at www.cleanegroup.org/publications-library.

ENDNOTES

1 See the Resilient Power Project (*www.resilient-power.org*) for more information about Clean Energy Group's efforts to enable greater solar and battery storage access among low-income communities and communities of color.

2 Versions of the ConnectedSolutions program have also been adopted in Rhode Island, Connecticut, and New Hampshire, and similar programs have been proposed in other states, such as New Jersey and Virginia.

3 Todd Olinsky-Paul, "Energy Storage: The New Efficiency—How States Can Use Energy Efficiency Funds to Support Battery Storage and Flatten Costly Demand Peaks," *Clean Energy Group*, April 2019, *www.cleanegroup.org/wp-content/uploads/energy-storage-the-new-efficiency.pdf.*

4 "Massachusetts Battery Storage Measures: Benefits and Costs," *Applied Economics Clinic,* July 2018, *www.cleanegroup.org/ceg-resources/resource/massachusetts-battery-storage-measures-benefits-and-costs*.

5 The combination of battery storage and renewable generation can often serve as a viable, cost-effective alternative to peaker power plants. To learn more about efforts to replace peaker power plants with batteries and renewables, see Clean Energy Group's "Phase Out Peakers" initiative at *www.cleanegroup.org/ceg-projects/phase-out-peakers*.

6 Hourly load data was not available for five of the six sites. For these sites, usage data from monthly utility bills was scaled to hourly load data using either commercial reference building load profiles from the U.S. Department of Energy's buildings database or load profiles from similar facilities within the same region.

7 For more information about demand charges and how energy storage can reduce demand-related utility charges, see "An Introduction to Demand Charges" at *www.cleanegroup.org/ceg-resources/resource/demand-charge-fact-sheet*.

8 When paired together, both solar PV and battery storage are eligible for the federal investment tax credit (ITC). Households and organizations that have enough taxable income are eligible for a 26 percent investment tax credit to offset the installed cost of a solar installation and related hardware, including battery storage. For storage to be eligible for the ITC at a commercial property, the battery system must be primarily charged by onsite solar (at least 75 percent of the time).

9 Configuring a battery system to provide backup power to a facility typically involves added design complexities and additional project costs that were not considered in this analysis.

Appendix: Techno-Economic Modeling Inputs and Assumptions

The following section details relevant inputs and assumptions used in modeling the technical and economic feasibility of solar PV and battery storage for the six multifamily affordable housing properties assessed in this report.

The analysis uses the Redcloud tool developed by muGrid Analytics (*https://mugrid.com/energy-optimization-redcloud-mugrid-analytics*). Redcloud is a design and dispatch optimization platform that models the performance of a combination of distributed generation and energy storage assets within the specific conditions of a site and the utility serving the site. Redcloud identifies the optimal mix of assets, sizing, and operating characteristics to meet the host site's goals to minimize life cycle cost (LCC) of energy over a specified period including capital costs (equipment, installation, replacement), operating costs (fuel, maintenance, service), utility bill savings, revenue from incentives, and revenue from tax benefits. The model calculates and maximizes net present value (NPV) as the difference between current case LCC and base case LCC. Redcloud determines optimal sizing and dispatching of energy assets that maximizes NPV. Other non-financial goals and constraints impact design solutions selected but are not explicitly assigned financial values in the model.

General inputs and assumptions

- *Analysis period*: 25 years
- *Discount rate:* 9%
- *Utility tariff escalation rate:* 3%
- *Tax rate:* 21%

Solar inputs and assumptions

- *Solar system installed cost:* $3.00 per watt
- *Inverter replacement:* $44 per kilowatt (occurs in year 16)
- *Operations and maintenance:* $20 per kilowatt-year
- *Annual solar performance derate:* 0.7% per year

Battery storage inputs and assumptions

- *Battery storage system installed cost:* $1,000 per kilowatt-hour (lithium-ion batteries)
- *Battery replacement:* $150 per kilowatt and $100 per kilowatt-hour (occurs in year 11)
- *Operations and maintenance:* $5.63 per kilowatt-year
- *Battery control software:* $2,500 per year
- *Round-trip efficiency:* 90%

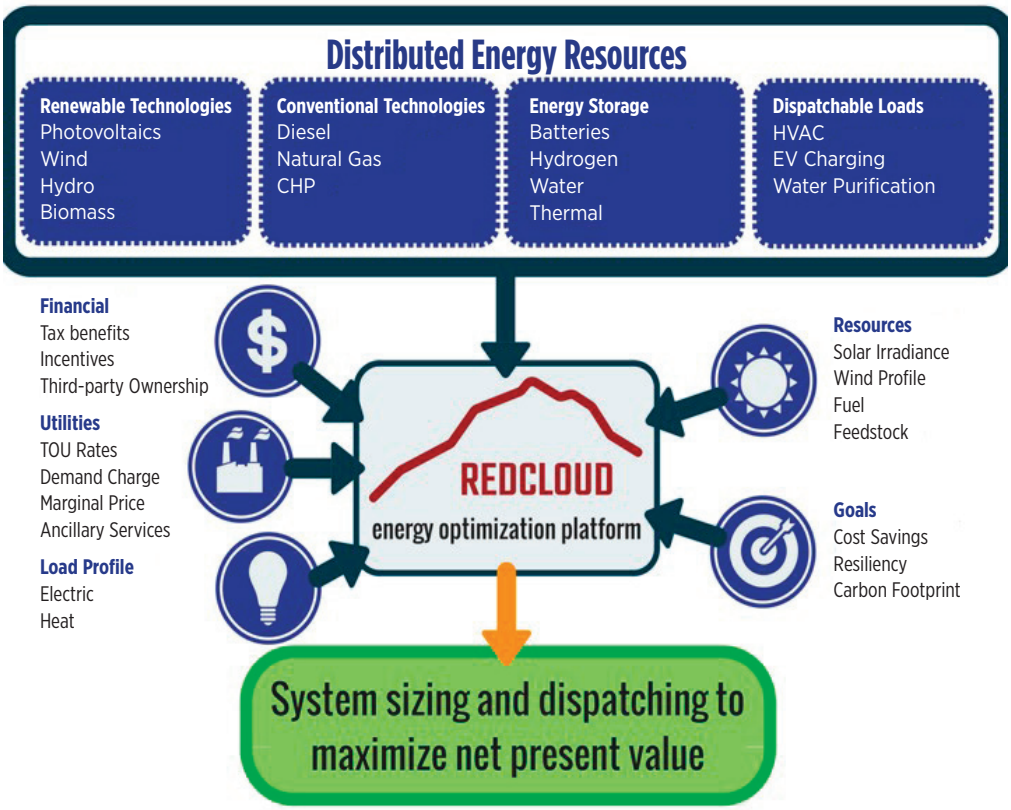
APPENDIX TABLE 1

Solar Massachusetts Renewable Target (SMART) Program Incentives

	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6
SMART Block	4	4	4	4	6	6
Base Compensation	$0.12	$0.12	$0.11	$0.10	$0.05	$0.05
Location Based Adder (Roof)	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
Off-taker Based Adder (Low-income property)	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Storage Adder	$0.04	$0.04	$0.04	$0.03	$0.04	$0.04
Total SMART Incentive	**$0.21**	**$0.21**	**$0.20**	**$0.18**	**$0.14**	**$0.14**

Programs and incentives

- *Federal Investment Tax Credit (ITC):* 26%
- *Modified Accelerated Cost Recovery System (MACRS):* 100% Bonus



The analyses assume that each site participates in the ConnectedSolutions Winter and Summer Daily commercial programs. The model assumes that the maximum number of events will be called each year and that the battery fully participates in each event. This approach yields the upper limit of what the program can generate in revenue and the upper constraint on required battery performance throughout each period.

While participation in ConnectedSolutions does not require it, participants may engage the services of a curtailment service provider (CSP) to facilitate registration and participation in the program. A CSP will make sure the participating battery storage system meets the program's metering and reporting requirements. Organizations engaging a CSP will typically split their incentive payments with the CSP under a negotiated contract. As ConnectedSolutions is still a relatively new program, the terms of these splits have not yet been standardized. The analyses assume a software driven approach with ongoing, incremental operating expenses for ConnectedSolutions instead of working with a CSP.

ConnectedSolutions contracts are currently five years in duration, well short of the 25-year project life used for the analyses. The analyses assume that the ConnectedSolutions program will be extended throughout the 25-year period and that the battery system will continue to participate in the program at the existing level of compensation rates, with no escalator.

APPENDIX TABLE 2

ConnectedSolutions Program Details and Assumptions

	Winter	Summer Targeted	Summer Daily
Projected number of events	4–6	2–8	30–60
Events assumed for analysis	6	8	60
Payment	$50/kW	$100/kW	$200/kW
Months	Dec–Mar	Jun–Sep	Jun–Sep
Days	M–F	M–F	M–F
Time	2–7 PM	2–7 PM	2–7 PM
Estimated event length	3 hours	3 hours	2-3 hours
Event length assumed for analysis	3 hours	3 hours	3 hours

ABOUT THE AUTHORS

Seth Mullendore
Vice President, Project Director
Clean Energy Group

Seth is Vice President and Project Director for Clean Energy Group, overseeing projects ranging from customer-sited solar and battery storage to the replacement of power plants with clean technologies. Seth works with policy makers, project developers, industry, advocates, and community and environmental justice groups to advance clean energy policies and projects, with a focus on achieving greater access to solar and battery storage technologies for underserved communities. Much of his work pertains to the research and reporting of energy storage technologies, policies, and supporting market structures. Prior to joining CEG, Seth served as a Sustainable Energy Fellow with Union of Concerned Scientists and worked with Maine Clean Communities to help advance clean transportation initiatives. Seth holds a M.S. in Civil & Environmental Engineering from Stanford University, and a B.S. in Geosciences from the University of Southern Maine.

Todd Olinsky-Paul
Senior Project Director
Clean Energy Group

Todd is Senior Project Director for Clean Energy Group (CEG) and Clean Energy States Alliance (CESA). He directs CESA's Energy Storage and Technology Advancement Partnership (ESTAP), a federal-state funding and information sharing project that aims to accelerate the deployment of electrical energy storage technologies in the United States. Todd also works on CEG's Resilient Power Project, supporting solar+storage behind the meter for critical infrastructure energy resiliency. Todd's recent focus has been on the development of energy storage policy and programs at the state level. Todd has a M.S. in Environmental Policy from Bard College and a B.A. from Brown University.

Geoff Oxnam
Chief Executive Officer, Founder
American Microgrid Solutions

Geoff is the founder and Chief Executive Officer of American Microgrid Solutions, an advanced energy services company dedicated to helping clients improve performance, resilience, savings, and sustainability. American Microgrid Solutions works with a broad range of clients across the country including municipalities, senior housing facilities and commercial property owners. Geoff has a background in hybrid power system development, utilities, and telecom operations. Prior to founding American Microgrid Solutions in 2016, Geoff served as Vice President of Operations for a nationally recognized municipal utility that provides electric, natural gas, water, wastewater, broadband Internet, cable television and utility management software solutions. Geoff also has a background in environmental advocacy through his work with the Chesapeake Bay Foundation and is an award-winning journalist. Geoff earned his Bachelor of Arts from Williams College and a Master of Business Administration from The Johns Hopkins University Carey Business School.

Dr. Travis Simpkins
Chief Technology Officer
muGrid Analytics

Travis is Chief Technology Officer at muGrid Analytics, an owner's advisory and project development firm focused on delivering maximum economic return for clients' energy investment dollar. muGrid serves micro- and minigrid clients in the commercial and industrial sector and in the developing world. Though he was formally trained as an integrated circuit designer, he has spent most of the past decade helping to solve the world's energy challenge. He joined the National Renewable Energy Laboratory in 2010 and proceeded to reinvent their approach to modeling renewable energy systems. He pioneered a purely quantitative approach to analyzing and optimizing the costs and benefits of solar, wind, biomass, waste-to-energy, and other renewable technologies. His innovative research in this field led to him creating the REopt tool. Dr. Simpkins holds a S.M. and Ph.D. in Electrical Engineering and Computer Science from the Massachusetts Institute of Technology, a certificate of Financial Engineering from the MIT Sloan School of Management, and a B.S. in Electrical Engineering and Applied Physics from Case Western Reserve University. He is a Senior Member of the IEEE and has published numerous papers in the fields of energy system optimization, applied optics, and integrated circuits.

Amy Simpkins
Chief Executive Officer
muGrid Analytics

Amy is Chief Executive Officer at muGrid Analytics. Prior to joining muGrid, Amy was an engineer and spacecraft systems architect with Lockheed Martin, where she worked on advanced R&D, design integration, and flight operations for critical spacecraft missions. Her technical expertise includes system and software architecture, system-level performance modeling, and design tradespace analysis. Amy has also provided independent strategic vision consulting to startups and small businesses. Amy holds an M.S. in Astronautical Engineering from the University of Southern California and an S.B. in Aeronautics and Astronautics from the Massachusetts Institute of Technology.

ConnectedSolutions

THE NEW ECONOMICS OF SOLAR+STORAGE FOR AFFORDABLE HOUSING IN MASSACHUSETTS

Clean Energy Group (CEG) is a leading national, nonprofit advocacy organization working on innovative policy, technology, and finance strategies in the areas of clean energy and climate change.

CEG's energy storage policy work is focused on the advancement of state, federal, and local policies that support increased deployment of energy storage technologies. Battery storage technologies are critical to accelerate the clean energy transition, to enable a more reliable and efficient electric power system, and to promote greater energy equity, health, and resilience for all communities.

Learn more about Clean Energy Group and its Energy Storage Project at *www.cleanegroup.org/ceg-projects/energy-storage-policy*.

CleanEnergyGroup
Innovation in Finance, Technology & Policy
50 State Street, Suite 1 • Montpelier, VT 05602
802.223.2554 | www.cleanegroup.org | info@cleanegroup.org

Appendix E

Sunrun Inc.

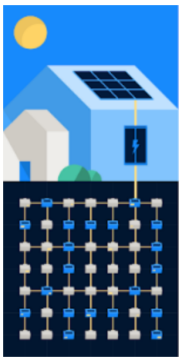
Meeting the Utility Needs with Customer Solar + Storage to Reduce Costs for All

Meeting Utility Needs with Customer Solar+Storage to Reduce Costs for All

Utilities around the country are using customer-sited, non-utility owned battery storage to reduce costs for all ratepayers. Almost every state in New England uses customer programs to leverage performance from customer batteries. So called Bring-Your-Own-Device (BYOD) programs unlock value from residential and commercial batteries without putting ratepayers at risk. This reduces costs and increases resilience.

Much of our utility costs are attributed to the load a utility has during its system peak (electricity consumption when electricity demand is at its highest). These costs are passed on to customers. However, if the utility can reduce its load during that time, its customers will pay less. BYOD programs allow the utility to work with customers and aggregators to dispatch batteries to send energy to the grid to address a grid need. This reduces costs for all of the utility customers.

Benefits of BYOD include:



1. **Low Risk**: Customers and their storage providers/aggregators finance the systems & ratepayer capital is not put at risk. BYOD can also be structured to pay for only verified savings or value delivery.
2. **Simple**: BYOD can be as simple as a set schedule for battery discharge, with no utility software upgrades. When ready, utilities can add additional program elements like locational value & shorter dispatch notice.
3. **Partnerships**: BYOD combines the core competencies of utilities and competitive industry for the greatest ratepayer benefit and can jumpstart a storage market by bringing down battery costs.
4. **Resiliency**: When the grid goes down, BYOD batteries provide critical backup power.

Examples of Residential Battery Programs:

1. In **Massachusetts**, all of the electric utilities are using approved Energy Efficiency budgets to provide payments in a BYOD for batteries that reduce peak costs. This has made MA a national leader.
2. In **NY**, **PSEG-LI** has a geographically targeted Non-Wires BYOD to deliver load reduction,reduce local system congestion and provide backup power in an area hit by Superstorm Sandy.
3. **GMP in Vermont** realized significant peak-time savings with a BYOD program to reduce Capacity Market yearly peaks and monthly transmission peaks. Home batteries have saved GMP customers millions of dollars.
4. **Eversource NH** has proposed a BYOD program to defer a new line into a rural town. These batteries will provide backup when the existing line goes out and reduce costs associated with monthly and yearly peak demand.

How to Create a BYOD Program: Creating a BYOD program is simple.

A BYOD battery program is a $/kw month/season/year payment for load reduction and injection by residential batteries, generally developed and enrolled by aggregators in partnership with customers. Load reduction and injection can be calibrated according to the value that an aggregator is contracted to provide to a utility, such as capacity market peak. A base value for load reduction can be established for the service territory, with potential for additional values layered on for location-specific performance, such as a NWA. This is a straightforward way to promote solar+storage integration across a utility territory and unlock the value of DERs without getting into the complexity of rate design issues.

BYOD programs are also beneficial in that they do not rely upon rate-based assets and therefore avoid the risk of utility-owned stranded assets paid for by ratepayers. They support the development of a competitive and self-sustaining storage market due to their open and transparent nature. These programs encourage firms to enter new markets and make diverse financing options available to customers.
Finally, the upfront or performance payments can substantially reduce the cost of batteries, expanding access to clean and resilient power further down the income spectrum. New York and nearly every state in New England has a BYOD program in place or will soon.

Key Elements of a BYOD Program

Customers participating in the BYOD program will install a compatible battery system. Once installed, they will follow enrollment instructions individually or through an aggregator. The enrollment will include a verification process that confirms the device can be utilized in the program platform. Once integration into the platform is confirmed, the participating customer or a designated aggregator will begin receiving participation payments in exchange for dispatching the device. For customers not participating through an aggregator, the participation payment could be provided as a bill credit. For customers that enroll with an aggregator, the participation payment will remit as a direct payment to the aggregator who will manage customers' batteries and the customer value proposition/program participation payment. The utility collaborates with aggregators to explore options for customers to participate on different levels and "pay-for-performance" when they provide services benefiting the utility system and ratepayers.

The program would include the following characteristics:

1. Participants and aggregators use non-utility owned energy storage to participate in the program.
2. Direct control of the DER remains with the system owner or another party they designate for this purpose, such as an aggregator entity. This enables the customer or aggregator to manage and coordinate all functions of the DER (TOU management, backup power, BYOD participation, etc.).
3. Customers with solar-paired energy storage are able to participate without limits or any additional conditions beyond those that would otherwise apply.
4. Program payments may be distributed directly to an aggregator entity, either at the election of an individual participating customer or via a direct services agreement between the utility and the aggregator (e.g., for a specific amount of capacity).
5. Payment rates are established under a standardized minimum fixed rate system for the duration of participation, subject to performance rules consistent with the use case, punitive measures for non-performance, and potential enhanced payments for performance.
6. Benefits and risks are shared between participants and non-participants.
7. Customers may opt out of the program.
8. Customers shall not be forced to depart from their current rate schedule or net metering agreement, and the program shall be a rider that is additional to the underlying rate.

Examples of Residential BYOD Programs

1. Massachusetts's Statewide BYOD Program (ConnectedSolutions)

The Massachusetts Department of Public Utilities incorporated energy storage into the state's 2019-2021 energy efficiency plan and approved a statewide BYOD program for peak reduction, finding that the BYOD

program passed important benefit-cost analyses.[1] The state's energy efficiency budget will provide funding for payments to participating aggregators and customers. The new program follows an evolution in thinking away from annual kWh reductions toward ways to reduce system peaks, given that peak hours represent the costliest and dirtiest generation periods on the grid. BYOD programs are uniquely structured to help lower peak demand during these critical hours.

2. PSEG Long Island's Behind-the-Meter Energy Storage with Solar Program[2]

Through its Utility 2.0 Long Range Plan[3], PSEG Long Island enhanced its system-wide Super Savers program with the introduction of a Standard Offer $/kW-year payment for qualified capacity savings. PSEG Long Island offers a payment to third party aggregators, selected via a qualification process that allows PSEG Long Island to remotely control customers' energy storage systems to reduce load during called events. PSEG Long Island compensates the third-party aggregator on a pay-for-performance basis for load reduction, with the expectation that customers will also receive a rebate or cost savings, either through a portion of the rebate from PSEG Long Island transferred to them, and/or an upfront discount from the aggregator for the battery installation. This structure provides space for the storage market to innovate and implement solutions that will achieve maximum program participation.

While this BYOD is system-wide, it is also innovative in that it incorporates local adders for transmission and distribution congestion and further allows the ability to stack with Non-Wire Alternatives. The BYOD structure is an ideal method to address distribution level issues by engaging an enrolled fleet on the grid and also addressing localized issues as the need arises.

The program includes co-marketing with PSEG Long Island encouraging battery sales to complement solar installations. This reduces customer acquisition and consumer prices. PSEG Long Island partners with equipment manufacturers and contractors on collateral material to support and drive participation, including targeted direct mail outreach to energy storage prospects, driving interest and contractor leads.

3. Green Mountain Power's Residential Storage Program

Green Mountain Power (GMP) has a BYOD program in which customers who adopt residential storage can opt to provide GMP with dispatch rights for monthly peak shaving. Customers can select upfront compensation ($850 per kW pledged for performance) or ongoing payments.[4]

The program is open to customers across the GMP service territory. This enables GMP to access battery capacity and bring a battery offering to its customers in partnership with solar/storage providers, without taking on the responsibility to manage the deployment of the resources. Solar/storage providers are able to customize offers to suit customer preferences and can enroll customers as part of an aggregation.

This program has been extremely successful. According to GMP, its BYOD program saved ratepayers $500,000 by using 500 batteries to reduce peak demand during a 2018 heat wave.[5] Because of this

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[1] *See* https://www.cleanegroup.org/ceg-resources/resource/energy-storage-the-new-efficiency/ and https://www.nationalgridus.com/media/pdfs/resi-ways-to-save/program-materials-for-connectedsolutions-for-small-scale-batteries-v16-ma.pdf

[2] See further explanation in "REST BYOD Elements"

[3] https://www.lipower.org/wp-content/uploads/2018/06/2018-06-29-PSEG-LI-Utility-2.0-2018-AnnualUpdate.pdf

[4] https://greenmountainpower.com/bring-your-own-device/

[5] https://www.utilitydive.com/news/tesla-batteries-save-500k-for-green-mountain-power-through-hot-weather-pea/528419/

success, the program has undergone several transformations to pilot and then adopt best practices. The most recent version includes direct integration between GMP and aggregators to simplify the experience for both residential customers and the utility. In addition, due to the BYOD program's success, GMP has now filed it to be a permanent tariff with PUC.

Appendix F

Massachusetts Department of Public Utilities

Docket Nos. 18-110 through 18-119, *2019-2021 Three-Year Plans Order*

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 18-110 January 29, 2019

Petition of Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-111

Petition of The Berkshire Gas Company, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-112

Petition of Fitchburg Gas and Electric Light Company, d/b/a Unitil (Gas Division), pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-113

Petition of Liberty Utilities (New England Natural Gas Company) Corp., d/b/a Liberty Utilities, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-114

Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-115

Petition of NSTAR Gas Company, d/b/a Eversource Energy, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-116

Petition of Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-117

Petition of Fitchburg Gas and Electric Light Company, d/b/a Unitil (Electric Division), pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-118

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

D.P.U. 18-119

Petition of NSTAR Electric Company d/b/a Eversource Energy, pursuant to G.L. c. 25, § 21 for approval by the Department of Public Utilities of its Three-Year Energy Efficiency Plan for 2019 through 2021.

APPEARANCES: Emmett E. Lyne, Esq.
Jodi K. Hanover, Esq.
Jonathan A. Goldberg, Esq.
Rich May, P.C.
176 Federal Street, 6th Floor
Boston, Massachusetts 02110

FOR: BAY STATE GAS COMPANY
Petitioner (D.P.U. 18-110)

-and-

THE BERKSHIRE GAS COMPANY
Petitioner (D.P.U. 18-111)

Danielle C. Winter, Esq.
Kerri A. Mahoney, Esq.
Keegan Werlin LLP
99 High Street, 29th Floor
Boston, Massachusetts 02110

FOR: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (GAS DIVISION)
Petitioner (D.P.U. 18-112)

-and-

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (ELECTRIC DIVISION)
Petitioner (D.P.U. 18-117)

-and-

LIBERTY UTILITIES (NEW ENGLAND NATURAL GAS COMPANY) CORP.
Petitioner (D.P.U. 18-113)

Stacey M. Donnelly, Esq.
Diana Chiang, Esq.
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
FOR: BOSTON GAS COMPANY AND COLONIAL GAS COMPANY
Petitioner (D.P.U. 18-114)
Intervenor (D.P.U. 18-116)

-and-

MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY
Petitioner (D.P.U. 18-118)

John K. Habib, Esq.
Ashley S. Wagner, Esq.
Keegan Werlin LLP
99 High Street, 29th Floor
Boston, Massachusetts 02110
FOR: NSTAR GAS COMPANY
Petitioner (D.P.U. 18-115)

-and-

NSTAR ELECTRIC COMPANY
Petitioner (D.P.U. 18-119)
Intervenor (D.P.U. 18-116)

Jeffrey M. Bernstein, Esq.
Jo Ann Bodemer, Esq.
BCK LAW, P.C.
271 Waverley Oaks Road, Suite 203
Waltham, Massachusetts 02452
FOR: CAPE LIGHT COMPACT JPE
Petitioner (D.P.U. 18-116)

Maura Healey, Attorney General
Commonwealth of Massachusetts
By: Donald W. Boecke
Joseph F. Dorfler
Assistant Attorneys General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Rachel Graham Evans, Esq.
Daniel Burstein, Esq.
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, Massachusetts 02114
FOR: MASSACHUSETTS DEPARTMENT OF ENERGY RESOURCES
Intervenor

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, Massachusetts 01930
FOR: LOW-INCOME WEATHERIZATION AND FUEL ASSISTANCE PROGRAM NETWORK AND THE LOW-INCOME ENERGY AFFORDABILITY NETWORK
Intervenors

Caitlin Peale Sloan, Esq.
Amy Laura Cahn, Esq.
Conservation Law Foundation
62 Summer Street
Boston, Massachusetts 02110
FOR: CONSERVATION LAW FOUNDATION
Intervenor

Amy E. Boyd, Esq.
Acadia Center
31 Milk Street, Suite 501
Boston, Massachusetts 02109
FOR: ACADIA CENTER
Intervenor

Paul W. Gromer, Esq.
Paul Gromer, LLC
85 Merrimac Street, 3rd Floor
Boston, Massachusetts 02114
FOR: NORTHEAST ENERGY EFFICIENCY COUNCIL
Intervenor

Laura S. Olton, Esq.
LSO Energy Advisors, LLC
38 Thackeray Road
Wellesley, Massachusetts 02481
FOR: POWEROPTIONS, INC.
Intervenor

Justin Davidson, Esq.
Massachusetts Association of Realtors
333 Wyman Street, Suite 200
Waltham, Massachusetts 02451
FOR: MASSACHUSETTS ASSOCIATION OF REALTORS
Intervenor

Christine O'Connor, City Solicitor
City of Lowell Law Department
375 Merrimack Street
Lowell, Massachusetts 01852
FOR: CITY OF LOWELL
Intervenor (D.P.U. 18-118)

Robert A. Rio, Esq.
Associated Industries of Massachusetts
One Beacon Street, 16th Floor
Boston, Massachusetts 02109
FOR: ASSOCIATED INDUSTRIES OF MASSACHUSETTS
Limited Participant

Gregory P. Vasil, Esq.
Greater Boston Real Estate Board
One Center Plaza, Mezzanine Suite
Boston, Massachusetts 02108
FOR: GREATER BOSTON REAL ESTATE BOARD
Limited Participant (D.P.U. 18-110, D.P.U. 18-114, D.P.U. 18-115, D.P.U. 18-118, D.P.U. 18-119)

Beren Argetsinger, Esq.
Keyes & Fox LLP
P.O. Box 166
Burdett, New York 14818
FOR: SUNRUN, INC.
Limited Participant (D.P.U. 18-116, D.P.U. 18-117, D.P.U. 18-118, D.P.U. 18-119)

TABLE OF CONTENTS

I. INTRODUCTION AND PROCEDURAL HISTORY

On October 31, 2018, Bay State Gas Company, d/b/a Columbia Gas of Massachusetts ("Columbia Gas"); The Berkshire Gas Company ("Berkshire"); Boston Gas Company and Colonial Gas Company, each d/b/a National Grid ("National Grid (gas)");[1] Fitchburg Gas and Electric Light Company, d/b/a Unitil ("Unitil (gas)"); NSTAR Gas Company, d/b/a Eversource Energy ("NSTAR Gas"); Liberty Utilities (New England Natural Gas Company) Corp., d/b/a Liberty Utilities ("Liberty"); Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid (electric)"); Fitchburg Gas and Electric Light Company, d/b/a Unitil ("Unitil (electric)"); NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric"); and the towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE ("Compact") (together, "Program Administrators") each filed a three-year energy efficiency plan with the Department of Public Utilities ("Department") for calendar years 2019 through 2021 ("Three-Year Plans"). The Program Administrators filed their Three-Year Plans pursuant to An Act Relative to Green Communities, St. 2008, c. 169, codified at G.L. c. 25, §§ 19, 21-22, as amended by An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209 ("Energy Act of 2012"), and by An Act to Advance Clean

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[1] National Grid (gas) also administers energy efficiency programs for Blackstone Gas Company. Blackstone Gas Company, and Boston Gas Company and Colonial Gas Company, D.P.U. 15-79 (2015).

Energy, St. 2018, c. 227 ("Energy Act of 2018") (collectively "Green Communities Act"), and Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines Consistent with An Act Relative to Green Communities, D.P.U. 08-50 (2008); D.P.U. 08-50-A (2009); D.P.U. 08-50-B (2009); D.P.U. 08-50-C (2011); D.P.U. 08-50-D (2012); Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 11-120-A, Phase II (2013) ("Guidelines"). Each Program Administrator seeks approval of its Three-Year Plan, including proposed programs, program budgets, cost-recovery mechanisms and, with the exception of the Compact, a proposed performance incentive mechanism.[2] Pursuant to the Energy Act of 2012, the Program Administrators have also incorporated their Residential Conservation Services ("RCS") filings in their respective Three-Year Plans. St. 2012, c. 209, § 32(h), (i).

On November 1, 2018, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E in each Three-Year Plan docket. On November 6, 2018, the Department stamp-granted the petitions to intervene of the Massachusetts Department of Energy Resources ("DOER"), Conservation Law Foundation ("CLF"), Low-Income Weatherization and Fuel Assistance Program

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[2] The Department docketed these matters as follows: (1) D.P.U. 18-110 for Columbia Gas; (2) D.P.U. 18-111 for Berkshire; (3) D.P.U. 18-112 for Unitil (gas); (4) D.P.U. 18-113 for Liberty; (5) D.P.U. 18-114 for National Grid (gas); (6) D.P.U. 18-115 for NSTAR Gas; (7) D.P.U. 18-116 for the Compact; (8) D.P.U. 18-117 for Unitil (electric); (9) D.P.U. 18-118 for National Grid (electric); and (10) D.P.U. 18-119 for NSTAR Electric.

Network and the Low-Income Energy Affordability Network (together, "LEAN"), Acadia Center ("Acadia"), Northeast Energy Efficiency Council ("NEEC"), and PowerOptions, Inc. ("PowerOptions") as full parties in each Three-Year Plan docket. Also, on November 6, 2018, the Department stamp-granted the City of Lowell's petition to intervene in D.P.U. 18-118 and the petition for limited participant status of Associated Industries of Massachusetts ("AIM") in each docket. On November 9, 2018, the Department granted the petitions to intervene of NSTAR Electric and National Grid (gas) in D.P.U. 18-116. Cape Light Compact JPE, D.P.U. 18-116, Hearing Officer Ruling at 5 (November 9, 2018). On November 21, 2018, the Department granted the petition for limited participant status of Sunrun Inc. in D.P.U. 18-116, D.P.U. 18-117, D.P.U. 18-118, and D.P.U. 18-119. D.P.U. 18-116, Fitchburg Gas and Electric Light Company, D.P.U. 18-117, Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-118, NSTAR Electric Company, D.P.U. 18-119, Hearing Officer Ruling at 6 (November 21, 2018). On November 26, 2018, the Department stamp-granted the petition to intervene of the Massachusetts Association of Realtors ("MAR") in each docket and the petition for limited participant status of the Greater Boston Real Estate Board ("GBREB") in D.P.U. 18-110, D.P.U. 18-114, D.P.U. 18-115, D.P.U. 18-118, and D.P.U. 18-119.

Pursuant to notice duly issued, the Department held a joint public hearing on December 3, 2018.[3] The Department held three days of evidentiary hearings on

[3] The Department held a joint public hearing in each docket. These cases, however, are not consolidated and remain separate proceedings.

December 10, 11, and 17, 2018.[4] On December 31, 2018, the Program Administrators (jointly), the Attorney General, DOER, Acadia, CLF, LEAN, MAR, and PowerOptions filed briefs in each docket, National Grid (gas) filed a brief in D.P.U. 18-116, the Compact filed a supplemental brief in D.P.U. 18-116, and GBREB filed a brief in D.P.U. 18-110, D.P.U. 18-114, D.P.U. 18-115, D.P.U. 18-118, and D.P.U. 18-119. On January 8, 2019, the Program Administrators (jointly), the Attorney General, DOER, Acadia, CLF, and MAR filed reply briefs in each docket, National Grid (gas) and NSTAR Gas each filed a reply brief in D.P.U. 18-116, and GBREB filed a reply brief in D.P.U. 18-110, D.P.U. 18-114, D.P.U. 18-115, D.P.U. 18-118, and D.P.U. 18-119. The evidentiary records for D.P.U. 18-110 through D.P.U. 18-119 include approximately 1,950 exhibits and seven responses to record requests.

II. BACKGROUND

A. Introduction

Pursuant to the Green Communities Act, all Program Administrators are required to develop energy efficiency plans that "provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, § 21(b)(1). The Green Communities Act establishes an Energy

[4] The Department held joint evidentiary hearings on December 10 and 11, 2018, on common issues. The Department also held a Compact-specific evidentiary hearing on December 17, 2018.

Efficiency Advisory Council ("Council")[5] and directs Program Administrators, in coordination with the Council, to prepare a three-year, statewide energy efficiency plan ("Statewide Plan"). G.L. c. 25, § 21(b)(1).

Programs contained in the Statewide Plan may include, but are not limited to, the following: (1) efficiency and load management programs, including programs for energy storage and other active demand management technologies and strategic electrification; (2) demand response programs; (3) programs for research, development, and commercialization of products or processes that are more energy-efficient than those generally available; (4) programs for the development of markets for such products and processes, including recommendations for new appliance and product efficiency standards; (5) programs providing support for energy use assessment, real time monitoring systems, engineering studies and services related to new construction or major building renovation, including integration of such assessments, systems, studies and services with building energy

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[5] The Council's 15 voting members represent the following interests: (1) residential consumers; (2) the low-income weatherization and fuel assistance program network; (3) the environmental community; (4) businesses, including large commercial and industrial end-users; (5) the manufacturing industry; (6) energy efficiency experts; (7) organized labor; (8) the Commonwealth of Massachusetts Department of Environmental Protection ("DEP"); (9) the Attorney General; (10) the Commonwealth of Massachusetts Executive Office of Housing and Economic Development; (11) the Massachusetts Non-profit Network; (12) a city or town in the Commonwealth of Massachusetts; (13) MAR; (14) a business employing fewer than ten persons located in the Commonwealth of Massachusetts that performs energy efficiency services; and (15) DOER. G.L. c. 25, § 22(a). The Council membership also includes one non-voting member representing each Program Administrator, one from the heating and oil industry, one from ISO New England Inc. ("ISO-NE"), and one from energy efficiency businesses. G.L. c. 25, § 22(a).

codes programs and processes, or those regarding the development of high performance or sustainable buildings that exceed code; (6) programs for the design, manufacture, commercialization, and purchase of energy-efficient appliances and heating, air conditioning, and lighting devices; (7) programs for planning and evaluation; (8) programs providing commercial, industrial, and institutional customers with greater flexibility and control over demand-side investments funded by the programs at their facilities; (9) programs for public education regarding energy efficiency and demand management; and (10) programs that result in customers switching to renewable energy sources or other clean energy technologies. G.L. c. 25, § 21(b)(2); St. 2018, c. 227, §§ 2, 4.

The Program Administrators must submit a Statewide Plan to the Council every three years, by April 30th. G.L. c. 25, § 21(c). The Council then has three months to review the Statewide Plan and submit its approval or comments on the Statewide Plan to the Program Administrators.[6] G.L. c. 25, § 21(c). If not approved, the Program Administrators may change the Statewide Plan to reflect the Council's input. G.L. c. 25, § 21(c).

Each Program Administrator must also develop and file with the Department an individual Three-Year Plan, based on the Statewide Plan, which includes Program Administrator-specific information. G.L. c. 25, § 21(d)(1). The Program Administrators must, by October 31st of that same year, submit their respective Three-Year Plans to the Department together with the Council's approval or comments and a statement of any unresolved issues. G.L. c. 25, § 21(d)(1). The Department is then required to conduct a

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[6] Approval requires a two-thirds majority vote of the Council. G.L. c. 25, § 22(b).

public hearing to allow interested persons to be heard on the Three-Year Plans. G.L. c. 25, § 21(d)(1). The Department must, within 90 days of the filing date, approve, modify, or reject and require the resubmission of the Three-Year Plans. G.L. c. 25, § 21(d)(2).

B. Energy Efficiency Advisory Council Resolutions

As required by the Green Communities Act, the Council has worked closely with the Program Administrators to develop the energy efficiency programs and budgets found in the Statewide Plan. G.L. c. 25, § 22(b). During this process, the Council issued three resolutions regarding its recommendations concerning various elements of the Statewide Plan and individual Program Administrators' Three-Year Plans: (1) a February 28, 2018 "Resolution Concerning Its Priorities for the Development, Implementation, and Evaluation of the Statewide Plan;" (2) a July 31, 2018 "Resolution Regarding the April 30th Draft of the Statewide Plan;" and (3) an October 30, 2018 "Resolution Regarding the 2019-2021 Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Investment Plans"(Statewide Plan, Exh. 1, Apps. D, E, G).

Following the February 28, 2018 resolution, the Program Administrators, Council consultants, DOER, and the Attorney General worked collaboratively to review certain aspects of the Three-Year Plans as well as savings and cost assumptions. On July 31, 2018, the Council found that the draft Statewide Plan, submitted on April 30, 2018, required additional programing details and analytical support (Statewide Plan, Exh. 1, App. E). The Program Administrators submitted a revised draft Statewide Plan to the Council on September 14, 2018 (Statewide Plan, Exh. 1, App. G). On October 19, 2018, the Program

Administrators, DOER, and the Attorney General reached an agreement on the 2019-2021 goals, budgets, performance incentive pool, and other terms reflected in the Statewide Plan ("Term Sheet") (Statewide Plan, Exh. 1, App. F).

On October 22, 2018, the Program Administrators submitted updated data tables and a memorandum outlining the enhancements contained in the Statewide Plan (Statewide Plan, Exh. 1, App. F). On October 30, 2018, the Council unanimously passed a resolution supporting the Statewide Plan and, to the extent they are consistent with the Statewide Plan, the Program Administrators' respective Three-Year Plans (Statewide Plan, Exh. 1, App. G).

C. Department Review of Three-Year Plans

Pursuant to the Green Communities Act, each Program Administrator's Three-Year Plan must provide for the acquisition of all available energy efficiency resources that are cost effective or less expensive than supply. G.L. c. 25, §§ 19(a), 21(a), 21(b)(1), 21(b)(2), 21(d)(2). Further, a Program Administrator must demonstrate that it will meet its resource needs first through cost-effective energy efficiency and demand reduction resources in order to mitigate capacity and energy costs for all customers. G.L. c. 25, §§ 19(a), 19(b), 21(a), 21(b)(1); see also Guidelines § 3.4.7. The Three-Year Plans must provide for the acquisition of these resources with the lowest reasonable customer contribution. G.L. c. 25, § 21(b)(1).

For the purpose of evaluating cost effectiveness, the Green Communities Act, as amended by the Energy Act of 2018, provides that review occurs at the sector level (i.e., residential, low income, and commercial and industrial ("C&I")). St. 2018, c. 227, § 6. If a sector benefit-cost ratio exceeds one, then the sector is deemed to be cost effective.

St. 2018, c. 227, § 6. If, however, a sector fails the cost-effectiveness test, then its component programs shall be modified so that the sector is cost effective, or the program must be terminated. St. 2018, c. 227, § 6.

In order to evaluate whether the mandate of all available cost-effective energy efficiency has been met, the Department weighs, among other things, whether the Program Administrator (1) plans for a sustainable effort in its continued delivery of energy efficiency, (2) has considered new technologies and enhancements, (3) has included the results of avoided costs, potential and evaluation studies, and (4) has sought to design programs to address identified barriers. 2016-2018 Three-Year Energy Efficiency Plans, D.P.U. 15-160 through D.P.U. 15-169, at 25-27 (2016) ("2016-2018 Three-Year Plans Order"); 2013-2015 Three-Year Energy Efficiency Plans, D.P.U. 12-100 through D.P.U. 12-111, at 37-40 (2013) ("2013-2015 Three-Year Plans Order").

In addition, when reviewing the Three-Year Plans, the Department must ensure the following: (1) that the Program Administrators have minimized administrative costs to the fullest extent practicable; (2) that Program Administrators will use competitive procurement processes to the fullest extent practicable; and (3) that the low-income sector is allocated at least ten percent of the funds for electric energy efficiency programs and 20 percent of the funds for gas energy efficiency programs. G.L. c. 25, §§ 19(a), (b), (c), 21(b)(3).

Finally, to recover the costs related to energy efficiency, electric Program Administrators must first fund the Three-Year Plans from other revenue sources.[7] The Department may also approve funding from gas and electric ratepayers through a fully reconciling funding mechanism, after considering the rate and bill impacts on consumers. G.L. c. 25, § 19(a), (b); Guidelines § 3.2.1.6.2; 3.2.2; D.P.U. 08-50-A at 56-60; D.P.U. 08-50-B at 18-19.

In this Order, the Department addresses the following elements of the Three-Year Plans: (1) energy savings, (2) administrative costs, competitive procurement, and low income allocation; (3) cost effectiveness; (4) performance incentives; and (5) funding sources. Additionally, the Department addresses certain elements that are specific to the Compact and other issues.

III. ENERGY SAVINGS

A. Introduction

The Green Communities Act requires each Program Administrator's Three-Year Plan to provide for the acquisition of all available cost-effective energy efficiency resources. G.L. c. 25, §§ 19(a), 19(b), § 21(a), 21(b)(1); see also Guidelines § 3.4.7. In order to achieve this mandate, the Program Administrators work with the Council to develop the savings goals contained in the Statewide Plan. G.L. c. 25, § 21(b)(1). When reviewing the

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[7] The revenue sources are (1) a mandatory $0.0025 per kilowatt-hour ("kWh"), system benefits charge ("SBC"), (2) revenues from the forward capacity market ("FCM"), administered by ISO-NE, (3) revenues from cap and trade pollution control programs (e.g., Regional Greenhouse Gas Initiative ("RGGI"), and (4) other funding sources. Guidelines § 3.2.1; see also G.L. c. 25, § 19(a).

individual savings goals, the Department must ensure that each Program Administrator has taken appropriate steps to demonstrate that its Three-Year Plan (1) establishes a sustainable effort in its continued delivery of energy efficiency, (2) has considered new technologies and enhancements, (3) has included the results of avoided costs, potential and evaluation, measurement, and verification ("EM&V") studies, and (4) has sought to design programs to address identified barriers. 2016-2018 Three-Year Plans Order, at 25-27; 2013-2015 Three-Year Plans Order, at 37-40. These issues are relevant to the Department's ultimate determination of whether the Three-Year Plans will provide for the acquisition of all available cost-effective energy efficiency and demand reduction resources. See G.L. c. 25, §§ 19(a), 19(b), 21(b)(1).

B. Program Administrators Proposal

1. Savings Goals

The Program Administrators state that they engaged in a collaborative planning process for setting the savings goals contained in the Statewide Plan (Statewide Plan, Exh. 1, at 144). Development of the Statewide Plan involved discussions between the Program Administrators, the Executive Office of Energy and Environmental Affairs ("EEA"), DOER, the Attorney General, and the Council's consultants regarding program savings goals, budgets, and key priorities (Statewide Plan, Exh. 1, at 11, 150). Pursuant to G.L. c. 25, § 21, the Council reviewed a draft Statewide Plan submitted by the Program Administrators on April 30, 2018, and subsequently approved the Statewide Plan on October 30, 2018 (Statewide Plan, Exh. 1, at 21).

The Program Administrators state that they developed their individual savings goals based on the following considerations: (1) the Green Communities Act, which requires the acquisition of all available cost-effective energy efficiency; (2) the need for long-term program sustainability; (3) the directives, priorities, and recommendations of the Council and other stakeholders; (4) avoided costs; (5) the Department's directives in prior energy efficiency Orders; (6) customer bill impacts; (7) cost drivers; (8) energy efficiency potential studies;[8] (9) recent EM&V study results; (10) efficiency standards; and (11) the Program Administrators' experience implementing energy efficiency programs over the past three decades (Statewide Plan, Exh. 1, at 144-151). The Program Administrators state that the gas and electric statewide savings goals contained in the Statewide Plan are consistent with the Term Sheet (Statewide Plan, Exh. 1, at 151).

The aggregate gas and electric statewide savings goals for the term and each Program Administrator's individual savings goal, expressed as a percentage of sales, are shown in Tables 1 and 2 below, respectively.[9]

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[8] To provide them with a better understanding of the remaining technical, economic, and achievable energy efficiency savings opportunities within their service territories, each Program Administrator states that it completed an energy efficiency potential study (Statewide Plan, Exh. 1, at 147-148, App. N).

[9] In addition, the electric Program Administrators' Three-Year Plans include significant oil savings (Statewide Plan, Exh. 1, App. C - Electric (Rev.) (December 20, 2018)).

Table 1: Individual Electric Program Administrator Savings Goals (as a Percentage of Sales)[10]

	Total 2019-2021
National Grid (electric)	2.71%
NSTAR Electric	2.76%
Unitil (electric)	1.47%
Compact	2.14%
Aggregate Statewide Goal	2.67%

Table 2: Individual Gas Program Administrator Savings Goals (as a Percentage of Sales)[11]

	Total 2019-2021
National Grid (gas)	1.28%
NSTAR Gas	1.34%
Columbia Gas	1.28%
Unitil (gas)	0.78%
Berkshire	0.65%
Liberty	0.58%
Aggregate Statewide Goal	1.25%

2. Active Demand Reduction Offerings

The electric Program Administrators propose the following seven active demand reduction offerings as part of the Statewide Plan:[12] (1) residential direct load control;

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[10] Sources: For each electric Program Administrator, Statewide Plan, Exh. 1, App. F at 11-18.

[11] Sources: For each gas Program Administrator, Statewide Plan, Exh. 1, App. F at 11-18.

(2) residential storage performance; (3) C&I interruptible load curtailment (summer); (4) C&I interruptible load curtailment (winter); (5) C&I storage performance (daily dispatch); (6) C&I storage performance (targeted dispatch – summer); and (7) C&I storage performance (targeted dispatch – winter) (see, e.g., Statewide Plan, Exh. 1, at 67-69, 121-124; Exh. Eversource Energy (electric)-5 (Rev.) (December 20, 2018)). In addition, the electric Program Administrators propose to expand the HEAT Loan program and offer five-year incentive commitments to customers installing new storage projects to assist with financing (see, e.g., Statewide Plan, Exh. 1, at 68; Exh. Eversource Energy (electric)-2, at 61-62; Exh. DPU-Electric 2-15; Exh. DPU-Electric 2-16).

The electric Program Administrators also propose to offer performance-based incentives for the active demand reduction offerings (see, e.g., Exh. Eversource Energy (electric)-2, at 57). In particular, customers participating in the residential direct load control offering will receive incentives based on annual enrollment, while customers participating in all other active demand reduction offerings will receive incentives based on verified demand reductions (see, e.g., Exh. Eversource Energy (electric)-2, at 57). The electric Program Administrators anticipate that the active demand reduction offerings will result in approximately 200 megawatts ("MW") of peak demand reduction and 50 MW of

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[12] In addition to the statewide offerings, the Compact, NSTAR Electric, and National Grid (electric) each propose Program Administrator-specific active demand reduction offerings (Statewide Plan, Exh. 1, App. K). The Compact's offerings are discussed in Section VIII below. The offerings of NSTAR Electric and National Grid (electric) are discussed in the Analysis and Findings below.

winter demand reduction by 2021 (Statewide Plan, Exh. 1, App. C – Electric, Table IV.D.3.2.i).

The electric Program Administrators propose to offer the residential direct load control offering to customers with eligible controllable communicating devices (e.g., thermostats controlling cooling loads) and to target summer peak demand reductions (see, e.g., Statewide Plan, Exh. 1, at 67-68; Exh. Eversource Energy (electric)-2, at 55). Through the proposed residential storage performance offering, the electric Program Administrators intend to dispatch residential storage systems (1) on a daily basis during summer peak periods[13] and (2) on a targeted basis during winter periods (Statewide Plan, Exh. 1, at 68).

The electric Program Administrators state that the proposed C&I interruptible load curtailment offerings will be technology-neutral and will provide incentives for verifiable load shedding in response to Program Administrator-called events during summer and/or winter peak periods (Statewide Plan, Exh. 1, at 122-123). Finally, the electric Program Administrators propose to offer increased performance incentives for C&I storage systems through the C&I storage performance offerings for verifiable load reductions during the summer or winter periods (Statewide Plan, Exh. 1, at 123).

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[13] The electric Program Administrators hypothesize that storage can be dispatched more frequently than other active demand reduction technologies and that a daily dispatch during the summer would act like traditional energy efficiency, thereby reducing the system peak (see, e.g., Exhs. Eversource Energy (electric)-2, at 59; DPU-Electric 2-4). The electric Program Administrators state they may explore a residential targeted dispatch offering for the summer if customers are not willing to enroll in a daily dispatch offering (Tr. 1, at 26).

3. Evaluation, Measurement, and Verification

The Program Administrators propose to continue the evaluation framework that they previously employed to support third-party EM&V efforts (Statewide Plan, Exh. 1, at 174). In particular, the Program Administrators propose to focus their EM&V activities on the following three research areas: (1) residential; (2) C&I; and (3) special and cross-cutting[14] (Statewide Plan, Exh. 1, at 175). Within each research area, the Program Administrators propose to conduct the following types of EM&V studies: (1) impact evaluations; (2) baseline studies; (3) net-to-gross studies; (4) market effects evaluations; (5) non-energy impact ("NEI") studies; (6) cost and measure life studies; (7) market characterization studies; and (8) process evaluations (Statewide Plan, Exh. 1, at 176). The Program Administrators propose to allocate $71,894,765 (or 2.6 percent of the total proposed budget) for statewide EM&V activities during the upcoming Three-Year Plan term (Statewide Plan, Exh. 1, at 141, App. C - Electric (Rev.) (December 20, 2018) at 12; App. C - Gas (Rev.) (December 20, 2018) at 7). The Program Administrators propose to allocate all EM&V costs to a new Evaluation and Market Research line item under the hard-to-measure category rather than to allocate these costs to individual programs (Statewide Plan, Exh. 1, at 134-135; App. C (Rev.) (December 20, 2018)).

The Program Administrators state that, together with the EM&V consultant, they have established an Evaluation Management Committee to serve as a steering committee for

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[14] The Program Administrators state that certain studies may be cross-sector (i.e., study both the residential and C&I sectors) (Statewide Plan, Exh. 1, at 175).

statewide evaluation issues, provide guidance and direction to each of the evaluation research areas, and assist in setting research priorities (Statewide Plan, Exh. 1, at 175). Finally, the Program Administrators state that, together with the Evaluation Management Committee, they have developed a strategic evaluation plan that will serve as a long-term planning document to guide evaluation activities in the 2019 through 2021 Three-Year Plan term (Statewide Plan, Exh. 1, at 176, App. S at 4).

C. Positions of the Parties

1. Program Administrators

The Program Administrators submit that, consistent with G.L c. 25, § 21(b)(1), the Three-Year Plans include savings goals that are designed to achieve all available cost-effective energy efficiency and demand reduction measures for the three-year period beginning January 1, 2019 (Program Administrators Brief at 12). The Program Administrators contend that the savings goals in the proposed Three-Year Plans take into consideration a variety of complex factors, including service territory-specific characteristics, technical innovations, bill impacts, economic and environmental benefits, cost efficiency, and the need to establish integrated efforts that can be sustained over time (Program Administrators Brief at 12). The Program Administrators argue that the Three-Year Plans include aggressive savings goals, even as energy efficiency markets are becoming saturated and baselines for claimable savings increase (Program Administrators Brief at 12, citing Statewide Plan, Exh. 1, at 13).

The Program Administrators maintain that they engaged in a highly collaborative planning process and relied on Council and stakeholder input, as well as the results of multiple studies and analyses, to arrive at their final savings goals (Program Administrators Brief at 13). In addition, in compliance with the Department's directives, each Program Administrator maintains that it conducted a potential study for its service territory (Program Administrators Brief at 13, citing Statewide Plan, Exh. 1, App. N; 2016-2018 Three-Year Plans Order, at 25). The Program Administrators assert that they coordinated extensively in the development of each potential study, made the studies publicly available, and shared the study results with the Council (Program Administrators Brief at 13, citing Exh. DPU-Comm 9-3; Tr. 1, at 91-92). In response to CLF's assertion that the gas Program Administrators did not develop a gas demand response program, the gas Program Administrators argue that, based on the results of pilot programs in other states, an analysis of gas demand response (either as part of the potential studies or as a demonstration offering) would not be cost effective (Program Administrators Reply Brief at 11-12, citing Exhs. DPU-Gas 1-1; DPU-Gas 2-1, DPU-Gas 2-2; Tr. 1, at 95-96).

The Program Administrators argue that any requirement to use uniform methods and definitions in future potential studies, as recommended by CLF and Acadia, would dilute the service-territory specific purpose of such studies (Program Administrators Brief at 14-15, citing Exh. DPU-Comm 9-3; Tr. 1, at 87-93; Program Administrators Reply Brief at 16-17, citing Exh. DPU-Comm 9-3). The Program Administrators assert that different assumptions and methods are essential to ensure that the potential studies produce actionable information

based on each Program Administrator's unique service-territory characteristics (Program Administrators Reply Brief at 18).

The Program Administrators recommend that the Department approve the active demand reduction offerings, asserting that the active demand reduction proposals are consistent with the Green Communities Act and the goal of pursuing all cost-effective demand reduction resources (Program Administrators Brief at 25, Program Administrators Reply Brief at 11). The Program Administrators assert that the proposed active demand reduction offerings were unanimously supported by the Council and draw on lessons learned from demonstration projects and demand reduction experts (Program Administrators Brief at 22; Program Administrators Reply Brief at 9). The Program Administrators argue that their proposed pay-for-performance approach ensures customers are paid for verifiable demand reductions (Program Administrators Reply Brief at 10).

The Program Administrators maintain that the proposed active demand reduction offerings are appropriately designed and that implementation can begin upon Department approval (Program Administrators Brief at 25; Program Administrators Reply Brief at 10). The Program Administrators contend, however, that certain implementation and contract details cannot be finalized until the offerings are approved (Program Administrators Brief at 25; Program Administrators Reply Brief at 10-11). In particular, the Program Administrators maintain that for the residential storage performance offering, implementation efforts including assessing the cost efficiency of investing in the application program interface ("API") integration necessary to dispatch each type of storage system at scale cannot begin

until Department approval (Program Administrators Brief at 25; Program Administrators Reply Brief at 11). In this regard, the Program Administrators contend that PowerOptions incorrectly relied on evidence related to APIs for the proposed statewide residential storage offering in support of its faulty assertion that the proposed C&I storage performance offerings are not yet developed[15] (Program Administrators Reply Brief at 11 n.11). Finally, the Program Administrators contend that additional residential storage systems will be installed as a result of the proposed storage performance offering and, therefore, the acquisition of APIs for most storage system types will be a prudent expenditure (Program Administrators Brief at 25).

The Program Administrators contend that their proposed EM&V framework appropriately employs strategies, study areas, budgets, and stakeholder roles that satisfy the Department's precedent and Guidelines (Program Administrators Brief at 48-49, citing Exh. 1, at 175-177, App. S; 2016-2018 Three-Year Plans Order, at 30; 2013-2015 Three-Year Plans Order, at 59; Guidelines § 3.5). Finally, the Program Administrators argue that their proposal to allocate all EM&V costs to a new line item under the hard-to-measure category rather than to allocate these costs to individual programs better reflects the reality that the benefits of EM&V efforts are often applicable to multiple programs (Program Administrators Brief at 37).

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[15] The Program Administrators note that the dispatch of C&I storage under the proposed active demand reduction offerings does not require APIs (Program Administrators Brief at 25 n.15).

2. Attorney General

The Attorney General asserts that the aggregate electric savings goal is both ambitious and aggressive, at 2.70 percent of retail electricity sales (Attorney General Brief at 6). Similarly, the Attorney General argues that the aggregate gas savings goal of 1.25 percent of retail gas sales is a steady and proportionate increase in gas savings from the previous three-year term (Attorney General Brief at 9). The Attorney General concludes that the savings goals and the proposed budgets designed to meet these goals appropriately balance the achievement of all cost-effective energy efficiency, achievement of environmental goals, and customer rate impacts (Attorney General Brief at 10). Finally, the Attorney General maintains that she supports the new strategies proposed by the Program Administrators to capture active peak demand reduction (Attorney General Brief at 2).

3. Department of Energy Resources

DOER opines that the Statewide Plan shows a willingness on the part of the Program Administrators to adapt to a changing regulatory landscape and the evolving needs of energy consumers in Massachusetts (DOER Brief at 8). In particular, DOER notes that the electric Program Administrators have committed to a nation-leading 2.70 percent savings goal and have proposed new initiatives that align with the 2018 Energy Act (DOER Brief at 8).

DOER maintains that the aggressive savings goals in the Statewide Plan are expected to deliver more than 35.6 million megawatt-hour ("MWh") in lifetime electric savings and more than 1.19 billion therms in lifetime gas savings (DOER Brief at 9). DOER asserts that the total MMBtu savings of 261.9 million are estimated to deliver more than $8.56 billion in

benefits, which is more than three dollars in benefits for every dollar invested (DOER Brief at 9).

In addition, DOER asserts that it strongly supports the energy savings goals in the Program Administrators' Three-Year Plans (DOER Brief at 8-9). DOER recognizes that much of the "low-hanging fruit" in energy efficiency has been captured over the past decade and concludes that the proposed savings goals will achieve all cost-effective energy efficiency at a cost that is significantly less than the avoided cost of supply (DOER Brief at 9).

DOER supports the active demand reduction offerings proposed by the Program Administrators (DOER Brief at 13). DOER asserts that the offerings are cost effective and will benefit customers during both summer and winter periods of peak demand when energy costs are highest (DOER Brief at 13). In addition, DOER contends that the proposed active demand reduction offerings align with the Commonwealth's policy goals of reducing costs and increasing reliability through reductions in summer and winter peak demand (DOER Brief at 13). Finally, DOER maintains that the proposed active demand reduction offerings have been appropriately designed to ensure that participation and savings will be realized during the 2019-2021 Three-Year Plan term by drawing on the experience of earlier demonstration projects and DOER's peak demand reduction grant projects, as well as stakeholder input (DOER Brief at 13; DOER Reply Brief at 2).

4. Acadia Center

Acadia argues that the potential studies conducted by the Program Administrators used multiple methods and reporting formats, rendering the studies "essentially useless" (Acadia

Brief at 24). Accordingly, Acadia requests the Department to direct the Program Administrators to adopt a uniform research method for future potential studies, with common definitions and assumptions, but allowing for service territory-specific differences within the common framework (Acadia Brief at 24-25). In addition, Acadia argues that the Department should set a deadline for the completion of such studies so that the Council and stakeholders can conduct a meaningful review of the studies (Acadia Brief at 24-25).

In addition, Acadia argues that there is a disconnect between untapped savings potential and certain Program Administrator's proposed savings goals (Acadia Brief at 25). Specifically, Acadia argues that both Liberty and Unitil (gas) have proposed savings goals that are sizably lower than the statewide average savings goal and do not correspond to the untapped potential in their respective service territories (Acadia Brief at 25-26, citing Statewide Plan, Exh. 1, App. F). In addition, Acadia argues that Liberty and Unitil (gas) have failed to propose any unique programs to address the barriers to achieving the untapped savings potential in their service territories (e.g., programs to address high concentrations of renters and moderate-income customers) (Acadia Brief at 26). Acadia recommends that the Department require these Program Administrators to revise their proposed savings goals to reflect all untapped potential (Acadia Brief at 26).

Acadia recommends that the Department approve the proposed statewide active demand reduction offerings (Acadia Brief at 11). Acadia argues that the active demand reduction offerings are consistent with Council priorities and recent amendments to the Green Communities Act that underscore the importance of energy storage and active demand

(Acadia Brief at 11). Acadia also maintains that the proposed active demand reduction offerings appropriately draw from demonstration projects undertaken between 2016 through 2018, and are consistent with the Department's stated expectation that Program Administrators would implement a statewide active demand reduction offering as soon as possible (Acadia Brief at 10-11, citing 2016-2018 Three-Year Plans Order, at 142-143).

5. Conservation Law Foundation

CLF acknowledges that the Three-Year Plan shows progress toward ensuring equitable access to energy efficiency resources by underserved communities (CLC Brief at 21-22). CLF asserts, however, that the Program Administrators should be required to provide more details regarding the following: (1) the partnership strategy; (2) marketing for hard-to-reach customers; (3) language accessibility; (4) serving moderate-income households; and (5) reaching renters and rental units (CLF Brief at 20-32). CLF acknowledges that certain Program Administrators' marketing strategies targeting hard-to-reach customers are more costly than previous marketing efforts, but it argues that these investments are necessary to overcome participation barriers (CLF Brief at 22-23). In addition, CLF asserts that the Program Administrators should consult with state and municipal officials to expand the language offerings for energy efficiency program marketing (CLF Brief at 23-24).

To address participation in underserved communities, CLF argues that the Program Administrators should be required to develop strategies to remove barriers to participation (CLF Brief at 20). For example, CLF asserts that the Three-Year Plan does not include any significant new offerings to address pre-weatherization barriers for moderate-income

households (CLF Brief at 25-26). In future three-year plans, CLF suggests that the Program Administrators consider ways to eliminate pre-weatherization barriers as part of measure delivery, instead of relying solely on HEAT Loan financing options (CLF Brief at 26-27).

In addition, CLF argues that future potential studies should be conducted using a centralized process that is overseen by a third-party (CLF Brief at 42). Alternatively, if the Program Administrators are permitted to continue to conduct their own potential studies, CLF argues that the Department should require the Program Administrators to use a common outline, format, and definitions (CLF Brief at 39-40, 42). CLF asserts that such consistency will facilitate stakeholder review of the studies (CLF Brief at 39). CLF also asserts that the Program Administrators should consult more frequently with the Council when preparing and reviewing potential studies (CLF Brief at 40).

While CLF does not oppose the proposed statewide active demand reduction offerings, it contends that the statewide offering is less robust than the Compact's proposed storage offering (CLF Brief at 46). CLF recommends that the Department require all Program Administrators to adopt an approach similar to the Compact's, should the Compact's storage offering prove successful (CLF Brief at 47). Finally, CLF argues that the gas Program Administrators have offered insufficient evidence to support their decision not to include gas demand response offerings in their Three-Year Plan (CLF Brief at 47).

6. PowerOptions

PowerOptions appreciates the Program Administrators efforts to address certain underserved markets, such as small businesses and renters (PowerOptions Brief at 5).

PowerOptions argues, however, that the Three-Year Plans do not adequately address non-profit entities (PowerOptions Brief at 4). In particular, PowerOptions asserts that the Statewide Plan contains only two brief references to addressing barriers in serving non-profits (PowerOptions Brief at 5-6, citing Statewide Plan, Exh. 1, at 98, 116)). PowerOptions recommends that Program Administrators develop formal marketing strategies and partnerships within the non-profit community to disseminate information about energy efficiency financing tools for non-profits (PowerOptions Brief at 6-7).

PowerOptions asserts that it generally supports the proposed active demand reduction offerings, particularly the winter active demand reduction target (PowerOptions Brief at 8). However, PowerOptions raises concerns with respect to the lack of detail provided for the C&I storage performance offering (PowerOptions Brief at 9). PowerOptions asserts that, without more program design details, it is impossible for the Department and stakeholders to fully evaluate the effectiveness of the offering (PowerOptions Brief at 9). Therefore, PowerOptions argues that the Department should require the Program Administrators to provide more details on the proposed C&I storage performance offering in order to fully evaluate the proposal (PowerOptions Brief at 9, 13).

D. Analysis and Findings

1. Savings Goals

Energy savings represent the electricity, natural gas, heating oil, and other resources saved as a result of the deployment of energy efficiency. The Department considers energy

savings in order to evaluate the degree to which the proposed Three-Year Plans achieve their stated goal of reducing energy usage.

The Statewide Plan contains aggregate electric and gas savings goals, as well as individual savings goals for each electric and gas Program Administrator (Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). These savings goals were developed through a collaborative process between the Program Administrators and the Council that culminated with an agreement on the core elements of the Statewide Plan (i.e., savings goals, program budgets, and performance incentives) as reflected in the Term Sheet (Statewide Plan, Exh. 1, at 21, 151, App. F). Before the individual Three-Year Plans were filed with the Department, the Council endorsed the savings goals in the Statewide Plan as meeting the Green Communities Act's requirement to achieve all available, cost-effective energy efficiency (Statewide Plan, Exh. 1, at 22, App. G). In addition, the Council supported the individual Program Administrator's savings goals to the extent they are consistent with the Statewide Plan (Statewide Plan, Exh. 1, Apps. F, G).

Acadia asserts that Liberty and Unitil (gas) have proposed savings goals that are lower than the statewide average (Acadia Brief at 25-26). Acadia recommends that the Department require these Program Administrators to modify their savings goals to reflect untapped potential in their service territories (Acadia Brief at 25). Conversely, the Program Administrators maintain that Liberty and Unitil (gas) have set appropriately aggressive savings goals that are based on (1) service territory-specific potential studies, (2) unique characteristics of each Program Administrator's customer base, (3) program design costs,

(4) market conditions, and (5) labor and workforce availability (Program Administrators Reply Brief at 27).

Contrary to Acadia's assertions, the Department finds that each Program Administrator provided a reliable potential study, using valid research methods consistent with Department directives[16] (Statewide Plan, Exh. 1, Apps. F, N). Liberty's potential study presents achievable savings between 0.52 and 0.65 percent of retail sales over the term of its Three-Year Plan (Statewide Plan, Exh. 1, App. N-Liberty, at 9-10; App. F at 17). Liberty proposes a savings goal of 0.58 percent of retail sales (Statewide Plan, Exh. 1, App. N-Liberty, at 9-10). Similarly, the potential study of Unitil (gas) presents achievable savings between 0.71 and 0.86 percent of retail sales over the term of its Three-Year Plan (Statewide Plan, Exhs. 1, App. N-Unitil (Gas) at 9-10; App. F at 6, 47; DPU-Unitil (Gas) 1-3). Unitil (gas) proposes a savings goal of 0.78 percent of retail sales (Statewide Plan, Exhs. 1, App. N-Unitil (Gas) at 9-10; App. F at 6, 47; DPU-Unitil (Gas) 1-3). The Department finds that Liberty and Unitil (gas) have proposed savings goals that are both appropriate and aligned with their potential study findings.

The Department appreciates the efforts of the Program Administrators and the Council to develop the savings goals in the Statewide Plan. The support of this diverse group of stakeholders facilitates the Department's review of the Three-Year Plans, and we give significant weight to the endorsement by the Council of the savings goals in the Statewide

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[16] Proposed improvements to future potential studies are addressed in Section III.D.4, below.

Plan and the individual savings goals in the Three-Year Plans. 2016-2018 Three-Year Plans Order, at 23. After review, the Department finds that the statewide and individual Program Administrator savings goals developed through this process appropriately take into consideration program sustainability and territory-specific savings drivers (Statewide Plan, Exh. 1, at 144-151, App. N; Exhs. BGC-2, at 55-57, 64-66; CMA-2, at 60-61, 66-70; FGE (gas)-2, at 59-61, 66-74; LU-2, at 55-57, 62-66; NG-Gas-2, at 63-65, 71-72; Eversource Energy (gas)-2, at 56-57, 63-65; Compact-2, at 64-66; 103-105; FGE (electric)-2, at 71-72, 78-86; NG-Electric-2, at 76-78, 84-86; Eversource Energy (electric)-2, at 70-71, 77-79). Further, the Department finds that the aggregate and individual gas and electric savings goals are consistent with the achievement of all available cost-effective energy efficiency (Statewide Plan, Exh. 1, at 144-151, App. N). Accordingly, the Department approves the statewide and individual Program Administrator savings goals. Going forward, in future three-year plans filings, any Program Administrator-specific programming included as part of the Statewide Plan should also indicate the incremental budget and projected savings, broken down by rate class and category, relative to the Statewide Plan.

2. Active Demand Reduction Offerings

a. Introduction

The electric Program Administrators propose statewide active demand reduction offerings, for the first time, as part of their 2019-2021 Three-Year Plans. These proposed offerings and the associated savings goals were developed through a collaborative process and

endorsed by the Council (Statewide Plan, Exh. 1, at 22, App. G). Furthermore, Acadia, the Attorney General, CLF, DOER, and PowerOptions support the proposed statewide active demand reduction offerings (see Acadia Brief at 11; Attorney General Brief at 2; CLF Brief at 46; DOER Brief at 13; PowerOptions Brief at 8).

The proposed active demand reduction offerings are generally consistent with the Department's expectation that the Program Administrators would leverage the results of the demand response demonstration projects approved as part of the 2016-2018 three-year plans to support the deployment of cost-effective demand response offerings at scale. 2016-2018 Three-Year Plans Order, at 142-143. For example, the proposed residential direct load control, C&I interruptible load curtailment, and targeted storage offerings were informed by the Compact's and National Grid (electric)'s existing demand response demonstration projects (Exhs. DPU-Electric 2-2; DPU-Electric 2-4).

With certain exceptions and modifications addressed below, the Department approves the Program Administrators' proposed statewide active demand reduction offerings. These active demand reduction offerings and associated demand reduction savings goals were developed through a collaborative process between the Program Administrators and the Council that culminated in the unanimous endorsement of the Council (Statewide Plan, Exh. 1, App. G). Accordingly, the Department finds that the proposed statewide active demand reduction offerings and attendant demand reduction savings goals are reasonable and consistent with the achievement of all available cost-effective demand reduction. G.L. c. 25, § 21(b)(1).

National Grid (electric) proposes a program to allow customers with electric vehicles ("EV") to pause or shift charging during system peak periods that is designed to operate like the statewide active demand initiatives (Exhs. 1, App. K (National Grid (electric)) at 2-3). In addition, NSTAR Electric proposes to undertake EV load management research and development ("R&D")[17] (Statewide Plan, Exh. 1, App. K (NSTAR Electric) at 1-2; Exhs. DPU-NSTAR Electric 5-1 through 5-5; Tr. 1, at 19-21). No party addressed these proposals on brief.

After review, the Department finds that the National Grid (electric) and NSTAR Electric active demand reduction proposals are reasonable and consistent with the statewide active demand reduction programs approved above. Therefore, we approve the National Grid (electric) and NSTAR Electric active demand reduction programs. NSTAR Electric shall identify its EV load management R&D as a separate item and include updates on its progress in EV load management R&D (including the evaluation results) in its Annual Reports and Term Report.

b. Daily Dispatch

The Department is concerned with the lack of support (e.g., research papers, analysis, pilot program results) offered by the Program Administrators for the proposed deployment of the two statewide daily dispatch offerings (i.e., residential storage performance and C&I storage performance (daily dispatch)) (see, e.g., Exhs. DPU-Electric 2-4; DPU-Electric 6-2;

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[17] The purpose of EV load management R&D is to understand how customers react to different incentive structures and EV load management strategies (Statewide Plan, Exh. 1, App. K at 1-2).

Tr. 1, at 26, 33). Although NSTAR Electric is currently testing the daily dispatch of storage through a Department-approved demonstration offering,[18] it acknowledges that the results of that demonstration offering may not inform a residential daily dispatch offering given the material differences between the two offerings (Tr. 1, at 28-32).

While the Department appreciates the desire of the electric Program Administrators to provide innovative active demand reduction offerings to their customers, we are not persuaded by the evidence presented here that a statewide deployment of an untested form of dispatch is an appropriate use of ratepayer funds. Accordingly, the Department does not approve a full-scale deployment of the proposed daily dispatch offerings (i.e., residential storage performance, and C&I storage performance (daily dispatch)).

Nonetheless, the Department finds merit in exploring the potential for daily dispatch, particularly at the residential level. Accordingly, each electric Program Administrator may use a portion of the proposed budget allocated to the daily dispatch offerings to design demonstration offerings to test the daily dispatch of storage.[19] The goal of such demonstration offerings should be to support the potential launch of wide-scale, statewide daily dispatch offerings for residential and/or C&I customers, where cost effective, later in the 2019-2021 Three-Year Plan term. In addition, the electric Program Administrators may

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[18] See NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-178, at 44 (2017).

[19] The electric Program Administrators shall coordinate with the Council and each other regarding the design of any such demonstration offerings so as not to unnecessarily duplicate research imminently undertaken by the other electric Program Administrators.

use the evaluated results of NSTAR Electric's demonstration offering, when available, in D.P.U. 16-178, to inform a proposed wide-scale C&I daily dispatch offering for deployment later in the 2019-2021 Three-Year Plan term.

Such an approach is consistent with the Program Administrators' proposal to ramp up their daily dispatch offerings over the Three-Year Plan term (see e.g., Tr. 1, at 27; Exh. Eversource Energy (electric)-5 (Rev.) (December 20, 2018)). Further, this approach appropriately considers the ability of a daily dispatch offering to deliver cost-effective benefits to customers prior to a statewide deployment. D.P.U. 16-178, at 25-26.

The Program Administrators shall update the Council on the results of any daily dispatch demonstration offerings.[20] To the extent that the Program Administrators determine that the results of any additional demonstration offerings or NSTAR Electric's demonstration offering in D.P.U. 16-178 support cost-effective statewide offerings for residential and/or C&I customers, the Program Administrators shall seek Council approval to implement such offerings. Subsequently, the Program Administrators shall submit a compliance filing to the Department describing the proposed offering(s) and budget(s). Absent approval from the Department, the total budget for such offerings (i.e., demonstration offering budget plus statewide program budget) shall not exceed the planned budget allocated to the proposed residential storage performance and C&I storage performance (daily dispatch) offerings in these proceedings.

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[20] In addition, each electric Program Administrator shall provide an update to the Department on the status of any daily dispatch demonstration offerings as part of its Annual Report.

Alternatively, the electric Program Administrators may allocate the planned budget for the daily dispatch offerings to targeted dispatch offerings for residential and C&I customers. If the Program Administrators do not use the budget allocated for the proposed daily dispatch offerings to fund either a small-scale demonstration offering to test daily dispatch or a targeted storage offering in lieu of the daily dispatch offerings, the funds may not be reallocated to any other measure.

c. Incentive Structure

The electric Program Administrators propose to offer performance-based incentives for each active demand reduction offering (see, e.g., Exh. Eversource Energy (electric)-2, at 57). The Program Administrators also seek Department approval to enter into five-year commitments to provide such incentives to customers that install new storage systems under these offerings (see, e.g., Exh. Eversource Energy (electric)-2, at 61-62).

The Department agrees with the Program Administrators' assessment that pay-for-performance incentives appropriately protect ratepayers because incentives will only be paid for actual performance (see, e.g., Exh. Eversource Energy (electric)-2, at 64). In addition, the Department finds that, in light of the significant upfront investment required for storage, a longer-term commitment to provide incentives is appropriate (see, e.g., Exh. Eversource Energy (electric)-2, at 61-62). Accordingly, the Department approves the electric Program Administrators' proposal to enter into five-year commitments to provide performance-based incentives to customers installing new storage systems. As part of the evaluation process, the electric Program Administrators shall assess the efficacy of the

five-year incentive commitment and whether, as increasing amounts of storage are deployed, a five-year commitment continues to be warranted.

Finally, the Department notes that the C&I storage performance offering has a significantly higher incentive level than the C&I interruptible load curtailment offering for the same service (see Statewide Plan, Exh. 1, at 123). Given the nascent state of energy storage deployment in the Commonwealth, the Department finds the higher incentive for the C&I storage performance offering appropriate at this time. However, as deployment of energy storage systems increases and storage costs decline, the electric Program Administrators shall review the incentive levels and adjust them accordingly to minimize bill impacts and ensure ratepayer dollars are spent prudently.

3. Evaluation, Measurement, and Verification

EM&V is the systematic collection and analysis of information to document the impact and effect of energy efficiency programs, in terms of costs and benefits, and to improve their effectiveness. 2016-2018 Three-Year Plans Order, at 30; 2013-2015 Three-Year Plans Order, at 58; 2010-2012 Electric Three-Year Energy Efficiency Plans, D.P.U. 09-116 through D.P.U. 09-120, at 125 (2010) ("2010-2012 Electric Three-Year Plans Order"); 2010-2012 Gas Three-Year Energy Efficiency Plans, D.P.U. 09-121 through D.P.U. 09-128, at 115 (2010) ("2010-2012 Gas Three-Year Plans Order"). The Department's Guidelines require each Three-Year Plan to include an evaluation plan that describes how the Program Administrator will evaluate the energy efficiency programs during the term. Guidelines § 3.5.2; see also, G.L. c. 25, § 21(b)(2).

The Program Administrators propose a budget of $71.9 million to fund statewide EM&V activities during the Three-Year Plan term (Statewide Plan, App. C - Electric (Rev.) (December 20, 2018) at 12; App. C - Gas (Rev.) (December 20, 2018) at 7; App. S at 4). The Program Administrators' proposed EM&V framework includes the following elements: (1) three EM&V research areas (i.e., residential, C&I, and special and cross-cutting); and (2) eight types of EM&V studies (i.e., impact evaluations, baseline studies, net-to-gross studies, market effects evaluations, NEI studies, cost and measure life studies, market characterization studies, and process evaluations) (Statewide Plan, App. C - Electric (Rev.) (December 20, 2018) at 12; App. C - Gas (Rev.) (December 20, 2018) at 7; App. S at 4). The Program Administrators have created a strategic evaluation plan to identify evaluation priorities for the upcoming term and the Evaluation Management Committee will provide oversight of the EM&V activities (Statewide Plan, App. C - Electric (Rev.) (December 20, 2018) at 12; App. C - Gas (Rev.) (December 20, 2018) at 7; App. S at 4).

The Program Administrators have demonstrated that their proposed EM&V framework is appropriate in terms of funding, scope, oversight and planning (Statewide Plan, Exh. 1, at 174-178; App. C (Rev.) (December 20, 2018); App. S). Accordingly, the Department finds that the proposed EM&V framework is consistent with the Green Communities Act, Department precedent, and Guidelines. G.L. c. 25, § 21(b)(2); Guidelines § 3.5. Further, because the Program Administrators have shown that EM&V efforts often apply to multiple programs, the Department approves the Program Administrators' proposal

to allocate EM&V costs to a single line item under the hard-to-measure category (Statewide Plan, Exh. 1, at 134-135; App. C (Rev.) (December 20, 2018)).

4. Future Potential Studies

In 2016-2018 Three-Year Plans Order, at 25, the Department directed the Program Administrators to conduct an analysis of the remaining cost-effective energy efficiency potential in their service territories every three years. Each Program Administrator conducted an energy efficiency potential study consistent with the Department's directives.

Acadia and CLF assert that inconsistent study methods and formatting of the potential studies hindered stakeholders' ability to provide input during the planning process for the Three-Year Plans (Acadia Brief at 24; CLF Brief at 39). To address this issue, CLF argues that future potential studies should be centralized and overseen by a third-party (CLF Brief at 42). Alternatively, CLF and Acadia recommend that future potential studies (1) use consistent methods, definitions, and formatting, and (2) be completed on a set deadline (Acadia Brief at 24-25; CLF Brief at 39-42).

In response, the Program Administrators maintain that uniformity in potential studies would dilute the value of the studies for each individual Program Administrator (Program Administrators Reply Brief at 15-16). The Program Administrators maintain, however, that it would be possible to conduct potential studies in a manner that allows for individualized analyses of each service territory while presenting the findings in a uniform manner using common definitions (Program Administrators Reply Brief at 18, citing Tr. 1, at 87).

The Department appreciates the efforts of each Program Administrator to complete its potential study in compliance with Department directives. We agree, however, that the current approach to conducting potential studies can be refined. Each Program Administrator has a unique service territory with different customer characteristics and economic landscapes that require individualized potential studies in order to evaluate the remaining energy efficiency potential in the face of unique challenges (Statewide Plan, Exh. 1, at 147-148; Tr. 1, at 88-90). Although we will not require third-party oversight as recommended by CLF, the individualized potential studies should demonstrate consistency among the Program Administrators in terms of timing, formatting, and definitions to enhance their value to the Department and stakeholders.

For all future potential studies, the Program Administrators shall (1) coordinate studies to present findings using common definitions for the various levels of achievable potential, such that the study results are comparable, and (2) with input from the Council, establish a common study deadline to submit final potential study results. Finally, as part of its next three-year plan filing, each Program Administrator shall include detailed testimony and exhibits addressing how the findings of its potential study were used to inform the development of its savings goal during the energy efficiency planning process.

5. Strategic Enhancements and New Technologies

As part of their Three-Year Plans, the Program Administrators propose to implement a number of strategic enhancements to each core initiative aimed at new technologies

(Statewide Plan, Exh. 1, at 29-31).[21] In addition, the Three-Year Plans include several enhancements designed to address residential sector barriers, including (1) an enhanced home weatherization program; (2) special attention to moderate-income customers, renters, and customers with language barriers; (3) updated residential and new home offerings, including a passive house offering; (4) a new municipal and community partnership strategy; and (5) a temperature optimization program (Statewide Plan, Exh. 1, at 33-37, 55, 42-43, 69-70; Exhs. DPU-Comm 6-1; DPU-Comm 6-2).

The Three-Year Plans also include several enhancements designed to address C&I sector barriers, including (1) an enhanced new construction and major renovations initiative, (2) an enhanced building retrofit program with a focus on HVAC optimization and small business engagement, (3) educational offerings for additional outreach to municipalities, and (4) customized services for franchise businesses (Statewide Plan, Exh. 1, at 82, 91-99, 104-105, 107). Finally, as addressed above, NSTAR Electric and National Grid (electric) have each proposed to implement demand response demonstration offerings to evaluate the opportunities, benefits, and cost effectiveness of demand response potential in their service areas[22] (Statewide Plan, Exh. 1, App. K).

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[21] In coordination with LEAN and the Massachusetts Technical Assessment Committee, the Program Administrators state that they will continue to assess new technologies in order to ensure that only proven technologies are offered through the energy efficiency programs (Statewide Plan, Exh. 1, at 73).

[22] The Compact's proposed demand response demonstration offering is addressed in Section VIII, below.

CLF argues that the gas Program Administrators have offered insufficient evidence to support their decision not to include gas demand response offerings in their Three-Year Plans (CLF Brief at 47). In response, the gas Program Administrators argue that, based on the results of pilot programs in other states, an analysis of gas demand response (either as part of the potential studies or as a demonstration offering) would not be cost effective (Program Administrators Reply Brief at 11-12; Exhs. DPU-Gas 1-1; DPU-Gas 2-1, DPU Gas 2-2; Tr. 1, at 95-96).

The Department finds that the gas Program Administrators have submitted adequate evidence to support their decision not to offer a full-scale demand response program at this time (Exhs. DPU-Gas 1-1; DPU-Gas 2-1, DPU-Gas 2-2; Tr. 1, at 95-96). We find, however, that the Program Administrators have not convincingly shown that further exploration into potential savings from gas demand response is unsuitable. We note that the Program Administrators testified that they foresee no specific obstacles to further study of gas demand response and would consider conducting such analysis as part of future potential studies (Tr. 1, at 96-97). Accordingly, the Department directs the gas Program Administrators to continue to review the potential for cost-effective savings from gas demand response offerings. As part of its next three-year plan filing, each gas Program Administrator shall include detailed testimony and exhibits addressing such study and the feasibility of gas demand response offerings.

In consideration of our findings with respect to participation barriers in Section III.D.6 below, the Department finds that the Three-Year Plans appropriately incorporate

strategic enhancements (1) aimed at new technologies, and (2) designed to address participation barriers in order to ensure that the Three-Year Plans will provide for the acquisition of all available cost-effective energy efficiency and demand reduction resources. G.L. c. 25, §§ 19(a), 19(b), 21(b)(1).

6. Participation Barriers

As described in Section III.B above, the Three-Year Plans include several proposed enhancements designed to address both residential and C&I sector barriers. The Program Administrators maintain that these proposals are based on the experience they have gained from past efforts to better serve hard-to-reach customers, including renters, moderate income customers, non-English speaking customers, and non-profits (Program Administrators Reply Brief at 7-9, citing Statewide Plan, Exh. 1, at 28, 35-37, 52, 56, 95-102, 116).

In addition to offering several recommended improvements, CLF argues that the Program Administrators should be required to provide more information about the proposed residential enhancements (CLF Brief at 20-32). With respect to the C&I enhancements, PowerOptions recommends that the Program Administrators should be required to develop marketing strategies and partnerships within the non-profit community (PowerOptions Brief at 4, 6-7). In response, the Program Administrators assert that the Statewide Plan is not an implementation manual, but rather a strategic plan that provides them with the flexibility to respond to changing circumstances and input from stakeholders (Program Administrators Reply Brief at 9, citing Statewide Plan, Exh. 1, at 12).

One important way that the Program Administrators propose to improve community-wide engagement and gain better insights into underserved customers is through their new municipal and community partnership strategy (Statewide Plan, Exh. 1, at 35-36). This residential enhancement is intended to build stronger relationships with local governments in order to leverage their valuable knowledge and connections, facilitate outreach and awareness, and obtain feedback on strategies to reach underserved populations (Statewide Plan, Exh. 1, at 35-36). The Department notes that the municipal and community partnership strategy was under development when the Three-Year Plan was filed; the Program Administrators state that it will not be fully implemented until the third or fourth quarter 2019 (Exh. DPU-Comm 6-1). The Department encourages the Program Administrators to work with CLF and other stakeholders to incorporate their input as the municipal community partnership strategy is finalized and deployed. Likewise, the Department encourages the Program Administrators to work with PowerOptions to determine if improved marketing strategies will better reach the non-profit community.

As part of its 2019 Annual Report, each Program Administrator shall include an update on the implementation of the various enhancements designed to address residential and C&I sector barriers, including the municipal and community partnership strategy. Finally, with regard to CLF's specific recommendations regarding pre-weatherization barriers, the Department notes that the Program Administrators have identified pre-weatherization costs as a barrier and have proposed to mitigate this barrier through the customization of in-home assessments and expanding the allowable financing for pre-weatherization costs (Statewide

Plan, Exh. 1, at 34, 48, 53-55, 131-132). The Department encourages the Program Administrators, in the development of their next three-year plans, to continue to explore innovative strategies to address pre-weatherization barriers for customers, including moderate-income households.

E. Conclusion

For the reasons discussed above, the Department finds that the gas and electric savings goals are reasonable and consistent with the achievement of all available cost-effective energy efficiency. With the exception of the statewide deployment of daily dispatch (i.e., residential storage performance offering, and the C&I storage performance offering (daily dispatch)), the Department approves each electric Program Administrator's[23] proposed statewide active demand reduction offerings as consistent with the achievement of all available cost-effective demand reduction. The Program Administrators shall comply with the directives contained herein regarding the alternate use of the funds allocated to the proposed daily dispatch storage performance offerings.

Further, the Department finds that the Program Administrators have appropriately incorporated strategic enhancements to the residential and C&I programs that are designed to incorporate new technologies and address various barriers to participation in energy efficiency programs. Over this and future three-year plans terms, the Department encourages the Program Administrators to continue to explore and implement strategies to better reach

[23] Prior to implementing any statewide active demand reduction offerings, the Compact must comply with all directives contained in Section VIII, below.

underserved populations and hard-to-reach customers, including renters, moderate income customers, non-English speaking customers, and non-profits.

IV. ADMINISTRATIVE COSTS, COMPETITIVE PROCUREMENT, AND LOW-INCOME ALLOCATION

A. Introduction

In reviewing the Three-Year Plans, the Department is charged with ensuring that the Program Administrators have (1) minimized administrative costs to the fullest extent practicable and (2) used competitive procurement processes to the fullest extent practicable. G.L. c. 25, §§ 19(a), (b); Guidelines §§ 3.3.6, 3.3.7. In addition, each Program Administrator must demonstrate that it has allocated at least ten percent of the funds for electric energy efficiency programs and 20 percent of the funds for gas energy efficiency programs to the low-income sector. G.L. c. 25, § 19(c).

B. Program Administrators Proposal

1. Minimization of Administrative Costs

The electric Program Administrators propose to spend an average of 4.4 percent of their total energy efficiency expenditures on Program Planning and Administration ("PP&A") over the three-year term (Statewide Plan, Exh. 1, App. C - Electric, Table IV.C.1 (Rev.) (December 20, 2018)). The gas Program Administrators propose to spend an average of 4.0 percent of their total energy efficiency expenditures on PP&A over the three-year term (Statewide Plan, Exh. 1, App. C – Gas, Table IV.C.1 (Rev.) (December 20, 2018)). Each Program Administrator's PP&A costs as a percentage of total program expenditures for

2019 through 2021 are presented in the Gas and Electric Budget Comparison Tables (see, e.g., Statewide Plan, Exh. FGE-4, Table IV.C.2.2 (Rev.) (December 20, 2018)).

2. Competitive Procurement

The Program Administrators use competitive procurement processes to engage energy efficiency contractors and vendors to perform activities including, but not limited to, audit delivery, quality control, monitoring and evaluation, marketing, and website design (Statewide Plan, Exh. 1, at 158). The Program Administrators state that, where practicable, over the term of the Three-Year Plans, they intend to continue to issue requests for proposals to competitively procure these services in a manner that minimizes costs to ratepayers, while maximizing the associated benefits of those investments (Statewide Plan, Exh. 1, at 158). The Program Administrators do not, however, use competitive procurement to engage certain energy efficiency service providers (e.g., legal services) (Exh. DPU-Comm 8-1).

3. Low-Income Program Budgets

Each Program Administrator included a table in its Three-Year Plan showing the percentage of its energy efficiency program budget that it projects to spend on low-income programs (see, e.g., Exh. 1, App. C, Table V.B (Rev.) (December 20, 2018)). The electric Program Administrators project that they will spend, on average, 11.39 percent of the total energy efficiency program budget on low-income residential demand-side management and education programs over the three-year term (Statewide Plan, Exh. 1, App. C - Electric, Table V.B (Rev.) (December 20, 2018)). The gas Program Administrators project that they will spend, on average, 21.83 percent of the total energy efficiency program budget on

low-income residential demand-side management and education programs over the three-year term (Statewide Plan, Exh. 1, App. C - Gas, Table V.B (Rev.) (December 20, 2018)). In addition, for each plan year, each Program Administrator projects that it will meet or exceed the applicable statutory minimum on low-income spending (Statewide Plan, Exh. 1, at 157-158).

C. Position of the Program Administrators

1. Minimization of Administrative Costs

The Program Administrators argue that they have minimized administrative costs to the fullest extent practicable (Program Administrators Brief at 38-39, citing Statewide Plan, Exh. 1, at 155-157). In particular, the Program Administrators assert that they engage in a statewide collaborative process that allows them to share costs that would otherwise be borne by each Program Administrator, resulting in economies of scale that reduce costs for each Program Administrator (Program Administrators Brief at 39, citing Statewide Plan, Exh. 1, at 156). In addition, the Program Administrators argue that they carefully track administrative costs and that administrative costs as a proportion of overall spending are projected to remain proportional to the levels of administrative costs in the last two three-year plans (Program Administrators Brief at 41, citing Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018), Table IV.C.2.2).

The Program Administrators maintain that, consistent with the Department's directives in 2016-2018 Three-Year Plans Order, at 42, they have engaged a third-party vendor to prepare a report on the best practices for minimizing administrative costs (Program

Administrators Brief at 40, citing Statewide Plan, Exh. 1, App. P (Best Practices for Minimizing Program Planning and Administrative Costs for the Massachusetts Utilities and Energy Efficiency Services Providers ("PP&A Report")). According to the Program Administrators, the PP&A Report contains the following recommendations: (1) Program Administrators should focus on ways to improve consistency in accounting practices; (2) Program Administrators should seek to streamline the cost reporting and data request processes; (3) Program Administrators should follow cost accounting best practices in allocation, tracking, and control; (4) Program Administrators should seek new ways to minimize the regulatory, collaboration, facilitation, reporting, and ad hoc request burdens without compromising goal attainment; and (5) Program Administrators should implement an annual process to stress-test status quo processes and spending (Program Administrators Brief at 40). The Program Administrators assert that they will use these recommendations during the Three-Year Plan term to assist in their efforts to minimize administrative costs to the greatest extent practicable without negatively affecting program delivery (Program Administrators Brief at 38, citing Statewide Plan, Exh. 1, at 40-41).

2. Competitive Procurement

The Program Administrators argue that they use competitive procurement processes to the fullest extent practicable (Program Administrators Brief at 42-43, citing Statewide Plan, Exh. 1, at 158). Specifically, the Program Administrators maintain that they have competitively procured the following services: (1) energy assessment delivery; (2) quality

control; (3) monitoring and evaluation; (4) potential studies; and (5) marketing (Program Administrators Brief at 42, citing Statewide Plan, Exh. 1, at 158).

The Program Administrators assert, however, that there are certain instances where competitive procurement is not warranted (Program Administrators Brief at 42). For example, with respect to regulatory and legal services, analytical consultants, and certain other experts and service providers, Program Administrators argue that they must retain providers who are uniquely qualified to perform the services (Program Administrators Brief at 42). Further, the Program Administrators contend that there are instances where they have a substantial working relationship with a specific provider who has extensive knowledge of the Program Administrator's operations such that overall costs are minimized (Program Administrators Brief at 42-43).

3. Low-Income Program Budgets

The Program Administrators assert that they have appropriately allocated funding to low-income programs in compliance with G.L. c. 25, § 19(c) (Program Administrators Brief at 41-42, citing Statewide Plan, Exh. 1, at 157-158). In this regard, the Program Administrators maintain that the electric Program Administrators propose to allocate approximately 11.4 percent of the total budget for the three-year term to the low-income residential sector (Program Administrators Brief at 41, citing Statewide Plan, Exh. 1, at 157; App. C - Electric (Rev.), Table V.B.1). Similarly, the Program Administrators maintain that the gas Program Administrators propose to allocate approximately 21.8 percent of the total budget for the three-year term to the low-income residential sector (Program Administrators

Brief at 41, citing Statewide Plan, Exh. 1, at 158; App. C - Gas, Table V.B.1 (Rev.) (December 20, 2018).

In addition, the Program Administrators argue each of their proposed low-income program budget over the Three-Year Plan term either meets or exceeds statutory minimums (Program Administrators Brief at 41). The Program Administrators assert that they will continue to work collaboratively with LEAN to capture all-available cost-effective energy efficiency in the low-income sector (Program Administrators Brief at 41, citing Statewide Plan, Exh. 1, at 32).

D. Analysis and Findings

1. Minimization of Administrative Costs

Consistent with Department Guidelines § 3.3.6, each Program Administrator has included in its Three-Year Plan a description and supporting documentation of the steps it has taken to minimize administrative costs (Statewide Plan, Exh. 1, at 156). As shown in the data tables (i.e., Budget Comparison Table-Three Year Plan vs. Previous Years, Section IV.C - Program Administrator Budgets), each Program Administrator's PP&A costs remain relatively flat as a percentage of its total budget over the 2019-2021 Three-Year Plan term (see, e.g., Exh. FGE-4, Table IV.C.2.2 (Rev.) (December 20, 2018)). In addition, total PP&A costs, as a percentage of the statewide budget, remain proportional to the administrative costs for the prior three-year plan term (Statewide Plan, Exh. 1, App. C, Table IV.C.2.2 (Rev.) (December 20, 2018)).

The Program Administrators have shown that statewide collaboration in program planning, implementation, and evaluation contributes to economies of scale that reduce costs for each Program Administrator (Statewide Plan, Exh. 1, at 156). The Department fully expects that this collaboration will continue throughout the 2019 through 2021 Three-Year Plan term.

In response to concerns about the overall level of PP&A spending, the Department directed the Program Administrators to engage a consultant to study best practices to minimize such costs. 2016-2018 Three-Year Plans Order, at 42. Consistent with that directive, the Program Administrators recently completed a report that contains several recommendations for minimizing administrative costs (Statewide Plan, Exh. 1, App. P at 18-21). As part of its 2019 Annual Report, each Program Administrator shall explain how it has adopted these recommendations to further minimize administrative costs to the fullest extent practicable.

Based on a review of planned program costs, the Department finds that the Program Administrators have appropriately balanced the requirement to minimize PP&A costs with the need to maximize program quality and oversight (see, e.g., Exh. FGE-4, Table IV.C.2.2, Table IV.C.-3 (Rev.) (December 20, 2018)). Accordingly, the Department finds that each Program Administrator's Three-Year Plan is designed to minimize administrative costs to the fullest extent practicable consistent with the requirements of G.L. c. 25, §§ 19(a), (b).

2. Competitive Procurement

As noted above, each Program Administrator is required to demonstrate that it has used competitive procurement processes to the fullest extent practicable. G.L. c. 25, §§ 19(a), (b). The Department has consistently found that competitive procurement serves as a means of cost containment and provides an essential, objective benchmark for the reasonableness of the cost of services. 2013-2015 Three-Year Plans Order, at 152. In addition, competitive procurement keeps a consultant or an attorney with an established relationship with a company from taking that relationship for granted. 2013-2015 Three-Year Plans Order, at 152, citing Bay State Gas Company, D.P.U. 12-25, at 186 (2012); Fitchburg Gas and Electric Light Company, D.P.U. 11-01/11-02, at 236 (2011); New England Gas Company, D.P.U. 10-114, at 221 (2011).

For the 2019 through 2021 Three-Year Plans, each Program Administrator has competitively procured a high percentage of its program activities (see, e.g., Exh. FGE-4, Table V.D (Rev.) (December 20, 2018)). Where such procurements were used, the Program Administrators have demonstrated that they were done in a manner designed to minimize costs to ratepayers (e.g., through the use of statewide solicitations and collaboration in the procurement of services) (Statewide Plan, Exh. 1, at 158).

There are a limited number of areas where the Program Administrators have decided not to use competitive procurements to engage third-party energy efficiency services, including legal services (Exh. DPU-Comm 8-1). The Program Administrators maintain that their decision not to competitively procure such services is appropriate for several reasons,

including the complexity of issues and specialized knowledge required to address them (Exh. DPU-Comm 8-1). The Department will not make any substantive findings on the reasonableness of the Program Administrators' decision not to competitively procure such services in this Order. Instead, at the time final cost recovery is sought, each Program Administrator will be required to present clear evidence showing the reasonableness of such costs.

This last issue notwithstanding, based on our review of the evidence presented, the Department finds that each Program Administrator's 2019 through 2021 Three-Year Plan is designed to use competitive procurement processes to the fullest extent practicable, consistent with the requirements of G.L. c. 25, §§ 19(a), (b) (see e.g., Exh. FGE-4, Table V.D.1 (Rev) (December 20, 2018)).

3. Low-Income Program Budgets

As shown in the Low-Income Minimum Data Tables, Section V.B - Allocation of Funds, each Program Administrator proposes a low-income program budget that meets or exceeds the statutory minimum over the three-year planning period (see, e.g., Exh. FGE-4, Table V.B (Rev.) (December 20, 2018)). Accordingly, the Department finds that each Program Administrator has satisfied the low-income budget requirements of G.L. c. 25, § 19(c).

E. Conclusion

Based on our review, the Department concludes that each Program Administrator's 2019 through 2021 Three-Year Plan is designed to minimize administrative costs and use

competitive procurement processes to the fullest extent practicable, in compliance with G.L. c. 25, §§ 19(a), (b) and Guidelines §§ 3.3.6, 3.3.7. In each area where a Program Administrator has not competitively procured outside services, it will be required to present clear evidence demonstrating that such costs are reasonable prior to final cost recovery. In addition, the Department finds that each electric and gas Program Administrator has proposed to spend at least ten percent and 20 percent of its energy efficiency program budget over the three-year planning period, respectively, on low-income demand-side management and education programs, in compliance with G.L. c 25, § 19(c).

V. COST EFFECTIVENESS

A. Introduction

The Department is required to review the Three-Year Plans for cost effectiveness. G.L. c. 25, § 21(b)(3). This review ensures that the Three-Year Plans are designed to capture energy savings and other benefits with values greater than costs. G.L. c. 25, § 21(b)(3). Under the Green Communities Act, as amended by the Energy Act of 2018, for the purpose of cost-effectiveness review, programs are aggregated by sector.[24] G.L. c. 25, § 21(b)(3). When screening for cost effectiveness, the Program Administrators may include, as benefits, certain avoided costs of complying with reasonably foreseeable environmental

[24] The Department also requires the Program Administrators to report cost effectiveness at the program and core initiative level. 2013-2015 Three-Year Plans Order, at 105; 2019-2021 Three-Year Energy Efficiency Plans, D.P.U. 18-110 through D.P.U. 18-119, Hearing Officer Procedural Memorandum at 2 n.1 (October 3, 2018).

laws and regulations. D.P.U. 08-50-A at 2, 14-16; Massachusetts Electric Company v. Department of Public Utilities, 419 Mass. 239, at 241, 246 (1994); Guidelines § 3.4.4.1(a(v).

B. Program Administrators Proposal

1. Cost-Effectiveness Screening

The Program Administrators have screened each sector, program, and core initiative for cost effectiveness using the Total Resource Cost ("TRC") test (Statewide Plan, Exh. 1, at 166). The Program Administrators state that the Statewide Plan and the Program Administrator-specific Three-Year Plans include cost-effective sectors and programs for each plan year and over the entire 2019-2021 Three-Year Plan term (Statewide Plan, Exh. 1, at 166; see, e.g., Exh. LU-4 (Rev.) (December 20, 2018), Table IV.D.1).

2. Avoided Cost of Greenhouse Gas Emissions

The Program Administrators propose to include the avoided costs of complying with environmental laws and regulations as benefits under the TRC test (Statewide Plan, Exh. 1, at 171). To this end, the Program Administrators presented three methods of calculating the avoided cost of greenhouse gas ("GHG") emissions. Two methods are described in the Avoided Energy Supply Components in New England: 2018 Report ("AESC Study"), which evaluates the total environmental cost of GHG emissions and then subtracts the embedded cost of GHG emissions to arrive at the non-embedded cost of GHG emissions (Statewide Plan, Exh. 1, App. H at 157). The AESC Study developed one approach based on global marginal abatement costs and a second approach based on regional (i.e., New England) marginal abatement costs (Statewide Plan, Exh. 1, App. H at 157).

The third calculation method is described in the Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act ("Supplemental Study") prepared outside of the AESC stakeholder process at the request of DOER as a supplement to the AESC Study (Statewide Plan, Exh. 1, App. I at 3). The Supplemental Study considers seven potential strategies to comply with the Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"), evaluates the all-in cost of GWSA compliance, and then subtracts the embedded cost of GHG emissions to arrive at the incremental avoided cost of GWSA compliance (Statewide Plan, Exh. 1, at 171, App. I at 7-9).

When screening for cost effectiveness, the Program Administrators applied the results from the Supplemental Study to include the incremental avoided costs of GWSA compliance as a benefit in the TRC test (Statewide Plan, Exh. 1, at 171). The Program Administrators also provided benefit calculations both with and without the Supplemental Study results in order to demonstrate the impact of the Supplemental Study on cost effectiveness (Statewide Plan, Exh. 1, at 171, App. C).

C. Positions of the Parties

1. Program Administrators

The Program Administrators assert that, consistent with Department requirements, they evaluated the expected benefits and costs associated with the Statewide Plan using the TRC test (Program Administrators Brief at 30, citing Statewide Plan, Exh. 1, at 252; see, e.g., Exhs. LU-4 (Rev.) (December 20, 2018), LU-5 (Rev.) (December 20, 2018); see Guidelines § 3.4; 2013-2015 Three-Year Plans Order, at 105-108; D.P.U. 08-50-A).

Further, the Program Administrators argue that they appropriately applied all cost-effectiveness screening requirements in developing the Statewide Plan (Program Administrators Brief at 29). The Program Administrators maintain that the Statewide Plan shows strong overall statewide cost effectiveness, with a three-year portfolio level benefit-cost ratio ("BCR") of 2.35 for electric Program Administrators and 1.91 for gas Program Administrators (Program Administrators Brief at 29).

The Program Administrators assert that, under the Department's Guidelines, they may include certain avoided costs of complying with environmental laws and regulations as benefits under the TRC test (Program Administrators Brief at 31). The Program Administrators maintain, however, that such avoided costs must be from reasonably foreseeable laws, regulations, or policies that will result in a cost included in electric or gas prices (Program Administrators Brief at 31, citing 419 Mass. 239; D.P.U. 08-50-A at 2). The Program Administrators maintain that they included the avoided cost values identified in the Supplemental Study as benefits in the TRC test (Program Administrators Brief at 31, citing Statewide Plan, Exh. 1, at 171). The Program Administrators assert that the Supplemental Study correctly assumes a counterfactual case that presumes no incremental energy efficiency in 2018 and beyond, and relies on the costs and emissions-reducing potential of seven compliance strategies that were identified as currently being deployed in Massachusetts under existing laws or regulations, or pursuant to the Clean Energy and Climate Plan for 2020 (Program Administrators Brief at 31-32, citing Statewide Plan, Exh. 1, App. I at 4).

The Program Administrators contend that, consistent with the Green Communities Act, all sectors are projected to be cost effective over the 2019-2021 Three-Year Plan term (Program Administrators Brief at 32). In addition, the Program Administrators assert that each Program Administrator's programs and core initiatives are cost effective as planned (Program Administrators Brief at 32). The Program Administrators acknowledge that, for some Program Administrators, certain core initiatives during a particular program year are not cost effective as planned if the Supplemental Study benefits are removed; however, each program is projected to be cost effective without the Supplemental Study benefits over the entire 2019-2021 Three-Year Plan term (Program Administrators Brief at 32-33, citing Exhs. CMA-4, Table IV.D.1; DPU-Columbia 1-3).

The Program Administrators reject arguments made by CLF and NEEC[25] that they have failed to fully incorporate the changes made by the Energy Act of 2018 related to sector cost effectiveness in their Three-Year Plans (Program Administrators Reply Brief at 2-3). The Program Administrators argue that CLF and NEEC have advanced interpretations of the Green Communities Act that are counter to the plain language of the statute and contrary to the overall statutory scheme (Program Administrators Reply Brief at 4, citing CLF Brief at 9; Exh. NEEC-Comm 2-3). Instead, the Program Administrators argue that their Three-Year Plans are appropriately designed to provide all cost-effective energy efficiency and demand

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[25] NEEC did not file a brief in this proceeding, but the Program Administrators claim that NEEC advanced interpretations of the Green Communities Act in its pre-hearing statement and information requests (Program Administrators Reply Brief at 4, citing NEEC Pre-hearing Statement at 2; Exhs. NEEC-Comm 1-1 through NEEC-Comm 1-6; NEEC-Comm 2-1 through NEEC-Comm 2-3).

reductions and be complementary to other renewable energy programs (e.g., the Solar Massachusetts Renewable Target ("SMART") program) (Program Administrators Reply Brief at 4-5, citing An Act Relative to Solar Energy, St. 2016, c. 75). The Program Administrators argue that interpreting the Green Communities Act in the manner suggested by CLF and NEEC would divert efforts away from their statutory mandate to pursue all cost-effective energy efficiency (Program Administrators Reply Brief at 4-5).

2. Attorney General

The Attorney General maintains that the recent amendments to the Green Communities Act addressing energy efficiency were intended to broaden the scope and focus of energy efficiency measures to expressly include considerations of the environmental impacts associated with energy use (Attorney General Brief at 7-8). In this regard, the Attorney General observes that the amendments to the Green Communities Act establish the goal of including measures that are "designed to result in cost-effective reductions in [GHG] emissions" (Attorney General Brief at 8, quoting Energy Act of 2018 at § 2). The Attorney General asserts that, while the amendments push energy efficiency planning, the Three-Year Plans remain subject to existing checks and restraints in the Green Communities Act on overall funding, cost effectiveness, and ratepayer bill impacts, each of which were not affected by the Energy Act of 2018 (Attorney General Brief at 8-9).

3. Department of Energy Resources

DOER observes that the Department uses the TRC test to evaluate the cost effectiveness of energy efficiency programs and that the Energy Act of 2018 changed the

standard for the review of cost effectiveness to consider an aggregate of programs at the sector level (DOER Brief at 2, 9-10). DOER asserts that because the TRC test includes the avoided cost of energy supply as one of the most significant program benefits, application of this test satisfies the Green Communities Act's requirement that energy efficiency programs be less expensive than supply (DOER Brief at 2).

DOER argues that the Supplemental Study provides a more thorough assessment than the AESC Study of the costs that will be avoided through the implementation of energy efficiency measures (DOER Brief at 10). In particular, DOER asserts that the Supplemental Study captures the costs of fulfilling the Commonwealth's statutory obligations under the GWSA while also incorporating the policies adopted in the Clean Energy and Climate Plan for 2020 (DOER Brief at 12). Accordingly, DOER argues that the Department should approve the Program Administrators' inclusion of the results of the Supplemental Study in the calculations of avoided costs for the purpose of assessing the cost effectiveness of the Three-Year Plans (DOER Brief at 12).

4. Acadia Center

Acadia argues that the Department should approve the Statewide Plan because the proposed programs are projected to be cost effective over the 2019-2021 Three-Year Plan term (Acadia Brief at 7). Acadia argues that the Supplemental Study appropriately accounts for GWSA compliance costs and, therefore, Acadia favors inclusion of the Supplemental Study results in assessing cost effectiveness (Acadia Brief at 7-9, 22). Acadia maintains that, even excluding the Supplemental Study results, the aggregate BCR is projected to be 2.09 for

the electric Program Administrators and 1.74 for the gas Program Administrators (Acadia Brief at 7-9).

Alternately, Acadia asserts that the AESC Study fails to include the full avoided costs of compliance with the GWSA (Acadia Brief at 21-22). Acadia asserts that, without energy efficiency to achieve GWSA compliance, the Commonwealth must rely on other emissions reduction techniques (Acadia Brief at 23). Acadia argues that these other emissions reduction techniques are reasonably foreseeable environmental compliance costs, which are correctly included in the Supplemental Study (Acadia Brief at 23).

5. Conservation Law Foundation

CLF contends that the Program Administrators made no program changes as a result of the provisions of the Energy Act of 2018 related to sector cost effectiveness (CLF Brief at 13-14). Therefore, CLF argues that the Department should require the Program Administrators to amend their Three-Year Plans to fully implement the changes to the Green Communities Act (CLF Brief at 13-14).

In addition, CLF argues that advances in GWSA implementation require the Program Administrators to incorporate additional avoided GWSA compliance costs in their cost-effectiveness testing (CLF Brief at 37). In this regard, CLF argues that the Department should accept the Supplemental Study because it calculates these additional avoided costs, is based on the method used in the AESC Study, and was completed by the consultant that produced the AESC Study (CLF Brief at 37-38). Finally, CLF maintains that future AESC

studies should include a Massachusetts-specific avoided cost of GWSA compliance (CLF Brief at 38).

D. Analysis and Findings

1. Introduction

The Department is required to review all energy efficiency programs contained in the Three-Year Plans for cost effectiveness. G.L. c. 25, § 21(b)(3). This review ensures that programs are designed to capture energy savings and other benefits with values greater than costs. G.L. c. 25, § 21(b)(3). Under the Green Communities Act, as amended by the Energy Act of 2018, for the purpose of cost-effectiveness review, programs are aggregated by sector. G.L. c. 25, § 21(b)(3). Any sector with a BCR greater than 1.0 (indicating benefits are greater than costs) shall be considered cost effective. G.L. c. 25, § 21(b)(3). If a sector fails the cost-effectiveness test as part of the review process, its component programs shall either be modified so that the sector meets the test or be terminated. G.L. c. 25, § 21(b)(3).

The Guidelines establish the method by which the Department determines cost effectiveness. Guidelines § 3.4. The Department evaluates cost effectiveness using the TRC test, which includes all benefits and costs associated with the energy system and program participants. Guidelines § 3.4.3. A program, or sector, is cost effective if the cumulative present value of its benefits is equal to or greater than the cumulative present value of its costs.[26,27] Guidelines § 3.4.3.1.

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[26] Benefits and costs are addressed in Guidelines §§ 3.4.4 and 3.4.5, respectively.

2. Cost-Effectiveness Screening

The Department finds that, based on projected benefits and costs, exclusive of the avoided cost of GHG emissions, all proposed energy efficiency sectors and programs are projected to be cost effective each year and over the term of the Three-Year Plans[28] (Exhs. CMA-4 (Rev.) (December 20, 2018); NG-Gas-4 (Rev.) (December 20, 2018); FGE-Gas-4 (Rev.) (December 20, 2018); LU-4 (Rev.) (December 20, 2018); Eversource Energy (gas)-4 (Rev.) (December 20, 2018); Berkshire-4 (Rev.) (December 20, 2018); Compact-4 (Rev.) (December 20, 2018); FGE-Electric-4 (Rev.) (December 20, 2018); NG-Electric-4 (Rev.) (December 20, 2018); Eversource Energy (electric)-4 (Rev.) (December 20, 2018)). The Department addresses avoided cost benefits from the Supplemental Study and the AESC Study below.

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27 The Program Administrators may classify certain programs as core initiatives and then consolidate them into larger program offerings. 2013-2015 Three-Year Plans Order, at 105. The Department found that such reclassification is appropriate as it provides Program Administrators with needed flexibility in program implementation and reduces customer confusion regarding product offerings. 2013-2015 Three-Year Plans Order, at 105. To the extent that any core initiatives within programs are not projected to be cost effective over the plan term, the Program Administrator must demonstrate in its Term Report how it plans to achieve cost-effective core initiatives going forward. 2016-2018 Three-Year Plans Order, at 77.

28 Certain core initiatives for Columbia Gas, Unitil (gas), Unitil (electric), and the Compact are not projected to be cost effective during certain program years when the benefits from the Supplemental Study are removed (see, e.g., Exhs. CMA-4 (Rev.) (December 20, 2018); DPU-Columbia 1-3). However, as described above, each program and sector is projected to be cost effective without the Supplemental Study benefits over the entire 2019-2021 Three-Year Plan term.

3. Avoided Cost of Greenhouse Gas Emissions

a. Introduction

The Department has recognized the importance of including the avoided cost of GHG emissions in a cost-benefit analysis of energy efficiency programs. D.P.U. 08-50-A at 17. However, in order for the Department to rely on these benefits when assessing cost effectiveness, the method of calculating avoided costs must be robust and properly supported.[29] D.P.U. 08-50-A at 16; D.P.U. 11-120-A, Phase II at 18. The Department appreciates DOER's efforts commissioning the Supplemental Study (Statewide Plan, Exh. 1, at 171). However, the Department has identified several issues with respect to the method and modeling used to calculate the avoided cost of GWSA compliance in the Supplemental Study.[30] These issues do not affect our findings above that the Three-Year Plans are cost effective, because the Program Administrators have demonstrated that, even absent the results of the Supplemental Study, all programs and sectors are projected to be cost effective over the Three-Year Plan term. The Department expects, however, that each of these issues will be addressed in all future studies of the avoided cost of GHG emissions.

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[29] The Program Administrators must support the avoided cost value with evidence and must adequately explain how the value was derived. D.P.U. 11-120-A, Phase II at 18, citing Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 240-241 (2002).

[30] The same consultant completed both the AESC Study and the Supplemental Study; however, contrary to CLF's assertions, the Supplemental Study uses a different method than the AESC Study (CLF Brief at 37-38; Statewide Plan, Exh. 1, Apps. H at 33, 76-84; I at 7-12; Tr. 2 at 189-190, 213-214).

b. Supplemental Study

The Department has identified multiple issues with the Supplemental Study. First, the modeling in the Supplemental Study is not consistent with the study's assumptions. In particular, the Supplemental Study states that it is based on the assumption of a counter-factual scenario of no incremental energy efficiency where additional GHG emissions reduction measures need to be implemented in order to comply with the GWSA (Statewide Plan, Exh. 1, App. I at 4). However, the Supplemental Study does not estimate the amount of additional GHG emissions reductions that are needed if there were no incremental energy efficiency (Exh. DPU-Comm 3-3, Att.; Tr. 2, at 195-197). Further, the Supplemental Study does not estimate the amount of expansion needed for each GHG emissions reduction strategy if there were no incremental energy efficiency (Exh. DPU-Comm 3-3, Att.; Tr. 2, at 197). Therefore, although we find that the overall assumption of a counter-factual scenario of no incremental energy efficiency is reasonable, the GWSA modeling in the Supplemental Study is not consistent with this assumption.

Second, the Supplemental Study takes a conflicting view of the regional (i.e., New England) approach versus the Massachusetts-specific approach. In particular, the Supplemental Study provides that, because the AESC Study was developed on behalf of stakeholders throughout the New England region, a Massachusetts-specific carbon value needs to be developed for the proposed Three-Year Plans (Tr. 2, at 189-190). However, in the GWSA model, the Supplemental Study uses the renewable energy generation potential of all six states in the New England region to account for compliance with the GWSA

(Exh. DPU-Comm 3-3, Att.; Tr. 2, at 198-199). Essentially, the Supplemental Study proposes to apply the GHG emissions reduction potential of the entire New England region to Massachusetts' GWSA compliance, including the strategies that reduce emissions in the other New England states (Exh. DPU-Comm 3-3, Att.; Tr. 2, at 198-199). As a result, the Department is concerned that the Supplemental Study will likely lead to double counting of GHG emissions reduction between Massachusetts and the other New England states because there is no guarantee that all of the renewable energy generation in the other New England states will be available for GWSA compliance[31] (Exh. DPU-Comm 3-3, Att.; Tr. 2, at 197-198).

Third, the Supplemental Study presents unreasonable and conflicting assumptions on how the avoided cost is calculated for the light duty vehicle electrification strategy. While light duty vehicle electrification requires the purchase of EVs, the Supplemental Study does not include the costs of EV purchase and, instead, only includes the cost of EV charging infrastructure (Exh. DPU-Comm 3-3, Att.; Tr. 2, at 190-192). In calculating the cost of EV charging infrastructure, the Supplemental Study consultant testified that the study includes only "costs that are likely to be incurred by the electric distribution companies and, therefore, avoidable by energy efficiency" (Tr. 2, at 192). However, the Supplemental Study consultant also testified that the EV charging infrastructure costs included in the study are public charging stations that will not necessarily be built by the electric distribution

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[31] The Supplemental Study consultant testified that "each one of these strategies lives within a set of. . . regulations and legislation. So it's not just within GWSA" (Tr. 2, at 198).

companies, but "could be built by anyone" (Tr. 2, at 193-194). These conflicting assumptions call into question the reliability of the calculation of the avoided cost for the light duty vehicle electrification strategy as presented in the Supplemental Study.

Fourth, several mistakes and inconsistencies in the Supplemental Study reduce its credibility. These mistakes and inconsistencies include errors in column titles in a few important tables and charts, errant references to key variables in the GWSA model, and data errors on several variables in the GWSA model (Exh. DPU-Comm 3-3, Att.; Tr. 2, at 170-171, 177-180; Statewide Plan, Exh. 1, Apps. H at 367; I at 10). Further, in forecasting the offshore wind price, the Supplemental Study takes a Section 83C[32] long-term contract price in 2017 and applies it through 2030, without addressing the fact that any subsequent offshore wind procurement under Section 83C would need to be at a lower price than the previous procurement (Exh. DPU-Comm 3-3, Att.; Tr. 2, at 201-202). See 220 CMR 23.04(5).

For the reasons identified above, the Department has concerns regarding the Supplemental Study. More specifically, the Department does not have sufficient confidence in the method and modeling used in the Supplemental Study to rely on it in evaluating the cost effectiveness of the proposed Three-Year Plans.

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[32] Section 83C of the Green Communities Act, as amended by An Act to Promote Energy Diversity, St. 2016, c. 188, allows the distribution companies to conduct one or more competitive offshore wind solicitations through a staggered procurement schedule occurring within 24 months of the previous solicitation.

c. Avoided Energy Supply Components

As described above, the AESC Study includes the following two approaches to estimating the total environmental cost of GHG emissions: (1) a global marginal abatement cost estimate; and (2) a New England marginal abatement cost estimate (Statewide Plan, Exh. 1, App. H at 157). The global marginal abatement cost estimate is identical to the prior 2015 AESC study value, at $100 per short ton of CO_2-equivalent. The New England marginal abatement cost estimate is based on a projection of future costs of offshore wind energy, at $68 per short ton of CO_2-equivalent (Statewide Plan, Exh. 1, App. H at 157). The New England marginal abatement cost estimate was conducted at the request of the AESC study group, in order to identify a carbon value that is more relevant than the global value to Massachusetts and other New England states (Statewide Plan, Exh. 1, App. H at 159; Tr. 2, at 184).

The total environmental cost of GHG emissions includes both embedded and non-embedded costs, so the non-embedded cost of GHG emissions is derived by subtracting the embedded cost of GHG emissions from either of the two marginal abatement cost estimate values above (Statewide Plan, Exh. 1, App. H at 157-158). For Massachusetts, the embedded cost of GHG emissions is comprised of (1) compliance costs associated with RGGI and (2) two DEP regulations, 310 CMR 7.74 (Reducing CO_2 Emissions from Electricity Generating Facilities) and 310 CMR 7.75 (Clean Energy Standard) (Statewide Plan, Exh. 1, App. H at 157, 367, Table 137).

For the reasons discussed below, the Department finds that the New England marginal abatement cost estimate contained in the AESC Study is appropriate to use to derive the non-embedded cost of GHG emissions that should be applied to assess the cost effectiveness of the proposed Three-Year Plans. First, the environmental cost of GHG emissions, as part of the AESC Study, was developed through stakeholder consensus. The AESC study group that oversaw the design and production of the AESC Study is composed of Program Administrators, state agencies, consumer advocacy organizations, and environmental advocacy organizations (Statewide Plan, Exh. 1, App. H at 20). Consistent with the previous 2013 and 2015 AESC studies, the AESC study group and its consultant used the marginal abatement cost method (instead of the environmental damage cost or externality method) to estimate the total environmental cost of GHG emissions (Statewide Plan, Exh. 1, App. H at 157-158). Given the challenges involved in estimating the environmental costs of GHG emissions, the Department prefers a valuation process that is consensus-based and vetted by multiple stakeholders from various perspectives.

Second, the New England marginal abatement cost method complies with Guidelines § 3.4.3.1. The Program Administrators include reasonably foreseeable environmental compliance costs in evaluating energy resources. See D.P.U. 08-50-A at 15-17. The New England marginal abatement cost method included in the AESC Study is not based on environmental damage costs or externalities. Rather, it is based on the costs of an abatement technology that is generally considered to be appropriate for New England and for

Massachusetts, in particular, to estimate the reasonably foreseeable environmental compliance costs[33] (Statewide Plan, Exh. 1, App. H at 159-160).

Finally, it is clear that energy efficiency alone is not able to bring Massachusetts into full compliance with the GWSA (Statewide Plan, Exh. 1, App. I at 4). For this reason, energy efficiency is only one of many strategies that the Commonwealth needs to deploy to meet the GWSA's targets (Statewide Plan, Exh. 1, at 171-173). Therefore, what the New England marginal abatement cost method accomplishes in the instant dockets is to estimate, on a per short ton basis, a localized and reasonable cost value of reducing GHG emissions. This value can be used to arrive at the non-embedded cost of GHG emissions that the Program Administrators can claim as one of the benefits of the proposed energy efficiency programs, within the context of contributing to GWSA compliance. The per-short-ton avoided cost can be applied to each proposed energy efficiency program based on the savings they are projected to achieve and based on the GHG emission rates of fuels relevant to each proposed energy efficiency program (Statewide Plan, Exh. 1, App. I at 25-26; Tr. 2, at 184-189).

In conclusion, the Department determines that we have sufficient evidence to rely on the New England marginal abatement cost estimate in the AESC Study as the basis to derive

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[33] In particular, the Energy Act of 2018 requires the procurement of 1,600 MW of offshore wind by June 2027, and authorizes another 1,600 MW of offshore wind procurement by December 2035. See 220 CMR 23.00. The AESC Study estimates the costs of the marginal abatement technology based on offshore wind projects that have already been constructed in Maryland and Europe, or are under contract in Massachusetts pursuant to Section 83C (Statewide Plan, Exh. 1, App. H at 159-160).

the non-embedded cost of GHG emissions to include in the cost-benefit analysis of the proposed Three-Year Plans. The Department found above that all programs and sectors are cost effective without the non-embedded cost of GHG emissions. Adding these additional benefits as measured by the AESC Study, all programs and sectors remain cost effective (Statewide Plan, Exh. 1, at 166; see e.g., Exh. CMA-4, Table IV.D.1 (Rev.) (December 20, 2018)). The Program Administrators shall continue to evaluate the total environmental cost of GHG emissions, including both the embedded and non-embedded costs, within all future AESC studies that are overseen by the AESC study group.

To ensure that all planned data reflect this avoided cost, within 21 days of the date of this Order, the Program Administrators shall submit updated data tables, as well as updated BCR and performance incentive models that include the non-embedded cost of GHG emissions derived from the New England marginal abatement cost of $68 per short ton CO_2-equivalent contained in the AESC Study (Statewide Plan, Exh. 1, App. H, app. K). As part of this filing, the Program Administrators shall show (1) how the non-embedded cost of GHG emissions is derived from the New England marginal abatement cost of $68 per short ton CO_2-equivalent and (2) how the non-embedded cost of GHG emissions is applied in the BCR models for electricity, natural gas, and other fuels based on their respective GHG emission rates.

4. Green Communities Act Amendments

As described above, the Green Communities Act, as amended by the Energy Act of 2018, now allows programs to be aggregated by sector for purpose of cost-effectiveness

review. G.L. c. 25, § 21(b)(3). CLF contends that the Program Administrators made no program changes as a result of this recent shift to sector cost effectiveness and, therefore, recommends that the Department require the Program Administrators to amend their Three-Year Plans in a subsequent proceeding to fully implement these changes (CLF Brief at 13-14). CLF's view is not shared by the Program Administrators or other parties to these proceedings, including the Attorney General and DOER (Program Administrators Reply Brief at 2-5; Attorney General Brief at 7-10; DOER Brief at 8-10, 13-16).

Contrary to CLF's assertions, the Department finds that the Three-Year Plans appropriately incorporate the changes made by the Energy Act of 2018 to the Green Communities Act (Statewide Plan, Exh. 1, at 27-135). The Three-Year Plans include a range of new approaches and strategies that were enabled by the Energy Act of 2018, including strategic electrification, support for customers seeking to switch to renewable energy and clean energy technologies, and measures that are designed to demonstrate benefits (1) through verified energy and demand reduction savings or (2) that will be tested through a demonstration effort (Statewide Plan, Exh. 1, at 18, 59, 69, 110, 129; Exhs. DPU-Comm 1-7; DPU-Comm 2-5; DPU-Comm 5-8; NEEC-Comm 2-1(b); NEEC-Comm 2-2). Further, consistent with the energy efficiency planning process, the Program Administrators and the Council will continue to regularly evaluate energy efficiency opportunities and, where appropriate, propose changes in the future to incorporate additional measures or other adjustments (Exhs. NEEC-Comm 1-3; NEEC-Comm 2-3).

As the Attorney General correctly notes, while the recent amendments to the Green Communities Act expand the scope and flexibility of energy efficiency planning, the Three-Year Plans must continue to comply with ratepayer protections in the Green Communities Act regarding cost effectiveness, funding, and bill impacts (Attorney General Brief at 8-9). G.L. c. 25, §§ 19-21. Each of these essential ratepayer protections was not affected by the Energy Act of 2018.

In particular, the Energy Act of 2018 did not impact the statutory requirement that the Department consider "the effect of any rate increases on residential and commercial customers" in evaluating other funding sources for energy efficiency programs or the statutory mandate that "[t]o mitigate capacity and energy costs for all customers, the [D]epartment shall ensure that . . . resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, §§ 19(a)(3)(i), 21(a). Following the amendments, the Green Communities Act continues to require "the lowest reasonable customer contribution" in acquiring all cost-effective energy efficiency and demand reduction resources, and though it now includes active demand management technologies and strategic electrification as possible efficiency and load management programs, the Legislature tempers the expected expansion of electricity consumption with the need to "minimiz[e] ratepayer costs." G.L. c. 25, § 21(b)(1), (2)(iv)(A).

In considering cost effectiveness at the aggregated sector level, it is possible that measures could be installed that have, for example, an in-service rate of zero percent,

bringing no benefits to ratepayers or the Commonwealth, yet the BCRs for all sectors would remain above 1.0 (RR-Acadia-Compact-1). In effectuating requirements of the Green Communities Act, the Department must continue to ensure that the use of ratepayer dollars to fund energy efficiency programs and measures is justified by the benefits achieved. There is nothing to suggest that, in amending the Green Communities Act, the Legislature intended that ratepayer dollars could be spent frivolously, particularly where the overall purpose in pursuing energy efficiency measures remains the achievement of all cost-effective energy efficiency while minimizing ratepayer costs.[34] G.L. c. 25, § 21(a), (b)(1), (b)(2)(iv)(A).

In the pursuit of all cost-effective energy efficiency, the Program Administrators must balance the additional flexibility in program design and implementation afforded by the Energy Act of 2018, with the prudent spending of ratepayer funds. In doing so, the Program Administrators must consider cost efficiency, as well as cost effectiveness. The Department addresses the use of performance incentives to address cost efficiency in Section VI below. Further, as discussed in Section VII.D.5 below, the Department has found that the Program

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[34] The Legislature's intent must be ascertained from all of the Green Communities Act's words, as amended, "construed by the ordinary and approved usage of the language" and "considered in connection with the cause of its enactment, the mischief or imperfection to be remedied and the main object to be accomplished." Harvard Crimson, Inc. v. President & Fellows of Harvard College, 445 Mass. 745, 749 (2006). Plain and unambiguous statutory language is "conclusive as to legislative intent," but we will not adopt a literal construction where the consequences would be "absurd or unreasonable" and could not be what the Legislature intended. Sharris v. Commonwealth, 480 Mass. 586, 594 (2018) (quoting Attorney General v. School Committee of Essex, 387 Mass. 326, 336 (1982)).

Administrators have appropriately considered bill impacts when developing their proposed Three-Year Plans (Statewide Plan, Exh. 1, at 145, 150-151, 187).

Finally, the Department requires the Program Administrators to continue to report cost-effectiveness at the program and core initiative level, in addition to the sector level. 2013-2015 Three-Year Plans Order, at 105; 2019-2021 Three-Year Energy Efficiency Plans, D.P.U. 18-110 through D.P.U. 18-119, Hearing Officer Procedural Memorandum at 2 n.1 (October 3, 2018). Where a core initiative or a program is not projected to be cost-effective, the Program Administrators should be prepared to demonstrate, in their Annual Reports and Term Reports, how they intend to achieve cost-effective programs and core initiatives going forward.

5. Benefit-Cost Ratio Model

To facilitate our cost-effectiveness review, the Department has directed the Program Administrators to include all formulas, linkages, and pivot tables in the data tables when filed. 2013-2015 Three-Year Plans Order, at 160. In their initial Three-Year Plan filings, the Program Administrators did not provide documentation showing how the BCR model outputs were linked to the data table inputs (see, e.g., Exhs. CMA-4 (Rev.) (December 20, 2018); CMA-5 (Rev.) (December 20, 2018)). In response to discovery, the Program Administrators subsequently provided a sufficient explanation of the relationship between the BCR models and the data tables, as well as a detailed list of all calculated fields used in creating the pivot tables (Exhs. DPU-Comm 12-2; DPU-Comm 12-3).

In order to enable the Department to verify the data tables and otherwise effectively review the Three-Year Plans within the 90-day statutory time limit prescribed by G.L. c. 25, § 21(d)(2), it is imperative for the Program Administrators to improve the transparency of the supporting data tables. Therefore, as part of their initial filings in future three-year plan proceedings, the Program Administrators shall provide (1) an explanation of all linkages between the BCR models and the data tables and (2) a detailed list of calculated fields and all other interim steps and data sets used in creating the pivot tables in a format consistent with Exhibits DPU-Comm 12-2 and DPU-Comm 12-3.

6. Conclusion

After review, the Department finds that each Program Administrator has demonstrated that, exclusive of the avoided costs of GHG emissions, its Three-Year Plan includes cost-effective sectors and programs for each plan year and over the entire 2019-2021 Three-Year Plan term. In addition, the Department finds that all programs and sectors remain cost-effective for each plan year and over the entire 2019-2021 Three-Year Plan term when the non-embedded cost of GHG emissions, as derived in the AESC Study, is included in the cost-benefit analysis.

Finally, as discussed above, the Department finds that the Three-Year Plans appropriately incorporate the changes made by the Energy Act of 2018 to the Green Communities Act with regard to the captured energy savings and other benefits that have values greater than costs. In particular, we find that the Three-Year Plans appropriately reflect the recent amendments to the Green Communities Act, expanding the scope and

flexibility of energy efficiency planning, while continuing to comply with ratepayer protections in the Green Communities Act regarding cost effectiveness, funding, and bill impacts.

VI. PERFORMANCE INCENTIVES

A. Introduction

The Green Communities Act provides that the Three-Year Plans shall include a proposed mechanism that provides incentives to the Program Administrators based on their success in meeting or exceeding the plan goals. G.L. c. 25, § 21(b)(2). Section 3.6.2 of the Department's Guidelines outlines principles for the design of a performance incentive mechanism. Pursuant to the Guidelines, an incentive mechanism must achieve the following: (1) be designed to encourage Program Administrators to pursue all available cost-effective energy efficiency; (2) be designed to encourage energy efficiency programs that will best achieve the Commonwealth's energy goals; (3) be based on clearly defined goals and activities that can be sufficiently monitored, quantified, and verified after the fact; (4) be available only for activities in which the Program Administrator plays a distinct and clear role in bringing about the desired outcome; (5) be as consistent as possible across all electric and gas Program Administrators; and (6) avoid any perverse incentives. Guidelines § 3.6.2. Further, the Guidelines specify that the amount of funds available for performance incentives should be kept as low as possible in order to minimize the costs to electricity and gas customers, while still providing appropriate incentives for the Program Administrators. Guidelines §§ 3.6.2, 3.6.3.

B. Program Administrators Proposal

1. Performance Incentive Mechanism

The Program Administrators[35] propose to implement a performance incentive mechanism for each year of the Three-Year Plan term (Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). The Program Administrators propose a statewide incentive pool equal to $116.7 million for electric Program Administrators, and $23.5 million for gas Program Administrators (Statewide Plan, Exh. 1, at 160).

The Program Administrators state that the proposed incentive mechanism is based on the performance incentive model approved by the Department for the 2016 through 2018 three-year plans (see Statewide Plan, Exh. 1, at 159). However, for the 2019-2021 Three-Year Plan term, the Program Administrators propose to (1) add performance incentive components related to renters and active demand reduction, and (2) change how the value component is calculated (Statewide Plan, Exh. 1, at 159, 162).

The structure of the proposed incentive mechanism includes the following: (1) a value component; (2) a savings component; and (3) a renter component (Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). For electric Program Administrators, the savings component[36] includes the following two subparts: (1) an energy efficiency and

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35 The Compact does not receive a performance incentive. D.P.U. 08-50-A at 51. Accordingly, all references to "Program Administrators" in this section do not include the Compact.

36 The Program Administrators traditionally achieve incentives through the savings component based on total benefits achieved (Statewide Plan, Exh. 1, at 162)

passive demand component; and (2) an active demand reduction savings component (Statewide Plan, Exh. 1, at 159). The total performance incentive is the sum of the value, savings, and renter components (Statewide Plan, Exh. 1, at 160).

The Program Administrators propose to collect performance incentive dollars through each component at a predetermined payout rate when their evaluated performance falls between the threshold and exemplary levels (Statewide Plan, Exh. 1, at 162). The threshold and exemplary levels are calculated based on the design level performance, which is defined as 100 percent of a Program Administrator's projected benefits and net benefits (Statewide Plan, Exh. 1, at 158 n.38, 162). Exemplary performance is defined as 125 percent of design-level performance, while threshold performance requires the achievement of 75 percent of design-level performance, by component (Statewide Plan, Exh. 1, at 162). The cap for the total possible performance incentive earned across all components is 125 percent of design-level performance (Statewide Plan, Exh. 1, at 162). The proposed payout rates for both the savings and value components remain constant for all Program Administrators for each year of the Three-Year Plan term (Statewide Plan, Exh. 1, App. R).

The Program Administrators propose to allocate the statewide incentive pool for the savings and value components using common payout rates, based on the dollar value of benefits and net benefits, respectively (Statewide Plan, Exh. 1, at 162). At a statewide level, 61.5 percent of the incentive has been allocated to the savings component and 38.5 percent of the incentive has been allocated to the value component (Statewide Plan, Exh. 1, at 160-161). The incentive payments that a Program Administrator can receive through the savings and

value components are based on total benefits and net benefits, respectively, achieved through the implementation of a Program Administrator's energy efficiency programs (Statewide Plan, Exh. 1, at 159).

Currently, Program Administrators are required to collect performance incentives at the design level during the term, and they must reconcile actual performance incentives following approval of their Three-Year Term Reports (Statewide Plan, Exh. 1, at 166). Guidelines § 3.6.4.2. The Program Administrators propose to modify this schedule so that the Program Administrators would initially reconcile their actual earned performance incentives with the projected design-level incentives in the Energy Efficiency Surcharge ("EES") filing following the filing of the Term Reports (rather than in the EES filing following the Department's approval of the Term Reports) (Statewide Plan, Exhs. 1, at 160, 166; DPU-Comm 7-1).

2. Renter Component

The Program Administrators propose to allocate one million dollars for gas and two million dollars for electric from the statewide incentive pool to a new renter[37] component of the performance incentive mechanism (Statewide Plan, Exh. 1, at 164; Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). The Program Administrators state that the

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[37] Renter participants, under the renter component, include any rental dwelling unit that benefits from a measure in the Residential Coordinated Delivery, Income-Eligible Coordinated Delivery, or C&I Existing Buildings (Residential End Use) initiatives and any rental unit that receives a customized energy savings package through the Residential Retail initiative (Statewide Plan, Exh. 1, at 164-165; Exhs. DPU-Comm 1-9; DPU-Comm 1-10).

purpose of the renter component is to achieve greater success in targeting renters with energy efficiency efforts (Exh. DPU-Comm 1-13). Under the proposal, the Program Administrators would receive approximately $20 per renter served (Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). The payout rate per renter does not change if the Program Administrator does not meet the threshold level for the renter component (Exh. DPU-Comm 1-6).

In addition, the Program Administrators state that the purpose of the renter component is to assist in the tracking and reporting of the number of renter participants[38] (Exh. DPU-Comm 1-10). The Program Administrators state that the tracking and reporting of renters will provide insight into how these customers access energy efficiency initiatives from the perspective of both program implementation and EM&V (Exh. DPU-Comm 1-10).

3. Active Demand Reduction Savings Component

As described in Section III above, the electric Program Administrators propose several new statewide active demand reduction offerings (Statewide Plan, Exh. 1, at 162). At the recommendation of the Council, the Program Administrators have proposed to implement a specialized incentive mechanism designed to provide additional incentives for successfully achieving benefits associated with the statewide active demand reduction efforts (Statewide Plan, Exh. 1, at 163).

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[38] The Program Administrators state that they have not previously tracked whether a customer was a renter of a unit or building (Exhs. DPU-Comm 1-4; DPU-Comm 1-10).

The proposed active demand reduction savings component of the performance incentive mechanism consists of two payout rates (Statewide Plan, Exh. 1, App. F at 5). The Program Administrators propose to establish the initial payout rate based on performance incentive dollars per planned total benefits from active demand reduction using the five million dollar pool allocated to the active demand reduction savings component (Statewide Plan, Exh. 1, App. F at 5). The active demand reduction savings component payout rate will be determined by dividing the five million dollars allocated for the targeted active demand payout rate by planned total benefits from active demand (Statewide Plan, Exh. 1, at 163).[39]

4. Value Component

The Program Administrators have previously calculated the value component using net benefits (i.e., the difference between total benefits and total resource costs). See 2016-2018 Three-Year Plans Order, at 57 n.28. For the 2019-2021 Three-Year Plans, the Program Administrators propose to use actual spending, as opposed to total resource costs, to calculate the performance incentives associated with the value component (Statewide Plan, Exh. 1, at 162). Statewide incentives for the value component will be allocated on the basis of the dollar value of net benefits using common payout rates for the incentive pool for both gas and electric (Statewide Plan, Exh. 1, at 162; Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). Finally, the common payout rate will be determined by dividing the

[39] The targeted active demand reduction savings payout rate will not apply to gas Program Administrators (Exh. DPU-Comm 1-1).

value component performance incentive pools by statewide planned portfolio benefits[40] (Statewide Plan, Exh. 1, at 162; Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)).

C. Positions of the Parties

1. Program Administrators

The Program Administrators assert that the proposed performance incentive mechanism, including the (1) active demand reduction savings component, (2) renter component, (3) calculation of net benefits in the value component, and (4) proposed change in reconciliation timing, is consistent with the Department's standards for the design of performance incentives and, therefore, should be approved (Program Administrators Brief at 57). In addition, the Program Administrators argue that the proposed performance incentive mechanism, incentive pool, and payout rates are consistent with the Green Communities Act and Department precedent (Program Administrators Brief at 53, citing 2013-2015 Three-Year Plans Order, at 98).

The Program Administrators maintain that, for electric Program Administrators, the proposed savings component includes (1) an energy efficiency and passive demand reduction component and (2) an active demand reduction component (Program Administrators Brief at 53). The Program Administrators argue that the renter, savings, and value components are

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[40] The Program Administrators propose that the threshold for earning performance incentives for the value component will be based on achieving 75 percent of planned portfolio net benefits, capped at 125 percent of design level (Statewide Plan, Exh. 1, at 162).

designed to work in conjunction with each other to encourage the pursuit of all cost-effective energy efficiency and demand reduction opportunities (Program Administrators Brief at 53, citing Exh. DPU-Comm 10-6).

Finally, the Program Administrators assert that adoption of the renter component will allow them to more accurately capture the number of renters served during the 2019-2021 Three-Year Plan term (Program Administrators Brief at 55). The Program Administrators maintain that the Council unanimously supported the proposed renter component (Program Administrators Brief at 55-56, citing Statewide Plan, Exh. 1, at 164; Exh. DPU-Comm 1-10; Tr. 2, at 243).

2. Attorney General

The Attorney General asserts that the proposed renter component of the performance incentive mechanism is necessary to both encourage and document Program Administrator success in meeting the challenges surrounding the delivery of energy efficiency to renters (Attorney General Brief at 14). The Attorney General argues that the structure of the proposed renter component will provide a sufficient incentive for the Program Administrators to deliver such services (Attorney General Brief at 13). The Attorney General maintains that adoption of the renter component represents progress toward ensuring equity in the funding and distribution of the energy efficiency program benefits and, therefore, she encourages the Department to approve the proposed renter component of the performance incentive mechanism (Attorney General Reply Brief at 2-3).

3. Department of Energy Resources

DOER supports Department approval of the proposed renter and active demand reduction savings components of the performance incentive mechanism (DOER Brief at 16). DOER maintains that the renter component will provide an appropriate incentive for Program Administrators to improve their engagement with renters and facilitate the tracking of the number of renters participating in the Residential Coordinated Delivery, Income-Eligible Coordinated Delivery, and C&I Existing Buildings (Residential End Use) initiatives (DOER Brief at 18). DOER asserts that the Program Administrators will not earn an incentive in the renter component without first addressing the existing barriers for renter participation (DOER Brief at 18-19).

In addition, DOER argues that the active demand reduction savings component is specifically tailored to ensure that the Program Administrators achieve benefits associated with statewide active demand reduction efforts (DOER Brief at 17). DOER argues that because the Program Administrators will receive a payout for every dollar of benefits achieved once active demand reduction threshold benefits are met, the Program Administrators will receive an incentive to fully invest in these programs (DOER Brief at 17-18).

DOER asserts that the two other proposed changes to the performance incentive mechanism (i.e., value component and timing of reconciliation) were not discussed with the Council or negotiated as part of the Term Sheet (DOER Reply Brief at 8). While DOER does not express an opinion as to the timing of reconciliation of performance incentives,

DOER maintains that it does not currently support the Program Administrators' proposed change to the value component of the performance incentive mechanism (DOER Reply Brief at 8-9). In particular, DOER argues that it is concerned that by changing the calculation from using total resource costs to using Program Administrator-specific costs, the value component will no longer measure the total net benefits to customers as the customer contribution is removed from the calculation (DOER Reply Brief at 8). DOER claims that this change could result in the Program Administrators favoring measures that require lower Program Administrator-specific investment rather than measures that have the higher net benefit to customers (DOER Reply Brief at 8).

4. Acadia Center

Acadia encourages the Department to approve the proposed renter and active demand reduction performance incentive components (Acadia Brief at 21). Acadia argues that these proposed incentive components do not suffer from any of the design defects that the Department found to be disqualifying in prior three-year plan filings (Acadia Brief at 17-18). In particular, Acadia argues that the proposed components are (1) specific to each Program Administrator, (2) easily numerically verified, (3) not sector specific, and (4) designed to provide incentives for activities that potentially use more energy (active demand management) or have not been adequately addressed by the Program Administrators (serving renters at parity with owners) (Acadia Brief at 17).

Acadia argues that the proposed renter component is an innovative approach to reward Program Administrators for facilitating an improved understanding of renter participation

(Acadia Brief at 19-20). Acadia maintains that the proposed renter component will appropriately focus the Program Administrators' attention on addressing renter participation issues (Acadia Brief at 19-20). Finally, although Acadia recognizes that the savings component already encourages Program Administrators to pursue all cost-effective energy efficiency and demand reduction, it asserts that a targeted incentive for active demand management is needed to encourage Program Administrators to pursue these activities (Acadia Brief at 21).

5. Conservation Law Foundation

CLF generally supports the proposed renter and active demand reduction components of the Program Administrators' performance incentive mechanism (CLF Brief at 30, 47).

6. Low-Income Energy Affordability Network

LEAN argues that low-income tenants and households are already well served by the Program Administrators and, therefore, the proposed renter component is not effectively designed (LEAN Brief at 7-8). LEAN contends that, in the case of the gas incentive, normal low-income tenant participation all but guarantees the total tenant goal will be reached (LEAN Brief at 7). As to the electric incentive, LEAN asserts that if there is a shortfall in achieving the renter performance metric as the Three-Year Plan term is coming to a close, the structure of the proposed incentive may encourage over-delivery of proven low-income programs, distorting other low-income objectives and accomplishing little for non-low-income tenants (LEAN Brief at 7-8).

7. PowerOptions

PowerOptions maintains that it generally supports the active demand response and renter components of the proposed performance incentive mechanism (PowerOptions Brief at 3, 10). PowerOptions argues, however, that the renter component unnecessarily excludes C&I renters, such as non-profits, that do not provide a residential end use (PowerOptions Brief at 12).

D. Analysis and Findings

1. Introduction

The Green Communities Act provides that the Three-Year Plans shall include a proposed incentive mechanism. G.L. c. 25, § 21(b)(2). As described above, the Program Administrators have proposed an incentive mechanism that is largely based on the performance incentive model approved by the Department for the 2016 through 2018 three-year plan term (Statewide Plan, Exh. 1, at 159). For the 2019-2021 Three-Year Plan term, however, the Program Administrators propose to (1) add performance incentive components related to renters and active demand reduction and (2) change to how the value component is calculated (Statewide Plan, Exh. 1, at 159, 162). The Program Administrators also propose to alter the timing of the reconciliation of the performance incentives at the end of the Three-Year Plan term (Statewide Plan, Exh. 1, at 160, 166).

2. Performance Incentive Mechanism

a. Statewide Incentive Pool

The electric Program Administrators propose a statewide performance incentive pool of approximately $116.7 million for 3,308,544,000 kWh of total electric savings, or

approximately $0.035 per kWh of savings (Statewide Plan, Exh. 1, App. C - Electric (Rev.) (December 20, 2018)). The gas Program Administrators propose a statewide performance incentive pool of approximately $23.5 million for 96,462,193 therms of total gas savings, or approximately $0.24 per therm of savings (Statewide Plan, Exh. 1, App. C – Gas (Rev.) (December 20, 2018)). The proposed statewide incentive pool is reflected in the Term Sheet (Statewide Plan, Exh. 1, App. F).

As part of the last three-year plans, the Department approved a statewide incentive pool equal to approximately 5.5 percent of the electric Program Administrators' budgets for each year, before taxes, and approximately 2.8 percent of the gas Program Administrators' budgets each year, before taxes. 2016-2018 Three-Year Plans Order, at 66. In the instant Three-Year Plans, the proposed statewide incentive pool is approximately six percent of the electric Program Administrators' budgets for each year, before taxes, and approximately three percent of the gas Program Administrators' budgets for each year, before taxes (Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)).

The Department finds that the proposed statewide incentive pool, as a percentage of Program Administrators' budgets, is consistent with the statewide incentive pool in previous three-year plans (Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). 2016-2018 Three-Year Plans Order, at 66. This is the case even though the Program Administrators have proposed to include an additional savings component to the performance incentive mechanism (Statewide Plan, Exh. 1, at 162). After review, subject to the treatment of the renter component addressed in Section VI.D.2.d below, the Department finds that the

funds available for performance incentives have been kept as low as possible, while still providing appropriate incentives for the Program Administrators (see Statewide Plan, Exh. 1, App. R (Rev.) (December 20, 2018)). Guidelines §§ 3.6.2, 3.6.3.

b. Timing of Reconciliation

The Program Administrators are permitted to include design-level performance incentives as part of the budgets for the applicable plan year, which are collected through the EES (Statewide Plan, Exh. 1, at 166, citing Guidelines § 3.6.4.2). Currently, the Program Administrators reconcile their actual earned performance incentives with the projected design-level incentives only after the Department has verified savings and incentive achievement as part of its approval of the Term Reports (Statewide Plan, Exh. 1, at 166, citing Guidelines § 3.6.4.2; Exh. DPU-Comm 7-1). The Program Administrators propose to modify this schedule so that they will initially reconcile their actual earned performance incentives with the projected design level incentives in the EES filing following the filing of the Term Reports (rather than in the EES filing following the Department's approval of the Term Reports) (Statewide Plan, Exh. 1, at 160, 166; Exh. DPU-Comm 7-1). In a subsequent EES filing, the Program Administrators would reconcile any differences between the actual performance incentives reported in the Term Reports and the actual performance incentives approved by the Department in the Term Reports (Statewide Plan, Exh. 1, at 166).

The Department finds that the Program Administrators' proposal to reconcile actual earned performance incentives with design-level performance incentives in the EES filing following the filing of the Term Reports is reasonable as it will minimize the level of interest

costs while not increasing any administrative or regulatory burdens (Statewide Plan, Exh. 1, at 160, 166; Exhs. DPU-Comm 7-1; DPU-Comm 7-2). Accordingly, the Department approves the Program Administrators' proposal.

c. Savings and Value Components

The Program Administrators propose to allocate the statewide incentive pool to each component of the performance incentive mechanism as follows: (1) 61.5 percent to the savings component and (2) 38.5 percent to the value component (Statewide Plan, Exh. 1, App. R (Rev.) (December 20, 2018)). The Program Administrators' proposed incentive mechanism also includes the application of uniform statewide payout rates for the savings and value components (see Statewide Plan, Exh. 1, at 159). The incentive payments that the Program Administrators propose to receive through the savings and value components are based on total benefits and the difference between total benefits and actual spending, respectively, achieved through the implementation of a Program Administrator's energy efficiency programs (Statewide Plan, Exh. 1, at 159).

In previous three-year plans, the value component was calculated using net benefits (i.e., the difference between total benefits and total resource costs). See 2016-2018 Three-Year Plans Order, at 57 n.28. The total resource costs used in this calculation were comprised of program implementation costs[41] and participant costs (Exh. DPU-Comm 12-3). For the 2019-2021 Three-Year Plans, the Program Administrators

[41] For the purposes of net benefits calculations, performance incentives were not included (see Statewide Plan, Exh. 1, at 159 n.39).

propose to use actual spending, as opposed to total resource costs, to calculate the performance incentive associated with the value component (Statewide Plan, Exh. 1, at 162).

In the benefit-cost screening model, the total resource cost of measures is fixed[42] (e.g., the actual cost of a light bulb does not change due to the participant incentive or the customer contribution) (see, e.g., Exh. CMA-5). Therefore, under the current method of calculating the value component, total resource costs remain the same no matter what the split is between participant incentive and customer contribution. Under the Program Administrators' proposal, the value component calculation will no longer represent net benefits but instead, total benefits minus implementation costs (Statewide Plan, Exhs. 1 at 162; App. R (Rev.) (December 20, 2018); see, e.g., Exh. CMA-4 (Rev.) (December 20, 2018)). Absent customer contributions, performance incentives will be based on implementation costs. For this reason, DOER maintains that a revised calculation of the value component could result in Program Administrators favoring measures that require lower Program Administrator-specific investment rather than measures that have a higher net benefit to customers (DOER Reply Brief at 8). We disagree.

The Program Administrators have shown that they continuously review the measures in their programs to achieve the right level of participant incentives (Exh. DPU-Comm 4-9). For example, the Program Administrators revised their weatherization incentives in 2017, as increased savings per insulation job and increased levels of customer participation were

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[42] If participant incentives increase, participant costs decrease, which continues until a 100 percent incentive is offered (see, e.g., Exh. CMA-5).

determined to justify a higher participant incentive (Exh. DPU-Comm 11-6). Further, the savings component, which remains the largest component of the performance incentive mechanism (at 61.5 percent of the total incentive), will continue to be based on total benefits (Statewide Plan, Exh. 1, App. R (Rev.) (December 20, 2018)). Therefore, we do not find it likely that the Program Administrators will favor lower participant incentives to earn a higher value component at the cost of a lower savings component. Instead, we find that the proposed changes to the calculation of the value component will encourage the Program Administrators to find the right participant incentive in order to maximize, not only the value component, but the overall performance incentive.

For the reasons discussed above, the Department approves the Program Administrators' proposal to calculate the value component using actual spending, as opposed to total resource costs. To allow the Department and other stakeholders to assess the differences in calculation methods, each Program Administrator shall provide an illustrative report as part of its Term Report showing a calculation of the value component using net benefits and a calculation of the value component using the revised method approved by the Department.

d. Renter Component

The Program Administrators propose to add a new renter component to the performance incentive mechanism and allocate funds from the statewide incentive pool to this effort (i.e., one million dollars for gas and two million dollars for electric) (Statewide Plan, Exh. 1, at 164; Statewide Plan, Exh. 1, App. C (Rev.) (December 20, 2018)). The Program

Administrators maintain that the purpose of the new renter component is to provide them with additional encouragement to successfully serve all residential renters and to track the number of renters served (Program Administrators Reply Brief at 18, citing Statewide Plan, Exh. 1, at 164; Exh. DPU-Comm 1-10; Tr. 2, at 243). DOER and other parties largely support the adoption of the renter component[43] (Attorney General Brief at 13-14; DOER Brief at 18-19; Acadia Brief at 18-20; CLF Brief at 27-31).

Through multiple programs over several plan years, the Program Administrators have been serving renters. The Program Administrators were not, however, consistently tracking the status of these participants as renters because it was not considered essential to the achievement of savings (Tr. 2, at 239; Program Administrators Brief at 55). See 2016-2018 Three-Year Plans Order, at 26; see also 2013-2015 Three-Year Plans Order, at 45-48. As a result, the primary barrier to understanding how renters have been served is a lack of actionable information regarding levels of renter participation (Exhs. DPU-Comm 1-4; DPU-Comm 1-10; DPU-Comm 1-20).

The Department has several concerns about the proposed design of the renter component. First, under the renter component as designed, the Program Administrator would collect a $20 incentive payment for serving a renter and then could also apply any savings or benefits from serving that renter to achievement of the savings and value components (Exh. DPU-Comm 1-4). This would lead to a Program Administrator achieving

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[43] Although it supports the proposal, PowerOptions asserts that the renter component should be expanded to include C&I renters not providing a residential end use, such as non-profits (PowerOptions Brief at 12).

an incentive in multiple incentive components for a single action. Further, even if the renter component threshold[44] is not achieved, it still would be possible for a Program Administrator to receive performance incentives for the benefits and net benefits associated with the measures installed if those components achieve their threshold levels (Exhs. DPU-Comm 1-6; DPU-Comm 10-5). In that case, Program Administrators still would be collecting performance incentives related to activities that had failed to achieve a threshold level goal, rendering the renter component threshold superfluous.

Most importantly, the Department has long held that performance metrics should induce Program Administrators to undertake activities they would not otherwise undertake. Performance Metrics, D.P.U. 13-67, at 10-11 (2014), citing 2010-2012 Gas Three-Year Plans Order, at 109-110; 2010-2012 Electric Three-Year Plans Order, at 120. Here, the proposed renter component would provide performance incentive payments to the Program Administrators to undertake activities that they are already obligated by the Green Communities Act to undertake. See G.L. c. 25, § 21(a); D.P.U. 13-67, at 12, citing Order on New and Revised Performance Incentive Metrics, D.P.U. 09-120-B through D.P.U. 09-127-B (2010). Further, the Program Administrators have already undertaken activities in an effort to serve renters more successfully. See 2016-2018 Three-Year Plans Order, at 26; 2013-2015 Three-Year Plans Order, at 45-48. Given that the Program Administrators are already obligated to serve renters, the real issue is whether a performance

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[44] The proposed threshold for earning performance incentives for the renter component is based on achieving 75 percent of planned portfolio renter participants and will be capped at 125 percent of design level (Statewide Plan, Exh. 1, at 165).

incentive is a necessary and appropriate tool to ensure that renter participants will be appropriately tracked.

The Program Administrators state they are willing to track renter participation and could weigh the results against the renter participant target that was developed as part of the renter component (Tr. 2, at 245). Further, the Program Administrators have confirmed that they could develop an alternate method to track renters, even without the incentive provided by the renter component (Tr. 2, at 244-245). Accordingly, the Department finds that a performance incentive is not necessary to ensure that renter participation will be appropriately tracked.

For the reasons discussed above, the Department declines to approve the proposed renter component. The Program Administrators shall remove all incentive dollars allocated to the renter component from their performance incentive models. Instead, the Department directs the Program Administrators to track and report the number of renter participants by dwelling unit. In addition, the Program Administrators shall track and report all readily available Mass Save participant data by (1) renter or owner status, (2) income-level, and (3) primary language.

e. Active Demand Reduction Savings Component

The 2019-2021 Three-Year Plans include several proposed active demand reduction initiatives (see Section III above) as well as a targeted savings component incentive mechanism for active demand reduction for electric Program Administrators (Statewide Plan, Exh. 1, at 169; Statewide Plan, Exh. 1, App. R (Rev.) (December 20, 2018)). The proposed

active demand reduction component, which has not been offered as part of previous three-year plans, is designed to encourage the accelerated performance of active demand measures in the 2019-2021 Three-Year Plans (Tr. 2, at 246). Acadia and DOER support the proposed active demand reduction savings component as a means to encourage electric Program Administrators to pursue demand reduction efforts (DOER Brief at 17; Acadia Brief at 21).

The active demand reduction market[45] is new and not as robust as the energy efficiency market that the Program Administrators have helped cultivate and transform over several decades (Statewide Plan, Exh. 1, at 162-163; see Tr. 2, at 246). The Program Administrators correctly maintain that significant efforts will be required on their part to develop a market that can successfully deliver active demand reduction benefits for customers (Program Administrators Brief at 54, citing Statewide Plan, Exh. 1, at 162-163; see Tr. 2, at 246). After review, the Department finds the proposed active demand reduction savings component is appropriately designed to overcome barriers to the nascent active demand reduction market and otherwise consistent with the Department's principles for the design of a performance incentive mechanism. Accordingly, the Department approves the proposed active demand reduction component.

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[45] Unlike large C&I customers, most residential and small C&I customers currently do not pay demand charges or employ time varying rates and, therefore, have no direct incentive to decrease usage during specific peak demand periods (Statewide Plan, Exh. 1, at 67).

Savings from active demand reduction measures could be counted either as active demand reduction savings or as traditional energy efficiency savings in the performance incentive model and, therefore, the savings will need to be appropriately tracked and allocated (Tr. 2, at 248-249). Consistent with Department precedent concerning split incentives, the Program Administrators shall ensure, through the Common Assumptions Working Group, that all savings associated with active demand reduction are appropriately tracked and consistently allocated to the savings component to avoid the double counting of benefits in the performance incentive model (Tr. 2, at 248-252). 2016-2018 Three-Year Plans Order, at 68-69.

f. Cost-Effective Programs

As discussed in Section V above, the Energy Act of 2018 allows for cost effectiveness to be aggregated at the sector level. G.L. c. 25, § 21(b)(3). Those amendments to the Green Communities Act did not, however, impact the statutory requirement that the Department consider "the effect of any rate increases on residential and commercial customers" in evaluating other funding sources for energy efficiency programs or the statutory mandate that "[t]o mitigate capacity and energy costs for all customers, the [D]epartment shall ensure that . . . resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply." G.L. c. 25, §§ 19(a)(3)(i), 21(a). In considering how to fulfill our mandate to weigh rate and bill impacts as well as our general authority to ensure that costs collected from ratepayers are reasonable and prudently incurred, the Department determines it is

appropriate to continue to allow recovery of performance incentives only for the delivery of cost-effective programs.[46]

As we have stated previously, there must a balance between flexibility and managing spending efficiently as program budgets continue to increase. 2016-2018 Three-Year Plans Order, at 77. Just as reviewing cost effectiveness at the sector level[47] will afford the Program Administrators greater flexibility in program design, we find that tying the achievement of performance incentives to the delivery of cost-effective programs will send the appropriate signals for Program Administrators to focus on cost efficiency, as well as cost effectiveness. The Department expects that the Program Administrators will continue to deliver cost-effective core initiatives over the Three-Year Plan term and manage their costs efficiently to maximize benefits for customers. See 2016-2018 Three-Year Plans Order, at 77. In the instance that a program is not cost effective in a particular year or over the term, the Program Administrators shall remove performance incentives for the associated non-cost-effective core initiatives only.

This change to the performance incentive model is not intended to prevent a Program Administrator from achieving the threshold level.[48] In order to address this potential

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46 A program is cost effective if its benefits are greater than its costs, and is comprised of one or more core initiatives. (see Statewide Plan, Exh. 1, App. R (Rev.) (December 20, 2018)).

47 A sector is made of up programs, which are comprised of core initiatives.

48 The performance incentive model calculates total benefits and net benefits to determine if a Program Administrator meets its threshold level of performance for

unintended consequence, all costs and benefits associated with both cost-effective and the non-cost-effective core initiatives shall be included in the calculation of the savings and value components of the model submitted with the Term Report. After the model produces a total performance incentive to be collected, the Program Administrator shall reduce the total performance incentive by the planned amount of performance incentive associated with the reported non-cost-effective core initiatives.[49]

By allowing the Program Administrators to aggregate cost effectiveness at the sector level while permitting performance incentives only for cost-effective programs, the Department can fulfill the Legislative mandate expanding the scope and flexibility of energy efficiency planning while continuing to incorporate the essential ratepayer protections in the Green Communities Act regarding cost effectiveness, funding, and bill impacts.

E. Conclusion

For the reasons discussed above, the Department approves the Program Administrators' proposed (1) structure of the performance incentive mechanism for the savings and value components, and (2) calculation of the savings and value component payout rates. The Department declines to approve the proposed renter component and, instead,

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earning an incentive (Statewide Plan, Exh. 1, App. R (Rev.) (December 20, 2018)). See 2016-2018 Three-Year Plans Order, at 57-58.

49 Similarly, in planning each program and core initiative, costs and benefits should be allocated a performance incentive amount, even if it is not planned to be cost effective (see, e.g., Exh. CMA-4 (Rev.) (December 20, 2018)). The Program Administrator can only earn the associated performance incentive if a program is shown to be cost effective in the Annual Reports or Term Report.

directs the Program Administrators to track and report certain data about renter participants. The Department approves the proposed active demand reduction component.

With the exception of the dollar amounts associated with the renter component, the Department approves the Program Administrators' proposed statewide incentive pool (Statewide Plan, Exh. 1, App. R (Rev.) (December 20, 2018)). The Program Administrators shall calculate performance incentives under the value component using actual spending. As part of their Term Reports, the Program Administrators shall show an illustrative calculation of the value component using net benefits. Finally, the Program Administrators may recover performance incentives only for the delivery of cost-effective programs.

VII. FUNDING SOURCES

A. Introduction

For electric Program Administrators, the Green Communities Act identifies four funding sources for energy efficiency programs: (1) revenues collected from ratepayers through the SBC; (2) proceeds from the Program Administrators' participation in the FCM; (3) proceeds from cap and trade pollution control programs, including but not limited to RGGI; and (4) other funding as approved by the Department, including revenues to be recovered from ratepayers through a fully reconciling funding mechanism (i.e., an EES). G.L. c. 25, §§ 19(a), 21(b)(2)(vii). In approving a funding mechanism for electric Program Administrators, the Department must consider: (1) the availability of other private or public funds; (2) whether past programs have lowered the cost of electricity to consumers; and (3) the effect of any rate increases on consumers. G.L. c. 25, § 19(a).

For gas Program Administrators, the Green Communities Act requires the individual gas three-year plans to include a fully reconciling funding mechanism to collect energy efficiency program costs from ratepayers (i.e., EES). G.L. c. 25, § 21(b)(2)(vii); see also G.L. c. 25, § 21(d)(2). In approving a funding mechanism for gas Program Administrators, the Department must consider the effect of any rate increases on consumers. D.P.U. 08-50-A at 56; Guidelines § 3.2.2.2.

B. Program Administrators Proposal

1. Non-Energy Efficiency Surcharge Revenues

Each electric Program Administrator projected revenues from non-EES funding sources for each year of its Three-Year Plan in the following manner: (1) projected SBC revenues calculated as the product of the statutorily mandated SBC of $0.0025 per kWh and projected sales for the applicable year; (2) projected FCM revenues calculated as the product of the clearing prices of the FCM in the applicable year and the energy efficiency capacity that is designated by ISO-NE as an FCM capacity resource for the year; and (3) projected RGGI revenues calculated by multiplying projected RGGI clearing prices by a projection of allowance sales in each RGGI auction, with 55 percent of the revenues allocated to electric efficiency programs (Statewide Plan, Exh. 1, at 183-184; App. C - Electric, Table IV.B.3.3).

The electric Program Administrators propose to allocate SBC, FCM, and RGGI revenues to each customer sector in proportion to each class' kWh consumption (Statewide Plan, Exh. 1, at 182).

2. Energy Efficiency Surcharge Revenues

The electric Program Administrators propose to collect the difference between (1) the proposed budget for the applicable year and (2) projected revenues from non-EES funding sources for that year through their energy efficiency reconciliation factor ("EERF") tariffs (see, e.g., Statewide Plan, Exh. 1, at 184-185; Exh. NG-Electric-4, 17 (Rev.) (December 20, 2018)). The electric Program Administrators calculate separate EERFs for their residential, low-income, and C&I customer classes (see, e.g., Exh. NG-Electric-4 (Rev.) (December 20, 2018)).

The gas Program Administrators propose to collect their proposed budgets for each year through their local distribution adjustment factor ("LDAF") as established by their local distribution adjustment clause ("LDAC") tariffs (Statewide Plan, Exh. 1, at 26, 183, 185).

3. Other Funding Sources

The Program Administrators, citing an absence of viable other funding sources, do not project any revenues from other funding sources during the upcoming three-year term (Statewide Plan, Exh. 1, at 185). The Program Administrators state, however, that they will continue to actively pursue other sources of funding during the Three-Year Plan term (Statewide Plan, Exh. 1, at 185).

4. Bill Impacts

Each Program Administrator submitted bill impacts for both non-participants and participants for each year of the Three-Year Plan (see, e.g., Statewide Plan, Exh. 1, at 186-187; Exh. NG-Electric-6). To calculate bill impacts for program participants, the

Program Administrators developed statewide estimates to approximate savings for each customer class[50] (Statewide Plan, Exh. 1, at 186-187). The participant bill impacts are based on average monthly usage levels (pre-participation) over the term of the Three-Year Plan (see, e.g., Statewide Plan, Exh. 1, at 186-187; Exh. NG-Electric-6).

C. Positions of the Parties

1. Program Administrators

The Program Administrators argue that they have complied with all statutory and Department requirements with respect to energy efficiency program funding (Program Administrators Brief at 47). The Program Administrators maintain that the bill impacts associated with the proposed Three-Year Plans demonstrate their focus to acquire all cost-effective energy efficiency with the lowest reasonable customer contribution (Program Administrators Brief at 40, 44). The Program Administrators contend that the bill impacts are reasonable in light of the total anticipated benefits of approximately $8.5 billion and persistence of savings to be achieved (Program Administrators Brief at 44-45). The Program Administrators contend that, contrary to CLF's assertions, all Program Administrators seek to develop aggressive programs, and then assess the potential rate impacts, and refine the programs through an iterative process as well as a rigorous stakeholder process (Program Administrators Reply Brief at 5 n.7). Therefore, the Program Administrators argue that the

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50 For residential and C&I participants, the Program Administrators estimated low, medium, and high levels of savings. For residential gas non-heating, low-income, and street lighting participants, the Program Administrators identified only a single level of savings because these participants typically have all potential measures installed (Statewide Plan, Exh. 1, at 186-187).

Department should find that the bill impacts are reasonable and consistent with Department precedent, and that the Department should approve the funding of the energy efficiency programs as proposed (Program Administrators Brief at 45, 47).

2. Attorney General

The Attorney General argues that the customer bill impacts are measured and sustainable in light of the projected savings and total benefits (Attorney General Brief at 3)

3. Department of Energy Resources

DOER argues that the Program Administrators' Three-Year Plans strike an appropriate balance between the pursuit of all cost-effective energy efficiency and demand reduction, and bill impacts on ratepayers (DOER Brief at 8). In addition, DOER maintains that the Program Administrators have taken appropriate steps to identify other funding sources to minimize bill impacts related to the Three-Year Plans (DOER Brief at 10).

4. Conservation Law Foundation

CLF contends that the Program Administrators are using bill impacts to avoid implementing new initiatives with significant upfront costs (e.g., the Cape and Vineyard Electrification Offering ("CVEO")) rather than developing a plan to achieve all cost-effective energy efficiency, then assessing the customer contribution, and adjusting as necessary (CLF Brief at 14-15). CLF argues that bill impacts should be a factor for Department consideration rather than a limiting factor for the Program Administrators in designing the Three-Year Plans (CLF Brief at 15). In weighing the reasonableness of bill impacts, CLF recommends that the Department compare the change between a representative customer's

highest, lowest, and average monthly bills within a rate class during a recent year to give the analysis context (CLF Brief at 15 n.7).

5. PowerOptions

PowerOptions asserts that the 2019-2021 Three-Year Plans represent a significant increase in the C&I budget compared to previous years (PowerOptions Brief at 7). Therefore, PowerOptions recommends that the Department review the electric C&I sector budget to ensure the funding levels are appropriately sized to balance bill impacts and the achievement of savings (PowerOptions Brief at 8).

D. Analysis and Findings

1. Non-Energy Efficiency Surcharge Revenues

The electric Program Administrators anticipate that they will receive revenues through the following non-EES funding sources: (1) the SBC; (2) participation in the FCM; and (3) RGGI proceeds (Statewide Plan, Exh. 1, at 182). The Department finds that each electric Program Administrator projected its SBC revenues over the three-year term in a reasonable manner, using Department-approved methods for projecting sales over the term (Statewide Plan, Exh. 1, at 183). The Department also finds that each electric Program Administrator projected its FCM revenues over the three-year term in a reasonable manner (Statewide Plan, Exh. 1, at 183-184).

Historically, the Program Administrators have assumed that, based on G.L. c. 25, §19(a), not less than 80 percent of RGGI revenues would be allocated to electric energy efficiency programs (Statewide Plan, Exh. 1, at 184, citing G.L. c. 25, §19(a)). In recent

years, however, significantly less RGGI revenues than projected have been allocated to electric energy efficiency programs (i.e., between 55 to 79 percent in 2016, between 28 to 70 percent in 2017, between 27 to 40 percent in 2018) (Exh. DPU-Electric 4-1, Att.).

As noted above, in the current Three-Year Plans, the electric Program Administrators have assumed that only 55 percent of projected RGGI revenues will be allocated by DOER to electric energy efficiency programs (Statewide Plan, Exh. 1, at 183-184; App. C - Electric, Table IV.B.3.3). For these Three-Year Plans, the Program Administrators consulted DOER to forecast the RGGI revenues that will be allocated to electric energy efficiency programs (Statewide Plan, Exh. 1, at 184). In this regard, DOER explains that it first allocates RGGI revenues to the non-energy efficiency related purposes set forth in G.L. c. 21A, § 22(c)(1), and then it allocates 80 percent of the remaining funds to offset the cost of electric energy efficiency program delivery (Exh. DPU-DOER 1-1).

The Department must consider the effect of any rate increases on consumers prior to approval of an energy efficiency funding mechanism and, therefore, it is essential that projections of non-EES revenues are as accurate as possible. G.L. c. 25, § 19(a). The costs of energy efficiency programs are borne by ratepayers and, therefore, any decrease in non-EES revenues represents a direct increase in costs for electric customers. Given the potential conflict between the language regarding the allocation of RGGI funding contained in G.L. c. 25, § 19(a) and G.L. c. 21A, § 22(c)(1), the Department does not have a sufficient record to determine whether each electric Program Administrator has projected its RGGI revenues over the three-year term in a reasonable manner. Instead, the Department finds that

further discussion between the electric Program Administrators and DOER is warranted to resolve this issue in order to ensure that RGGI revenues are projected and allocated in a transparent manner that is consistent with the Green Communities Act (see Exh. DPU-DOER 1-1). The Program Administrators, in consultation with DOER, shall file a report with the Department addressing this issue no later than July 1, 2019.

2. Energy Efficiency Surcharge Revenues

Pursuant to the Green Communities Act, each Three-Year Plan must include a fully reconciling funding mechanism (i.e., an EES). G.L. c. 25, § 21(b)(2)(vii); see also G.L. c. 25, § 21(d)(2). The Guidelines specify the manner in which revenue from the EES may be collected from ratepayers. Guidelines §§ 3.2.1.6, 3.2.2.

The Department finds that the electric Program Administrators' proposal to collect their projected budgets through the EES contained in their EERF tariffs is consistent with the Guidelines. Similarly, the Department finds that the gas Program Administrators' proposal to collect their projected budgets through the EES contained in their LDAC tariffs is consistent with the Guidelines.

3. Other Funding Sources

In approving an energy efficiency funding mechanism for the electric Program Administrators, the Department must consider the availability of other private or public funds. G.L. c. 25, § 19(a)(3)(ii). Although the Green Communities Act does not contain a similar requirement for gas Program Administrators, the Guidelines require gas three-year

plans to include a description of all other sources of funding that were considered to fund the energy efficiency programs. Guidelines § 3.2.2.1.

The Program Administrators have adequately demonstrated that outside funding sources for energy efficiency investments are currently scarce (Statewide Plan, Exh. 1, at 185-186). Accordingly, the Department finds that the Program Administrators have adequately considered the availability of other private or public funds. G.L. c. 25, § 19(a)(3)(ii). The Department expects, however, that the Program Administrators will continue to aggressively identify and pursue all potential sources of other energy efficiency funding and shall account for outside funding wherever practicable.

4. Cost of Electricity to Consumers

In approving an energy efficiency funding mechanism for the electric Program Administrators, the Department must consider whether past programs have lowered the cost of electricity to consumers. G.L. c. 25, § 19(a)(3)(iii). The Department finds that both program participants and non-participants benefit from lower electricity costs from energy efficiency program savings (see Statewide Plan, Exh. 1, App. H, at 27-29). In particular, the Department finds that program participants have benefitted through lowered levels of consumption, and participants and non-participants have benefitted though reduced wholesale electricity prices and avoided investments in transmission and distribution (see Statewide Plan, Exh. 1, App. H at 26-29, 110-132, 212-233; see also Exh. Eversource Energy (electric)-6, at 110-340). Accordingly, the Department finds that past energy efficiency programs have lowered electricity costs to consumers.

5. Bill Impacts

The Department must consider bill impacts when approving the use of customer funds for energy efficiency programs. D.P.U. 08-50-A at 56-58; Guidelines §§ 3.2.1.5, 3.2.1.6.3, 3.2.2.1, 3.2.2.2; see G.L. c. 25, § 19(a). The Department has determined that a bill impact analysis with a short-term perspective that isolates the effect of a proposed change in the EES is appropriate in this regard as it provides an accurate and understandable assessment of the change that will actually appear on customers' bills. D.P.U. 08-50-D at 11-12. We have recognized, however, that when considering the reasonableness of a short-term bill impact, it is also important to look at the long-term benefits that energy efficiency will provide. See D.P.U. 08-50-D at 11-12.

Unlike some other activities that only cause increases in rates, investments in energy efficiency will result in direct customer benefits, in terms of reduced consumption and reduced costs, which will persist for the lives of the energy efficiency measures installed. D.P.U. 08-50-A at 58; 2010-2012 Electric Three-Year Plans Order, at 88; 2010-2012 Gas Three-Year Plans Order, at 74. On a statewide basis, the Three-Year Plans are expected to provide total benefits of approximately $8.5 billion and net benefits of approximately $5.8 billion, resulting in approximately three dollars in benefits for every dollar spent, over the lifetime of the efficiency measures installed (Statewide Plan, Exh. 1, at 10). Total lifetime energy savings associated with the proposed energy efficiency programs will cost roughly $0.054 per kWh for electric efficiency programs and $0.64 per therm for gas efficiency programs, which is below the cost of the traditional energy resources that would

otherwise need to be purchased by consumers (Statewide Plan, Exh. 1, at 142-143, App. H at 22-23).

Significant additional benefits will also flow to Massachusetts residents from energy efficiency program investments. For example, the energy efficiency programs in the Three-Year Plans are expected to reduce statewide CO_2 emissions by more than 2.6 million short tons over the three-year term (Statewide Plan, Exh. 1, at 7). The Department finds that the energy efficiency programs in these Three-Year Plans will create a solid foundation for future energy efficiency activities as the Program Administrators continue their sustained efforts to achieve all cost-effective energy efficiency.

The Department is particularly mindful of the burdens associated with increased rates. As we have observed, while energy efficiency programs result in increases in rates, investments in energy efficiency programs also result in savings on a participant's entire bill because of the participant's reduced energy consumption. D.P.U. 08-50-A at 58.

Contrary to CLF's arguments, the Department finds that the Program Administrators have appropriately considered bill impacts when developing their proposed Three-Year Plans (see CLF Brief at 15; Statewide Plan, Exh. 1, at 145, 150-151, 187). We note that the bill impacts reflect savings targets that were developed through the Council's robust stakeholder process and approved unanimously by the Council (see Statewide Plan, Exh. 1, App. G).

Further, in response to PowerOptions' arguments, we find that the Program Administrators have appropriately weighed bill impacts when considering the proposed increases to the electric C&I sector budgets (PowerOptions Brief at 7, citing Statewide Plan,

Exh. 1, App. C - Electric at 13). As noted above, in consultation with the Council, the Program Administrators have set savings targets for these Three-Year Plans that are designed to achieve all cost effective energy efficiency and demand response. To achieve these goals, the electric Program Administrators propose budgets that include several new programs and initiatives that will provide significant benefits to C&I customers, including active demand reduction (Statewide Plan, Exhs. 1, at 76-80). In addition, the electric Program Administrators propose to broaden their non-electric services to C&I customers, including incentives for cost-effective oil heating equipment (Statewide Plan, Exh. 1, at 110-111). As the Attorney General and DOER note, the proposed budgets, including the electric C&I budgets, are appropriately designed to pursue savings targets while minimizing customer bill impacts (Attorney General Brief at 10; DOER Brief at 8).

Based on our review, and in consideration of the significant benefits provided by energy efficiency resources and mindful of the burdens associated with increased rates, the Department finds that the bill impacts associated with the Three-Year Plans are within the range of what is reasonable (see Exhs. CMA-6 (Rev.) (November 1, 2018), NG-Gas-6, FGE (Gas)-6, LU-6 (Rev.) (November 1, 2018), Eversource Energy (gas)-6, BGC-6, NG- Electric-6, FGE (Electric)-6, Eversource Energy (electric)-6, Compact-6 (Rev.) (December 20, 2018).[51]

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[51] The bill impacts we find reasonable here fully consider and incorporate the current thresholds for midterm modifications that a Program Administrator can make without review by the Department pursuant to Guidelines at § 3.8, and the additional RCS budget funding for energy scorecards addressed in Section IX.E, below.

E. Conclusion

After the consideration of: (1) the availability of other private or public funds; (2) whether past programs have lowered the cost of electricity to consumers; and (3) the effect of rate increases on consumers, the Department finds that each Program Administrator may recover the funds to implement its energy efficiency plan through its EES. The electric Program Administrators shall, in consultation with DOER, file a report with the Department no later than July 1, 2019, addressing the allocation of RGGI revenues.

VIII. CAPE LIGHT COMPACT

A. Introduction

The Compact is the only energy efficiency Program Administrator that is not an investor-owned utility. Rather, the Compact is a municipal aggregator that has also received Department approval to administer electric energy efficiency in its service area. See, e.g., Cape Light Compact, D.P.U. 15-166 (2016). NSTAR Electric is the electric distribution company serving the Compact's customers. National Grid (gas) is the local gas distribution company serving natural gas customers in the Compact's service area.

Based on our review of the Compact's proposed Three-Year Plan, several issues warrant discussion in the sections below: (1) the Compact's proposed Statewide Plan enhancements; (2) coordination of the Compact's proposed active demand reduction offerings with NSTAR Electric; (3) the allocation of costs between the Compact's municipal aggregation plan and its energy efficiency plan; and (4) the administration of energy efficiency services to gas customers in the National Grid (gas) service territory.

B. Statewide Plan Enhancements

1. Introduction

Pursuant to G.L. c. 164, § 134(b), the Compact may propose enhancements to the Statewide Plan (Exh. DPU-Compact 1-32 (Rev.) at 1). In its 2019-2021 Three-Year Plan, the Compact proposes to offer the following new enhancements to the Statewide Plan: (1) an upfront, 100 percent incentive for storage systems and (2) a strategic electrification offering, CVEO (Statewide Plan, Exh. 1, App. K – Cape Light Compact; Exh. DPU-Compact 1-32 (Rev.)). In addition, the Compact proposes to continue to offer the following enhancements: (1) an uncapped, 100 percent incentive for qualified weatherization measures to electric customers (a) who are year-round renters and responsible for paying the electric bill, or (b) whose operations are managed by municipalities or other government entities; (2) cost-effective thermal measures to save oil, propane, and other unregulated fuels under the Compact's New Construction and Major Renovation program for C&I customers; (3) specialized incentives that cover up to 100 percent of cost-effective measures for C&I municipal customers; (4) a 95 percent incentive for qualifying small business tenants; (5) zero interest financing for small business customers; (6) a business energy audit and a core offering of deemed savings measures, some at 100 percent incentive coverage; (7) a 100 percent incentive for standard direct install measures for small business customers; and (8) a 100 percent incentive for all cost-effective measures for qualifying non-profits[52]

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[52] The Compact first identified items (2) through (8) as Statewide Plan enhancements in its initial filing and in discovery responses (Statewide Plan, Exh. 1, App. K – Cape Light Compact; Exh. DPU-Compact 1-32 (Rev.)). The Compact later reversed itself

(Statewide Plan, Exh. 1, App. K – Cape Light Compact; Exh. DPU-Compact 1-32 (Rev.)).

2. Cape Light Compact Proposal

a. Enhanced Storage Incentive

The Compact proposes to install 1,000 battery storage systems during the 2019-2021 Three-Year Plan term (it proposes to install 700 of these battery storage systems through the CVEO) (Exh. Compact-2 (Joint Prefiled Testimony) at 14). The Compact states that it will offer a "bring your own battery" program if enough batteries can be enrolled to overcome the fixed costs necessary to acquire the ability to dispatch the batteries (Exh. Compact-2 (Joint Prefiled Testimony) at 17).

The Compact proposes an upfront, 100 percent incentive to participating residential and C&I customers in exchange for dispatch rights over the warrantied life of the batteries (i.e., ten years) (Exh. Compact-2 (Joint Prefiled Testimony) at 14). Consistent with the proposed statewide daily dispatch active demand reduction offerings, the Compact proposes to dispatch the batteries on a daily basis during the summer months and on a targeted basis during the winter months (Exh. Compact-2 (Joint Prefiled Testimony) at 16).

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and testified that these incentives were previously offered through custom C&I measures and, therefore, were consistent with the Statewide Plan (i.e., they were not Statewide Plan enhancements) (Tr. 3, at 367-368). Based on the representations made by the Compact in its initial filing and responses to discovery, and its description of these incentives in prior three-year plan filings, the Department will treat these proposed incentives as Statewide Plan enhancements (see, e.g., D.P.U. 15-166, Exh. 1, App. L).

b. Cape and Vineyard Electrification Offering

The Compact proposes to offer a strategic electrification offering (i.e., the CVEO), which will provide enhanced incentives for the combined installation of (1) cold-climate air-source heat pumps, (2) solar photovoltaic ("PV"), and (3) behind-the-meter battery storage (Exh. Compact-2 (Joint Prefiled Testimony) at 4). The Compact states that the CVEO is designed to reduce overall customer energy usage, while offsetting the increased electric usage from cold-climate air-source heat pumps with renewable energy generation and providing storage for active demand reduction and resiliency purposes (Exh. Compact-2 (Joint Prefiled Testimony) at 4-5).

Through the CVEO, the Compact proposes to target 700 residential customers that heat their homes with oil, propane, or electric baseboard heat, split evenly across low-income, moderate-income, extended-moderate-income, and market-rate customers (Exh. Compact-2 (Joint Prefiled Testimony) at 6). Participating customers will be required to implement all three measures; however, customers that have already installed one or two of the three measures will still be eligible for enhanced incentives for the remaining measure(s) (Exhs. Compact-2 (Joint Prefiled Testimony) at 7, 11; DPU-Compact 1-4; DPU-Compact 1-5).

The Compact proposes tiered incentives so that the customer contribution increases as the customer's ability to pay increases (Exhs. Compact-2 (Joint Prefiled Testimony) at 7; DPU-Compact 1-14). For the cold-climate air-source heat pump component, low- and moderate-income customers will receive the measure at no cost. Extended-moderate-income

and market-rate customers will be offered 70 percent and 45 percent incentives, respectively, with the balance eligible for funding through the HEAT Loan (Exh. Compact-2 (Joint Prefiled Testimony) at 8).

For the solar PV component, low-income customers will receive the measure at no cost, moderate-income customers will receive a 60 percent incentive with the balance eligible for funding through the HEAT Loan, and extended-moderate-income and market-rate customers will be able to fund the entire cost through the HEAT Loan (Exh. Compact-2 (Joint Prefiled Testimony) at 8). For the storage component, all customers will be eligible for an upfront, 100 percent incentive (Exhs. Compact-2 (Joint Prefiled Testimony) at 8; DPU-Compact 1-15).

The Compact proposes a budget of approximately $37 million over the three-year term for the CVEO, which includes the costs for all batteries included in the Compact's active demand reduction efforts[53] (Exh. Compact-2 (Joint Prefiled Testimony) at 9-10). The Compact states that it intends to competitively procure a qualified vendor to serve as the CVEO program coordinator to facilitate its implementation (Exh. Compact-2 (Joint Prefiled Testimony) at 10). Finally, the Compact states that it intends to evaluate the CVEO consistent with the statewide evaluation protocols (Exh. Compact-2 (Joint Prefiled Testimony) at 10).

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[53] The Compact states that it has requested outside funding from DOER and the Massachusetts Clean Energy Center for its proposed CVEO enhancements, but it has not secured any outside funding to date (Exh. Compact-2 (Joint Prefiled Testimony) at 11).

3. Positions of the Parties

a. Cape Light Compact

The Compact contends that its Three-Year Plan is designed to capture all cost-effective energy efficiency and demand reduction resources in a manner that is tailored to meet the demands of its unique service area (Program Administrators Brief at 64). The Compact further asserts that its proposed Three-Year Plan incorporates Council and stakeholder input and provides significant benefits to customers in its service area and the Commonwealth without overly burdensome bill impacts (Program Administrators Brief at 65-66).

The Compact argues that, as part of its Three-Year Plan, it has proposed to implement limited, cost-effective enhancements to the Statewide Plan that are sensitive to customer bill impacts and minimize administrative costs (Program Administrators Brief at 64-65). The Compact argues that if the Department does not approve these proposed measures designed for its unique service area, that decision would undermine the Compact's energy efficiency planning, the Green Communities Act's directives regarding the pursuit of all cost-effective energy efficiency, and the authority of the Compact under G.L. c. 164, § 134(b) to offer enhancements to the Statewide Plan (Program Administrators Brief at 65). Therefore, the Compact requests that the Department approve its proposed Three-Year Plan, as filed (Program Administrators Brief at 65). Further, the Compact argues that the Department should certify the Compact's proposed Three-Year Plan and find that it is an

energy plan that it is consistent with state energy efficiency goals under G.L. c. 164, § 134(b)[54] (Program Administrators Brief at 68).

The Compact states that, as a public entity, it has no shareholders, has no rate of return, does not collect performance incentives, and is accountable to its Governing Board, comprised of representatives appointed by its municipal members (Program Administrators Brief at 66). The Compact asserts that its Governing Board sets policy and oversees the development and implementation of the Compact's energy efficiency programs (Program Administrators Brief at 66). The Compact maintains that its governing structure allows it to be responsive to consumer needs and concerns (Program Administrators Brief at 66).

With respect to its proposed enhancements, the Compact maintains that it designed the CVEO proposal based on feedback from LEAN, the Attorney General, DOER, and the Massachusetts Clean Energy Center (Program Administrators Brief at 67). The Compact argues that the Council also had the opportunity to review and comment on the CVEO prior to submission to the Department (Program Administrators Brief at 67). Finally, the Compact notes that its customers and several state legislators have expressed support for the proposed CVEO (Program Administrators Brief at 67).

The Compact contends that the CVEO is an integrated approach to strategic electrification focused on moving customers off oil, propane, and electric baseboard heat

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[54] The Compact contends that since the passage of the Green Communities Act, the Department's approval of the Compact's three-year plans was an implicit certification that its energy plans were consistent with state energy efficiency goals (Program Administrators Brief at 68).

(Program Administrators Brief at 69). The Compact maintains that the bundling of three established technologies through the CVEO (i.e., cold-climate air-source heat pumps, solar PV, and behind-the-meter battery storage) will provide residential customers with the opportunity to optimize their overall energy usage (Program Administrators Brief at 69). Further, the Compact asserts that the CVEO is consistent with the recent amendments to the Green Communities Act because it (1) promotes strategic electrification through the use of heat pumps, (2) includes storage, and (3) supports customer switching to renewable energy sources through the solar PV component (Program Administrators Brief at 70).

The Compact argues that the proposed CVEO incentive levels are necessary and appropriate (Program Administrators Brief at 70). More specifically, the Compact asserts that, with the exception of moderate-income customers, the proposed heat pump incentive is consistent with the proposed statewide incentives (Program Administrators Brief at 71). The Compact argues that an increased incentive for moderate-income customers is warranted because these customers do not have sufficient disposable income to support the installation of higher priced energy efficiency measures (Program Administrators Brief at 71).

Further, the Compact notes that it is the only Program Administrator to propose solar PV incentives as part of its Three-Year Plan (Program Administrators Brief at 73). The Compact asserts that it is appropriate to offer solar PV incentives to low- and moderate-income customers because these customers do not have the disposable income or the capacity to take on additional debt to finance solar PV (Program Administrators Brief at 73). The Compact maintains that its proposed incentive structure is designed to

complement the incentives already available through the SMART program (Program Administrators Brief at 73 n.40).

The Compact argues that its proposed, upfront 100 percent storage incentive will ensure that the CVEO will result in cost-effective demand reductions in the Compact's service area, which it maintains has a higher proportion of residential and small business customers than the other Program Administrators' service territories (Program Administrators Brief at 72). The Compact contends that an upfront storage incentive is appropriate for these customers because, without coincident peak or demand charges, or time-varying rates, these customers lack a direct financial incentive to reduce demand during peak times (Program Administrators Brief at 72). The Compact maintains that the Council has recommended the implementation of an upfront storage incentive and that its proposed incentive structure will provide valuable information for future statewide battery storage measures (Program Administrators Brief at 72, citing Tr. 3, at 398-399). In addition, the Compact asserts that its analysis suggests that an upfront incentive is less costly over a ten-year period than the statewide pay-for-performance approach (Program Administrators Brief at 72-73, citing Exh. Compact-13).

The Compact asserts that each of the CVEO's three measures is cost effective, resulting in an additional $2.54 in benefits for every enhancement dollar spent (Program Administrators Brief at 75-76). In particular, the Compact argues that its proposed battery storage offering remains cost effective even if the measure life is reduced by half (Program Administrators Brief at 74). In addition, the Compact maintains that its Three-Year Plan

remains cost effective at the sector level even if an in-service rate of zero is assumed for the battery units (Program Administrators Brief at 74).

The Compact maintains that the proposed CVEO budget is comprehensive and may, in fact, be overstated as it assumes that all participants would require all three measures (Program Administrators Brief at 74). Nonetheless, the Compact asserts that the bill impacts associated with the CVEO are reasonable in light of the additional benefits and savings that it will yield (Program Administrators Brief at 74).

The Compact maintains that it plans to evaluate the CVEO consistent with the statewide evaluation protocols (Program Administrators Brief at 76). The Compact asserts that it will share progress and results with the other Program Administrators through working groups and/or management committees (Program Administrators Brief at 76). Finally, the Compact maintains that it will review forthcoming evaluations of other Program Administrators' active demand reduction demonstration offerings to better implement the CVEO (Program Administrators Brief at 76).

b. Attorney General

The Attorney General maintains that the proposed CVEO is intended to advance the policy objectives of the Energy Act of 2018, including the promotion of clean renewable energy and energy storage (Attorney General Brief at 14; Attorney General Reply Brief at 4). Although the Attorney General supports the concept of the CVEO, she questions certain aspects of the expert analysis provided by the Compact to support it (Attorney General Brief at 16-18, citing Exh. Compact-12; Attorney General Reply Brief at 3-4). Accordingly, the

Attorney General argues that the Department should carefully assess whether the costs of the CVEO can be accommodated with reasonable customer bill impacts (Attorney General Brief at 16-18; Attorney General Reply Brief at 3-4).

c. Department of Energy Resources

DOER supports the Compact's enhanced storage incentive as a strategy to ensure the equitable deployment of active demand reduction programs in the Compact's service area (DOER Reply Brief at 9). DOER notes that the Compact is the only Program Administrator to propose a cost-effective upfront rebate for energy storage, as requested by the Council (DOER Reply Brief at 9). Further, DOER states that it supports the CVEO as a concept and maintains that it is appropriately designed to help low- and moderate-income customers (DOER Reply Brief at 9). However, DOER argues that there are significant incentives and financing currently available for solar PV systems and the Department should not permit the Compact to finance the solar PV component of the CVEO through its Three-Year Plan (DOER Reply Brief at 9). DOER recommends that the Department should direct the Compact to educate its customers regarding these other solar PV funding sources (DOER Reply Brief at 9).

d. Acadia Center

Acadia supports the Compact's enhanced incentives for storage and its bundled offering of technologies in the CVEO (Acadia Brief at 11-12). Acadia asserts that the Compact is the only Program Administrator that proposes to offer upfront rebates for storage as requested by the Council (Acadia Brief at 11-12). Acadia argues that upfront incentives

for storage are necessary given the lack of time-varying rates and demand charges (Acadia Brief at 12). Acadia maintains that it is within the Compact's authority under G.L. c. 164, § 134(b) to propose these enhanced incentives and that they are consistent with the statutory requirement to pursue all cost-effective energy efficiency and demand resources (Acadia Brief at 12-13). Therefore, Acadia recommends that the Department approve the Compact's Three-Year Plan as proposed, including the enhanced storage incentive and CVEO (Acadia Brief at 13).

e. Conservation Law Foundation

CLF argues that the Compact's proposed CVEO and enhanced storage incentive offerings are cost effective and innovative strategies that are designed to meet the requirements of the Green Communities Act (CLF Brief at 45). CLF maintains that the Compact has the statutory authority under G.L. c. 164, § 134(b) to offer enhanced incentives beyond those contained in the Statewide Plan (CLF Brief at 44). In this regard, CLF argues that the other Program Administrators have not pursued cost-effective strategies as aggressively as the Compact has (CLF Brief at 44).

4. Analysis and Findings

a. Introduction

General Laws c. 164, § 134(b) provides that municipal aggregators "shall not be prohibited from proposing for certification an energy plan which is more specific, detailed, or comprehensive or which covers additional subject areas than any such state-wide conservation goals." As part of its 2019-2021 Three-Year Plan, the Compact proposes to

offer several enhancements to the Statewide Plan, pursuant to G.L. c. 164, § 134(b) (see, e.g., Exh. DPU-Compact 1-32 (Rev.) at 1).

The Compact's proposed enhancements to the Statewide Plan generally take the form of enhanced incentives at levels that are materially different from the Statewide Plan (see, e.g., Statewide Plan, Exh. 1, App. K – Cape Light Compact at 11; Exh. DPU-Compact 1-32 (Rev.) at 1; RR-DPU-Compact 2-2; Tr. 3, at 367-368). See, e.g., D.P.U. 15-166, Exh. 1, App. L. As the basis for its proposed enhancements, the Compact often cites the "unique" nature of its service area; however, as discussed below, it is often without adequate explanation or support for these claims (see, e.g., Program Administrators Brief at 64, 65, 72; Exh. DPU-Compact 1-32 (Rev.)). Additionally, the Compact has not obtained any outside funding for these Statewide Plan enhancements, instead the Compact proposes to collect all costs related to such enhancements from electric ratepayers through its EES (Exhs. Compact-2 (Joint Prefiled Testimony) at 11; DPU-Compact 1-12).

The Department must consider the proposed Statewide Plan enhancements in the context of the comprehensive statutory scheme for energy efficiency provided by the Green Communities Act.[55] As described in Section V above, above, the Department's review must

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[55] There is no question that the Compact's Three-Year Plan, though authorized by G.L. c. 164, § 134, is subject to the standards set forth in G.L. c. 25, §§ 19-22 for the development and evaluation of energy efficiency plans. Chapter 25, § 21 explicitly applies to certified energy plans by municipal aggregators under G.L. c. 164, § 134. Even without an express connection between the statutes, the Legislature is presumed to be aware of existing legislation when enacting subsequent legislation and, therefore, statutes are interpreted to form a consistent body of law. See Parris v. Sheriff of Suffolk County, 93 Mass. App. Ct. 864, 868 (2018) (citations omitted). In 2008, the Green Communities Act amended G.L. c. 25 to add

ensure, among other things, that the Compact's proposed enhancements to the Statewide Plan comply with all ratepayer protections in the Green Communities Act regarding cost effectiveness, funding, and bill impacts. G.L. c. 25, § 21(a), (b)(1), (b)(2)(iv)(A). Customers within the Compact's service area may opt out of participation in the Compact's municipal aggregation program, but they may not opt out of having the Compact as their energy efficiency Program Administrator. The Compact relies on funds from ratepayers to support its energy efficiency programs. In addition to the other requirements of the Green Communities Act, the Department must ensure that the Compact spends its energy efficiency funds in a reasonable and prudent manner, just as we do for the other Program Administrators, when implementing its energy efficiency plans.[56] Accordingly, our review of

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Sections 19 through 22, which created the Council and established a comprehensive—and extremely effective—statewide statutory scheme aimed at maximizing energy efficiency in the Commonwealth. See G.L. c. 25, § 19-22. As we have previously found, the purpose of the Green Communities Act was to "provide forthwith for renewable and alternative energy and energy efficiency in the [C]ommonwealth…." Paragon Holdings, LLC, D.P.U. 14-119, at 4 (2014), citing Green Communities Act at Preamble. We must construe statutes that address the same subject matter harmoniously, "so that effect is given to every provision in all of them," Green v. Wyman-Gordon Company, 422 Mass. 551, 554 (1996), and the statutes do not "undercut each other." Burbank Apartments Tenant Association v. Kargman, 474 Mass. 107, 124–125 (2016). The Preamble to the Electric Restructuring Act of 1997, St. 1997, c. 164 ("Restructuring Act"), which created G.L. c. 164, § 134, stated, in part, that one of "the primary elements of a more competitive electricity market will be . . . enhanced environmental protection goals." Restructuring Act at Preamble. Read together, these statutes evince the Legislature's intent to unify energy efficiency strategies and goals in the Commonwealth, which has resulted in Massachusetts leading the country in energy efficiency.

[56] The Compact does not collect performance incentives, which provide other Program Administrators with an incentive to maximize benefits while minimizing ratepayer costs. See, e.g., 2016-2018 Three-Year Plans Order, at 56.

the Compact's proposed enhancements to the Statewide Plan requires the Department to protect ratepayer interests.

The Department has reviewed the following enhanced incentives: (1) an uncapped, 100 percent incentive for qualified weatherization measures to electric customers (a) who are year-round renters and responsible for paying the electric bill, or (b) whose operations are managed by municipalities or other government entities; (2) cost-effective thermal measures to save oil, propane, and other unregulated fuels under the Compact's New Construction and Major Renovation program for C&I customers; (3) specialized incentives that cover up to 100 percent of cost-effective measures for C&I municipal customers; (4) a 95 percent incentive for qualifying small business tenants; (5) zero interest financing for small business customers; (6) a business energy audit and a core offering of deemed savings measures, some at 100 percent incentive coverage; (7) a 100 percent incentive for standard direct install measures for small business customers; and (8) a 100 percent incentive for all cost-effective measures for qualifying non-profits. After review, the Department finds that these specific enhanced incentive proposals are reasonable and consistent with past program design. Therefore, the Department approves the continuation of these enhanced incentives. Prior to its next three-year plan filing, the Compact should conduct an analysis of these enhanced incentives through the statewide evaluation protocols to determine if these enhanced incentives (including incentive levels) continue to be warranted.[57,58]

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[57] One aspect of the evaluation should consider a comparable customer group receiving similar service with a lower incentive level.

In the sections below, the Department addresses the Compact's two new proposed enhancements to the Statewide Plan: the enhanced storage incentive and the CVEO. After that analysis, to facilitate Department and stakeholder review, the Department outlines additional filing requirements for future proposed Statewide Plan enhancements under G.L. c. 164, § 134(b).

b. Enhanced Storage Incentive

The Compact is the only Program Administrator proposing to offer an upfront, 100 percent incentive to all customer classes for battery storage systems. In exchange, participating customers must agree to allow the Compact to dispatch the batteries for demand reduction purposes over the warrantied life of the battery, usually ten years (Exh. Compact-2 (Joint Prefiled Testimony) at 14).

The savings design structure of the Compact-specific enhanced storage incentive offering is consistent with the proposed statewide active demand reduction daily dispatch offering; the Compact intends to dispatch participating batteries on a daily basis during summer peak periods (Exh. Compact-2 (Joint Prefiled Testimony) at 16). Consistent with our findings in Section III.D.2 above, with respect to the proposed statewide daily dispatch offerings, we find that the Compact has not provided sufficient support for its proposal to deploy a daily dispatch offering at scale.

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[58] Conversely, the Department notes that certain previous incentive offerings have been adopted at the statewide level (Tr. 3, at 363; Exh. DPU-Comm 11-6). The Program Administrators shall conduct an evaluation through the statewide evaluation protocols to determine if these enhanced incentives should be more widely adopted.

Although the design structure is consistent, the Compact's proposed incentive and contractual arrangements are materially different from the statewide offering. The Department finds that the Compact has not provided sufficient support for the design of its enhanced incentive (i.e., an upfront, 100 percent incentive to all customer classes with a ten-year dispatch commitment).[59] As discussed in Section V above, in its review of energy efficiency plans, the Department must balance cost effectiveness with cost efficiency to ensure that realized benefits are maximized at the least cost to customers as mandated by the Green Communities Act. G.L. c. 25, § 21(b)(1), (2)(iv)(A). Although a 100 percent incentive may be cost effective,[60] the Compact must demonstrate that an incentive at this level is a prudent expenditure of ratepayer funds (i.e., the incentive level is at the least cost necessary to achieve the desired result).

The absolute length of the proposed dispatch commitment creates other problems that the Compact has not sufficiently addressed.[61] The Compact proposes to have full dispatch

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59 The average customer incentive is expected to be $10,000 (Exh. Compact-5a (Rev.) at Tab ADRYr2).

60 In 2020, when the Compact proposes to put the enhanced storage initiative into place, the Compact estimates that a residential customer's bill will increase by 3.26 percent and a C&I customer's bill will increase by approximately 7.79 percent (RR-DPU-Compact-2).

61 The Program Administrators' initial filing included testimony supporting the need for a five-year commitment as part of a pay-for-performance offering to provide customers with revenue certainty to overcome the significant upfront investment participating customers must make in the battery storage system (see, e.g., Exh. NG-Electric-2, at 67-69). The Compact, by comparison, included no explanation in its initial filing of why a ten-year upfront commitment is appropriate.

rights over the warrantied lifetime of the battery (usually ten years) in exchange for an upfront, 100 percent incentive. In approving an energy efficiency plan, the Department generally expects the provision of incentives for (and active involvement with) approved measures to occur within the three-year term. The Department recognizes that active demand reduction programs may initially warrant longer-term commitments. The term of the commitment must balance the need to provide sufficient incentive to realize savings with the recognition that costs and customer needs change over time.[62] In Section III.D.2 above, above, the Department approved a five-year commitment as part of the statewide pay-for-performance model in light of the need to provide sufficient revenue certainty to overcome the significant upfront investment in storage. However, given the Compact's proposed upfront, 100 percent incentive, the Department finds no evidence that a ten-year term is either necessary or appropriate.

For each of the reasons discussed above, the Department does not approve the Compact's enhanced storage incentive proposal.[63] Should the Compact seek to implement an

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[62] Customers may move or otherwise wish to discontinue participation over a contract term. Also, the boundaries of the Compact's service area could change over time, depending on the continued participation of member towns in its municipal aggregation program. Cape Light Compact, D.T.E. 00-47-C at 24 (2001).

[63] Once the Compact has addressed the distribution system coordination issues described in Section VIII.C, below, it may use a portion of the budget allocated to its proposed daily dispatch offerings to design a demonstration offering to test the daily dispatch of storage, provided no other Program Administrator has implemented such an offering (see Section III.B.2, above). The Compact shall comply with all other directives in Section III.B.2 above, regarding coordination with the Council and other Program Administrators regarding the design of any such demonstration offering. The

enhanced storage incentive design once a statewide, wide-scale daily dispatch offering is shown to be appropriate, it will be required to provide sufficient support for the design of its incentive proposal, including the incentive level, incentive commitment, and incentive model (i.e., upfront incentive versus performance based).

c. Cape and Vineyard Electrification Offering

The Department appreciates the Compact's efforts to respond to the recent amendments to the Green Communities Act through proposals like the CVEO. The proposed bundling of incentives to optimize energy usage merits close consideration and, in particular, we support the emphasis on equitably serving all customer classes.[64] However, given the short period over which the offering was developed,[65] the design of the CVEO did not benefit from a full, robust stakeholder process like most components of the Statewide Plan. While the Compact states that it consulted with several stakeholders regarding the design of the CVEO, including the Attorney General and DOER, we note that these parties have raised

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Compact shall present any such proposal to the Council and then to the Department for review and approval.

64 The approach of equitably serving low-income customers could address barriers to entry for these customers. See Joint Petition of Electric Distribution Companies for Approval of Model SMART Provision, D.P.U. 17-140-A at 57-60 (2018).

65 The Energy Act of 2018, which, among other things, allows Program Administrators to pursue energy storage and strategic electrification as part of their energy efficiency plans, became law on August 9, 2018. The Compact states that, while it considered some of the measures included in the proposed CVEO earlier in the planning process, the CVEO as a complete offering was not publicly presented until September 14, 2018 (Tr. 3, at 422-423). The Compact filed its Three-Year Plan with the Department on October 31, 2018.

material concerns about different aspects of the proposal (see Attorney General Brief at 16-18; Attorney General Reply Brief at 3-4; DOER Reply Brief at 9). The Attorney General and DOER only support the concept of the CVEO, not its proposed structure (see Attorney General Brief at 16-18; Attorney General Reply Brief at 3-4; DOER Reply Brief at 9). Further, contrary to the Compact's assertion, the Council never explicitly discussed the CVEO (see Tr. 3, at 410-411).

In addition, the Department strongly shares DOER's concern that, given the availability of other solar PV incentives and financing programs, it is not appropriate for the Compact to finance the solar PV component of the CVEO through its Three-Year Plan (see DOER Reply Brief at 9). In this regard, the Department must consider how any proposed solar PV incentives comply with the statutory directive to transition to a stable solar marketplace at a reasonable cost to ratepayers. See An Act Relative to Solar Energy, St. 2016, c. 75.

Based on the above, the Department does not approve the proposed CVEO and associated budget at this time. Instead, the Department finds that it is appropriate for the Compact to refine its proposed CVEO offering prior to Department review. Once stakeholders have thoroughly vetted the offering and the Council has approved it, the Compact may submit a revised CVEO proposal and budget to the Department for our review. The Department expects that all issues identified by the Department (and raised by the Attorney General and DOER) in this proceeding will be addressed in a future CVEO proposal.

d. Future Statewide Plan Enhancements

The Green Communities Act requires the Department to issue a decision on the three-year plans within 90 days of the submission of the Statewide Plan by the Program Administrators. G.L. c. 25, § 21(d)(2). The Department has historically evaluated the Compact's proposed Statewide Plan enhancements along with any other Program Administrator-specific programming during its review of the Statewide Plan. See, e.g., 2016-2018 Three-Year Plans Order, at 6-7.

As discussed above, the Compact has proposed to (1) continue to offer eight existing Statewide Plan enhancements and (2) implement two new Statewide Plan enhancements, each of which departs materially from the Statewide Plan offerings. We note that the Statewide Plan enhancements offered by the Compact have generally taken the form of increased incentives, at times as high as 100 percent of the proposed cost (Statewide Plan, Exh. 1, App. K – Cape Light Compact). See D.P.U. 15-166, Exh. 1, App. L.

As reflected in the number of information requests served specifically on the Compact and the need for a separate day of evidentiary hearings devoted exclusively to the Compact's proposed enhancements, the Department had to expend considerable resources to gather a complete understanding of the Compact's Statewide Plan enhancement proposals. And, as our analysis above reveals, the two new proposed Statewide Plan enhancements raised a number of complex issues for our consideration. To facilitate an efficient review of future proposals, the Compact shall include a supplement in its initial three-year plan filing that identifies all proposed Statewide Plan enhancements (both new and existing). The filing must

include detailed testimony and exhibits (1) describing each proposed Statewide Plan enhancement, (2) explaining and supporting why each proposed enhancement is necessary and consistent with all requirements of the Green Communities Act, (3) describing Council and stakeholder review of each proposal, and (4) clearly identifying the incremental budget and projected savings, broken down by rate class and category, relative to the Statewide Plan.

C. Active Demand Reduction Coordination

1. Introduction

The Department has recognized that active demand reduction offerings have the potential to impact the local distribution system in a manner that is different from other energy efficiency programs. Cape Light Compact, D.P.U. 17-84, at 21 (2018). Accordingly, because the Compact is not an electric distribution company, it is required to coordinate with NSTAR Electric to ensure that its proposed active demand reduction offerings will not adversely impact reliability. See D.P.U. 17-84, at 21.

The Compact states that it has met with NSTAR Electric twice (i.e., on October 24, 2018, and on November 15, 2018) to discuss the implementation and coordination of the Compact's proposed energy storage offering for the purposes of minimizing any potential impacts on the operation and reliability of the distribution system (Exhs. Compact-2 (Joint Prefiled Testimony) at 13; DPU-Compact 1-19; DPU-Compact 3-3; Tr. 3, at 425). The Compact states that the topics of discussion included the following: (1) battery installation locations; (2) coordination on battery installation sites; (3) dispatch of battery systems; (4) identification of constrained circuits; and (5) disposition of the batteries

after the contract term (Exhs. DPU-Compact 1-19; DPU-Compact 3-3). The Department addresses the appropriateness of the Compact's coordination with NSTAR Electric below.

2. Positions of the Parties

a. Cape Light Compact

The Compact asserts that it has engaged in ongoing communications with NSTAR Electric regarding the dispatch of battery storage (Program Administrators Brief at 76). As a result of these communications, the Compact asserts that NSTAR Electric recently presented it with a draft memorandum of understanding ("MOU") outlining a proposal for the coordinated dispatch of the Compact's battery storage (Program Administrators Brief at 76). The Compact maintains that it is currently reviewing NSTAR Electric's proposal and expects that an acceptable arrangement can be reached prior to the Compact's planned implementation of its battery storage proposal in 2020 (Program Administrators Brief at 76).

b. NSTAR Electric

Although NSTAR Electric maintains that it supports the majority of the Compact's proposed Three-Year Plan, it expresses reservations about the Compact's battery storage proposal (NSTAR Electric Reply Brief at 8). NSTAR Electric argues that because the Compact is not a public utility, it has no obligation to provide safe and reliable electric distribution service like NSTAR Electric does (NSTAR Electric Reply Brief at 3). NSTAR Electric argues that, as the electric distribution service provider in the Compact's service area, it must ensure that the Compact's deployment of any active demand

management offerings does not affect electric distribution safety and reliability (NSTAR Electric Reply Brief at 4). NSTAR Electric argues that the Compact's proposal has the potential to adversely impact distribution safety and reliability absent sufficient control by NSTAR Electric over the storage assets (NSTAR Electric Reply Brief at 8).

More specifically, NSTAR Electric maintains that it is concerned both by the number and location of batteries the Compact is proposing to dispatch (NSTAR Electric Reply Brief at 4). NSTAR Electric contends that it is necessary to study the interconnection and operation of the 1,000 batteries in total to understand the impact on the local distribution system if the batteries are dispatched in unison (NSTAR Electric Reply Brief at 4). NSTAR Electric argues that, absent such study, the Compact can offer no evidence to support its characterization of the load reduction as "relatively small" (NSTAR Electric Reply Brief at 4, citing Exh. DPU-Compact 3-3). NSTAR Electric further argues that, without such study, there may be significant operational conflicts between NSTAR Electric's reliability-driven storage investments and the Compact's proposed behind-the-meter storage investments (NSTAR Electric Reply Brief at 5).

NSTAR Electric maintains that, should the Department approve the Compact's proposed storage offering, such approval must be conditioned on NSTAR Electric having the sole authority to dispatch the units and other necessary conditions (NSTAR Electric Reply Brief at 6). NSTAR Electric asserts that its negotiations with the Compact (as reflected in the draft MOU) are intended to ensure that it has full control over the dispatch of the Compact's proposed storage assets (NSTAR Electric Reply Brief at 5). In addition,

NSTAR Electric contends that the negotiations are designed to ensure that it will receive appropriate information on (1) the location of all dispatchable assets for its review and approval, (2) the potential to aggregate multiple assets for coordinated dispatch, and (3) the customers participating in any such aggregation of assets (NSTAR Electric Reply Brief at 5). NSTAR Electric maintains that the MOU addresses other important issues, including the following: (1) submission of applications for interconnection on an aggregated basis for review; (2) payment by the Compact of reasonable incremental costs incurred by NSTAR Electric; (3) restrictions on the ability of assets to participate in other programs; and (4) duration of NSTAR Electric's right to control the dispatch of the assets (NSTAR Electric Reply Brief at 5). NSTAR Electric argues that this level of involvement is necessary to mitigate any potential adverse impacts associated with the operation of such assets on the distribution system (NSTAR Electric Reply Brief at 6).

Finally, in the event the Department does not approve the Compact's storage proposal, NSTAR Electric recommends the Department investigate alternative models to offer storage opportunities to the Compact's customers (NSTAR Electric Reply Brief at 7). Specifically, NSTAR Electric recommends the Department allow it to partner with storage developers to implement behind-the-meter storage for the Compact's customers (NSTAR Electric Reply Brief at 7). NSTAR Electric argues that this alternative model would allow it to operate storage assets across three states through a centrally controlled dispatch platform to help lower ISO-NE system peaks (NSTAR Electric Reply Brief at 7-8). Further, NSTAR Electric maintains that this alternative model would obviate the need for the

Compact to procure a duplicative dispatch software platform and capabilities (NSTAR Electric Reply Brief at 8).

3. Analysis and Findings

As an initial matter, on January 14, 2019, the Compact filed a motion to strike NSTAR Electric's reply brief ("Motion to Strike"). The Compact argues that the majority of the reply brief consists of unsworn testimony and alleged facts regarding the potential impact of the Compact's proposed active demand reduction offerings on the reliability of the distribution system that are not supported by the record in this proceeding[66] (Motion to Strike at 1, 6-8). Therefore, the Compact maintains that NSTAR Electric's reply brief constitutes extra-record evidence that should be disregarded in its entirety (Motion to Strike at 10). NSTAR Electric did not file a response to the Motion to Strike.

Department regulations provide that no person may present additional evidence after having rested, except upon motion and a showing of good cause. 220 CMR 1.11(8). Further, the Department has found that it is axiomatic that a party's post-hearing brief may not serve the purpose of presenting facts or other evidence that is not in the record. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 12 (2016), citing Boston Gas Company, D.P.U. 88-67, at 7 (Phase II) (1989). After review, the Department finds that NSTAR Electric's reply brief presents legal and policy-based arguments that do not rise to the level of extra-record evidence. Accordingly, the Department denies the Compact's

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66 The Compact identified the specific parts of NSTAR Electric's reply brief with which it takes issue, including portions of the Introduction at 1-2, Section II at 4-6, and Section III at 7-8 (Motion to Strike, App A).

Motion to Strike. The Department will accord appropriate weight to NSTAR Electric's reply brief to the extent it offers relevant legal and policy-based argument.[67]

The Department has found that, because the Compact is an energy efficiency Program Administrator that is not an electric distribution company, it must coordinate with NSTAR Electric to ensure that any proposed active demand reduction offerings will not adversely impact the reliability of the local distribution system. D.P.U. 17-84, at 21. Consistent with this directive, the Compact has engaged in discussions with NSTAR Electric regarding its proposed active demand reduction offerings. However, the Compact and NSTAR Electric have not yet finalized any agreement in this regard (see Tr. 3, at 425; Program Administrators Brief at 76).

The Department finds that it is premature to consider the Compact's proposed active demand reduction offerings (including the statewide offerings and any Compact-specific enhancements) until a final agreement with NSTAR Electric is in place. Absent such an agreement, the Department is unable to determine whether the Compact's proposed offerings will undermine NSTAR Electric's obligation to provide safe and reliable service to its distribution customers. See 220 CMR 11.01; Investigation into the Interconnection of Distributed Generation, D.P.U. 11-75-E at 34 (2013); Report to the Legislature Re: Maintenance and Repair Standards for Distribution Systems of Investor-Owned Gas and Electric Distribution Companies, D.P.U. 08-78, at 4 (2009); Incentive Regulation,

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[67] The Department notes, however, that we did not need to rely on any of the purported extra-record facts challenged by the Compact in reaching our findings below.

D.P.U. 94-158, at 3 (1995). Accordingly, the Department does not approve any active demand reduction offerings for the Compact at this time.[68]

On or before September 30, 2019, the Compact shall file a report with the Department outlining the status of its efforts to reach a final agreement with NSTAR Electric regarding (1) all aspects of the coordination necessary to implement active demand reduction offerings in the Compact's service area and (2) how any costs related to such coordination will be addressed. A copy of any signed agreement should be included with this report. The Department will review the agreement to determine if it adequately addresses distribution reliability concerns and whether the proposed treatment of any related costs is reasonable.

If the Compact and NSTAR Electric cannot reach a signed agreement addressing all issues by September 30, 2019, the Compact shall notify the Department and the Council. The Department then requests that the Council, within 60 days of any such notification, provide the Department with its recommendation regarding alternative models to offer active demand reduction opportunities in the Compact's service area that do not implicate concerns about the reliability of the distribution system.

We are cognizant that the time required for the Compact and NSTAR Electric to reach agreement regarding system reliability could affect the timeline for Compact customer participation in the statewide active demand reduction offerings. However, the Compact

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68 This directive includes, but is not limited to, any of the offerings identified in Exhibit Compact-5a (Rev.). Until a final agreement with NSTAR Electric is reached (or until otherwise ordered by the Department), the Compact shall not offer any active demand reduction program, initiative, offering, or pilot that requires dispatch or otherwise could adversely impact distribution customers.

testified that it did not intend to implement the majority of its active demand reduction offerings until 2020 (see Tr. 3, at 378; Exh. Compact-5a (Rev.); RR-DPU-Compact-2; Program Administrators Brief at 76). Therefore, the Department fully expects that appropriate active demand reduction opportunities will be available to the Compact's customers with a minimum of delay.

D. Cost Allocation

1. Introduction

The Compact has two primary core functions: (1) administering its approved energy efficiency programs; and (2) administering its municipal aggregation power supply program (Tr. 3, at 329). In addition, the Compact states that it undertakes various advocacy activities on behalf of its municipal aggregation program participants and its energy efficiency customers[69] (Tr. 3, at 330, 336). Energy efficiency-related expenditures are funded through an EES that is collected from all electric customers in the Compact's service area (Tr. 3, at 329). Municipal aggregation-related expenses are funded through an operational adder collected from municipal aggregation program participants (Tr. 3, at 329-330).

The Compact maintains that it implements a series of internal controls to ensure that only energy efficiency-related costs (and no municipal aggregation-related costs) are recovered through the EES (Exh. DPU-Compact 1-1; Program Administrators Brief

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69 For example, the Compact identifies the following two activities on its website (https://www.capelightcompact.org/advocacy/) under consumer advocacy: (1) the Compact's participation in the Department's various grid modernization proceedings (e.g., D.P.U. 12-76, D.P.U. 15-121); and (2) the Compact's participation in NSTAR Electric's rate case (D.P.U. 17-05).

at 66 n.32). These internal controls include the following: (1) invoice review; (2) maintenance of separate bank accounts for the municipal aggregation and energy efficiency programs; and (3) use of an outside auditor to review its financial accounts and prepare annual audits (Exh. DPU-Compact 1-1; Program Administrators Brief at 66 n.32).

The Compact states that it allocates indirect or shared expenses (e.g., treasury services, payroll services, insurance) between its municipal aggregation program and energy efficiency program by the relative budget of each program or using alternate allocation methods set by the Compact's Governing Board[70] (Exh. DPU-Compact 3-1). The Compact states that these allocations are reviewed annually by the Governing Board and that any changes to the allocation factors would be reflected in the Compact's EES filings and its annual municipal aggregation operations budget (Tr. 3, at 334-335).

2. Analysis and Findings

The Compact, like other Program Administrators, must carefully track and allocate all expenditures to ensure that only energy efficiency-related costs are recovered through its EES. Direct costs must be tracked and charged to the appropriate program budget. Indirect or shared costs must be allocated between the municipal aggregation and energy efficiency programs based on appropriate allocation factors.

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[70] For example, the Compact states that costs for its insurance, office space, and office phones are allocated based on a policy decision from the Governing Board. Staff salaries and benefits/pensions are allocated based on the hours spent on each program (Exh. DPU-Compact 3-1).

The Compact identified the categories of costs that are shared between its energy efficiency and municipal aggregation programs and the allocation methods it proposes to use to assign these shared costs to each (Exh. DPU-Compact 3-1). After review, subject to our findings regarding the allocation of consumer advocacy costs below, the Department finds the methods identified by the Compact to allocate shared costs are reasonable and we approve these methods for use in the upcoming Three-Year Plan term.

To increase transparency and facilitate review of future EES and three-year plan filings, the Department directs the Compact to identify the allocation methods and resulting allocation factors used to assign shared costs to its energy efficiency and municipal aggregation programs. In each filing, the Compact also shall include a separate data table showing these allocations. The Department directs the Compact to include in its Annual Reports and Term Report a comparison of planned allocations versus actual spent dollars and an explanation of any significant variance (i.e., a variance of greater than ten percent). See Energy Efficiency Three-Year Term Report Template, D.P.U. 11-120-B (2016).

Finally, one area of shared costs that is of particular interest to the Department is the allocation of consumer advocacy costs. The Compact maintains that all non-energy efficiency-related consumer advocacy costs are funded from its municipal aggregation operations budget (Tr. 3, at 336). In this regard, the Compact's municipal aggregation plan includes the following component:

> Ongoing consumer advocacy and representation at the state level through participation in [Department] proceedings, the legislative development process, the stakeholder community and before other regulatory and governmental bodies.

Cape Light Compact, D.P.U. 14-69, Municipal Aggregation Plan at 12 (April 3, 2014). The Department anticipates that the Compact will classify the large majority of consumer advocacy costs as non-energy efficiency related to be recovered through its municipal aggregation budget. Where the Compact classifies any consumer advocacy costs as energy efficiency related, it must be prepared to demonstrate, at the time final cost recovery is sought, that such activities have a direct energy efficiency-related benefit. Failure to make such showing will result in disallowance of such costs.[71] To facilitate this review, in each Annual Report and Term Report, the Compact shall identify any consumer advocacy costs (including related legal and consulting costs) that were charged to its energy efficiency budget and provide an explanation supporting the direct energy efficiency-related benefit of such activities.

E. Provision of Energy Efficiency Services to Mutual Customers

1. Introduction

During the investigation of the Compact's 2016-2018 three-year plan, National Grid (gas) raised issues regarding the Compact's provision of energy efficiency to gas customers in the National Grid (gas) service territory ("mutual customers"). 2016-2018 Three-Year Plans Order, at 116-117. The Compact and National Grid (gas) filed an interim agreement dated December 10, 2015, regarding the administration of energy efficiency services to mutual customers. Cape Light Compact, D.P.U. 15-166, Agreement (December 21, 2015). The Department directed the Compact and National Grid (gas) to file a final agreement

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[71] Disallowed costs shall not be recovered through the EES.

regarding the provision of gas energy efficiency services to their mutual customers for Department review. 2016-2018 Three-Year Plans Order, at 119.

A final agreement between the Compact and National Grid (gas) was not reached and, on October 5, 2016, National Grid (gas) filed a petition with the Department requesting approval to provide energy efficiency services to its natural gas heating customers on Cape Cod in accordance with its approved 2016-2018 three-year plan. This matter was docketed as D.P.U. 16-169 and it is currently pending before the Department. In its proposed Three-Year Plan, the Compact proposes to continue to provide certain energy efficiency services to mutual customers (Exh. DPU-Compact 1-31).

2. Positions of the Parties

a. Cape Light Compact

The Compact argues that it administers its Three-Year Plan to all electric customers in its service area in a fuel-neutral manner (Compact Brief at 1). According to the Compact, the practice of serving customers in this manner was established in 2001 (Compact Brief at 2). The Compact contends that it is not administering gas measures to customers of National Grid (gas), rather it is appropriately installing certain electric weatherization measures for mutual customers, including air sealing and insulation, that produce both electric and gas savings (Compact Brief at 2).

In response to the argument of National Grid (gas) that it should follow the statewide coordination protocol, the Compact argues that this protocol is neither written nor binding as it was not required by Department directive (Compact Brief at 2). According to the

Compact, even if the Department were to adopt the statewide coordination protocol, the Compact's authority to implement Statewide Plan enhancements under G.L. c. 164, § 134(b) would allow it to provide energy efficiency services to mutual customers (Compact Brief at 3).

b. National Grid (gas)

National Grid (gas) argues that the Compact continues to provide home energy audits and weatherization measures to customers who heat their homes with gas, which is inconsistent with the statewide coordination protocol agreed to by all other Program Administrators (National Grid (gas) Brief at 1, citing Exh. DPU-Comm 11-5). National Grid (gas) contends that Program Administrators coordinate to provide energy efficiency services based on the customer's primary heating fuel, so gas program administrators serve customers that heat with natural gas, and electric program administrators serve customers that heat with fuels other than natural gas (National Grid (gas) Brief at 1, citing Exh. DPU-Comm 11-5). According to National Grid (gas), this statewide coordination protocol is appropriate because (1) it aligns the costs with the customers receiving the benefits, (2) it is fair and unbiased for all Program Administrators, and (3) it allows Program Administrators to plan and implement their three-year plans without confusion (National Grid (gas) Reply Brief at 2). National Grid (gas) also argues that use of the statewide coordination protocol would prevent the existing cross-subsidization of gas energy efficiency measures by the Compact's customers (National Grid (gas) Reply Brief at 2). Accordingly, National Grid (gas) requests that the Department direct the Compact to follow the statewide coordination protocol when

administering its 2019-2021 Three-Year Plan (National Grid (gas) Brief at 2; National Grid (gas) Reply Brief at 4).

3. Analysis and Findings

The Department has previously recognized the importance of consistency in the delivery of energy efficiency services in areas where electric and gas Program Administrators have overlapping service territories. 2016-2018 Three-Year Plans Order, at 118. We appreciate that the Program Administrators have established and follow a statewide coordination protocol (Exh. DPU-Comm 11-5). Further, the Department commends the Program Administrators' recent efforts in aligning customer incentive levels and removing caps for weatherization measures offered statewide so that all customers can benefit from the same experience (Exh. DPU-Comm 11-6).

The issues raised by National Grid (gas) in this proceeding regarding the provision of energy efficiency services to mutual customers under its and the Compact's respective Three-Year Plans are complex, and the Department finds that they involve certain issues of law and fact common to those raised by National Grid (gas) in D.P.U. 16-169. Accordingly, the Department will not make any findings regarding the provision of energy efficiency services to mutual customers in this Order. Instead, the Department will address these issues comprehensively as part of its subsequent Order in D.P.U. 16-169.

F. Conclusion

The Department has reviewed the Compact's proposed Three-Year Plan, including its proposed enhancement to the Statewide Plan. After review, the Department approves the

continuation of the following enhanced incentives: (1) an uncapped, 100 percent incentive for qualified weatherization measures to electric customers (a) who are year-round renters and responsible for paying the electric bill, or (b) whose operations are managed by municipalities or other government entities; (2) cost-effective thermal measures to save oil, propane, and other unregulated fuels under the Compact's New Construction and Major Renovation program for C&I customers; (3) specialized incentives that cover up to 100 percent of cost-effective measures for C&I municipal customers; (4) a 95 percent incentive for qualifying small business tenants; (5) zero interest financing for small business customers; (6) a business energy audit and a core offering of deemed savings measures, some at 100 percent incentive coverage; (7) a 100 percent incentive for standard direct install measures for small business customers; and (8) a 100 percent incentive for all cost-effective measures for qualifying non-profits.

The Department appreciates the Compact's efforts to respond to the recent amendments to the Green Communities Act through proposals like the CVEO, however, the proposal did not benefit from sufficient stakeholder input prior to filing. The Department does not approve the Compact's proposed enhanced storage incentive and the bundled enhanced incentive, the CVEO, at this time.[72] The Compact may, however, seek Department

[72] The Compact is, however, permitted to offer cold-climate air-source heat pumps consistent with the structure and incentives of the Statewide Plan. The Compact is not permitted to offer battery storage or solar PV to any customers until the Department has determined that the Compact has resolved each of the issues identified herein.

approval for a revised offering after it has received stakeholder feedback and Council approval.

Because there are important issues regarding distribution system safety and reliability that remain to be resolved, the Compact may not offer any active demand reduction program, initiative, offering, or pilot that requires dispatch or could adversely impact distribution customers. In compliance with the directives herein, the Compact shall work with NSTAR Electric and the Council, as necessary, to reach an agreement that allows the Compact's customers access to active demand reduction offerings.

To ensure that all planned data reflect the directives above, within 21 days of the date of this Order, the Compact shall submit updated data tables as well as an updated BCR model. Finally, the Department notes that in its most recent EERF filing, the Compact filed a motion seeking clarification regarding whether certain budgets associated with its Three-Year Plan are within the scope of the allowed EES granted by the Department in the preliminary Order issued December 26, 2018 in its EERF filing. Cape Light Compact JPE, D.P.U. 18-128, Motion of the Cape Light Compact JPE for Clarification (January 7, 2019), citing Order on Petition for Approval of the Compact's 2018 EES, for Effect January 1, 2019 (2018). We take this opportunity to clarify that we consider each of the items listed in Appendix K to be enhancements to the Statewide Plan, consistent with the Compact's previous filings. Within 21 days of the date of this Order, the Compact shall file

an updated EES for effect April 1, 2019, that is consistent with the findings in this Order.[73] The updated EES should include any revisions submitted as part of the December 20, 2018 filing of revised tables.

IX. OTHER ISSUES

A. Strategic Electrification, and Renewable and Clean Energy Technologies

1. Introduction

As discussed above, the Energy Act of 2018 amended the Green Communities Act to expand the scope of energy efficiency programs that are eligible for inclusion in the Three-Year Plans. Energy Act of 2018, at § 2. In pursuit of the achievement of all cost-effective energy efficiency and demand reduction resources, the Program Administrators may now include programs that (1) provide energy and demand savings through strategic electrification that result in cost-effective reductions in GHG emissions and minimize ratepayer costs, and (2) result in customers switching to renewable energy sources or other clean energy technologies. G.L. c. 25, § 21(b)(2)(iv)(A), (J).

2. Program Administrators Proposal

The Program Administrators propose to implement new approaches to promote strategic electrification and to assist customers seeking to switch to renewable energy and other clean energy technologies (Statewide Plan, Exh. 1, at 10). The Program

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[73] The updated EES should reflect, among other things, the removal of any additional incentives proposed for cold-climate air-source heat pumps as part of the CVEO, all costs associated with solar PV, and all costs associated with all active demand reduction offerings. To the extent that the Compact subsequently receives Department approval for any of these programs, it may file a revised EES with the Department at that time.

Administrators state that these strategies are designed to further their overall energy optimization approach, which includes providing customers with enhanced education to help them reduce their total energy use based on individual needs and goals (Statewide Plan, Exh. 1, at 18; Exhs. DPU-Comm 2-6; DPU-Comm 2-7).

Specifically, the Program Administrators propose to offer customer incentives for strategic electrification measures and to support switching to clean energy technologies (Exh. DPU-Comm 2-5). The Program Administrators propose to offer the same incentive levels regardless of the customer's original fuel source (Exh. DPU-Comm 5-6). In this regard, customer incentives for displacing oil or propane use or switching to renewable energy and clean energy technologies will be based on the customer's total energy reduction (in MMBtu) based on the difference between the energy saved by displacing one fuel source and the increase in energy used by the new fuel source (Exh. DPU-Comm 1-7).

3. Positions of the Parties

a. Program Administrators

The Program Administrators argue that their proposal to offer incentives for strategic electrification and to support switching to renewable energy and clean energy technologies are appropriately designed to motivate customers to reduce overall energy consumption by supporting fuel-neutral heating options (Program Administrators Brief at 26). While the Program Administrators acknowledge that they have previously offered incentives for heat pumps and similar measures, they argue that those prior programs were designed to encourage the adoption of higher-efficiency heating systems and not to reduce overall energy

consumption like the current proposals (Program Administrators Brief at 26). The Program Administrators argue that the Department should approve their proposed offerings because they are cost effective, intended to result in overall energy reductions, and will be marketed to customers who are expected to experience overall energy and bill savings (Program Administrators Brief at 27).

b. Department of Energy Resources

DOER maintains that the Three-Year Plans represent a critical and positive shift in energy efficiency program delivery through the adoption of new approaches, including strategic electrification, fuel-switching to clean energy sources, and the broadening of electric programs to focus on overall energy reduction (DOER Brief at 13). DOER argues that the fuel switching approach proposed by the Program Administrators aligns with the Commonwealth's long-term energy policy goals and will provide customers with an expanded set of heating and hot water solutions, including cold-climate air-source heat pumps and wood pellet heating conversions, where appropriate (DOER Brief at 15-16). In addition, DOER maintains that the Program Administrators' proposed approach will provide enhanced information to customers regarding expected costs, energy savings, and the GHG impacts of fuel conversions (DOER Brief at 15). Finally, DOER asserts that the Program Administrators' strategic electrification proposals will allow Massachusetts to leverage its investments in a clean electric grid, lowering both emissions and costs (DOER Brief at 16).

c. Acadia Center

Acadia supports the Program Administrators' proposed strategic electrification efforts (Acadia Brief at 15; Acadia Reply Brief at 4). Acadia argues that the Department should approve the proposal because it appropriately features cold-climate air-source heat pumps, provides strategic electrification, and allows only electric Program Administrators to count the incremental MMBtu savings from switching or displacing oil and propane (Acadia Brief at 14-15, citing Exh. DPU-Comm-1, at 59; Statewide Plan, Exh. 1, App. F at 7).

d. Conservation Law Foundation

CLF contends the Program Administrators took too passive an approach to renewable and other clean energy technologies in the Three-Year Plans, despite the recent changes to the Green Communities Act that allow the Three-Year Plans to include programs to help customers switch to renewable and other clean energy technologies (CLF Brief at 8-9, citing G.L. c. 25, § 21(b)(2)(iv)(A), (J)). In addition, CLF argues that the Program Administrators have failed to identify a robust list of such technologies in order to establish a baseline of what is available to pursue in energy efficiency plans (CLF Brief at 8-10, citing G.L. c. 25, § 21(b)(2)(iv)(J)).

CLF contends that the Department should require the Program Administrators to focus their energy optimization efforts on the prioritization of strategic electrification and fuel switching to renewable and other clean energy technologies, rather than their allegedly "fuel-neutral" approach (CLF Brief at 8-12). In this vein, CLF argues that the Program Administrators should make renewable and clean energy options maximally valuable to

customers rather than continuing to push gas conversions with supposedly fuel-neutral marketing that encourages fuel switching to gas (CLF Brief at 11-12). Finally, CLF maintains that the Program Administrators should ensure that marketing and education about incentives available for high-efficiency gas equipment is given less weight than marketing and education regarding the costs and benefits of cold-climate air-source heat pumps, solar plus storage, and other renewable and clean energy technologies (CLF Brief at 12).

e. PowerOptions

PowerOptions asserts that the Three-Year Plans are appropriately designed to instill a culture of energy efficiency that transcends fuel type (PowerOptions Brief at 10). PowerOptions argues that a holistic approach to reducing overall energy use, rather than a focus on reducing only gas or electricity use, will allow the Program Administrators to better adapt the energy efficiency programs to meet customer needs (PowerOptions Brief at 10). Finally, PowerOptions maintains that it is supportive of air-source heat pumps as the primary measure proposed by the Program Administrators, and it argues that strategic electrification is necessary to achieve GHG reduction goals (PowerOptions Brief at 10).

4. Analysis and Findings

Consistent with recent amendments to the Green Communities Act, the Program Administrators propose to incorporate new approaches in their Three-Year Plans that provide education and support for strategic electrification and for customers seeking to switch to renewable energy and clean energy technologies, such as wood pellet heating and other renewable thermal heating and water heating technologies (Statewide Plan, Exh. 1, at 18, 59,

69, 110-111, 129; Exhs. DPU-Comm 1-7; DPU-Comm 2-5; DPU-Comm 2-6; DPU-Comm 5-8; NEEC-Comm 1-5; NEEC-Comm 2-2). G.L. c. 25, § 21(b)(2)(iv)(A), (J). These proposed strategies received wide support from the parties, including DOER (see, e.g., DOER Brief at 13-16). After review, the Department finds that the Program Administrators have demonstrated that these proposed strategies are designed to provide cost-effective GHG emission reductions, while minimizing costs to ratepayers, and are an appropriate part of the Program Administrators' overall plan to provide all cost-effective energy efficiency and demand reductions under the Green Communities Act. G.L. c. 25, § 21(b)(2)(iv)(A), (J), (d)(2).

CLF argues that the Program Administrators should be required to prioritize customer education and marketing efforts for strategic electrification and fuel switching to renewable and other clean energy technologies, over a fuel neutral approach that still encourages fuel switching to gas (CLF Brief at 11). In response, the Program Administrators maintain that offering incentives that motivate customers to reduce overall energy consumption through strategic electrification or switch to renewable energy and clean energy sources, is part of their overall energy optimization approach, which they claim is appropriately focused on reducing customer energy use and demand (Program Administrators Brief at 26; Tr. 1, at 118).

Strategic electrification and programs that encourage a switch to renewable energy and clean energy technologies are some of the new tools that the Program Administrators can now include in their Three-Year Plans in an effort to reduce GHG emissions. G.L. c. 25,

§ 21(b)(2)(iv)(A), (J). The availability of these new tools is intended to enhance, but not replace, the Program Administrators' traditional focus since 2010 on the pursuit of all available cost-effective energy efficiency and demand reduction resources. With the Program Administrators' energy optimization approach, the goal going into a home is to provide customer education on every available option, including heat pumps and renewables, rather than pursuing only more efficient versions of what the customer currently has (e.g., a more efficient oil heating system to replace a standard oil heating system) (Tr. 1, at 128-129). While the Department encourages the Program Administrators to provide appropriate customer education and marketing for strategic electrification and renewable/clean energy[74] switching initiatives, such marketing and customer education needs to be a balanced part of the Program Administrators' overall energy optimization approach. As the Department finds above, this approach is appropriately designed to deliver cost-effective savings with appropriate consideration of the long- and short-term rate and bill impacts that these strategies bring.

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[74] The Department notes that renewable electric generation (e.g., solar PV, biomass, and wind) has dedicated ratepayer and taxpayer funding sources to support the installation thereof. See, e.g., G.L. c. 25, § 20. For example, the SMART program provides incentives to encourage certain types of renewable electric generation and energy storage installations. An Act Relative to Solar Energy, St. 2016, c. 75 (establishing new SMART program framework).

B. Converting Fuel Savings to MMBtu

1. Program Administrators Proposal

The Program Administrators propose to provide key data points to measure the success of these Three-Year Plans and also to provide metrics to compare with prior three-year plans, in order to facilitate stakeholder review of the impacts of the various programs (Statewide Plan, Exh. 1, at 15-16). To accomplish this, the Program Administrators propose to provide net lifetime all fuel savings measured in MMBtu, excluding MMBtus associated with active demand reduction efforts (Statewide Plan, Exh. 1, at 16). The Program Administrators maintain that such calculations will illustrate the net effect of all fuel savings efforts (i.e., electric, natural gas, oil, and propane), as well as the impact of fuel conversions that result in overall lower energy use (Statewide Plan, Exh. 1, at 16).

2. Analysis and Findings

In an effort to provide comparable data points among different fuel types, the Program Administrators propose to convert all fuel savings to MMBtu (Statewide Plan, Exh. 1, at 15-16). The Department is concerned, however, about the method used by the Program Administrators for such conversions. In particular, the Program Administrators use a simplified method of (1) converting electricity used on-site but generated offsite and (2) converting electricity generated at combined heat and power plants (Exh. DPU-Comm 4-1). Electricity used on-site, but generated offsite, contains embedded energy with heat values from a mix of fuels that generate the electricity; however, the

Program Administrators failed to consider this embedded energy during the unit conversion (Exh. DPU-Comm 4-1). Further, the Program Administrators employed the concept of marginal GHG emission rates when calculating the heat value of combined heat and power plants (Exh. DPU-Comm 4-1). The Department has concerns about mixing heat values with GHG emission rates when converting energy savings for combined heat and power plants (Exh. DPU-Comm 4-1).

The Department appreciates the Program Administrators' efforts in attempting to convert all fuel savings into a common unit of measurement. However, in light of the issues discussed above, we direct the Program Administrators to further study and propose a more refined method to account for the conversion of electric savings to MMBtu savings. The Program Administrators shall report the progress or results of this study as part of their 2019 Annual Reports.

C. Merrimack Valley

1. Introduction

As part of its October 30, 2018, resolution, the Council stated that it expects Columbia Gas to dedicate targeted efforts to support the installation of high-efficiency equipment and weatherization measures in homes and businesses affected by the September 2018 incident in the Merrimack Valley (Statewide Plan, Exh. 1, App. G at 3).

2. Columbia Gas Proposal

Columbia Gas states that, in setting its proposed savings goals in its Three-Year Plan, it took into account planned and targeted efforts to support the installation of high-efficiency

equipment and weatherization measures in the Merrimack Valley (Exh. CMA-2, at 68). Columbia Gas states that it will encourage increased participation in its energy efficiency programs in Lawrence, Andover, and North Andover (i.e., the affected municipalities in the Merrimack Valley) through (1) additional resources to support customers, (2) increased participant incentives/rebates, and (3) targeted marketing efforts (Exh. DPU-Columbia 1-1).

For example, Columbia Gas proposes to send additional crews to perform home assessments in the affected area (Exh. DPU-Columbia 1-1). For affected residential customers whose home assessments recommend weatherization measures, Columbia Gas proposes to waive the customer contribution for such measures (Exh. DPU-Columbia 1-1). Further, Columbia Gas proposes to offer increased rebates and manage the rebate process for the residential self-installation of high-efficiency equipment (Exh. DPU-Columbia 1-1).

Similarly, Columbia Gas proposes to assign additional project managers to assist affected small business owners with the installation of new equipment and to provide additional rebates to small businesses that pursue high-efficiency equipment installation on their own (Exh. DPU-Columbia 1-1). Additionally, Columbia Gas states that qualified small businesses (including non-profits and faith organizations) will be eligible for no-cost weatherization measures or enhanced incentives to mitigate certain barriers to energy efficiency installations through C&I retrofit and direct install programs (Exh. DPU-Columbia 1-1). Finally, Columbia Gas proposes to coordinate marketing and education efforts related to dedicated resources for the Merrimack Valley with National Grid (electric) (Exh. DPU-Columbia 1-1).

Columbia Gas states that it already has started to roll out some of these offerings but that adequately serving the Merrimack Valley will require sustained efforts throughout 2019 (Exh. DPU-Columbia 1-1). Therefore, Columbia Gas proposes to evaluate the costs and savings of the relevant programs over the course of the year (Exh. DPU-Columbia 1-1).

3. Positions of the Parties

a. Columbia Gas

Columbia Gas argues that its proposed efforts to target affected customers in the Merrimack Valley align with the expectations of the Council in its October 30, 2018 resolution (Exh. DPU-Columbia 1-1). In addition, Columbia Gas asserts that targeting affected customers in the Merrimack Valley, as a specific geographic area that has a large concentration of underserved customers, is consistent with the stakeholder recommendations it received throughout the development of its Three-Year Plan (Exh. DPU-Columbia 1-1).

b. Conservation Law Foundation

CLF supports Columbia Gas' use of energy efficiency resources in assisting customers affected by the September 2018 incident in the Merrimack Valley, especially in Lawrence, which it notes is an environmental justice community[75] (CLF Brief at 49). CLF requests that the Department require Columbia Gas to report on the progress of its efforts in the

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[75] In Massachusetts, a community is identified as an environmental justice community if any of the following are true: (1) it is a block group whose annual median household income is equal to or less than 65 percent of the statewide median; (2) 25 percent or more of the residents identify as a race other than white; or (3) 25 percent or more of households have no one over the age of 14 who speaks English only or very well. Environmental Justice Policy of the Executive Office of Energy and Environmental Affairs (January 31, 2017).

Merrimack Valley, including the following: (1) progress updates; (2) installation updates; (3) budget updates; (4) marketing updates; (5) progress on addressing barriers; (6) pilots or new technology updates; and (7) coordination with National Grid (electric) (CLF Brief at 50).

4. Analysis and Findings

Columbia Gas already has begun implementing targeted efforts to support the installation of high-efficiency equipment and weatherization measures for residential and business customers affected by the September 2018 incident in the Merrimack Valley (Exhs. CMA-2, at 68; DPU-Columbia 1-1). The bulk of these efforts will be rolled out during 2019 (Exh. DPU-Columbia 1-1). This provides an opportunity for Columbia Gas to pursue the lowering of energy demand for the affected area.

As part of its 2019 Annual Report, Columbia Gas shall include a detailed report on the status of its targeted efficiency measures in the Merrimack Valley. Further, Columbia Gas shall provide reports on the status of its targeted efforts in the Merrimack Valley as part of its quarterly updates to the Council, beginning with its first quarterly report of 2019. Both the Annual Report to the Department and the quarterly reports to the Council should address all relevant information regarding customer participation, costs, benefits, and savings resulting from these efforts in the Merrimack Valley.

D. Data Reporting and Tracking

1. Program Administrators Proposal

With respect to data reporting and tracking in the Three-Year Plan term, the Program Administrators propose to (1) continue to maintain Mass Save Data[76] and (2) include additional information on a bi-annual basis as part of their quarterly reports to the Council[77] (Statewide Plan, Exh. 1, at 179-180). Specifically, the Program Administrators propose to provide the following bi-annual information to the Council: (1) the number of approved applicants in the moderate income offering; (2) the number of approved applicants in the moderate income offering that result in weatherization jobs; (3) the number of participants (excluding upstream and behavior) by zip code, broken out by (a) residential-sector initiatives subtracting moderate income offering participants, (b) moderate-income offering, and (c) low-income initiatives; (4) small business savings, budgets, and participation across all C&I initiatives; and (5) streetlight conversions (Statewide Plan, Exh. 1, at 179).

Finally, the Program Administrators have agreed to include six additional performance indicators in their quarterly reports to the Council (Statewide Plan, Exh. 1, App. F at 9).

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[76] Mass Save Data is the publicly accessible statewide energy efficiency database developed and maintained by the Program Administrators. 2016-2018 Three-Year Plans Order, at 145. Mass Save Data contains both granular and high level information that, while protecting customer privacy, draws on contractor evaluations, customer profile studies, and geographic information (Statewide Plan, Exh. 1, at 180-181). Mass Save Data is available at http://www.MassSaveData.com.

[77] Currently, the Program Administrators provide publicly available reports to the Council (e.g., monthly data dashboards) and quarterly reports pursuant to G.L. c. 25, §22(d)).

The Program Administrators state that these additional performance indicators will be developed in consultation with the Council (Statewide Plan, Exh. 1, at 179).

2. Positions of the Parties

a. Program Administrators

The Program Administrators argue that they are committed to providing transparent and publicly accessible energy efficiency data, while ensuring customer confidentiality (Program Administrators Reply Brief at 22). The Program Administrators maintain that they provide these data through the Mass Save Data database, which contains information that is complementary to the data that the Program Administrators provide to the Department and the Council (Program Administrators Reply Brief at 22). Further, the Program Administrators maintain that they have agreed to work with the Council to report data on up to six additional, mutually agreed-upon performance indicators (Program Administrators Reply Brief at 22).

The Program Administrators assert that they can reasonably collect low-income participation data by zip code and will comply with the Council's request to provide these data bi-annually (Program Administrators Reply Brief at 22-23). In response to LEAN's assertion that the provision of such data every six months will not be meaningful, the Program Administrators acknowledge that snapshots of these data, provided at this level of granularity and frequency, should not be relied upon to draw any conclusions regarding program participation in one community versus another (Program Administrators Reply Brief at 23). Instead, the Program Administrators maintain that they will continue to rely on

customer profile studies and information collected over a longer term to determine the effects of energy efficiency programs on various communities and demographics (Program Administrators Reply Brief at 23). Finally, the Program Administrators maintain that providing zip code level participation data does not implicate any customer privacy concerns (Program Administrators Reply Brief at 23).

In response to CLF's argument that the Program Administrators should be required to track information on customer age, race, ethnicity, disability, income, and primary language, the Program Administrators assert that the Department has found that the Green Communities Act does not obligate them to track and report such data (Program Administrators Reply Brief at 23-24, citing 2010-2012 Electric Three-Year Plans Order, at 156). Further, the Program Administrators argue that the provision of such data would add significant, unnecessary costs and may deter customer participation in energy efficiency programs and initiatives (Program Administrators Reply Brief at 26). The Program Administrators note, however, that while they do not track customer demographic information while delivering program services, they do engage third-party evaluators to develop publicly available customer profile studies that examine the level of service to customers across all energy efficiency programs by town, income level, renter status, age brackets, and non-English speakers (Program Administrators Reply Brief at 24-25). In addition, for the 2019 through 2021 term, the Program Administrators maintain that they intend to conduct evaluations that will collect data regarding participation levels and potential barriers for

residential and business customers by income level and by non-English speaking populations (Program Administrators Reply Brief at 25-26, citing Statewide Plan, Exh. 1, at 29).

b. Acadia Center

Acadia argues that reliable, publicly available, disaggregated data on energy efficiency participants are needed to ensure equity in program accessibility (Acadia Reply Brief at 2). Therefore, Acadia requests that the Department require the Program Administrators to track and publicly report enhanced data on participant race, ethnicity, language, and income (Acadia Reply Brief at 4).

c. Conservation Law Foundation

CLF argues that energy efficiency resources are an important means to address energy insecurity and financial inequality in underserved communities, and there are insufficient data to assess participation in the Three-Year Plans by customers in underserved communities (CLF Brief at 16, 18-20). While CLF supports the Program Administrators' efforts to expand data collection and reporting, it asks the Department to consider the value of further expanding data collection to better serve environmental justice communities (e.g., tracking and reporting participant data disaggregated by race, ethnicity, language spoken, renters, homeowners, age, and income level, other than low income) (CLF Brief at 32, 36).

d. Low-Income Energy Affordability Network

LEAN requests that the Department deny the Program Administrators' proposal to report low-income participation data by zip code every six months to the Council (LEAN Brief at 6). LEAN asserts that six-month reporting by zip code will provide no reliable basis

upon which to draw conclusions about equitable service to low-income households because every geographic area cannot be simultaneously served in a six-month period (LEAN Brief at 5). LEAN argues that reporting low-income participation data over a longer period will provide a more meaningful measure of service across geographic areas (LEAN Brief at 6).

e. PowerOptions

PowerOptions asserts that digestible data reporting is important for both the Council and the public to assess the effectiveness of the energy efficiency programs (PowerOptions Brief at 12). To this end, PowerOptions maintains that it will work with the Program Administrators to develop the six new performance indicators intended to track Council priorities and Three-Year Plan progress (PowerOptions Brief at 12-13).

3. Analysis and Findings

The Program Administrators track and report various data related to their energy efficiency programs and initiatives pursuant to statutory requirements, Department directives, and Council agreements. See, e.g., G.L. c. 25, §§ 21(b), (c), (d); G.L. c. 25, §§ 22(d); D.P.U. 11-120-A, Phase II. The Program Administrators propose to continue to use Mass Save Data as the publicly facing repository for performance, cost, savings, usage, emissions mitigation, and measure-specific data[78] (Statewide Plan Exh. 1, at 180). In addition, as part of their quarterly reports to the Council, the Program Administrators have agreed to (1) include certain additional energy efficiency information on a bi-annual basis and (2)

[78] Mass Save Data presents customer usage data on a monthly and annual basis, and customer savings and incentives on an annual basis. These data are aggregated by zip code to the town and county levels (Statewide Plan, Exh. 1, at 180-181).

develop and report on six additional performance indicators (Statewide Plan, Exh. 1, at 179; App. F at 9).

Since it was first developed in 2014, the Program Administrators have continued to enhance and expand Mass Save Data (Statewide Plan Exh. 1, at 180). In its current form, Mass Save Data remains an essential tool to provide publicly accessible, transparent energy efficiency data in a format that fully ensures customer confidentiality (Statewide Plan Exh. 1, at 180-181). Accordingly, the Department approves the Program Administrators' proposal to continue to use Mass Save Data for energy efficiency data reporting.

CLF requests that the Program Administrators expand their data collection efforts to track and report on customer demographic information, including age, race, ethnicity, disability, income, and primary language (CLF Brief at 20). The Department shares the Program Administrators' concern that the tracking of such demographic data could implicate customer privacy issues and may deter participation in energy efficiency programs and initiatives by customers who do not want to disclose this information (Program Administrators Reply Brief at 25). In addition, the Green Communities Act does not require the Program Administrators to report such demographic data. 2010-2012 Electric Three-Year Plans Order, at 156; 2010-2012 Gas Three-Year Plans Order, at 163-164. With the exception of the data reporting directives addressed in Section VI.D above,[79] the Department

[79] In Section VI.D above, the Department directs the Program Administrators to track and report readily available data regarding renter participation. The renter population has been a hard-to-reach segment and was identified by the Council for further tracking and exploration (Statewide Plan, Exh. 1, Apps. D, E, F).

will not require the Program Administrators to track and report demographic data in the manner requested by CLF.

As an alternate source of demographic data, the Department notes that the Program Administrators retain third-party evaluators to develop customer-specific profile studies that examine the level of service to customer by town, income level, renter status, age bracket, and non-English speakers; these studies are publicly available.[80] Finally, for the 2019 through 2021 Three-Year Plan term, the Program Administrators will conduct evaluations that address participation levels and unaddressed barriers by income level and non-English speaking populations (Statewide Plan, Exh. 1, at 29). These efforts will be an important tool to help the Program Administrators and stakeholders improve the delivery of energy efficiency services to customers in underserved communities.

LEAN opposes the Program Administrators' decision to report low-income participation, by zip code, to the Council every six months (LEAN Brief at 6). LEAN asserts that this information will not provide a sufficient basis on which to draw conclusions on the equitable distribution of energy efficiency services to low-income customers (LEAN Brief at 5-6). The Program Administrators readily acknowledge that a snapshot of such data should not be relied upon, by itself, to draw conclusion on program participation (Program Administrators Reply Brief at 23). Rather, the Program Administrators state that they will

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[80] The 2013-2015 Residential Customer Profile Report is available at http://ma-eeac.org/studies/.

continue to rely on customer profile studies, and other information collected over time, to inform any decisions on program delivery (Program Administrators Reply Brief at 23).

The Program Administrators have agreed to provide the additional data at the request of the Council (Program Administrators Reply Brief at 23). We recognize LEAN's concern that such data, if improperly used, may lead to inaccurate conclusions. In this instance, however, the information will be presented to the Council where its utility can be debated. Accordingly, we approve the Program Administrators' proposal to include additional information (including the contested low-income participation data) on a bi-annual basis as part of their quarterly reports to the Council.

E. Residential Conservation Services and Energy Scorecards

1. Introduction

The RCS statute was promulgated in 1980 and provides a framework for in-home energy conservation services for residential customers. G.L. c. 164 App., §§ 2-1 to 2-10. Pursuant to the Energy Act of 2012, the Program Administrators have elected to incorporate their RCS filings for 2019-2021 in their respective Three-Year Plans. St. 2012, c. 209, §§ 32(h), (i). Therefore, the Department must review the reasonableness of the proposed RCS budgets in the instant proceedings. G.L. c. 164 App., § 2-7(b); St. 2012, c. 209, § 32(i).

On April 17, 2017, DOER promulgated revised RCS regulations, 225 CMR 4.00. On September 19, 2018, DOER released final guidelines ("RCS Guidelines")[81] interpreting 225 CMR 4.00. The RCS Guidelines include a requirement that the Program Administrators must provide DOER-approved energy scorecards in conjunction with in-home energy audits (RCS Guidelines § 2.B.1).

2. Program Administrators Proposal

Each Program Administrator proposes to include its RCS budget as part of the Residential Existing Buildings program for each year of the Three-Year Plan (Statewide Plan, Exh. 1, at 47). The Program Administrators propose to use the RCS budgets to fund all costs related to residential energy assessments and site visits that are part of the broader Residential Coordinated Delivery initiative (Statewide Plan, Exh. 1, at 52). The Program Administrators state that they developed the Residential Coordinated Delivery initiative as part of a redesigned approach for providing energy efficiency services to residential customers in existing buildings (Statewide Plan, Exh. 1, at 52). The Program Administrators propose to recover RCS costs through the EES (Statewide Plan, Exh. 1, at 184 n.52).

The Program Administrators have agreed to implement energy scorecards as part of the residential in-home energy assessments (Statewide Plan, Exh. 1, at 52 n.24). The Program Administrators state they will develop the design for such scorecards in

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[81] DOER, Guideline Interpreting 225 CMR 4.00 (September 24, 2018), available at https://www.mass.gov/files/documents/2018/09/24/RCS%20Guideline%20Final%209-24-18.pdf. Pursuant to 220 CMR 1.10(2), the Department takes official notice of the RCS Guidelines.

collaboration with DOER (Statewide Plan, Exh. 1, at 52 n.24). The Program Administrators further state that their target date for the roll out of energy scorecards is July 2019 (Statewide Plan, Exh 1, at 52 n.24). The proposed RCS budgets do not, however, include any allocated funding for the energy scorecards (Exhs. DPU-Comm 11-4; DPU-Comm 2-1).

3. Positions of the Parties

a. Program Administrators

The Program Administrators maintain that they have assented to DOER's directives to develop energy scorecards for residential customers who obtain in-home energy audits (Program Administrators Brief at 77). The Program Administrators assert that they intend to develop a design for such scorecards in consultation with DOER and determine an appropriate budget for scorecard implementation (Program Administrators Brief at 77). The Program Administrators seek Department guidance on the process they should follow to implement the energy scorecards (Program Administrators Brief at 78).

b. Attorney General

The Attorney General argues that the concerns raised by GBREB and MAR regarding the energy scorecards lack merit (Attorney General Reply Brief at 3). Contrary to GBREB and MAR's assertions, the Attorney General maintains that adoption of energy performance scores for residential properties has not been rejected by the Legislature (Attorney General Reply Brief at 3, citing GBREB Brief at 7; MAR Brief at 8). Further, the Attorney General argues that an energy scorecard would not be compulsory for all residential real estate sale transactions (Attorney General Reply Brief at 3).

c. Department of Energy Resources

DOER argues that the Department should approve the RCS budgets as proposed because they meet the standard for reasonableness (DOER Reply Brief at 3). In addition, DOER argues that the Program Administrators should be permitted to seek a midterm modification to their Three-Year Plans if the implementation of energy scorecards leads to an increase in RCS budgets of greater than 20 percent (or an alternate dollar value as specified by the Department) (DOER Reply Brief at 7, citing Guidelines § 3.8.1(3)).

DOER maintains that the energy scorecards will enhance the in-home energy assessment reports by providing information to customers about the benefits of implementing recommended energy efficiency measures (DOER Brief at 20; DOER Reply Brief at 4). DOER argues that a pilot program found significant customer support for information provided in the form of an energy scorecard (DOER Reply Brief at 4). Further, DOER maintains that the energy scorecards will be provided in conjunction with information on rebates, incentives, and financing available for energy upgrades (DOER Reply Brief at 5).

In response to the arguments raised by GBREB and MAR, DOER asserts that both 225 CMR 4.00 and the RCS Guidelines require energy scorecards and, therefore, GBREB and MAR have no basis to assert that the Department should reject the energy scorecards (DOER Reply Brief at 3, citing GBREB Brief at 6; MAR Brief at 6). In addition, DOER disputes GBREB and MAR's allegations that its energy scorecard requirements are an attempt to circumvent Legislative intent regarding scorecards as part of real estate transactions (DOER Reply Brief at 4).

Finally, DOER argues that, contrary to GBREB and MAR's assertions, energy scorecards are not required to be cost effective (DOER Reply Brief at 6). Instead, DOER argues that the Department is only required to review the reasonableness of the proposed RCS budgets without regard to RCS program cost effectiveness (DOER Reply Brief at 6, citing 2016-2018 Three-Year Plans Order, at 99).

d. Acadia Center

Acadia argues that the Department should approve the energy scorecards as proposed and any associated RCS budgets (Acadia Brief at 6; Acadia Reply Brief at 4).

e. Greater Boston Real Estate Board

GBREB argues that the Department should not preapprove the proposed energy scorecards as part of its approval of the RCS budgets and, instead, direct the Program Administrators to file a midterm modification if and when energy scorecard program details and budgets have been finalized (GBREB Brief at 6; GBREB Reply Brief at 2-3). In particular, GBREB contends that the record does not support preapproval of the proposed energy scorecard program and cautions that energy scorecards could have significant and unintended consequences for the residential real estate market, which the Program Administrators have failed to account for in terms of cost effectiveness (GBREB Brief at 6-8; GBREB Reply Brief at 2).

GRBEB further argues that neither DOER nor the Program Administrators have provided any specific authority for or analysis of the proposed energy scorecard program (GBREB Reply Brief at 2, citing Program Administrators Brief at 7; DOER Brief at 20).

Finally, GBREB asserts that use of home energy scoring has been rejected by the Legislature on two prior occasions (GBREB Brief at 7).

f. Massachusetts Association of Realtors

MAR argues that energy scorecards will have significant and unintended consequences for the residential real estate market in Massachusetts (MAR Reply Brief at 2). In addition, MAR asserts that cost effectiveness of energy scorecards cannot be measured based on the evidence offered by the Program Administrators (MAR Brief at 7; MAR Reply Brief at 2). In particular, MAR argues that the budget and design of the proposed energy scorecard program have yet to be developed and, therefore, the cost effectiveness of the energy scorecards cannot be determined (MAR Brief at 7; MAR Reply Brief at 2).

MAR maintains that the Program Administrators offer no specific authority for or analysis of the proposed energy scorecard program, yet they request approval of the program (MAR Reply Brief at 1-2). Therefore, MAR argues that the Department should not preapprove the proposed energy scorecard program as part of its review of the RCS budgets and, instead, should require the Program Administrators to file midterm modifications to their Three-Year Plans, once the design of the proposed program is complete (MAR Brief at 10; MAR Reply Brief at 2).

4. Analysis and Findings

The Department has reviewed the Program Administrators' proposed RCS budgets for the 2019 through 2021 Three-Year Plan term and finds that the budgets are reasonable (see,

e.g., Exh. CMA-4 (Rev.) (December 20, 2018)). Accordingly, the Department approves the Program Administrators' proposed RCS budgets for 2019 through 2021.

Other than confirming that they intend to implement energy scorecards as part of the RCS program in the near future, the Program Administrators have not included an energy scorecard proposal or allocated any funding for energy scorecards in the RCS budgets approved by the Department above (Statewide Plan, Exh. 1, at 52 n.24; Exhs. DPU-Comm 11-4; DPU-Comm 2-1). Accordingly, the Department will not make any substantive findings regarding energy scorecards or associated RCS budgets in the instant proceeding. The Department encourages the Program Administrators to work collaboratively with DOER and other stakeholders, including GBREB and MAR, in designing the energy scorecards to ensure that ratepayers receive the greatest benefits.[82]

The Department's Guidelines do not address the process for amending an approved RCS budget. To the extent that the Program Administrators can implement energy scorecards within the scope of their approved RCS budgets, the Program Administrators will not be required to obtain Department approval.[83] However, to the extent that implementation of energy scorecards will require an increase to the approved RCS budget of greater than

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82 The RCS Guidelines at 4 n.4 provides that energy scorecard "design criteria and minimum requirements will be determined by DOER with the input of [Program Administrators], their audit vendors, and customer representatives."

83 As part of its 2019 Annual Report, each Program Administrator shall address the implementation of energy scorecards, including budget.

20 percent, the Program Administrator shall file an amended RCS budget for Department review.

F. Pilgrim Fund

1. Introduction

NSTAR Electric seeks Department approval to apply approximately $275,000 (plus applicable interest) remaining in the Pilgrim Fund to supplement its low-income energy efficiency program delivery during the Three-Year Plan term (Statewide Plan, Exh. 1, App. K at 1). NSTAR Electric maintains that the Pilgrim Fund was created through various settlements between Commonwealth Electric Company ("Commonwealth"), the Attorney General, and LEAN to fund, among other things, low-income energy efficiency[84] (Statewide Plan, Exh. 1, App. K at 1).

Specifically, NSTAR Electric proposes to use these funds to complete health- and safety-related repairs through its Income-Eligible Coordinated Delivery Initiative (Statewide Plan, Exh. 1, App. K at 1). NSTAR Electric states that these repairs will address barriers that traditionally prohibit the installation of energy efficiency upgrades, such as knob and tube wiring, substandard roofs, faulty windows, and other physical obstacles to

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[84] The Pilgrim Fund is the result of an earlier settlement between Commonwealth and Boston Edison Company related to an outage at the Pilgrim Nuclear Power Station. Under the terms of the earlier settlement, Boston Edison Company paid Commonwealth certain funds to be applied to demand-side management programs that were to be specified by the Attorney General and then filed with the Department for approval (Statewide Plan, Exh. 1, App. K at 1). For further background on the Pilgrim Fund, refer to Cambridge Electric Light Co., D.P.U. 91-80, Phase 2-A (1992), and Cambridge Electric Light Company and Commonwealth Electric Company, D.P.U. 95-95 (1996).

weatherization (Statewide Plan, Exh. 1, App. K at 1). NSTAR Electric estimates that 35 to 40 homes will be served with these funds, at an average cost of $7,000 to $8,000 per home[85] (Statewide Plan, Exh. 1, App. K at 1). NSTAR Electric proposes to work collaboratively with the Attorney General and LEAN to administer these funds (Statewide Plan, Exh. 1, App. K at 1).

2. Positions of the Parties

a. NSTAR Electric

NSTAR Electric argues that use of the remaining Pilgrim Fund proceeds in the manner it proposes will provide an appropriate opportunity to undertake needed repairs in low-income households that could otherwise prohibit the installation of energy efficiency upgrades (Program Administrators Brief at 58).

b. Attorney General

The Attorney General supports the application of the remaining Pilgrim Fund proceeds as proposed by NSTAR Electric (Attorney General Reply Brief at 1-2). In particular, the Attorney General argues that the proceeds from the fund will benefit qualified low-income customers and deliver energy savings in an area not covered under traditional energy efficiency program funding (Attorney General Reply Brief at 2). The Attorney General maintains that she will work with LEAN and NSTAR Electric to ensure all existing

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85 NSTAR Electric states that repairs will be made to low-income single- and multi-family housing in the former Commonwealth and Cambridge Electric Light Company service areas (Statewide Plan, Exh. 1, App. K at 1).

funding is optimally leveraged before the disposition of any Pilgrim Fund proceeds (Attorney General Reply Brief at 2).

3. Analysis and Findings

The Department approves NSTAR Electric's proposal to use the remaining Pilgrim Fund proceeds, as part of its Income-Eligible Coordinated Delivery Initiative, to remediate pre-weatherization barriers. The Department finds that the use of such funds in the manner proposed by NSTAR Electric is consistent with the intent of the various settlements that created the Pilgrim Fund and will provide an important benefit to low-income customers who may not otherwise receive energy efficiency upgrades and services. The Department directs NSTAR Electric to work with LEAN and the Attorney General to ensure that the remaining Pilgrim Fund amounts are used to deliver the maximum benefit to eligible low-income customers.

G. Interim Continuation

Pursuant to the Green Communities Act, Program Administrators are required to file their three-year plans by October 31st of the year prior to the first year of the three-year plan. G.L. c. 25, § 21(d)(1). The Department must issue an Order on the three-year plans within 90 days of filing. G.L. c. 25, § 21(d)(2). The timing of the Program Administrators' filings and the Department's review results in the previously approved energy efficiency programs ending approximately 30 days prior to the Department's approval of the new three-year plans.

In recognition of the need for continuity of energy efficiency programs, the Department has allowed for interim continuation of existing energy efficiency programs, pending approval of proposed new programs under review. See, e.g., 2013-2015 Three-Year Plans, Order on Motions for Interim Continuation (2012); 2010-2012 Three-Year Plans, Order on Motions for Interim Continuation (2009). Consistent with this practice, the Department has approved the Program Administrators' request to continue the existing Department-approved energy efficiency and RCS programs until the Department concludes its investigation of the Three-Year Plans in the instant dockets. 2019-2021 Three-Year Plans, Order on Motions for Interim Continuation (2018).

In order to ensure the continuity of energy efficiency programs in the future and obviate the need for motions for interim continuation, each Program Administrator may continue all energy efficiency and RCS programs approved in this Order, until the Department concludes its investigation of the subsequent three-year plans, unless otherwise ordered by the Department. The Program Administrators shall continue their existing energy efficiency and RCS programs at Department-approved expenditure levels for program-year 2021. All funds expended during the interim continuation of energy efficiency and RCS programs will be charged against the Program Administrators' 2022 budgets.

X. CONCLUSION

Each Program Administrator's Three-Year Plan must provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply. See G.L. c. 25, §§ 19(a), 19(b), 21(b)(1); see also Guidelines

§ 3.4.7. The Department has reviewed the savings goals contained in the Three-Year Plans and finds that they are reasonable and are consistent with the achievement of all available cost-effective energy efficiency and demand reduction resources. In developing these goals, the Department finds that the Program Administrators have appropriately considered program sustainability as well new technologies and enhancements. In addition, the Department finds that the Program Administrators have appropriately considered service territory-specific savings drivers and have designed initiatives to address identified barriers. The Department expects that the Program Administrators will continue to identify and explore innovative strategies to address barriers to participation in energy efficiency for hard-to-reach customers.

Consistent with the requirements of G.L. c. 25, §§ 19(a), 19(c), 21(b)(2), the Department finds that each Program Administrator's Three-Year Plan: (1) is designed to minimize administrative costs to the fullest extent practicable; (2) uses competitive procurement to the fullest extent practicable; and (3) includes a budget for low-income programs that meets the statutory minimums of ten percent for electric Program Administrators and 20 percent for gas Program Administrators.

The Green Communities Act requires the Department to ensure that the energy efficiency sectors included in the Three-Year Plans are cost effective. G.L. c. 25, § 21(b)(3). The Department finds that each Program Administrator: (1) has appropriately evaluated the cost effectiveness of its energy efficiency programs; and (2) has demonstrated that, based on the projected benefits and costs, all energy efficiency sectors and programs are cost effective for each plan year and over the entire 2019-2021 Three-Year Plan term.

Pursuant to the Green Communities Act, the Three-Year Plans include a mechanism designed to provide an incentive to eligible Program Administrators based on their success in meeting or exceeding certain performance goals. G.L. c. 25, § 21(b)(2)(v). Subject to certain modifications and disallowances addressed herein, the Department approves: (1) the statewide incentive pool; (2) the structure of the performance incentive mechanism for the savings and value components; and (3) the calculation of the savings and value component payout rates.

With respect to energy efficiency program funding, the Department has considered (1) the availability of other private or public funds, (2) whether past programs have lowered the cost of electricity to consumers, and (3) the effect of rate increases on consumers, and finds that each Program Administrator may recover the funds to implement its Three-Year Plan through the EES. G.L. c. 25, §§ 19(a), 21(b)(2)(vii). In particular, the Department finds that the proposed budgets are appropriately designed to achieve savings goals while minimizing customer rate impacts.

Subject to the modifications and disallowances addressed herein, the Department concludes that each Program Administrator's Three-Year Plan is consistent with the Green Communities Act, the Guidelines, and Department precedent. Accordingly, subject to the modifications, disallowances, and directives contained herein, the Department approves each Program Administrator's Three-Year Plan and budget.

Significant benefits will flow to Massachusetts ratepayers from the energy efficiency program investments we approve today. The Three-Year Plans approved today incorporate

innovative approaches designed to achieve untapped energy and fuel savings while emphasizing a continued commitment to the appropriate use of ratepayer dollars. The energy efficiency programs in these Three-Year Plans will create a solid foundation for future energy efficiency activities as the Program Administrators continue their sustained efforts to achieve all cost-effective energy efficiency.

XI. ORDER

Accordingly, after due notice, hearing, and consideration, it is:

ORDERED: That the three-year energy efficiency plans for 2019 through 2020 filed by Bay State Gas Company, d/b/a Columbia Gas of Massachusetts; The Berkshire Gas Company; Boston Gas Company and Colonial Gas Company, each d/b/a National Grid; Fitchburg Gas and Electric Company, d/b/a Unitil (gas); NSTAR Gas Company, d/b/a Eversource Energy; Liberty Utilities (New England Natural Gas Company) Corporation d/b/a Liberty Utilities; the Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE; Fitchburg Gas and Electric Light Company, d/b/a Unitil (electric); Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; NSTAR Electric Company d/b/a Eversource Energy are APPROVED, subject to the modifications, disallowances, and conditions contained herein; and it is

FURTHER ORDERED: That Bay State Gas Company, d/b/a Columbia Gas of Massachusetts; The Berkshire Gas Company; Boston Gas Company and Colonial Gas Company, each d/b/a National Grid; Fitchburg Gas and Electric Company, d/b/a Unitil (gas); NSTAR Gas Company, d/b/a Eversource Energy; Liberty Utilities (New England Natural Gas Company) Corporation d/b/a Liberty Utilities; the Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County acting together as the Cape Light Compact JPE; Fitchburg Gas and Electric Light Company, d/b/a Unitil (electric); Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; NSTAR Electric Company d/b/a Eversource Energy shall comply with all other directives contained in this Order.

By Order of the Department,

/s/
Angela M. O'Connor, Chairman

/s/
Robert E. Hayden, Commissioner

/s/
Cecile M. Fraser, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

Appendix G

Massachusetts Department of Public Utilities

Docket Nos. 20-33 through 20-36, *Energy Efficiency Order*

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-33 July 28, 2020

Petition of Fitchburg Gas and Electric Light Company, d/b/a Unitil (Electric Division), for approval by the Department of Public Utilities of its Active Demand Reduction, Daily Dispatch Pay-For Performance offering.

D.P.U. 20-34

Petition of Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE, for approval by the Department of Public Utilities of its Active Demand Reduction, Daily Dispatch Pay-For Performance offering.

D.P.U. 20-35

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of its Active Demand Reduction, Daily Dispatch Pay-For Performance offering.

D.P.U. 20-36

Petition of NSTAR Electric Company d/b/a Eversource Energy, for approval by the Department of Public Utilities of its Active Demand Reduction, Daily Dispatch Pay-For Performance offering.

APPEARANCES: Danielle C. Winter, Esq.
Kerri A. Mahoney, Esq.
Keegan Werlin LLP
99 High Street, 29th Floor
Boston, Massachusetts 02110
FOR: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY (ELCTRIC DIVISION)
Petitioner (D.P.U. 20-33)

Stacey M. Donnelly, Esq.
Diana Chiang, Esq.
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
FOR: MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY
Petitioner (D.P.U. 20-35)

John K. Habib, Esq.
Ashley S. Wagner, Esq.
Keegan Werlin LLP
99 High Street, 29th Floor
Boston, Massachusetts 02110
FOR: NSTAR ELECTRIC COMPANY
Petitioner (D.P.U. 20-36)
Intervenor (D.P.U. 20-34)

Jeffrey M. Bernstein, Esq.
Audrey Eidelman, Esq.
BCK LAW, P.C.
271 Waverley Oaks Road, Suite 203
Waltham, Massachusetts 02452
FOR: CAPE LIGHT COMPACT JPE
Petitioner (D.P.U. 20-34)

Maura Healey, Attorney General
Commonwealth of Massachusetts
By: Donald W. Boecke
Assistant Attorney General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Rachel Graham Evans, Esq.
Daniel Burstein, Esq.
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, Massachusetts 02114
FOR: MASSACHUSETTS DEPARTMENT OF ENERGY RESOURCES
Intervenor

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, Massachusetts 01930
FOR: LOW-INCOME WEATHERIZATION AND FUEL ASSISTANCE PROGRAM NETWORK AND THE LOW-INCOME ENERGY AFFORDABILITY NETWORK
Intervenors

Caitlin Peale Sloan, Esq.
Amy Laura Cahn, Esq.
Conservation Law Foundation
62 Summer Street
Boston, Massachusetts 02110
FOR: CONSERVATION LAW FOUNDATION
Intervenor

Amy E. Boyd, Esq.
Acadia Center
31 Milk Street, Suite 501
Boston, Massachusetts 02109
FOR: ACADIA CENTER
Intervenor

Paul W. Gromer, Esq.
Paul Gromer, LLC
85 Merrimac Street, 3rd Floor
Boston, Massachusetts 02114
FOR: NORTHEAST ENERGY EFFICIENCY COUNCIL
Intervenor

Laura S. Olton, Esq.
LSO Energy Advisors, LLC
38 Thackeray Road
Wellesley, Massachusetts 02481
FOR: POWEROPTIONS, INC.
Intervenor

Justin Davidson, Esq.
Massachusetts Association of Realtors
333 Wyman Street, Suite 200
Waltham, Massachusetts 02451
FOR: MASSACHUSETTS ASSOCIATION OF REALTORS
Intervenor

Christine O'Connor, City Solicitor
City of Lowell Law Department
375 Merrimack Street
Lowell, Massachusetts 01852
FOR: CITY OF LOWELL
Intervenor (D.P.U. 20-35)

Robert A. Rio, Esq.
Associated Industries of Massachusetts
One Beacon Street, 16th Floor
Boston, Massachusetts 02109
FOR: ASSOCIATED INDUSTRIES OF MASSACHUSETTS
Limited Participant

Gregory P. Vasil, Esq.
Greater Boston Real Estate Board
One Center Plaza, Mezzanine Suite
Boston, Massachusetts 02108
FOR: GREATER BOSTON REAL ESTATE BOARD
Limited Participant (D.P.U. 20-35, D.P.U. 20-36)

Beren Argetsinger, Esq.
Keyes & Fox LLP
P.O. Box 166
Burdett, New York 14818
FOR: SUNRUN, INC.
Limited Participant (D.P.U. 20-34, D.P.U. 20-33, D.P.U. 20-35, D.P.U. 20-36)

I. INTRODUCTION

On October 31, 2018, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid (electric)"); Fitchburg Gas and Electric Light Company, d/b/a Unitil ("Unitil (electric)"); NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric"); and the towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE ("Compact") (together, "Program Administrators") each filed a three-year energy efficiency plan with the Department of Public Utilities ("Department") for calendar years 2019 through 2021 ("2019-2021 Three-Year Plans").[1] These filings were docketed as Fitchburg Gas and Electric Light Company d/b/a Unitil (electric), D.P.U. 18-117; Cape Light Compact JPE, D.P.U. 18-116; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, D.P.U. 18-118; and NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 18-119.

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[1] In addition to the electric Program Administrators, Bay State Gas Company, d/b/a Columbia Gas of Massachusetts; The Berkshire Gas Company; Boston Gas Company and Colonial Gas Company, each d/b/a National Grid; Fitchburg Gas and Electric Light Company, d/b/a Unitil (gas); NSTAR Gas Company, d/b/a Eversource Energy; and Liberty Utilities (New England Natural Gas Company) Corp., d/b/a Liberty Utilities each filed a gas three-year energy efficiency plan. The gas Program Administrators and their respective three-year energy efficiency plans are not subject to the instant Order.

The electric Program Administrators proposed the following residential and commercial and industrial ("C&I") active demand reduction offerings in their 2019-2021 Three-Year Plans: (1) residential direct load control; (2) residential storage performance; (3) C&I interruptible load curtailment (summer); (4) C&I interruptible load curtailment (winter); (5) C&I storage performance (daily dispatch); (6) C&I storage performance (targeted dispatch – summer); and (7) C&I storage performance (targeted dispatch – winter). 2019-2021 Three-Year Energy Efficiency Plans, D.P.U. 18-110 through D.P.U. 18-119, at 14, 30 (2019) ("2019-2021 Three-Year Plans Order"). As discussed below, the Department approved the proposed active demand reduction offerings, with the exception of the daily dispatch offerings (i.e., residential storage performance and C&I storage performance (daily dispatch)). 2019-2021 Three-Year Plans Order, at 30. The Department's decision not to approve the daily dispatch offerings cited the lack of support (e.g., research papers, analysis, pilot program results) offered by the electric Program Administrators. 2019-2021 Three Year Plans Order, at 31. The Department did, however, provide conditions under which the electric Program Administrators could test their daily dispatch offerings and then make compliance filings with the Department for approval of these offerings. 2019-2021 Three-Year Plans Order, at 30.

On March 16, 2020, in response to the Department's directives in the 2019-2021 Three-Year Plans Order, Unitil (electric), the Compact, National Grid (electric), and NSTAR Electric each submitted a compliance filing seeking approval of their respective daily dispatch offerings. The Department docketed these filings as Fitchburg Gas and Electric Light

Company d/b/a Unitil (electric); D.P.U. 20-33, Cape Light Compact JPE, D.P.U. 20-34; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid (electric), D.P.U. 20-35; and NSTAR Electric Company d/b/a Eversource Energy, D.P.U. 20-36, respectively. The electric Program Administrators' proposals are compliance phases of D.P.U. 18-117, D.P.U. 18-116, D.P.U. 18-118, and D.P.U. 18-119.[2]

On April 27, 2020, the Department issued a Hearing Officer Memorandum stating that because the electric Program Administrators' proposals are compliance phases of D.P.U. 18-117, D.P.U. 18-116, D.P.U. 18-118, and D.P.U. 18-119, those parties to D.P.U. 18-117, D.P.U. 18-116, D.P.U. 18-118, and D.P.U. 18-119, who were granted either full party intervenor status or limited participant status may participate as intervenors or limited participants, respectively, in D.P.U. 20-33, D.P.U. 20-34, D.P.U. 20-35, and D.P.U. 20-36. D.P.U. 20-33 through 20-36, Hearing Officer Memorandum at 2 (April 27, 2020). The Hearing Officer Memorandum set a procedural schedule for these compliance filings. The Department issued two rounds of common information requests to the electric Program Administrators, and one round of Compact-specific information requests to the Compact. No other party issued information requests.[3]

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[2] The compliance phases of these cases are not consolidated and remain separate proceedings. 2019-2021 Three-Year Plans Order, at 3 n.3

[3] On its own motion, pursuant to 220 CMR 1.10(3), the Department moves into the evidentiary record of these proceedings the electric Program Administrators' respective compliance filings and their responses to information requests DPU-Common 1-1 through DPU-Common 1-9, DPU-Common 2-1 through DPU-Common 2-2, and DPU-Compact 1-1. The Department finds that the evidentiary records in D.P.U. 20-33 through 20-36 provide an adequate basis to

II. PROGRAM ADMINISTRATOR PROPOSAL

Consistent with the Department's directives in the 2019-2021 Three-Year Plans Order, the electric Program Administrators state that National Grid (electric), Unitil (electric), and NSTAR Electric deployed daily dispatch demonstrations during 2019 to determine whether the results of these demonstrations would support cost-effective statewide daily dispatch offerings for residential and/or C&I customers (see D.P.U. 20-35, Exh. EJM at 5).[4] The Compact did not deploy a daily dispatch demonstration. The results of the demonstrations are discussed below.[5]

National Grid deployed its residential daily dispatch demonstration (approved in D.P.U. 18-118) between July 1, 2019 and September 30, 2019, with 50 full participants (D.P.U. 20-35, Exh. EJM at 7). National Grid reports that it paid $44,823 in incentives to

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address the electric Program Administrators' respective compliance filings without the need for adjudicatory hearings.

[4] The prefiled testimonies filed by each electric Program Administrator are substantially the same.

[5] In the 2019-2021 Three-Year Plans Order, at 138-139, the Department also determined that it was premature to consider the Compact's proposed active demand reduction offerings (including the statewide offerings and any Compact-specific enhancements), until a final agreement with NSTAR Electric was in place to ensure that any active demand reduction offering would not adversely impact the reliability of the local distribution system. 2019-2021 Three-Year Plans Order, at 138-139. The Compact and NSTAR Electric have entered into an agreement regarding the implementation of active demand reduction offerings in the Compact's service territory, and the Department has approved the Compact's active demand reduction offerings and budgets (Exh. ATB at 5 n.3, citing Cape Light Compact JPE, D.P.U. 18-116-A (February 10, 2020).

participants and achieved 0.199 megawatts ("MW") in demand reduction (D.P.U. 20-35, Exh. EJM at 7). National Grid states that, on average, 63 percent of enrolled devices performed successfully, increasing to 93 percent by August 22, 2019, because of technologic improvements in its automated dispatch (D.P.U. 20-35, Exh. EJM at 7). Finally, National Grid asserts that 97 percent of participating customers reported that they are likely or very likely to continue to participate in the offer (D.P.U. 20-35, Exh. EJM at 8).

Unitil deployed its residential daily dispatch demonstration (approved in Fitchburg Gas and Electric Light Company, D.P.U. 16-184 (2017)) between July 1, 2019 and September 30, 2019 (D.P.U. 20-33, Exh. FGE at 8). Unitil states that it had four enrolled participants (D.P.U. 20-33, Exh. FGE, Attachment A, part(a) at 4). Because Unitil paid for the installation of the storage systems, customers were not eligible for an incentive (D.P.U. 20-33, Exh. FGE at 8). Unitil reports that its evaluation found that energy storage systems were successful at balancing solar photovoltaic output for the first two hours of an event, but were less successful by the fourth hour (D.P.U. 20-33, Exh. FGE at 8). Unitil reports that all four enrolled batteries participated in all event days, and that the total discharge for the four batteries averaged 5.1 kilowatts ("kW") per event, ranging from 0.5 kW to 6.8 kW (D.P.U. 20-33, Exh. FGE, Attachment A, part(a) at 4).

NSTAR Electric deployed its C&I storage (approved in NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-178 (2017)) and daily dispatch pay for performance (approved in D.P.U. 18-119) demonstrations with three customers (D.P.U. 20-36, Exh. ES at 9). NSTAR Electric states that two customers participated

between July 1, 2019 and September 30, 2019, and the third customer participated for four weeks during the fall of 2019, once its equipment was installed (D.P.U. 20-36, Exh. ES at 9). NSTAR Electric stated that it paid for the installation of the two storage systems that participated under the D.P.U. 16-178 demonstration and, therefore, these systems were not eligible for incentives (D.P.U. 20-36, Exh. ES at 9). For the third demonstration, NSTAR Electric paid $82,075 in incentives ($200.00 per kW) (D.P.U. 20-36, Exh. ES at 9). NSTAR Electric also reports that it achieved an evaluated average of 0.972 MWs in demand reduction from its demonstrations, with customers meeting 91 percent of their committed dispatch levels (D.P.U. 20-36, Exh. ES at 9-10).

The electric Program Administrators assert that the daily dispatch demonstrations performed as expected, delivered daily peak demand reductions, and will be cost-effective (see D.P.U. 20-35, Exh. EJM at 10). The electric Program Administrators state that the proposed offers are the same as described in the 2019-2021 Three-Year Plans, but that they may refine forecast strategies, incentive levels, and the enrollment process over time, but the fundamental offering designs are the same as originally proposed (see D.P.U. 20-35, Exh. EJM at 10-11). The electric Program Administrators further assert that they shared the results and lessons learned from these demonstrations, as well as the lessons learned from the Eversource and Unitil demonstrations approved in D.P.U. 16-178 and D.P.U. 16-184, respectively (Petition at 3; see D.P.U. 20-35, Exh. EJM at 6-11). Based on the evaluated results of these demonstration offerings, the electric Program Administrators assert that there

is sufficient evidence to support the wide-scale deployment of the daily dispatch pay-for-performance offerings (D.P.U. 20-35, Exh. EJM at 11-12, and Attachment A).

The electric Program Administrators assert that their compliance filings do not change the electric Program Administrators' budgets for the residential active demand reduction core initiatives or the C&I active demand reduction core initiatives, of which the active demand response offerings are a part (see D.P.U. 20-35, Exh. EJM at 11; Exh. DPU-Common 2-2). The electric Program Administrators state that the final planned budgets (filed on February 19, 2019) already include projected costs for wide-scale implementation of the daily dispatch pay-for-performance offerings (see D.P.U. 20-35, Exh. EJM at 11-12).[6] Further, the electric Program Administrators assert that, under the Department's Energy Efficiency Guidelines, they project to have sufficient flexibility within their existing planned budgets to support the

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[6] Consistent with the Department's Energy Efficiency Guidelines, § 3.3.3 (established pursuant to Energy Efficiency Guidelines, D.P.U. 11-120-A, Phase II (2013), Program Administrators present energy efficiency program and core initiative budgets and program costs broken out by cost category. Costs are assigned to the relevant cost category within the relevant program, core initiative, or hard-to-measure program. Costs that are not appropriately assigned directly to a program are allocated among relevant programs on an appropriate basis and tracked accordingly (Exh. DPU-Common 2-1). The proposed residential and C&I daily dispatch storage performance offerings, measures, and budgets are part of the active demand core initiatives, not separate core initiatives or programs (Exh. DPU-Common 2-1). The Program Administrators do not budget or track costs by cost category by measure because not all expenditures are directly tied to a specific measure (Exh. DPU-Common 2-1). Costs that are directly related to a specific measure, such as incentive costs, are included in the benefit/cost ratio models (Exh. DPU-Common 2-1). Other costs, such as administrative costs, evaluations, and marketing, are generally allocated at the core initiative level, rather than to specific measures (Exh. DPU-Common 2-1).

daily dispatch offerings at this time (see D.P.U. 20-35, Exh. EJM at 10-11, citing Energy Efficiency Guidelines, § 3.8).

National Grid states that its final planned incentive cost for the daily dispatch offer is $1,521,880 in 2020, and $2,151,936 in 2021 (D.P.U. 20-35, Exh. EJM at 12). Further, National Grid states that it planned for 6,763 kW reductions in 2020, and 9,696 kW reductions in 2021 (D.P.U. 20-35, Exh. EJM at 12).

Unitil asserts that its final planned incentive cost for the daily dispatch offer is $225 per kW average summer performance and $50 average winter performance, in 2020 and 2021 (D.P.U. 20-33, Exh. FGE at 11). Unitil states that due to the economic challenges experienced in its service territory, Unitil planned for 0 kW reductions in 2020 and 2021 for its residential customers and 100 kW reductions in 2020 and 2021 for its C&I customers (D.P.U. 20-33, Exh. FGE at 11).

NSTAR Electric states that its final planned incentive cost for the daily dispatch offer is $1,291,250 in 2020, and $2,568,750 in 2021 (D.P.U. 20-36, Exh. ES at 12). NSTAR Electric asserts that it planned for 5,150 kW reductions in 2020, and 10,250 kW reductions in 2021 (D.P.U. 20-36, Exh. ES at 12).

The Compact's states that its planned incentive cost for the daily dispatch offer is $385,475 in 2020, and $409,125 in 2021 (D.P.U. 20-34, Exh. ATB at 12). The Compact asserts that it has planned for 1,520 kW reductions in 2020, and 1,600 kW reductions in 2021 (D.P.U. 20-34, Exh. ATB at 12).

III. ANALYSIS AND FINDINGS

As noted above, in their 2019-2021 Three-Year Plans, the electric Program Administrators proposed statewide active demand reduction offerings for the first time. The Department found that the proposed active demand reduction offerings were generally consistent with the Department's expectation that the electric Program Administrators would leverage the results of the demand response demonstration projects approved as part of the 2016-2018 Three-Year Plans to support the deployment of cost-effective demand response offerings at scale. 2019-2021 Three-Year Plans Order, at 30, citing 2016-2018 Three-Year Energy Efficiency Plans, D.P.U. 15-160 through D.P.U. 15-169, at 142-143 (2016).

With certain exceptions and modifications, the Department found that the proposed statewide active demand reduction offerings and attendant demand reduction savings goals were reasonable and consistent with the achievement of all available cost-effective demand reduction. 2019-2021 Three Year Plans Order, at 30. Accordingly, the Department approved the electric Program Administrators' proposed statewide active demand reduction offerings, except for the daily dispatch offerings (i.e., residential storage performance, and C&I storage performance (daily dispatch)). 2019-2021 Three Year Plans Order, at 30. The Department expressed concern with the lack of support (e.g., research papers, analysis, pilot program results) offered by the electric Program Administrators for the proposed daily dispatch offerings. 2019-2021 Three Year Plans Order, at 31. Accordingly, the Department did not approve a full-scale deployment of the proposed daily dispatch offerings. 2019-2021 Three Year Plans Order, at 32.

The Department did, however, find merit in exploring the potential for daily dispatch offerings and authorized each electric Program Administrator to use a portion of the proposed budget allocated to the daily dispatch offerings to design demonstration offerings to test the daily dispatch of storage. 2019-2021 Three Year Plans Order, at 32.

The Department stated that if the electric Program Administrators determine that the results of any additional demonstration offerings or NSTAR Electric's demonstration offering in D.P.U. 16-178, support cost-effective statewide daily dispatch offerings for residential and/or C&I customers, then the electric Program Administrators must (1) seek Energy Efficiency Advisory Council approval to implement such offerings and (2) submit a compliance filing to the Department describing the proposed offering(s) and budget(s). 2019-2021 Three Year Plans Order, at 33. The Department further stated that absent approval from the Department, the total budget for such offerings (i.e., demonstration offering budget plus statewide program budget) shall not exceed the planned budget allocated to the proposed residential storage performance and C&I storage performance (daily dispatch) offerings. 2019-2021 Three Year Plans Order, at 33.

The records in these compliance filings demonstrate the following. First, the electric Program Administrators appropriately used a portion of their proposed budgets allocated to the daily dispatch offerings to design demonstration offerings to test the daily dispatch of storage (Exh. DPU-Common 2-2; see D.P.U. 20-36, Exh. ES at 11-12). Second, the electric Program Administrators determined that the results of their demonstration offerings (including D.P.U. 16-178) do support cost-effective statewide daily dispatch offerings for

residential and/or C&I customers. Third, the electric Program Administrators sought and received Council approval to implement their respective proposed residential and C&I daily demand response offerings (see D.P.U. 20-35, Exh. EJM, Attachment B (Energy Efficiency Advisory Council resolution). Finally, each electric Program Administrator has demonstrated that the total budget for such offerings (i.e., demonstration offering budget plus statewide program budget) does not exceed the planned budget allocated to the proposed residential storage performance and C&I storage performance (daily dispatch) offerings (Exh. DPU-Common 2-1).

Accordingly, the Department finds that Unitil (electric), the Compact, National Grid (electric), and NSTAR Electric respective compliance filings comply with the Department's directives in the 2019-2021 Three-Year Plans Order and are hereby approved. Further, the Department notes that we approved the budgets for Unitil (electric), National Grid (electric), and NSTAR Electric respective daily dispatch offerings in the 2019-2021 Three-Year Plans Order at 32. The Department further notes that in the 2019-2021 Three-Year Plans Order, the Department did not approve the Compact's proposed budget for its daily dispatch residential and C&I offerings, deferring approval of any active demand response offering until a final agreement with NSTAR Electric was in place to ensure that any active demand reduction offering would not adversely impact the reliability of the local distribution system. 2019-2021 Three-Year Plans Order, at 128,138-139, 148. The Department has since approved the Compact's active demand reduction offerings and budgets (D.P.U. 20-34, Exh. ATB at 5 n.3, citing Cape Light Compact JPE, D.P.U. 18-116-A (February 10, 2020).

Based on the record in the Compact's compliance filing, the Department hereby approves the Compact's request to implement the statewide daily dispatch offering. The Department further approves the Compact's proposal to allocate a portion of its active demand response budget, as allowed by the Department in D.P.U. 18-116-A, to the daily dispatch offering.

IV. ORDER

Accordingly, after due notice and consideration, it is:

ORDERED: That the proposed daily dispatch active demand response offerings addressed in the compliance filings filed by Fitchburg Gas and Electric Light Company, d/b/a Unitil (electric); the Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; NSTAR Electric Company d/b/a Eversource Energy are APPROVED for the remainder of the 2019-2020 energy efficiency plan term; and it is

FURTHER ORDERED: That the recovery of the costs associated with the proposed daily dispatch active demand response offerings through the currently reviewed and approved energy efficiency surcharges of Fitchburg Gas and Electric Light Company, d/b/a Unitil (electric); the Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and

Dukes County, acting together as the Cape Light Compact JPE; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; NSTAR Electric Company d/b/a Eversource Energy are APPROVED; and it is

FURTHER ORDERED: That the budget for daily dispatch active demand response offerings of Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County acting together as the Cape Light Compact JPE, set forth in D.P.U. 18-116-A is APPROVED.

By Order of the Department,

/s/
Matthew H. Nelson, Chair

/s/
Robert E. Hayden, Commissioner

/s/
Cecile M. Fraser, Commissioner