Tale of the Tape: A Comparison of Curtailment Impacts and Value Streams of Various Technologies in the C&I Sector

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ABSTRACT

Electric demand response (DR) is increasingly becoming a resource of interest to reduce transmission and distribution system peaks. Additionally, electric DR plays a role in the integration of intermittent renewable resources to achieve decarbonization goals with the potential benefit of providing value and revenue streams to utilities, customers, and the grid. In 2019, the authors presented a paper which examined evaluation methodologies planned across a diverse set of DR technologies. This discussion included how they were designed to maintain a continuity of evaluation perspective to ensure an apples-to-apples assessment of impacts across the various technology/pilot designs. These technologies included batteries, thermal storage, traditional dispatch, and building management systems (software). Those study activities were completed, enabling a discussion of findings for each technology individually and for electric DR as a whole.

The attempted use of common baselines and impact methods allows the authors to examine the impact methodologies and the effectiveness of two of the emerging storage technologies (battery and thermal storage) in achieving customer and grid peak reductions and compare them on a level field against traditional control-oriented technologies. Although there is a substantial body of DR evaluation work in the industry, this paper uniquely discusses the evaluation methodology for each technology and reviews which approaches worked best, the data gathered and used to support the impact assessment, and why a particular method worked better than others.

In this paper, the authors provide insights into the evaluation of the value streams associated with different DR technologies and to which party they accrue. Because grid reliability and mitigation of grid constraints are increasingly important topics across the United States, this paper also helps utilities and grid operators throughout the country learn the best practices and limitations of different DR technologies currently available. Elements of a concurrent process evaluation are used to discuss findings on the readiness of these technologies for DR applications. The lessons learned from these demonstration projects and research studies have far-reaching impacts on program design, implementation, and evaluation, thereby adding value to the energy efficiency industry. The paper also presents the results and estimated impacts of the various technologies examined.

Introduction

In the summer of 2019, Eversource, a large utility operating in Connecticut, New Hampshire, and Massachusetts, operated a series of demand response demonstration projects focusing on a diverse set of technologies along with a traditional dispatch initiative. This was the second year of operating many of these projects. The primary purpose of operating the various solutions was to reduce load during the ISO system peak hour, also known as the Installed Capacity hour (ICAP). These technologies were studied across multiple years to understand their effectiveness in reducing ICAP hour load. In addition to the ICAP hour load, these solutions also had other benefits that were evaluated, such as customer peak demand and utility event load reduction.

The authors studied batteries used for daily[1] and targeted[2] dispatch, thermal storage (HVAC and refrigeration storage), traditional dispatch, and Building Management System (BMS) controls (software). A paper summarizing the performance and market acceptance of the 2018 offerings was presented at the International Energy Program Evaluation Conference (IEPEC) in 2019 (Gopalakrishnan 2019). The present paper provides an update to many of the observations and conclusions in the 2019 paper with the advantage of larger participation groups and an additional year of project maturity.

This paper describes and compares the evaluation methodologies employed, results around key program impacts, challenges encountered, and observations made. The table below summarizes each technology deployed, the number of participating accounts and providers in the 2019 summer season, their reported MW reduction, and evaluated ICAP reduction. The BMS controls were not fully functional for the evaluation, and so the evaluation focused on functional testing and a process evaluation.

Table 1. 2019 DR demonstration portfolio summary

Technology	# of participating accounts	# of providers	Reported reduction (MW)	Evaluated ICAP Load Reduction (MW)
Battery (Daily)	3	1	1.07	1.09
Battery (Targeted)	2	1	0.12	0.11
HVAC Thermal Energy Storage	8	1	0.24	0.09
Refrigeration Thermal Energy Storage	8	1	1.27	0.58
BMS Controls	8	2	-	-
Traditional Dispatch	56	1	7.00	7.90
Total	85	7	16.30	9.77

Technology-Specific Dispatch Plans, Evaluation Methods, and Results

This section describes the dispatch strategies, detailed methodologies, and value streams for each technology tested as part of the demand demonstration portfolio. The goal of the project was to study the effectiveness of various technologies and dispatch strategies in reducing demand during those periods examined. The evaluation methods used by the authors here are consistent with those planned and discussed in a 2019 IEPEC paper (Gopalakrishnan, 2019). All technologies were evaluated for ICAP periods reductions. We begin with a discussion about our experience in applying common methods across all technologies.

Examining Use of Common Impact Evaluation Methods

In year 1 of this study (2018), the authors studied the possibility of employing consistent methods and data across the proposed solutions. Since the evaluation methodology for traditional dispatch (the most well-established solution) involved the use of facility-level interval data with a 10-of-10 baseline and a regression baseline, the authors examined the use of the same data and baseline methodology for the other solutions. The findings were as follows:

[1] A dispatch pattern that discharges the battery during the same period on a given set of days (e.g., from 1 pm to 5 pm weekdays)

[2] Refers to discharging the battery to achieve curtailment triggered for specific periods (e.g., peak associated with extreme weather conditions)

- Two battery storage solutions were deployed, one daily and one targeted. Since the demonstration programs paid incentives for equipment purchase up front and the batteries were sub metered, it was determined that any discharge/load reduction achieved was attributable to the program[3].
- The HVAC thermal storage solution, which involved the use of ice storage to offset RTU load, targeted a subset of RTUs at each facility, and the magnitude of facility load far exceeded the magnitude of the proposed reductions at each facility. Hence, the use of facility-level interval data did not work for this solution. The regression baseline used for this solution was, in principle, analogous with the regression baseline used for the curtailment solution. Since this was a daily dispatch solution, a 10-of-10 baseline approach was not appropriate.
- The refrigeration thermal storage solution, which involved offsetting refrigeration system power draw with phase change materials that delay the upward temperature drift of cold storage space temperature, targeted a subset of freezers/cold storage spaces within each facility. While the load reductions were more significant for this solution when compared to the HVAC solution, comparison with facility load still showed that the load reductions were in the noise of facility load magnitudes. The baseline regression methodology (in lieu of weather correlation, the authors settled on average non-dispatch hour load during similar operating hours for each month, with schedule being the primary variable). This is analogous with the regression baseline approach used for the curtailment solution where temperature and schedule are the primary variables. Since this was a daily dispatch solution, a 10-of-10 baseline approach was not appropriate. It is important to note that customer monthly peak demand reductions were calculated using facility interval data.
- The BMS controls solution did involve the use of facility-level interval data as well as similar baselines to curtailment, however, these solutions were not ready in time to effectively participate in the demonstration projects.

Battery Daily and Targeted Dispatch

Two different battery demand demonstrations were examined, including daily dispatch and targeted dispatch. The utility contracted with a battery vendor to install and dispatch the batteries. Each solution utilizes behind-the-meter lithium-ion batteries. Table 2 summarizes the various dispatch patterns in each demonstration.

Table 2. Battery dispatch summary

Dispatch Type	Participant #	Dispatch Pattern
Daily	1	4 pm to 7 pm non-holiday summer weekdays
	2	1 pm to 5 pm non-holiday fall weekdays
	3	Varying between 3 pm to 7 pm during non-holiday summer weekdays (including ICAP hour)
Targeted	1	5 Events: Four from 4 pm to 7 pm and one from 3 pm to 6 pm, all during non-holiday weekdays (including ICAP hour)
	2	

[3] In the 2021 summer season of the full-scale program offering, the incentives were designed to pay for performance rather than equipment, and so, the authors are currently studying the level of load reduction or battery discharge attributable to the program, which involves the use of facility level interval data as well as the 10-of-10 baseline approach used for curtailment solutions. Three baselines are being studied in addition to interviews with participants and vendors to develop appropriate baselines for battery solutions.

Baseline description: The authors used recorded battery charge and discharge data during the event window to calculate event and ICAP impacts. To quantify customer monthly peak reduction, the authors added the battery charge and discharge to the customer's facility interval data to produce a "no battery" counterfactual of customer load. This is discussed further in the methods section below.

Methods description: The analysis quantified the average event (daily or targeted) demand reduction as equal to the average battery load during the event window. ICAP reduction is the average demand reduction during the ISO NE ICAP hour (i.e., hour-ending 6 p.m. on July 30, 2019). Customer monthly billed peak load reduction was calculated as the difference in peak facility load during any 15-minute interval on weekdays from 9 a.m. to 6 p.m. in a billing period for the with battery and "no battery" counterfactual scenarios.

Impact findings:

1. The battery demonstration projects studied included incentives for battery purchase and installation. Under these circumstances, impacts were appropriately based on interval facility and battery charge and discharge data. Customer motivation for purchasing the battery can influence the curtailment baseline. While there are nuances in the scenarios that might be encountered, two common ones are summarized in Table 3 below.

   Table 3. Purchase scenarios

Purchase Scenario	Savings/Baseline Method
Direct program influence on battery purchase	Program induced purchase means that the counterfactual is a no-battery scenario. In this case, no baseline is required, and average battery discharge during the event hours can be considered the measurement of response.
Battery purchase not primarily influenced by the program	In this case, the counterfactual is customer use of a battery without program incentives to reduce demand during event windows. To isolate impact of program, evaluators need to consider how the customer uses the battery on non-event days by using a 10-of-10 unadjusted baseline (via battery data). This approach only considers battery discharge during the event hours on non-event baseline days and nullifies charging activity during event hours on non-event baseline days.

2. Control optimization of batteries is critical in facilities with other DERs, such as CHP systems. Although seasonal demand reductions achieved show the battery technology performed reliably, specific instances of nonperformance were observed, notably at facilities with CHP. Interaction with controls and logic associated with CHP can cause undesirable instructions to be given to the batteries that likely degraded customers' monthly demand charge benefit. Administrators of similar battery daily dispatch programs must be prepared for troubleshooting during the first season of operation before the battery controls can be fully optimized for these revenue streams. Two sites with pre-existing CHP systems where new batteries were installed created limitations for the battery system's daily dispatch potential. These unexpected occurrences revealed challenges with mixed objectives. The utility expected the battery to dispatch daily with the goal of managing load during a specified time of day, whereas the vendor was managing the battery system to shave customer peak demand to reduce bill costs (regardless of coincidence with scheduled daily dispatch). Usually, these two goals were in alignment but when there

were unusual circumstances related to CHP presence, they were mutually exclusive, and it caused performance problems.

- An older 2 MW CHP system at one daily dispatch site helps cut the facility's utility-facing load nearly in half. At this point in its lifecycle, it has a turndown limit of 80% and is slow to adjust to the fast-changing electricity needs of the facility's manufacturing equipment as various production machines ramp up and down. The battery vendor noted that it was common for the facility load to spike or drop by up to 500 kW very quickly. This load volatility made it difficult for the vendor to determine the level at which to discharge the battery for daily dispatch. If a large piece of equipment shut off during the daily dispatch window, the inability of the CHP system to ramp its output down past 80%, combined with battery discharge, could decrease load below the site's 220 kW minimum import requirement[4], tripping the CHP system offline. The vendor reported that this happened several times; in fact, while testing to determine how high they could set dispatch kW without causing a CHP system outage, the vendor found that the CHP system would shut off if the load fell past 420 kW (well above the facility's minimum import). After considerable trial and error, the vendor was able to settle at around 430 kW as a consistent level of import for daily dispatch events, resulting in a much lower battery dispatch level than the vendor had originally planned to deliver at the site.
- Similar to this site, another daily dispatch site with an on-site CHP system that disrupted the battery's daily dispatch routine in summer 2021. On the morning of July 26th, a Friday, the CHP system plant tripped offline at 9 a.m. The battery began to dispatch to make up for the loss in power generation, and in doing so used up its charge. As such, the system was unable to discharge during the daily dispatch window later that afternoon. In discussions with the vendor, the evaluation team learned that the battery discharged because it had been set to prioritize demand charge management.

3. Targeted and daily dispatch battery curtailment can be reliably estimated and very effective at reducing ICAP, seasonal, daily, and customer peak loads after being optimized, benefitting the grid, the customer, and the utility.
    - The daily dispatch of batteries was very effective at reliably curtailing demand during daily periods, including the ICAP hour. The evaluated average load reduction of the three daily dispatch battery systems during periods of dispatch was 972 kW, or 91% of their commitment of 1,070 kW. The two battery systems in place during the 2019 ICAP hour committed 695 kW as their average daily dispatch load reduction and were able to discharge at a much higher rate over the ICAP of 1,090 kW. This was not due to evaluation methods, rather by maximizing discharge over a shorter period when there was high certainty around when ICAP would occur.
    - The targeted dispatch of batteries was similarly very effective at curtailing demand during seasonal and daily periods, including the ICAP hour. The two targeted dispatch battery systems committed average load reduction during the dispatch period was 104.7 kW, or 90% of their commitment of 116.7 kW. The load reduction during the 2019 ICAP hour was 108.1 kW.

<u>Process findings:</u>

1. The installation and optimization period required to refine battery operation can be much longer and complex than anticipated. Start-up delays were numerous due to various causes, including defective hardware, communications problems, contract term negotiations, interconnection reviews, zoning

[4] Contractual minimum purchase of electricity from the grid.

concerns, and needing to design and commission systems so that they complement existing on-site CHP systems.

Key recommendations:

- When battery purchase and installation is part of the program, we recommend using charge and discharge data for determining impacts. Other approaches add unnecessary uncertainty compared to the granular revenue grade data available from the equipment itself.
- The level of program influence on battery purchase can affect baseline assumptions. For customers with their own battery where the battery purchase was not influenced by a program, we recommend considering a baseline approach that uses discharge during the event hours on non-event baseline days and nullifies charging activity during event hours on non-event baseline days.
- We recommend administrators and other stakeholders plan for long and complex installation and programming periods to optimize battery performance, particularly in the presence of other DERs such as CHP systems. These systems should be optimized together rather than as independent systems.

Thermal Energy Storage

Thermal energy storage (TES), as used in the demonstration, stocks thermal energy by cooling a storage medium so that it can be used later for cooling applications in pursuit of daily load reduction during summer weekday afternoons. One solution is ice-water-based thermal storage to reduce peak space air conditioning load. The second uses bricks of phase change media (PCM) in warehouse freezers with controls to enable compressor and condenser load reduction during peak hours. These are presented together with methods and findings unique to each discussed separately.

Dispatch pattern description: The two thermal storage solutions were deployed at eight customers each to test their effectiveness in mitigating utility peak demand during the summer months. One solution sought to limit peak demand by reducing summer air conditioning loads at commercial and industrial facilities, while the other solution sought to limit peak demand by reducing refrigeration loads at cold-storage facilities. Both solutions were deployed daily during scheduled dispatch windows in the summer. The dispatch windows were modified during the season to meet the anticipated ICAP hour.

Baseline: The authors used the non-dispatch hours on weekdays from June through September to develop a weather-normalized baseline model for the HVAC solution (Figure 1). The baseline regression equation was applied to the temperature during the dispatch hours to determine how the RTUs would have performed during those hours, i.e., the counterfactual load. A similar baseline was employed for the refrigeration-based solution, however, the data indicated no relationship between the refrigeration system power draw and outside air temperature (OAT). The evaluators found that the pre-existing periods (typically between April and May) typically had a narrow range of OATs, and there were clear month-to-month variations in load based on a comparison of refrigeration system power data between April (in gray below) and September (in orange below). Hence, the evaluators used the average performance from June through September on weekday non-dispatch hours to calculate the baseline load. The ICAP hour baselines were calculated based on the same baseline methodology.

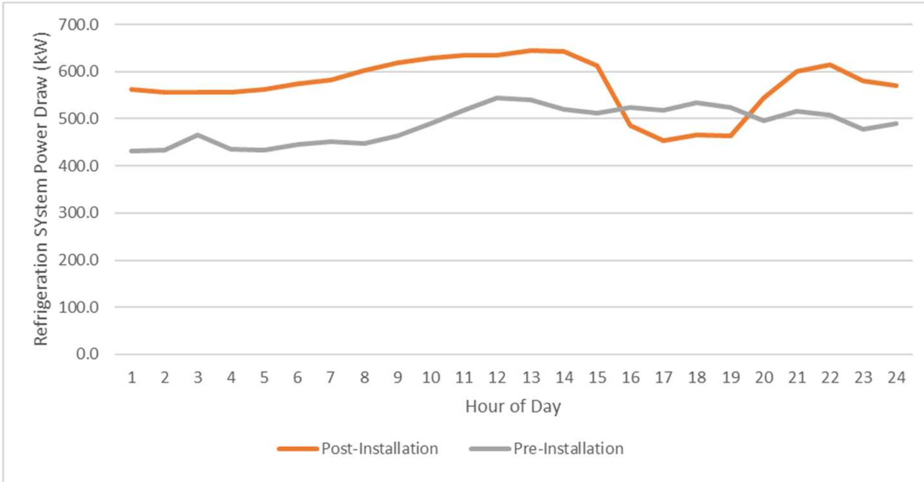

Figure 1. Evidence of pre and post seasonal difference for refrigeration thermal storage solution

<u>Methods description:</u> For thermal storage projects, the team used metered asset-level (asset-level refers to affected equipment) power draw to quantify the delivered demand reduction during the dispatch windows. During the site visits, the authors verified the space temperatures of affected spaces, confirmed the nameplate and controls of existing equipment, and obtained trend data from the BMS where available. The team analyzed utility interval data to estimate the customer monthly billed peak demand reductions.

The team considered using analytic techniques to estimate the solution impacts. In preliminary data assessments, it was apparent that the load reduction as a percent of total building load was small and difficult to isolate definitively from total consumption. The authors decided that the analysis needed to be performed at the asset level with metering of affected equipment and site observations combined with an engineering analysis.

<u>Impact findings, HVAC thermal storage:</u>

1. The vendor committed an average load reduction of 241.0 kW across eight sites during the three-hour daily dispatch window. This solution provided an average load reduction of 61.9 kW across the eight sites based on the evaluation findings. The ISO-NE system peak (ICAP) hour occurred on July 30, 2019, from 5 p.m. to 6 p.m. During the ICAP hour, this solution provided 86.1 kW of demand reduction. No energy use reductions (kWh savings) were claimed, expected, or evaluated for this solution since the ice making energy use was expected to be equivalent to the dispatch energy savings. The daily dispatch schedule was not modified by the vendor to dispatch to reduce facility peak demand. The dispatch schedule was set to the anticipated ICAP hour which has no bearing or correlation with when the facility monthly peak demand occurs. Hence, no customer monthly peak demand reductions were claimed, expected, or evaluated for this solution.
2. The solution was successful in offsetting the rooftop unit (RTU) cooling load during the dispatch window; however, a majority of the RTUs selected for control were oversized and underutilized, resulting in lower-than-expected demand reduction. This does not reflect the lack of ability or potential for the technology, RTUs selected for controls must be utilized to present the opportunity for demand savings.

<u>Process Findings, HVAC thermal storage:</u>

1. Incompatibility with targeted RTUs. This solution included the installation of a secondary coil to provide the TES cooling within the targeted RTUs. This proved to be a major challenge. Multiple large customers

with several RTUs were unable to participate (and not evaluated) because their RTUs were not large enough to accommodate the installation of an additional cooling coil. This impacted customer satisfaction due to time spent before the incompatibility issues were identified.
2. Delivery and installation of equipment was challenging. Due to the size of the equipment, all but one facility had difficulty getting the equipment to the proposed locations at the sites. This resulted in delays and, in some cases, cancellation of installations. Impact evaluation was conducted as of the date of installation and commissioning. Canceled sites were not evaluated.

<u>Impact findings, refrigeration storage PCM thermal storage:</u>

1. The vendor committed an average load reduction of 1,270.0 kW across eight sites during the three-hour daily dispatch window. This solution provided an average demand reduction of 515.6 kW during the event window based on evaluation findings. The ISO-NE system peak (ICAP) hour occurred on July 30, 2019, from 5 p.m. to 6 p.m. During the ICAP hour, this vendor provided 576.8 kW of demand reduction. The aggregate customer monthly peak demand reduction was found to be 252.6 kW.
2. The evaluators calculated the net energy impact of this solution by calculating the percent change in system daily energy use for 2019 summer weekends (no load shedding) and weekdays (with load shedding). To normalize for weekday-weekend differences not due to load shedding, the same comparison was made for the pre-installation period and used to adjust the percentage. The net energy savings based on this approach was found to be material (126,420 kWh), indicating that the refrigeration system was more efficient with the PCM and controls.
3. This solution was reliable and successful in shedding load during the dispatch window.

<u>Process findings, refrigeration storage PCM thermal storage:</u>

1. This solution had the narrowest targeted facility type of the demand demonstration projects, as the technology is effective only for cold storage facilities with large freezers (not refrigerators). The vendor sought customers with a substantial amount of freezer area, the ability to shut off the refrigeration system, a location where the freezer is largely closed off to minimize airflow, and a storage space rather than a process line. This greatly minimized the pool of customers the vendor could recruit.
2. Some facilities did not have adequate existing refrigeration system controls in place to allow for the automation of the thermal storage solution. In these cases, the vendor had to work with the facility refrigeration vendors to install more advanced controls. Other facilities with adequate controls said they preferred to integrate the solutions themselves but were unable to dedicate staff to the integration in time for the start of the 2019 summer season. These sites had to dispatch manually until the integration of controls could be completed.

<u>Key recommendations:</u>

- Vendors should improve their application screening process. Both vendors encountered difficulties in installation, commissioning, and performance due to equipment-selection issues that could have been avoided by employing better data collection processes during the scoping process. The following data collection activities could improve the effectiveness of these installations:
    - Meter targeted RTUs to ensure that they are sufficiently loaded during peak hours. This would prevent underperformance due to lack of load that was noticed across all eight of the HVAC solution's participants. In particular, spaces that are intermittently used, such as training rooms, storage areas, and event halls, should be avoided.
    - The HVAC solution has multiple instances where customers were engaged and interested, and began to do a lot of groundwork, only to find out that the solution was either incompatible with their RTUs or was not feasible due to spatial or installation constraints. To avid customer

frustration during the screening site visit, the vendor should verify that the pre-existing RTUs have sufficient space for an additional cooling coil and confirm that the proposed location of the solution would be feasible for installation.
    - The age, condition, and controls of the existing refrigeration system should be collected during scoping to ensure that the solution is feasible for the refrigeration solution.
    - For industrial refrigeration, work with customers in advance to ensure compatibility with existing refrigeration plants, especially regarding refrigerant type (e.g., ammonia) and related safety protocols.
- Develop case study marketing materials. Having an installed project that vendors could show to other interested customers was a concrete and relatable way to discuss how the system worked. Tours of the site are best to enable other facilities to see the unit. Additionally, developing a short case study brochure allows vendors to introduce the successful project right away and is a comparatively small lift.

BMS Controls

BMS control technologies are like manual curtailment in that load reduction can come from HVAC, lighting, refrigeration, process equipment, or other non-critical systems like fountains or lobby TV screens. However, BMS controls solution differs from the manual solution in the way customers are alerted to the need for DR, the types of events that trigger the alerts, and the pre-arrangement of actions taken. BMS controls are typically automated to trigger curtailment based on conditions, for example when they are approaching a monthly peak or when a peak system hour is forecasted. BMS controls can also produce energy savings (kWh) through permanent load reduction or system optimization.

<u>Dispatch pattern description:</u> There were two vendors that administered the BMS controls demonstrations with an enrollment goal of 23 customers with a planned cumulative reduction of 6.6 MW during periods of vendor dispatch targeting peak periods, including the ICAP hour. One of the vendors developed a sequence of operations that would roll out at sites during predicted peaks and reduce load until a particular threshold was achieved. The other did not develop to the point of establishing curtailment periods and planned actions. Both vendors had planned elements of producing customer energy savings (kWh).

<u>Baseline description:</u> Unfortunately, the magnitude, duration, and frequency of events was not consistent with the nature of events anticipated. This prevented the use of standard 10-of-10 baselines. The authors examined two baselines to determine how best to isolate the active demand response aspects of the BMS vendor's efforts.
- A rolling, meter before-meter after (MBMA) baseline. This approach replicated activation period load reductions produced by the vendor and used those to produce counterfactual values during the activation period.
- A regression baseline. This approach used a weather-based regression that used all BMS controls non-active load data to estimate load levels during BMS controls-active periods.

<u>Methods description:</u> The impact evaluation focused on active load reduction (as opposed to passive load reduction) efforts via the BMS. Due to several recruitment and logistical reasons, participation levels in the 2019 season were smaller than expected (10 participants). In addition, among the 10 participants, software interface and other data issues limited the availability of information for the analytic based impact analysis.

<u>Impact findings:</u>
1. The software BMS control solutions did not provide a verifiable reduction of customer monthly peaks, energy, or summer system peak loads. The evaluated BMS impact results ranged from no evidence of bill

demand effects to modest effects. Both BMS control offerings appear to have opportunities for optimization that might produce impacts verifiable through a combination of engineering and load analysis in future seasons.

2. The impact analysis attempted for this demonstration highlights the challenges inherent in estimating load reduction and bill demand effects for a dynamic control system like BMS controls. The threshold-oriented approach to peak load management for the BMS controls in this demonstration created a structural challenge to the regression approach. The MBMA approach offers a less variable estimate of load reduction by design but could still misrepresent the true load reduction. A combination of engineering and load data analysis may be required to fully assess the billed demand effects of vendor BMS controls implementations.

<u>Process findings:</u>

1. This technology solution greatly benefits from M&V plans that are developed and vetted early in the project development process to ensure that the intended metrics are quantifiable and evaluable.
2. Customers can be very difficult to recruit into BMS DR programs. Customers were found to often be hesitant to allow external entities to control building systems, some including process related equipment. In addition, network access and other data security concerns also hampered recruitment.
3. BMS control projects can have long lead times and an arduous project development process. All the stakeholders must be involved and on the same page from inception to avoid the implementation hurdles encountered by both vendors such as data security issues and delays in obtaining approvals.

Key recommendations:

1. Data collection during the early stages of BMS project development should be more thorough to ensure project feasibility. System control issues and equipment and setpoint discrepancies can entirely eliminate the effectiveness of the BMS impacts.
2. Vet M&V plans during the project development phase to ensure that performance metrics are quantifiable. This will ensure performance can be adequately measured and reported.
3. Program administrators and vendors should ensure that the performance metrics and goals are explicitly defined in the scope of work and/or RFP. This helps ensure the priorities of the utility demand demonstration projects line up with the vendor's priorities.

Traditional Manual Dispatch

In traditional manual curtailment, the provider and participant agree in advance on the amount of load reduction a site can deliver. The provider does not install any equipment or controls and is not involved with how the participant reduces load. Most participants reduce HVAC or lighting loads or temporarily reduce production, but it is up to them to choose which equipment to shut off and how to activate the intervention. Note that activation may be manual or programmed by the participant, and the nature of the response may vary from event to event.

Dispatch pattern description: The manual curtailment demand demonstration utilizes active DR to reduce demand during peak periods. During the summer availability period, DR is dispatched with the intent of reducing load during the ISO NE ICAP hour. The summer 2019 manual curtailment demand demonstration had 56 participants. Participants in 2019 were dispatched once on Tuesday, July 30, 2019 from 4 p.m. to 7 p.m. for a mandatory demand response event, which included the ICAP hour (5 p.m. to 6 p.m.).

Baseline description: The authors estimated counterfactual load using two distinct baselines, an average 10-of-10 baseline with symmetric, additive adjustment and a regression baseline.

The average 10-of-10 baseline was constructed using utility interval data from the 10 most recent non-event, non-holiday weekdays prior to an event. The unadjusted baseline shape was calculated as the average of load in each interval across the 10 days. The additive adjustment shifts the unadjusted baseline shape by the difference between actual load and the unadjusted baseline during the hour occurring two hours before the event (adjustment window). A symmetric adjustment may shift the unadjusted baseline shape upward or downward.

The regression baseline fits a regression model to an individual customer's load data across the entire season. The regression specification describes load for each hour of the day as a function of cooling degree-days (CDD), weekends and holidays, calendar month, and event day terms. The cooling degree-day base is determined by regression best fit. The model is applied to event day conditions without the event day terms in effect to estimate load on that day absent the event.

Methods description: For manual curtailment projects, the team used utility interval data to quantify the delivered demand reduction during event periods. Demand reduction was quantified using two baselines, an average 10-of-10 baseline with symmetric, additive adjustment and an ex-post regression baseline. The demonstration used the average 10-of-10 baseline for settlement. Demand reduction was calculated as the average difference between the baseline and actual load during event hours.

This study did not have any recommendations.

Impact findings:

1. Manual dispatch performed reliably and in accordance with its goals. The reported and evaluated average load reduction estimates for the demonstration's settlement baseline both exceeded the 7 MW that the vendor contracted to provide. The evaluation estimated 7.9 MW of load reduction during the ISO NE ICAP hour, also exceeding the committed estimate. This study found standard 10 of 10 baseline approaches were best indicators of performance during curtailment periods.
2. Regression methods were not able to reliably quantify load reduction impacts. Regression load reduction estimates were less than 10% of the estimates using the demonstration's settlement baseline, an average 10-of-10 with symmetric additive adjustment. The success of any baseline in estimating load reduction varies with program design and the participants. We present and discuss case studies illustrating when regression analysis can succeed and fail in a companion paper (Gopalakrishnan, 2022). There are two primary reasons for the difference between the load reduction estimates and the adjusted settlement baseline:
    a. The demonstration project has a substantial number of accounts with highly variable load. These accounts undermine the regression baseline's ability to estimate the baseline load.
    b. Three-quarters of the load for the accounts that aren't highly-variable are non-weather-correlated, thereby undermining the regression baseline's effectiveness in estimating the baseline load.

<u>Process findings:</u>

1. Customer ratings of the technology and their program experience suggested a general satisfaction with this demonstration, despite some of the limitations of a manual curtailment approach. All but one participant said they would continue to use this DR solution.

Summary of Findings

Customers generally benefit economically from DR in three ways. First, customers may be able to reduce their utility monthly peak demand charge. Second, they may reduce a supplier charge associated with their load at the time of the New England system annual peak hour (ISO-NE Installed Capacity hour). Third, they may receive payments from their DR vendor for targeted or daily dispatch during the event period. In addition, vendors can benefit from being paid by the utility and/or the ISO for delivering reduced load when dispatched. Finally, the system benefits from reduce peaks during critical capacity periods.

Table 4 presents the evaluation methods, data requirements, and benefit (monthly charge, ICAP reduction, dispatch reduction payments) for customers, a vendor, or the grid itself in the various demand demonstration project technologies. All studies used interval data and the battery studies also used charge and discharge data. BMS controls were analyzed and are included in the table below although we were unable to verify or estimate savings claims due to small participation rates and data issues. All other technologies had quantified installed capacity reductions and dispatch reductions. For batteries and thermal energy systems we were also able to estimate customer monthly peak reductions.

Evaluating batteries using charge and discharge data, which is typically revenue grade and readily available from the batteries themselves, provides a cost effective and accurate means of determining the performance of this technology. Caveats to this are when the battery purchase is program influenced and the need for consumption data to estimate customer specific monthly peak demand impacts.

The cost of analysis of asset level thermal storage solutions is comparable with traditional manual curtailment, however the expense of asset level data collection, when not provided by the vendor (as was the case for HVAC thermal storage), makes it a more costly evaluation method. Due to the issues detailed in the "Examining Use of Common Impact Evaluation Methods" section, these methods are necessary to calculate defensible impact metrics for these solutions.

BMS control systems that are used for active DR and manual traditional curtailment DR are both ideally evaluated using facility level interval data with the aforementioned settlement style (10-of-10) and regression baselines. Using facility interval data is the most cost effective and defensible way to scale demand response impact analyses when possible.

Table 4. 2019 DR demonstration portfolio summary

Technology	Recommended evaluation method	Data requirements	Value stream evaluated	ICAP MW reduction	
				Committed	Evaluated
Program Influenced Battery (Daily Dispatch)	Battery data, measurement	Battery charge and discharge data. Spot measurements of battery output to validate the accuracy of meters.	Customer Monthly Peak Reduction, Installed Capacity Reduction, Daily Dispatch Reduction (program incentive)	1.07	1.09
Program Influenced Battery (Targeted)	Battery data, measurement	Battery charge and discharge data. Spot measurements of battery output to validate the accuracy of meters.	Customer Monthly Peak Reduction, Installed Capacity Reduction, Targeted Dispatch Reduction (program incentive)	0.12	0.11
Thermal storage	Equipment measurement	Power draw of affected equipment (existing equipment as well as new equipment installed by the vendors), space temperatures and relative humidity, utility interval data	Customer Monthly Peak Reduction, Installed Capacity Reduction, Dispatch Reduction (program incentive)	1.51	0.67
Manual curtailment	10 of 10 symmetrically adjusted baseline	Utility interval data (same year and historical), facility BMS data when available	Installed Capacity Reduction, Targeted Dispatch Reduction (program incentive)	7.0	7.9
BMS Controls	Combined engineering, interval load analysis	Utility interval data (same year and historical), facility BMS data when available, asset level metered data	Customer Monthly Peak Reduction, Installed Capacity Reduction	6.6	-

Table 5 below provides key findings by DR technology. We recommend that implementers, administrators, evaluators, and other stakeholders use these observations as a basis for considering how to position these solutions for implementation and evaluation success. This includes findings on the performance of each technology, observations on evaluation approach, and other issues that can impact performance.

Table 5. Summary of findings by technology

Technology	Performance Value Streams	Implementation, Evaluation, and Performance Observations
Daily Dispatch and Targeted Batteries	• Customer monthly peak • ICAP • Program event reduction	• When the program influences battery purchase, charge and discharge data is sufficient for determining ICAP and event period impacts • The level of program influence on battery purchase can affect baseline assumptions • Optimizing battery performance can be very prolonged, particularly in the presence of other DERS
TES (HVAC)	• ICAP • Program event reduction • Customer monthly peak (depending on dispatch schedule)	• Needs asset level versus premise level data. • Oversized and underutilized HVAC units result in low demand reduction. • Incompatibility of solution with targeted RTUs is an implementation and recruitment challenge. • Due to the size of the equipment, facilities can have difficulty getting the equipment to the proposed locations at the sites. This results in delays and, in some cases, cancellation of installations
TES (Refrigeration)	• ICAP • Program event reduction • Customer monthly peak (depending on dispatch schedule) • Energy savings (kWh)	• Needs asset level versus premise level data. • This solution had the narrowest targeted audience type of the demand demonstration projects, as their technology is effective only for cold storage facilities with large freezers (not refrigerators). This greatly minimized the pool of customers they could recruit. • Some facilities did not have adequate existing refrigeration system controls in place to allow for the automation of the thermal storage solution. • Condition and vintage of underlying refrigeration equipment can be a constraint.
Manual Dispatch	• ICAP • Program event reduction	• Regression analysis approaches were not successful in quantifying reduction estimates due to highly variable consumption unrelated to weather. • Standard 10 of 10 baseline approaches were best indicators of performance during curtailment periods.
BMS Controls	Unable to be Determined	• Concerns about external entities controlling building systems and sensitivities around network access and data security concerns can greatly hamper recruitment into BMS based DR solution programs • The evaluated BMS impact results were largely unquantifiable due to data limitations, though impacts appeared to range from no evidence of demand effects to modest effects

Technology	Performance Value Streams	Implementation, Evaluation, and Performance Observations
		• A combination of asset level engineering and load analysis appears to be the best way to verify impacts for BMS measures • This technology solution benefits from a full understanding of the dispatch pattern and M&V plans that are developed and vetted early in the project development process to ensure that metrics are quantifiable and evaluable • Data collection during early stages of BMS intervention can help assure project feasibility and effectiveness.

In conclusion, each dispatch technology has its merits and challenges. While a one-size-fits-all approach would be expeditious, each solution has its own appropriate data gathering and methodological uniqueness that drives the need for different evaluation methods. This is detailed in the section “Examining Use of Common Impact Evaluation Methods” above.

All technologies but BMS controls were found to have data, and method combinations are available to estimate ICAP, Customer Monthly Peak Reduction, and Dispatch Reduction estimates with confidence. These quantified resources provide value to ISO NE by reducing capacity costs, provide revenue to customers (ICAP, dispatch reduction, monthly peak), provide revenue to vendors (dispatch reduction), and provide value to program administrators by providing them the ability to deal with constrained circuits and nodes through strategic dispatch of these solutions.

Through this paper, we offer process and impact findings, factors affecting data gathering and evaluation method selection, solution-specific value streams, and key recommendations. This information can be used in a variety of ways including:

- Effective program design to maximize impacts and evaluability
- Strategic selection of solutions for different purposes (daily load mitigation versus emergency response)
- Selection of effective evaluation methods and data gathering techniques to measure true impact on the grid
- Knowledge of solution-specific recruitment, site selection, installation, and program delivery challenges and barriers to overcome

References

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