FINAL REPORT

ACES Fifth Aggregated Project Report

MassCEC

Date: July 1, 2022

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1 REPORT OVERVIEW

This report is DNV's fifth ACES Aggregated Project Report to assess and quantify revenues from the ACES Program Grantees (the Grantees) that have had their data transfers approved by DNV and MassCEC.[1] DNV will prepare quarterly reports for the first year of the reporting cycle and biannual reports during the remaining years, followed by a program summary report.

1.1 Scope of fifth aggregated report

The scope of this fifth report covers all Grantees with approved data streams through October 31, 2021.

The Grantees are proceeding through the ACES program deliverables at their own pace, completing milestones from project kickoff meetings through project readiness assessments, construction, commissioning, and establishing data transfer. As each Grantee commissions their energy storage system (ESS), DNV and MassCEC work closely with the Grantees to establish regular data reporting. Once the reported data is consistent and largely free of errors and omissions, DNV and MassCEC approve the data stream and the Grantee moves to the reporting stage. Grantees will prepare quarterly and biannual reports for the first three years of operations from the data-approval date at the same frequency as these aggregated reports (quarterly during the first year, biannually for the second and third year).

Since Grantees were approved at different times, the start date for reporting differs across Grantees, but each has provided data from their approved start date through October 2021.

There are eight Grantees with approved operational reports spanning April 2019 through October 2021 (there are no additional Grantees since the fourth aggregated report). To date, DNV has received and approved a total of 46 operational reports from these Grantees. A ninth Grantee has approved data and a first operational report under review by DNV and MassCEC, but revenues have not yet been verified and thus are not included in this report.

DNV and MassCEC have been working closely with the Grantees to ensure they submit their operational reports in a timely fashion. The number of submitted operational reports has been increasing as more Grantees enter their reporting periods. Initial reports also document revenues achieved prior to the data reporting period with the earliest reported revenues starting in January 2019.

1.2 Report structure

This report is structured to summarize revenues and analyses of Grantee performance, broken out into the following sections:

- **Section 2: Market Development Memo.** Each aggregated report includes memos that summarize Grantee activities related to key aspects of ESS project development and/or operations. DNV and MassCEC determine the topics in advance; this report includes a memo on Regional Network Service (RNS) dispatch efficiency.
- **Section 3: Monetizable Revenues and Operational Strategy Tables.** This section first presents a summary discussion of Grantee performance across all monetizable revenues reported in the scope of this report, followed by a discussion of the individual revenue strategies pursued by the Grantees. All the Grantee information presented in the body of the report will remain anonymous.
- **Section 4: Non-Monetizable Benefits.** This section highlights the various non-monetizable benefits reported by Grantees. Most Grantees have been focused on calibrating their operations, and not many have reported non-

[1] ERS was acquired by DNV in January 2021. The first three quarterly reports in this series were produced under the ERS name. This report and all subsequent reports will reflect the DNV name.

monetizable benefits to date. Many Grantees plan to explore these benefits and test the feasibility of other potential benefits during the second and third years of their ESS operations.

2 MARKET DEVELOPMENT MEMO

This section presents the market development memo for the fifth aggregated report. The topic for this memo is regional network service (RNS) dispatch effectiveness. The following memo contains our analysis of industry trends based on Grantee-submitted documentation. The memos reflect program achievements through October 2021, and all Grantee data has been anonymized to protect privacy and confidentiality.

2.1 Regional network service (RNS) dispatch effectiveness

This memo explores how Grantees dispatch their energy storage systems (ESS) to achieve monthly regional network service (RNS) revenues. This analysis includes seven Grantees with data from April 2019 through October 2021.

2.1.1 Overview and background

RNS charges are peak demand charges billed to municipal light departments and other large customers and are associated with transmission and distribution infrastructure requirements to support regional peak loads. RNS peak demand costs are based on monthly regional network peaks which vary slightly by ISO-NE region (and by Grantee). The RNS charges are determined primarily by Schedule 9 of the ISO-NE Open Access Transmission Tariff (OATT) and were approximately $9.20 per kW for the 2018/2019 fiscal year, $9.33 per kW for 2019/2020, and increased to $10.77 per kW for the 2020/2021 fiscal year. Additional discussion of RNS revenues is included in Section 3.3 of this report.

Overall, RNS charges are one of the most lucrative revenue streams for the Grantees. Of the seven Grantees analyzed for this memo, six list RNS charges as the site’s primary or secondary revenue stream. To target RNS revenue most successfully, Grantees often use predictive models—either in-house or through contracted services—to forecast monthly RNS peak hours. Each of the analyzed Grantees cites such models in their most recent operational reporting.

2.1.2 Methodology

For the contents of this memo, DNV analyzed Grantee data to assess the accuracy and precision of RNS predictive models and the success rate of targeted dispatch for the RNS hour. While Grantees provide daily charge and discharge data, the data acquisition systems do not identify the revenue stream(s) influencing discharge patterns, nor do they differentiate between active dispatching and passive discharges due to parasitic loads. DNV analysis employed the following algorithm to estimate the number of times each Grantee discharges per month specifically to target the RNS peak. DNV then used the algorithmic results to study the effectiveness of Grantees’ predictive modeling techniques. DNV followed these steps:

- **Calculated maximum daily site kW and duration of discharge for each Grantee.** DNV defined ‘discharging’ as any time interval with ESS kW less than zero.[2]
- **Compared results to actual RNS peak windows to define an “RNS-like” signature discharge**. Battery dispatch strategies and patterns are unique to each Grantee. Thus, DNV calculated battery dispatch patterns on actual RNS days by looking at maximum discharge and total duration of discharge, generating an “RNS-like” signature for each Grantee. Days with similar patterns (i.e., comparable maximum discharges and total durations) were then tagged as RNS-like discharges.
- **Calculated RNS estimated discharge effectiveness by dividing the number of actual RNS events hit by the number of RNS-like discharges**.[3] In some cases, the Grantees report missing the peak hour due to unexpected system malfunction. Although the Grantee may have had a planned discharge during the RNS window, malfunction-related misses were still considered misses for the sake of this analysis and will decrease the overall discharge

[2] DNV decided to exclude kWh data from this analysis as it is not a provided field for every Grantee.

[3] DNV considered RNS events as opposed to individual hours. For example, if a Grantee successfully hit an RNS window with a single dispatch attempt of 3-hour duration, they would be given an effectiveness of 100%, as opposed to 33%.

effectiveness accordingly. For instance, Grantee 1 missed RNS peak windows in January and February 2021 due to system malfunction. If it were to be assumed that the Grantee's ESS system would have otherwise discharged as planned, and those two instances were counted as RNS hits, Grantee 1's overall discharge effectiveness would increase from 6.6% to 7.3%.

DNV considered results of the above method for three Grantee categories: RNS-primary, daily discharge, and integrated DER. Results vary between groups due to the nature of each Grantee's operational patterns and revenue strategies. DNV defines the three categories as follows:

- **RNS-primary:** Grantees whose ESS operations are optimized primarily to target ICAP and/or RNS peak windows. Grantees included in this category are Grantee 3, Grantee 4, Grantee 6, and Grantee 7.
- **Daily dispatch:** Grantees whose ESS operations include consistent daily discharge windows. At present, this category includes Grantee 2 with a flywheel storage system.
- **Integrated DER:** Grantees whose systems include DER components such as solar production and who target other revenues streams including demand response, peak shaving, or the Clean Peak Standard. Grantees included in this category are Grantee 1 and Grantee 5.

2.1.3 Overall Results

Table 2-1, below, shows the average number of RNS-like discharges, the RNS capture rate, and the estimated discharge effectiveness for each Grantee, grouped by the categorizations above.

Table 2-1. RNS metrics and estimated discharge effectiveness

Category	Grantee	Average RNS-Like Discharges per Month	RNS Capture Rate (Months Hit/Months Attempted)	Estimated Discharge Effectiveness[4]
RNS-Primary	**Grantee 3**	3.3	62%	11.3%
	Grantee 4	3.2	96%	28.9%
	Grantee 6	4.8	85%	15.9%
	Grantee 7	3.2	96%	29.3%
Daily Dispatch	**Grantee 2**	24.8	90%	3.0%
Integrated DER	**Grantee 1**	11.8	83%	6.8%
	Grantee 5	16.3	83%	5.4%

Figure 2-1 through Figure 2-3 show the number of RNS-like discharges for each reporting month, grouped by the categorizations above. Solid bars correspond to months when each Grantee hit the RNS peak hour and dashed bars correspond to months when the Grantee missed the RNS peak hour. Instances of zero discharges for Grantee 2 or Grantee 3 signify months without DNV-verified data.

[4] To calculate the Estimated Discharge Effectiveness, DNV divided the Actual RNS windows hit by the total RNS-like discharge events.

Figure 2-1. RNS-like discharges per month for RNS-primary Grantees

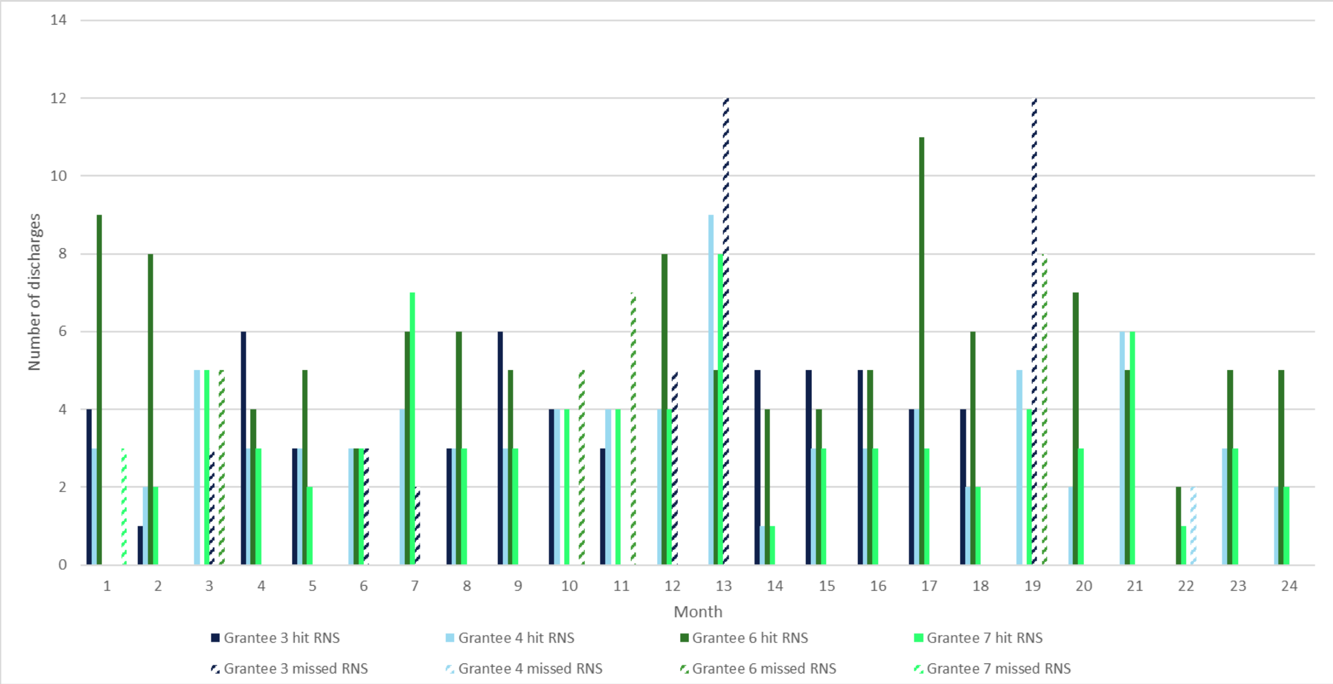


Figure 2-2. RNS-like discharges per month for daily dispatch Grantees

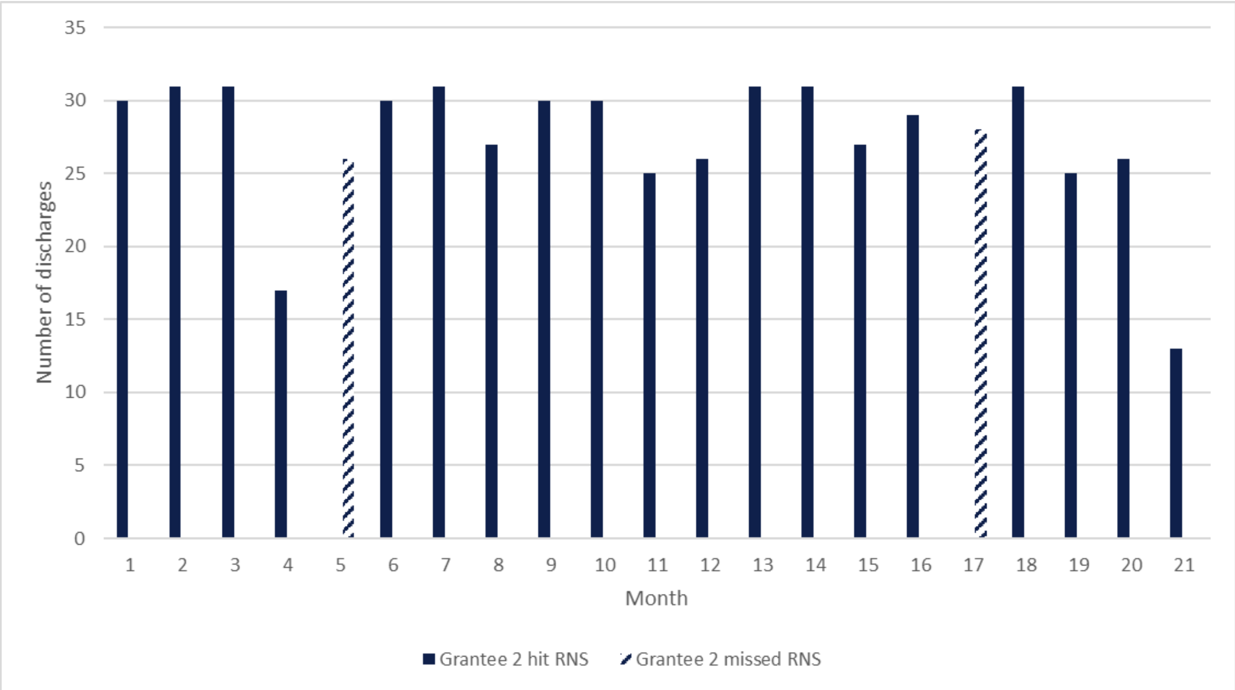
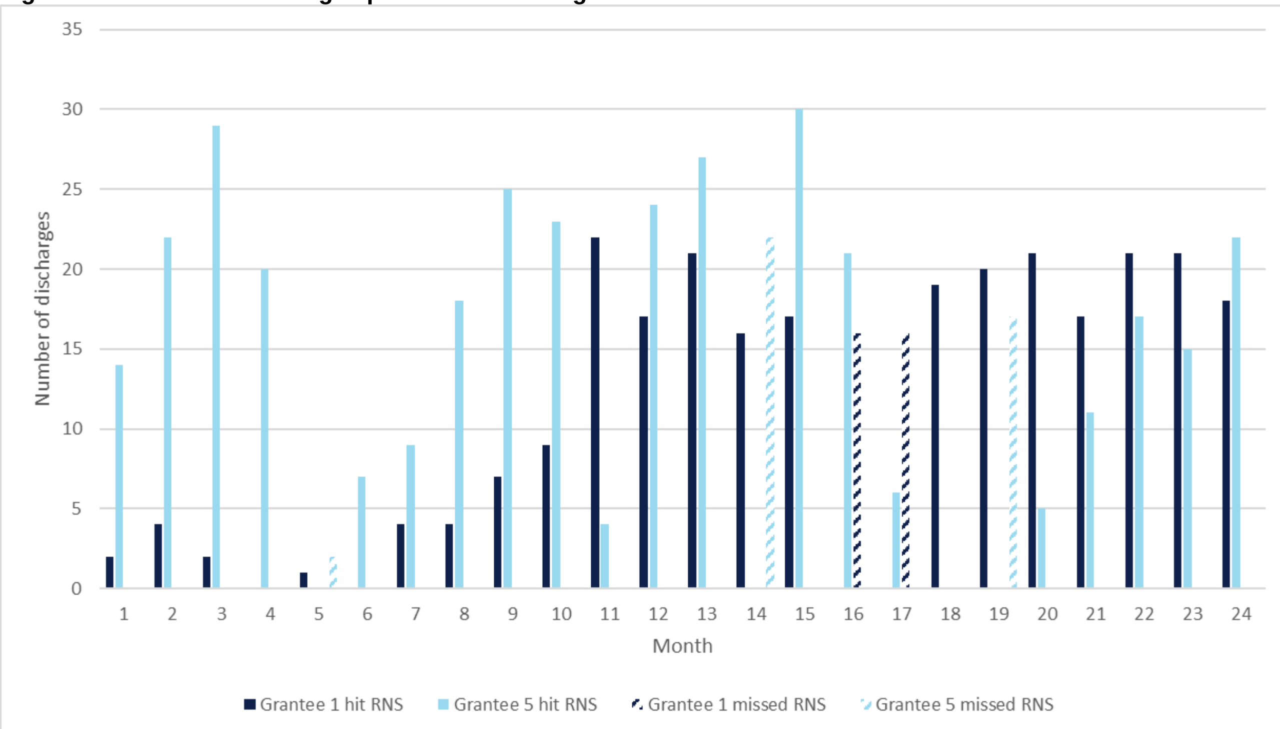


Figure 2-3. RNS-like discharges per month for integrated DER Grantees



2.1.4 Seasonal Analysis

DNV also conducted monthly analysis to analyze any seasonal impacts on the success of RNS predictive modelling. Figure 2-4 and Figure 2-5, below, show the number of RNS discharges and the RNS misses grouped by month and season. Figure 2-4 includes all of 2020 for the RNS-Primary grantees (although Grantee 3 only has verified data through October 2020). Figure 2-5 includes all months from January 2020 to September 2021 for the Integrated DER grantees.[5] As above, solid bars correspond to months when each Grantee hit the RNS peak hour and dashed bars correspond to months when the Grantee missed the RNS peak hour. Percentage values above each month signify the estimated discharge effectiveness for the month as a whole, aggregating values for all Grantees in the designated category.

Table 2-2 highlights missed RNS peak hours by season and month, with additional explanation for why the RNS hour was missed.

[5] DNV did not include the Daily Dispatch grantee in seasonal analysis due to its consistent dispatch schedule regardless of season.

Figure 2-4. Discharges per month with seasonal groupings for RNS-Primary Grantees

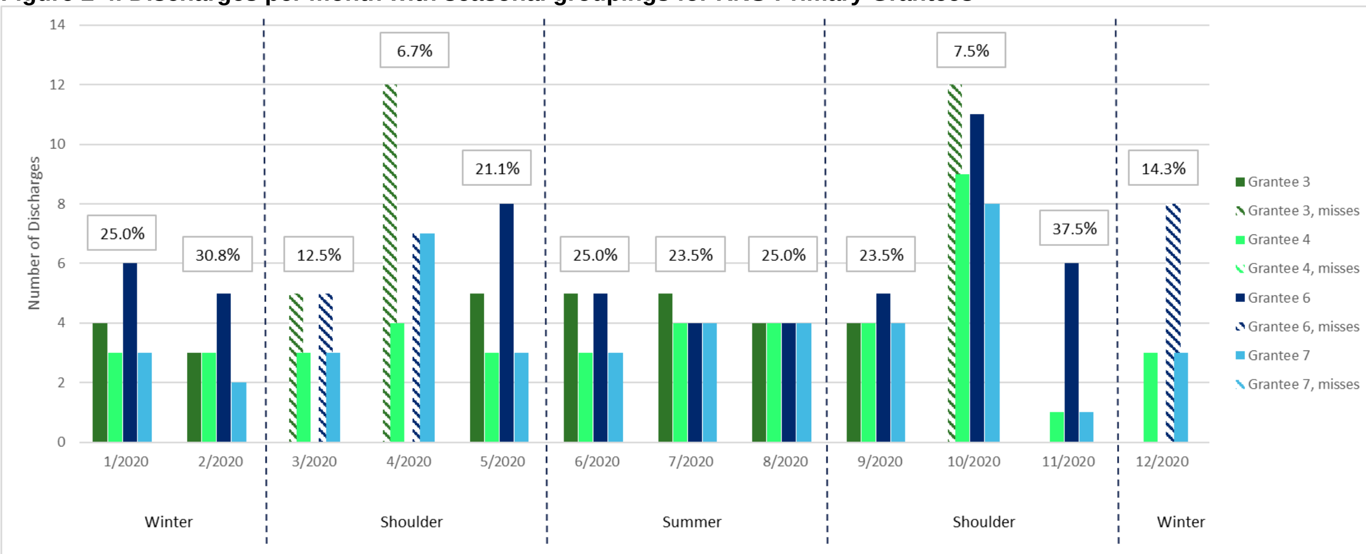


Figure 2-5. Discharges per month with seasonal groupings for Integrated DER Grantees

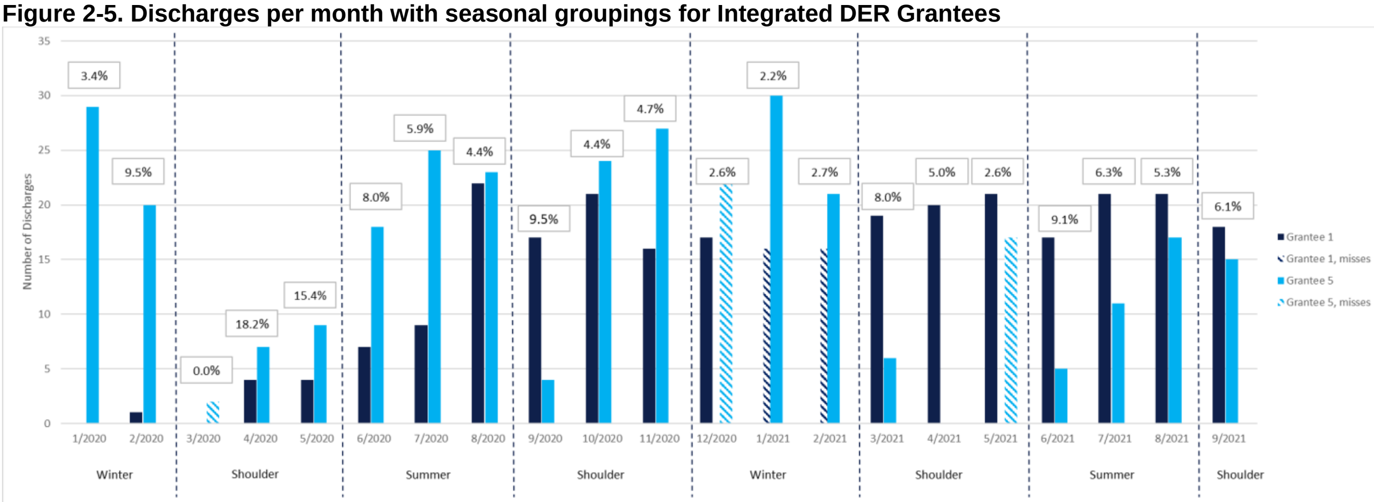


Table 2-2. RNS misses by season, with Grantee explanation

Season	Months with Missed RNS Windows	Grantees with Missed Monthly RNS Window	Reason for Miss
Winter	Jan-20	Grantee 1	System malfunction
	Dec-20	Grantee 5	Missed forecast
		Grantee 6	System malfunction
	Jan-21	Grantee 1	System malfunction
	Feb-21	Grantee 1	System malfunction
Summer	May-21	Grantee 5	System malfunction
Shoulder	Mar-20	Grantee 3	Missed forecast
		Grantee 5	Missed forecast
		Grantee 6	Missed forecast

Season	Months with Missed RNS Windows	Grantees with Missed Monthly RNS Window	Reason for Miss
	Apr-20	Grantee 3	Missed forecast
		Grantee 6	Missed forecast
	Oct-20	Grantee 3	Missed forecast

2.1.5 Findings

After reviewing the results above for each category of Grantees, we have developed the following findings.

- **Grantees are successfully discharging their ESS during RNS hours to achieve this revenue, with an average 85% capture rate across all Grantees**.
- **ESS dispatch strategy influences estimated discharge effectiveness**. DNV observed differences in operation and performance across the three Grantee groupings:
  - **RNS-primary Grantees have the highest estimated discharge effectiveness**. The group shows an average 21.4% discharge effectiveness (or RNS hits divided by RNS-like discharges). This result is expected, as these Grantees minimize the overall number of discharges per month while maximizing their RNS-window targeting.
  - **Daily dispatch Grantees have the lowest estimated discharge effectiveness due to operational design of the ESS**. These ESS are discharged most days of the month, with little variance in overall discharge power. Hence, while the discharge effectiveness is the lowest at 3.0%, the low score is likely due to system operation strategy as opposed to ineffective predictive modeling. While the Grantee does ensure that planned discharge cycles match their RNS predictions each month, the invariability of daily discharge patterns makes it difficult to distinguish any one discharge as an RNS-predicted period.
  - **Integrated DER Grantees have the second highest estimated discharge effectiveness, with a group average of 6.1%.** These Grantees also participate in seasonal demand reduction programs and the Clean Peak Standard program, and dispatch for program-dictated events and CPES-specific event hours. These dispatch events are difficult to distinguish from RNS-like dispatches due to their similar signature: near-full-capacity discharge for three- to four-hour duration.
- **Other targeted revenue streams impact system strategy and dispatch patterns.** Grantees in the RNS-primary group with peak-hour-focused dispatch strategies hit more RNS hours with fewer RNS-like dispatches (2-5 per month). In contrast, Grantees in the daily dispatch and integrated DER groups show different operational strategies and less variability between dispatch signatures. Integrated DER Grantees specifically may place priority of another revenue stream over that of an RNS discharge. Some RNS misses could be a result of prioritizing non-RNS operations instead of inaccurate predictive models. Hence, the RNS estimated discharge effectiveness for the integrated DER group appears lower than that of the RNS-primary Grantees, though higher than that of daily dispatchers.

- **Weather conditions affect RNS peak hours, especially in the case of unexpected or unseasonal weather**. In July 2021, for example, one Grantee cited severe thunderstorms as the reason for missing the RNS hour. Thunderstorms were expected to cause a suppressed load, and the Grantee adjusted the planned dispatch window accordingly. However, the thunderstorm was less severe than expected and failed to impact the system load, causing the Grantee to miss the peak hour. In general, inclement or unpredictable weather in certain transmission zones may affect the success rate of RNS predictive models or cause deviation from usual peak hour predictions.

- **Initial Grantee data suggests that while summer and winter seasons have more consistent peak schedules, peak behavior in shoulder seasons is more difficult to predict**.[6] While the dataset is limited, as shown in Table 2-2, throughout summer and winter, the majority of peaks missed were due to technical malfunctions, while all missed peaks in the shoulder seasons were the result of missed forecasts.
- **Grantees have improved their RNS-window targeting and peak prediction over time.** For example, Grantee 3 noted that March 2020 was the first occurrence of a weekend peak window, resulting in their system missing the dispatch window. After March 2020, the Grantee began monitoring system loads on weekends to prevent similar misses in future. As Grantees gained more experience with peak prediction, their success in predicting RNS windows increased as well.
- **Further research in the future could supplement our understanding of predictive modeling.** Future insights could be supplemented by analysis of predictive models and RNS revenues over time—from initial battery operation to present—by further consideration of weather and predictive trends, or by studying interactive effects with other revenue streams.

[6] DNV based summer, winter, and shoulder season periods of the Clean Peak Energy Standard (CPES) definitions. Summer is defined as June-August. Winter is defined as December-February. Shoulder months include March, April, October, and November. While the seasonal windows for CPES are broken up in mid-May and mid-September, DNV included those months in the shoulder seasons for month-level analysis.

3 MONETIZABLE REVENUES AND OPERATIONAL STRATEGY TABLES

This section outlines the primary revenue strategies pursued by the Grantees and the aggregate performance of those Grantees for each revenue strategy. Note that this analysis uses the most recent available data for each Grantee, and DNV may update the individual revenue strategy analyses once new data is available in future reports. For some revenue strategies, such as installed capacity (ICAP) and regional network service (RNS) revenue, there is a lag between when the revenue is achieved and when DNV can independently calculate revenues and/or see them reported by Grantees. Table 3-1 shows a summary of the Grantee use cases, ratio of ESS system nameplate power to peak load, and total months of data reported.

Table 3-1. Summary of Grantee use cases and data reported

Grantee	Use Case	Ratio of ESS System kW to Peak Load (%)	Total Months of Data Reported To Date
Grantee 1	Behind the meter – solar plus storage	7.6%	24
Grantee 2	Municipal Light Plant (MLP Asset)	N.D.	24
Grantee 3	Municipal Light Plant (MLP Asset)	10.1%	25
Grantee 4	Municipal Light Plant (MLP Asset)	N.D.	25
Grantee 5	Municipal Light Plant (MLP Asset)	33.3%	23
Grantee 6	Municipal Light Plant (MLP Asset)	10.2%	26
Grantee 7	Municipal Light Plant (MLP Asset)	7.1%	25
Grantee 8	Merchant, solar plus storage	N/A	18

3.1 Summary of revenues and operational strategies

Table 3-2 summarizes by use case the Grantee-achieved revenues reviewed to date. With the exception of ISO-NE ICAP revenues, this report presents data and revenues only from the approved start of the Grantees' data reporting timeline and does not include data prior to the approved data transfer.

Table 3-2. Summary of achieved revenues by use case

Revenues/Use Case	Number of Grantees	ICAP Tag Reduction	RNS Charge Reduction	Demand Response Programs	Peak Demand Reduction	Arbitrage	SMART	Clean Peak Standard
Municipal Light Plant (MLP Asset)	6	$1,801,599	$2,401,460	$143,520	$29,298	$23,263	$0	$0
Behind the meter – solar plus storage	1	$124,688	$299,974	$359,120	$0	$12,792	$0	$159,749
Merchant, solar plus storage	1	$0	$0	$0	$0	$0	$70,899	$0
Totals	**8**	**$1,926,287**	**$2,701,434**	**$502,640**	**$29,298**	**$36,055**	**$70,899**	**$159,749**

Note that in Table 3-2, ICAP tag revenues are three-year annual estimates, whereas other revenues are the sum across the months currently reported by Grantees. The 2021 ISO NE system peak hour has been preliminarily established as June 29, hour ending 6 p.m., and initial estimates of revenues achieved by ESS deployments during this hour are included with revenues achieved from the 2019 and 2020 ISO NE system peak in this table.

Table 3-2 shows that municipal light and power departments were the quickest to get their systems operational and were the most lucrative systems observed to date. The bulk (over 90%) of the achieved revenues was through ISO-NE peak hour (ICAP tag) and transmission zone (RNS) demand reductions.

Table 3-3 shows a summary of the predicted annual revenues against the total capital costs and estimated simple payback. The simple payback was estimated by extrapolating the average monthly revenues achieved to annual estimates and do not include the impacts of operations and maintenance costs. These impacts may be included in future reports once more data is available.

Table 3-3. System overview and simple payback estimate by use case

Use Case	Total kW Capacity	Total kWh Capacity	Average Estimated Annual Revenues	Capital Cost	Total Capital Cost after Grants	Simple Payback before Grant	Simple Payback after Grant
Municipal Light Plant (MLP Asset)	14,528	28,804	$2,206,494	$13,392,837	$9,550,274	6.1	4.3
Behind the meter – solar plus storage	1,320	4,000	$404,943	$2,500,000	$1,356,800	6.2	3.4
Merchant, solar plus storage	500	1,170	$35,450	$764,390	$382,196	21.6	10.8
Totals	**16,348**	**33,974**	**$2,646,887**	**$16,657,227**	**$11,289,270**	**6.3**	**4.3**

Table 3-4 shows a summary of the submitted predicted revenues against the DNV-verified revenues, as well as some overall performance metrics in terms of available power capacity realized as demand reductions. The normalized revenue per kW of available power capacity is also shown to allow comparison between the revenue streams.

Table 3-4. Summary of Grantee achieved revenues

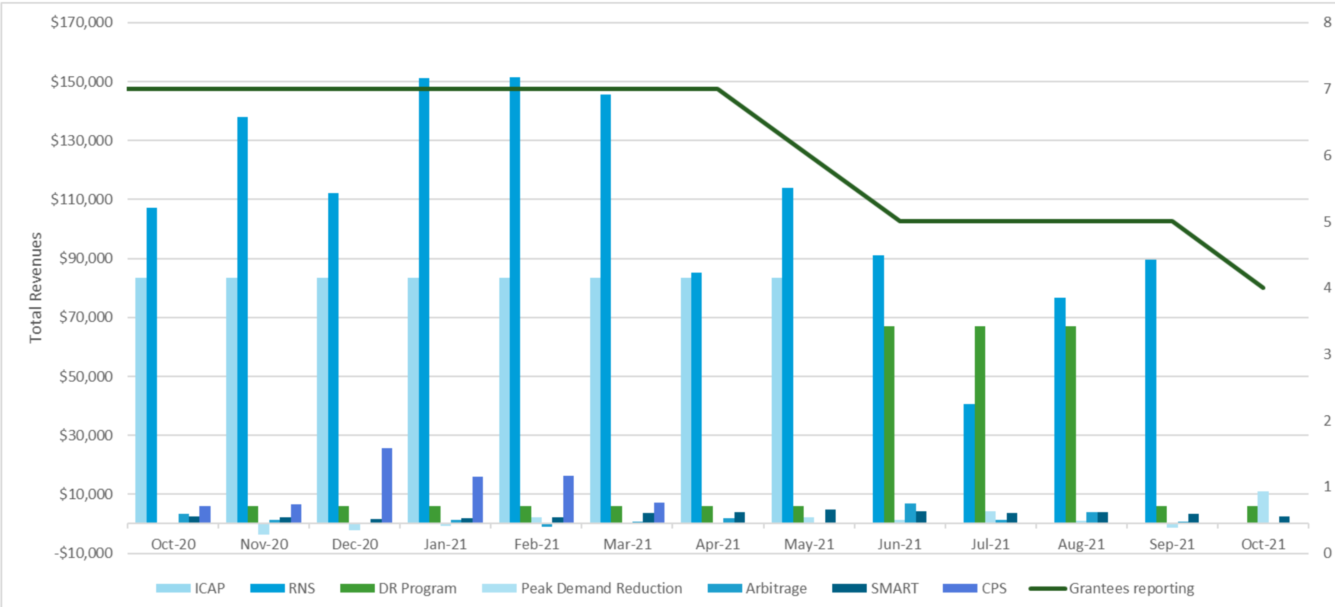
Revenue Strategy	Reporting Coverage	No. of Grantees Reporting	Predicted Revenues	Realized Revenue	Total ESS Capacity (kW)	Percent Capacity Realized	Avg. $/kW Revenue per Month
ICAP[1]	2019, and 2020 system peak	7	$1,875,083	$1,926,287	31,696	69%	$5.02
RNS	Apr 2019 to Oct 2021	7	$2,590,458	$2,701,434	387,752	66%	$6.70
Demand response (DR)[2]	Jun 2019 to Oct 2021	2	$113,336	$502,640	33,240	86%	$10.28
Peak demand reduction	Nov 2019 to Oct 2021	1	$257,416	$29,298	24,000	6%	$1.22
Energy arbitrage	Jun 2019 to Oct 2021	5	$99,894	$36,055	N/A	N/A	$0.11
SMART storage adder	Nov 2019 to Oct 2021	1	$73,501	$70,899	N/A	N/A	$5.91
Clean Peak Energy Standard	Jan 2020 to Mar 2021	1	N/A	$159,749	1,320	N/A	$8.07
Totals	**Apr 2019 to Oct 2021**	**8**	**$5,009,689**	**$5,426,362**			

[1] ICAP revenues are annual estimates.
[2] Demand response averages calculated only during months with DR commitments and reported revenues.
[3] Demand response program revenue percent capacity realized is not a direct reflection of realized demand reductions and includes percent losses associated with limitations in enrollment capacity.

As shown in Table 3-4, the eight Grantees included in this report generated revenues (or cost savings) from six different applications of their systems. Throughout this report, revenues are used synonymously with cost savings. The most common revenue strategies are ICAP and RNS demand charge revenues. Demand response revenues are proving to exceed expectations and, for some projects, have replaced other revenue strategies, such as peak demand reduction in terms of deployment priorities. Energy arbitrage benefits were marginal and sometimes even negative for some Grantees as locational marginal price (LMP) differences were not large enough to warrant targeted arbitrage dispatches. Thus, any arbitrage benefits or costs are a byproduct of other demand reduction deployment strategies.

For a deeper understanding of the monthly revenues achieved, DNV has compiled the monthly revenues achieved across Grantees, grouped by the revenue strategy, in Figure 3-1. As the total revenues are dependent on the number of Grantees reporting, this figure includes the number of Grantees reporting data each month for context. Note that the number of Grantees reporting applies to all revenue streams except ICAP revenues for which the data shown in Figure 3-1 represents the current estimates of revenues from eight Grantees.

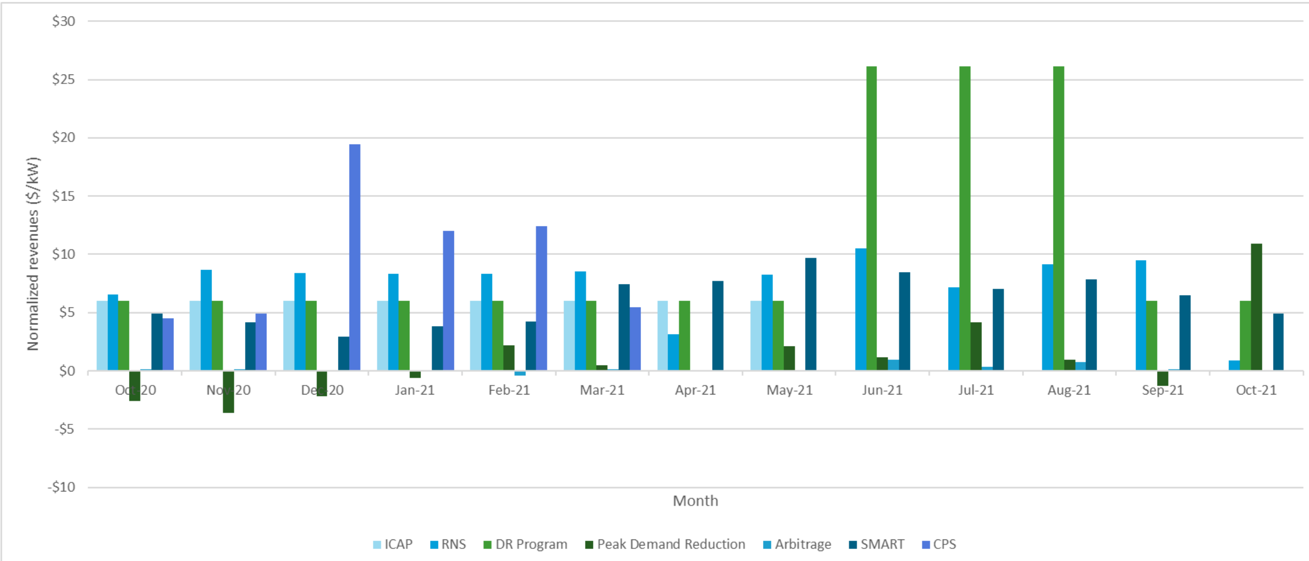
Figure 3-1. Comparison of monthly revenues achieved



ICAP revenues from deployment during the 2019 system peak are not realized until June 2020; they are then realized monthly between June 2020 and May 2021. All applicable Grantees who reported their annual ICAP performance associated with deployment during the 2019 system peak have submitted operational reports covering the July 2020 system peak. However, revenue from deployment during the 2021 system peak are not yet realized.

DNV normalized the revenues on a per kW of power capacity basis to provide better context about the revenues achievable given a system size. Figure 3-2 shows a bar graph of these monthly capacity normalized revenues. Note that the 2020 ISO NE system peak occurred on July 27, from 5 p.m. to 6 p.m., and the 2021 ISO NE system peak occurred on June 29, from 5 p.m. to 6 p.m., but as explained above for the 2021 system peak, the ICAP revenues will not start accruing until June 2022 and are not included.

Figure 3-2. Monthly revenues normalized against system capacity (kW)



The most striking observation from Figure 3-2 is that the DR program revenues for summer 2020 and summer 2021 dwarfed all other revenue strategies in terms of revenues per kW of system capacity. This was driven by one Grantee's participation in Eversource's summer daily dispatch program, which provided a $200 per kW payment based on Grantee performance. The daily dispatch DR revenues are allocated across the four-month program window between June and September. Note that this is a summer-only program, and DR programs available in other seasons pay a significantly lower rate. Additionally, the Eversource program called a DR event that aligned with the 2020 ISO-NE system peak, which enabled the Grantee to stack ICAP revenue with DR program revenue for that event's battery dispatch. While further discussion of DR revenues is provided in Section 3.4, at a high level this suggests that DR has the potential to provide significant revenue to ESS projects alongside demand charge management strategies.

RNS and ICAP revenues are similar in terms of benefit per kW, however, RNS revenues are harder to achieve consistently. Conversely, while ICAP revenues are large and easier to predict, they have a long waiting period before they are accrued.

3.2 ICAP revenue

ICAP refers to the installed capacity (kW) charges that suppliers are billed by ISO-NE each month. ICAP charges are passed on to municipal light departments and other very large customers who typically receive power at distribution-level voltages. This charge is associated with the costs of generators to meet the peak power demands for the ISO-NE region and is determined by the forward capacity market auctions (FCA) and the suppliers' load during the ISO-NE system peak (their ICAP tag), as well as a monthly adjustment factor. The monthly adjustment factor is associated with the installed capacity requirement (ICR) and accounts for differences in actual peak load versus the total load that needs to be made available based on required reserve margins, as well as other factors such as line losses and reconfiguration auctions. The ICR is generally about 150% of actual load but varies month to month. Essentially, this factor ensures that generators that have made capacity available are paid for the costs of providing this available power. The monthly ICAP charges can be summarized by the following formula:

$$ICAP\ charge\ per\ month = Capacity\ rate\ \times ICAP\ tag\ \times ICR\ ratio$$

ICAP charges are billed monthly from June through May of the year following the system peak. For example, the 2019 ISO-NE system peak occurred on July 30, hour ending 18, and charges for suppliers' portions of that load are billed starting in

June 2020. The ICAP peak hour is not known in advance. Suppliers typically need to wait until the end of the year, or at least the end of the summer, to get confirmation on when the peak occurred.

ICAP charge reductions are the most common and important use case for energy storage systems, as they are determined by a single hour and affect capacity charges for a 12-month period. However, these benefits are typically only available to municipal light and power departments, as well as the largest commercial customers who receive power at distribution level voltages.

The forward capacity rate is determined three years in advance through the FCA and is $5.297 per kW per month for the 2020 year (FCA #11 June 2020–May 2021, applied on the 2019 ISO-NE system peak). For the 2021 year (FCA #12 June 2021–May 2022), the forward capacity rate is $4.63 per kW per month. FCA #13 and #14 results were $3.80 and $2.00 per kW per month, respectively, indicating that short-term future ICAP revenues will be less than the 2020-2021 year. However, Grantees generally reported that ICAP tag rates are expected to increase in the long run. A summary of the ISO NE system peak hour days and hours is provided in Table 3-5.

Table 3-5. Summary of the ISO NE system peak hour days and hours[7]

Peak Date	Peak Hour		System Peak Load
	Hour Begin	Hour End	MW
8/09/2001	14:00	15:00	-24,723
8/14/2002	14:00	15:00	-25,103
8/22/2003	14:00	15:00	-24,311
8/30/2004	15:00	16:00	-23,719
7/27/2005	14:00	15:00	-26,618
8/02/2006	14:00	15:00	-28,038
8/03/2007	14:00	15:00	-25,773
6/10/2008	14:00	15:00	-25,691
8/18/2009	14:00	15:00	-24,708
7/06/2010	14:00	15:00	-26,701
7/22/2011	14:00	15:00	-27,312
7/17/2012	16:00	17:00	-25,543
7/19/2013	16:00	17:00	-26,911
7/02/2014	14:00	15:00	-24,068
7/29/2015	16:00	17:00	-24,052
8/12/2016	14:00	15:00	-25,111
6/13/2017	16:00	17:00	-23,508
8/29/2018	16:00	17:00	-25,559
7/30/2019	17:00	18:00	-23,929
7/27/2020	17:00	18:00	-24,695
6/29/2021	17:00	18:00	-25,159

[7] ISO NE website: https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/season-peak-hour-data

Note, the ISO NE system peak hour trends towards later in the day, which is a result of increasing amounts of distributed solar PV generation being brought online in the region, which lowers the system load during the early afternoon hours.

3.2.1 Grantee ICAP revenue summary

Approximately 75% of all the ACES Grantees plan to discharge their ESS to target reductions of ICAP charges. Out of the eight Grantees included in the scope of this report, six reported on ICAP benefits resulting from the load reductions during the 2019 system peak. Of those, only three Grantees had started reporting regular data to DNV by the July 2019 system peak. For the other three Grantees, 2019 ICAP hour performance was provided to DNV in the context of their operational reporting, and we have attempted to include these revenues in this summary with the caveat that we are unable to fully verify these results. Out of the eight Grantees included in the scope of this report, six reported on ICAP benefits from the 2020 system peak. Table 3-6 shows a summary of the 2019 and 2020 ICAP parameters and metrics.

Table 3-6. 2019 ICAP revenue summary

Revenue Stream Criteria	2019	2020
Grantees reporting	6	7
System peak day and hour	July 30, hour ending 18	July 27, hour ending 18
ISO-NE capacity rate	$5.30 per kW per month[1]	$4.63 per kW per month[1]
Estimated ICR ratio	1.5	1.5
Total estimated revenues	$999,814	$926,473

[1] https://www.iso-ne.com/about/key-stats/markets#fcaresults

All six Grantees targeting system peak reductions were able to reduce demand for the 2019 ISO-NE system peak hour. Out of the six Grantees reporting benefits for the 2020 system peak, one did not achieve any demand reductions during the peak hour due to an unplanned maintenance issue. DNV was able to verify the deployments for all Grantees for the 2020 system peak. Figure 3-3 shows the annual estimated revenues by Grantee assuming the parameters listed above in Table 3-6.

Figure 3-3. Estimated annual ICAP revenues by Grantee

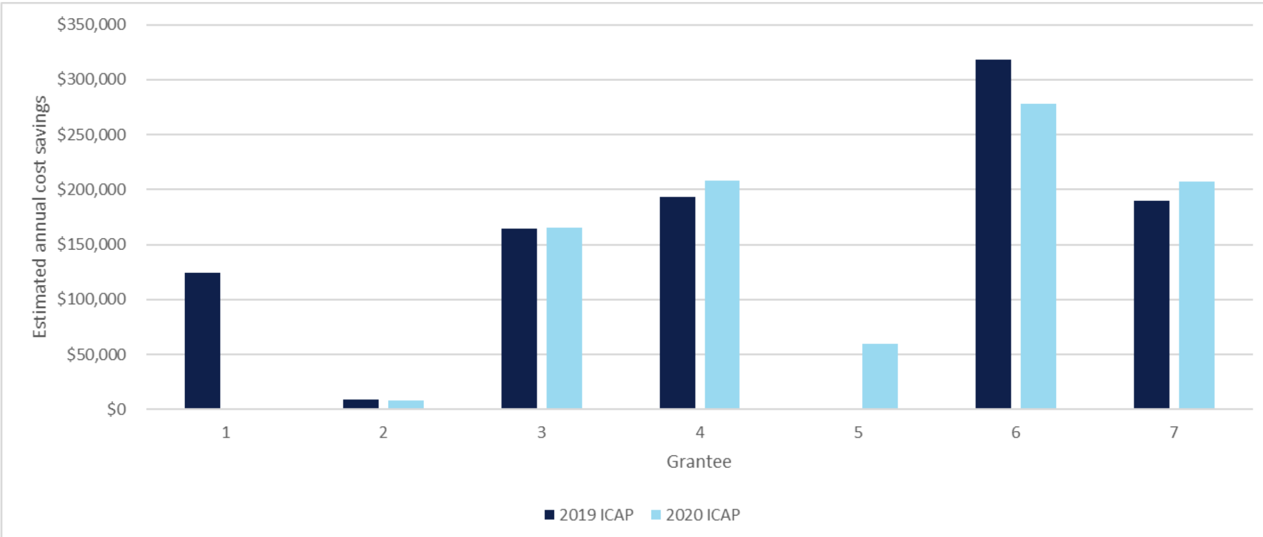
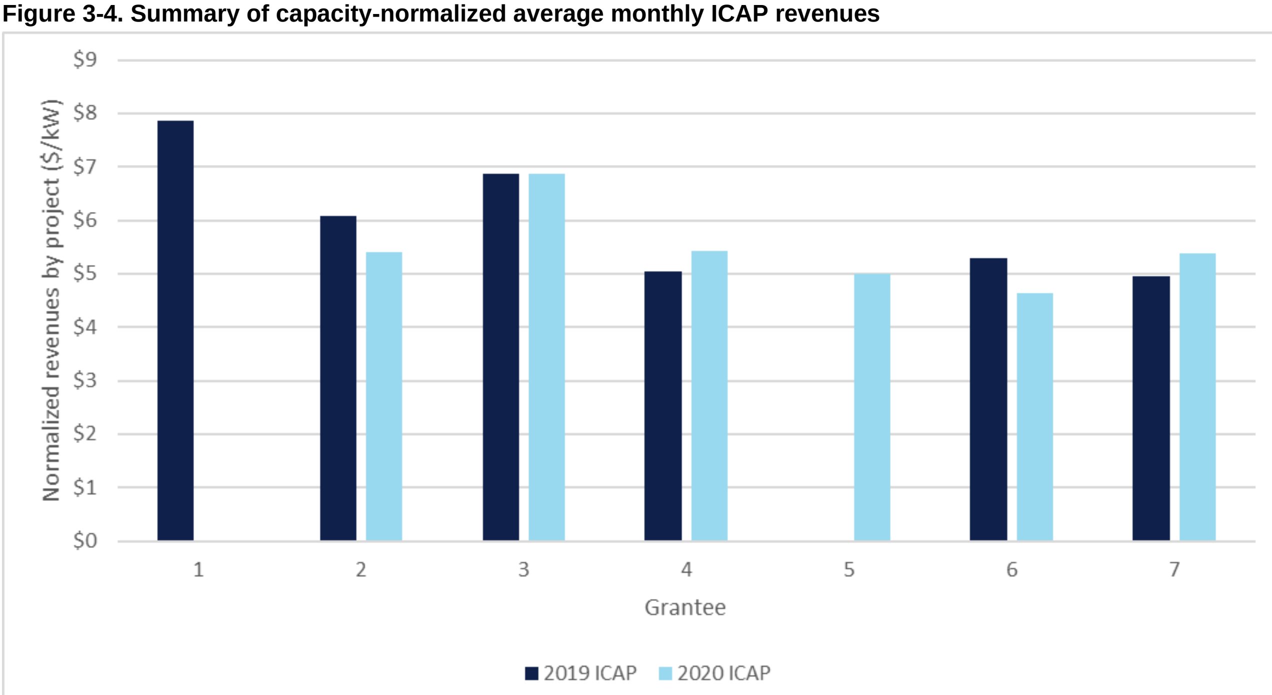


Figure 3-3 shows that Grantee 1 missed the 2020 system peak as mentioned above, and thus had no cost savings. Grantee 5 was not reporting at the time of the 2019 ICAP peak hour.

Because the total revenues are determined by the size of the system, DNV also tabulated the estimated average monthly revenues on a per kW of system capacity basis. These are shown in Figure 3-4. Similar to the total revenues by Grantee, these also assume a constant capacity rate and ICR adjustment factor of 1.5 for all months of both the 2020-2021, and 2021-2022 capacity years.

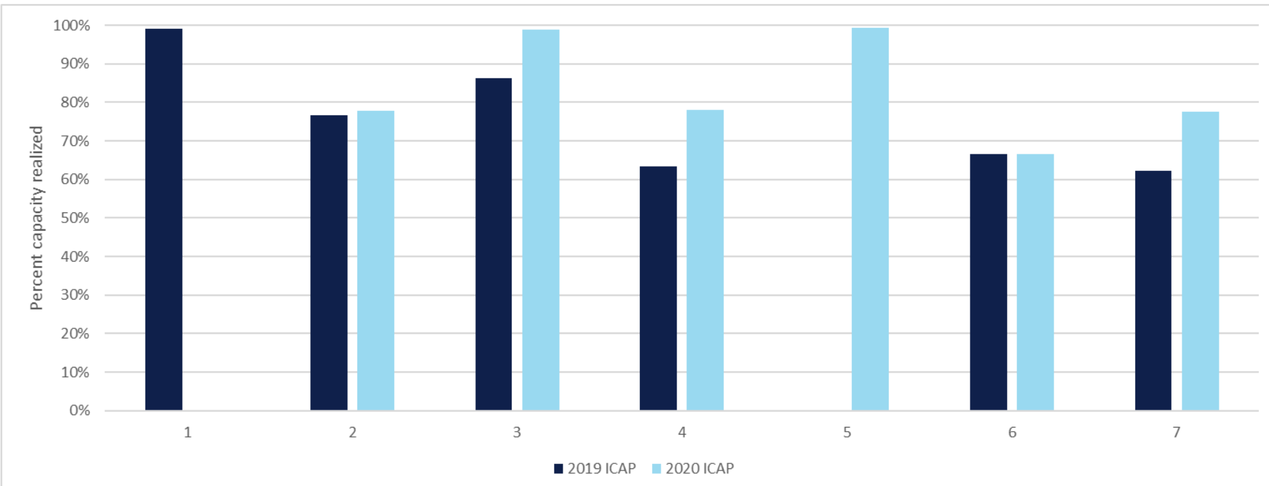
Figure 3-4. Summary of capacity-normalized average monthly ICAP revenues



It is important to note that the revenues normalized to system capacity reflect the Grantees' abilities to discharge the ESS at the system's full inverter (output) capacity during the peak hour. Depending on the confidence in the ICAP hour prediction, some Grantees choose to deploy their system at less-than-full capacity during the peak hour to enable discharge over a longer duration. This mitigates the risk of missing the ICAP hour but could reduce the achieved revenues, depending on the discharge duration of the ESS. For example, if a system is rated for energy capacity of 10 MWh and has a rated power output of 5 MW, the system operator may choose to deploy for two hours at 5 MW or for three hours at 3.33 MW.

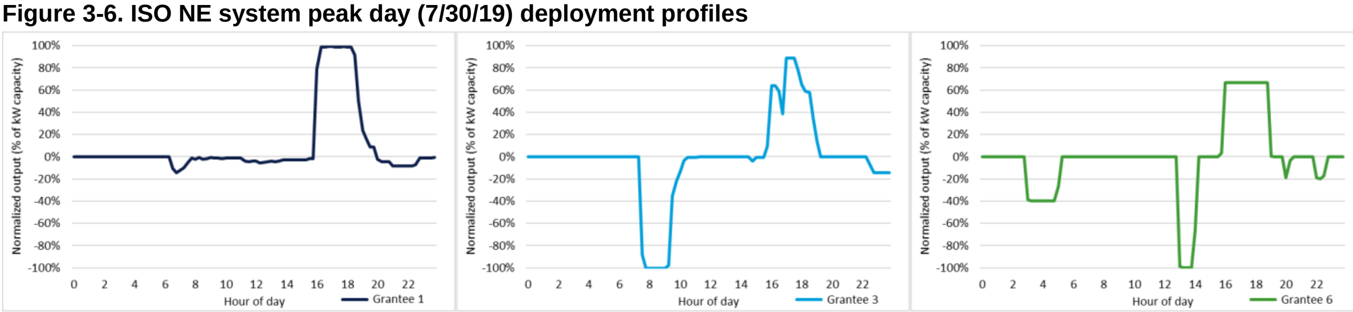
Figure 3-5 illustrates this dynamic by visualizing the percent capacity realized by the Grantees during the 2019 peak hour. The maximum achievable revenue per kW is determined by multiplying the capacity rate ($5.30 for 2019 or $4.63 for 2020) with the ICR ratio (1.5); this results in an upper bound of $7.95 (2019) or $6.95 (2020) per kW per month. Note the relative similarities between the percent capacity realized during the ICAP hour (Figure 3-5) and the normalized revenues achieved (Figure 3-4).

Figure 3-5. Percent capacity realized during 2019 and 2020 ISO-NE peak hours



The deployment profiles for the Grantees during the 2019 ISO-NE system peak day are shown in Figure 3-6. Note that, as mentioned above, only three Grantees provided operational data covering this day.

Figure 3-6. ISO NE system peak day (7/30/19) deployment profiles



The deployment profiles for the Grantees during the 2020 ISO-NE system peak day are shown in Figure 3-7.

Figure 3-7. ISO NE system peak day (7/27/20) deployment profiles

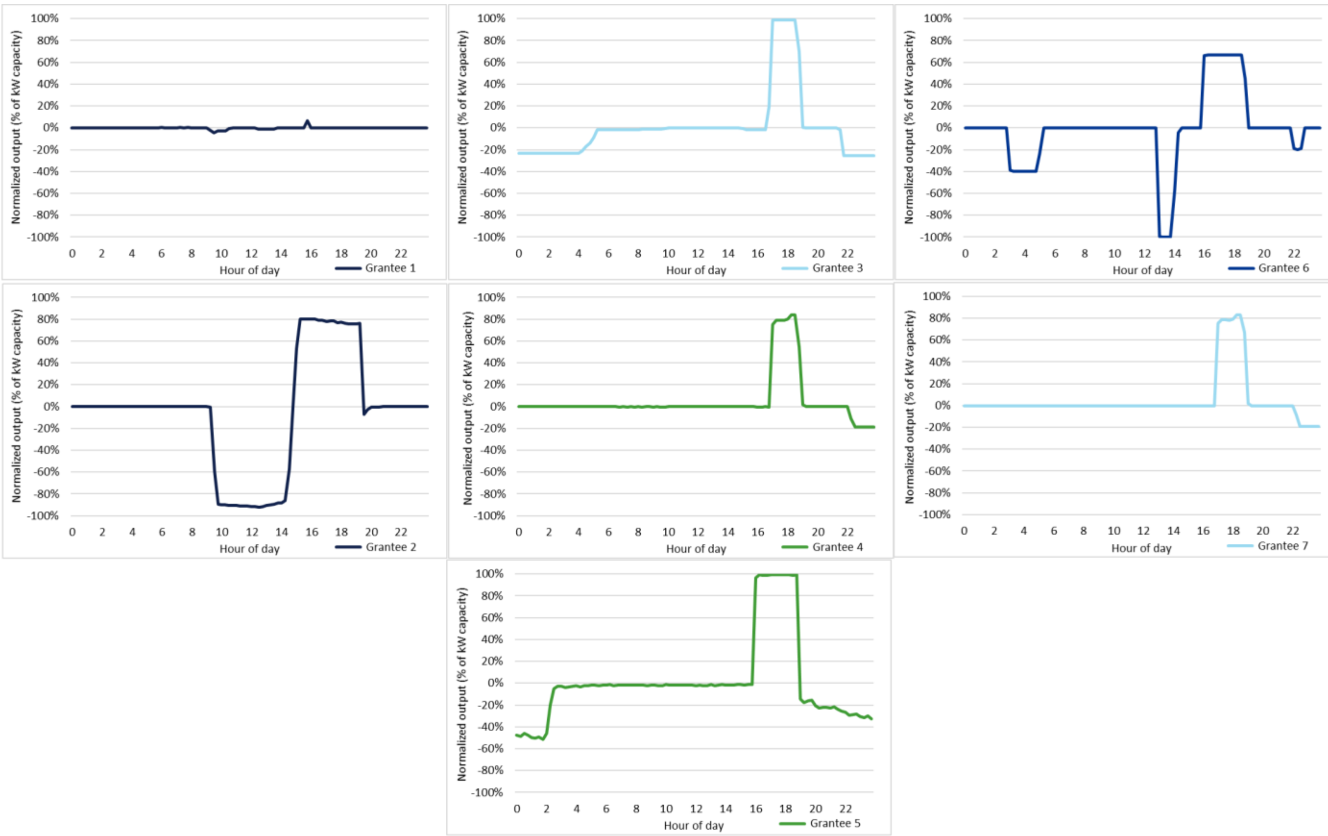


Figure 3-6 and Figure 3-7 depict ESS activity for the Grantees on the ISO-NE System peak days for 2019 and 2020—July 30, 2019, and July 27, 2020, respectively. ESS discharge is indicated by positive values, whereas charging is represented by negative values. DNV notes that the charging profiles of the ESS varied across Grantees, with some systems charging in a single event and others across multiple events throughout the day.

In 2019, all three Grantees deployed for about three hours from approximately 4 p.m. to 7 p.m., anticipating the ISO-NE peak during this window. Ultimately, all three discharges coincided with the ISO-NE peak which occurred during the 5 p.m. to 6 p.m. window.

In 2020, five out of the eight Grantees discharged the ESS during the ISO-NE peak hour. The Grantees typically discharged the ESS over a two- to three-hour window between 3 p.m. and 6 p.m., anticipating the ISO-NE peak during this window.

In 2021, six out of the eight Grantees discharged during the ISO-NE peak hour on June 29 from 5 p.m. to 6.p.m. (with one additional Grantee yet to provide data for this date). Grantees will realize revenue from the 2021 peak hour beginning in June 2022.

3.2.2 Additional ICAP insights

DNV's analysis of the 2019 and 2020 ICAP Grantee data and operational reports yielded the following additional insights regarding ICAP revenue and ISO-NE system loads:

- ICAP tag rates are decreasing over the ACES reporting period and will result in less realized revenues for the second and third reporting years. Grantees report that these rates are expected to increase in the long run.

- System peaks are easier to predict than regional peaks in part because ISO-NE provides good access to detailed live loading data and larger systems are also generally more predictable than smaller systems where a relatively small load variation could impact the peak hour.
- The 2019 ICAP hour was the first annual peak to occur from 5 p.m. to 6 p.m. in the 11 years since the creation of the forward capacity market 14 years ago. System peak hours have shifted later in the day as increasing amounts of solar PV capacity have been installed. The 2020 and 2021 ICAP hours also occurred from 5 p.m. to 6 p.m.
- The 2019 system peak load of 23,919 MW reported by ISO-NE is the second-lowest annual system peak load over the last 10 years, only 2% higher than 2017's 23,508 MW (the lowest regional system peak load over the last decade) and 12% lower than 2012's 27,312 MW (the highest regional system peak load over the last decade). However, 2020 and 2021 system peak loads increased from the 2019 low.

3.3 Regional network service (RNS) revenue summary

Municipal light departments and other large customers that see ICAP tag charges are also billed a peak demand charge associated with RNS, which reflect the costs associated with transmission and distribution infrastructure requirements to support regional peak loads. Whereas ICAP costs are based on the annual system peak, RNS peak demand costs are based on a monthly regional network peak. These monthly regional peaks and charges vary, albeit marginally, across different ISO-NE regions and therefore for Grantees. Grantees use different models to predict these peaks and sometimes rely on the assumption that regional peaks will align with system peaks, which is not always the case.

Similar to ICAP Tag charges, which operate on a fiscal year starting in June, the RNS charges refresh in June of each year. The RNS charges are determined primarily by Schedule 9 of the ISO-NE Open Access Transmission Tariff (OATT) and were approximately $9.20 per kW for the 2018/2019 fiscal year, $9.33 per kW for 2019/2020, $10.77 per kW for the 2020/2021 fiscal year, and increased to $11.75 for the 2021/2022 fiscal year. Added to the Schedule 9 charges are a small Schedule 1 charge, which was about $0.13 per kW for 2018/2019 and 2019/2020, nearly $0.15 for 2020/2021, and increased to nearly $0.16 for 2021/2022.

RNS charges are arguably the second most important revenue source for ACES Grantees because they are determined during a single regional network peak for the month. They are harder to predict than the ICAP hour, and Grantees typically discharge multiple days during the month based on their RNS projections. For most Grantees included in this report, this entailed four to ten deployments per month.

3.3.1 Grantee RNS revenue summary

At the time of this report, seven Grantees are reporting RNS revenues across 31 months. Table 3-7 shows the summary of total RNS benefits achieved over this reporting period.

Table 3-7. RNS revenues summary

Revenue Stream Criteria	Value
Analysis period	April 2019 to October 2021
Typical RNS hour	5–6 p.m. or 6–7 p.m.
RNS Schedule 9 and 1 charges – 2018/2019	$9.335 per kW
RNS Schedule 9 and 1 charges – 2019/2020	$9.461 per kW
RNS Schedule 9 and 1 charges – 2020/2021	$10.917 per kW
RNS Schedule 9 and 1 charges – 2021/2022	$11.904 per kW
Total RNS revenues achieved	**$2,701,434**

The Grantees included in this report hit 85% of the monthly RNS peaks and realized 66% of the total possible capacity that could have been realized for demand reductions during these regional network peaks. The total revenues by month for each Grantee are shown in Figure 3-8.

Figure 3-8. Monthly RNS revenues by Grantee

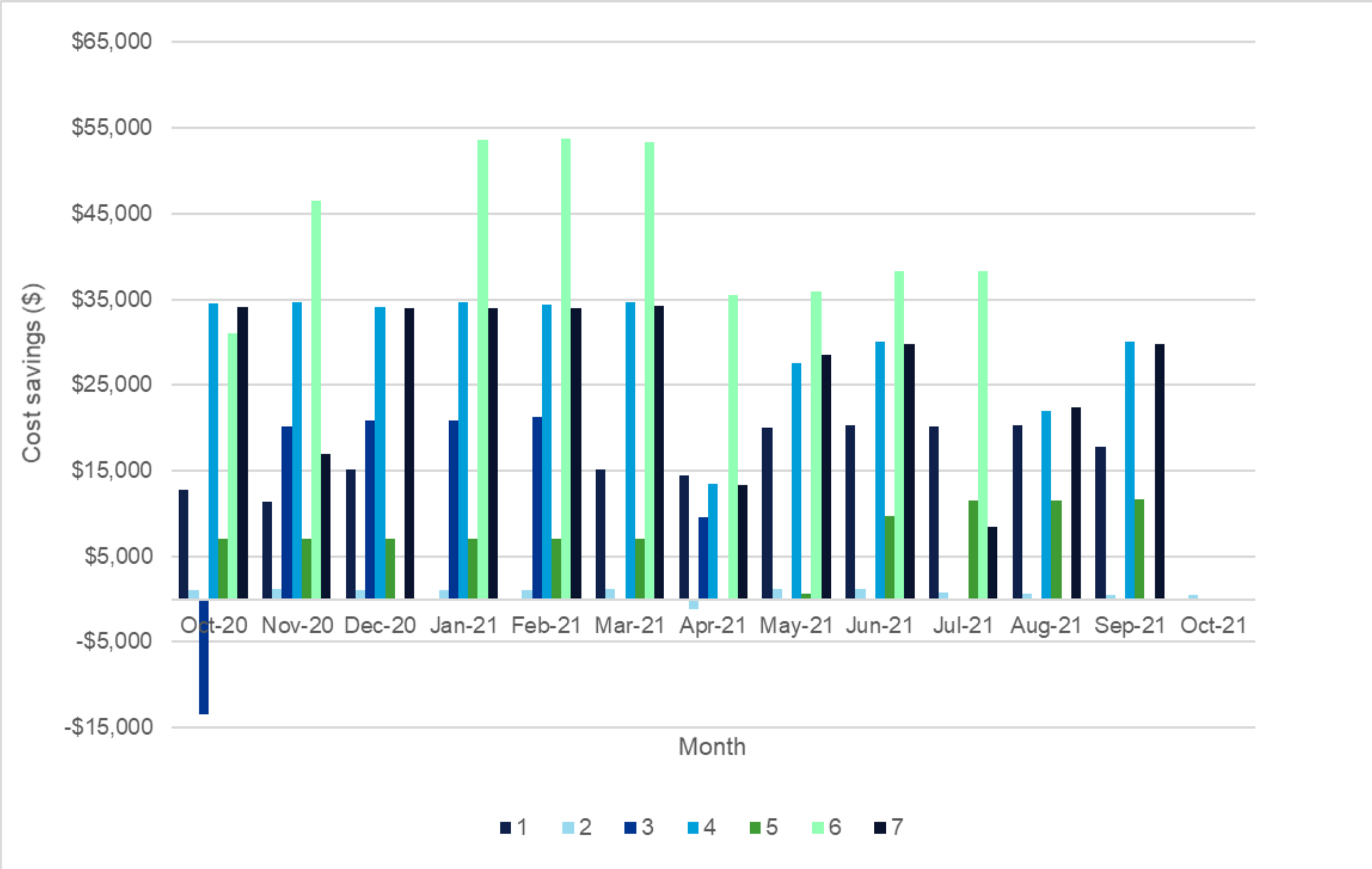


Table 3-8 shows the monthly RNS revenues by Grantee in table form.

Table 3-8. Monthly RNS revenues by Grantee

Month	Grantee 1	Grantee 2	Grantee 3	Grantee 4	Grantee 5	Grantee 6	Grantee 7	Totals
Apr-19	N/A	N/A	$18,154	N/A	N/A	N/A	N/A	$18,154
May-19	N/A	N/A	$11,182	N/A	N/A	N/A	N/A	$11,182
Jun-19	N/A	N/A	$0	N/A	N/A	$25,387	N/A	$25,387
Jul-19	N/A	N/A	$16,112	N/A	N/A	$31,097	N/A	$47,209
Aug-19	N/A	N/A	$1,237	N/A	N/A	-$100	N/A	$1,137
Sep-19	N/A	N/A	$284	N/A	N/A	$30,984	N/A	$31,268
Oct-19	$14,530	N/A	$11,433	$17	N/A	$31,013	-$90	$56,903
Nov-19	$14,371	$1,051	$17,139	$23,941	$3,442	$30,061	$23,714	$113,719
Dec-19	$14,721	$932	$17,461	$29,825	$1,747	$30,995	$29,316	$124,998
Jan-20	$0	$861	$17,535	$23,928	$7,048	$43,595	$23,713	$116,680
Feb-20	$13,478	$892	$12,406	$28,105	$7,048	$46,548	$28,332	$136,809
Mar-20	$0	-$7	$0	$30,006	$7,049	-$108	$29,746	$66,686
Apr-20	$11,399	$1,180	$0	$26,263	$7,050	-$109	$26,132	$71,914
May-20	$12,625	$1,297	$7,929	$19,140	$7,051	$31,020	$18,893	$97,954

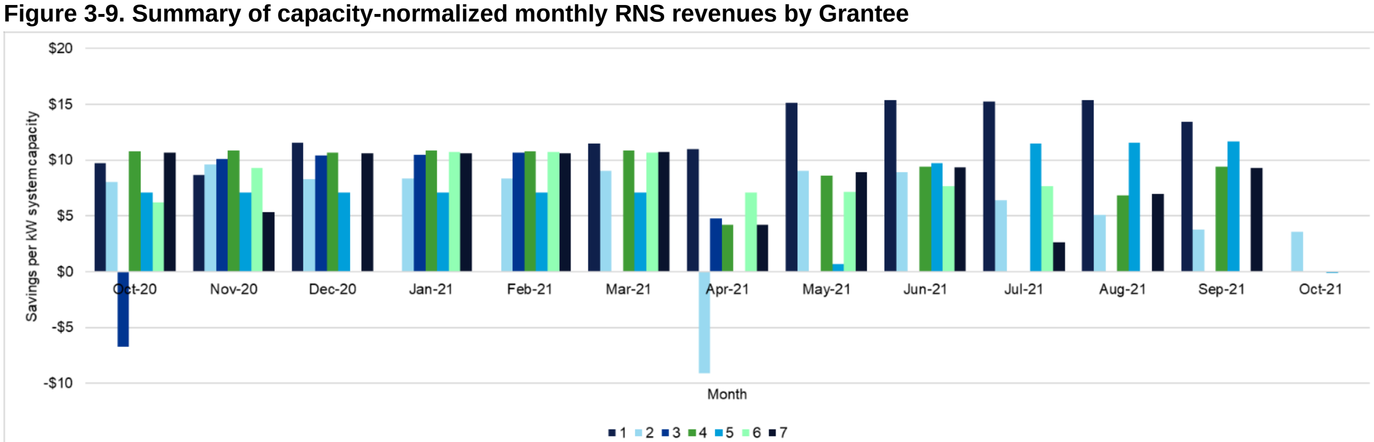
Month	Grantee 1	Grantee 2	Grantee 3	Grantee 4	Grantee 5	Grantee 6	Grantee 7	Totals
Jun-20	$14,865	$1,263	$14,327	$26,981	$7,052	$31,085	$26,744	$122,317
Jul-20	$11,328	$943	$20,205	$27,294	$7,053	$31,098	$27,106	$125,026
Aug-20	$12,582	$894	$14,863	$28,204	$7,054	$31,097	$27,981	$122,673
Sep-20	$12,639	$894	$14,666	$27,496	$7,055	$28,049	$17,121	$107,920
Oct-20	$12,798	$1,026	-$13,376	$34,466	$7,056	$31,094	$34,069	$107,133
Nov-20	$11,413	$1,230	$20,225	$34,643	$7,057	$46,480	$16,989	$138,038
Dec-20	$15,212	$1,059	$20,853	$34,130	$7,058	$0	$33,936	$112,247
Jan-21	$13	$1,070	$20,926	$34,624	$7,059	$53,620	$33,940	$151,251
Feb-21	$0	$1,068	$21,314	$34,444	$7,060	$53,760	$33,980	$151,626
Mar-21	$15,183	$1,153	$0	$34,632	$7,061	$53,386	$34,308	$145,723
Apr-21	$14,489	-$1,167	$9,528	$13,536	$0	$35,526	$13,351	$85,262
May-21	$19,973	$1,159	N.D.	$27,593	$684	$35,897	$28,556	$113,862
Jun-21	$20,267	$1,144	N.D.	$30,047	$9,692	N.D.	$29,822	$129,302
Jul-21	$20,099	$815	N.D.	-$160	$11,479	N.D.	$8,426	$78,990
Aug-21	$20,253	$651	N.D.	$21,932	$11,515	N.D.	$22,345	$76,696
Sep-21	$17,737	$480	N.D.	$30,095	$11,653	N.D.	$29,751	$89,716
Oct-21	N.D.	$455	N.D.	N.D.	-$141	N.D.	N.D.	$314

N/A stands for not applicable, meaning the project reporting period had not started yet.

N.D. stands for no data, meaning the Grantee hasn't reported data for this month yet. Total will update once we receive additional data.

Similar to ICAP revenues, RNS revenues are proportional to the system size, so DNV tabulated the capacity normalized RNS revenues for each reporting Grantee, as well. These are shown by month in Figure 3-9 for the most recent 12 months available. Although the RNS peak demand costs are somewhat higher than ICAP costs on a per kW basis, it is harder to hit these peaks consistently and all Grantees missed at least one regional peak for any 12-month period. In October 2020 and April 2021, a Grantee missed the forecasted peak and was charging the system during the peak hour, resulting in the large negative values.

Figure 3-9. Summary of capacity-normalized monthly RNS revenues by Grantee



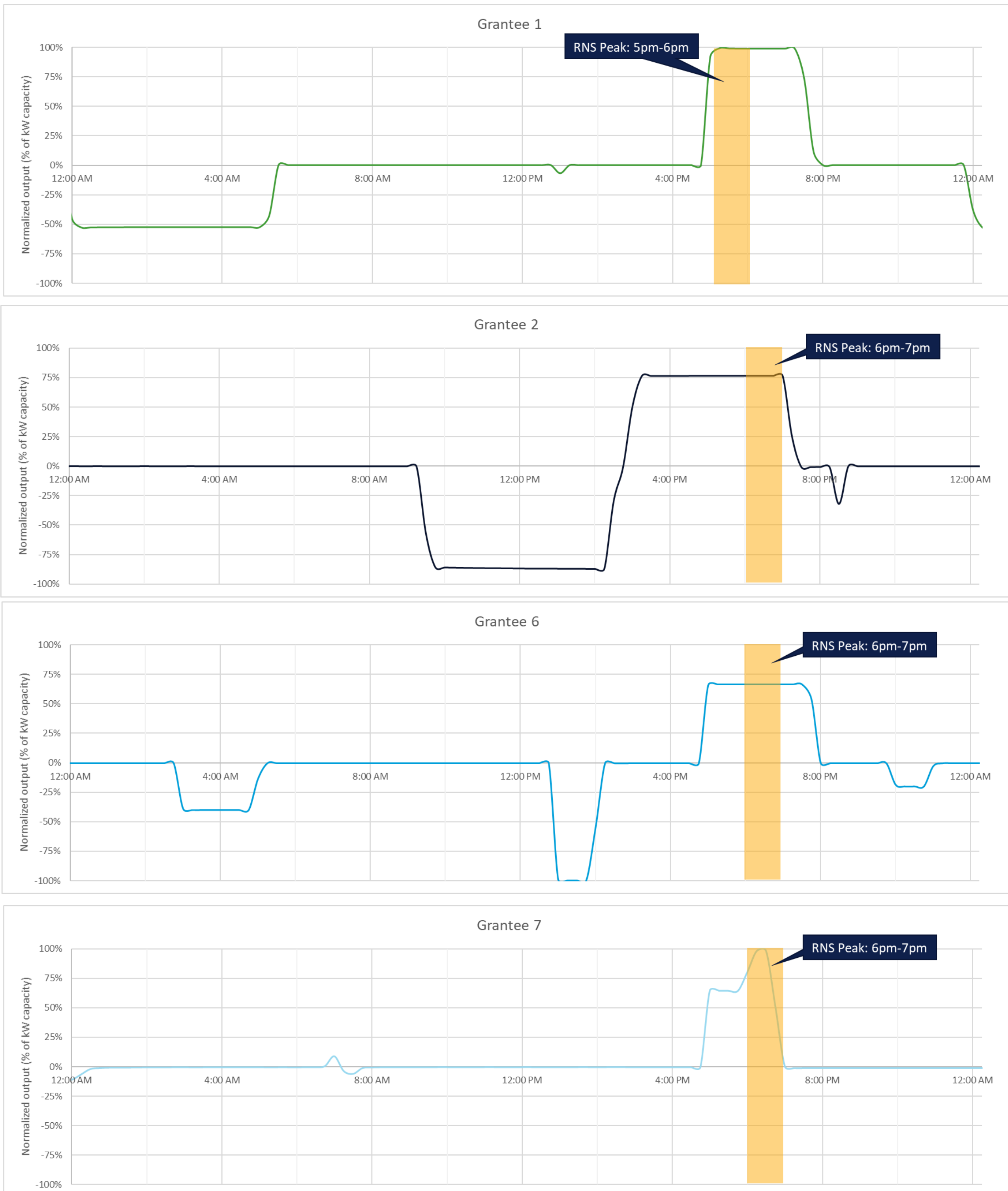
As shown in the figures and table above, two Grantees missed the April 2021 RNS peaks but were successful in deploying during most other months. One Grantee noted that the April RNS peak was during the late morning to early afternoon hours, an uncommon peak window. While the Grantee's predictive system accurately forecasted the April peak the day before it occurred, the Grantee did not note the uncommon window early enough to adjust their dispatch patterns, and resultingly missed the peak. This Grantee planned to play closer attention to their forecasted windows to avoid such misses in future.

For context in understanding monthly deployment trends, Figure 3-10 shows the deployment in percent capacity during May 2021 for four Grantees. As discussed in Section 2.1, ESS operational strategies and targeted revenue streams impact overall dispatch behavior. Grantees 6 and 7 have clearly identifiable RNS targeting, while Grantee 2 dispatches in the same fashion almost every day, and Grantee 1 dispatches more frequently during the month to pursue other revenue streams. Still, the independently predicted RNS hour dispatches across these four Grantees seem to align in the later part of May.

Figure 3-10. RNS deployment profiles for May 2021

The Grantees' predictive algorithms drive ESS dispatches during several anticipated peak periods in order to hit the RNS. Note that while the monthly dispatch profiles look similar, Grantees must reduce their loads during the peak hour to achieve the RNS revenue in a given month. Figure 3-11 shows the performance of these same four Grantees on the RNS peak day, which was later determined to be May 26, 2021. All four of the Grantees were able to hit the peak.

Figure 3-11. RNS deployment profiles for May 26, 2021



The Grantees reporting data for this report represent three different transmission networks: the Western Massachusetts Electric Company (WMECO), New England Power Company, and Boston Edison. Table 3-8 shows the date and hour ending of the peak load for each transmission network as reported to us by the Grantees.

Table 3-8. Regional transmission network peak day and hour (ending)

Month	Western Massachusetts Electric Company (WMECO)	New England Power Company (NEP)	Boston Edison (BE)
April 2019	N.D.	4/9/19 8:00 PM	4/9/19 8:00 PM
May 2019	N.D.	5/20/19 7:00 PM	5/20/19 6:00 PM
June 2019	N.D.	6/28/19 6:00 PM	6/28/19 6:00 PM
July 2019	7/21/19 6:00 PM	7/30/19 6:00 PM[1]	7/30/19 6:00 PM[1]
August 2019	8/19/19 4:00 PM	8/19/19 4:00 PM	8/19/19 4:00 PM
September 2019	9/11/19 6:00 PM	9/23/19 6:00 PM	9/23/19 5:00 PM
October 2019	10/2/19 3:00 PM	10/2/19 3:00 PM	10/2/19 1:00 PM
November 2019	11/13/19 6:00 PM	11/13/19 6:00 PM	11/13/19 6:00 PM
December 2019	12/19/19 7:00 PM	12/19/19 6:00 PM	12/19/19 6:00 PM
January 2020	1/20/20 6:00 PM	1/20/20 6:00 PM	1/21/20 6:00 PM
February 2020	2/14/20 7:00 PM	2/14/20 7:00 PM	2/14/20 7:00 PM
March 2020	3/23/20 6:00 PM	3/1/20 7:00 PM	3/1/20 7:00 PM
April 2020	4/27/20 6:00 PM	4/27/20 6:00 PM	4/27/20 6:00 PM
May 2020	5/29/20 6:00 PM	5/29/20 6:00 PM	5/29/20 6:00 PM
June 2020	6/22/20 6:00 PM	6/23/20 6:00 PM	6/23/20 6:00 PM
July 2020	7/21/20 6:00 PM	7/27/20 6:00 PM[2]	7/28/20 5:00 PM
August 2020	8/12/20 6:00 PM	8/11/20 6:00 PM	8/11/20 6:00 PM
September 2020	9/8/20 6:00 PM	9/10/20 6:00 PM	9/10/20 4:00 PM
October 2020	10/26/20 6:00 PM	10/30/20 7:00 PM	10/30/20 1:00 PM
November-20	11/18/20 5:00 PM	11/18/20 6:00 PM	11/18/20 6:00 PM
December-20	12/16/20 5:00 PM	12/17/20 6:00 PM	12/17/20 6:00 PM
January-21	1/29/21 6:00 PM	1/29/21 6:00 PM	1/29/21 6:00 PM
February-21	2/1/21 5:00 PM	2/1/21 6:00 PM	2/1/21 6:00 PM
March-21	3/2/21 6:00 PM	3/2/21 7:00 PM	3/2/21 7:00 PM
April-21	4/2/21 8:00 PM	4/16/21 12:00 PM	4/16/21 6:00 PM
May-21	5/26/21 6:00 PM	5/26/21 7:00 PM	5/26/21 7:00 PM
June-21	6/29/21 6:00 PM	6/29/21 6:00 PM	6/30/21 6:00 PM
July-21	7/16/21 5:00 PM	7/16/21 6:00 PM	7/16/21 6:00 PM
August-21	8/12/21 6:00 PM	8/12/21 6:00 PM	8/26/21 6:00 PM
September-21	9/15/21 6:00 PM	9/15/21 6:00 PM	9/15/21 6:00 PM
October-21	N.D.	10/14/21 7:00 PM	10/13/21 7:00 PM

[1]ISO NE 2019/2020 system peak day and hour (ending).
[2]ISO NE 2020/2021 system peak day and hour (ending).
N.D. stands for no data.

3.3.2 Additional RNS insights

- RNS revenues are the second-most lucrative for Grantees, but there is risk of missing regional peaks due to regional variability and a lack of available regional load data. RNS peak forecasting is performed by all Grantees either in-hour or through third parties targeting RNS revenue.
- Regional load curves are flattening as more distributed generation resources are added to the ISO-NE region, and it is becoming increasingly harder to predict these peaks.
- Regional transmission peaks most often occur from 5 p.m. to 6 p.m., but during swing months they often occur earlier in the afternoon.

3.4 Demand response revenue

DR programs compensate participants for reducing their load during prescribed event periods. They are typically offered either by a utility (like Eversource Active Demand Reduction Program) or by a grid operator (like ISO-NE Price Responsive Demand). DR events are typically called during times of high grid-level demand and driven by economic and/or reliability considerations.

Many participants in DR programs achieve load reductions by curtailing systems, processes, and activities such as turning down/off the HVAC system or reducing production volume. However, behind-the-meter energy storage systems are increasingly used for DR participation, as well.

DR programs are pay-for-performance programs where the economic compensation is tied to the achieved performance. Some programs also have penalties for non-performance. While the compensation mechanisms for DR programs vary from one program to another, there are typically two distinct components:

1. **Capacity payment** – Typically these are monthly payments proportional to the pledged capacity (the load that the participant commits to reduce during a DR event) and are paid regardless of whether an event is called or not.
2. **Performance payment** – Payments based on achieved performance during a DR event period.

DR events commonly span three or four hours, and the participants generally receive day-ahead notification of upcoming events. The short duration of the event and advance notice makes ESS well-suited for DR, as facilities can manage ESS charging to maximize DR event performance. Because of these factors, there is less revenue uncertainty in DR participation than with ICAP and RNS dispatches, where the facilities forecast peak periods and dispatch their ESS projects hoping that their projections align with system and/or regional peaks.

Facilities seldom participate in DR programs directly. Rather, they enlist the services of DR aggregators who integrate assets and enroll them for DR program participation. While the revenue-sharing arrangement between the facility and the DR aggregator is typically determined on a case-by-case basis, the aggregator's portion of the revenue can account for up to one-third of the DR revenue. Both of the Grantees reporting DR revenue in this report achieved DR revenues through an aggregator.

3.4.1 Grantee DR revenue summary

Of the eight Grantees included in this report, two have reported on DR program revenues. Table 3-9 shows the summary of DR program achieved revenues for this period.

Table 3-9. DR Grantee revenue summary

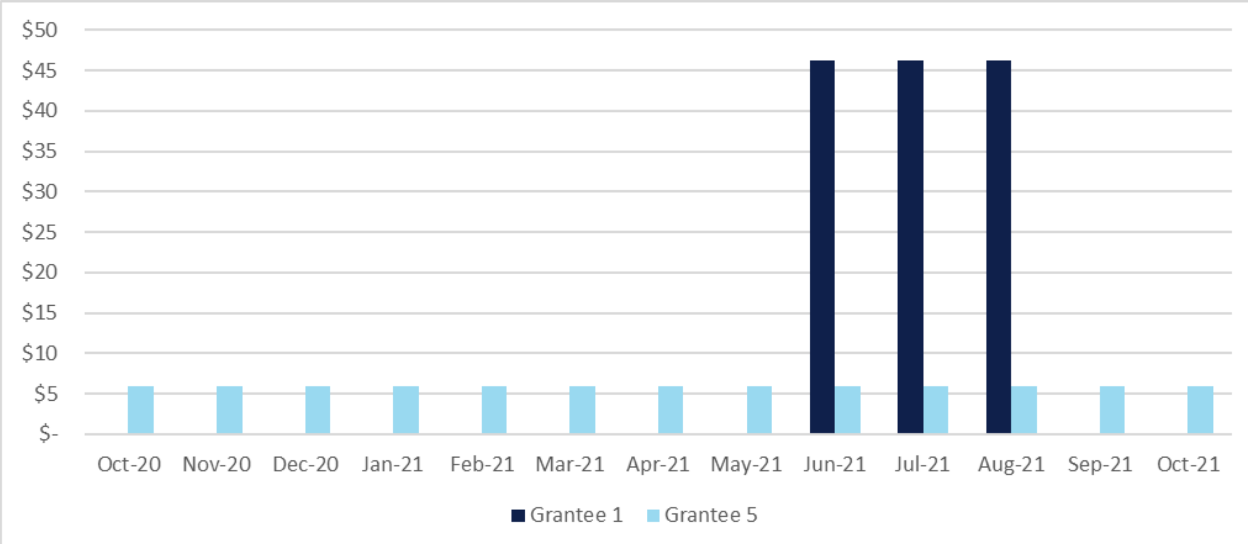
Revenue Stream Criteria	Value
Analysis period	October 2019 to October 2021
Number of Grantees reporting revenue	2
Total revenue	$502,649

The two Grantees included in this report achieved DR program revenues from two different DR programs: the Eversource Active Demand Reduction program and the ISO-NE Price Responsive Demand program, both outlined below.

- The **Eversource Active Demand Reduction** program includes two components:
  - ***Targeted Storage*** events have a three-hour duration and are activated by the program administrator during periods of peak demand. Incentive rates vary by season and consist of $100 per kW during the summer season (June to September) and $50 per kW during the winter season (December to March).
  - ***Summer Daily Dispatch*** covers weekday non-holidays throughout the summer (June to September) with typically up to 60 events called. The summer daily dispatch incentive is $200 per kW during the season.
- The **ISO NE Price Responsive Demand** program:
  - The Grantee who achieved revenues through the ISO NE Price Responsive Demand program did so through an aggregator and was guaranteed a fixed monthly payment based on fixed commitment for up to four hours of capacity deployment. This could be called during any month with a 30-minute notice.
  - No events were called for the Grantee who participated, but the Grantee still received their fixed monthly payments as arranged for having the resource available.

Figure 3-12 shows a monthly summary of the demand response program revenues achieved by the two reporting grantees over the months of operational report coverage.

Figure 3-12. Monthly capacity-normalized demand response program revenues



3.4.2 Additional DR insights

For the Grantee enrolled in the Eversource Active Demand Summer Daily Dispatch program for the summer 2021 period, DR revenues accounted for a significant portion of the revenues achieved to date. The amount of revenues achieved by this participation was greater than both the annual ICAP and RNS revenues, indicating that this program can serve as a core business case for ESS projects. The Active Demand Summer Daily Dispatch revenues stand out as significantly more profitable and reliable than most other revenue sources based on this limited data.

3.5 Energy arbitrage

Energy arbitrage involves time shifting the facility's electric load by charging the ESS at periods of low electricity costs (typically an off-peak period spanning overnight or early morning hours) and discharging it during periods of high electricity costs (typically an on-peak period spanning afternoon and/or evening hours). The ESS discharge offsets the volume of electricity that the facility needs to purchase during the on-peak period and thereby reduces the facility's electric bill.

Monetizable benefits for this revenue stream are calculated by computing the difference between the electricity costs to charge the system and the avoided electricity costs by the system's discharge.

This revenue stream is designed to arbitrage intra-day differences in electricity prices, and thus it is feasible only if there are temporally sensitive components in a facility's retail electric bills. Typically, a component of the volumetric electric prices involves a time-of-use component, which is pegged to the LMP.

Because of the energy lost due to the ESS round-trip efficiency (RTE) and attendant auxiliary and/or parasitic loads such as heating or controls, the gross energy input into an energy storage system will always be greater than its energy output—i.e., there will be an energy loss associated with its operation. Therefore, facilities seeking revenue from energy arbitrage will only dispatch the battery for this revenue strategy if the difference between on-peak and off-peak prices is large enough to offset the RTE losses.

3.5.1 Grantee energy arbitrage revenue summary

Unlike the other revenue streams described in this report, the ESS dispatch for energy arbitrage typically does not yield a large monetizable benefit over any single day. The revenue per cycle of system discharge is smaller by an order of magnitude when compared to revenue streams like ICAP and RNS revenues and accrues in small increments over the year.

Battery ESS projects typically have warranty requirements that place an upper bound on the total number of discharge cycles per year to maintain and extend system life. Because of this, Grantees with battery ESS typically do not dispatch daily. To date, five of the eight Grantees included in the scope of the report have reported energy arbitrage revenues. However, none of the five Grantees actively dispatch the ESS to leverage energy arbitrage alone; the energy arbitrage revenues achieved are incidental, occurring from ESS dispatch for ICAP, RNS, and CPES savings.

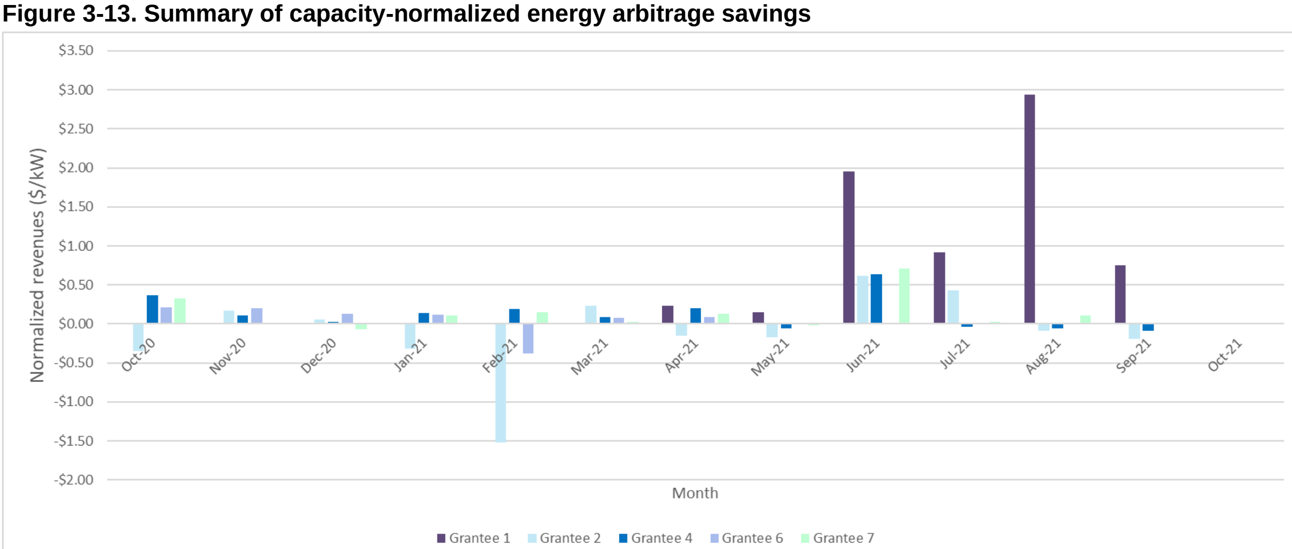
DNV used the granular ESS discharge/charge data, hourly real-time LMP for the specific reliability region accessed from ISO-NE's API, and site-specific adjustment factors to evaluate the energy arbitrage benefits accrued for participating Grantees. Table 3-10 shows the total arbitrage benefits accrued by the five Grantees reporting these benefits for this period.

Table 3-10. Energy arbitrage ACES revenue

Revenue Stream Criteria	Value
Analysis period	June 2019–October 2021
Number of Grantees reporting revenue	5
Total revenue	$36,055

Figure 3-13 shows the verified monthly arbitrage benefits achieved by each Grantee over the reporting period.

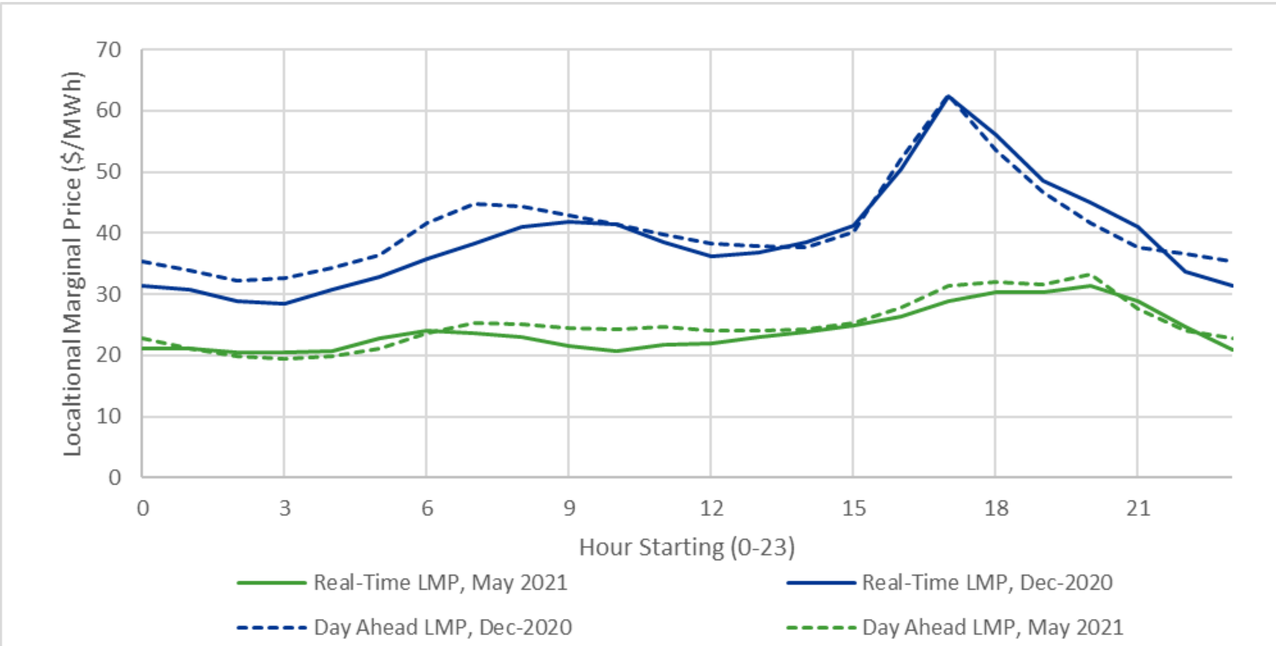
Figure 3-13. Summary of capacity-normalized energy arbitrage savings



3.5.2 Additional energy arbitrage insights

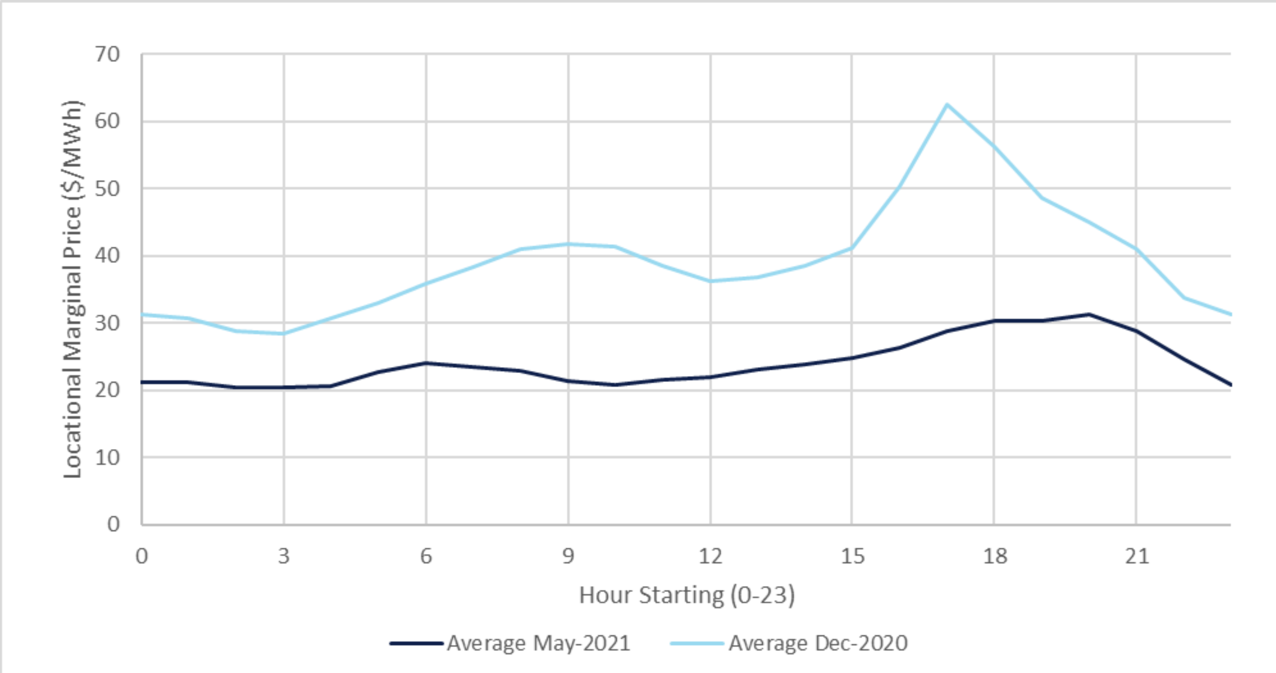
DNV identified differences between the arbitrage revenues reported by Grantees and the revenues calculated from the reported data. This is primarily due to differences in modeling approaches. DNV used real-time LMP values to assess revenues, while some Grantees used day-ahead LMP values or based their estimates on fixed energy costs. Other differences, such as handling of daylight savings time, also played a small role. Figure 3-14 shows the differences between real-time and day-ahead LMP values during two months within the reporting period. While the values are similar in direction and magnitude for either period, there are observable differences between them.

Figure 3-14. Comparison of hub-level real-time and day-ahead LMP values



There are also differences in the magnitude and intra-day variation of LMP prices throughout the year, which impact the opportunities for energy arbitrage. Figure 3-15 depicts the differences between two months in the reporting period. Note that the LMP in December 2020 is higher and varies greatly throughout the day, making it more conducive for energy arbitrage. Conversely, May 2021 saw relatively flat and lower LMP, suggesting that there is less of an arbitrage opportunity.

Figure 3-15. Average hourly hub-level real-time LMP value monthly variability



3.6 Peak demand reduction

Demand charges—charges based on peak demand set by the facility[8]—account for a significant portion of the monthly electricity bills in a typical commercial facility. These charges are typically set by the facility's 15-minute average peak demand for the month and are based on a published rate structure. Behind-the-meter ESS can be strategically dispatched during periods of facility peak demand to reduce the monthly peak demand charges. This revenue stream is called peak demand reduction, or peak shaving. ESS projects commonly leverage sophisticated statistical models of facility load profiles to inform their dispatch. While the magnitude of peak shaving revenue can be comparable to that of ICAP and RNS savings, it is largely driven by a facility's load profile and the retail electric rate structure in place at the facility. It is notable that commercial facility demand profiles can be significantly harder to predict than system or regional profiles due to the complexity of commercial and industrial facility operation. Commercial peak demand management could also require a daily dispatch over the month in comparison to RNS deployments, which are usually only a handful of events each month.

In contrast to a standard monthly demand rate where all hours of all days of the billing period are evaluated for demand charge calculations, time-of-use (TOU) rates commonly focus on a concentrated period of grid constraint to estimate peak demand. These windows typically include only certain daytime hours of the weekdays, and a facility's demand during the weekend or during nighttime hours does not impact the monthly demand charges. Therefore, TOU rates provide the ESS the flexibility to dispatch for other revenue streams outside the TOU windows. In addition, because the TOU windows do not span the entire day, they enable an ESS to achieve higher demand charge reduction given the same energy input. For example, a 1000 kWh ESS dispatching over a four-hour *on-peak* window achieves a 250 kW peak demand reduction whereas the same ESS dispatching over a 12-hour window achieves only 83.3 kW peak demand reduction. Finally, TOU rates typically have higher demand charges (in $/kW) during the on-peak period. All these factors can make the presence of TOU rates at the facility a key factor in driving peak shaving revenues.

[8] As opposed to charges based on peak demand on the regional transmission network (RNS) or ISO NE system overall (ICAP).

To date, only one of the eight Grantees included in the scope of this report actively dispatches their ESS to seek peak demand reduction.

3.6.1 Grantee peak demand management summary

It was anticipated that peak demand management would be an important source of revenue for commercial facilities participating in the ACES program, but that has not been realized to date. Instead, the one Grantee pursuing peak demand management has prioritized their other revenue strategies (primarily RNS and DR). For comparison to ICAP and RNS revenues, the anticipated normalized per kW revenues for this project was on the order of $11.20 per kW.

Indications from other Grantees approaching reporting on this strategy also show that peak demand management is difficult to achieve effectively. Several Grantees have communicated that DR program revenues are a more reliable and effective way to achieve revenues than peak demand management. We expect that as more Grantees report on peak demand management revenues, our findings on this topic will become more robust.

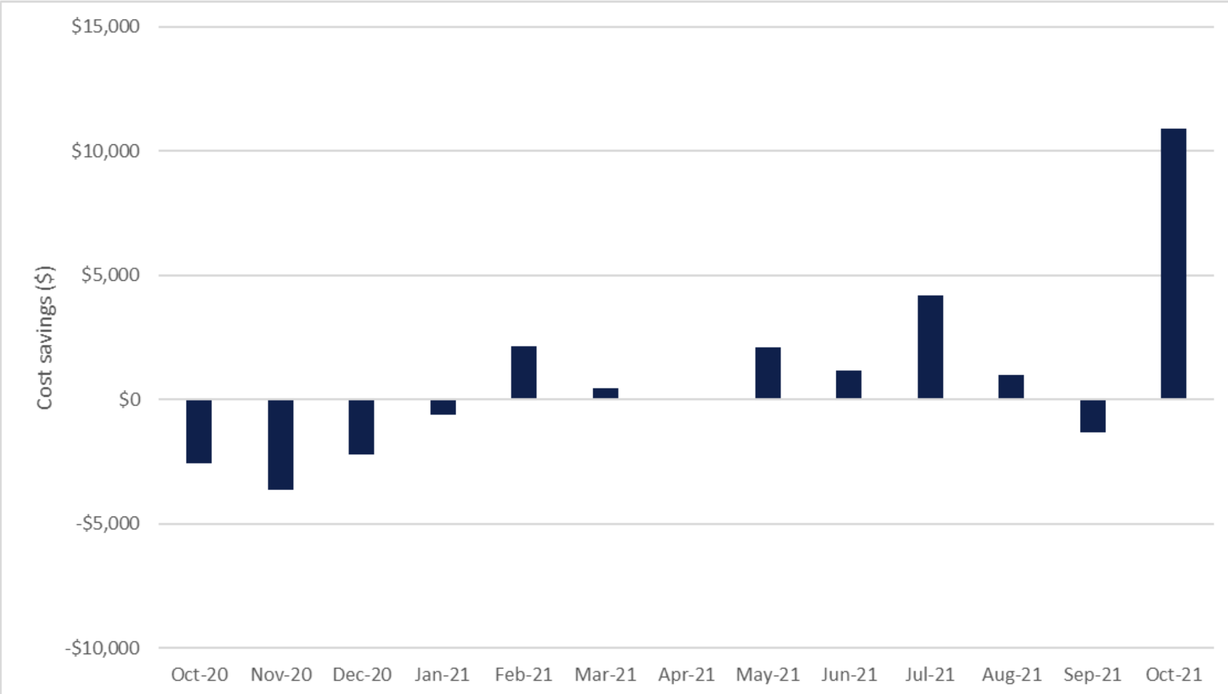
Table 3-11 shows the total peak demand reduction benefits accrued by the one Grantee reporting these benefits for this period.

Table 3-11. Peak demand reduction ACES revenue

Revenue Stream Criteria	Value
Analysis period	November 2019–October 2021
Number of Grantees reporting revenue	1
Total revenue	$29,298

Figure 3-16 shows the monthly revenues realized by the Grantee who receives these commercial demand charges. As discussed, this revenue stream has been deprioritized in favor of more lucrative revenue streams such as ICAP and demand response.

Figure 3-16. Monthly peak demand reduction revenues



3.7 SMART Program revenue

The Solar Massachusetts Renewable Target (SMART) Program was created by the DOER to promote the long-term sustainable solar incentive program in the Commonwealth. SMART is a declining block program with declining incentives as capacity blocks are filled. The SMART program includes adders for project features, including incorporating energy storage into solar project development.

3.7.1 Grantee SMART revenues

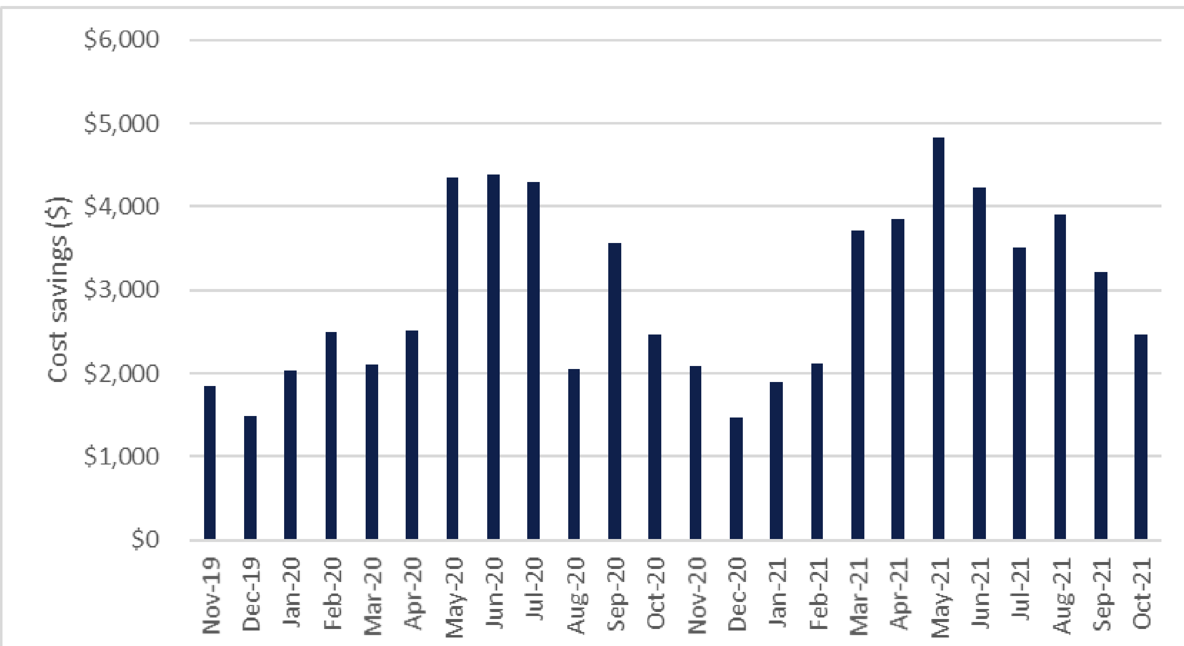
Of the eight Grantees included in this report, only one Grantee currently reports revenues from the SMART program as a result of the energy storage adder. This is a battery project co-located with a ground-mounted solar installation; the battery provides solar PV smoothing for the local grid and also achieves revenues through participation in the SMART program. The SMART program provides a fixed per kWh adder for the addition of energy storage, but the total SMART compensation rate varies with the net metering rate to provide an agreed upon total rate. Table 3-12 shows the summary of achieved SMART storage adder revenues.

Table 3-12. SMART ACES Revenue

Revenue Stream Criteria	Value
Analysis period	November 2019–October 2021
SMART storage adder rate	$0.04687 per kWh
Number of Grantees reporting revenue	1
Total SMART storage adder revenue	$70,899

As discussed above, the SMART storage adder revenues are dependent on the amount of solar generation and do not depend on ESS deployments, other than meeting the annual SMART requirement of 52 cycles per year. Figure 3-17 shows the monthly SMART revenues achieved by the Grantee who pursued this end use.

Figure 3-17. Monthly SMART revenues



Note that the Grantee's solar PV array was disconnected by the local utility in August 2020 and was not reconnected for at least 10 days, which resulted in significantly less generation and revenues for the month. The Grantee has also experienced regular outages with the ESS resulting in lower-than-expected revenue generation across multiple months.

3.8 Clean Peak Energy Standard

The Clean Peak Energy Standard (CPES) was created by the Massachusetts Department of Energy Resources (DOER) to procure more clean energy during peak periods of demand. Started in August 2020, the CPES program provides incentives to clean energy technologies (renewables, energy storage systems charged with renewables, and other demand response systems) that can supply electricity or reduce demand during daily peak periods.

The DOER specifies a four-hour peak window for each season. Program participants can earn Clean Peak Energy Certificates (CPECs) by generating clean electricity of discharging their clean energy storage system during the peak window on any given business day. Seasonal multipliers are included for summer and winter demand periods (awarding four times more CPECs in these seasons), and a resilience multiplier is included for any participant whose system can provide electricity during an outage (awarding 1.5 times more CPECs to resilient systems). Program participants then generate revenue by selling CPECs to retail electricity suppliers who must meet a minimum CPEC purchase requirement. At program inception in 2020, the CPEC purchase requirement was set at 1.5% of the electricity provider's kWh sales, and the requirement will increase with each program year.[9]

3.8.1 Grantee Clean Peak Standard revenues

Of the eight Grantees included in this report, only one Grantee currently reports revenue from the CPES program. This Grantee enrolled as a Clean Peak Resource and began reporting CPEC revenue in January 2021 while also reporting revenue from retroactively minted CPECs backdating to January 1, 2020. As of the most recent reporting period, CPES ranked the fourth highest of the Grantee's five active revenue streams in terms of total value generated (behind ICAP, RNS, and Demand Reduction streams).

CPEC monthly revenue ranged from $252 to $25,704 with an average revenue of $10,650 across 15 months. Table 3-13 shows the summary of Clean Peak Standard earnings achieved to date.

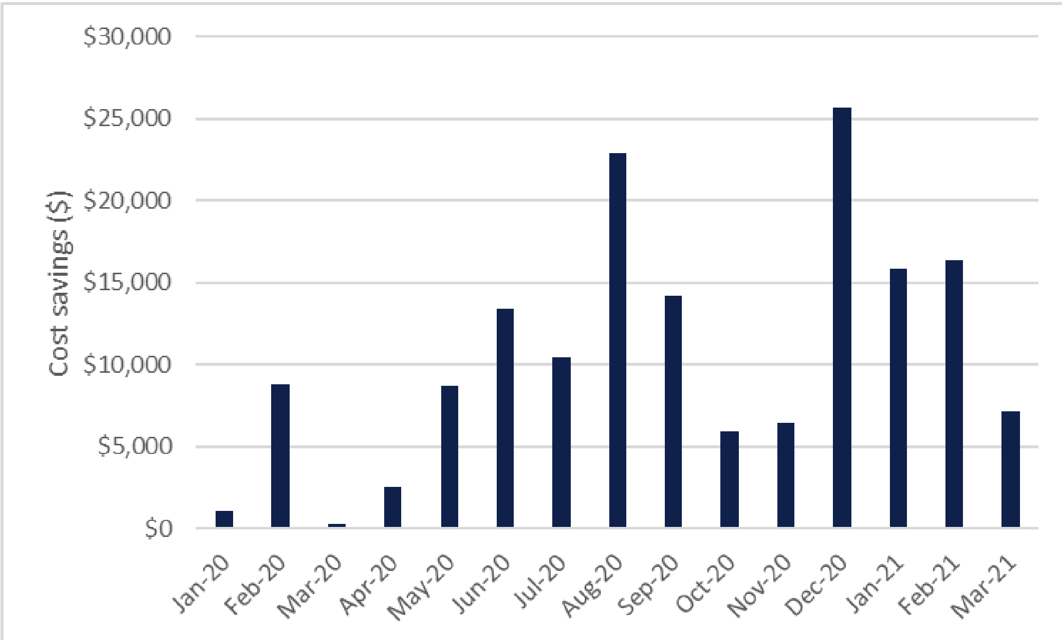
Table 3-13. Clean Peak Energy Standard ACES revenue

Revenue Stream Criteria	Value
Analysis period	January 2020–March 2021
Number of Grantees reporting revenue	1
Total revenue	$159,749

In September 2020, the Grantee adjusted BESS operation to optimize CPEC earnings, discharging during specified program peak periods and charging overnight. Regardless of adjusting battery operations for the CPES program, ICAP, RNS, and demand response revenue continued to be equal to or greater than the revenue generated for those programs pre-CPEC optimization. Figure 3-18 shows the monthly CPES revenues achieved by the Grantee who pursued this end use.

[9] For more information on the Clean Peak Energy Standard, see the Commonwealth of Massachusetts's webpage: https://www.mass.gov/clean-peak-energy-standard.

Figure 3-18. Monthly CPES revenues



4 NON-MONETIZABLE BENEFITS

In addition to the monetizable revenue streams discussed in the prior section, Grantees are also required to report non-monetizable revenues from their projects. These revenues vary widely across the Grantees, but generally fall into the following categories:

- **Testing feasibility of potential future revenue streams**. Many Grantees are exploring both actual and simulated ESS dispatches to assess the future revenue potential for programs and strategies not currently part of the existing suite of monetizable revenues. While these vary across Grantees, they can include exploring revenue potential from ISO-NE's Ancillary Service Market, demand response programs, SMART, and others.
- **Avoided carbon and other greenhouse gas (GHG) impacts**. Some Grantees will be quantifying avoided carbon costs and other GHG impacts and benefits of the ACES projects. There are different methodologies available to quantify these impacts, and we expect to be able to report on these benefits across projects once more Grantees begin reporting this benefit.
- **Resiliency benefits.** ESS installations provide both local and grid-level resiliency benefits. Local benefits include the ability to deliver power to critical systems and loads during grid outages. Grid resiliency benefits include dispatching ESS to align with network peaks to assist electricity supply. This can have more significant impacts on small or island networks that may be more subject to resource constraints.
- **Educational opportunities**. Several Grantees provide educational opportunities through their projects, typically through ESS sited at universities that offer internships and opportunities to test future revenues or optimization opportunities.
- **System optimization opportunities**. ESS projects can provide various system benefits, including increasing renewable capacity on distribution systems, enabling load optimization across other on-site generators, and deferring transmission and distribution system upgrades by adding capacity to the grid.

4.1 Grantee non-monetizable revenue performance

While Grantees are expected to demonstrate non-monetizable benefits for the project, only one Grantee reported these benefits in their initial operational reports. We expect to include results and reported non-monetizable benefits once more Grantees report these in their corresponding quarterly and/or biannual operational reports.

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