PNNL-29279

Opportunities for Dispatchable Power Projects in the New England Independent System Operator Area

October 2019

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U.S. DEPARTMENT OF ENERGY | Prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830

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Pacific Northwest National Laboratory
Richland, Washington 99354

Executive Summary

During the course of a military base's exploration of Energy as a Service, industry representatives asserted there were financially rewarding opportunities for third parties to install and operate dispatchable power projects at customer sites within the Independent System Operator-New England (ISO-NE) region. Expected benefits were tied to reducing customer demand charges, demand response, and ISO-NE congestion-related fees. To verify this assertion, Pacific Northwest National Laboratory (PNNL) conducted an investigation into the feasibility of installing a battery energy storage system (BESS) behind-the-meter at a military base located in the ISO-NE area. This report presents the findings of this assessment. In addition to the bill-reducing benefits of storage, dispatchable power also could provide potentially high-value resiliency benefits. These resiliency benefits were not evaluated here. While the focus of this report is battery storage, the lessons learned are applicable to other forms of dispatchable energy.

Energy storage is a flexible and adaptable technology that serves as an increasingly valuable asset in today's continuously evolving electrical grid. Its scalability and ability to provide a wide range of benefits has made it of high interest for those looking to solve a variety of issues ranging from integration of variable renewable energy generation to energy market participation. Accurate estimation of these benefits is a complex task.

There is multi-dimensional competition for energy in a BESS. If more energy is used in one hour, there is less available for the next hour. Similarly, the BESS cannot satisfy all use-case requirements simultaneously. Using PNNL's Battery Storage Evaluation Tool, the research team simulated a year of battery activity and co-optimized benefits between all use-cases considered in the analysis to measure technically achievable results. The value of these benefits included both those specific to the tariff structure the military facility faces from the distribution utility that serves the base as well as other benefits associated with the supply of energy in the ISO-NE area. In addition to investigating the benefit of each service, PNNL conducted a supplemental analysis to determine optimal sizing for the BESS given the characteristics of the facility and the landscape of economic opportunities.

Because of the nature of the facility's operations, the specific characteristics of the military base and its identify and location cannot be shared. Nevertheless, the lessons learned from this analysis that can be shared offer value to others seeking information on similar investments.

The following key lessons can be drawn from this analysis.

- The base case analysis of a 1 megawatt (MW)/2 megawatt-hour (MWh) BESS yields 10-year present value (PV) benefits ($4.26 million) that exceed PV system costs ($1.23 million). The most valuable application is the demand response service, which generates nearly $1.43 million (33.6% of total benefits) in total 10-year PV benefits, closely followed by Installed Capacity and Regional Network Service charge reduction at $1.03 million (24.2% of total) and $1.02 million (23.9% of total), respectively.[1] This gives a benefit-cost ratio (BCR) for the base case of 3.5 and a payback period of 3 years.

[1] Regional Network Service is a monthly charge that represents a payment for pool transmission facilities to transmit electricity within the New England Balancing Area.

- PNNL ran several alternative scenarios to evaluate the sensitivity of results with respect to changes in assumptions:
  - Under the assumption that during relevant hours the battery helps reduce load by a pre-determined amount for demand charge and demand response services, the BCR decreased to 2.9. This scenario assumed the military would employ a less sophisticated, more readily achievable operating strategy.
  - The highest BCR at 3.7 was achieved with a 0.5 MW/1 MWh BESS.
  - A scenario where Installed Capacity and Regional Network Service benefits were reduced by 50% also was considered. This results in a decrease in net benefits by $1.02 million and a proportionately lower but still high BCR of 2.63.
  - Each of the scenarios evaluated in this report yielded BCRs of at least 2.5.

These results rely on tariffs and fees charged by utilities and ISO-NE that are subject to adjustment. Therefore, projects with BCRs close to 1 should be approached with caution. That said, demand charges have increased historically and at least some of these charges are likely to continue. The region's generation mix is expected to change, albeit gradually, through the addition of more customer-side resources (e.g., photovoltaic systems and batteries) and deployment of utility solar and wind projects. It should be noted that without significant reduction in regional electricity demand, the increased penetration of these resources is unlikely to alleviate the fundamental sources of current demand charges; namely, delivery-system congestion.

These results appear to confirm industry claims for the economic value of dispatchable resources located behind-the-meter at customer sites in the ISO-NE region. If a BESS is financed using third-party funds, such as through a power purchase agreement, it would likely extend the payback period because third parties retain a profit share; however, under any reasonable terms, a BESS or similar dispatchable resource would still be economically attractive to a third-party investor working with a federal customer host. A third-party financed project would also shift market and performance risk to the third party. That, and expected improvements in the performance and cost of battery technologies, results in our recommendation that federal agencies explore options to finance BESSs at their sites in the ISO-NE region.

Acknowledgments

The authors wish to thank Alice Orrell of PNNL for her thoughtful review of this report, and Tracy Niro of the U.S. Department of Energy's Federal Energy Management Program for her support of this report. We are also grateful to Dr. Imre Gyuk, who is the Energy Storage Program Manager in the Office of Electricity at the U.S. Department of Energy, for providing financial support and leadership in the development of the methods and tools used to conduct the evaluation presented in this report.

Acronyms and Abbreviations

BCR	benefit-cost ratio
BESS	battery energy storage system
BSET	Battery Storage Evaluation Tool
DOE	U.S. Department of Energy
DR	Demand Response
ICAP	Installed Capacity
ISO-NE	Independent System Operator - New England
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
O&M	operation and maintenance
PNNL	Pacific Northwest National Laboratory
PV	present value
RNS	Regional Network Service
RTE	Round-trip efficiency
SA	Sensitivity Analysis

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1.0 Introduction

During the course of a military base's exploration of Energy as a Service, industry representatives asserted there were financially rewarding opportunities for third parties to install and operate dispatchable power projects at customer sites within the Independent System Operator-New England (ISO-NE) region. Benefits defined by third parties included reductions in utility demand charges, other fees, and ISO-NE congestion charges. If true, this would provide federal agencies with options to either reduce utility bills and/or generate a stream of revenues to reinvest in other energy projects. Additionally, an onsite power project would provide energy resilience benefits to the host customer.

Energy storage is a flexible and adaptable technology that serves as an increasingly valuable asset in today's continuously evolving electrical grid. Its scalability and ability to provide a wide range of benefits has made it of high interest for those looking to solve a variety of issues ranging from integration of variable renewable energy generation to energy market participation. Accurate estimation of these benefits is a complex task.

There is multi-dimensional competition for energy in a battery energy storage system (BESS). If more is used in one hour, there is less available for the next hour. Similarly, the BESS cannot satisfy all use case requirements simultaneously. Using Pacific Northwest National Laboratory's (PNNL) Battery Storage Evaluation Tool (BSET), the research team simulated a year of battery activity and co-optimized benefits between all use cases considered in the analysis to measure technically achievable results. The value of these benefits included both those specific to the tariff structure the military facility faces from the distribution utility that serves the base as well as other benefits associated with the supply of energy in the ISO-NE service area. In addition to investigating the benefit of each service, PNNL conducted a supplemental analysis to determine optimal sizing for the BESS given the characteristics of the facility and the landscape of economic opportunities. While the focus of this report is battery storage, the lessons learned are applicable to other forms of dispatchable energy.

2.0 Approach

Electricity markets in New England are deregulated at both the wholesale and retail levels for customers served by regulated utilities. Customers served by municipal or other public entities are not required to allow retail customer choice. Consequently, deregulated retail electricity costs are unbundled into three primary components: 1) local delivery costs charged by the incumbent regulated utility, 2) regional transmission delivery costs, and 3) commodity electricity prices. Large federal power customers are generally on a utility tariff with time-of-demand features, typically peak and off-peak or time-of-use. Electricity demand in the ISO-NE region typically peaks during the summer sometime between 2:00 and 10:00 P.M.; however, the peak demand on the transmission system may not be the same as for the local distribution utility because of differences in customer composition (e.g., residential versus commercial). Federal loads tend to follow commercial customer load patterns and peak in mid-afternoon rather than in the early evening when residential demand typically peaks. That is the case for the customer selected for PNNL's analysis.

The largest regulated utility in the ISO-NE region is Eversource, based in Massachusetts. Its commercial customer tariffs incorporate a typical peak hour price format that has a seasonal (summer/winter) differential. This rate design includes a peak kilowatt (kW) demand charge in addition to an energy charge measured in kilowatt-hours (kWh). ISO-NE has a similar tariff for use of the regional transmission system. To compensate for congestion on either the distribution or transmission system, both Eversource and ISO-NE have location-specific peak rates. The customer selected for this analysis is in Eversource's Boston demand zone. The economic analysis evaluated the costs and benefits of a dispatchable power source that could reduce demand during the applicable Eversource and ISO-NE peak periods.

ISO-NE, like most other ISOs, also operates markets for ancillary services. Ancillary services are power products that are usually provided by generating resources including spare generating capacity (Installed Capacity [ICAP] and Operating Capacity) that can be called upon when demand peaks unexpectedly and quick responding resources may be needed to ensure power frequency is maintained within a band around the mandatory 60-Hertz standard. Although these services have traditionally been provided by generators, they may also be met by varying power use or using power resources located on the customer-side of the meter.

ISO-NE's markets for ancillary services cater primarily to wholesale power providers rather than retail customers, although this is changing. Nevertheless, current ISO-NE requirements for some ancillary services have requirements, including minimum asset size thresholds that are difficult for retail customers to meet cost effectively. Accordingly, ancillary service markets were ignored in this analysis. It should be noted that third parties exist who can consolidate demand responsive capabilities across multiple customers to provide ancillary services to ISO-NE and that ISO-NE is gradually redesigning its markets to accommodate offers from individual retail customers. Consequently, these markets may be more open, and lucrative, to retail customers in the future.

3.0 Economic Methodology

The business case for a customer-sited dispatchable resource is a function of benefits versus costs. The benefits in this example currently rest on the avoided costs of demand and congestion fees from the local distribution utility and ISO-NE as well as prospects for avoiding high peak power costs in commodity spot markets. The latter was not evaluated because it is customary for federal customers to limit the risk of volatile power market prices by both pooling demand with other federal customers and employing "block" power purchase strategies that guarantee the power seller a specified amount of power to sell in exchange for a price fixed for each block of power. The cost side of the business case is the cost of the power resource, including the cost of the asset and its operation and maintenance, or alternatively, the cost of the services provided by an asset owned and/or operated by a third party for the benefit of the customer as it may be through an energy savings performance contract or a power purchase agreement. Cost information for this analysis used current costs of a BESS provided in Mongird et al. (2019).

The base case consists of a 1-MW/2-MWh BESS deployed behind-the-meter for a customer with a peak demand of at least 5 MW. The use cases evaluated in this analysis are listed below:

- Demand Charge Reduction
- Energy Charge Reduction
- Demand Response (DR) Participation
- ICAP and Regional Network Service (RNS) Charge Reduction.

The methodology used for each of these use cases is described in the following subsections.

3.1 Demand Charges

The Eversource tariff selected for analysis includes demand charges tied to energy purchases from the power grid during the most load-intensive hour each month. A BESS will be able to reduce the load or basis on which the fee is calculated. These demand charges include fees for distribution and transmission system use. The distribution charge varies by season (i.e., summer or winter). The transmission charge is a single rate applied throughout the year. Table 1 presents the demand charge rates used in this analysis that were effective as of July 1, 2019.

Table 1. Distribution and Transmission Demand Charge by Season

Rate Component	Summer ($/kW)	Winter ($/kW)
Distribution Charge	15.04	8.87
Transmission Charge	9.05	9.05

Summer months are all months between June and September, while the months of October through May are winter months. The seasonal rates are used to calculate monthly demand charges based on the peak kilowatts of maximum demand that month. For example, for the month of August, if the peak demand was 11,000 kW on August 20 at 2:50 PM, then:

$$Distribution\ Charge = \frac{\$15.04}{kW} \times 11{,}000\ kW = \$165{,}400$$

$$Transmission\ Charge = \frac{\$9.04}{kW} \times 11{,}000\ kW = \$99{,}440$$

$$Total\ Demand\ Charge = Distribution\ Charge + Transmission\ Charge = \$264{,}840$$

If a BESS could reduce peak demand by 250 kW, the benefit for the above example would be $6,020. Demand-charge benefits accrue monthly.

3.2 Energy Charges

The utility bill's energy charge is calculated each month as a sum of peak and off-peak charges. The components of energy charges include distribution, transmission, renewable energy, and an energy efficiency charge. While energy rates can vary by season, the customer in question faces a flat rate of $0.01998/kWh across all seasons (Summer/Winter) and times (Peak/Off-Peak).

The peak hours are defined as 7:00 AM to 8:00 PM on all weekdays, except holidays.[1] These rates are used to calculate monthly energy demand, which is the sum of peak and off-peak energy charges, based on total kWh consumption during these periods. As an example, assuming in the month of August the energy consumption during peak hours was 1,750,000 kWh and usage during off-peak hours approximately 3,250,000 kWh, then,

$$Energy\ Charges\ for\ Peak\ Hours = \frac{\$0.01998}{kWh} \times 1{,}750{,}000\ kWh = \$34{,}965$$

$$Energy\ Charges\ for\ Off\ Peak\ Hours = \frac{\$0.01998}{kWh} \times 3{,}250{,}000\ kWh = \$64{,}935$$

$$\begin{aligned} Total\ Energy\ Charge &= Energy\ Charge\ for\ Peak\ Hours + Energy\ Charge\ for\ Off\ Peak\ Hours \\ &= \$\ 99{,}900 \end{aligned}$$

Energy costs incurred during charging and RTE losses are included in the formulation.

3.3 Demand Response

Energy storage devices are eligible to participate in the Eversource Connected Solutions Demand Reduction program. Participation can be directly coordinated with Eversource or through aggregators who facilitate the DR programs for the energy storage unit. The DR program offers daily and targeted dispatch options and the incentive payment depends on average kilowatt reduction during events called within each season. The daily dispatch option is only available in the summer. The notification for these events is delivered the day before the event by phone, email, or text. The event lasts between 2 to 3 hours for daily dispatch and 3 hours for targeted dispatch. An event can happen anytime between 2:00 P.M. to 7:00 P.M. on non-holiday weekdays during the summer or winter periods. The incentives and event details are listed in Table 2.

[1] A list of holidays can be found in Appendix A.

Table 2. Incentives and Event Details by Dispatch Type

	Daily Dispatch (summer only)	Summer Targeted Dispatch	Winter Targeted Dispatch
Incentive (per average kW reduction per season)	$200	$100	$50
Maximum number of events	60	8	5

The DR benefit each season can be calculated using the incentive rates depending on average kilowatt reduction during peak events each season. If the average reduction during peak events over the summer is 100 kW, the incentive would be calculated as:

$$DR\ Incentive = 100\ kW\ \times \frac{\$200}{kW} = \$20{,}000$$

Based on input directly from Eversource, we assumed the daily dispatch events will start on July 1 and would be held on every non-holiday weekday from 4:00 P.M. to 7:00 P.M. until all 60 calls take place. The summer and winter targeted dispatches are typically scheduled to occur on the days when Eversource expects the summer and winter peaks to happen. For the winter program, we assume that calls occur on the five peak days registered during winter for the ISO-NE Zone appropriate to this facility in 2018, as presented in Table 3. Further, we assume these calls will take place from 4:00 P.M. and 7:00 P.M. for each of these dates.

Table 3. Peak Winter Load Days/Times in ISO-NE Zone for 2018

Date	Peak Hour
January 1, 2018	18
January 2, 2018	18
January 5, 2018	18
January 6, 2018	18
January 7, 2018	18

We assume that the BESS would participate in the daily dispatch and targeted winter dispatch program. While additional benefits could be obtained by participating in the summer targeted dispatch program, the BESS would have to provide twice the capacity to obtain those benefits simultaneously while also participating in the daily dispatch program. It is also important to note that since the benefit is calculated based on the average amount of energy provided in each of the three DR call hours, a BESS with less than an energy-to-power ratio of 3 would not be able to provide full power for the entire 3-hour period.

3.4 ICAP and RNS

There is a forward capacity market that has been implemented by ISO-NE. Forward capacity market charges are allocated to utility customers based on the following equation:

$$Capacity\ Payment = Capacity\ Service\ Obligation\ (CSO) \times Net\ Regional\ Clearing\ Price$$

The capacity costs are based on an ICAP tag. The ICAP tag establishes a capacity cost based on the customer’s load during the peak load hour registered each year in the ISO-NE area.

The capacity payment is equal to the multiplied by the net regional clearing prices for the ISO-NE Forward Capacity Auction. To reduce these charges, the BESS must be used to reduce load for 1 hour each year on the day of a shortage event. The peak load hour for the year in 2018, for example, occurred on August 29 from 4:00 P.M. to 5:00 P.M.

ISO-NE Forward Capacity Auction regional clearing prices are presented in Table 4. Note that the Forward Capacity Auction is carried out annually covering future time periods, and thus the clearing prices currently extend through the 2022 to 2023 time period (ISO-NE 2019a). From 2023 through 2031, annualized net regional clearing prices presented are based on an average of multiple price forecasts obtained by PNNL from previous projects in ISO-NE.

Table 4. ISO-NE Net Regional Clearing Prices

	Net Regional Clearing Price ($/kW-month)	
Time Period	Actual	Forecast
2019-2020	7.03	
2020-2021	5.30	
2021-2022	4.63	
2022-2023	3.80	
2023		5.81
2024		6.40
2025		7.02
2026		7.56
2027		7.41
2028		7.65
2029		7.88
2030		7.41
2031		7.65

RNS is a monthly charge that represents a payment for pool transmission facilities to transmit electricity within the New England Balancing Area. The monthly charge is based on the pool RNS rate and the monthly zonal network load. The RNS rate used for this analysis was $9.82/kW-month (ISO-NE 2019b). The RNS benefit results from the ability of the ISO-NE system to shave monthly peak loads (generation and transmission). The impact of ICAP and RNS-related charges requires the use of a price-setting algorithm. In the absence of detailed information, PNNL used the regional RNS rate as the basis of the base case benefits calculation but has also explored sensitivity analyses tied to varying this rate. More interaction with Eversource would be required to precisely determine ICAP and RNS reductions.

Table 5 presents the hours that defined the peak load for each month in 2018. The BESS would benefit from reducing load during these hours.

Table 5. Peak Load Time and Date to Determine RNS Payment for 2018

Month	Peak Day Date	Peak Hour	Real Time LMP ($/MWh)	Peak Demand (MW)
1	5	18	398.71	4,059
2	7	18	64.90	3,547
3	7	18	34.88	3,334
4	16	12	244.60	3,101
5	3	15	49.70	3,518
6	18	18	39.26	4,373
7	3	17	56.03	5,016
8	29	17	142.19	5,317
9	6	16	96.43	5,104
10	10	17	69.57	3,619
11	15	18	106.75	3,397
12	18	18	53.62	3,549

4.0 Project Costs

Because a generic lithium-ion BESS was used for this study and no separate cost analysis was conducted, costs and technical performance are defined based on a recent study completed by PNNL. Costs associated with the BESS primarily are capital costs and operation and maintenance (O&M) costs. For a lithium-ion battery, the capital costs are estimated to be $388 per kW of power and $372 per kWh of energy. In addition, O&M costs are divided into fixed and variable components, which are estimated to be $10 per kW-year and $0.0003 per kWh, respectively (Mongird et al. 2019). It is important to note that while the capital costs are only applicable at the initial stage, the variable costs are calculated annually over the 10-year time horizon.

Our base case for this analysis is a 1 MW/2 MWh BESS with a one-time capital cost of $1,132,000 ($388 x 1,000 kW + $372 x 2,000 kWh) in Year 0 (2020 in this case), and total O&M costs of $10,184 for Year 1 (2021 in this case). After Year 1, O&M costs increase at the rate of 2% per year, which is our assumed rate of inflation. The costs of energy are outlined in Section 3.2 of this report. Energy throughput is based on the results of our BSET optimization. Using Mongird et al. (2019), the initial round-trip efficiency (RTE) for the lithium-ion BESS is estimated at 86% but the average RTE over the 10-year economic life of the unit, assuming 0.5% annual degradation, is 83.75%. We use 83.75% average RTE for the simulation runs.

These costs are then converted into present value (PV) terms using a customer provided nominal discount rate of 2.6%. This leads to the total PV cost of the system. The discount rates, the rates of inflation, and the capacities of the BESSs in various scenario analyses are varied to perform sensitivity analyses (SA) around the base-case results. These analyses are presented later in this report.

5.0 Battery Storage Evaluation Tool

The capacity of the BESS to generate value is constrained by its operating characteristics and its ability to provide energy when needed for each application; that is, some services are in conflict and cannot be provided simultaneously. There is competition for the energy in the battery both from an intertemporal and on an application basis. Knowledge of the battery's characteristics and the landscape of economic opportunities matters in terms of optimizing value. To resolve these conflicts, the research team employed BSET.

The model was used to perform a look-ahead optimization hourly to determine the battery base-operating point. The simulation was then used to determine the actual battery operation. The detailed modeling and formulation of this method can be found in Wu et al. (2013). The optimization tool performs tradeoffs between services. As services are provided, the revenue or value derived from the service is logged as is the time the BESS is engaged in providing each service. Energy costs incurred during charging and RTE losses are included in the formulation.

BSET was used to define the potential economic benefit of the BESS on an annual basis and determine the number of hours each BESS would be actively engaged in the provision of each service under optimal conditions.

6.0 Results

The first step in estimating the benefits associated with the BESS operation in this analysis was to evaluate the benefits of each individual service when the battery operation is co-optimizing under the base case scenario. As outlined earlier, the base case consists of a 1-MW/2-MWh BESS deployed behind-the-meter for a customer with a peak demand of at least 5 MW, and employs the following assumptions:

- The current tariff structure outlined in the methodology applies, and unless the annual growth rate of these benefits is otherwise outlined, each benefit grows at a 2% average annual rate of inflation.
- The BESS is not constrained to provide a fixed amount of energy reduction during each DR event or peak load day and can be used to the extent that it is optimal and generates the maximum return on investment.

Table 6 and Figure 1 present the results of the base-case analysis. The 10-year PV benefits for the base case ($4.26 million) exceed the PV costs ($1.23 million) as shown in Figure 1. The most valuable application is the DR service, which generates nearly $1.43 million in total 10-year PV benefits (33.6% of total benefits), closely followed by ICAP and RNS charge reduction at $1.03 million (24.2% of total benefits) and $1.02 million (23.9% of total benefits), respectively. Finally, demand charge reduction produces $0.8 million (18.8% of total benefits). These results yield a benefit-cost ratio (BCR) of 3.5, and a payback period of 3 years.

Table 6. PV Costs and Benefits of Energy Storage System

Type	Cost	Benefit
Capital Cost	$ 1,132,000	
O&M Cost	95,430	
Demand-Charge Reduction		$ 792,136
DR		1,427,336
ICAP		1,026,554
RNS Payment Reduction		1,018,902
Energy Charge Reduction		(5,563)
Total	$1,227,430	$4,259,367

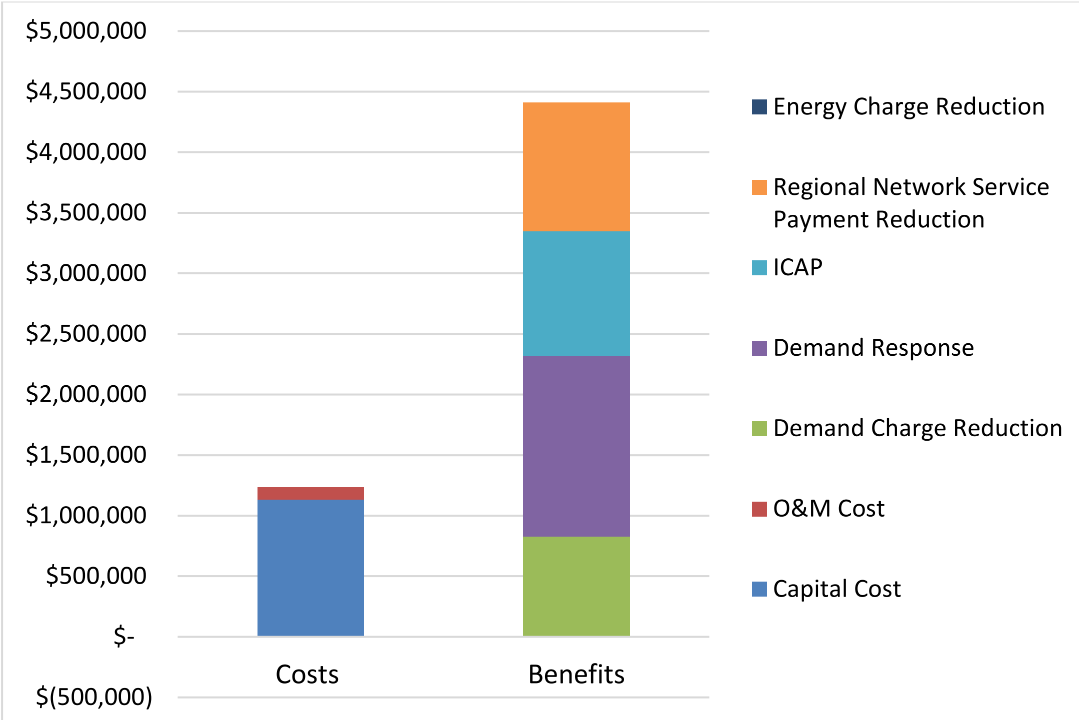

Figure 1. Base-Case PV Benefits and Costs

7.0 Sensitivity Analyses

To explore the sensitivity of the results to varying a number of key assumptions, the research team conducted a series of sensitivity analyses. The various scenarios are outlined below, and their impacts were measured in comparison to the base case. Each of the SA scenarios were performed by making the following adjustments to the assumptions:

- SA 1: There is a constraint on power output during DR and ICAP hours (i.e., the BESS provides an equal amount of energy reduction instead of being able to provide an optimal reduction on an hour-by-hour basis)
- SA 2: Varying power and energy capacity combinations
- SA 3: 50% reduction in ICAP and RNS benefits
- SA 4: DR and RNS benefits reduced by 10% annually
- SA 5: Annual discount rate increased or decreased by 1%
- SA 6: Nominal inflation increased or decreased by 1%.

The results of each sensitivity analysis, except for SA 2, are presented in Figure 2. SA 2 results are presented in detail in Table 7 and Figure 3.

7.1 SA 1: Power Output Constraints

To achieve the results under the base case, the BESS needs to be operated optimally during demand charge and DR hours, keeping in mind the system losses and future capacity use. This requires an additional degree of sophistication and battery output monitoring, which could prove quite challenging. Under SA 1, we assume that during the relevant hours, the battery helps reduce load by a pre-determined amount. In this case, for example, the battery's energy capacity is 2 MWh and if the DR event lasts for three hours, the battery reduces load by 666 kW each hour. If the ICAP hour occurs during those hours, we would only provide 666 kW toward reduction in the ICAP charge. The results from this analysis are shown in Figure 2.

There is an expected reduction in benefits in this case given that the battery is not being utilized optimally. Since the costs are the same, the total benefits drop to $3.6 million and the BCR is reduced to 2.9. While this outcome is less than optimal, it could be more realistic given the challenges associated with predicting regional peak load hours.

7.2 SA 2: Variation of Energy-to-Power Ratio

SA 2 explores different power and energy capacity combinations for the BESS to analyze how the BCR changes as the size as well as energy-to-power ratio of the system is changed. The results from this are highlighted in Table 7. In addition, Figure 3 lists color-coded BCRs for each energy-to-power combination. Changes from yellow to green represents improvement in BCR. The BESS with 0.5-MW power capacity and 1-MWh energy capacity yields the highest BCR at 3.7. The base-case power and energy combination is encased in a box in Table 7.

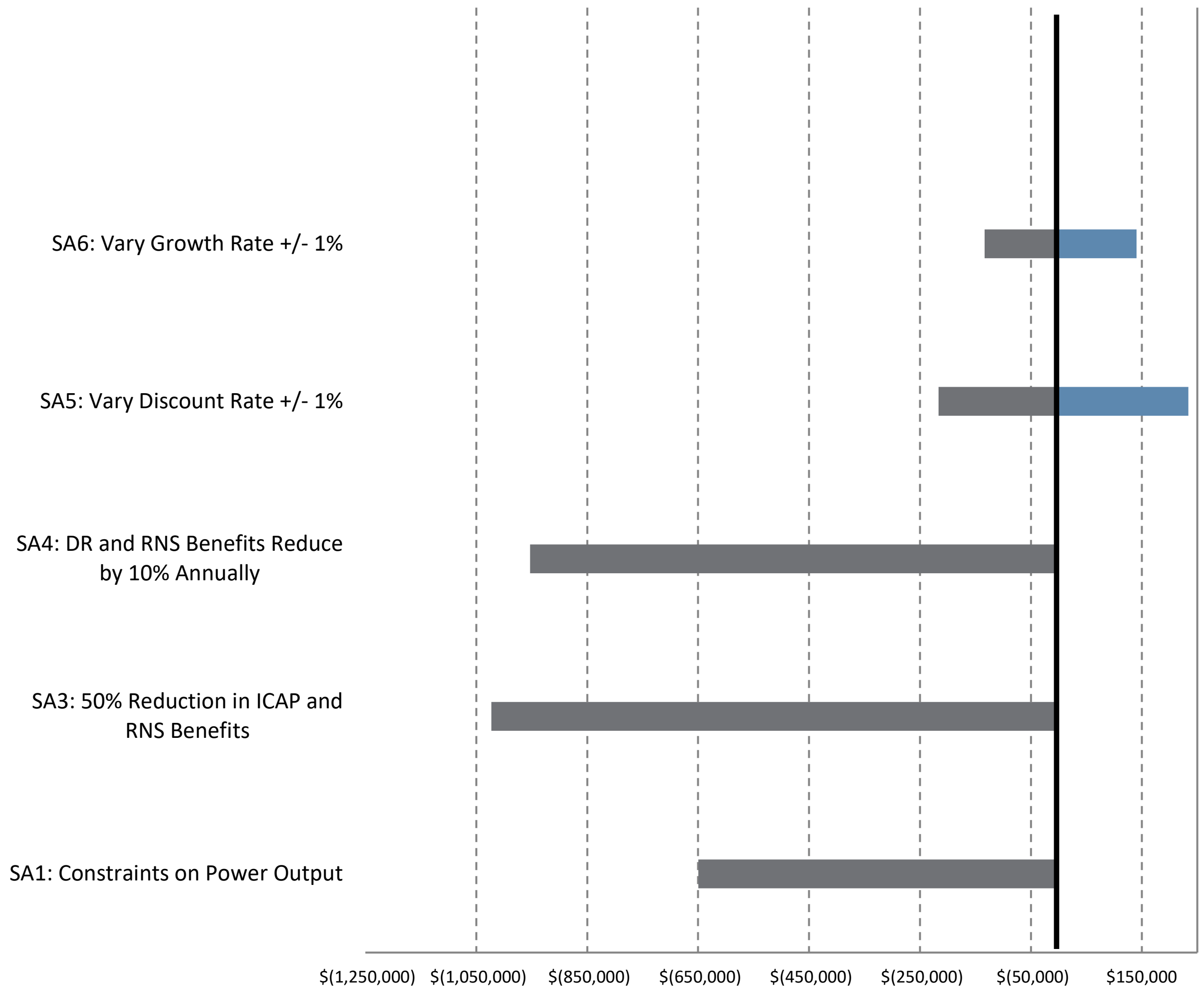

Figure 2. Results of Various Sensitivity Analyses

Table 7. Costs and Benefits by Energy-to-Power Ratio

BESS Power Capacity (MW)	**0.5**	**0.5**	**0.5**	**1**	**1**	**1**	**1.5**	**1.5**	**1.5**	**2**	**2**	**2**
BESS Energy Capacity (MWh)	**0.5**	**1**	**1.5**	**1**	**2**	**3**	**1.5**	**3**	**4.5**	**2**	**4**	**6**
PV Benefits ($Millions)	1.54	2.27	2.86	2.90	4.26	5.36	4.24	6.22	7.81	5.57	8.15	10.21
PV Costs ($Millions)	0.43	0.61	0.80	0.86	1.23	1.60	1.28	1.84	2.40	1.71	2.45	3.20
Net Benefits ($Millions)	1.12	1.66	2.06	2.05	3.03	3.76	2.96	4.38	5.41	3.86	5.70	7.01
BCR	3.6	3.7	3.6	3.4	3.5	3.4	3.3	3.4	3.3	3.3	3.3	3.2

Energy Capacity (MWh)	Power Capacity (MW) 0.5	1	1.5	2
0.5	3.6			
1	3.7	3.4		
1.5	3.6		3.3	
2		3.5		3.3
3		3.4	3.4	
4				3.3
4.5			3.3	
6				3.2

Figure 3. BCR by BESS Energy and Power Combination

7.3 SA 3: Reduction in ICAP Benefits by 50%

ICAP and RNS benefits are revised annually and may not grow at the same rate as predicted. A scenario in which ICAP and RNS benefits are reduced by 50% is considered. This results in a decline of net benefits by $1.02 million, as shown in Figure 3, and a reduction of the BCR to 2.63.

7.4 SA 4: Reduction of DR and ICAP Benefits by 10% Annually

DR benefits in this case are unusually high due to a lucrative DR program for commercial customers with energy storage. These programs may not remain so lucrative in the future. Additionally, the RNS benefits may reduce each year due to several factors, including system upgrades. To factor this into the analysis, a scenario which assumes a 10% reduction in DR and RNS benefits each year is considered. This leads to a decline in net benefits by $0.95 million, as indicated by Figure 2.

7.5 SA 5: Vary Discount Rate by ±1%

Varying the discount rate by increasing or decreasing it by one percentage point also leads to a change in net benefits, but the results are less sensitive to the discount rate assumption than some of the other assumptions. Increasing the discount rate from 2.6% to 3.6% reduces net benefits by $0.21 million, whereas decreasing the discount rate from 2.6% to 1.6% increases net benefits by $0.23 million. This is shown in Figure 2.

7.6 SA 6: Vary Growth Rate by ±1%

Last, we increase and decrease the rate of inflation by one percentage point. Increasing the inflation rate from 2% to 3% increases net benefits by $0.14 million and decreasing it from 2% to 1% reduces net benefits by $0.13 million, as presented in Figure 2.

Most sensitivity analyses result in negative impacts to the economic results compared to the base case, suggesting that the base case used in this case was aggressive. The most negative impact is revealed in SA 3 when a 50% reduction in ICAP and RNS benefits is assumed.

8.0 Conclusion

PNNL evaluated the monetary benefits that could realistically be achieved from a behind-the-meter BESS located at a military base in the ISO-NE service area. The base case analysis evaluated the financial benefits of a 1 MW/2 MWh BESS for a customer with a peak demand of at least 5 MW.

This assessment examined the financial feasibility of the project by monetizing the value derived from five services that it could provide in the region. A methodology and tariff structure were developed and BSET was used to optimize benefits and explore tradeoffs between services. A 10-year time horizon was evaluated for lithium-ion BESSs at varying scales, subject to the internal and external operating constraints of the BESSs.

The following lessons can be drawn from this analysis:

- The base case analysis of a 1 MW/2 MWh BESS yields 10-year PV benefits ($4.26 million) that exceed system costs ($1.23 million). The most valuable application is the DR service, which generates nearly $1.43 million (33.6% of total) in total 10-year PV benefits, closely followed by reductions in the ICAP cost ($1.03 million [24.2% of total])and RNS charge ($1.02 million [23.9% of total]). This gives a BCR for the base case of 3.5, and a 3-year payback period.
- PNNL ran several alternative scenarios to evaluate the sensitivity of results with respect to changes in assumptions:
  - Under the assumption that during relevant hours, the BESS would help reduce load by a pre-determined amount for demand-charge and demand response services, the BCR decreased to 2.9. This scenario assumed a less sophisticated, easily implementable operating strategy.
  - The highest BCR at 3.7 was achieved with a 0.5 MW/1 MWh BESS.
  - A scenario where ICAP and RNS benefits were reduced by 50% also was considered. This resulted in a decrease of net benefits by $1.02 million and a proportionately lower but still high BCR of 2.63.
  - All SA scenarios achieved a BCR of at least 2.5.

These results rely on tariffs and fees charged by utilities and ISO-NE that are subject to adjustment. Therefore, projects with BCRs close to one should be approached with caution. With that noted, demand charges have increased historically and at least some of these charges are likely to continue to do so. The region's generation mix is expected to change, albeit gradually, through the addition of more customer-side resources (e.g., photovoltaic systems and batteries) and deployment of utility solar and wind projects. It should be noted that without significant reduction in regional electricity demand, the increased penetration of these resources is unlikely to alleviate the fundamental sources of current demand charges; namely, delivery-system congestion.

These results appear to confirm industry claims for the economic value of dispatchable resources located behind-the-meter at customer sites in the ISO-NE region. If a BESS is financed using third-party funds, such as through a power purchase agreement, it would likely extend the payback period because third parties retain a profit share; however, under any reasonable terms a BESS or similar dispatchable resource would still be economically attractive to a third-party investor working with a federal customer host. A third-party financed project would also shift market and performance risk to the third party. That, and expected improvements in the performance and cost of battery technologies, results in our recommendation that federal agencies would be well served to explore options to finance BESSs at their sites in the ISO-NE region.

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Appendix A – Holidays to be Considered for Off-Peak Billing

The following legal holidays shall be recognized as holidays for purposes of billing service in off-peak periods:

Holiday	Day Celebrated
*New Year's Day	January 1st
Martin Luther King, Jr. Civil Rights Day	Third Monday in January
Washington's Birthday	Third Monday in February
Memorial Day	Last Monday in May
*Independence Day	July 4th
Labor Day	First Monday in September
Columbus Day	Second Monday in October
*Veterans Day	November 11th
Thanksgiving Day	When appointed
*Christmas	December 25th

* If these days fall on Sunday, the following day shall be considered the holiday.

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