Assessing Cost-Optimal Battery Energy and Solar-Plus-Storage Systems for Federal Customers: A Nationwide Assessment

Preprint

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National Renewable Energy Laboratory

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Assessing Cost-optimal Battery Energy and Solar-Plus-Storage Systems for Federal Customers: A Nationwide Assessment

Ted Kwasnik, Emma Elgqvist, and Kate Anderson, National Renewable Energy Laboratory

ABSTRACT

Prior research has identified that the financial viability of behind-the-meter battery energy storage systems is heavily dependent on technology cost, utility rate structure, energy consumption patterns, and co-deployment with synergistic technologies like solar photovoltaics (PV), among other factors. This study builds on existing research by comprehensively evaluating the economics of battery energy storage systems (BESS) and solar-plus-storage systems for a reference office building at 755 reference sites under 834 utility rates, and four storage capital cost scenarios. Results indicate that even with dramatic cost reductions, BESS is likely to be cost-effective only under utility rates that include demand charges, and possibly include time-of-use (TOU) pricing as well. Even under these utility rates, BESS systems provide marginal savings, and office building operators are unlikely to deploy the technology for cost savings alone. Solar-plus-storage systems provide more savings than BESS and allow for larger economic storage capacities. Solar-plus-storage provides compelling savings opportunities at baseline prices, and even at capital costs 25% higher than baseline. Solar-plus-storage is most effective where there are demand charges and energy pricing schemes include TOU pricing, or where electricity is expensive (at least $0.30/kWh). Our case studies illustrate that the presence of demand charges, even at similar energy costs, can be the deciding factor in BESS and solar-plus-storage viability. The findings and maps from this assessment may be of use to planners, building owners, and developers looking for potentially economic storage opportunities.

Introduction

As the capital cost of battery energy storage systems (BESS) decline, opportunities for commercial buildings to achieve net savings through peak demand management and energy arbitrage are emerging. As with other distributed energy technologies, the opportunity for a site to cost-effectively deploy BESS depends on a variety of complex factors including technology costs (both capital and operations and maintenance), incentives, technology configuration (i.e. stand-alone BESS vs co-deployment with other behind-the-meter technologies), value streams monetized, utility rate design, and site electricity consumption patterns. Prior studies on the techno-economic potential of BESS in the United States, described below, have identified three primary drivers: the utility rate of the site, whether the BESS is installed along with solar photovoltaics (PV), and the capital cost of the technology.

The cost of battery storage has rapidly declined over the past decade, and is expected to continue to decline. Cole and Frazier (2019) analyze over 25 publications and report that costs for a 4-hour utility scale lithium ion battery will drop a quarter by 2025, and by half by 2035. They also report that some estimates suggest 50% cost reductions will be achieved before 2025. While costs for commercial behind-the-meter BESS are expected to be higher than utility scale projects, costs are anticipated to follow similar relative cost reduction trends. Prior studies (Long et al. 2016), Khalilpour and Vassallo 2016; McLaren et al. 2019) show that as BESS capital costs decrease, the opportunities to cost-effectively deploy the technology increase.

Long et al. (2016) find that beyond capital costs, the site utility rate structure, specifically demand charges, is the most influential factor in BESS economics. Their assessment of 16 commercial building types in 15 climate zones suggests that battery energy storage systems are never cost-effective when utility rates do not include demand charges. Wu et al. (2016) similarly provide evidence that reductions in demand charges account for most of the benefit of a battery energy storage system. They further find that battery costs play a more dominant role than load profile in determining cost-effectiveness.

When BESS is coupled with solar PV, economics continue to be shaped by utility rates (McLaren et al. 2019; Merei et al. 2016; Bortolini, Gamberi, and Graziani 2014; Moiteaux 2016; Vishwanath et al. 2015; Hida et al. 2010) and technology costs (Khalilpour and Vassallo 2016; McLaren et al. 2019). McLaren et al. (2019) find that the economics of BESS are enhanced by co-locating solar PV, and note that beyond demand charge reductions, BESS coupled with PV can also reduce costs from energy time-of-use (TOU) utility rates.

While key drivers of behind-the-meter BESS economics have been identified, our understanding of the extent to which behind-the-meter battery storage is economically viable across the United States at current costs is limited. Savings from storage are inherently related to utility rates and energy consumption patterns that are highly variable across geographies and customer classes. To illustrate savings potential, a number of studies use a few reference utility rates as case studies, but few quantitatively assess national trends. Long et al (2016) explore storage viability at 240 sites, yet only BESS systems are considered, and results are not presented visually such that conclusions can be drawn about where and for whom battery storage is viable. McLaren et al (2019) examine 16 U.S. locations and identify that utility rates containing TOU and demand charge features are favorable to BESS deployment, but it is not immediately clear if and where these utility rates are common.

This study builds upon the existing literature by using REopt Lite, a publicly accessible distributed energy resource optimization platform, to evaluate cost-optimal storage capacities and savings potentials for 2,541 situations representative of varying utility rates, climate zones, and solar resource intensities across the United States under four storage capital cost scenarios (baseline, +25%, -25% and -50%). Results from this analysis are distilled into maps to visualize the sensitivity of storage viability to storage capital costs nationally under both BESS and solar-plus-storage configurations. Specific case studies are also discussed to illustrate how differences in geography, utility rate, and customer load can be expected to influence storage viability.

Methods

In this analysis, we employ REopt Lite, a publicly-accessible distributed energy resource (DER) optimization tool developed by the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), to identify cost-optimal storage capacity and the savings potential for reference sites across the United States under multiple popular utility rates available at the site, two system configurations (BESS and solar-plus-storage) and four storage capital cost scenarios (baseline, +25%, -25% and -50%). REopt Lite uses mixed-integer linear programming to identify the optimal selection, sizing, and dispatch of candidate distributed energy resource technologies (including storage and solar PV). Results ensure site energy needs are met at an hourly resolution and at minimum life-cycle cost. Key inputs to the model include site location, hourly electric load profile, utility rate, technology costs and performance characteristics, and financial parameters (i.e., discount and utility cost escalation rate).

The 755 reference sites are derived by subdividing select utility service areas by state, climate zone, and solar resource intensity. For a particular system configuration and storage capital cost benchmark (baseline, +25%, -25%, -50%), storage viability is assessed at a reference site for each of the most common utility rates offered by the site's utility. Accordingly, our results are based on a total of 2,541 REopt Lite optimization cases nationally.

More information about how reference sites were derived, how common utility rates were identified, and the techno-economic assumptions that went into calculations of cost-effectiveness are discussed in greater detail in the following sections.

Reference Sites

Reference sites are intended to reflect variability in customer load and solar resource availability within and between popular utilities. We derive reference sites by first selecting the service area boundaries for all U.S. Investor Owned Utilities (IOU's) and any non-IOU's that served over 400,000 customers in 2010, for a total of 178 utility service territories. We add to this selection the 45 largest area non-IOU's such that reference sites exist for all 50 states.

We subdivide each of the total 223 selected utility service areas into reference sites. Subdivision boundaries are variable such that each utility service territory typically yields 3-4 reference sites. Through this process, if climate and solar resource are consistent across a utility territory, the utility will yield only one reference site. Otherwise, a utility's derived reference sites will reflect the variability in both climate and solar resource.

Climate zones broadly reflect 15 unique classifications according to moisture (i.e. dry, humid, marine) and temperature (i.e. very hot, hot, mild, cold, sub-artic) as identified by the DOE Building America Program (DOE 2019). See Appendix 1 for a full list of climate zones. Furthermore, solar intensity is quantified by grouping average daily global horizonal irradiance (GHI) values in increments of 500 watt-hours per square meter. Over the continental United States and Hawaii, solar resource intensity is derived from National Solar Radiation Database data averaged from 1998 to 2014 and available at a 4 kilometer resolution (NREL 2014). In Alaska, solar resource intensity was sourced from a NASA Power Of World Energy Resources (POWER) dataset assimilated from climatological data spanning 1983 to 2013 and available at a more coarse 1 degree resolution (NASA 2018).

In total, the subdivision of popular utility service areas results in 755 reference sites in all 50 states. For each reference site, we analyze each of the common utility rates available to the site. We next describe how common utility rates were identified.

Common Utility Rates

To identify the most common utility rates at reference sites in IOU territories, we use the Federal Energy Regulatory Commission's (FERC) Electric Utility Annual Report, also known as Form 1 and made available from the ABB Velocity Suite (ABB 2019). From the utility's rate information included in Form 1, we identify the most common commercial utility rates as those that either serve the most customers, yield the most commercial revenue, or account for the most amount of energy sold to commercial customers. We then manually parse the Utility Rate Database (URDB) for similarly named rates from that utility. The Utility Rate Database (URDB) is a publicly available data repository of utility rates offered by electric utilities in the United States for commercial, residential and industrial customers (OpenEI 2014). Since the names do not often form a single match from Form 1 to the URDB, one reported rate on Form 1 may have multiple matches in the URDB. For reference, URDB rates are commonly differentiated by voltage (i.e. primary vs secondary), phase (i.e. single vs three), customer load size (i.e. small, medium, large) or other key attributes, whereas Form 1 rates are not. Accordingly, we exclude unbundled rates, high voltage rates (i.e. transmission), rates designed for small or larger loads than our reference profile, and uncommon use case rates (i.e. farm pumping rate, interruptible).

In selecting common utility rates for non-IOU's, for each utility we select commercial utility rates in the URDB with a name reflective of a general service type. Similar to the IOU utility rate identification process, we exclude unbundled rates, high voltage rates (i.e. transmission) and rates tailored to loads smaller or larger than the reference building profile.

Through this process, we identify 834 common utility rates across all utilities. Given the variability in number and types of utility rates offered by each utility, the number of common utility rates per utility we identify is variable. Moreover, as previously stated, the number of reference sites yielded by each utility service territory depends on the number of states, climate zones, and solar resource regions in the utility service territory. Accordingly, in total we identify 2,541 permutations of utilities, states, common utility rates, climate zone and solar resource. For each permutation, we run a REopt Lite optimization case for each system configuration and capital cost scenario. Of all optimization cases (these cases reflect a REopt run using inputs from the reference site and one of the common utility rates, and will be referred to as 'optimization cases' later in the results):

- 28% are associated with utility rates that contain energy TOU pricing
- nearly two-thirds (63%) with utility rates that contain demand charge components.

Utility rates with demand charges occur most often in California where 60% of optimization cases have demand charge components in their utility rate. Utility rates with demand charges are also prevalent in Arizona, New Mexico, New York, Ohio and Oregon where over 75% of optimization cases in each state contain demand charges of some kind. Energy TOU pricing also occurs most often in California, where 80% of optimization cases in California include TOU utility rates. Energy TOU pricing is also popular in New Mexico and Oregon where 38% and 48% of optimization cases, respectively, include TOU utility rates.

Building Load Profile

For each scenario, we use the medium office building load profile as defined in the DOE Commercial Reference Building (CRB) datasets (Deru et al. 2011) to represent a realistic load relevant to federal customers. Still, within the CRB dataset, the timing of energy use and amount of energy consumed varies by climate zone. For example, the annual load of a medium office varies from 14.8 kWh/ft^2/year in San Francisco, CA to 23.6 kWh/ft^2/year in Fairbanks, AK.

Summary of Analysis Assumptions

We evaluate two system configurations (BESS and solar-plus-storage) across a range of four capital cost scenarios established in relation to a baseline. The capital cost assumptions used in this analysis are shown in Table 1. Baseline capital cost values for PV are based on the published benchmark prices in the 2019 NREL Annual Technology Baseline (W Cole et al. 2019). Similarly, storage capital costs were based industry cost reports (Wood Mackenzie Power & Renewables and the Energy Storage Association (ESA) 2019; Lazard 2018). The thresholds at which cost scenarios were assessed relative to the baseline (i.e. +25%, -25%, -50%) are intended to reflect a reasonable range of possible costs at current and near-term prices.

Table 1. Capital Cost Assumptions by System Configuration and Capital Cost Scenario

System Configuration	Capital Cost Scenario	PV Cost ($/kW)	BESS Power Cost ($/kW)	BESS Energy Cost ($/kW)
Solar-plus-Storage	Baseline	$1,600/kW	$840/kW	$420/kWh
	Baseline +25%	$1,600/kW	$1050/kW	$525/kWh
	Baseline -25%	$1,600/kW	$630/kW	$315/kWh
	Baseline -50%	$1,600/kW	$420/kW	$210/kWh
BESS	Baseline	Not Evaluated	$840/kW	$420/kWh
	Baseline +25%	Not Evaluated	$1050/kW	$525/kWh
	Baseline -25%	Not Evaluated	$630/kW	$315/kWh
	Baseline -50%	Not Evaluated	$420/kW	$210/kWh

Other model assumptions are described in Table 2. Again, these assumptions are based on default REopt Lite settings which draw largely from the NREL Annual Technology Baseline (W Cole et al. 2019) and are documented in the REopt Lite user manual (NREL 2019).

Table 2. REopt Lite Default Optimization Assumptions

Parameter	Default Assumption
Ownership Model	Direct Purchase
Analysis Period	25 years
Discount Rate	8.3%
Nominal Utility Cost Escalation Rate	2.3%
Inflation Rate	2.5%
Incentives	PV: 30% Investment Tax Credit and 5-year Modified Accelerated Cost Recovery System (MACRS) BESS: 7-year MACRS
Net Metering Limit	0 kW (Not Allowed)
Electricity Sellback over net metering	$0/kWh
PV Operation and Maintenance Cost	$16/kW-year
BESS Replacement Cost	$410/kW and 200/kWh in Year 10
Solar Resource	NSRDB TMY2 data

Analysis Outputs

REopt Lite outputs include cost-optimal technology capacities and hourly annual dispatch, as well as the life-cycle cost (LCC) of the business-as-usual (BAU) solution and LCC of the optimal solution. LCC considers capital costs, operations and maintenance costs, incentives, and utility costs.

In this study we translate LCC into a percent savings metric by dividing the difference in LCC among the optimal and BAU solutions by the BAU solution LCC:

$$\textit{Percent Savings} = \frac{\text{Optimal LCC} - \text{BAU LCC}}{\text{BAU LCC}} \qquad \text{(Equation 1)}$$

Note that a percent savings above zero indicates a system is economic because the savings exceed the investment costs. If the percent savings is less than zero, while the system may be able to achieve cost reductions, it cannot recoup all investment costs, and it is more economic not to install the system at all. The higher the percent savings, the more value the system provides. This savings metric provides a relative economic potential metric for BESS that can be compared across reference sites regardless of how the BAU life-cycle cost may vary (due to differences in utility rate and load).

To generate geospatial maps showing average savings across all the utility service territories assessed, we generated a 1-arc second grid over the continental United States, Alaska and Hawaii. At each cell in the grid, we identify all optimization cases resulting from all reference sites (a subdivision of a utility service area resulting from state, climate zone and solar resource region boundaries) that touch the cell and derive an average savings.

Results and Discussion

Our results nationally largely focus on the savings afforded by a solar-plus storage or BESS system, and the capacities at which systems are cost-effective given a storage capital cost scenario.

National BESS Trends

Figure 1 below illustrates where BESS systems in the United States are cost-effective on average across all optimization cases at baseline storage capital costs. Out of 2,541 optimization cases, 21% (n=523) have economic storage opportunities. As reported in Table 3, the average savings across all optimization scenarios is 0.3% and the average system capacity is 8 kW / 20 kWh. At baseline storage cost assumptions, less than 2% of optimization cases achieve savings above 1% and no optimization case yields savings higher than 5%. Given the marginal savings at baseline capital costs, the capacity should be interpreted as offering few cost savings beyond paying back its own capital costs over the financial period.

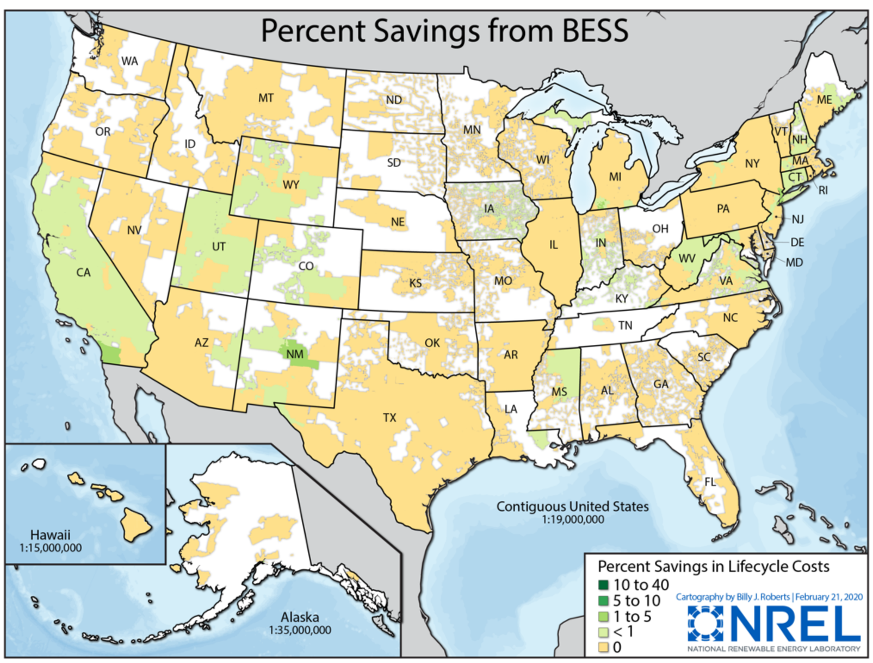

Figure 1. Average Percent Savings for a BESS System Across the United States for All Reference Sites Mapped to a Common Grid

The optimization cases with the highest savings are those with savings over 1% and are attributable to utility rates associated with major IOU's in New York and California, as well as one electric cooperative in New Mexico. The 12 unique utility rates among these 49 optimization cases all contain demand charge components, and three-quarters of them also contain energy TOU pricing. Accordingly, BESS systems that are able to achieve lifetime savings likely do so primarily by reducing demand charges, and to a lesser extent by reducing expensive grid electricity purchases. Four utility rates in southern California and New York are particularly well suited to BESS, as even when capital costs increase 25%, all optimization cases associated with these utility rates retain savings above 1%.

With a 25% reduction in storage capital costs, the number of optimization cases that result in at least some BESS savings increases to 33% of all optimization cases (n= 830 out of 2,541). Average storage capacities rise notably too relative to the baseline (See Table 3). Still savings reflect that BESS provides little value if the operator intent is purely to maximize cost savings. The new marginally economic opportunities appear in 27 states throughout the country, all at savings well below 1%. Of the optimization cases that were already economic at baseline capital costs, savings increase 0.6% on average (the maximum increase in savings is 3.6%).

With a 50% reduction in storage capital costs, 48% of all optimization cases achieve at least some savings (n=1219), though the magnitude of savings is not highly compelling from a cost perspective. Table 3 also shows that the proportional increase in system size relative to the 25% reductions in capital cost scenario is in line with size increases between other scenarios. Most of the new savings opportunities at this cost reduction are marginal and the average savings among these newly economic opportunities is well below 1%. At most, a system that was not economic at baseline storage prices will achieve 2.7% savings at 50% capital cost reductions. Moreover, among optimization cases that were cost-effective at baseline prices we see a savings increase of 2.5% on average (11.7% maximum increase).

Table 3. Average Savings and Storage Capacity for BESS by Capital Cost Scenario

Capital Cost Scenario	Percent of All Optimization Cases (n=2,541) with Savings > 0	Mean Savings where Savings > 0	Mean Storage Capacity where Savings > 0
Baseline + 25%	16%	0.3%	8 kW / 20 kWh
Baseline	21%	0.5%	12 kW / 34 kWh
Baseline - 25%	33%	0.8%	18 kW / 75 kWh
Baseline - 50%	48%	1.4%	27 kW / 158 kWh

National BESS Trends by Rate

Figure 2 below illustrates how demand charges are the primary driver of BESS system economics across all capital cost scenarios. Nearly all optimization cases that are economic are associated with utility rates that contain demand charges. At any storage capital cost scenario assessed, few optimization cases that yield positive savings are associated with utility rates that lack demand charges. In the few cases where an optimization case without demand charges yields positive savings, these results are attributable to expensive energy prices (i.e. prices over $0.55/kWh). Moreover, from Figure 2 we also see that with reduced capital costs most of the newly economic opportunities for BESS systems will occur where maximum energy prices are less than $0.10/kWh.

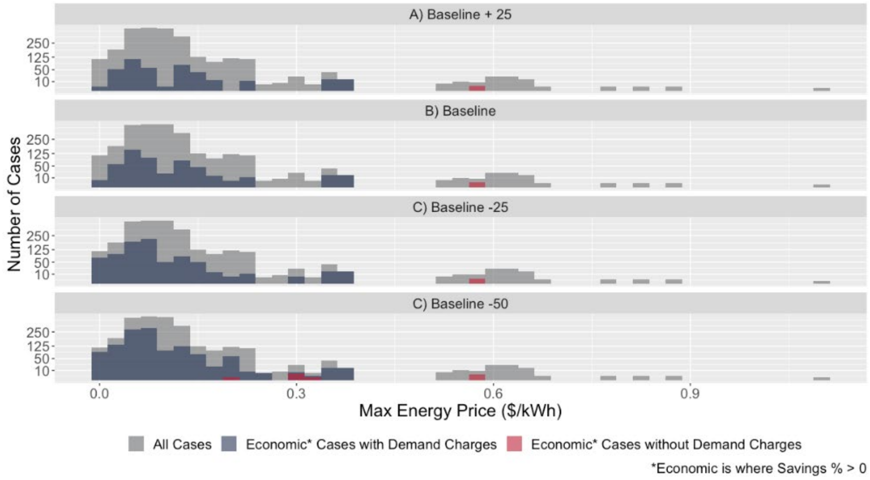

Figure 2. Occurrences of Economic BESS Systems by Maximum Energy Price, Presence of Demand Charges and Capital Cost Scenario

Figure 3 illustrates how very few rates without demand charges (where maximum demand charge is $0.00) ever become economic for BESS. It also illustrates that most of the utility rates with demand charges that are economic for BESS systems in the baseline capital cost scenario contain maximum demand charges between $10/kW – $20/kW and greater. As capital costs are reduced by 25% there is a notable increase in the number of optimization cases that become economic at the lower end of this spectrum. At 50% capital cost reductions, the newly economic utility rates for BESS deployment that emerge have demand charges between $5/kW and $10/kW.

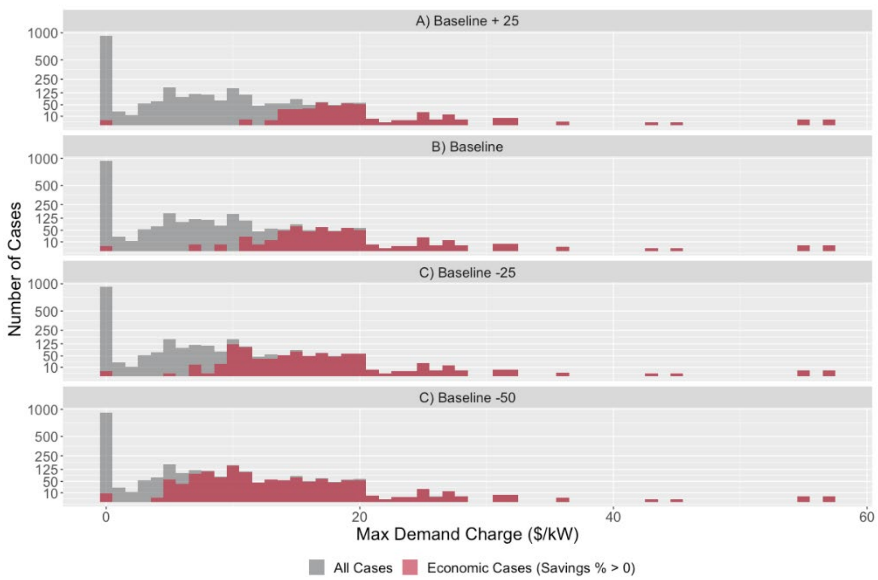

Figure 3. Occurrences of Economic BESS Systems by Maximum Demand Charge and Capital Cost Scenario

National Solar-Plus-Storage Trends

Solar-plus-storage systems afford greater savings across more utility rates and locations than do storage systems alone. At baseline capital costs, 27% of optimization cases (n=699 of 2,541) are economic and the average savings is robust at over 9%. Moreover, 18% of optimization cases yield savings greater than 1%, and one in ten optimization cases results in savings over 10%. Two utilities even offer multiple utility rates that would result in savings greater than 40%. As shown in Table 4, the average storage power and energy capacities in a solar-plus-storage system at these capital costs (40 kW / 175 kWh) are between 3 – 5 times larger than the average for BESS (12 kW / 34 kWh).

As shown in Figure 4 below, the locations with the highest potential for solar-plus-storage savings include Alaska, California, Colorado, Hawaii, New Hampshire, New York, and Vermont. Even if storage capital costs were to increase 25%, these same states would still see comparable savings from solar-plus-storage systems.

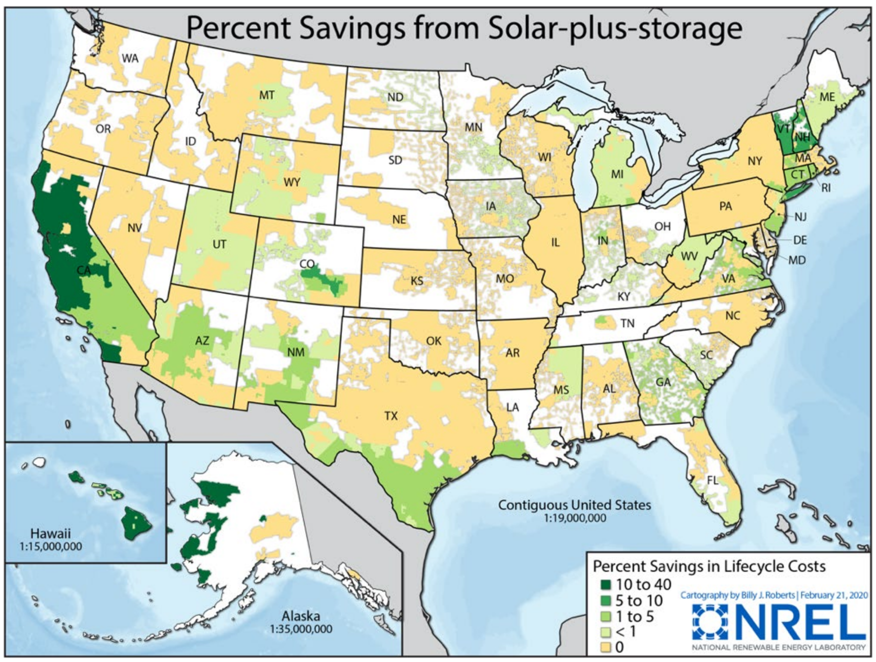

Figure 4. Average Percent Savings for a Solar-plus-Storage System Across the United States for All Reference Sites Mapped to a Common Grid

In California, Colorado, New Hampshire, New York, and Vermont, where maximum savings opportunities are over 8% (and as high as 43% in California), all optimization cases that yield positive savings are associated with utility rates that have demand charge components, and over two-thirds with utility rates that implement energy TOU pricing. Thus, solar PV enhances a storage system's ability to reduce peak demand and energy consumption at expensive times. On the other hand, in places like Alaska and Hawaii where the maximum savings are over 33% (and as high as 42% in Hawaii), no utility rates have TOU demand charges and less than one in four contain either flat demand charges or energy TOU components. At these locations the high cost of electricity (more than $0.34/kWh under some utility rates) help to explain the savings in that storage primarily serves to increase the consumption of relatively cheap solar.

With a 25% reduction in capital costs, 39% of optimization cases (n=988) are economic and the average capacity of economic systems rises slightly (See Table 4). Note that the mean savings dips at this reduced capital cost scenario relative to the baseline. While the economics of optimization cases that had been economic at baseline storage capital costs do improve (by 1.5% on average) with capital cost reductions, a wave of new opportunities (307 optimization cases that had been uneconomic at baseline costs) also become economic at marginal savings rates (1.8% on average among these new opportunities). These new economic opportunities bring down the cumulative average. Of the optimization cases that become economic with a 25% reduction in capital costs, those with the largest savings opportunities are associated with utility rates in Connecticut, Massachusetts, and Pennsylvania that include flat demand charges, as well as with locations in Arizona, Colorado and New Mexico where solar resource is high.

At capital costs half that of the baseline scenario, 55% of optimization cases (n=1397) are economic and the average capacity that is viable (55 kW / 287 kWh) is larger than for any other scenario (See Table 4). The optimization cases that become economic at this cost threshold occur in 47 states and on average reduce total costs by 3.9% (at most they save 24%). The strongest additional savings opportunities occur largely in the same areas where solar-plus-storage was profitable in the baseline scenario (Arizona, California, Colorado, Connecticut, New Mexico, and Massachusetts). Interestingly, at capital costs half that of the baseline scenario, savings opportunities over 10% also emerge in Alabama, Florida, Kentucky, Ohio, and Wisconsin where energy TOU pricing or flat demand charges exist. Of optimization cases that were economic in the baseline scenario, we see a 4.3% increase in savings on average (12.8% maximum).

Table 4. Average Savings and Storage Capacity for Solar-plus-Storage by Capital Cost Scenario

Capital Cost Scenario	Percent of All Optimization Cases (n=2,541) with Savings > 0	Mean Savings where Savings > 0	Mean Storage Capacity where Savings > 0
Baseline + 25%	21%	9.1%	26 kW / 99 kWh
Baseline	27%	9.5%	40 kW / 175 kWh
Baseline - 25%	39%	8%	46 kW / 221 kWh
Baseline - 50%	55%	8.5%	55 kW / 287 kWh

National Solar-plus-Storage Trends by Utility Rate

Compared to Figure 2 illustrating BESS trends, Figure 5 reveals that solar-plus-storage systems are more often economic than BESS systems in situations without demand charges. Still, among utility rates without demand charges, energy prices must be high (greater than $0.30/kWh and commonly closer to $0.60/kWh at baseline capital cost assumptions) for such optimization cases to be economic. For utility rates with demand charges, from Figure 5 we see that as capital costs fall, many of the new opportunities for economic solar-plus-storage will occur where maximum energy prices are less than $0.10/kWh.

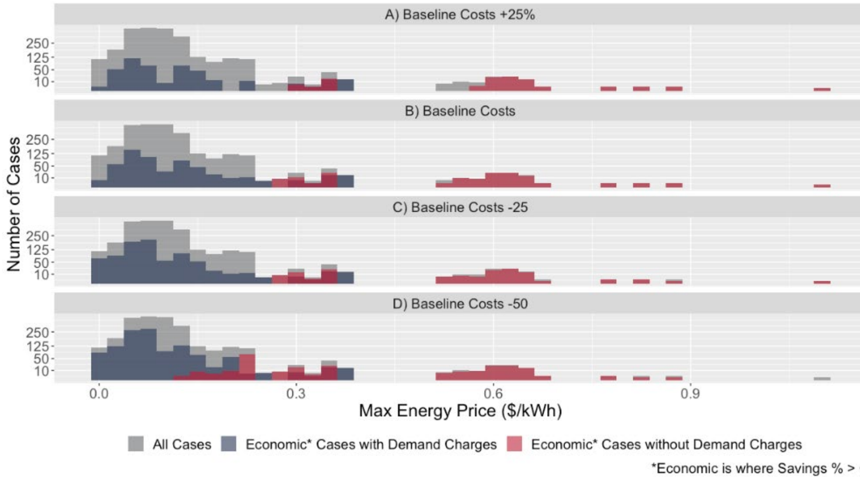

Figure 5. Occurrences of Economic Solar-Plus-Storage Systems by Maximum Energy Price, Presence of Demand Charges and Capital Cost Scenario

Figure 6 similarly shows that many optimization cases without demand charges (where maximum demand charge is $0.00) are economic for solar-plus-storage deployment even at baseline capital cost assumptions. These cases are likely attributable to a solar-plus-storage system being leveraged to consume cheap energy produced from onsite solar PV. Otherwise, the demand rate thresholds at which optimization cases become economic for solar-plus-storage are similar to those for BESS systems previously discussed. At baseline capital cost assumptions, utility rates with demand charges between $10/kW-$20/kW and greater are economic for solar-plus-storage. The range is similar at 25% reductions in capital cost assumptions and extends to $5/kW-$20/kW at 50% reductions in capital costs.

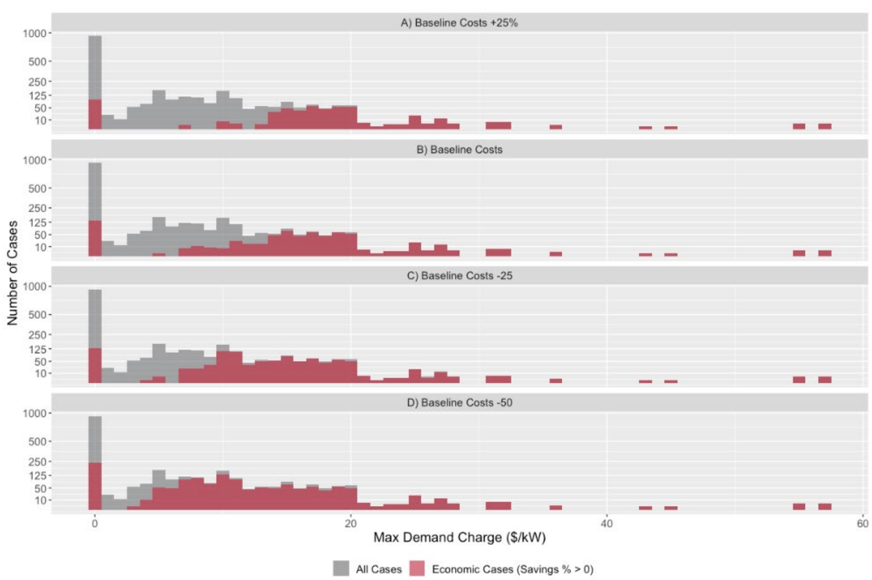

Figure 6. Occurrences of Economic Solar-Plus-Storage Systems by Max Demand Charge and Capital Cost Scenario

Case Studies

We examine four case studies in depth to illustrate the interaction between savings, utility rate and storage capital costs.

Cincinnati, Ohio

The utility serving Cincinnati, Ohio is associated with three study areas that vary by climate zone and four utility rates. None of these utility rates contain demand charges or TOU pricing, and the price of energy is low ($0.03 - $0.10 kWh). Accordingly, even at 50% capital cost reductions, storage is not viable as BESS or solar-plus-storage. There is no opportunity for savings from shifting low cost energy to high price times of day, or from reducing demand charges. Therefore, while storage may serve resilience purposes in this region, it is not expected to be economic under normal grid operations.

Vermont

Vermont is largely covered by one reference site associated with one utility and three utility rates. At baseline storage costs, for one of these utility rates, where energy costs are $0.146/kWh and no TOU pricing or demand charges are in place, there are no identified savings opportunities for BESS or solar-plus-storage. However, for two utility rates that do include demand charges (both at $14.59/kW) and similar energy costs ($0.15/kWh), savings as high as 8% are possible for a solar-plus-storage, and BESS savings are less than 0.01%. While BESS is not compelling at such negligible savings, this finding is important because it indicates that a BESS system can recuperate its capital costs through demand charge reductions. We also see from this example that adding solar PV can enable BESS by producing relatively cheap energy that can be stored and used to offset more expensive grid energy purchases.

Even when storage capital costs are reduced by 50%, BESS savings under the two utility rates with demand charges remain marginal at 0.3%. Likewise, solar-plus-storage savings under these utility rates are only marginally higher than the baseline scenario at 10%. Thus, storage or solar capital costs would need to be dramatically reduced for more substantial savings to be achieved under these utility rates. Savings are never achieved for the utility rate without demand charges under solar-plus-storage or BESS systems because there are no savings to be realized from demand charge reductions.

San Diego, California

San Diego is subdivided into three reference sites that vary by solar resource intensity, all served by San Diego Gas and Electric. All 8 common utility rates for this utility include demand charges (ranging from $1/kW - $32/kW) and energy TOU pricing (prices range from $0.09/kWh - $0.14/kWh with the highest tier being $0.05/kWh more than the lowest tier on average). At baseline capital costs, BESS is economic for all three reference sites. Their average optimal system capacity is 68 kW/241 kWh and savings vary from 2.2 – 4.7%. The highest savings are attributable to differences in utility rate structure. For the result with the highest savings, the utility rate has peak TOU energy prices that are $0.01/kWh higher than peak prices among the other common San Diego Gas and Electric utility rates, and its demand charges are up to $16/kW higher.

When solar is considered alongside storage, average storage capacity increases by two to threefold to 120 kW/653 kWh and savings increase to 19 – 23%. Moreover, we observe at these study regions that an increase in solar irradiance intensity is attributable to an additional 0.1 – 2% in savings.

Reducing storage costs by 25% has a larger relative impact on BESS systems compared to solar-plus-storage systems. Cost-optimal BESS system capacities increase by a factor of two to four, to 153 kW/854 kWh at these capital costs, and savings from these larger systems double. Storage capacities in solar-plus-storage systems see a smaller increase to 155 kW/925 kWh and a smaller savings increase to 23 – 29%. At these lower capital costs, differences in solar resource intensity matter slightly more for solar-plus-storage viability, as an increase in solar intensity may add up to an additional 2.6% in savings.

At capital costs half that of the baseline scenario, average cost-optimal storage capacities are nearly identical between BESS (187 kW/1273 kWh) and solar-plus-storage systems (185 kW/1225 kWh). Solar does continue to add considerable value, however, as BESS savings range from 10-16% and solar-plus-storage are on the order of 28-36%. Again, differences in solar resource intensity matter slightly more for storage viability at these storage costs than they do at baseline costs, as an increase in solar intensity may add an additional 0.6% in savings.

We see from the San Diego case study that in areas of high solar resource and where demand charges and energy TOU utility rates are prevalent, both BESS and solar-plus-storage systems provide savings opportunities that only improve as costs decline. Solar-plus-storage savings are compelling at baseline costs, whereas 50% reductions in capital costs would be necessary to make BESS alone an attractive option. We also consistently see that at all capital costs assessed in this study, the addition of solar PV to a BESS enhances the savings potential as low cost solar can be dispatched asynchronously to reduce demand charges and offset grid purchases. Finally, we also observe that even an increase in solar resource intensity as low as 500 W/m^2 may improve savings potential as much as 2.6%.

Portland, Oregon

Similar to our previous San Diego example, Portland, Oregon is served by a utility that spans three reference sites that vary by solar resource intensity and is associated with four identified common utility rates. These four utility rates also all contain energy TOU pricing and tiered demand charges. In Portland, however, under baseline storage capital costs, no utility rate under any solar resource intensity in the region affords savings for either BESS or solar-plus-storage systems. This lack of a savings opportunity is attributable to the overall low energy prices (\$0.01 - \$0.09 / kWh) and low demand charges (the max demand tier for any of these utility rates is \$7.10/kW). The relatively poor solar resource also reduces economic viability of solar-plus-storage systems. Demand charge reductions, the key driver of BESS viability, are insufficient under these utility rates to cover the capital costs of storage in a BESS or solar-plus-storage system.

At a quarter reduction in storage capital costs, we see that BESS is marginally economic. On average a 3.6kW/4.7kWh system is able to recuperate its capital costs through demand charges reductions and energy arbitrage (savings < 0.01%). Similarly, solar-plus-storage systems afford marginal savings (0.01% savings on average) for slightly more storage capacity (3.8 kW/5 kWh on average). At 50% reductions to storage capital costs, the capacity increases to an average of 15kW/26 kWh and 17 kW/30kWh for BESS and solar-plus-storage systems respectively. Savings for both BESS and solar-plus-storage remain marginal (< 1%). Thus, the low costs of energy and poor solar resource in the region continue to inhibit high savings potential for storage in this region even at 50% storage capital cost reductions.

Conclusion

Our results indicate that even with dramatic cost reductions, BESS is likely to be cost-effective only under utility rates that include demand charges, and possibly include TOU pricing as well. Even under these utility rates, BESS alone only provides marginal savings, and building operators are unlikely to deploy the technology for cost savings alone. Solar-plus-storage systems provide more savings than BESS and allow for larger economic storage capacities. Solar-plus-storage provides compelling savings opportunities at baseline prices, and even at capital costs 25% higher than baseline. Solar-plus-storage is most effective where there are demand charges and energy utility rates include TOU pricing, or where electricity is expensive (at least $0.30/kWh). Our case studies illustrate that the presence of demand charges, even at similar energy costs, can be the deciding factor in BESS and solar-plus-storage viability.

This comprehensive assessment of storage economic viability builds on previous research that investigates the conditions under which storage is cost effective. We quantify potential savings nationally using a metric that readily facilitates comparison between sites with different loads and utility rates. The findings and maps may be of use to planners, building owners, developers, and energy service providers looking for potentially economic storage opportunities. In the near future, case-by-case assessment and inclusion of additional financial factors (i.e. local incentives and resilience benefits) will likely yield additional opportunities to cost-effectively deploy solar-plus-storage in the near-term and BESS in the long-term should capital costs continue to dramatically decline.

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Appendix 1

DOE Building America Climate Regions
The follow table contains the 15 Building America (DOE 2019) climate zones by which utility service areas were subdivided.

Climate Zone	Representative City	Description
1A	Miami, Florida	Moist
2A	Houston, Texas	Moist
2B	Phoenix, Arizona	Dry
3A	Atlanta, Georgia	Moist
3B	Las Vegas, Nevada	Dry
3C	San Francisco, California	Marine
4A	Baltimore, Maryland	Moist
4B	Albuquerque, New Mexico	Dry
4C	Seattle, Washington	Marine
5A	Chicago, Illinois	Moist
5B	Boulder, Colorado	Dry
6A	Minneapolis, Minnesota	Moist
6B	Helena, Montana	Dry
7	Duluth, Minnesota	Cold
8	Fairbanks, Alaska	Cold