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# Assigning value to energy storage systems at multiple points in an electrical grid

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The ability to define the potential value that energy storage systems (ESSs) could generate through various applications in electric power systems, and an understanding of how these values change due to variations in ESS performance and parameters, market structure, utility structures, and valuation methodologies is highly important in advancing ESS deployment. This paper presents a taxonomy for assigning benefits to the use cases or services provided by ESSs, defines approaches for monetizing the value associated with these services, assigns values, or more precisely ranges of values, to major ESS applications by region based on a review of an extensive set of literature, and summarizes and evaluates the capabilities of several available tools currently used to estimate value for specific ESS deployments.

**Broader context**

Driven by renewable portfolio standards in 29 U.S. states plus Washington D.C. and three U.S. territories, the total contribution of renewable resources to the electricity generation portfolio in the U.S. is expected to grow substantially over the next 30 years. With the advent of smart grid technologies and the growing need to integrate renewables, with their intermittent generation profile, a future with more distributed energy resources is increasingly becoming a necessary reality. Over the last decade, significant improvements have been made in the cost, performance, and reliability of energy storage systems (ESSs); however, the ability to make an economic case for energy storage has proven challenging due in part to an absence of consensus around how to value or model the services ESSs can provide to the grid. This article attempts to address the current gap in the literature by presenting a taxonomy for assigning benefits to the services provided by ESSs, defining approaches for monetizing the value associated with these services, assigning values to major ESS applications by region based on a review of an extensive set of literature, and summarizing and evaluating the capabilities of several tools currently used to estimate value for specific ESS deployments.

## Introduction

Driven by renewable portfolio standards (RPS) in 29 U.S. states plus Washington D.C. and three U.S. territories, the total contribution of renewable resources to the electricity generation portfolio in the U.S. is expected to grow substantially over the next 30 years.[1] States including Oregon, California, and Hawaii have set RPS targets at or above 50% by 2045. With the advent of smart grid technologies and the growing need for enhanced grid flexibility, a future with more distributed energy resources (DER) is increasingly becoming a necessary reality.

Over the last decade, significant improvements have been made in the cost, performance, and reliability of energy storage systems (ESSs). The value and effectiveness of energy storage in supporting a cleaner, more resilient future grid are being validated through numerous field demonstrations and analyses; however, federal and state agencies continue to struggle with the challenge posed by energy storage. The Federal Energy Regulatory Commission (FERC), which regulates the interstate transmission of electricity in the U.S., has requested that markets provide information governing storage access to market participation, including eligibility, technical qualification, performance requirements, and bid parameters. The goal of FERC Docket AD 16–20 is to "remove barriers to the participation of electric storage resources and distributed energy resource aggregations in the capacity, energy, and ancillary service markets operated by regional transmission organizations (RTO) and independent system operators (ISO)".[2] States are deploying a diverse set of approaches to encourage ESS deployment, including research and development set-asides, adjustments to the resource planning process, and procurement targets.[3] The State of California, responding to the short, steep ramps caused in the afternoon as photovoltaic production recedes and electricity demand increases quickly, passed Assembly Bill (AB) 2514. AB 2514 established a 1.325 gigawatt (GW) procurement target by 2020 for the three investor-owned utilities operating in the state, with targets established at the transmission, distribution, and

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customer levels.[4] The State of Washington issued a policy statement on the treatment of energy storage technologies in the integrated resource planning and resource acquisition process. The policy statement outlined three principles for levelling the playing field for energy storage: changing planning paradigms, providing modelling guidance, and identifying principles for regulatory treatment of energy storage investments. The policy statement encouraged utilities to evaluate benefits at multiple points in the grid when making investment decisions, adopting models with the capacity to evaluate sub-hourly benefits, and use the "net cost" method where benefits associated with storage that are not captured in traditional IRP models (*e.g.*, distribution deferral) are netted out of the costs of storage.[5]

While policy advancements at the federal and state level continue, more work is required to develop engineering planning tools for assigning value and integrating energy storage into the grid. Existing tools used in the integrated resource planning process often fail to capture benefits at the transmission or distribution levels, and also ignore benefits associated with customer energy management of behind-the-meter (BTM) resources. A few software tools partially address placement, sizing, and overall control strategies for stationary energy storage, but none effectively capture the entirety of the value streams energy storage can provide. New models must be developed that enable value assessments of storage resulting from optimal placement and sizing within the transmission and distribution systems. Before developing such models, however, more information is needed to understand the depth and breadth of these values streams, how to quantify them, and their value to the grid.

This article defines several services ESSs provide, presents a valuation taxonomy, documents the results of numerous studies that monetize the value of these services, defines characteristics for an ideal energy storage valuation model, and compares the features found in several valuation tools.

Energy storage has a number of attributes that provide tremendous flexibility to grid operators. These attributes distinguish storage from traditional forms of power generation. The capacity to provide distributed, highly responsive energy means it can address the flexible operations required to integrate renewables and maintain grid reliability. Energy storage types include a suite of technologies, including electro-chemical battery systems (*e.g.*, lithium-ion, redox flow, sodium–sulphur, lead–acid), pumped storage hydro, flywheels, compressed air energy storage, and other emerging technologies. Among the characteristics that drive the value of ESSs are the following:

• the capacity to act as both generation and load;

• the ability to provide benefits at the transmission, distribution, and utilization levels;

• the ability for some storage systems to be housed in mobile units and moved between sites to address specific system needs, such as avoiding customer interruptions during extended maintenance operations or deferring investment in distribution assets;

• the capacity to be more effective than conventional generation in meeting ramping requirements and responding to regulation signals at the sub-second level;[6]

• the modular nature of energy storage, which allows it to scale up as needed to reduce the risk and present value costs of investments;

• the ability to be placed BTM at customer sites; and

• the capability to avoid start-ups of least-efficient peaking plants.

These unique characteristics enable energy storage to provide extensive value to the grid, and should be reflected in the set of value streams evaluated for any project. Services provided by energy storage have differing purposes, and vary based on grid topology, benefitting parties, and markets in which they are realized. Further, there are varying rules, requirements, and capabilities tied to value capture. To monetize the value of energy storage, these services must be modelled and co-optimized in a manner that addresses the physical and performance-related limitations of the ESS. Because no ESS can meet the needs of all services simultaneously, valuation models are necessary to determine technically achievable returns on investment.

## A taxonomy of services

The authors conducted an extensive literature search and made note of several service matrices developed for energy storage. The individual services offered by ESSs can be segmented into five categories as defined in Akhil *et al.* (2015).[7] The authors have refined the use cases presented in Akhil *et al.* (2015) based on its review of valuation literature, as presented in Table 1.

The table is by no means exhaustive; however, it captures the bulk of the values generated by ESSs as well as many other DERs. Further, the matrix aligns well with studied literature. It is important to note that only a subset of these use cases is likely to be relevant for energy storage at any given site.

## Energy storage valuation

Existing production cost and capacity expansion tools fail to provide a complete and accurate characterization of the potential value that energy storage can provide to the electrical grid. These system models rarely capture benefits at the sub-hourly level, do not address location-specific benefits, and often fail to characterize distribution- and customer-level benefits. Further, control strategies that can be integrated into grid operational software and supervisory control of the storage unit exist in limited form. The lack of knowledge on the part of utilities, system operators, legislators, and regulators about the technical capabilities of energy storage is still a significant barrier to ESS penetration in the marketplace.

The lack of knowledge concerning energy storage capabilities and the ability to generate value at multiple points in the grid results in an incomplete assessment of ESS value. By failing to capture full energy storage capabilities, nearly all utility models underestimate potential value streams, which dampens investment. Underinvestment in energy storage due to an inability to fully account for the services it provides can lead to sub-optimal outcomes during the resource planning process. For example, some models do provide 5 minute capabilities in tracking energy storage output, but even that level of detail undervalues

Table 1 Services provided by ESSs

| Category | Service | Value |
|---|---|---|
| Bulk energy | Capacity or resource adequacy | The ESS is dispatched during peak demand events to supply energy and shave peak energy demand. The ESS reduces the need for new peaking power plants and other peaking resources. |
| | Energy arbitrage | Trading in the wholesale energy markets by buying energy during off-peak low-price periods and selling it during peak high-price periods. |
| Ancillary services | Regulation | An ESS operator responds to an area control error (ACE) in order to provide a corrective response to all or a segment portion of a control area. |
| | Load following | Regulation of the power output of an ESS within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits. |
| | Spin/non-spin reserve | Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is offline generation capable of being brought onto the grid and synchronized to it within 30 minutes. |
| | Frequency response | The energy storage system provided energy in order to maintain frequency stability when it deviates outside the set limit, thereby keeping generation and load balanced within the system. |
| | Flexible ramping | Ramping capability provided in real time, financially binding in five-minute intervals in California ISO (CAISO), to meet the forecasted net load to cover upwards and downwards forecast error uncertainty. |
| | Voltage support | Voltage support consists of providing reactive power onto the grid in order to maintain a desired voltage level. |
| | Black start service | Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. |
| Transmission services | Transmission congestion relief | Use of an ESS to store energy when the transmission system is uncongested and provide relief during hours of high congestion. |
| | Transmission upgrade deferral | Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage. |
| Distribution services | Distribution upgrade deferral | Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the distribution system to accommodate load growth or regulate voltage. |
| | Volt-VAR control | Volt–ampere reactive (VAR) is a unit used to measure reactive power in an alternating current (AC) electric power transmission and distribution system. VAR control manages the reactive power, usually attempting to get a power factor near unity. |
| | Conservation voltage reduction | Use of an ESS to reduce energy consumption by reducing feeder voltage. |
| Customer services | Power reliability | Power reliability refers to the use of an ESS to reduce or eliminate power outages to customers. |
| | Time of use (TOU) charge reduction | Reducing customer charges for electric energy when the price is specific to the time (season, day of week, time-of-day) when the energy is purchased. |
| | Demand charge reduction | Use of an ESS to reduce the maximum power draw by electric load in order to avoid peak demand charges. |

Source: Modified from Akhil *et al.* 2015.

the ability of energy storage to provide services at the second or even sub-second level. No models are currently capable of evaluating the full range of values described in this section and performing a co-optimization routine to estimate the maximum value provided by each service. Further, markets often fail to fully reward energy storage operators even when value is well defined.

Fig. 1 documents the results of numerous energy storage valuation studies with results estimated for each service. These values, which are tied to market revenue or avoided costs, were modelled by various research teams. In some cases, these values may not be captured through a market or ratemaking process.

When reviewing Fig. 1, the following should be noted:

• All values have been transformed into the dollars per kilowatt per year ($/kW-year) metric. Thus, if a 1 MW system generates a value of $50/kW-year for arbitrage, its operator could expect to receive $50 000 in annual arbitrage revenue. In many cases these values were not present in the literature; but given the total value of the service, the economic life of the storage system, the scale of the battery system and the discount rate, the value was calculated by the authors.

• All values were adjusted for inflation using the Producer Price Index for Electric Power Generation, Transmission, and Distribution published by the U.S. Bureau of Labour Statistics.[8]

• Findings are color-coded by FERC Power Market as identified in the figure legend.

The studies capture a broad range of values and cover many regions throughout the U.S. Results vary widely based on a number of factors, including:

• Market structure – presence or lack thereof, with some markets exhibiting higher prices than others

• Utility type – vertically integrated investor-owned utility, municipal, public utility district, or utility operating in an organized market

• Energy capacity of the battery

• Battery characteristics, including round trip efficiency (RTE)

• Regional electricity price differences

• Methodology – are services co-optimized, are they evaluated at a sub-hourly level, do they include transmission and distribution-level benefits, are the benefits location-specific?

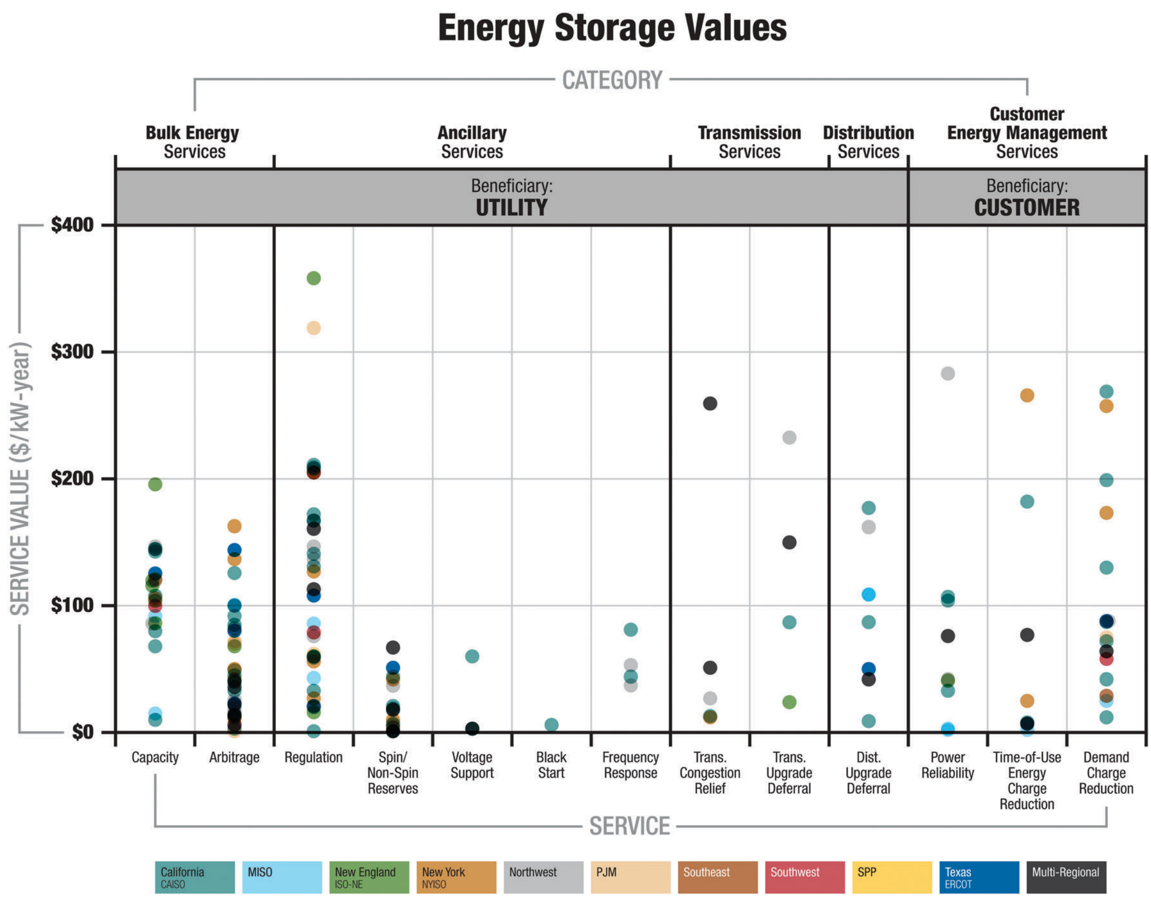


Fig. 1 Findings of recent energy storage valuations studies and transactions in the U.S.

• Characterization of the marginal unit, in terms of cost for next-best alternatives for a specific service (*e.g.*, combustion turbine for capacity) being replaced by storage

• Assumptions governing load and price growth.

The results of the literature review are further summarized in Table 2 and Fig. 2, and described in more detail later in this article. More confidence can be taken from the results for more well-studied services (*e.g.*, arbitrage, regulation). The results vary significantly by region and energy storage characteristics, including energy capacities, but the value for regulation tends to exceed those for other ancillary services and arbitrage. Capacity or resource adequacy, which is tied to the incremental cost of the next-best alternative for providing peaking resources, generally coalesces around \$80–\$140/kW-year. Transmission and distribution (T&D) deferral benefits vary significantly between studies (\$9–\$233/kW-year) depending on the cost of the deferred asset and the

Table 2 Value of services provided by ESSs in literature ($/kW-year)

| Category | Service | Number | Mean | Min | 25th percentile | 75th percentile | Max |
|---|---|---|---|---|---|---|---|
| Bulk energy | Capacity or resource adequacy | 21 | $106 | $10 | $86 | $134 | $196 |
| | Energy arbitrage | 39 | $52 | $1 | $14 | $82 | $163 |
| Ancillary services | Regulation | 34 | $123 | $1 | $58 | $180 | $359 |
| | Spin/non-spin reserve | 17 | $20 | $1 | $3 | $39 | $67 |
| | Frequency response | 4 | $54 | $37 | $39 | $74 | $81 |
| | Voltage support | 3 | $22 | $3 | $3 | $60 | $60 |
| | Black start service | 1 | $8 | $8 | $8 | $8 | $8 |
| Transmission services | Transmission congestion relief | 5 | $72 | $12 | $12 | $155 | $260 |
| | Transmission upgrade deferral | 5 | $124 | $24 | $40 | $212 | $233 |
| Distribution services | Distribution upgrade deferral | 8 | $93 | $9 | $44 | $148 | $177 |
| Customer services | Power reliability | 9 | $77 | $2 | $18 | $106 | $283 |
| | TOU charge reduction | 9 | $65 | $2 | $7 | $130 | $266 |
| | Demand charge reduction | 16 | $104 | $12 | $46 | $163 | $269 |

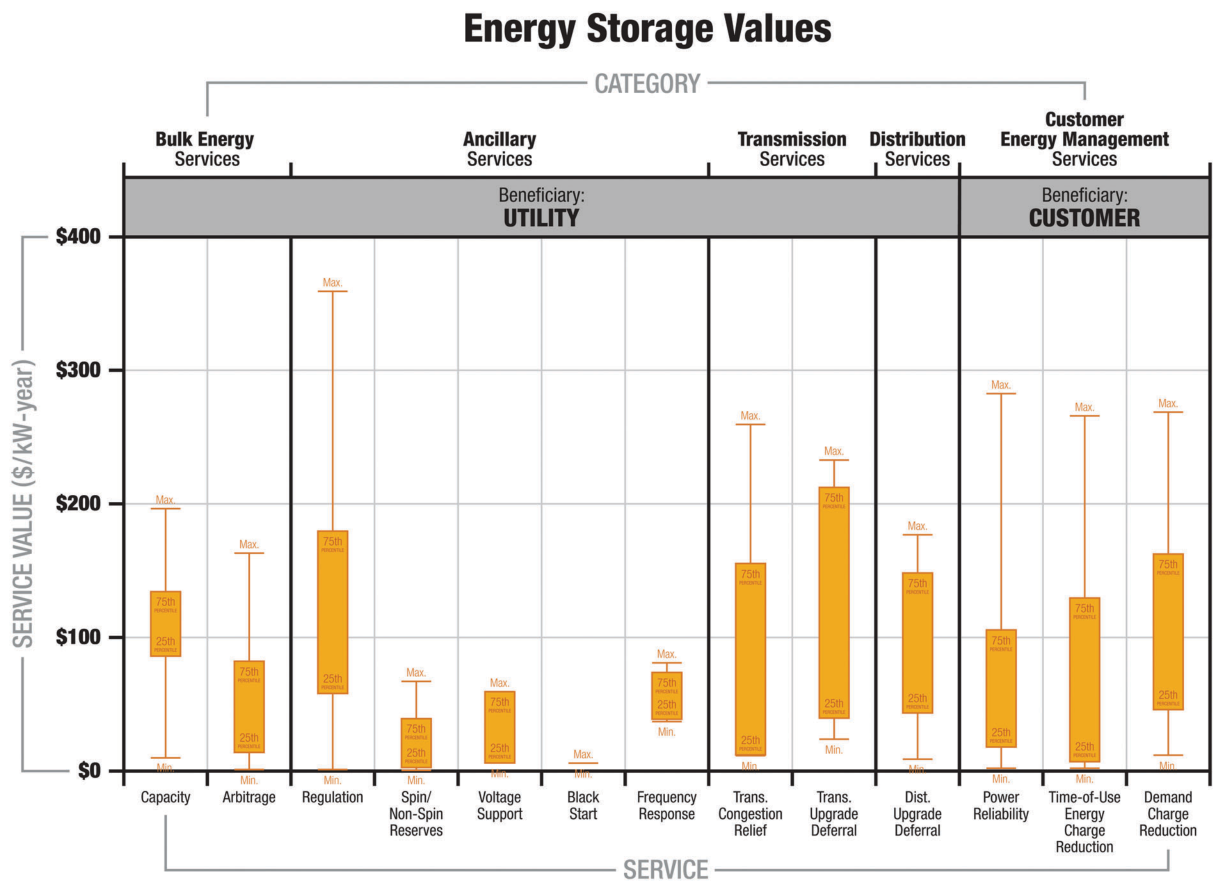


Fig. 2 Descriptive statistics for energy storage valuation studies.

discount rates used to calculate present value benefits. Customer services can be significant because they reflect the full cost of electricity supplied to customers, as opposed to a specific service supporting the grid at the transmission or distribution levels.

The remainder of this section discusses the value of energy storage on a service-by-service basis.

### Energy Arbitrage

Energy arbitrage benefits are derived from buying low and selling high in wholesale energy markets. Profits are therefore dependent on peak and off-peak price differentials, which vary by region and market, and by battery characteristics. For example, low RTE rates for battery systems reduce arbitrage profits due to higher energy losses. Within the literature, dispatch strategies for storage devices are based on optimization approaches for maximizing revenue. The reviewed studies cover the main system operators in the U.S., including the CAISO, Electric Reliability Council of Texas (ERCOT), Independent System Operator for New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), and the Pennsylvania/Jersey/Maryland Power Pool (PJM). Electricity price data used in the studies reviewed for this article covered periods ranging from 2005 to 2015.

The research team found 39 estimates of arbitrage value for ESSs in the literature, ranging from $1/kW-year to $163/kW-year. Findings in the 25th percentile registered at $14/kW-year while $82/kW-year represented the 75th percentile.

Bradbury *et al.* (2014) conducted an assessment of arbitrage in six major ISO regions across the U.S., and the estimated arbitrage benefit varied from $69/kW-year in ISO-NE to $146/kW-year in ERCOT.[9] Denholm *et al.* (2013), which evaluated arbitrage potential using a multi-regional approach, found that beyond a certain storage capacity in the system, marginal net benefits fell due to declining peak and off-peak price differentials.[10]

Technical assumptions governing energy storage size (discharge power and energy capacity), RTE, and variable operating cost played a critical role in defining value and, therefore, these factors cause total benefit estimates to vary. Byrne and Silva-Monroy (2014) showed how arbitrage benefit estimates could vary based on the foreknowledge of energy prices. Arbitrage benefit with perfect foreknowledge yielded a benefit of $47/kW-year while using last year's average price and the previous day's price, an estimate of $42/kW-year and $45/kW-year was found, which is 88% and 95%, respectively, of the benefit with perfect knowledge.[11] Some studies co-optimize arbitrage with regulation, thus reducing the energy available for providing arbitrage services. Analysis performed by Byrne *et al.* (2015) showed co-optimizing arbitrage with regulation on a system at times can generate negative arbitrage benefits due to energy being purchased to keep the storage system charged for regulation services.[12] Price volatility is another market parameter that contributes to varied results. The market type (day-ahead market or DAM *versus* real time market or RTM) can also affect results due to price volatility. An analysis conducted by Salles *et al.* (2014) showed at the same location (PJM) and year (2014), arbitrage benefit could potentially double within the RTM ($50/kW-year) as compared to the DAM ($25/kW-year).[13]

Table 3 presents summary information for each of the energy arbitrage studies reviewed (*e.g.*, when was it conducted, data source and year, financial assumptions, details about the storage device, and the benefit estimate) for this report.

**Regulation**

Regulation services result from an ESS operator responding to an ACE signal in order to provide a corrective response to all or a segment portion of a control area. Regulation services involve intra-hour balancing responses to deviations between load and generation. The benefits of regulation services in valuation studies are generally evaluated based on the price of those

Table 3 Literature review summary on energy arbitrage[9–31]

| Study year, authors | Data year, region | Lifecycle, discount rate, escalation rate | ESS size, discharge hour, efficiency, variable op. cost | Benefit ($/kW-year) |
|---|---|---|---|---|
| 2007, Walawalkar *et al.* | 2001–2005, New York City | 10 year, 10% | 1 MW, 4 MW h, 83% | 162 |
| | 2001–2005, New York East | | | 50 |
| | 2001–2005, New York West | | | 42 |
| 2007, Sayer *et al.* | 2005 Locational Marginal Price (LMP) inDAM, New York City (NYC) | 10 year, 10%, 2.5% | NA, 1–8 h, 70–90%, 0–4 c per kW h | 28–42 |
| 2009, Sioshansi *et al.* | 2007, PJM | | NA, 4 h, 80%, NA | 58 |
| 2010, Eyer and Corey | 2009 LMP in DAM, CAISO | 10 year, 10%, 2.5% | NA, 1–8 h, 70–90%, 0–2 c per kW h | 60–100 |
| 2010, Rastler | 2006–2008, U.S. | 15 year, 10%, 2.5% | 1 MW/2 MW h, NA, NA | 13 |
| 2011, Narula *et al.* | 2009 LMP in DAM, CAISO | 10 year, 10%, 2.5% | NA, 1–8 h, 70–90%, 0–2 c per kW h | 86 |
| 2012, Byrne and Silva-Monroy | 2010–2011 CAISO LMP | Annual revenue | 8 MW/32 MW h, 80%, NA | 25 (2010) 42 (2011) |
| 2013, Denholm *et al.* | 2006, Colorado (Public Service Company of Colorado, Western Area Power Administration-Colorado-Missouri Region) | Annual revenue | 300 MW, 8 hours, 75%, NA | 35 |
| 2013, Kaun | 2020, Bulk, CAISO | 20 year, 11.47%, 2% | 50 MW, 100 MW h, 83% | 82 |
| | 2020, Ancillary Service-Only, CAISO | 20 year, 11.47%, 2% | 20 MW, 5 MW h, 83% | 21 |
| | 2020, Substation, CAISO | 20 year, 11.47%, 2% | 1 MW, 4 MW h, 83% | 97 |
| 2013, Edgette *et al.* | 2013, Minnesota (modified CPUC data), No wholesale market participation | 20 year, 11.47%, 2% | 1 MW/4 MW h, 83%, 0.25 | 96 |
| | Same data, with MISO market participation | | | 47 |
| 2014, Byrne and Silva-Monroy | 2011–2012, ERCOT | Annual revenue | 8 MW/32 MW h, 80%, NA | 132 (2011) |
| | 2011, ERCOT | | (not available) | 47 (2012) |
| | 2011–2012, ERCOT | | | 42 (2012)) 126 (2011) 45 (2012) |
| 2014, Brattle | 2020, ERCOT | 15 year, 8% | 1000–8000 MW | 24 |
| 2014, Salles *et al.* | 2014, PJM DAM | Annual revenue | 1–14 MW h, 95%, NA | 25 (1 MW h) 100 (14 MW h) |
| | 2014, PJM RTM | | | 50 (1 MW h) 140 (14 MW h) |
| 2014, Bradbury *et al.* | 2008 LMP ERCOT | Average daily revenue | 1 MW/2 h, 90–98%, NA | 146 |
| | 2008 LMP NYISO | | | 139 |
| | 2008 LMP CAISO | | | 128 |
| | 2008 LMP MISO | | | 102 |
| | 2008 LMP PJM | | | 73 |
| | 2008 LMP ISONE | | | 69 |
| 2014, Wood *et al.* | 2013, Los Angeles Department of Water and Power (LADWP) (Beacon, Mount Cotton and Q09 solar farm) | 15 year, 4%, 1% | 20–35 MW, 10–17.5 MW h, NA, 0.2 c per kW h | 33 |
| 2014, Maitra *et al.* | 2013, LADWP (NR-CHA-5 Feeder) | | 2.5 MW, 3.5 h, NA, NA | 22 |
| 2015, Byrne *et al.* | 2014–2015, PJM | Annual revenue | 20 MW/15 min, 85%, NA | 1 |
| 2015, Fitzgerald | Case I, CAISO | 20 year, 6.77% | 140 kW–560 kW h | 6 |
| | Case II, NYISO | 20 year, 6.77% | 26 MW | 12 |
| | Case III, Southwest | 20 year, 6.77% | 4 kW–4 kW h | 6 |
| | Case IV, CAISO | 20 year, 6.77% | 5 kW–5 kW h | 3 |
| 2015, Kleinschmidt Group | 2025, Pacific Northwest | 40 year, 4%, 2% | 1000 MW | 19 |
| 2016, Olinksky-Paul | 2017–2018, Sterling Municipal Light Department (SMLD) in Sterling, Massachusetts | Annual revenue | 1 MW/1 MW h, NA, NA | 41 |
| 2016, Dahlke | 2015, MISO | Annual revenue | 2 MW/4 MW h, 90%, NA | 14 |
| 2017, Balducci *et al.* | 2017, Pacific Northwest | 20 year, 6.32%, 2.25% | 5 MW–10 MW h, 78–85% | 26 |
| 2018a, Balducci *et al.* | 2018, Pacific Northwest | 20 year, 5.5%, 2.25% | 5 MW–30 MW h, 67% | 16 |

services in a specified region, with value defined based on historic market data. In regions with no organized markets, the focus is on avoided costs estimated through production cost model runs that define the most efficient generation schedule given utility portfolios of assets. Production cost models can define the influence of additional energy storage capacity on overall regulation costs. As is the case with energy arbitrage, the amount of energy lost due to storage RTE losses also needs to be considered in evaluating benefits.

FERC orders have served to level the playing field for energy storage in frequency regulation markets but challenges remain for other services. At the transmission level, two FERC Orders address the market design of certain grid services (*e.g.*, frequency regulation) that ESSs are well suited to provide. FERC Order 784 requires transmission providers to consider both speed and accuracy in the determination of regulation and frequency response requirements,[32] and FERC Order 755 ensures that providers of frequency regulation are paid just and reasonable rates based on system performance. In providing frequency regulation, organizations are required to include both a capacity payment that considers the marginal unit's opportunity cost and a pay for performance component based on the mileage or the sum of the up and down signal followed by the provider.[33] Table 4 summarizes select market features in U.S. ISOs.[34] Note that ERCOT is not under FERC jurisdiction.

In addition to the traditional regulation signal obtained by low-pass filtering of an ACE, PJM generates a high-pass filtered version of ACE for fast-responding regulation assets like energy storage. The low-pass filter signal is referred to as Regulation A and is sent to traditional regulation sources. The low-pass filter results in a slower signal designed to address larger, longer fluctuations in grid conditions. The Regulation D signal based on the high-pass filter requires a near instantaneous response and is a faster, more dynamic signal.[35] The ratio of the high-pass filtered signal to the low-pass filtered signal is defined as the mileage and used to determine the performance-based component of the regulation payment. While PJM has historically attracted a significant degree of market participation from energy storage providers due to the design of its market, which more accurately compensates energy storage for its performance, there is evidence that market saturation has significantly affected profit potential in the PJM regulation market.[36]

The literature reviewed for this report provided 34 estimates of regulation benefits. The 25th percentile of the values was found to be \$58/kW-year while \$180/kW-year was obtained at the 75th percentile. Among the ISO cases studied in the references, ISO-NE corresponds to the highest estimate of regulation benefit (\$364/kW-year with 2012 data), which is closely followed by PJM (\$319/kW-year with 2014–2015 data). Studies conducted on ERCOT derived benefit estimates in the range of \$104–\$295/kW-year with contributors for variations being year of data (2011/2012) and knowledge of price (perfect knowledge/previous day's price). A study conducted on CAISO by Eyer and Corey (2010) showed the effect of regulation service duration on benefit calculations.[17] Operating for 50% and 80% of a year provided an estimate of \$109 and \$210/kW-year, respectively. The lowest estimate of regulation benefit (\$1/kW-year) was obtained from a study conducted on a distribution feeder in the LADWP area by Maitra *et al.* (2014).[25] This is attributed to the low regulation services price in the LADWP area, which registered a peak regulation price of \$0.31/MW h and off-peak regulation price of \$0.15/MW h.

Apart from energy price, different market mechanisms established for payment of ancillary services may impact benefit estimation. Avendano-Mora and Camm (2015) discussed performance score-based payment for regulation services in PJM and showed ±3% variation can result in a change of ±\$3 million in project net present value (NPV) for 50 MW of energy storage capacity.[37] This study also found storage replacement cost as another important assumption that could potentially impact benefit estimation – each additional replacement cost can reduce the NPV by 20%. A summary of the literature covering regulation service benefits is provided in Table 5 below.

## Capacity

The basis for estimating the capacity benefit of energy storage is typically either the reduced or avoided cost of a new peaking plant or a capacity price set through a local market. Capacity is often referred to as resource adequacy.

The capacity addition cost is calculated based on an increment of an installed cost of the next-best alternative—*e.g.*, a simple cycle or combined cycle combustion turbine technology—or combination of alternatives minus any energy and ancillary service benefits associated with plant operations. An annual fixed charge rate is used to determine the installation cost in terms of a \$/kW-year metric. Annual fixed O&M cost would also typically be included in the benefit estimation.

When estimating the capacity benefit of an energy storage system, one must also determine its incremental capacity equivalent (ICE) or the availability of the resource in relation to the next-best alternative against which it is being compared. Thus, if a particular energy storage device has only 60% of the reliability of a combustion turbine due to energy limitations, it would only be assigned 60% of the benefit. ICE is typically

Table 4 Summary of select market features in U.S. RTOs/ISOs

| | RTO/ISO | | | | | |
|---|---|---|---|---|---|---|
| Service | PJM | MISO | CAISO | NY ISO | ISO-NE | ERCOT |
| Capacity payment | Yes | Yes | Yes | Yes | Yes | No |
| Mileage payment | Yes | Yes | Yes | Yes | Yes | Yes |
| Accuracy payment | No | No | Yes | Yes | No | No |
| Basis of mileage payments | DA and real time | Real time | DA and real time | | | |

Table 5 Literature review summary on regulation[10–12,14,15,17,19–25,29–31,37,40,41,46,47]

| Study year, authors | Data year, region | Lifecycle, discount rate, escalation rate | ESS size, efficiency, variable cost | Benefit ($/kW-year) |
|---|---|---|---|---|
| 2007, Walawalkar *et al.* | 2001–2005, NYC, New York East, New York West | 10 year, 10% | 1 MW, 4 MW h, 83% | 203 |
| 2007, Sayer *et al.* | 2005, NYISO | 10 year, 10%, 2.5% | NA, 1–8 h, 70–90%, 50 $/MW h | 150 |
| 2010, Eyer and Corey | 2009, CAISO | 10 year, 10%, 2.5% | NA, 1–8 h, 70–90%, NA | 195 (avg. of 50% and 80% hours a year) |
| 2010, Rastler | 2006–2008, U.S. | 15 year, 10%, 2.5% | 1 MW/2 MW h | 145 (fast 1 h)<br>65 (1 h)<br>128 (15 min) |
| 2012, Byrne and Silva-Monroy | 2010–2011, CAISO LMP | Annual revenue | 8 MW/32 MW h, NA, NA | 117 (2010)<br>161 (2011) |
| 2011, Narula *et al.* | 2009, CAISO | 10 year, 10%, 2.5% | 1–40 MW | 195 |
| 2013, Denholm *et al.* | 2011, CAISO | Annual revenue | 100 MW, 8 hours, 75%, NA | 110 |
| 2013, Kaun | Bulk, CAISO | 20 year, 11.47%, 2% | 50 MW, 100 MW h, 83% | 161 |
| | Ancillary Service-Only, CAISO | 20 year, 11.47%, 2% | 20 MW, 5 MW h, 83% | 204 |
| | Substation, CAISO | 20 year, 11.47%, 2% | 1 MW, 4 MW h, 83% | 161 |
| 2013, Balducci | 2018, Pacific Northwest | 20 year, 7.8%, 2.5% | 4 MW/16 MW h | 59 |
| 2013, Edgette *et al.* | 2013, MISO | 20 year, 11.47%, 2% | 1 MW/4 MW h, 83%, 0.25 | 41 |
| 2014, Byrne and Silva-Monroy | 2011–2012, ERCOT LMP, Perfect Knowledge, Regulation and Arbitrage bundled | Annual revenue | 8 MW/32 MW h, NA, NA | 295 (2011)<br>116 (2012) |
| | 2011–2012, ERCOT LMP, Previous Day's Price | | | 253 (2011)<br>104 (2012) |
| 2014, Wood *et al.* | 2013, LADWP (Beacon, Mount Cotton and Q09 Solar Farm) | 15 year, 4%, 1% | 20–35 MW, 10–17.5 MW h, NA, 0.2 c per kW h | 133 |
| 2014, Maitra *et al.* | 2013, LADWP | | 2.5 MW, 3.5 h, NA, NA | 1 |
| 2016, Cutter | 2011, CAISO | Annual revenue | NA, 4 h, 75%, NA | 143 |
| 2014, Hibbard *et al.* | 2012, ISO-NE | 20 year, NA, NA, 10% and 2.5% assumed | 4 MW/16 MW h, 75%, NA | 364 |
| 2015, Byrne *et al.* | 2014–2015, PJM | Annual revenue | 20 MW/15 min, 85%, NA | 319 |
| 2015, Fitzgerald | Case I, CAISO | 20 year, 6.77% | 140 kW–560 kW h | 33 |
| | Case II, NYISO | 20 year, 6.77% | 26 MW | 56 |
| | Case III, Southwest | 20 year, 6.77% | 4 kW–4 kW h | 79 |
| | Case IV, CAISO | 20 year, 6.77% | 5 kW–5 kW h | 60 |
| 2015, Balducci | 2014, CAISO | 20 years, 3.9%, 2.5% | | 73 |
| 2015, Fox. | 2013, ERCOT | Annual revenue | 1 MW/2 MW h, NA, NA | 107 |
| 2015, Avendano-Mora and Camm | 2012–2014, PJM | 20 year, 11.47%, 2% | 50 MW/12.5 MW h, NA, NA | 62 |
| 2016, Dahlke | 2013–2015, MISO | Annual revenue | 2 MW/4 MW h, 90%, NA | 86 |
| 2016, Massachusetts DOER | 2015, MA (ISO-NE) | Annual revenue | 1766 MW state-wide deployment | 15 |
| 2017, Byrne *et al.* | 2017, MA (ISO-NE) | Annual revenue | 1 MW/1 MW h, 85–90% | 60 |
| 2017, Balducci *et al.* | 2017, Pacific Northwest | 20 year, 6.32%, 2.25% | 5 MW–10 MW h, 78–85% | 147 |
| 2018a, Balducci *et al.* | 2018, Pacific Northwest | 20 year, 5.5%, 2.25% | 5 MW–30 MW h, 67% | 137 |

calculated by performing a loss of load probability analysis or through some form of a performance test.

Denholm *et al.* (2013) suggested these costs would vary depending on equipment costs, location, and financing terms, with estimates ranging from a low value of $77/kW-year (PSCO 2011) to a high value $212/kW-year (CAISO 2012).[10] For capacity price markets, ISOs publish relevant capacity market data, which is used for benefit estimation and vary depending on location and market. In highly populated urban areas, it may be difficult and expensive to augment generation and transmission capacity, which leads to high capacity prices and by transfer a high benefit to energy storage when providing capacity services. For example, in NYISO, the capacity price for New York City (NYC) is higher than the rest of the system. Among the studies reviewed, 21 different capacity benefits were found with $86 and $134/kW-year at the 25th and 75th percentile values, respectively. A summary on the literature review findings of capacity benefits of energy storage is provided in Table 6.

### Spinning/non-spinning reserve

Estimation of spin/non-spin reserve benefits is tied to either prices evident in regional ancillary service markets or the cost of the next-best alternative available to provide the service as estimated through production cost model runs conducted by electricity service providers operating in regions without markets. The research team found 17 studies that estimated the value of spin/non-spin reserve, ranging from $1/kW-year to $67/kW-year. At the 25th percentile, the value was estimated at $3/kW-year. At the 75th percentile, the value was estimated at $39/kW-year. These studies covered the NYISO, MISO, ERCOT, CAISO, and Southwest regions. This service is a lower value benefit when compared to others presented thus far in this review.

Sayer *et al.* (2007) analysed the Eastern New York market data and found a $2/MW h reserve price when storage was used for other more valuable applications.[15] Based on an assumption of $30/MW h variable O&M cost and 3000 hours of annual service

Table 6 Capacity value estimates[6,15,17,18,21,24,26,27,28,29,31,38,42]

| Study year, authors | Price data year, region | Benefit ($/kW-year) |
|---|---|---|
| 2007, Sayer *et al.* | 2006, NYISO | 105 |
| 2010, Eyer and Corey | 2009, CAISO | 120 |
| 2010, Rastler | 2006–2008, CAISO, ERCOT, ISONE, NYISO, PJM | 84 (local)<br>15 (system) |
| 2013, Denholm *et al.* | 2013, PJM | 90 |
| | 2011, PSCO | 77 |
| | 2012, CAISO | 212 |
| 2013, Kaun | Bulk, CAISO | 65 |
| | Substation, CAISO | 104 |
| 2013, Balducci | 2018, Pacific Northwest | 142 |
| 2013, Edgette *et al.* | 2013, MISO | 88 |
| 2014, Wood *et al.* | 2014, LADWP | 9 |
| 2014, Hibbard *et al.* | 2013, ISO-NE | 199 |
| 2015, Fitzgerald | Case I, CAISO | 145 |
| | Case II, NYISO | 106 |
| | Case III, Southwest | 100 |
| | Case IV, CAISO | 145 |
| 2015, Kleinschmidt Group | 2015, Pacific Northwest | 120 |
| 2016, Olinsky-Paul | 2016, SMLD in Sterling, Massachusetts | 115 |
| 2016, Dahlke | 2015, MISO, Minnesota | 2 |
| | 2015, MISO, Illinois | 15 |
| Balducci *et al.*, 2018a | 2018, Pacific Northwest, Oregon | 86 |
| Schoenung, 2017 | 2017, ISO-NE, Vermont | 120 |

hours, a net benefit of $36/kW-year was estimated. Using CAISO data, Eyer and Corey (2010) estimated a reserve price of $20/kW-year, which is an average of a low-end estimation of $7.9/kW-year with $3/MW h of reserve price while providing services for 30% of the hours in a year and a high-end estimation of $31.5/kW-year with $6/MW h of reserve price and providing services for 60% of the hours in a year.[17]

Rastler (2010) estimated spinning/non-spinning reserve benefits of $14 and $2/kW-year, respectively.[18] Denholm *et al.* (2013) estimated spinning reserve benefits of $65/kW-year based on a reduction of production cost by adding a 100 MW storage system.[6] Edgette *et al.* (2013) estimated a spinning/non-spinning reserve price for a 1 MW/4 MW h system in Minnesota (MISO) at $4/kW-year[18] while Wood *et al.* estimated a reserve price of $1/kW-year when studying battery storage installations at three solar PV farms in Los Angeles.[24]

## Voltage support

The voltage support benefit of energy storage is typically valued by assessing the contribution made by storage to reduce the use of centrally located large generating plants to provide reactive power during region-wide voltage emergencies. Eyer and Corey (2010) estimated the low-end estimate of voltage support benefits at $400/kW and a high-end estimate of $800/kW for a 10 year lifecycle, which translate to $56/kW-year to $112/kW-year value.[17] Using the price of shunt capacitors, the most common technology for providing voltage support, Rastler (2010) estimated a benefit of $3–$17/kW-year.[18] Based on an assumption of $5 per kVAR-year of voltage support cost, Wood *et al.* (2014) estimated a transmission voltage support benefit of $3/kW-year.[24] The three studies summarized in this section were the only ones found by the research team to have evaluated the benefit of energy storage in providing voltage support.

## Black start

Black start benefits are estimated based on the payments by ISOs for procuring black start services, which could be through competitive market processes or strategically procured through bilateral agreements. Only one study was found that estimated the value of energy storage when providing black start capacity. Based on 2006 CAISO data, Rastler (2010) estimated a black start benefit of $8–$38/kW-year.[18]

## Frequency response

North American Electric Reliability Corporation (NERC) Standard BAL-003-1 requires that balancing authorities maintain sufficient frequency response capacity to maintain interconnection frequency within predefined bounds. In compliance with NERC Standard BAL-003-1, NERC establishes frequency response obligation allocations for each of the four interconnections in the U.S., and those obligations are in turn transferred onto balancing authorities within each interconnection. ESSs can provide energy in order to maintain frequency stability when it deviates outside the set limit, thereby keeping generation and load balanced within the system.

The 5 MW/1.25 MW h lithium-ion battery system referred to as the Salem Smart Power Center (SSPC), which is operated by Portland General Electric, is set to automatically respond to unexpected frequency excursions. Based on set points (high and low) established by a frequency response screen, the SSPC responded 181 times over 13 months for an average of 13.9 times per month. The SSPC is programmed to respond to frequency response events over a six to seven minute duration while providing 300 kW h of energy. The value of this service was estimated at $52.80 per kW-year.[30]

CAISO has contracted with two entities for primary frequency response: Seattle City Light (SCL) and Bonneville Power Administration (BPA). The SCL contract transfers 15 MW/0.1 Hz of frequency regulation to SCL at a contract price of \$1.22 million or \$81/kW-year.[43] The BPA contract transfers 50 MW/0.1 Hz of frequency regulation to BPA at a contract price of \$2.22 million or \$44.40 per kW-year.[44]

### Transmission and distribution upgrade deferral

Eyer and Corey (2010) determined the cost of transmission and distribution (T&D) upgrade deferral combined by estimating the cost of T&D upgrade to be deferred based on \$/kW to be added or the T&D marginal cost.[17] The value of cost deferral can be significant due to the nature of utility cost accounting. For example, if an energy storage system could be used to shave local load peaks resulting in deferral of a \$10 million substation for five years, the benefit would be \$3.2 million if the cost of capital to the utility minus inflation was 8%. Present value costs are estimated by dividing the cost of the asset by one plus the discount rate minus the cost inflation rate raised to the number of deferral years. If the discount rate minus cost inflation was 8%, moving the deferral out five years would reduce the present value cost of the asset to \$6.8 million (\$10 million/$1.08^5$).

Balducci *et al.* (2013) evaluated the benefits of deferring investment in a substation located on Bainbridge Island, Washington by nine years, estimating the deferral value at \$162/kW-year.[30] Sayer *et al.* (2007) estimated deferral benefits associated with 375 kW of storage capacity at \$445/kW or \$55/kW-year.[15] Rastler (2010) estimated a \$135/kW-year benefit for transmission upgrade deferral and \$37/kW-year benefit for distribution upgrade deferral.[18]

Brattle (2014) estimated transmission upgrade deferral benefits at \$36/kW-year based on average annual transmission cost for every unit of reduced peak demand. This estimate is consistent with the average annual transmission cost per kW of summer coincident peak load in ERCOT. On distribution upgrade deferral, Brattle (2014) noted that distribution system costs are driven by non-coincident, local peak loads. Brattle estimated the benefit of distribution investment deferral at \$14/kW-year.[48]

Edgette *et al.* (2013) estimated distribution upgrade deferral benefit of \$104/kW-year based on a Minnesota case study involving local peak shaving services.[22] A Massachusetts energy storage initiative report assessed a T&D upgrade deferral benefit of \$24/kW-year.[46] Based on an analysis performed on a distribution feeder (NR-CHA-5) in the LADWP area, Maitra *et al.* (2014) estimated a distribution upgrade deferral benefit of \$9 /kW-year; the goal was to limit transformer loading up to 90% using a 2.5 MW, three hour storage device.[25] These findings suggest that the value of T&D deferral is highly situational and location dependent.

Balducci *et al.* (2018b) demonstrated the breadth of benefits associated with energy storage by using an electro thermal life model to evaluate how energy storage could be used to defer investment in a 7.55 kilometre, 69 kilovolt (kV) submarine transmission cable that connects mainland Washington State near Anacortes and the San Juan Islands on Lopez Island. PV and energy storage will be used to reduce loading stress on the cable and have a potential life extension benefit. Using the electro thermal life model and the selected load cycle, potential life extension was estimated to be 3.3 years. With the cable cost estimated at \$40 million in 2018 dollars, the value of the deferral was estimated at \$2 million.[45]

### Transmission congestion relief

Sayer *et al.* (2007) reported that congestion is a growing concern for NYC and is managed by transmission congestion contracts (TCC), which reimburse the holders when there is congestion. The TCC effectively provides a way for energy buyers to manage the risk associated with uncertain energy congestion charges. Storage can reduce congestion charges as long as it is charged by the energy generated within NYC or with energy transmitted when there is little or no congestion. Benefits of reduced energy congestion are estimated based on the congestion price signals and TCC. According to NYC 2005 data, avoided congestion charges average \$10/kW-year.[15] Eyer and Corey (2010) reported excessive congestion exists for 10–15% of the year in California. Assuming a congestion charge is possible and would be more likely with the addition of renewable generation, a range of value was estimated at \$4.38–\$19.71/kW-year.[17] Rastler (2010) estimated transmission congestion benefits at \$46/kW-year.[18] Del Rosso and Eckroad (2014) studied the impact of energy storage on transmission congestion relief using a modified version of the IEEE Reliability Test System with a 50 MW/25 MW h battery storage system, deriving a benefit estimate of \$258/kW-year based on a 15-year project lifecycle and 7% discount rate.[49]

### Power reliability

Power reliability benefits can be evaluated based on utility costs or interruption costs to customers. When evaluating the benefits to utilities, avoided costs could include undelivered energy, restoration costs, costs associated with reliability-associated investments (*e.g.*, voltage regulators) or penalties paid for non-compliance with reliability targets. Interruption costs to customers are logged by studies that evaluate the impact of electricity disruptions to residential, commercial, and industrial customers.

Eyer and Corey (2010) evaluated the benefit of storage in providing electric power reliability based on an assessment of the annual number of hours when energy is not delivered. Based on standard assumptions of a 2.5 hour annual outage and \$20/MW h of unserved energy, a \$50/kW-year annual reliability benefit could be obtained from storage.[17] Rastler (2010) estimated a benefit of \$67/kW-year for power reliability enhancement by storage applications.[18] Neubauer *et al.* (2012) reported a combined power quality and reliability benefit of \$135/kW-year in California based on a 200 kW system with approximately five reliability events and 10 power quality events annually.[50] Edgette *et al.* (2013) studied two cases in Minnesota. In the 0.5 MW/2 MW h customer owned and controlled storage case, the value of storage was estimated at \$3/kW-year, while a 1 MW/4 MW h utility-owned and controlled storage system yielded a \$2/kW-year benefit.[22] Balducci *et al.* (2013) evaluated reliability benefits from a customer perspective, finding that a 4 MW/16 MW h ESS could significantly reduce the cost of outages on a feeder serving a small community in Washington State experiencing roughly 20 outages annually. Based on an assessment of interruption costs to customers located on Bainbridge Island, Washington, reliability benefits were estimated at \$273/kW-year.[38]

### Time of use charge reduction

TOU benefits associated with energy storage are typically derived from the difference between peak time savings by supplying electricity from storage and cost of the electricity used to charge the storage during an off-peak period. Energy storage can be used to store energy during low-price off-peak periods and then avoid higher-cost peak energy. Note that the peak and off-peak price differential must be sufficient to more than counterbalance the typical 15–30% RTE losses associated with charging and discharging ESSs.

Eyer and Corey (2010) used the Pacific Gas and Electric (PG&E) A-6 tariff to evaluate TOU benefit. Based on peak and off-peak energy prices of 37 cents per kW h and 11 cents per kW h, respectively, a storage battery of 1 MW at 80% efficiency could generate an annual benefit of \$167/kW-year. Based on Con Edison's tariff structure, a benefit of \$50/kW-year was found.[17] Rastler (2010) estimated a benefit of \$272/kW-year for TOU application.[18] Based on Xcel Energy's GS-TOU (S) tariff, Edgette *et al.* (2013) estimated a TOU benefit of \$2/kW-year with a customer owned and controlled 0.5 MW, 2 MW h storage system in Minnesota.[22] Wu *et al.* (2016) studied TOU benefits for an office building case using a 0.2 MW/0.8 MW h ESS in several cities across U.S. and found the following benefit values: San Francisco (\$7/kW-year), Chicago (\$7/kW-year), Houston (\$7/kW-year) and NYC (\$24/kW-year).[51]

### Demand charge reduction

Demand charges accrue based on a customer's peak loads. By reducing demand during those peak load periods, the basis of the demand charge is reduced. Fig. 3 presents the load for one-day at a U.S. military base located in California. The first pane shows the load without energy storage. The second pane shows that with energy storage operated in an optimal manner, load can be shifted and dispersed over the three hours following the original peak hour. Pane 3 shows energy input/output while Pane 4 shows the ESS's state of charge (SOC). The benefits to this base in California were estimated in Balducci *et al.* (2015) at \$130/kW-year.[39] Balducci *et al.* (2015) found that the vast majority of benefits associated with BTM storage were tied to demand charge reduction, with relatively few benefits associated with TOU charge reduction.

Using PG&E's E-19 tariff, Eyer and Corey (2010) estimated demand charge reduction benefits of \$54/kW-year.[13] Rastler (2010) conducted a multi-regional assessment that estimated the value of demand charge reduction at \$230/kW-year.[17] Neubauer *et al.* (2012) estimated a combined demand charge and TOU benefit of \$185/kW-year using Southern California Edison's (SCE's) TOU-GS-3-SOP tariff.[50]

In Minnesota, Xcel Energy's GS-TOU (S) tariff structure was used to estimate a \$24/kW-year benefit for demand charge reduction.[22] Maitra *et al.* (2014) studied 39 loads in a distribution feeder (NR-CHA-5) in the LADWP area and estimated the maximum potential benefit at \$80/kW-year from demand charge reduction for a load with 796 kW peak demand and a 300 kW, 4–5 hour battery storage.[25] A study conducted on BTM energy storage projects by Danley *et al.* (2014) in the Wright-Hennepin Cooperative Electric Association area estimated a demand charge reduction benefit of \$4/kW-year using a 9.2 kW, 2 hour battery with 60% efficiency and five cycles per month.[52]

DiOrio *et al.* (2015) evaluated the benefits associated with demand charge reductions in two cities – Los Angeles, California and Knoxville, Tennessee. Financial evaluations were conducted using assumptions of a 25 years lifecycle, 2.5% inflation rate, and 8.14% nominal discount rate. Based on the SCE TOU-GS-2 rate structure, a demand charge reduction benefit was estimated at \$42/kW-year with a 55 kW/110 kW h 92% efficient Li-ion storage system. Using the Knoxville Utility Board general power rate

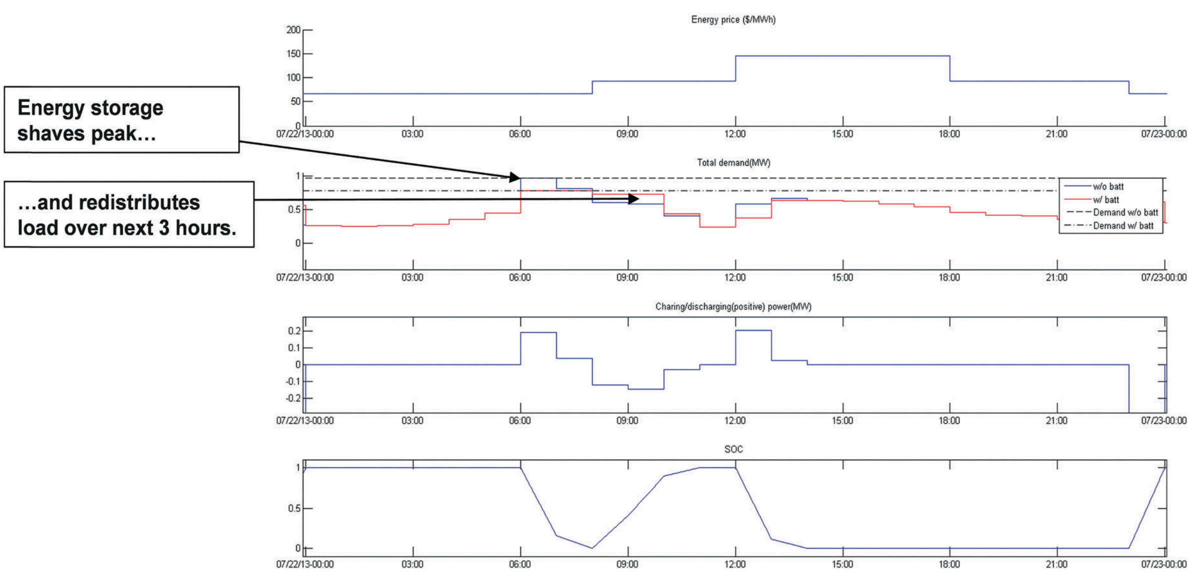


Fig. 3 Base load and battery operation for an illustrative day.

schedule, a benefit of \$29/kW-year was estimated based on a 150 kW/300 kW h storage system.[53] Schenkman (2015) reported a demand charge reduction benefit of \$51/kW-year from a commercial 3 kW, 4 kW h, 80% efficient Li-ion system.[54] Using a common office building load profile and a 0.2 MW/0.8 MW h energy storage system, demand charge reduction benefits in four U.S. cities were determined by Wu *et al.* (2016) as: San Francisco (\$72/kW-year), Chicago (\$75/kW-year), Houston (\$87 /kW-year), and NYC (\$256/kW-year).[51]

## A note on how energy storage characteristics and placement impact profitability

To study how ESS values vary by region and ESS capacity, the results of arbitrage studies were evaluated in more detail, and the values are presented in Fig. 4. Results are grouped based on regions across the U.S. and ESS energy-to-power ratios (EPR). In the location-based grouping, the largest number of studies completed was in CAISO (11), followed by PJM (7), ERCOT (7), and NYISO (4); sample size for other regions was two or less. Statistical measures (mean, standard deviation) of arbitrage values expressed in \$/kW-year at these locations [*e.g.*, CAISO (\$57, \$43), PJM (\$64, \$46), ERCOT (\$80, \$52), NYISO (\$98, \$61)] suggest how the values vary from one region to another. The maximum mean value for arbitrage was observed for NYISO (\$98/kW-year) and the minimum for ISO-NE (\$55/kW-year), which is very close to CAISO (\$56/kW-year). A boxplot of the region-based group of the data is shown in the top panel of Fig. 4. The red line within each box represents the mean value, bottom and top edges of the box are the first and third quartiles, respectively, and bottom and top whiskers are the minimum and maximum values of the group, respectively.

In the EPR-based group, the largest observed size was for the group with an EPR of 4 (14) followed by EPR 2 (8), EPR 1 (4), and EPR 8 (3). The same statistical measures (mean, standard deviation) for EPR-based groups show the variations in arbitrage values expressed in \$/kW-year (*e.g.*, EPR 1 (\$30, \$21), EPR 2 (\$94, \$44), EPR 3 (\$64, \$46), EPR 4 (\$70, \$40)] in relation to EPR ratios.

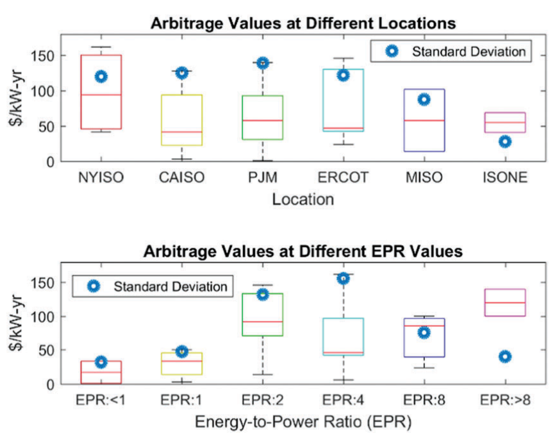


Fig. 4 Arbitrage value differentiated by location and EPR.

An increasing trend for mean values of arbitrage revenue is observed with the increase of EPR, which is consistent with the fact that arbitrage is an energy-intensive application. Economy of scale could also play a role for an increasing revenue trend. Statistical measures of size-based grouping are presented in the boxplot of the bottom panel of Fig. 4.

Balducci *et al.* (2017) explored the impact of EPR on return on investment (ROI) in an evaluation of the SSPC. When the SSPC was originally designed, it was meant to be operated as a component of a larger microgrid system with attention placed on engineering rather than economic goals. Thus, the SSPC holds a small energy capacity (1.25 MW h) in relation to its power capacity (5 MW). With an EPR of only 0.25, it is not well suited to engage in most energy-intensive application such as arbitrage or ancillary services. Thus, the research team studied scenarios with EPRs closer to industry standards (1.0–4.0).

With an EPR less than approximately 0.5, the cost is higher than total benefits and the ROI is thus less than 1, as shown in Fig. 5. As the ratio increases, benefits increase at a higher rate than the costs and therefore the ROI continues to increase until the EPR reaches a maximum ROI at 2.0. Once the EPR surpasses 2.0, benefits increase at a lower rate than costs causing the ROI ratio to decrease. At an EPR of approximately 3.5, costs surpass benefits and the ROI ratio falls once again below 1.0.[30]

In addition to power and energy capacity, other technical characteristics of ESS (*e.g.*, ESS ramp rate) can play a critical role in power intensive applications that require fast charge/discharge (*e.g.*, regulation) and therefore, will impact the value. Rastler (2010) showed how market changes brought by ISOs to incentivize fast response time could enhance the ESS revenue. Regulation benefit values extracted from this study showed fast 1 hour regulation benefit (\$145/kW-year) is approximately 2.23 times of the traditional 1-hour regulation (\$65/kW-year). Other benefits of fast ramp rate would be in managing the variability introduced by high penetration of renewable energy resources.[18]

## Energy storage valuation tools

Energy storage faces a somewhat unique challenge when attempting to determine its value to the electric power system;

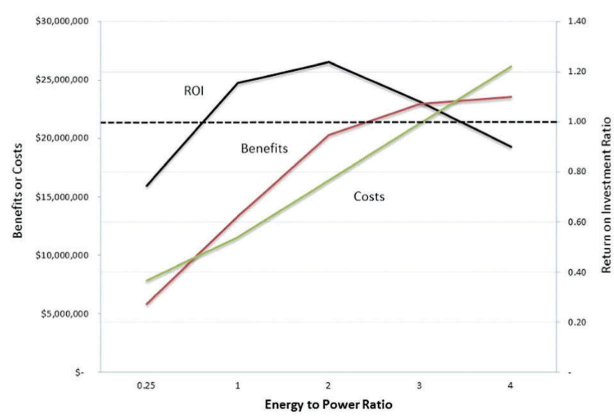


Fig. 5 Impacts of EPR on costs, benefits, and ROI of SSPC.

it does not fit easily into the existing planning and operations workflow. By charging or discharging ESSs can appear as either a generator or a load. The devices themselves, especially those that are electro-chemical batteries, have operational limitations and behaviours that are not easily captured with nameplate ratings or single value specifications. Because their current state is strongly influenced by all previous states (in a way not common for conventional generation) it can be difficult to schedule and dispatch ESSs as necessary to provide the most value.

Those responsible for finding least cost ways of meeting the electrical system's needs are considering how and in what ways energy storage could be used. To do this, ESSs need to be represented and modelled in a way that accurately captures their operational characteristics so that they can be fairly evaluated against other system assets. Bulk power system planners, distribution system planners, and energy customers need ways of understanding, in specific detail, how ESSs could address the problems they are facing. Furthermore, a broad understanding of how energy storage might be able to provide value outside a particular well-defined need can make it a more financially competitive option.

The complexity of correctly valuing ESSs comes not only from the devices themselves but also that which is introduced when multiple, potentially competing methods of gaining value from a given operational opportunity are evaluated. The ESS can only be charging or discharging at any one time and determining the current and future power exchanges is a complex question. Each value stream (commonly called "use cases") has requirements and limitations that must be respected to earn the given value. Furthermore, physical limitations from the electrical system should be considered and regulatory limitations may allow or disallow certain kinds of operations at certain times. Gaining value from a wide variety of services requires broad consideration.

The ideal model for an ESS would contain the following:

• **Thorough representation of the internal state of the device**. This is more than a simple SOC value. The most common type of ESS, electro-chemical batteries, are strongly dependent on their thermal state, affecting nearly every parameter of the device including output voltage and current (and hence, output power) as well as idle state losses. The ideal model would also contain a thermal aspect that would allow the relevant temperature(s) to be estimated based on the ambient temperature and the operating state of the battery. Changes in the SOC based on the state of the battery would be captured as would any lifetime and degradation effects on the battery model parameters (*e.g.*, energy capacity, maximum power, thermal limits). An ideal model would capture non-linearity in terms of changes in SOC varied by power output levels, SOC ranges, ESS state of health, and temperature. Other energy storage types have similar complexities in describing their internal state.

• **Estimation of electrical system effects due to the operation of the ESS**. Generally, an estimate of how the charging and discharging of the ESS is affecting the electrical system is important in estimating the value it can provide. If an operation to maximize value from a certain service causes specific problems in the electrical system, that use case will ultimately provide less value; its operation pattern must be altered to avoid generating the problem or be mitigated by some other means. Some services (*e.g.* voltage support) inherently require an estimate of certain electrical system parameters to estimate the value generated.

• **Estimation of market impacts due to the operation of the ESS**. For locations where markets are used to meet the needs of the power system, the participation of the ESS in these markets to gain value from a service may affect the outcomes of the market operation. Small installations (such as for individual electricity customers) do not typically participate in market operations and effectively act as price-takers but system planners considering larger installations or merchant generators thinking of specific applications would need to consider these effects. The price for a specific service will change by virtue of the entrance of a new market participant and the values being sought may evaporate as the supply curve shifts outward and new market points of equilibrium yield lower settlement prices. This issue would be of particular concern for large ESSs such as pumped storage hydro.

• **Accounting for uncertainties in provided forecasts**. Any method that produces an estimate of maximum value should take into account that perfect foresight of the upcoming battery, electrical system, and electricity market conditions is unachievable. Any given or assumed forecasts have a certain amount of uncertainty inherently with them and planning the operation of the ESS around these forecasts would ideally account for that. The method finding ESS value must not seek the absolute maximum value but the maximum forecast-risk-adjusted value.

• **Mathematical optimization considering all possible services simultaneously**. For a given forecast horizon (*e.g.*, twenty-four hours, one week, one year) the ideal model would consider all of the above mentioned complexities (ESS state, electrical system effects, market effects, forecast-error effects) and compute the mathematically optimal dispatch schedule for the ESS. This algorithm would not require the user to *a priori* specify one primary use case and let the algorithm squeeze in the others as it can but rather would allow the algorithm itself to discover the optimal schedule, guaranteeing the maximum value. Such an algorithm would also support simultaneous optimization for BTM use cases as well as those found in the electrical system as a whole.

• **Ability to define the optimal ratings and location within the power system**. As part of finding the mathematically optimal dispatch of the considered use cases, an even more robust algorithm would even be able to find the optimal power and energy rating necessary to capture the calculated values and the optimal location within the power system where such values are generated. Thus, such a model would need to evaluate services on a location-specific basis.

• **Freely available and easily usable**. The ideal model would be one readily available for all to use and would not require extensive training to understand and apply properly.

Obviously, there are no models that include all these ideal characteristics; the formation of such a complex model is a considerable challenge. Variation in electrical system and market design are hard to capture in a general way; typically such simulations are run in their own dedicated software as the appropriate models can be large and the computation required can be extensive. Variation across ESS technologies are also present, with the largest differences seen between the different general technologies and chemistries (flywheels *vs.* lithium batteries *vs.* lead-acid batteries) but there are also non-trivial variations between manufacturers particularly in chemical battery technologies where new chemistries are regularly being tested and developed. ESS optimization models can be used in combination with other models (*e.g.*, production cost models) to achieve more of these ideal characteristics.

The ESS models today generally implement a segment of this ideal model. They commonly:

• **Optimize across a limited number of use cases**. In the most general models, this optimization covers a handful of use-cases optimized simultaneously as the ideal model would. More often a single use case is optimized and supplementary use cases are opportunistically scheduled around the primary use case. It is also not unusual for models to forgo optimization entirely and instead serve as a simple calculator, tabulating the user-defined values derived from each manually-included use case.

• **Almost always ignore electrical system and market effects**. Because of the great difficulty in providing a general capability for representing the relevant electrical system and/or market environment, these aspects tend to be ignored, assuming the electrical effects are easily managed and the ESS is a price-taker. The big exception to this are the models typically designed for bulk power system studies which can be adapted to represent ESSs. They commonly capture both aspects but cover a very limited range of use cases, often only energy arbitrage and/or resource adequacy (capacity).

• **Tend to use simplistic representations of internal state**. Most ESS models are ratings-based, assuming any valid operating point within the nameplate power and energy rating. They typically use a constant RTE across all operating points and only track the SOC, ignoring thermal effects entirely as well as inter-dependencies between the captured model parameters. Battery lifetime and degradation effects are also typically ignored with the battery assumed to provide full operational ability until the day when it reaches end-of-life, at which point it is assumed to be replaced.

Table 7 provides brief summaries of some of the existing models mentioned in the literature. Many of these models are proprietary and information on their capabilities is not readily available. A careful reading of the available literature and follow-on contacts with model designers and operators were used to make assessments of their capabilities.

The capabilities of the models outlined in Table 7 are presented in Fig. 6. Fig. 6 defines the use cases that each model is capable of evaluating. It identified the energy storage scheduling technique for each model. For example, some models allow for co-optimization among all services while others rely on heuristic or hierarchical approaches. It defines the basis of the

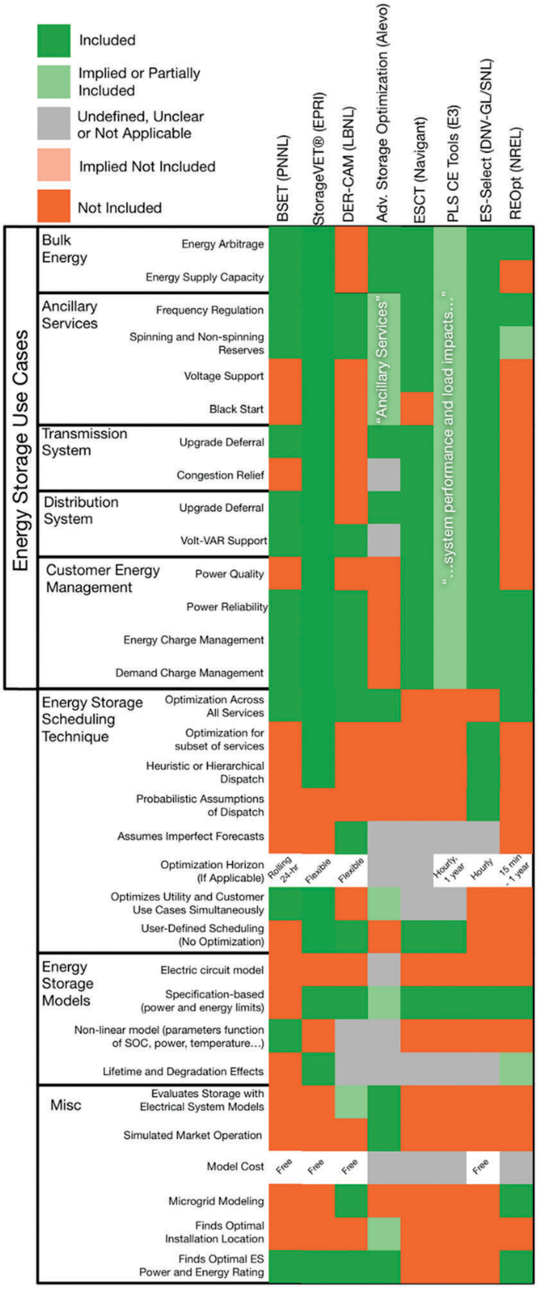


Fig. 6 Review of energy storage evaluation tools.

modules being used to characterize battery performance. Finally, it provides additional information covering various items, including whether the models can be used to evaluate microgrids, can the model be used to optimally scale the power and energy capacities of ESSs, and whether it can be used to find optimal installation locations.

Because no single model can provide a comprehensive representation, different models tend to be used to meet different valuation needs. Though these models address these requirements to varying degrees of satisfaction, the inherent limitations of each model make it blind to other potential values and may generate externalities that must be addressed in some way,

Table 7 Review of existing valuation tools

| Name of tool | Developer | Tool summary |
|---|---|---|
| BSET | Pacific Northwest National Laboratory | BSET is a publicly available model developed by Pacific Northwest National Laboratory as a part of a number of valuation studies that focus on true optimization of multiple use case value streams. The tool requires that the user provide time-series values and energy signals for each use case and BSET then finds the optimal schedule given the specified power and energy limitations of the ESS. BSET also has the ability to optimally size the ESS using the same provided value streams. Finally, it has both utility-owned battery system and BTM system modules.[55] |
| Storage VET | Electric Power Research Institute | StorageVET is available as a web-app at http://www.storagevet.com. The tool can be used to evaluate transmission-connected, distribution-connected, and customer-sited storage. It incorporates time-series loads, prices, and other information to simulate battery operations and estimate value. It is a price-taker model. The tool provides both co-optimization across multiple services and single-service optimization. Other advanced modelling modes allow it to interact with market models and micro-gird models, though it is not available through the web-app yet.[56,57] |
| DER CAM | Lawrence Berkeley National Laboratory | DER CAM is a microgrid planning and operations optimization model which can be used to evaluate the cost-effectiveness of energy storage (along with other microgrid assets) and as such is focused on BTM use cases. It does include a limited power flow calculation capability (LinDistFlow) to aid in microgrid operations. DER CAM has not been fully released though a version of it (going by the name WebOpt) is freely available as a web-app.[58–62] |
| Advanced Storage Optimization Tool | Alevo | Alevo was hired as a part of the Massachusetts Energy Storage Initiative to perform a general assessment of how large-scale deployment of energy storage in that state might take shape and the values it might provide. The study was extensive, providing not only value provided across the various use cases but also locations in the electrical grid and sizes of the storage devices at those locations. A production cost model was also used in the valuation effort though it is not clear if it used a separate or integrated model. The valuation model also identified to whom the values generated accrue, allowing policy makers to more clearly see some specific barriers to energy storage adoption in the state.[63] |
| Energy Storage Computational Tool (ESCT) | Navigant | Developed by Navigant to assist those involved with smart grid investment grants, the ESCT can be used to tabulate the values provided by energy storage devices. The user must select a primary and up to two secondary uses cases with the primary use case assumed to yield the highest value to the owner of the energy storage. Most importantly, "benefits from each application are calculated independently and aggregated in the results section of the model." This is a non-optimization model that eases the tabulation of values rather than truly optimizing the dispatch and determining the total possible value.[64] |
| Permanent Load-Shifting Cost-Effectiveness Tool (PLS CE) | E3 | E3 developed the Permanent Load-Shifting Cost-Effectiveness (PLS CE) Tool to help the three investor-owned utilities in California explore demand response and other load-shifting technologies as mandated by the California Public Utility Commission. The scope of the use cases evaluated by this tool is unclear but the "system impacts and customer loads" must be provided with the net present value over the life of the technology as an output. Given the required inputs, this also is a tabulation tool similar to Navigant's ESCT where no optimization is performed.[65] |
| ES-GRID | DNV GL | ES-Select was developed by DNV GL, formerly DNV-KEMA in collaboration with Sandia National Laboratories. The tool enables evaluation of cash flow and payback analyses. It allows for bundling of multiple grid options and compares storage options to gas turbines and demand response alternatives. It allows for analysis of storage located in the bulk energy system, transmission, distribution, and customer levels, with use cases differentiated at each level based on technical feasibility. ES-Select can be accessed online at http://www.sandia.gov/ess/tools/es-select-tool/. The ES-Select site includes model documentation.[66,67] |
| REopt | National Renewable Energy Laboratory (NREL) | REopt is a microgrid design and analysis tool developed by NREL that can be used to valuate BTM energy storage installations. It typically is run to optimize over an entire year on an hourly basis but can also be run at a higher temporal resolution of 15 minutes. There are multiple selectable optimization goals including minimizing energy costs and providing energy security. REopt also considers any net-metering constraints when defining the energy storage dispatch.[68,69] |

lowering the net value. Bulk power system planners may examine the effect of a large ESS on transmission congestion but may or may not consider its effects on other generators in the market or use the tool to define the precise location where the ESS could be installed so as to address distribution system needs. Models designed to aid residential or commercial customers to manage demand and time-varying energy charges may be able to find the optimal operating schedule to lower their bills but may not have any visibility of the effects on surrounding electrical system and the mitigating measures the distribution system operator must make. A distribution system operator may install an ESS to defer upgrade on a substation transformer but not consider the role that same ESS could play in the wholesale energy or ancillary service markets.

Each limitation in the model used prevents the entire reality from being captured well and effectively diminishes the role the ESS could be playing to meet the needs of all parties involved.

## Conclusions

With RPSs in the U.S. at or above 50 percent in some states and smart grid technologies proliferating, there is a growing need for enhanced grid flexibility and a growing realization that a future with more DERs is becoming a necessary reality. Energy storage possesses several unique attributes (*e.g.*, the capacity to act as generation and load, its effectiveness in meeting ramping requirements, and the ability to accurately track regulation signals) that are valuable to grid operators. The value and effectiveness of energy storage in supporting a cleaner, more resilient future grid are being validated through numerous field demonstrations and analyses, yet regulators and grid operators continue to struggle with the complexities and opportunities provided by energy storage.

The ability to define the potential value that ESSs could generate through various applications in electric power systems, and an understanding of how these values change due to variations in ESS performance and parameters, market structure, utility structures, and valuation methodologies is highly important in advancing ESS deployment. This paper presented a taxonomy for assigning benefits to the use cases or services provided by ESSs, defined approaches for monetizing the value associated with these services, assigned values, or more precisely ranges of values, to major ESS applications by region based on a review of an extensive set of literature, and summarized and evaluated the capabilities of several available tools currently used to estimate value for specific ESS deployments.

It is anticipated that the findings and discussions presented in this paper would be useful for a wide community of ESS industry stakeholders, including utilities, vendors, legislative authorities, researchers, utility commissions, and end-use customers to enhance industry acceptance of ESSs.

Categories of ESS applications considered in this review include bulk energy (*e.g.*, arbitrage), ancillary services (*e.g.*, regulation), T&D services (*e.g.*, congestion relief, upgrade deferral), and customer services (*e.g.*, power reliability, demand charge and TOU charge reduction). The highest mean values were registered for frequency regulation ($123/kW-year), capacity or resource adequacy benefits ($106/kW-year), and demand charge reduction ($104/kW-year). Regulation benefits varied significantly by location, with 25th and 75th percentile values measured at $58/kW-year and $180/kW-year, respectively. Benefits for voltage support, spin/non-spin reserve, and black start were all measured under $25/kW-year. It is observed that the benefit values vary widely as market and utility structures, ESS ratings, and valuation methodologies vary.

The authors reviewed eighteen energy storage valuation tools; eight are evaluated in this article. The review of these tools, which is based on experience in working with them, published information, and correspondence with tool developers suggests that most of the available modelling tools are not fully capable of capturing the entire range of ESS benefits. Limitations remain mainly in use case modelling and co-optimization capabilities. StorageVET (EPRI), ES-Select (DNV GL), BSET (PNNL), and ESCT (Navigant) are some of the few tools that provide a comprehensive range of use cases. However, all of these tools do not possess the co-optimization feature and not all of the advanced modules are freely available.

## Conflicts of interest

There are no conflicts to declare.

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