TECHNICAL APPENDIX A

DETAILED OVERVIEW OF SERVICES

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THE FUNDAMENTAL NATURE of the electricity grid requires that electricity must be consumed, somewhere along the grid, at the exact moment it is generated. This constraint requires ISOs and RTOs to continuously shift generation and / or load to ensure stable grid operation. This balancing act occurs across a wide time horizon ranging from fractions of a second to multiple months. Battery-based energy storage is a particularly well-suited technology to facilitate grid balancing on the low end of this time spectrum. Due to the way electricity grids and energy markets operate, it is helpful to classify services by both time scale and primary beneficiary.

We conducted a literature review of the myriad energy storage studies and tools developed over the past decade and created a consolidated list of thirteen services that energy storage can provide to various stakeholder groups across the electricity system. The thirteen services provided by energy storage fall into three high-level categories delineated by the stakeholder group receiving the largest benefit: customers, Independent system operators (ISO) / regional transmission organizations (RTO), and utilities. In the following section, we elaborate on the thirteen services and how they fit into each of these three stakeholder categories.

ISO / RTO SERVICES

Energy storage devices are capable of providing a suite of ancillary services that largely benefit ISOs / RTOs and vertically integrated utilities in non-restructured states. These various services are differentiated by the time horizon for which they are needed. For example, frequency regulation is used to correct short-term imbalances between supply and demand, while black start generation units supported by energy storage devices are used rarely, if ever, in emergency situations when the grid at large goes down.

In restructured areas of the U.S., generation, capacity, and ancillary services are traded on wholesale electricity markets. Products and services traded on these markets range from day-ahead energy sales to real-time signals for frequency regulation. In non-restructured areas, vertically integrated utilities conduct a merit order dispatch of generation assets to provide both energy and ancillary services.

FIGURE 1 ENERGY ARBITRAGE & LOAD FOLLOWING SERVICE SUMMARY

ENERGY ARBITRAGE & LOAD FOLLOWING				
Value Range [$/kW-year]	Grid level where value can be captured	Common service definitions	Incumbent technology	Regulatory barriers for behind-the-meter systems?
$3-$97	All	Mid-merit generation, Flexible generation	Thermal generators	Yes

Energy Arbitrage (includes load following)

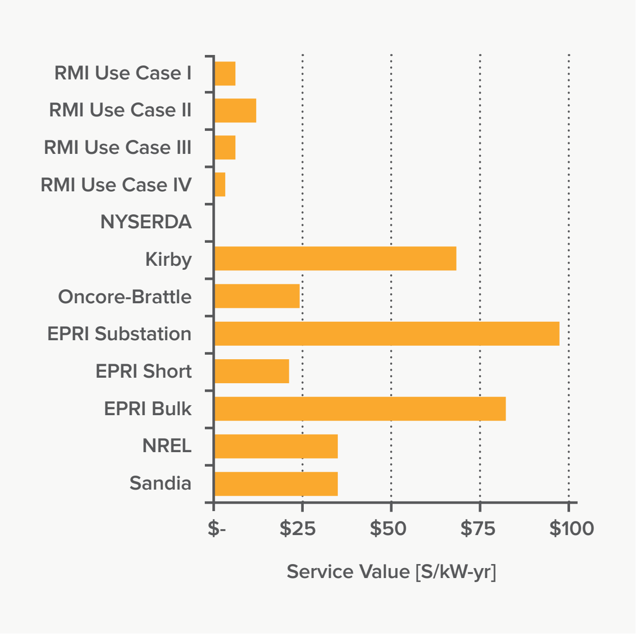
Definition

Load following manages the difference between day-ahead scheduled generator output, actual generator output, and actual demand. Typically, this involves arbitrage of wholesale electricity while the locational marginal price (LMP) of energy is low (typically during night time hours) and selling back to the wholesale market when LMPs are highest.

Background

ISOs / RTOs run a wholesale electricity market where participants place bids to purchase or sell electricity in hourly or sub-hourly intervals using a uniform clearing-price auction mechanism. Generators bid into this market, the ISO or RTO dispatches generators from lowest to highest bids until power demand is met, and all dispatched generators are then paid the bid price of the last unit of electricity needed to meet demand.

Arbitrage can be provided by any generator that has registered with FERC, is connected to the grid, and is able to find a counterparty to a transaction. Revenue from energy arbitrage is based on the difference between low and high wholesale energy prices. Arbitraging wholesale electricity in restructured markets can only be accomplished through on- / off-peak price differentials. Storage deployed in a traditional, non-restructured, vertically integrated utility can capture additional value by optimizing the system for least-cost operation by including such things as power plant start up and shut down costs—an optimization that is generally not fully captured in restructured wholesale markets.



Load following is delivered using a merit-order dispatch approach on the electricity market. The specific market products are varied: some ramp up, others ramp down, and some other emerging load-following products, like the CAISO's flexi-ramp product, reward generators for being able to offer a flexible amount of power over varying time periods in order to decrease the need for frequency regulation.[1]

Energy Storage and Energy Arbitrage (Including Load Following)

Typically, load following is not economically attractive as a standalone application for energy storage. However, since a single energy storage device can deliver a stack of different services, energy storage devices participating in day-ahead wholesale markets to perform arbitrage can also deliver a host of other services during non-committed hours. As such, energy storage deployed for another primary service can profitably provide load-following services after delivering the primary service.

Market calls for load following occur at the sub-fifteen-minute timescale. Because of this, energy storage is particularly well suited for load following due to the technology's fast ramping capability. Traditional thermal power plants providing this service often have sufficient capacity for load following, but they cannot ramp up or down nearly as fast as a battery-based energy storage system providing the same service. Furthermore, energy storage is a very capable mid-merit generation facility since its output can be adjusted throughout the day to respond to load / demand fluctuations with no penalty to efficiency.

FIGURE 2 FREQUENCY REGULATION SERVICE SUMMARY

FREQUENCY REGULATION				
Value Range [$/kW-year]	**Grid level where value can be captured**	**Common service definitions**	**Incumbent technology**	**Regulatory barriers for behind-the-meter systems?**
$28-$204	All	Regulation, Fast frequency response	Thermal generators	Yes

Frequency Regulation

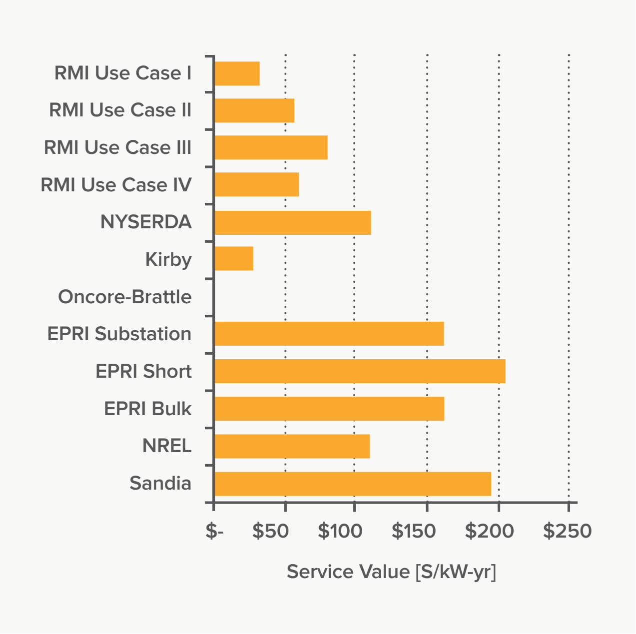
Definition

Regulation ensures that the frequency of the grid is held within an acceptable tolerance band in order to avoid grid instability.

Background

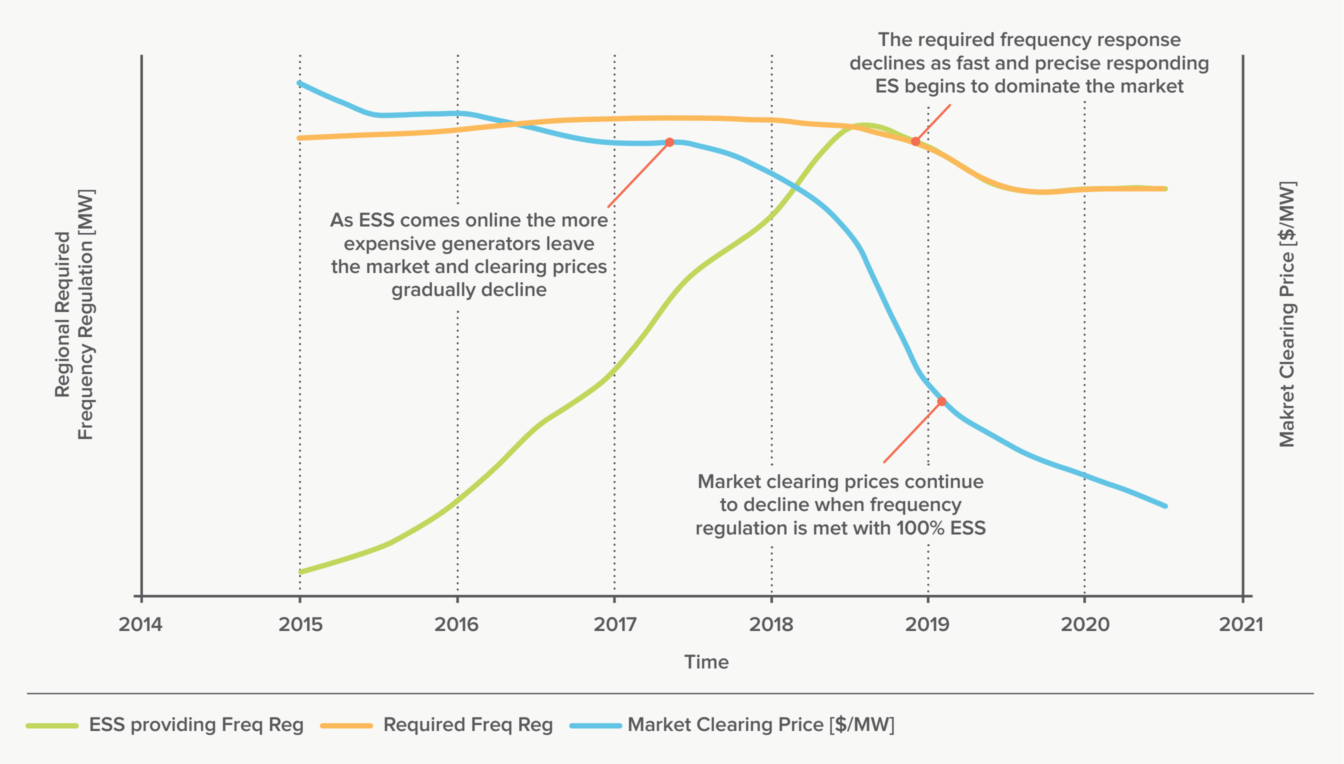
An imbalance between power generation and demand can cause the regional grid frequency to dip below or rise above a nominal value. Grid frequency must be held within a tight tolerance band to avoid grid instability events, such as rolling blackouts caused by generators operating outside of their frequency tolerance.

In restructured areas, frequency regulation is procured through wholesale ancillary service markets. Traditionally, these transactions involved a capacity payment based primarily on the opportunity cost of not participating in the energy market, plus any cost associated with a generator operating below maximum output for regulation up, or above minimum output for regulation down. For many years this compensation mechanism was independent of a resource's speed or accuracy in responding to system imbalances. However, FERC order 755 (Frequency Regulation Compensation Pay-for-Performance) created new rules for compensating frequency regulation resources. This order requires the ISOs and RTOs to compensate regulation providers based on the actual amount of regulation service provided and for that payment to reflect the accuracy and speed of service provision.



While an energy storage device is providing frequency regulation at its rated capacity, it is not able to directly provide other services. However, it can easily split its capacity between regulation and other services. For example, backup power and customer bill management services can still be provided while participating in the regulation market by reserving a portion of battery capacity for each service.

FIGURE 3:
ILLUSTRATIVE EFFECTS OF INCREASING ENERGY STORAGE PENETRATION ON FREQUENCY-REGULATION WHOLESALE-MARKET CLEARING PRICES



Energy Storage and Frequency Regulation

Again, because battery-based energy storage can rapidly ramp its power output up or down, the technology is particularly well suited to ensuring that grid frequency remains within an acceptable range. But thanks to FERC Order 755, energy storage's technical advantage is also financial: the order's requirement that grid service providers be compensated using performance-based metrics dramatically favors batteries and their fast-ramping capability.

This advantage also creates a potential problem for regulation markets everywhere. Because of how capacity payments are currently calculated, market-clearing prices for regulation may collapse when energy storage saturates a market. Currently, generators do not include lost opportunity costs in regulation bids. Instead, the market clearing process automatically assigns an opportunity cost to all participating assets, which allows the unit with the highest opportunity cost to set the market-clearing price. But energy storage has no opportunity cost associated with regulation, and when storage is deployed at scale and able to meet all market calls for regulation, the price could collapse under the current market-clearing mechanism. Figure 3 illustrates this dynamic.

FIGURE 4 SPINNING / NON-SPINNING RESERVES SERVICE SUMMARY

SPINNING/NON-SPINNING RESERVES				
Value Range [$/kW-year]	**Grid level where value can be captured**	**Common service definitions**	**Incumbent technology**	**Regulatory barriers for behind-the-meter systems?**
$1-$65	All	Reserves	Thermal generators	Yes

Spin / Non-Spin Reserves

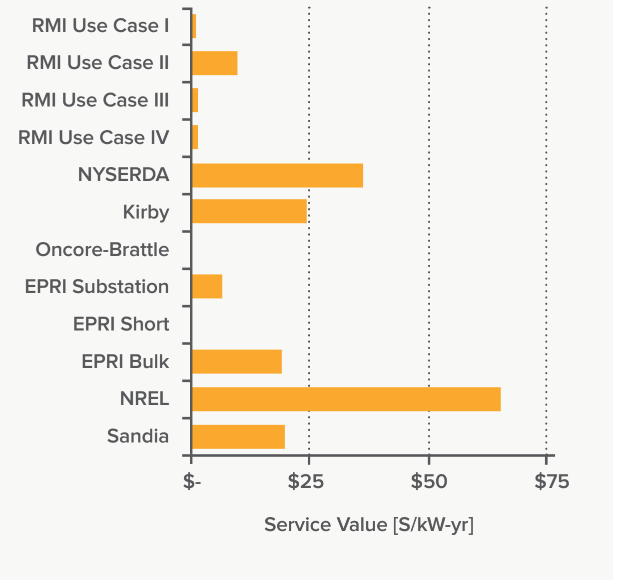
Definition

Spinning and Non Spinning reserves are reserve generating capacity that can be called upon to make up for unplanned capacity losses on the electricity market.

Background

Each system owner/operator registered in the North American Electric Reliability Corporation (NERC) compliance registry is required to maintain reliability and compliance with mandatory standards within their portions of the bulk electricity system. The most significant reliability requirement is the ability to accommodate the outage of the system's largest generator with minimal power and frequency variation. Generator owners that meet loads are able to choose whether they provide their own reserves, enter bilateral contracts, or purchase reserves on wholesale electricity markets. Events that require reserves to be dispatched are very infrequent but crucial for successful operation of the electricity system.

For ISOs and RTOs, reserves are procured through a reserve capacity market where prices reflect a lost opportunity cost and a reserve price offer procured through both a day-ahead and real-time hourly market. Clearing prices are determined for each hour based on a merit order dispatch of the resource's opportunity cost plus the resource's reserve price offer.



Energy Storage and Spin / Non-Spin Reserves

Reserves require a storage device to maintain a minimum discharge duration to meet hourly commitments in case of a contingency event. Since these events are infrequent, energy storage devices can provide reserve capacity while simultaneously providing several other services—so long as they maintain a certain charge level or pay non-compliance fees if they do not respond to a contingency event. This makes energy storage a ripe technology for provision of this particular service.

FIGURE 5 VOLTAGE SUPPORT SERVICE SUMMARY

VOLTAGE SUPPORT				
Value Range [$/kW-year]	**Grid level where value can be captured**	**Common service definitions**	**Incumbent technology**	**Regulatory barriers for behind-the-meter systems?**
$56	All	VoltVar, Reactive power	Thermal generators, capacity banks, load tap changers	Yes

Voltage Support

Definition

In order to ensure reliable and continuous electricity flow, voltage on the transmission and distribution system must be maintained within an acceptable range to ensure that both real and reactive power production and demand are matched.

Background

Voltage Regulation and Volt Ampere Reactive Regulation [Volt/VAR] is required on the electrical grid to maintain acceptable voltages and power factors at all points along transmission lines and on the distribution feeder under all loading conditions. Volt/VAR is also required to support reactive power needs of the bulk power system in the event of system emergencies. Generators are required to operate within a specific power-factor band and have been the primary providers of voltage support historically. Variation in Volt/VAR is managed through capacitor banks, load tap changers, and static VAR compensators. Currently, no market exists for Volt/Var provision and this service is procured through annual contracts and compensated at cost-of-service rate.[2]

Energy Storage and Voltage Support

Energy storage is well suited to provide distributed Volt/VAR support close to the point on the system where it is needed. Reactive power cannot be transmitted long distances efficiently, and power electronics providers are enabling distributed storage to supply reactive power more efficiently than traditional approaches to Volt/VAR in both regulated and deregulated markets.

Generally speaking, for battery-based energy storage to provide voltage support, it must be available within a few seconds and have the capacity to provide services for several minutes up to as long as one hour. Technically, a device providing voltage support can provide other ancillary services—provided that dispatch needs do not cause operational conflicts.

FIGURE 6 BLACK START SERVICE SUMMARY

BLACK START				
Value Range [$/kW-year]	Grid level where value can be captured	Common service definitions	Incumbent technology	Regulatory barriers for behind-the-meter systems?
$6	Transmission, Distribution, some BTM locations		Diesel GenSet	Yes

Black Start

Definition

In the event of a grid outage, black start generation assets restore operation to larger power stations in order to bring the regional grid back online.

Background

Generators of all sizes rely on the grid to “start up” a generation unit until the generator can run on its own power. However, in the event of a grid outage, many thermal power plants are unable to operate because the grid cannot provide power for the unit to come online in the first place. Accordingly, black start units (typically diesel gensets located on-site at thermal power plants) are run in emergency situations and used to start up larger units in order to help the grid come back online as a whole. Black start capability is compensated with a standard black start rate or a cost-of-service rate, depending on the ISO / RTO.

Energy Storage and Black Start

Grid operators create restoration plans to follow in the event of a widespread grid outage. These plans specify which units will come online and in what order. As part of these plans, energy storage systems can be colocated with power plants and provide black start support, just as diesel gensets do now. Systems located at these stations would be called upon very rarely, leaving black start-focused, colocated energy storage systems at the transmission level available to provide any number of other grid services.

However, energy storage systems could also be deployed at the distribution level (or even behind the meter, in some cases) and still be included in a grid operator’s restoration plan. This is because not all generators have black start emergency units colocated at the facilities themselves. Instead, grid operators create “cranking paths” from black start units to larger generation facilities with no on-site black start units. These paths are portions of the grid that can be isolated and energized to deliver power from a battery or other generator to help start up larger units when the grid is down. If one or several large commercial or industrial customers tied into the grid at any level had an energy storage system that coincided with the grid operator’s defined cranking path, those devices could provide black start capability for generating units along that same path.

UTILITY AND GRID OPERATOR SERVICES

Utility and grid operator services generally fall into two categories. The first set of services—**transmission and distribution system upgrade deferral**, focus on using investments in energy efficiency and distributed energy resources to defer large investments in infrastructure (typically at the distribution-level). On the distribution side, upgrades are normally driven by peak demand events that occur one to ten times per year, while transmission upgrades are driven mostly by large new interconnection requests. Deferring large investments with incremental amounts of energy storage to deal with these limited time-duration events at the distribution level can free up capital to be deployed elsewhere and avoid "over-sizing" the electricity grid in the face of uncertain demand growth. This dynamic is illustrated in Figure 7, where a distribution system's load is projected to exceed a system's rated capacity during a certain time of the day. Energy storage can be used to shave off the "peak" of the projected system load and avoid exceeding the capacity of the system.

The second set of capacity / deferral services revolve around **resource adequacy and transmission congestion relief**. These services are needed to meet system peaking requirements on a day-to-day basis and can be cost effectively performed by energy storage, as described below.

FIGURE 7:
TYPICAL HOURLY LOAD BEFORE AND AFTER ENERGY STORAGE IS DEPLOYED FOR UPGRADE DEFERRAL

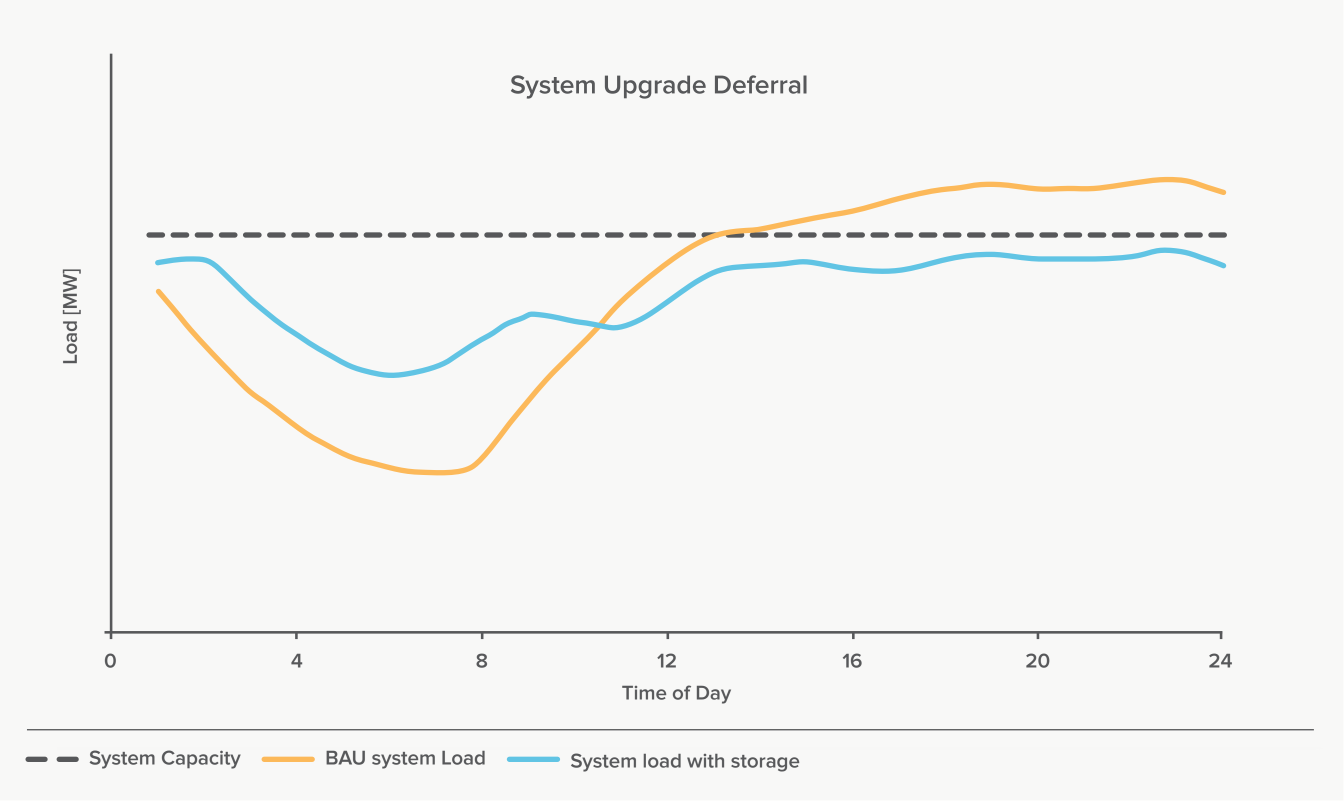


FIGURE 8 RESOURCE ADEQUACY SERVICE SUMMARY

RESOURCE ADEQUACY				
Value Range [$/kW-year]	**Grid level where value can be captured**	**Common service definitions**	**Incumbent technology**	**Regulatory barriers for behind-the-meter systems?**
$65-$155	All	Forward capacity, Reliability	All generators	Yes

Resource Adequacy (Includes Forward Capacity)

Definition

Instead of investing in new natural gas combustion turbines to meet future peak generation requirements during peak hours, grid operators and utilities can pay for other assets, including energy storage, to incrementally defer or reduce the need for such investment.

Background

In many places around the U.S., natural gas peaking plants are needed to meet system-wide peak demand. For the past decade, utilities and grid operators have increasingly turned towards natural gas combustion turbines to provide this peak capacity. However, depending on the characteristics of the electricity system in question, other peaking resources can also be used to ensure demand is met, including other types of centralized generation, distributed generation, demand response, energy storage, and energy efficiency.

To procure peaking electricity capacity in ERCOT, which does not have a dedicated capacity market, generation capacity costs are included in wholesale energy prices, which are allowed to skyrocket during scarcity events in order to allow peaking resources to recover their fixed costs. In other markets, like CAISO, market mechanisms allow for capacity-related payments where the price is set according to the cost of new entry for new generating assets.

Energy Storage and Resource Adequacy

Energy storage systems can be effectively used to meet peak electricity demand events. When energy storage participates in these markets, it typically pulls down the market-clearing price and can defer investment in combustion turbines in the future. Furthermore, given the modular nature of energy storage when compared to natural gas power plants, just the right amount of energy storage can be procured using capacity payments to ensure that system peaks are met. Advanced Microgrid Systems, for example, recently won a portion of Southern California Edison's (SCE) 250 MW energy storage procurement[3]. AMS will own and operate 50 MW of behind-the-meter storage on behalf of SCE to provide resource adequacy for SCE where and when it is needed.

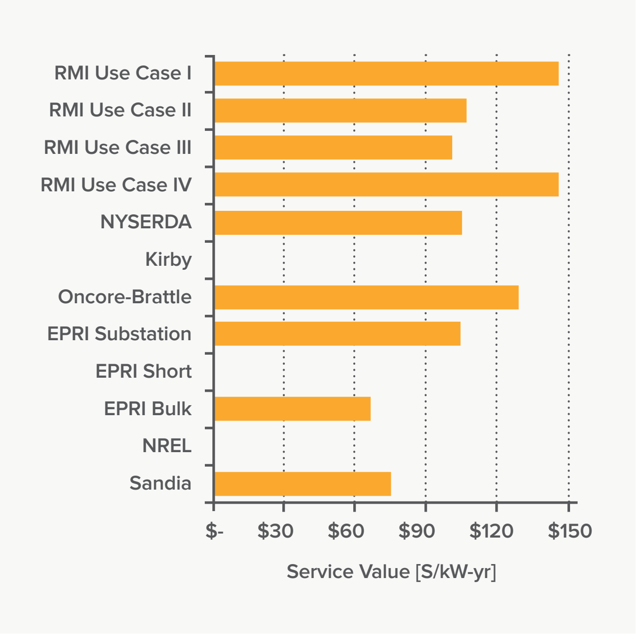


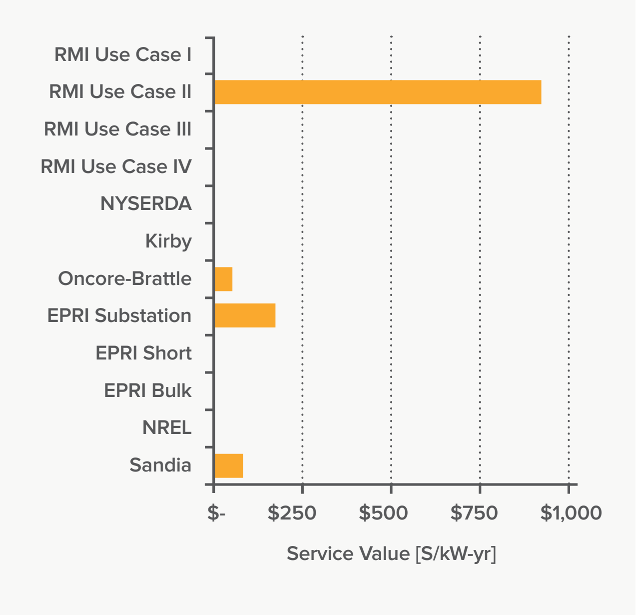
FIGURE 9 T&D UPGRADE DEFERRAL SERVICE SUMMARY

TRANSMISSION & DISTRIBUTION UPGRADE DEFERRAL				
Value Range [$/kW-year]	**Grid level where value can be captured**	**Common service definitions**	**Incumbent technology**	**Regulatory barriers for behind-the-meter systems?**
$51-$900	All	T&D upgrade deferral	Substations, transformers, other equipment	Yes

Distribution Deferral and Transmission Deferral

Definition

Delaying or entirely avoiding utility investments in transmission and distribution system upgrades that are necessary to meet future load growth on specific regions of the grid.



Background

When peak demand at a transmission or distribution node is at or near its rated load-carrying capacity and load growth forecasts indicate that the system may soon be overloaded, utilities invest in system upgrades to meet the forecasted load growth. These upgrades are normally driven by a small number of peak hours throughout the year that cause load to exceed the system capacity of certain equipment. Such upgrades generally increase the carrying capacity of a distribution substation by 25–50%, even though the near-term load growth forcing the upgrade only exceeds existing substation capacity by 1–3%.

Energy Storage and Distribution Deferral / Transmission Deferral

Instead of investing a large, lump sum to upgrade a transmission- or distribution-level substation, utilities can defer or completely avoid this investment by procuring or controlling incremental amounts of other technologies, including energy efficiency, photovoltaics, diesel gensets, and battery-based energy storage devices. Energy storage is especially well suited for this service. Batteries can be readily called upon (either through direct utility control, a smartly designed rate, or a market signal) for the few hours each year when the existing substation may be overloaded. Furthermore, instead of upgrading a 10 MW substation to an oversized 15 MW substation, as is normally done, a utility can procure the "right" amount of storage to meet load forecasts. And since the battery will only be called upon for some 20–60 hours each year to actually alleviate load on the substation, that means that the battery is able to deliver other services to the grid upwards of 99% of the time.

Upgrade deferral is, by definition, highly location-specific. The value of deferral varies dramatically depending on the condition and age of the transmission or distribution system, the prevailing load profile, and load forecasts. However, deferring upgrades is one of the more valuable services that an energy storage system can provide. Deferral benefits are based on the relevant utility's carrying charge (financial costs, taxes, and insurance) of the avoided equipment upgrade and are typically paid out over one to three years. The relative benefit of an upgrade deferral decreases as more storage is deployed in the area.

FIGURE 10 TRANSMISSION CONGESTION RELIEF SERVICE SUMMARY

TRANSMISSION CONGESTION RELIEF				
Value Range [$/kW-year]	Grid level where value can be captured	Common service definitions	Incumbent technology	Regulatory barriers for behind-the-meter systems?
$10-$12	All		Distributed generation, transmission lines	Yes

Transmission Congestion Relief

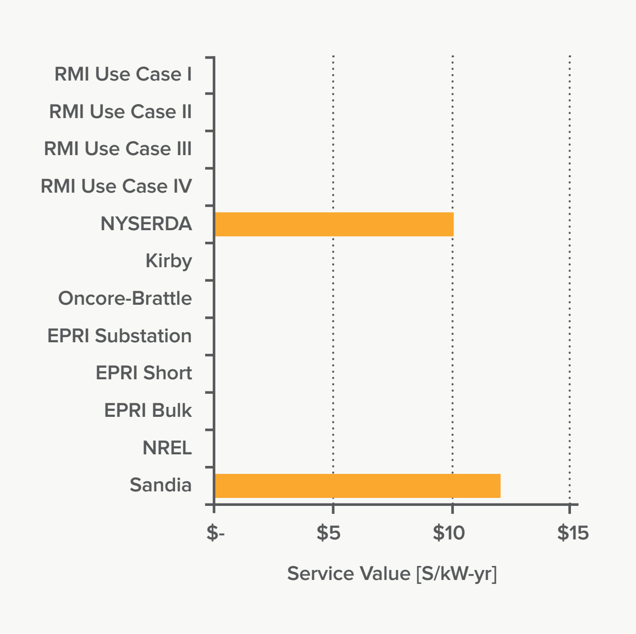
Definition

ISOs charge utilities for usage of congested transmission corridors during certain times of the day. Assets including energy storage can be deployed downstream of congested transmission corridors, discharge during congested periods, and decongest the transmission system in order for utilities and grid operators to avoid these charges.

Background

Transmission congestion occurs when there is insufficient transmission capacity to meet calls for power at the transmission level. When transmission congestion occurs, generators must be re-dispatched to alleviate congestion. The operating profile of these re-dispatched generators is less efficient than the non-constrained optimal economic dispatch. Accordingly, they generate higher-cost electricity to meet load that, in the absence of transmission congestion, would be served by a set of lower-cost resources.

Congestion manifests as increased production costs for vertically integrated utilities. In most restructured U.S. electricity markets, the cost of congestion is the difference between an increased LMP on one side of the congested corridor and a decreased LMP on the other, weighted by the amount of energy moving across the congested path.



Energy Storage and Transmission Congestion Relief

Energy storage can be used to mitigate transmission congestion when it is placed downstream of the point of congestion. Energy storage avoids real-time power transfer through a congested transmission node by storing power down stream of the congestion point during non-congested periods and dispatching that electricity during periods of congestion.

As with the other deferral and capacity-based services, energy storage devices cannot monetize this service everywhere since transmission congestion events only occur during periods of peak demand at locations with transmission capacity constraints. However, when transmission congestion is an issue and storage is deployed to solve it, storage can easily provide other services outside of the easy-to-predict congested periods.

Customer-focused services

These services provide direct monetary savings to end users. Accordingly, the value created by these services can only be captured when storage is deployed behind the meter.

Interestingly, even though the monetary value of these services flows directly to the behind-the-meter customer, the provision of these services creates benefits for ISOs / RTOs and utilities / grid operators. This is because, when energy storage maximizes on-site consumption of distributed solar PV, generates savings by optimizing load against a time of use rate, or reduces a building's peak demand charge, it is effectively smoothing the load profile of the building where it is located. A smoother, less peaky load profile is much easier and less costly to match up with centralized generating assets. Because of this, buildings with more uniform load profiles are actually capable of generating some level of value for several of the services already discussed in this report—even if customers are the only ones directly monetizing benefits under current rates and utility business models.[i]

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[i] *Load following, regulation, spinning / non spinning reserves, generation capacity, distribution upgrade deferral, transmission congestion relief, and transmission upgrade deferral.*

FIGURE 11 TOU BILL MANAGEMENT SERVICE SUMMARY

TIME-OF-USE BILL MANAGEMENT				
Value Range [$/kW-year]	Grid level where value can be captured	Common service definitions	Incumbent technology	Regulatory barriers for behind-the-meter systems?
$23-$230	BTM	TOU, Energy Shift	Energy storage, controllable loads	No

Time-of-Use Bill Management

Definition

By minimizing electricity purchases during peak electricity consumption hours when time-of-use (TOU) rates make electricity more expensive, behind-the-meter customers can reduce their bill.

Background

Many utilities are implementing time-of use-retail rates as a means to more accurately match a customers bill with the real cost of generation. TOU rates are generally structured as peak, partial-peak and off-peak time periods, where the time blocks differ in winter and summer based on the system load profile during these periods. This rate structure allows the utility to send a price signal to the customer that flattens the system's load profile and lowers overall production costs.

Energy Storage and Time-of-Use Bill Management

The goal of TOU rates is to shift a customer's demand from peak to off-peak periods. This can be done with simple behavior changes or smart controls. However, energy storage can accomplish the same goal without the need for behavioral changes by pre-charging during off-peak hours and discharging to meet customer load during peak periods. Furthermore, an energy storage system used for TOU bill management will be idle for a large portion of the day and therefore available to collect revenue from other grid services.

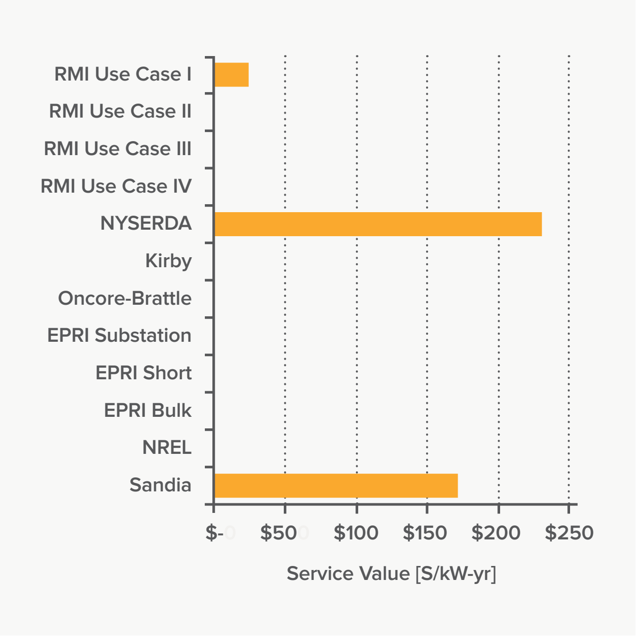


FIGURE 12:
EXAMPLE RESIDENTIAL HOURLY LOAD AND TIME-OF-USE RETAIL ELECTRICITY RATES

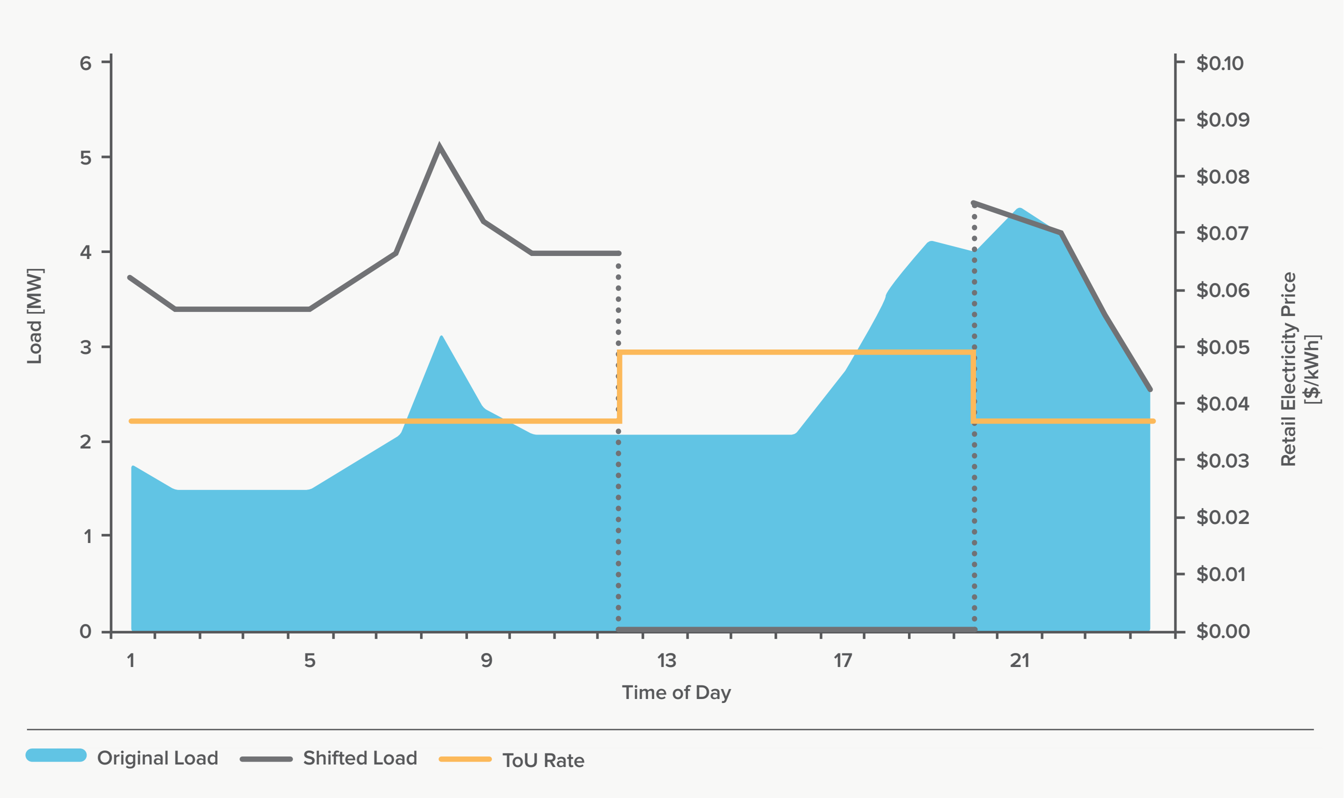


Figure 12 illustrates how time of use rates can change over the course of a day and how energy storage can shift a typical load (light blue area) to a different load profile (grey line) in order to avoid purchasing energy when it is expensive under the time of use rate.

FIGURE 13 SELF-CONSUMPTION OPTIMIZATION SERVICE SUMMARY

SELF CONSUMPTION OPTIMIZATION				
Value Range [$/kW-year]	Grid level where value can be captured	Common service definitions	Incumbent technology	Regulatory barriers for behind-the-meter systems?
$10-$51	BTM	On-site consumption	Distributed generation	No

Increased PV Self-Consumption

Definition

Minimizing the export of electricity generated by distributed PV systems to maximize the financial benefit of distributed PV in utility areas with rate structures unfavorable the export of excess PV generation.

Background

In places where net energy metering (NEM) is not offered, customers can opt to use energy storage or other methods to maximize self consumption of electricity generated by distributed solar systems. By maximizing on-site consumption of solar energy in non-NEM markets, each unit of energy generated and used on-site can be effectively valued at the retail rate of electricity—in many cases greatly enhancing the value of the solar system. Self-consumption has become a major trend in Germany and Australia, places where feed-in-tariff levels for residential PV customers have plummeted well below the retail rate, incentivizing customers to maximize the amount of PV they consume on-site.

Energy Storage and Increased PV Self-Consumption

Energy storage is the primary method being used by developers today to maximize solar self-consumption, even though many other methods exist, including smart controls, thermal storage using electric hot-water heaters, and dynamic electric-vehicle charging. As an example, the Hawaii Public Utility Commission recently considered a proposal from the Hawaiian Electric Utility Company (HECO) to replace NEM with a self-consumption tariff for all new rooftop PV customers. The self-consumption tariff would still credit customers at the retail rate for all kilowatt-hours consumed on site, but any exported energy from the solar system would only be credited at an avoided fuel cost. Another non-export tariff was also recently proposed in Hawaii. The proposed non-export tariff would not credit any exported PV generation at all. As illustrated in Figure 14 (on page 18), using energy storage to move as much of a building's load under a solar production curve as possible dramatically increases the value generated by a customer under either of these proposed rate structures.

FIGURE 14: RESIDENTIAL LOAD AND PV PRODUCTION BEFORE AND AFTER ENERGY STORAGE IS DEPLOYED

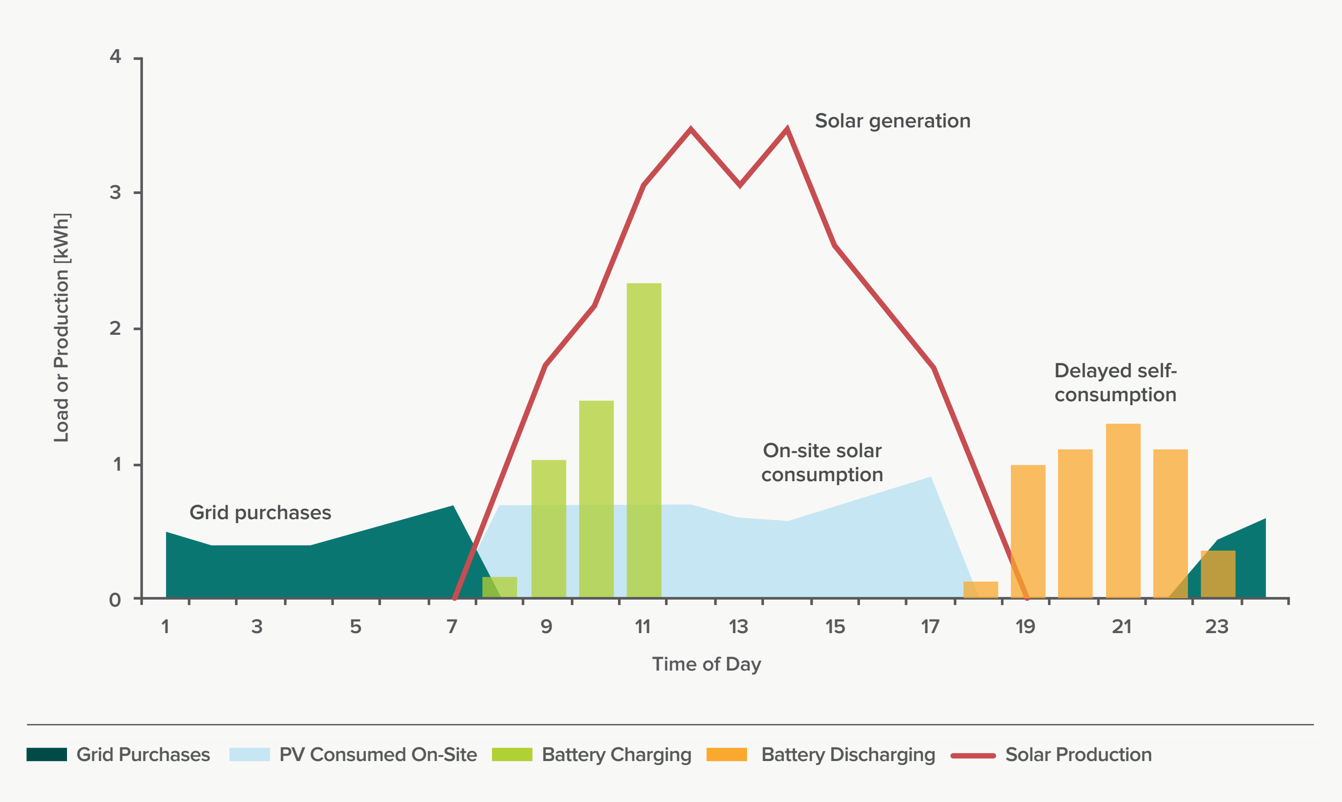
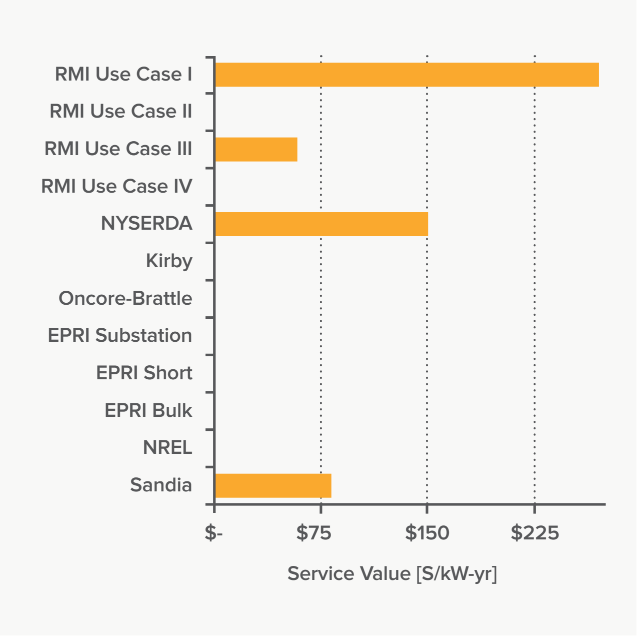


FIGURE 15 DEMAND CHARGE REDUCTION SERVICE SUMMARY

DEMAND CHARGE REDUCTION				
Value Range [$/kW-year]	**Grid level where value can be captured**	**Common service definitions**	**Incumbent technology**	**Regulatory barriers for behind-the-meter systems?**
$58-$269	BTM		Demand response, Controllable loads	No



Demand Charge Reduction

Definition

Commercial and residential customers can reduce power draw from the grid during specific time periods in order to reduce the demand charge component of electricity bills.

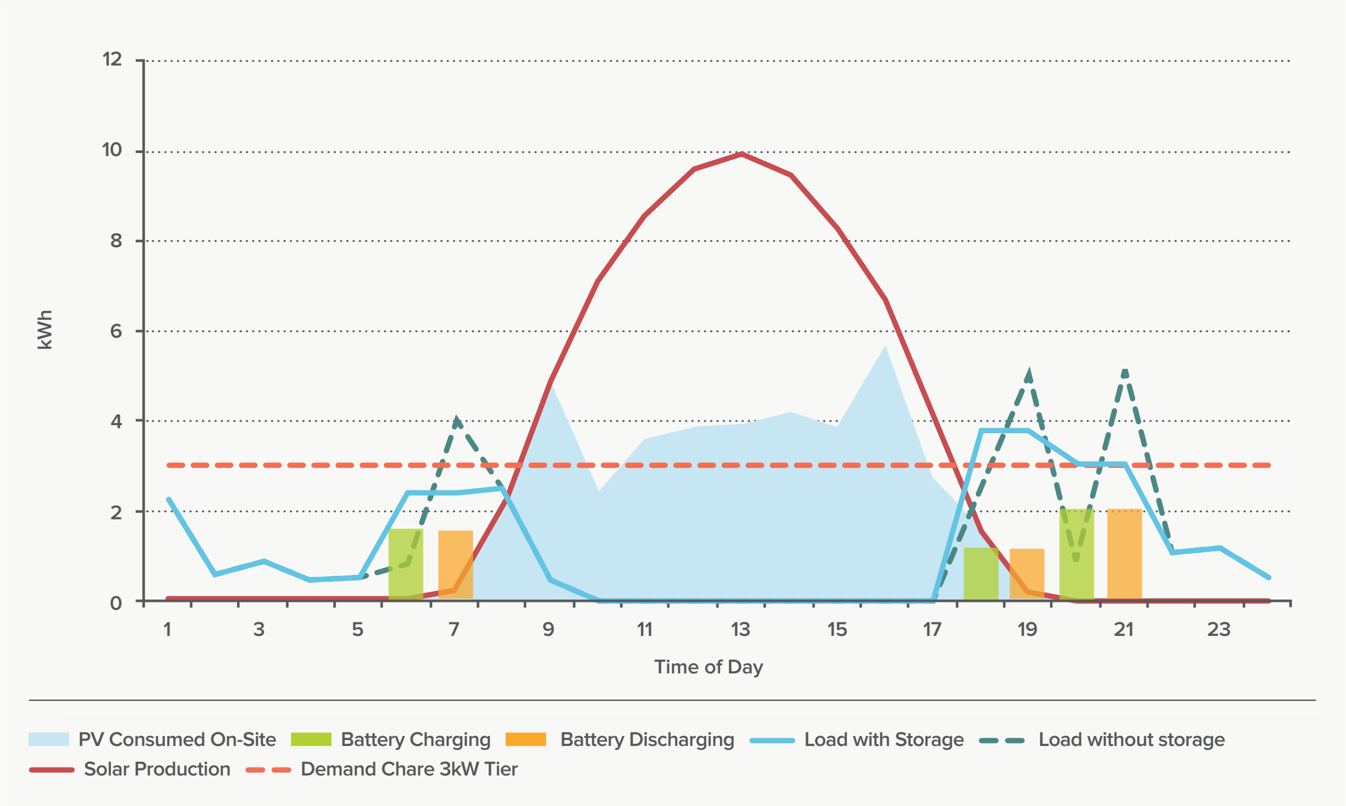
Background

Depending on the utility and rate structure, demand charges can account for over half of a commercial customer's monthly electricity costs. Furthermore, demand charges currently exist for some residential customers and a growing number of utilities are considering implementing demand charges in order to curb annual peak electricity demand growth. Many distributed energy resource developers are pursuing different approaches to help customers reduce their demand charges using a suite of different technologies, including advanced controls, distributed PV, targeted energy-efficiency measures, and energy storage.

Energy Storage and Demand Charge Reduction

Since battery-based energy storage can be reliably called upon at key times throughout the day, it is a very dependable approach to managing peak building loads and reducing demand charges. Depending on the utility, demand charges can be set based on time intervals as low as the highest 15-minute demand period of the month. Other distributed energy resources, like solar PV or smart controls, can be used to minimize demand charges as well and at a lower cost, but because of the time sensitive-nature of peak demand and the potential for intermittent generation to drop out, an energy storage system is able to reduce peak demand more reliably than other approaches. Figure 16 (on page 20) illustrates how energy storage performs this service. The building's metered load (dotted green line) originally exceeded 5 kW. By using energy storage to reduce the peaks of the building's load to less than 4 kW the demand charge is reduced by roughly 20%.

FIGURE 16: SAMPLE HOURLY LOAD DATA BEFORE AND AFTER ENERGY STORAGE IS DEPLOYED FOR DEMAND CHARGE REDUCTION.



New business models focused on electric vehicles with bi-directional chargers to provide demand charge reduction for commercial buildings are also being explored to provide this same service. As discussed in a recent NREL report,[4] periods of peak demand for commercial buildings are generally aligned with the periods when vehicles are parked at the workplace. Electric vehicles are currently a more cost-effective approach to demand charge reduction than stationary storage, and as little as 30 minutes of storage can provide sufficient power to reduce demand charges—thereby ensuring that electric vehicles have sufficient charge remaining to be driven away at the end of the day.[5]

Backup Power

Definition

In the event of a grid outage, energy storage can provide backup power at multiple scales ranging from sub-second-level power quality for industrial operations to diurnal backup when paired with onsite PV.

Background

The ability to keep power flowing during a grid failure is an immensely valuable service to customers of all types connected to the electricity grid. For large industrial customers, even the smallest variation in power quality resulting from grid instability can cost millions of dollars in lost productivity. During Superstorm Sandy, 8.5 million people were without power for days—or weeks in some cases—causing untold economic disruption. This service has long been valued and provided to different customers by many technologies, most prominently by on-site diesel gensets.

Energy Storage and Backup Power

Battery-based energy storage technologies and chemistries have evolved to a point where they can deliver reliable backup power at a price point well below that of diesel gensets when paired with a renewable generator.[6] Furthermore, battery-based storage is flexible enough to easily deliver specific power demands, depending on the characteristics of the load, which explains why high-power applications have been deployed alongside fuel cells and other distributed energy resources to support the loads of power-sensitive facilities like data centers. Energy-focused storage applications can also be deployed at a competitive price point due to the evolution of lower-cost non-lithium ion chemistries and their current use in microgrids across the globe.

TECHNICAL APPENDIX B

USE CASE ASSUMPTIONS AND DISPATCH RESULTS

TECHNICAL APPENDIX B: USE CASE ASSUMPTIONS AND DISPATCH RESULTS

IN ALL USE cases we assume a third-party ownership model subject to the following capital structure and capital costs.

Third-party ownership model assumptions:
- 6.77% Real WACC
- 20-year, modified straight-line depreciation
- 20-year financial life
- Battery replacements at a cost of $200/kWh in year 7 and $150/kWh in year 14
- Federal ITC captured on eligible systems

Commercial system capital costs:
- $500 / kWh
- $1,036 / kW
- Residential system capital costs:
- $500 / kWh
- $1,151 / kW

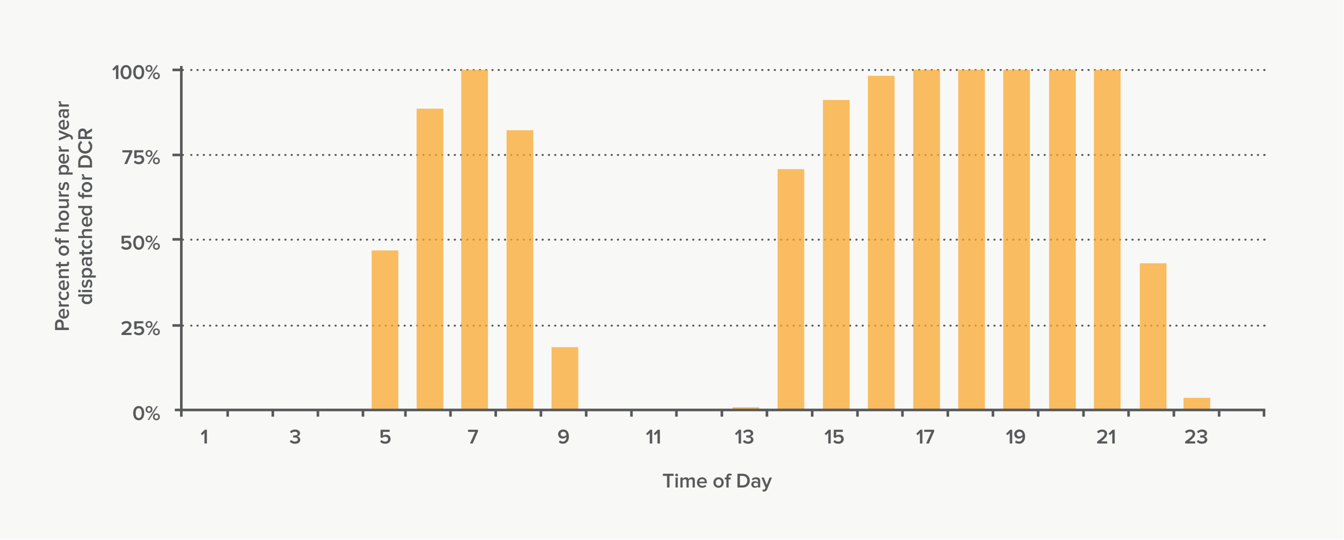
In the following section, we report scenario-specific assumptions around wholesale market prices, primary service storage dispatch results, and electricity tariff structure detail.

USE CASE 1 *Commercial Demand-Charge Management in San Francisco*

As a simplification from a true hourly dispatch model we used historic market clearing price data for the CAISO market in 2014 to estimate the average payment ancillary service providers would receive for a single hour of service provision depending on the time of day the service was provided. The capacity needed for a particular ancillary service fluctuates throughout the year as a result of seasonal variation in loads and generation capacity leading to seasonally varying market-clearing prices. We capture this seasonal variability by averaging the hourly market-clearing price from a sample of representative days throughout the year. Additionally, there is significant variation of clearing prices throughout the day. In the model the ancillary service value is segmented into three representative daily time blocks: morning (hours 1–8), mid day (hours 9–16), and evening (hours 17–24).

These time blocks are used to determine the compensation a battery or fleet of batteries receives for providing services as a function of the time when they are provided. Figure 17 shows the fraction of hours throughout the year when the system is charging or discharging for demand charge reduction.

FIGURE 17 FRACTIONAL HOURS OF THE YEAR A BATTERY IS DISPATCHED (CHARGING AND DISCHARGING) FOR COMMERCIAL DEMAND-CHARGE REDUCTION



For the remaining hours, when the system is not dispatched for demand charge reduction, it is able to provide other grid services. The revenues collected for ancillary services are calculated using average hourly CAISO market-clearing prices for regulation and spin / non-spin services. Resource adequacy payments are based on an assumed cost of new entry (CONE) of $145/kw-yr. Finally, load following and energy arbitrage revenues are calculated using $/kw-yr values as reported in the body of this work.

The revenues collected for ancillary services are calculated using time-dependent market-clearing prices for regulation, spin / non-spin services, and the time of day those services are provided. Figure 18 shows the hourly fluctuation in market-clearing price throughout the day. Figure 19 shows the time-blocked market-clearing price used in the dispatch model.

FIGURE 18 AVERAGE ANCILLARY SERVICE MARKET CLEARING PRICE IN NYISO (2014)

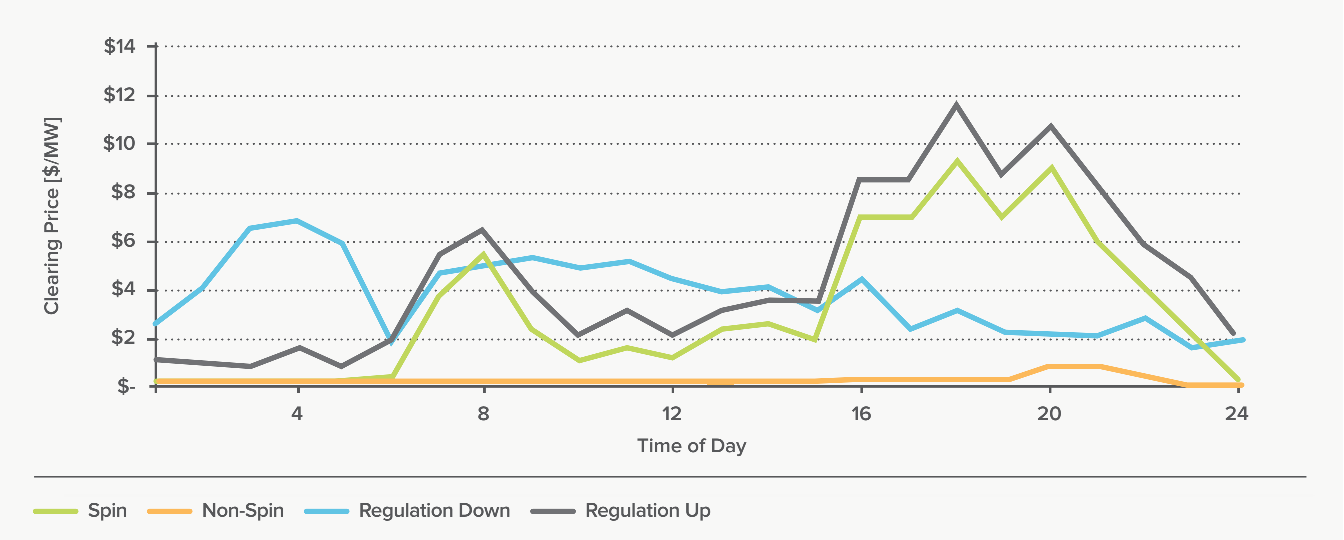
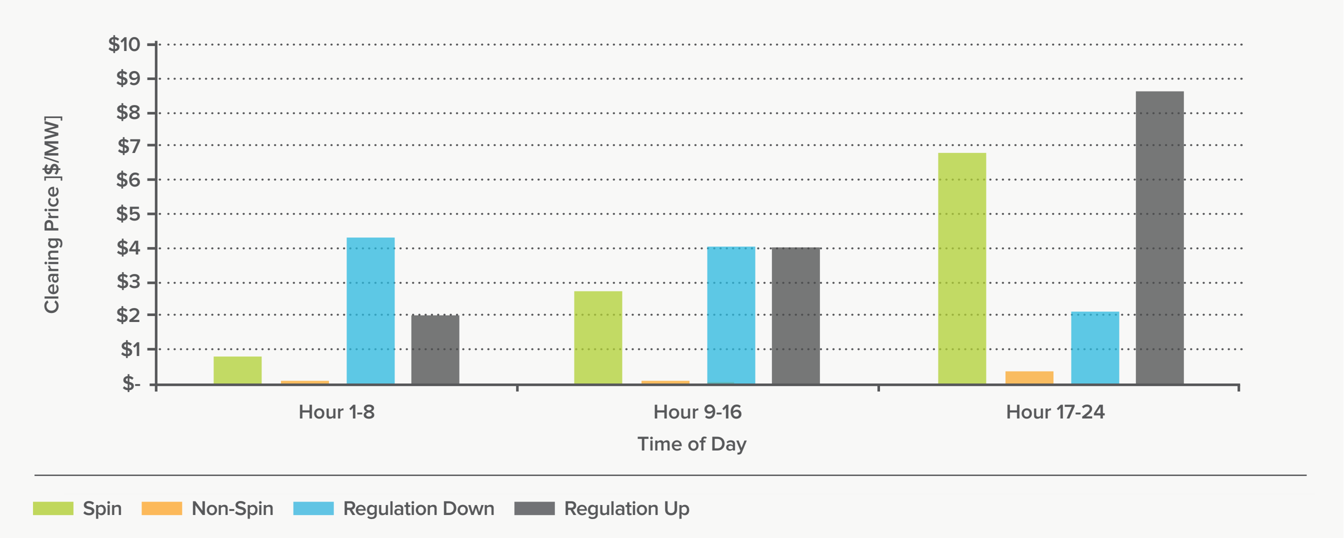


FIGURE 19 TIME-SEGMENTED ANCILLARY SERVICE PRICES USED IN THE SIMPLIFIED DISPATCH MODEL



USE CASE 2 *Distribution Upgrade Deferral in New York*

Figure 20 shows the hourly fluctuation in market-clearing price throughout the day for NYISO in 2014. Figure 21 shows the time-blocked market-clearing price used in the dispatch model.

We use the same methodology for calculating ancillary-service compensation as was used in Use Case 1. Resource adequacy payments are based on monthly Installed Capacity Market [ICAP] market-clearing prices in 2014 for winter and summer months. Finally, load following, black start, and energy arbitrage revenues are calculated using $/kw-yr values as summarized in the body of this report.

FIGURE 20 AVERAGE ANCILLARY SERVICE MARKET CLEARING PRICE IN NYISO (2014)

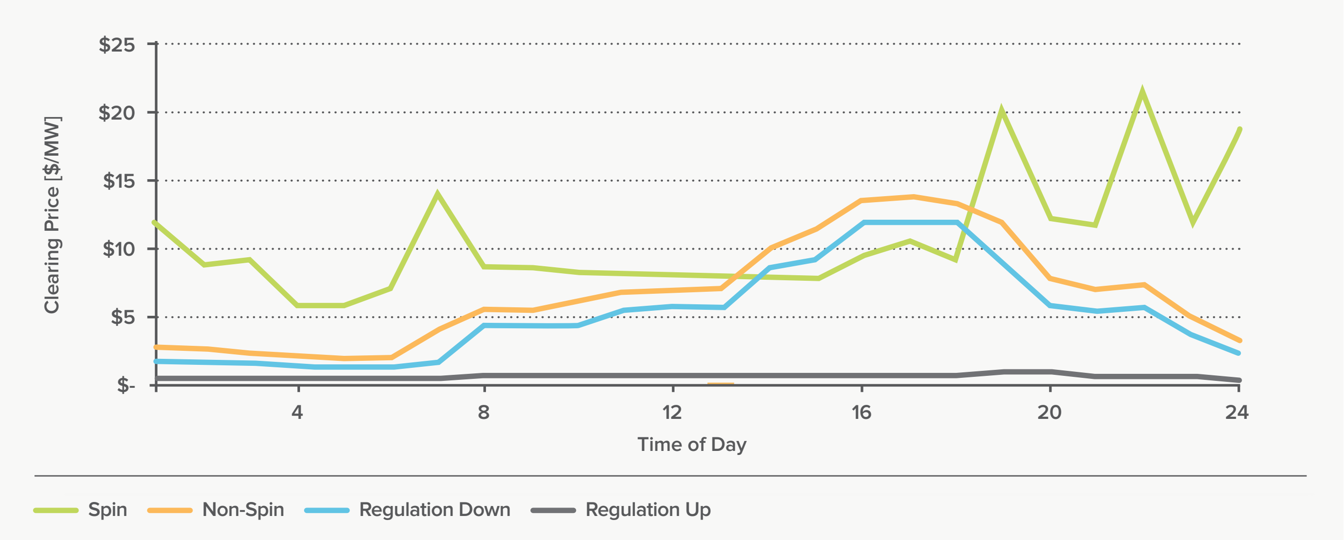
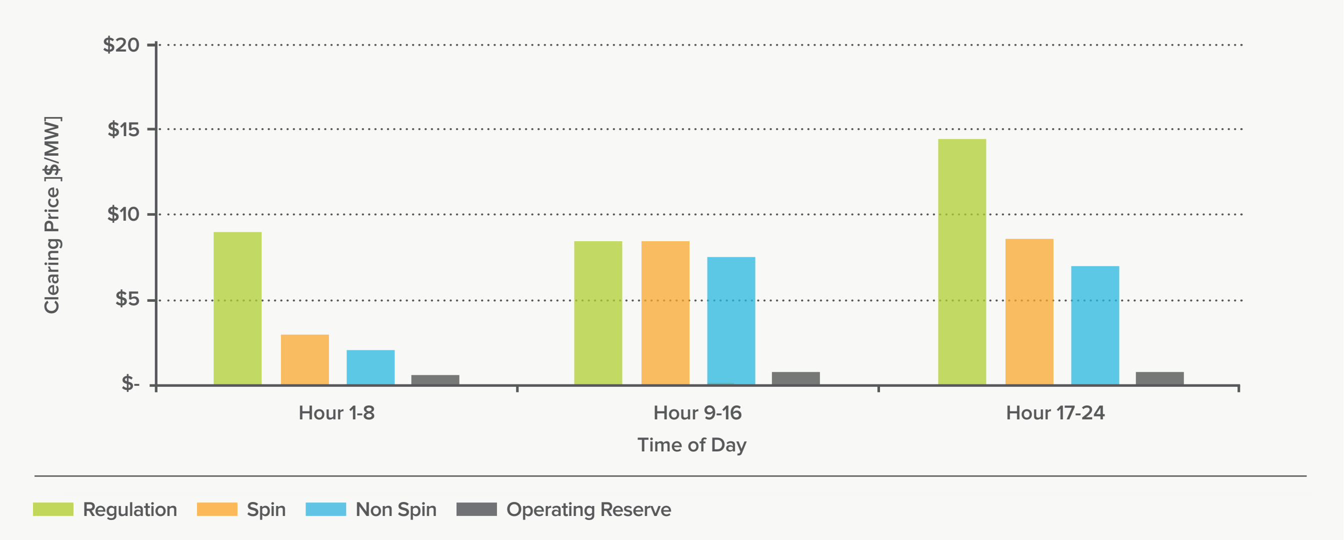


FIGURE 21 TIME SEGMENTED ANCILLARY SERVICE PRICES USED IN THE SIMPLIFIED DISPATCH MODEL



USE CASE 3 —*Residential Bill Management in Phoenix*

In this scenario a 4 kW system with one hour of discharge capacity is used to shift peak demands to times of lower demand. The model analyzes an 8,760-hour (full-year) hourly load profile and shifts the top 5 peak hours per day. Figure 22 shows the percentage of the time during which the battery system is charging or discharging for demand charge reduction. The hours when the system is not being dispatched to demand charge reduction, or has additional capacity, it is dispatched to provide other ancillary services.

Given the lack of available prices on ancillary services in Arizona, the revenues collected for ancillary services are calculated using average hourly CAISO market-clearing prices for regulation and spin / non-spin services. Resource adequacy payments are based on an assumed CONE of $145/kw-yr. Market-clearing price data and methodology is the same as discussed for Use Case 1. Finally, load following and energy arbitrage revenues are calculated using $/kw-yr values as reported in the body of this report.

The value of demand charge reduction and time of use management is calculated based on the annual electricity bill before and after energy storage is dispatched for bill management. We use the Salt River Project proposed E-27 customer generation price plan for residential service, as summarized below. Figure 23 shows the summer and winter TOU rate on the left axis and the demand charge tiers on the right access.

Salt River Project E-27 Rate Details

Fixed Charge of $32.41 /month

Demand Charge

- First 3 kW: $13.33/kW
- Next 7 kW: $12.07/kW
- Exceeding 10 kW: $22.98/kW

Energy Charge

- Winter: $0.043/kWh (On-Peak) / $0.039 (Off-Peak)
- Summer Peak: $0.063/kWh (On-Peak) / $0.042 (Off-Peak)
- Summer: $0.048/kWh (On-Peak) / $0.037 (Off-Peak)

FIGURE 22 FRACTIONAL HOURS OF THE YEAR A BATTERY IS DISPATCHED (CHARGING AND DISCHARGING) FOR RESIDENTIAL DEMAND CHARGE REDUCTION

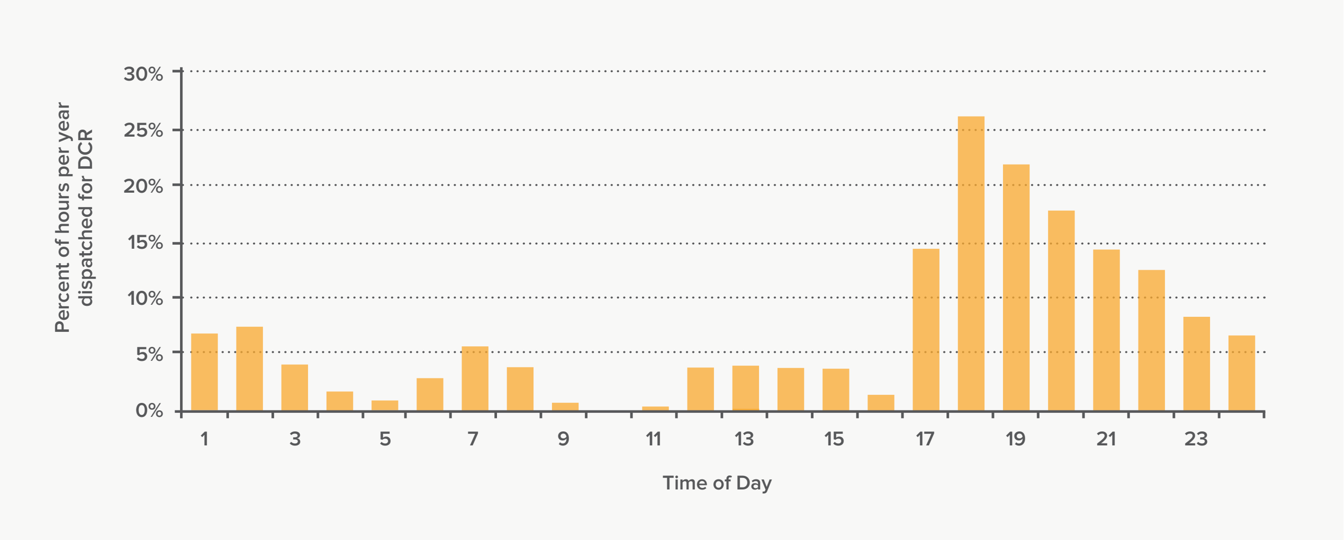
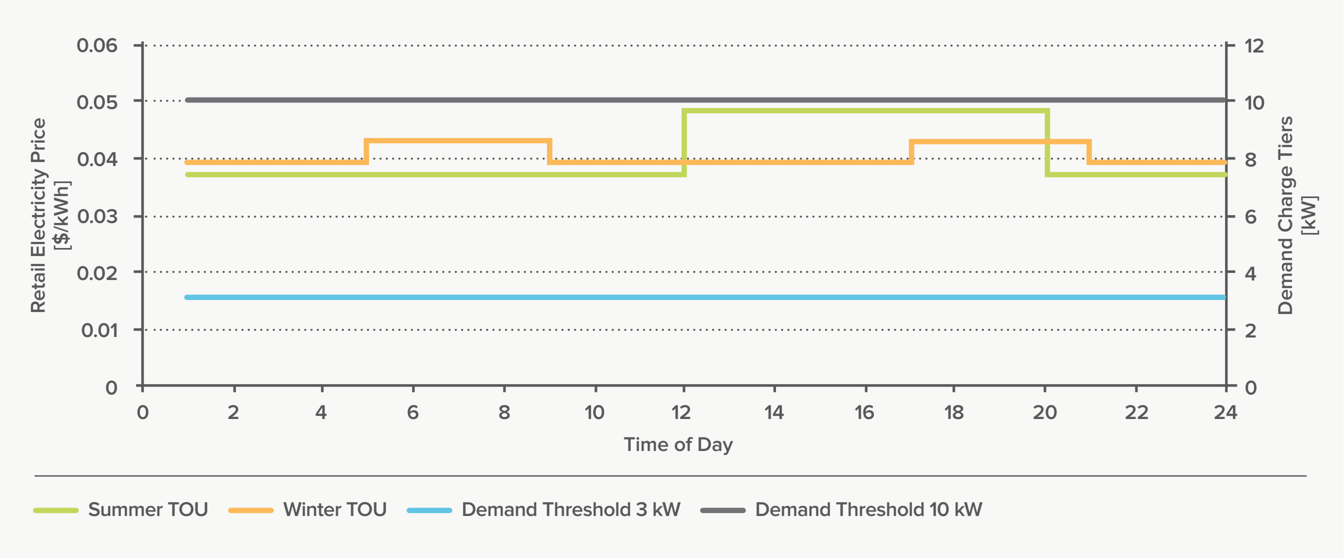


FIGURE 23 SALT RIVER PROJECT E-27 TARIFF STRUCTURE



USE CASE 4 *—Solar Self-Consumption in San Francisco*

In this scenario, a 5 kW system with one hour of discharge capacity is used to shift load from times of no or low solar production to times of excess solar production. The model analyzes an 8,760-hour (full-year) hourly load and PV production profile to determine when the battery charges and discharges. Figure 24 (on page 28) shows shows the percentage of the time during which the battery system is charging or discharging for self-consumption. The hours when the system is not being dispatched to demand charge reduction, or has additional capacity, it is dispatched to provide other ancillary services.

The value of energy storage for increased self-consumption is calculated based on the annual electricity bill before and after energy storage is dispatched for bill management. We use a modified PGE rate E-6 as summarized below. Figure 25 (on page 28) shows the summer and winter TOU rate as well as our assumed excess-PV-compensation wholesale rate.

PGE E6 TOU Rate Detail

- -Summer: May 1 through October 31
- Peak- $0.32/kWh (1:00 pm-7:00 pm)
- Partial peak- $0.20/kWh (10:00 am–1:00 pm & 7:00 pm–9:00 pm)
- Off-peak- $0.13/kWh

Winter: November 1 through April 30

- Peak- $0.15/kWh (5:00 pm–8:00 pm)
- Off-peak- $0.13/kWh

FIGURE 24 FRACTIONAL HOURS OF THE YEAR A BATTERY IS DISPATCHED (CHARGING AND DISCHARGING) FOR RESIDENTIAL SELF-CONSUMPTION

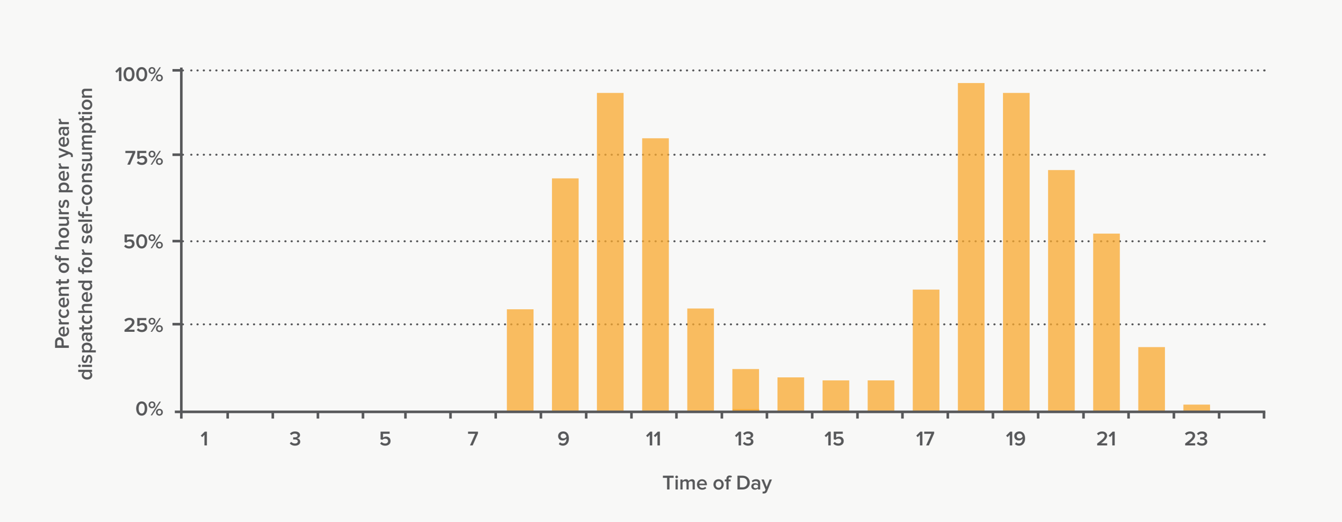
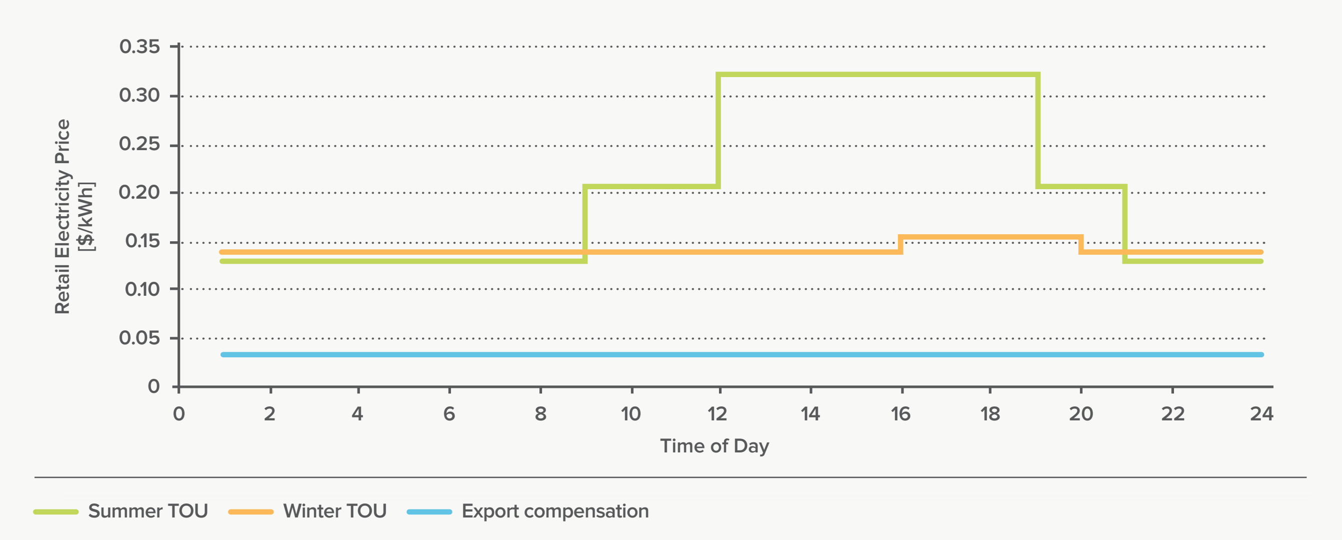
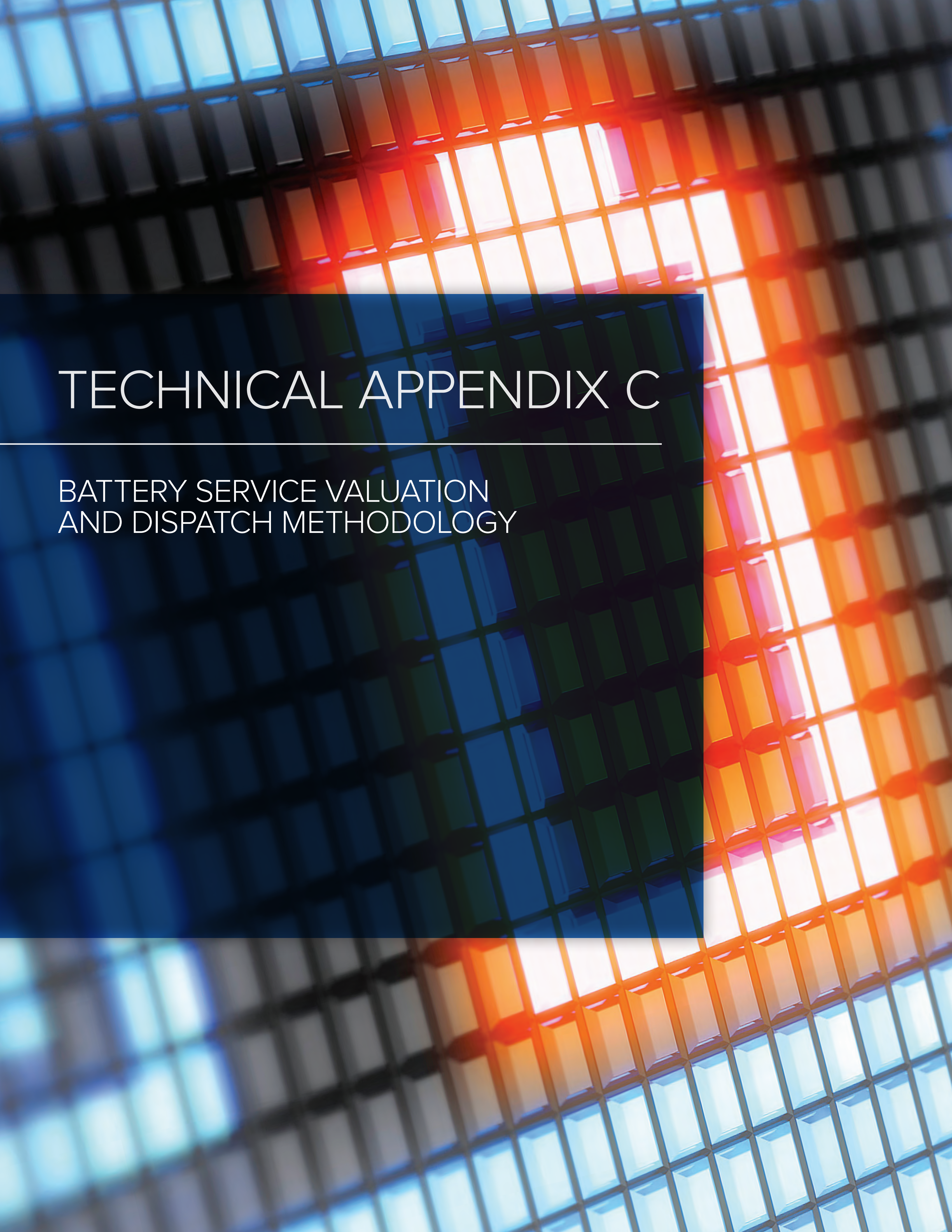


FIGURE 25 PGE E6 TOU RATE STRUCTURE





TECHNICAL APPENDIX C

BATTERY SERVICE VALUATION
AND DISPATCH METHODOLOGY

TECHNICAL APPENDIX C: BATTERY SERVICE VALUATION AND DISPATCH METHODOLOGY

THIS APPENDIX PROVIDES a detailed description of the methodology used to determine the monetary value assigned to energy storage service delivery. In addition to valuation methodology, we elaborate on dispatch constraints, such as maximum market size and minimum duration required.

Energy Arbitrage (Includes Load Following)

The payment that energy storage would receive for providing load following services, on an hourly basis, was derived from an the annual 'value' of load following services as reported in the literature reviewed for this report.[7] The required load following capacity of the system is taken as the difference between the system's / substation daily peak and the system's daily minimum value. Energy storage, being energy limited, can only provide load following for 2–4 hours, depending on the aggregated fleet capacity. In this work, we assume that load following services are provided roughly 3 hours per day for roughly 1,000 hours per year and deployed at or near the peak daily load.

Frequency Regulation and Spin / Non-Spin Reserves

Historic hourly market-clearing price data for ancillary services in both CAISO and NYISO markets were used to calculate an average regulation price for three time periods over the course of the day in order to reflect the hourly variation in ancillary-service clearing prices. Revenue from regulation is calculated using a capacity payment based on the time of day and a performance payment based on an assumed "mileage" indicative of a fast-responding energy storage device. Revenue from spin and non-spin service provision is calculated as a simple capacity payment based on the time of day the service is being provided and the capacity committed. Due to the infrequency of the actual deployment of spinning and non spinning events we do not include energy costs or revenue associated with charging or discharging the system for spin / non-spin reserves.

Distribution Deferral (New York-Specific Methodology)

The value of deferring or avoiding investment in a distribution or transmission system upgrade depends heavily on specific details related to the deferral.

For the distribution-deferral scenario in this report, we assume an aggregated suite of commercial and residential behind-the-meter energy storage systems will provide 50% of the required demand-side management to avoid system upgrades to New York's Brownsville #1 and Brownsville #2 substations.[7] We assume that other demand-management and energy-efficiency solutions will meet the remaining demand-side management requirements.

The value of deferring new traditional infrastructure investments for two years is calculated as the annual carrying cost associated with the expected $1 billion investment. We assume a fixed charge rate of 12%, resulting in an annual deferral benefit of $120 million. This deferral value is then split evenly between the energy storage fleet and the other demand-response and energy-efficiency programs we assume would be deployed prior to the energy storage systems. The dispatch constraints for the aggregated fleet require the system be available for about 60-120 hours during summer peak-loading events, with the ability to provide the committed capacity for eight-plus hours.

Time-of-Use Bill Management

The value of energy storage for TOU bill management is calculated as the difference in a customer's bill before and after storage is deployed to shift load, avoiding electricity purchases during peak pricing periods. The duty cycle on the storage system is modeled using hourly load data and charging and discharging constraints that determine when the storage device is dispatched for TOU management. In the event that the system has excess capacity in an hour it is committed to TOU management, the excess capacity is made available for other ancillary services.

Increased PV Self-Consumption

The annual value of the storage system dispatched for self-consumption is the difference in a customer's electricity bill with and without energy storage. The business-as-usual electricity bill is generated using simulated PV performance and a representative residential load profile specific to the region in question. We then use an hourly dispatch model to maximize the amount of solar energy used on site. We assume that net energy metering is replaced with a value of solar tariff, where the customer is credited for PV exported to the grid at an average wholesale energy price.

Demand Charge Reduction

Similar to TOU management, the value of demand charge reduction is calculated as the difference in a customers fixed, demand, and energy charges that result from deploying energy storage to minimize peak demand. Again similar to TOU management, the storage system is modeled on an hourly basis to determine when and how much of the system is dispatched to providing demand charge reduction.

TECHNICAL APPENDIX D

DETAILED OVERVIEW OF LITERATURE

TECHNICAL APPENDIX D:
DETAILED OVERVIEW OF LITERATURE

IN AN EFFORT to consolidate the myriad resources and reports addressing energy storage valuation, we conducted a meta-study of six of the more widely cited energy storage valuation publications from the past decade. In this appendix, we present a brief overview of each study covering project scope, storage applications evaluated, valuation methodology, temporal and spatial granularity, and a snapshot of the valuation results. The table below provides an overview of the reports included in the meta-study.

REPORT TITLE	INSTITUTE, LEAD AUTHOR, AND DATE
Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide	Sandia, Jim Eyer, 2010
The Value of Energy Storage for Grid Applications	NREL, Paul Denholm, 2013
Cost Effectiveness of Energy Storage in California – *Application of the EPRI Energy Storage Valuation Tool to Inform the California Public Utility Commission*	EPRI, Ben Kaun, 2013
The Value of Distributed Electricity Storage in Texas	Oncor, Judy Chang, 2014
Ancillary Services: Technical and Commercial Insights	Brendan Kirby, 2007
Guide to Estimating Benefits and Market Potential for Electricity Storage in New York	NYSERDA, Joseph Sayer, 2007

Title: Ancillary Services: Technical and Commercial Highlights
Prepared for: Wartsila
Author(s): Brendan Kirby
Published: 2007

Summary: This report presents a summary of cost drivers and market prices for ancillary services provided by conventional thermal generators. Kirby provides an overview of ancillary services highlighting market prices, response speeds, typical duration periods, and a summary of what each service provides to the grid operationally. This report does not address battery energy storage directly. However, modeling results for a gas-fired generating plant operating in California, Texas, New York, and Long Island for electricity capacity and three ancillary services (regulation, spinning reserve, and non-spinning reserve) are reported. Net profit is calculated for energy only and energy plus ancillary services for a single-unit, 100 MW, natural gas-fired, engine-driven generating plant. The major finding is that a thermal generator can increase its profits by 17–250% when participating in energy plus ancillary services over energy alone under an optimized dispatch model. Potential profits were greatest in California and lowest in Long Island. Revenue and operating costs were not specifically broken out.

SERVICE	ARBITRAGE	LOAD FOLLOWING	REGULATION	SPINNING / NON-SPINNING RESERVES	VOLTAGE SUPPORT	BLACK START	DISTRIBUTION UPGRADE DEFERRAL	TRANSMISSION CONGESTION RELIEF	TRANSMISSION UPGRADE DEFERRAL	SELF CONSUMPTION	TOU	DEMAND CHARGE
Evaluated	No	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No
Profit $/kW-yr	N/A	$16-$164	$17-$44	$1-$15 / $1-$39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Price [$/MW-hr]	N/A	N/A	$37-$400	$6-$300 / $3-$400	$1-$4/ kVar-yr	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Temporal Granularity	Profit analysis was conducted using an hourly time series model that first determines how a plant would respond to energy markets alone based on production costs and energy market prices. The model then analyzes profits for each ancillary service and chooses the most profitable combination of energy and ancillary service sales on an hourly basis.											
Distribution System Specific?	The hourly time series modeling was not distribution-system specific. The model was run for four different energy and ancillary service markets and based only on hourly wholesale market prices for energy and three ancillary-service products.											
Market Price Source	Prices are approximate ranges in $/MW-hr for 2005 and include CAISO, ERCOT, and NYISO											

Title: The Value of Distributed Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments
Prepared by: The Brattle Group; for Oncor
Author(s): Judy Chang; Ioannes Karkatsouli; Johannes Pfeifenberger; Lauren Regan; Kathleen Spees; James Marshal; Matthew Davis
Published: 2014

Summary: Oncor Electric Delivery Company, a T&D service provider, contracted the Brattle Group to conduct a study on the cost effectiveness of storage deployed on the distribution grid in Texas from three perspectives: 1) the retail customer, 2) wholesale electricity market participants and 3) the combined system (societal value). The report findings suggest that, from the whole system perspective, up to 5,000 MW / 15,000 MWh of energy storage would be cost effective based on an installed storage cost of $350/kWh. Storage value was categorized in 4 buckets (1) avoided distribution outages, (2) deferred T&D investment (3) production cost savings, and (4) avoided capacity investments. Due to the reporting in bulk-production cost savings the breakout of ancillary service value across services is not readily available. The main finding of this analysis is that, although the storage would be beneficial from a system perspective, it would not be deployed if done so solely by merchant developers, retail customers, or a utility only for capturing T&D deferral. Instead, it is essential to stack benefits from all stakeholders in order to overcome capital and operational costs of energy storage.

SERVICE	ELECTRICITY CAPACITY	AVOIDED CAPACITY INVESTMENT	REGULATION	SPINNING RESERVES	NON-SPINNING RESERVES	VOLTAGE SUPPORT	BLACK START	DISTRIBUTION UPGRADE DEFERRAL	TRANSMISSION UPGRADE DEFERRAL	SELF CONSUMPTION	TOU	DEMAND CHARGE
Evaluated	Yes	Yes	No	Yes	Yes	No	No	Yes	Yes	No	Yes	No
Value Range	$149/kW-year [i]							$14/kW-year	$36/kW-year [ii]	N/A	N/A	N/A
Temporal Granularity	Simulations were conducted using the Polaris Systems Optimization market-simulation tool to simulate optimal dispatch of energy storage based on fuel prices, market prices, and generation mix projected for 2020 resulting in wholesale market prices that are sufficient to support new generation investments (accordingly, electricity prices include capacity payments). The hourly simulation model was built to be consistent with ERCOT's day-ahead wholesale market.											
Distribution System Specific?	The report analyzed five years of outage statistics at each substation and feeder to estimate the value of avoided outages. Storage was imperfectly deployed at high-outage substations first. Deferred T&D upgrades were not location-specific and they did not conduct a detailed T&D planning analysis.											
Market Price Source	Simulated prices that were sufficient to support new generation investments.											

[i] *Wholesale electricity and ancillary service participation.*
[ii] *Assumed that benefit of investment deferral is equal to average annual transmission cost for a unit of reduced peak demand, used current averaged annual transmission cost per kw of summer coincident peak load in ERCOT.*

Title: **The Value of Energy Storage for Grid Applications; NREL**
Author(s): **Paul Denholm; Jennie Jorgenson; Marissa**
Hummon: **Thomas Jenkin; David Palchak; Brendan**
Kirby: **Ookie Ma; Mark O’Malley**
Published: **2013**

Summary: An effort of multiple national labs to understand the value of demand response and energy storage and to assess potential implications on associated markets and institutions, this analysis uses a commercial grid-simulation tool to investigate the value of grid-connected storage participating in wholesale energy markets for load leveling, spinning reserves, and regulation. PLEXOS was used to simulate a test system composed of two balancing areas that are isolated from the rest of the western Interconnection consisting of multiple individual utilities and specific generation assets. Three production-cost minimization scenarios were run: **(1) Energy only**, where the system is allowed on charge and discharge in response to system requirements but not allowed to participate in reserve services **(2) Reserves only**, where the system is only allowed to participate in spinning reserve and regulation markets and **(3) A co-optimized system** that can switch between services depending on which is most valuable at the time (spinning, regulation, or energy). In general, the results suggest that energy arbitrage is of lower value than regulation and reserves; given the option to participate in energy, reserves, and regulation, the system spent 90% of its available capacity providing regulation. When operating in the energy-only scenario, the major value of storage is lowered production costs, of which about 50% of the value was derived from fuel costs and 50% of the value from avoided starts.

SERVICE	ARBITRAGE	LOAD FOLLOWING	REGULATION	SPINNING / NON-SPINNING RESERVES	VOLTAGE SUPPORT	BLACK START	DISTRIBUTION UPGRADE DEFERRAL	TRANSMISSION CONGESTION RELIEF	TRANSMISSION UPGRADE DEFERRAL	SELF CONSUMPTION	TOU	DEMAND CHARGE
Evaluated	Yes	Yes	Yes	Yes/No	No	No	No	No	No	No	No	No
Market Price [$/MW-hr]			$5-$45	$0-$40								
Market Price [$/MW-hr]	$35		$109	$65								
Temporal Granularity	Hourly chronological unit commitment and economic dispatch using day-ahead forecasts for wind and solar optimized over a 48-hour commitment horizon with outage scheduling. Energy storage was simulated by modifying operation constraints of pumped hydro to resemble characteristics of battery storage.											
Distribution System Specific?	This is a transmission-level analysis. Storage is evaluated on a system large enough to represent a “real world” scenario. The system is composed of two balancing areas that are isolated from the rest of the interconnection by “turning off’ generation and load and aggregating transmission outside of the two balancing areas.											
Market Price Source	CAISO, NYISO, MISO, PLEXOS simulation											

Title: **Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide; Sandia National Labs**
Author(s): **Jim Eyer; Garth Corey**
Published: **2010**

Summary: This report conducts a high-level analysis of the business opportunities for battery energy storage and the benefits for utility uses of energy storage. The report characterizes 26 energy storage benefits bucketed into six categories (electric supply, ancillary services, grid system, utility customer, renewable energy integration, and incidental). Benefits are assessed both as individual benefits as well as aggregated (stacked) benefits. The authors propose eight financially attractive value propositions of example stacked use cases. They also make a high-level assessment of the potential market size and market value for 17 select benefits over a ten-year lifecycle, using a present-worth factor to estimate the net present value of a stream of annual revenues. The application-specific valuation methodologies are clearly presented and involve some rough analysis, due to data limitations, region specific valuation, and general difficulty in broadly valuing energy storage. The authors make a distinction between application vs. benefit, where application is the use case and benefit is associated with a monetary value. Application benefits are calculated in isolation of other applications (for example, if a battery is valued for regulation, it is assumed that that device is dedicated to regulation only). The concept of aggregated or stacked use cases is discussed but no economic dispatch or unit commitment is conducted to illustrate the potential.

SERVICE	ARBITRAGE	LOAD FOLLOWING	REGULATION	SPINNING / NON-SPINNING RESERVES	VOLTAGE SUPPORT	BLACK START	DISTRIBUTION UPGRADE DEFERRAL	TRANSMISSION CONGESTION RELIEF	TRANSMISSION UPGRADE DEFERRAL	SELF CONSUMPTION	TOU	DEMAND CHARGE
Evaluated	Yes		Yes	Yes/ No	No	No	No	No	No	No	No	No
Value Range	$77	$77	$195	$20	$56		$67-$128	$75	$67-$128		$171	$81
Temporal Granularity	Each benefit value was calculated based on high-level assumptions around how many hours (capacity factor) a device would be used in combination with the average hourly value or market price. For non-market based applications, other rough assumptions were used to generate a range of potential value.											
Distribution System Specific?	Application benefit calculations are not specific to any distribution system. Values were calculated for CA and U.S. typical systems based on wholesale market prices.											
Market Price Source	CAISO											

Title: **Cost-Effectiveness of Energy Storage in California**
Author(s): **Ben Kaun; Stella Chen**
Published: **2013**

Summary: This report presents the methodology and tools used to conduct a sensitivity analysis for energy storage in different use cases under various market conditions in California. This work was conducted to inform stakeholders of the CPUC regulatory proceeding investigating costs and benefits of energy storage in California. In this report, EPRI uses the Energy Storage Valuation Tool (ESVT), a tool in development by EPRI for use in California and elsewhere, to evaluate the cost-effectiveness of energy storage projects at the distribution level. This tool takes user-defined technical requirements for the grid, simulates storage operation to meet grid service requirements, and then optimizes remaining capacity for energy and ancillary service markets to maximize revenue. The analysis was conducted for three major use cases: (1) bulk transmission-connected energy storage, (2) short-duration energy storage for ancillary services, and (3) distributed energy storage at the utility substation. These use cases were subjected to various sensitivity analyses by adjusting market prices, storage duration and durability, technology type, and project start year. Cost/benefit ratios and breakeven capital costs were generated for 30 different scenarios with most cost/benefit ratios above one and breakeven capital costs ranging from $1,000-$4,000/kW installed, based on the direct costs and benefits of energy storage over the lifetime of the system. Assumed energy storage costs used for the cost/benefit ratio do not represent current energy storage costs.

SERVICE	ARBITRAGE	LOAD FOLLOWING	REGULATION	SPINNING / NON-SPINNING RESERVES	VOLTAGE SUPPORT	BLACK START	DISTRIBUTION UPGRADE DEFERRAL	TRANSMISSION CONGESTION RELIEF	TRANSMISSION UPGRADE DEFERRAL	SELF CONSUMPTION	TOU	DEMAND CHARGE
Evaluated	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	No	No	No
Market Price [$/MW-hr]	34-47 [$/MWh]	N/A	$7.8- $10.36	$8.13 /$1.11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Price [$/MW-hr]		$21-$97	$161-$204	$19/$0			$171					
Temporal Granularity	The ESVT dispatches storage based on the system's technical constraints (duration, capacity, efficiency, variable O&M costs) by prioritizing long-term commitment and then maximizes total profitability for the day-ahead markets using a dispatch optimization scheme. The dispatch uses optimization logic for the three use cases.											
Distribution System Specific?	This model is specific to wholesale energy markets in CAISO; it is not specific to a distribution network even though it does model a distribution-level benefit (distribution upgrade deferral). Use case 1 simulates bulk energy storage used to replicate the operation of a peaking fossil generator. Use case 2 is simulates smaller storage aimed only at participating in the regulation market. Use case 3 simulates the operation of a storage system located at the substation with the primary goal of deferring upgrade investments while providing system-capacity and ancillary services.											
Market Price Source	CAISO wholesale ancillary service day-ahead market clearing price &wholesale energy clearing price.											

METHODOLOGY AND ASSUMPTIONS:

Each report has slightly different assumptions and uses varying valuation methodologies. The following section highlights distinct methodologies used in each report categorized by application.

Energy Arbitrage

National Renewable Energy Laboratory

Uses a production-cost model to dispatch a vertically integrated generation fleet optimized to minimize overall cost of production. The commercial software PLEXOS is used to generate system marginal prices and annual production costs for runs with and without storage. The value of storage for energy arbitrage is calculated as the difference in total production cost between simulation runs.

Sandia National Laboratory

Uses a simple dispatch algorithm to evaluate a time series of prices and determine the highest net benefit from all possible transaction combinations with perfect forecasting knowledge of future electricity prices.

Electric Power Research Institute

Uses a dispatch algorithm optimized over a 24-hour interval to “buy low and sell high” while meeting energy storage operational constraints.

Oncor

Uses the Polaris System Optimization market simulation tool to generate year 2020 equilibrium market conditions in the ERCOT “energy–only” market that are sufficient to support new generation investments (capacity costs are bundled in energy prices).

Load Following

Sandia National Laboratory

Generic generation costs are used as proxies for market-based prices even though, ideally, market-based pricing would be used for this service based on both marginal cost and capacity cost. Costs were based on an assumed number of load-following hours each year at a generic marginal price including a conservative capacity payment.

Frequency Regulation

National Renewable Energy Laboratory

Uses PLEXOS to generate hourly marginal production costs to supply regulation and spinning reserve services required in the two balancing areas simulated. They assume the device can provide up to its full capacity and that the service is net-energy neutral in each simulation hour. The mix between regulation and reserve is determined by the PLEXOS optimization in each time interval.

Sandia National Laboratory

Revenue for up and down regulation is estimated based on CAISO market regulation clearing prices in 2006 escalated to 2008 dollars with a system device capacity factor at a lower bound value of 0.5 and an upper bound value 0.8.

Electric Power Research Institute

Regulation is split into regulation up and regulation down capacity bids; benefits are calculated based on regulation market value for each hour plus the day-ahead energy prices (and costs) for energy discharged (or charged). Including charging and variable O&M costs

Oncor

Specific ancillary services are not broken out. Instead, the Polaris Systems Optimization market-simulation tool is used to calculate realized system costs and wholesale energy and ancillary-service revenues for the simulation year.

Spin / Non-Spin Reserves

National Renewable Energy Laboratory

Uses PLEXOS to generate hourly marginal production costs to supply regulation and spinning reserve services required in the two balancing areas simulated.

Sandia National Laboratory

Revenue for reserves is calculated based on a generic low and high reserve market price assuming a device capacity factor with a lower bound value of 0.3 and an upper bound value of 0.6.

Electric Power Research Institute

Spinning reserve does not dispatch, but the system must have at least one hour of energy to qualify in the event a contingency event occurs. If charging at full capacity, the system can bid in at twice its rated capacity. Value calculated as market price multiplied by a capacity bid.

Oncor

Specific ancillary services are not broken out, rather the Polaris Systems Optimization market-simulation tool is used to calculate realized system costs and wholesale energy and ancillary-service revenues for the simulation year.

Voltage Support

Sandia National Laboratory

Generic assumption that storage would prevent one outage lasting one hour over the system's ten-year life cycle at an assumed cost of unserved load of $20–$40/MWh. The storage is assumed to be rated at 5% of peak load and thus 1 kW of storage can avoid a 20 kW outage for one hour.

Resource Adequacy (Includes Capacity Payments)

National Renewable Energy Laboratory

The report calculates the monetized capacity value of storage assuming a capacity factor of 90% for eight hours of storage based on a range of annualized values for capacity in PJM and CONE for PSCO and CAISO. The added value is calculated independently from the PLEXOS simulation as a separate additive value.

Sandia National Laboratory

The report uses a generic assumed installed cost of a new, clean, natural gas combustion turbine of $1,000/kW "on the margin" with an applied utility fixed charge rate of 0.11 with a $10/kW fixed O&M cost. Value is based on the assumption that 1kW of storage can offset $120/kW-year for avoiding the cost of new capacity investments.

Electric Power Research Institute

Systems that can successfully fulfill the service requirements of resource adequacy are compensated with the system capacity value equal to the CONE projected for the resource balance year (year the generation will be needed).

Oncor

The report assumes a levelized annual cost of new generation investments of $149/kW-year.

Distribution Deferral

Sandia National Laboratory

T&D upgrade deferral is bundled. See transmission deferral.

Electric Power Research Institute

Deferral value is calculated as the net present value of investment deferred by the number of deferral years. Deferral period is the number of years the storage is able to keep annual peak under the base-year peak-load hour. The investment value to occur when deferral ends is defined by the user.

Oncor

Avoided distribution outages are valued at typical ranges for value of lost load of different classes ($20,000/MWh C&I, $3,000/MWh Res) They assume that each kW of discharge capability from storage can defer one kW of distribution load and average distribution costs. The model uses $14/kW-yr based on Oncor's average annual distribution investments and load growth in 2014.

Transmission Congestion Relief

Sandia National Laboratory

Revenue based on avoided transmission congestion charges (assumed at $5–$15/MW per service hour) at an assumed percentage of the year (10–15%)

Transmission Deferral

Sandia National Laboratory

Deferral savings are calculated based on the marginal cost to upgrade transmission and distribution systems with an applied carrying-capacity factor.

Oncor

Assume the benefit of future transmission deferrals is equal to the average annual transmission cost for each unit of reduced peak demand, average cost of $36/kW-yr, which is the cost of transmission during summer coincident peak load in ERCOT.

Time-of-Use Bill Management

Sandia National Laboratory

Cost reduction is calculated based on PG&E residential A-6 tariff. The reduction in the building owner's bill occurs when a storage system with a six-hour duration is used to shift 720 hours of electricity purchases from on-peak to off-peak prices.

Oncor

The study assumes that retail customers would benefit from 75% of the value that the independent market participants could obtain in the ERCOT wholesale market, with the balance kept by developers who deploy the storage systems.

Demand Charge Reduction

Sandia National Laboratory

Cost reduction is calculated as the reduction in demand and energy charges when an 80%-efficient storage device with six hours of discharge capacity is used to eliminate peak load, based on PG&E E-19 tariff for commercial customers. Assumes storage avoids all demand charges during peak demand periods.

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[1] *See http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx for more information.*

[2] *Few general estimates of voltage support's value exist. However, according to one study voltage support is worth about $56 / KW / year, see Akhil et al. DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA. Sandia National Laboratories. July, 2013.*

[3] *See: http://www.greentechmedia.com/articles/read/advanced-microgrid-solutions-to-build-50mw-of-hybrid-electric-buildings*

[4] *Jeremy Neubauer and Mike Simpson. Deployment of Behind-The-Meter Energy Storage for Demand Charge Reduction. NREL. January, 2015.*

[5] *Ibid, 26.*

[6] *Lazard. Lazard's Levelized Cost of Energy Analysis—Version 8.0. Lazard, 2014. Page 3.*

[7] *The Value of Energy Storage for Grid Applications, NREL 2012; Energy Storage for the Electricity Grid; Benefits and Market Potential Assessment Guide, Sandia 2010;*

[8] *Consolidated Edison Request for Information: Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements, Issued July 15, 2014*