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City of

LOMPOC

October 13, 2017

John Mathias
California Energy Commission
1516 Ninth Street
MS-20 Sacramento, CA 95814
John.Mathias@energy.ca.gov

Dear Mr. Mathias:

The City of Lompoc hereby provides the status of its efforts regarding energy storage procurement targets and the policies adopted by the City of Lompoc Council pursuant to AB2514.

Consistent with AB2514, on May 15, 2012 the City of Lompoc Council adopted Resolution No. 5780(12) to conduct a study and evaluate potential energy storage capabilities. The results of this study indicated that implementation of the energy storage targets was not appropriate due to lack of cost effective options. Hence, no energy storage targets were set for 2016.

As required by AB2514, the City of Lompoc continued to monitor and research developments in energy storage technologies with particular attention to its cost and economic feasibility. In early 2017, the City contracted DNV-GL to perform a feasibility study to set energy storage targets for 2020. Based on the results from the DNV-GL study and additional analysis performed by the City staff, the City Council passed resolution No. 6143(17) determining, at this time, it is not cost-effective for the City of Lompoc Electric Utility to procure energy storage systems into the distribution grid or to establish procurement targets for December 31, 2020.

As mandated by AB2514, the City will continue to monitor and research developments in energy storage technologies in the future.

Please contact me at t_singh@ci.lompoc.ca.us or 805-875-8296 if you have any questions.

Tikan Singh

Tikan Singh, P.E.
Electrical Utility Manager

CERTIFIED COPY

RESOLUTION NO. 6143(17)

A Resolution of the City Council of the City of Lompoc, County of Santa Barbara, State of California, Determining Energy Storage Procurement Targets Are Not Cost Effective

WHEREAS, on September 29, 2010, the Governor of the State of California signed California Assembly Bill No. 2514, adding Subdivision 2836(b) to the Public Utilities Code (PUC); and

WHEREAS, pursuant to PUC subdivision 2836(b)(1), the governing board of each publicly-owned electric utility was directed to initiate a process to determine appropriate energy storage procurement targets, if any, to be achieved by December 31, 2016, and December 31, 2020; and

WHEREAS, pursuant to PUC subdivision 2836(b)(3) the governing board is required to reevaluate the determination made not less than every three years; and

WHEREAS, energy storage is defined in the legislation as "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching said energy," and

WHEREAS, in order to be viable, energy storage must be cost-effective and either reduce emissions of greenhouse gases, reduce a demand for peak electrical generation, defer or substitute investment in generation, transmission, or distribution assets, or improve the reliable operation of the electrical transmission or distribution grid; and

WHEREAS, the City Council adopted Resolution No. 5780(12) on May 15, 2012, directing an energy storage study to be conducted by August 2014; and

WHEREAS, an energy storage study has been conducted and it determined it is not cost-effective for the City of Lompoc to develop energy storage procurement targets at this time.

NOW, THEREFORE, THE CITY COUNCIL OF THE CITY OF LOMPOC, CALIFORNIA, DOES HEREBY RESOLVE AS FOLLOWS:

SECTION 1. Developing energy storage procurement targets is not cost-effective at this time.

SECTION 2. Effective Date. This Resolution is effective on the day of its adoption.

The foregoing Resolution was proposed by Council Member Starbuck, seconded by Council Member Vega, and was duly passed and adopted by the Council of the City of Lompoc at its regular meeting on October 3, 2017, by the following vote:

AYES:	Council Member(s): Dirk Starbuck, Victor Vega, Jenelle Osborne, James Mosby, and Mayor Bob Lingl.
NOES:	Council Member(s): None
ABSENT:	Council Member(s): None

Bob Lingl, Mayor
City of Lompoc

ATTEST:

Stacey Haddon, City Clerk
City of Lompoc

I HEREBY CERTIFY THAT THE foregoing instrument is a true and correct copy of the original on file in the Lompoc City Clerk's Department.
ATTEST:

City of LOMPOC

City Council Agenda Item

City Council Meeting Date: October 3, 2017

TO: Patrick Wiemiller, City Manager

FROM: Tikan Singh P.E., Electrical Utility Manager
t_singh@ci.lompoc.ca.us

SUBJECT: Adoption of Resolution No. 6143(17) Revision of Energy Storage Procurement Targets

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Recommendation:

Staff recommends the City Council adopt Resolution No. 6143(17) (attached) determining, at this time, it is not cost-effective for the City of Lompoc Electric Utility to procure energy storage systems into the distribution grid or to establish procurement targets for December 31, 2020.

Background:

On September 29, 2010, the Governor signed Assembly Bill No. 2514, which added Sections 2835-2839 to the Public Utilities Code (PUC). The purpose of that legislation is to integrate storage capacity into the electricity distribution grid.

Pursuant to PUC section 2836, the City of Lompoc (City) is required to determine appropriate energy storage targets. On May 15, 2012, in accordance with PUC subdivision 2836(b), the City Council adopted Resolution No. 5780(12) directing staff to initiate a study to determine appropriate energy storage procurement targets for December 31, 2016, and December 31, 2021, if any. Such determination must be reevaluated not less than once every three years after the first determination (October 7, 2014) was performed. The first three-year cycle ends on October 7, 2017.

Energy storage is defined in the legislation to mean "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching said energy." Furthermore, in order to be viable, energy storage must be cost-effective and either reduce emissions of greenhouse gases (GHG); reduce demand for peak electrical generation; defer or substitute for an investment in generation, transmission, or distribution assets; or improve the reliable operation of the electrical transmission or distribution grid.

Discussion:

Over the past three years, staff has reviewed several Department of Energy and Electrical Power Research Institute papers, documents, and reports. Staff reviewed information from technology assessments, market analysis, application assessments, and input from energy storage system vendors and system integrators. Additionally, staff participated in several meetings/seminars with other Northern California Power Agency (NCPA) member utilities, participated in energy storage webinars, and met with various equipment vendors. Recently, the City contracted with DNV GL to perform an Energy Storage Cost Analysis. The purpose of the analysis was to evaluate the viability and impact of integrating energy storage as well as cost-effectiveness methodologies that can be used to make storage procurement decisions. The findings of this research is explained below.

Potential Benefits of Energy Storage Systems

Some of the potential benefits of integrating energy storage systems into the City's electric grid are:

1. Load Shaving,
2. Electric efforts to reduce GHG
3. Substitute for an investment in distribution assets, and
4. Reliability.

Findings on the topics are discussed below:

1. Load Shaving

The primary purpose of energy storage is peak energy shaving or shifting energy demand from peak energy demand periods to lower energy demand periods when renewable energy, nuclear, and the most efficient (lower GHG emitting) fossil fuel generating stations are not operating at full capacity. This is desired in order to avoid constructing new fossil fuel generation facilities, and their appurtenant transmission interconnection facilities, and to avoid running less efficient and higher GHG-emitting generation facilities.

The City is located within the California Independent System Operator's (CAISO's) load-balancing area. CAISO's peak energy demand always occurs in the summer and was recorded at 46,232 megawatts (MW) on July 27, 2016. The City's energy demand, at the time of the CAISO peak, was 17.2 MW, or 0.037% of CAISO's total peak. Large investor and municipally-owned California utilities such as Pacific Gas and Electric (PG&E), Southern California Edison, San Diego Gas and Electric, and Los Angeles Department of Water and Power accounted for about 90% of CAISO's peak energy demand and are the primary drivers and targets of PUC subdivision 2835(b). Their service territories include heavy residential and commercial air conditioning and other large industrial motor loads.

CAISO's load factor, the ratio of average energy use to peak energy demand, is about 60%; the City's load factor is about 80%. Thus, the City's energy demand is more constant than the average CAISO member utility's energy demand. A peak event is considered to shift 20% from the baseline. Consequently, the cause of the difference in CAISO's average energy usage and peak energy demand, and, thus, the need for more fossil fuel generation and transmission assets, is larger utilities in CAISO's balancing area, not Lompoc.

2. <u>Electric Division's Efforts to Reduce GHG</u>

The City has already invested millions of dollars in renewable energy generation facilities, and currently receives about 25% of its energy from renewable bulk generation systems through our memberships in NCPA, Western Area Power Administration, Geothermal and Hydroelectric generation projects. Additionally, the City has already reduced its peak summer energy demand, through the City's Solar Photovoltaic (PV) net metering program, by 1.393 MW.

In addition, the Electric Utility has already developed a Renewable Energy Portfolio Procurement Plan and the Electric Utility is on course to supply 33% of retail energy sales with renewable energy (non-GHG emitting facilities) by 2020. Adding an energy storage system would not help the City in reducing GHG.

3. <u>Substitute for an Investment in Distribution Assets</u>

Distribution upgrade deferral involves using energy storage to delay or avoid upgrade investments that would otherwise be necessary to maintain adequate distribution capacity to serve all load requirements. Upgrade deferral may include replacement of an aging or over-stressed existing distribution transformer at a substation or re-conductoring distribution lines with larger wire. When a transformer is replaced with a new, larger transformer, its size is selected to accommodate future load growth over the next 15 to 20-year planning horizon. Thus, a large portion of this investment is underutilized for most of the new equipment's life. The upgrade of the transformer can be deferred by using a storage system to offload it during peak periods, extending its operational life by several years. If the storage system is containerized, then it can be physically moved to other substations where it can continue to defer similar upgrade decision points and further maximize the return on its investment. The average age for the City's existing transformers receiving station is 34 years. Although upgrade and replacement of the transformers will eventually be required, using an energy storage system is not a financially feasible method for increasing the life of the current equipment.

The Electric Utility does not need any new fossil fuel generation, only new renewable energy (non-GHG emitting facilities) to meet the Electric Utility's Renewable Energy Portfolio Standard procurement target. Additionally, the Electric Utility does not need any new transmission assets. Thus, it is not necessary to invest in energy storage to offset or substitute for an investment in generation or transmission. The Electric Utility does plan on investing in new distribution assets primarily to replace aging infrastructure and to gain additional operational efficiency, which will reduce distribution system energy losses and GHG emissions. New distribution infrastructure investments are also planned to meet new economic development needs, such as new commercial business facilities and new residential housing developments. These new distribution assets will be needed to provide a primary energy source to customers and would be required to provide a charging source for any potential energy storage system. Adding an energy storage system would not eliminate the need for critical upgrades and delaying these upgrades could prove more costly to the City.

4. Reliability

An energy storage system can effectively support customer loads when there is a total loss of power from the source utility. A system can be installed at the feeder level, such as community energy storage devices, or customer-sited behind the meter to pick up load when utility service is lost. However, in order to integrate a significant support the size of the system would have to range from 10 MW-25 MW. Implementing a system of that size would place a great burden on the fiscal impact of the utility as discussed in the Fiscal Impact section below.

The Electric Utility already has diesel generators at critical City facilities located throughout the City in the event of a transmission or distribution system issue. The Electric Utility has over 1,200 distribution service transformers throughout the City.

Energy Storage Technologies and Associated Costs

Currently there are five commercially available utility scale energy storage systems, they are:

i. Lithium Ion,
ii. Vanadium Redox,
iii. Flywheel Energy Storage,
iv. Compressed Air Energy Storage, and
v. Thermal Energy Storage

Each system is discussed below:

i. Lithium Ion

Lithium-Ion (Li-Ion) batteries utilize the exchange of lithium ions between electrodes to charge and discharge the battery. Li-Ion batteries are typically characterized as power devices capable of short durations (approximately 15 minutes to 1 hour) or stacked to form longer durations (but increasing costs). Rechargeable Li-ion batteries are commonly found in consumer electronic products, such as cell phones and laptops, and are the standard battery found in electric vehicles. In recent years this technology has developed and expanded its portfolio of applications considerably into utility-scale applications which, despite having very different requirements and features from consumer applications, benefit from the scale of manufacturing which lowers costs across markets.

Table 1 below depicts several key metrics and costs across different types of Li-Ion technologies

Table 1 - Cost Parameters and Metrics for Li-ion

Cost Parameter/Technology	Li-Ion NCM[1]	Li-Ion LFP[1]	Li-Ion LTO[1]
Energy storage equipment cost ($/kWh)[2]	$325-$450	$350-$525	$500-$850
Power conversion equipment cost ($/kW)[2]	$350-$500	$350-$500	$350-$500
Power control system cost ($/kW)	$80-$120	$80-$120	$80-$120
Balance of system ($/kW)	$80-$100	$80-$100	$80-$100
Installation ($/kWh)	$120-$180	$120-$180	$120-$180
Fixed O&M cost ($/kW yr)	$6-$11	$6-$11	$6-$11
Major Maintenance ($/kW)	$150-$400	$150-$400	$150-$400
Years between major maintenance	5	5	5
Installed costs ($/kW)	**$658-$1,980**	**$667-$2,483**	**$613-$2,780**

ii. Vanadium Redox

Vanadium Redox batteries (VRB), or Vanadium flow batteries, are based on the redox reaction between the two electrolytes in the system. "Redox" is the abbreviation for "reduction-oxidation" reaction. These reactions include all chemical processes in which atoms have their oxidation number changed. In a redox flow cell, a semi-permeable membrane separates the two electrolytes. This membrane permits ion flow, but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. A general VRB system includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves. Table 2 below depicts several key metrics and costs associated with vanadium redox technology.

[1] NCM = Nickel Manganese Cobalt($LiNiMnCoO_2$); LFP = Iron Phosphate($LiFePO_4$); LTO = Titanate(($Li_4Ti_5O_{12}$)

[2] k/Wh = kilowatt hours; k/W = kilowatt

Table 2 - Cost Parameters and Metrics for Vanadium Redox

Cost Parameter/Technology	VRB
Energy storage equipment cost ($/kWh)	$500-$700
Power conversion equipment cost ($/kW)	$500-$750
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100-$125
Installation ($/kWh)	$140-$200
Fixed O&M cost ($/kW yr)	$7-$12
Major Maintenance ($/kW)	$600-$800
Years between major maintenance	8
Installed costs ($/kW)	**$1,340-$8,215**

iii. Flywheel Energy Storage

A flywheel stores energy as the rotational kinetic energy of a spinning mass, i.e. the rotor. The rotor is accelerated by an electric machine acting as a motor during charging, and decelerates when energy is extracted (discharging mode) by the same machine acting as a generator. To reduce friction losses during rotation, in general, the rotor spins in a vacuum and magnetic bearings are used to keep the rotor in position. Table 3 below depicts several key metrics and costs associated with flywheel energy storage technology.

Table 3 - Cost Parameters and Metrics for Flywheel Energy Storage

Cost Parameter/Technology	Flywheel
Energy storage equipment cost ($/kWh)	$3,500-$5,500
Power conversion equipment cost ($/kW)	$350-$500
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100-$125
Installation ($/kWh)	$2,000-$3,000
Fixed O&M cost ($/kW yr)	$4-$6
Major Maintenance ($/kW)	$200-$300
Years between major maintenance	5
Installed costs ($/kW)	**$565-$9,265**

iv. Compressed Air Energy Storage

Compressed air energy storage (CAES) stores electricity by compressing air into a reservoir and generates electricity by expanding the compressed air in a gas turbine. The compression is performed by a compressor unit. Depending on the type of CAES, the heat produced during the compression is stored or released into the atmosphere. The compressed air is stored in a suitable geological formation such as salt domes, aquifers or depleted gas fields. The compressed air is released for power generation; it is heated by combustion of natural gas and then expanded in the gas turbine. Table 4 below depicts several key metrics and costs associated with CAES.

Table 4 - Cost Parameters and Metrics for CAES

Cost Parameter/Technology	CAES
Energy storage equipment cost ($/kWh)	$10-$30
Power conversion equipment cost ($/kW)	$400-$500
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100-$160
Installation ($/kWh)	$5-$10
Fixed O&M cost ($/kW yr)	$3-$5
Major Maintenance ($/kW)	$70-100
Years between major maintenance	4
Installed costs ($/kW)	**$660-$1,840**

v. Thermal Energy Storage

Thermal energy storage (TES) is a broad term for a variety of energy storage devices. It covers a wide range of very different technologies, wherein a medium is heated or cooled, and that energy is used at a later time. The energy to heat or cool the medium can come from the grid during off-peak times, renewable production that exceeds current demand, waste heat, or other sources. For the purposes of this report, the TES discussed is ice energy storage. Ice energy storage entails freezing water, or a water-based solution, at night to support space cooling during the day. The freezing process is conducted at night because lower ambient temperatures allow the ice to be made under thermodynamically beneficial conditions. Additionally, energy prices drop during the off-peak night hours. During the day, when temperatures and energy prices rise, the ice is melted and the cool air is circulated in the space. This can either reduce or eliminate the need for a conventional packaged air conditioning unit, dependent on the needs of the space and the local conditions. Table 5 below depicts several key metrics and costs associated with TES.

Table 5 - Cost Parameters and Metris for TES

Cost Parameter/Technology	TES
Energy storage equipment cost ($/kWh)	$200-$300
Power conversion equipment cost ($/kW)	N/A
Power control system cost ($/kW)	$80-120
Balance of system ($/kW)	$80-100
Installation ($/kWh)	$120-$180
Fixed O&M[3] cost ($/kW yr.)	$5-$7
Major Maintenance ($/kW)	$100-$125
Years between major maintenance	5
Installed costs ($/kW)	**$1,120-$3,100**

Cost for Load Shaving

The capital cost of energy storage equipment varies, based on the size of the facility and whether a single consolidated/centralized energy storage system is built, or if multiple/distributed energy storage systems are installed. The cost of equipment for a centralized target-sized of 20% of the City's peak load using a Li-ion NCM ES system (3.4 MW/6.8 MWh) is estimated to be $5.74 million. Energy storage system design and construction costs are estimated to be about $500,000 (for an existing electrical utility site) and annual O&M cost are estimated to be about $227,200 per year, which includes adding a new full-time employee at $200,000 and $27,200 for storage operation costs. The estimated life of the energy storage batteries, which are the bulk of the equipment cost, is estimated to be 10 years.

Cost for Reliability

Taking into consideration that the only reasonable usage the City can have for energy storage systems is assisting with reliability, a system of approximately 10,000 to 25,000 kW would be required to provide the City with power in case of loss of power from PG&E. Table 6 below depicts the fiscal impact of a potential 10,000 kW system installed and integrated to the local distribution system. Table 6 accounts only for the installed costs of the different options of energy storage systems. It does not account for additional land requirements, increased infrastructure (to commit the energy storage to the system) or additional personnel required.

[3] O&M = Operations and Maintenance Costs

Table 6 - Typical price for a 10,000 kW Energy Storage System

Typical system	Li-Ion NCM	Li-Ion LFP	Li-Ion LTO	VRB	Flywheel	CAES	TES
Size (kW)	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Duration (Hr)	2	2	2	2	2	2	2
Installed costs per kW ($/kW)	$ 1,690	$ 1,790	$ 2,265	$ 2,398	$ 14,658	$ 755	$ 990
Total Installed costs ($)	$16.9 M	$17.9 M	22.65 M	$23.97 M	$146.57 M	$7.55 M	$9.9 M

From Table 6 above, the cheapest option to provide the City with an energy storage system would be the compressed air energy storage technology at a cost of $7.55 million. However, from the previous explanation of CAES systems, a salt dome, aquifers or depleted gas field is required. Thermal energy storage would be the second least expensive option at $9.9 million. However, thermal energy storage is mostly used to support space cooling during the day, which is seldom required in Lompoc. Therefore, the least expensive and operationally viable option would be the Li-ion NCM energy storage system with a cost of $16.9 million.

Currently, the Electric Division is concentrating on converting remaining 4 kilovolt (kV) distribution systems to 12kV distribution systems for efficiency and reliability reasons, rebuilding old overhead 12kV circuits in the downtown area, and rebuilding 12kV underground facilities that are near the end of their service life. These are all capital and labor intensive projects, which are either ongoing or are multi-year projects with substantial work already completed. Without completing the projects, the efficiency and reliability goals will not be achieved. The 4kV to 12kV conversion project has been underway for several years and is anticipated to be completed in the next budget cycle. Estimated future budgetary savings to be realized after the completion of the conversion project have already been recommended to fund future costs of other distribution programs and would not be available to be used to secure an energy storage system.

<u>Fiscal Impact:</u>

There is no fiscal impact to the City, the City's General Fund or the City's Electric Utility associated with the passage of the proposed Resolution No. 6143(17) stating the determination that it is not cost-effective to set energy storage procurement targets at this time. However, if the City Council decided to fund a 10 MW/ 2.0-hour battery storage facility, the estimated resources required would include the following:

- Capital cost of at least $16.9 million (depending on location) for a ES with a 10 year life;
- $260,000 in increased annual O&M cost;
- The addition of at least one full-time equivalent position; and
- An additional $500,000 initial investment to provide interconnection for the ES to the existing distribution system (this is assuming a currently owned location is a viable option).

The cost of a 25MW Li-ion NCM ES system to fully cover the loss of PG&E's transmission source for two hours would be over $42.25 million, just for equipment.

Increase in retail Electric Utility Rates

Since the Electric Utility recommends funding current Capital and O&M programs at existing levels and the Utility cannot currently recover energy storage costs through participation in CAISO markets, the only viable funding source at this time would be increasing retail Electric Utility rates. A rate study would be required to evaluate the funding requirements to pay for energy storage costs through Electric Utility rates. The passage of Proposition 26 in 2010 prohibits the City from charging for services in excess of the cost of providing the services.

Conclusion:

With current cost figures, integrating storage capacity to the City distribution system would place a heavy financial burden that would directly affect the City ratepayers and the continuous operation of the Division.

Staff recommends adoption of City Council Resolution No. 6143(17), determining it is not cost-effective to develop an ES procurement target at this time.

Respectfully submitted,

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Tikan Singh P.E., Electrical Utility Manager

APPROVED FOR SUBMITTAL TO THE CITY MANAGER:

____
Larry Bean P.E., Utilities Director

APPROVED FOR SUBMITTAL TO THE CITY COUNCIL:

____
Patrick Wiemiller, City Manager

Attachment: Resolution No. 6143(17)

EXECUTIVE SUMMARY

Public Utilities Code Section 2836(b) requires the governing board of each local publicly owned electric utility to determine appropriate targets for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2020, on or before October 1, 2014. The statute also requires each governing board to reevaluate the determinations made pursuant to this subdivision not less than once every three years, with the first three- year period ending October 1, 2017. To this end, NCPA and SCPPA contracted DNV GL to support their members in re-evaluating energy storage targets, energy storage technologies, as well as cost-effectiveness methodologies that can be used to make storage procurement decisions. This report will focus mainly on describing energy storage cost-effectiveness methodologies.

Assessing the cost-effectiveness of storage presents a unique set of challenges. Energy storage is comprised of a group of technologies that vary in stages of development from traditional systems (eg. pumped hydro) to emerging technologies (eg. adiabatic compressed air). In addition, the performance characteristics of these technologies vary from power (short duration) to energy (long duration), and have extensive differences in sizes, configurations, efficiencies, as well as the number of discharge cycles specific technologies can perform. Finally, when sited at certain locations of the grid, the devices can often perform multiple functions to solve different problems. Each of these variations presents a unique set up challenges when assessing the technology. As utilities and government agencies continue to assess storage cost-effectiveness, the notion that simplified approaches to valuing storage are not adequate and in fact, may even lead to incorrect results.

In this report, DNV GL summarizes the cost-effectiveness methodologies and tools that are being used in the industry. While cost is relatively straightforward, benefits of storage is much harder to quantify due to the reasons above. It is important to caution that the cost-effectiveness analyses may be difficult (and expensive) to perform because they are specific to technology, location and applications. Instead of providing benefit values for each application in general, this report provides several examples of storage use cases to illustrate how storage benefits can be evaluated at the transmission, distribution and behind the meter locations.

These use cases indicate energy storage is cost-effective for a specific subset of assumptions for a range of benefits versus a range of costs. The range of benefits evaluated in these use cases include: market revenue potential, avoided distribution investment and customer bill savings. In each use case evaluated, the cost-effectiveness reaches a breakeven point when the benefits side of the equation being at the upper end of the assumed value range, and the storage cost side being at the lower end of the assumed cost range. While there are specific storage use cases that are cost-effective, one cannot generally conclude that storage is cost-effective for a specific application or for a specific technology at the current prices and benefits.

As part of this project to support POU's AB 2514 compliance, DNV GL includes three deliverables in the appendices.

- Appendix A: Technology specification. DNV GL reviewed seven utility-scale and behind the meter battery technologies: lithium ion (nickel manganese cobalt, Iron phosphate, titanate), vanadium flow batteries, flywheel, compressed air, and thermal energy storage. For each of these technologies, DNV GL provided a fact sheet to introduce the technology, a summary of its technical parameters, component costs, costs trends, as well as their suitability for various applications. The six technologies examined vary widely in technical parameters and costs. However, the general trend is that costs are coming down for all technologies, especially for lithium ion batteries. Different technologies are suitable for different applications. Lithium ion and flow batteries in generally are well-suited for all applications examined. Flywheels have very fast response times, high power ratings and show no degradation for cycling, therefore are most useful for power applications. Compressed air systems can support extremely long duration energy application, in some cases, over a day of continuous energy. For behind-the-meter applications, lithium ion batteries dominate the market to provide customer bill management. Thermal energy, such as ice bear, is a cost-effective solution for bill management when there is a high thermal load.

- Appendix B: AB 2514 target setting for IOUs. CPUC adopted an energy procurement target of 1,325 MW for the three Investor-Owned Utilities in California. In this memo, DNV GL describes the process and rationale used by the California Public Utilities Commission (CPUC) for determining and adopting energy storage procurement targets. Although the CPUC chose not to discuss the thought process that went into developing the targets, some of the major observations with respect to the targets include: (1) the cumulative target is approximately 2% of peak load projected for 2020, and the split targets between the IOUs followed roughly the ratios of projected peak demand of the utilities (2) The growth in targets from 200 MW to 1,325 MW over 4 biennial solicitation cycles amounted to about 35% growth per cycle (or about 15% compounded annual growth rate, compared to much higher growth rates already seen in the adoption of various renewable energy technologies). (3) The target at transmission level appeared to be slightly more than half of the total target, with the other half at the distribution level (divided between utility-side distribution and customer-side behind-the-meter). In addition, the memo provides an update on the progress achieved by the utilities relative to the CPUC procurement targets. All the IOUs are on track to meet their targets; in fact SCE and SDG&E have made rapid progress against their procurement targets (at 90% and 70% respectively) as of early 2017.

- Appendix C ES-Select Overview Presentation. ES-Select is a storage educational and screening tool developed for newcomers to the industry to help them understand the broad landscape of storage costs and benefits. Instead of requiring accurate inputs to provide accurate answers, it is designed to work with the uncertainties of storage and applications characteristics, costs, and benefits and provides answers in some reasonable “ranges.” Since the input of the tool is provided in ranges under normal distribution, the output is provided in ranges and the probability distribution of occurrence. ES-Select is not an appropriate tool to use to make decisions about storage deployment under a specific situation, but is a useful screening tool to help understand the range of technologies and applications in general.

1 INTRODUCTION

In 2013, AB 2514 codified Public Utilities Code Section 2836(b) to require the governing board of each local publicly owned electric utility to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems to be achieved by December 31, 2016, and December 31, 2020, on or before October 1, 2014. The statute also requires each governing board to reevaluate the determinations made pursuant to this subdivision not less than once every three years, with the first three- year period ending October 1, 2017. To this end, NCPA and SCPPA contracted with DNV GL to support their members in re-evaluating energy storage targets, energy storage technologies, as well as cost-effectiveness methodologies that can be used to make storage procurement decisions.

It is not unique for a statute to require utilities to procure emerging energy technologies as long as they are cost-effective. In 2006, SB 1 required utilities to procure cost-effective solar. Compared to storage, evaluating the costs and benefits of solar was more straightforward: there is a predominant technology, the generation profile is comparable, and the cost can simply be quantified and compared with each other based on a straightforward dollar per Watt metric. Unlike solar, assessing the cost-effectiveness of storage presents a unique set of challenges. Energy storage is comprised of a group of technologies that vary in stages of development: from traditional systems, such as pumped hydro that has been deployed for decades, to emerging systems such as adiabatic compressed air, to lithium ion batteries that has been expanding its portfolio of applications in recent years. In addition, the performance characteristics of these multiple technologies vary from power (short duration) to energy (long duration), and differ vastly in configurations, efficiencies, as well as the number of discharge cycles they can perform. Finally, when sited at certain locations of the grid, the devices can often perform multiple functions to solve different problems. Each of these variations presents a unique set up challenges when assessing the technology.

2 ENERGY STORAGE COST-EFFECTIVENESS METHODOLOGIES

At present, there are a wide range of tools and methodologies for evaluating the cost-effectiveness of energy storage. While costs estimates can be relatively straightforward, benefits are much harder to quantify. Performing a rigorous cost-effectiveness analysis depends on many factors, including technology, location, applications, market conditions, local grid conditions, and the available mix of other resources on the grid. On top of these factors, there are numerous tools and methods for evaluating storage benefits. For example, for frequency regulation application, analytical tools such as KERMIT[1], needs to simulate a 4-second change in frequency regulation setpoints to map the pathway (or mileage) of the storage cycles to calculate the performance payments. For capacity value, production cost modeling tools, such as PLEXOS[2] or PROMOD[3], need to simulate the entire market on an hourly basis for a given year to find out the value of storage capacity. When it comes to distribution applications, power flow models for distribution circuits would be needed to analyze steady state circuit performance parameters to test the efficacy of storage to mitigate loading and voltage impacts. Figure 1 shows the time fidelity required for various storage analyses and some of the available tools on the market.

[1] DNV KEMA Renewable Market Integration Tool

[2] PLEXOS® Integrated Energy Model (PLEXOS)

[3] ABB's electric market simulation tool

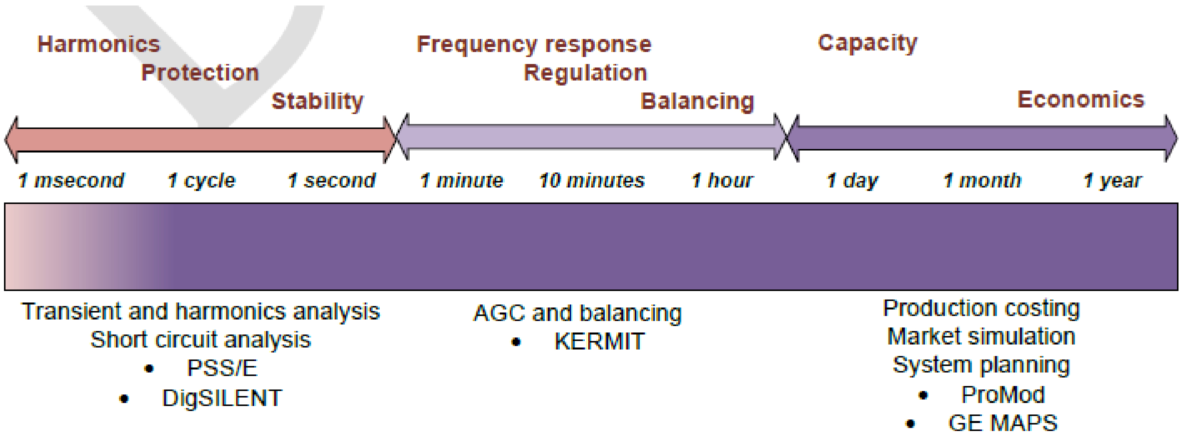


Figure 1 Time Fidelity Required for Storage Analysis and Current Tools

This document provides an overview of the prevailing cost-effectiveness methodologies currently being employed by the industry. A common challenge in developing comprehensive energy storage valuation methodologies is the relatively large number of potential storage applications. Each of these applications can take on varying magnitudes of value depending on the location of the storage device and corresponding system needs. Section 3 of this document contains a comprehensive definition list for each of the applications discussed in this report. Section 4 provides several case studies to illustrate how storage cost-effectiveness studies have been conducted and their associated results. To assist with describing these evaluation methodologies, DNV GL has segmented evaluation methodologies into three application areas: wholesale/transmission-connected, distribution-connected, and behind-the-meter.

2.1 Transmission-Connected Use Cases

For transmission-connected use cases, the benefits used in the cost-effectiveness modelling and evaluation include market revenues, i.e. market-based payments for the provision of Regulation Up (RegUp), Regulation Down (RegDown), Spinning Reserve (SR), Non Spinning Reserve (NSR) and other market services sold into the California Independent System Operator (CAISO) market, as well as local capacity payments from the utility to the storage owner, if any.

For market participation, energy storage valuation methodologies typically attempt to answer the following question: Given a storage device installed at a certain location that is eligible to participate in some number of CAISO markets/services, how should a storage device be operated such that its net benefit from market participation is maximized? For these market participation applications, the benefits are commonly considered only from the perspective of the device operator, and not from the perspective of the market or the utility. The bidding strategy and revenue potential are dependent only on the market prices available in the area in which the device is located. This is unlike a production costing dispatch approach, where devices are operated to minimize the cost to operate the market. Device-level benefits provide a starting point to derive its absolute worth to the utility / market. To derive the full benefits of a storage device to the utility, system level analysis and appropriate corrections are required. However, while evaluating the relative worth between two storage installations to the utility, device level benefits can provide a good indication of which one is better.

Some common assumptions on device level market participation include:

- Perfect Foresight: All inputs to the problem are exactly known before solving – e.g. prices, weather, renewable production, energy transactions while following ramping etc. This enables deterministic formulation, but this situation does not mimic real life. In reality, most inputs other than Day Ahead prices are not known exactly. The storage operator would devise a bidding strategy to maximize the probability of bids getting accepted and net expected benefits given uncertainty in inputs and errors in forecasted parameters.
- Price Taker: It is typically assumed that a storage device is relatively too small to impact the market clearing prices or affect the market price at a given node. The compensation to the device is the volume dispatched times the clearing price of energy or capacity.
- Zero Bid: Operator places $0 bid in capacity and/or energy markets based on perfect foresight dispatch computed. This implies that the bid is always accepted.
- Hourly Dispatch: Majority of tools do not resolve storage operation at time resolution finer than 1 hour. This primarily functions to reduce computation time, particularly when evaluating large number of scenarios. This assumption ignores the effect of convergence bidding or participation in real time energy imbalance services.

The analysis from the device perspective can typically be performed with spreadsheet modelling which can neglect system level constraints and coordinated operation of other devices in the system. When considering system level impacts, additional, more complex modelling tools are required.

Production cost simulation runs are typically used to determine the dispatch and relate hourly base clearing price for energy and ancillary service payments for a sample set of days that are then extrapolated for a representative year's 8760 market hours. Tools, such as DNV GL's KERMIT, can then be used for the inter-hour resolution needed to estimate the associated pay for performance benefit factors applied to the production simulation ancillary service base clearing prices. While there are other compensation schemes proposed and present within energy storage-based Power Purchase Agreement (PPA) term sheets today, there are not yet clear investment recovery mechanisms for these revenue streams. These potential additional services include: provision of volt-ampere reactive (VAR) to the local Participating Transmission Owner (PTO), blackstart capability, or fixed revenue streams via PPA with an LSE who wants to hedge market risk for their share of Ancillary Services costs.

When looking at the full system benefit, the benefit basis is the impact to system level metrics as solved in a production simulation. The modelled system benefits are estimated through comparing a portfolio without energy storage (usually known as base case) and a portfolio with energy storage included (change case). The primary system-level benefits include:

(1) Total cost of serving energy ($) and the average cost of energy ($/MWh)
(2) Total quantity of monitored emittants, including nitrogen oxide (NOx) and carbon dioxide (CO_2)
(3) Number of conventional gas-fired unit starts which could be translated into starting costs and aggregated into total system costs

2.2 Distribution Grid Use Cases

The most frequently noted utility-side distribution connected storage applications are upgrade deferral, distribution operation support, and reliability. Of these applications, the most commonly cited cost-effective distribution application is upgrade deferral.

Upgrade Deferral

Distribution upgrade deferral involves using storage to delay or avoid utility investments that would otherwise be necessary to maintain adequate distribution infrastructure capacity to serve all load requirements. Upgrade deferral may include delaying the replacement of an over-stressed existing distribution transformer at a substation or avoiding the re-conductoring of distribution lines for higher load carrying capacity. When a transformer is replaced with a new, larger transformer, its size is selected to accommodate future load growth over the next 15-year to 20-year planning horizon. The upgrade of a transformer can be deferred by using a storage system to reduce the load on the transformer during peak periods, extending its operational life by several years.

To estimate the number of years of deferral that a given energy storage configuration can provide, a cost-effectiveness model will typically require historical SCADA load data as well as forecasted load growth for the feeder or substation transformer bank being considered. The primary benefits typically used in the cost-effectiveness modelling and evaluation are transmission and distribution (T&D) upgrade deferral (annual carrying charge for the upgrade deferral period) and T&D upgrade avoidance (first-year T&D installed cost avoided). There are several secondary benefits calculated in terms of system performance, but which are not carried forward as part of the financial benefits due to no existing clear means to monetize these system benefits. These secondary benefits (‘with’ versus ‘without’ energy storage performance benefits) calculated in the load flow solution include, energy (I^2R and I^2X) loss reduction, reduction in voltage regulation device switching, and reduction in the steady state voltage range.

Going forward, “bundled-use” of an energy storage device deployed for distribution deferral may be possible with appropriate regulatory rules in place. That is, the storage asset could offer multiple bundled applications such as wholesale market participation during time periods (which is typically most of the time) when it is not being used for deferral service (by offsetting peak load on the associated transformer or feeder circuit). In this case, valuation methodology would involve considerations similar to the ones discussed in the previous section on transmission-connected use cases.

Distribution operation (Voltage Support/VAR Support)

Utilities regulate voltage within specified ANSI standard limits by installing and operating tap changing transformers and voltage regulators at the distribution substation and by switching feeder capacitors downstream to follow load changes. This need is pronounced on long, radial lines with high loading or on feeders with high penetration of intermittent PV systems which may be causing unacceptable voltage deviations for neighboring customers. Placing distributed storage closer to affected infrastructure can improve network voltage profile, mitigate fluctuations, and reduce network power losses. [1]

Benefit of this application is typically attributed to avoided cost of additional voltage regulation equipment or system upgrades. In the case of avoided voltage regulation equipment as the only energy storage application, this benefit is typically nominal and not significant enough to justify energy storage at its current prices. However, if storage can avoid the need for extensive re-conductoring which would otherwise be required to correct a voltage deviation issue, the associated avoided cost benefit can make energy storage a cost-effective solution. While hourly resolution for the load flow simulations is typically adequate for assessing steady state voltage performance, the transient voltage concerns would require a higher time resolution and dynamic-capable electric system model to 1) capture the PV intermittency-related impact on transient voltages and 2) test the efficacy of a transient-response-speed capable energy storage system.

Outage Mitigation / Reliability

A storage system can effectively support customer loads when there is a total loss of power from the source utility. This support requires a storage system and customer loads to island during the utility outage and resynchronize with the utility when power is restored. The energy capacity of the storage system relative to the size of the load it is supplying determines the time duration that the storage can serve that load. This time can be extended by supplementing the storage system with on-site diesel gen-sets that can continue supporting the load for long-duration outages that are beyond the capacity of the storage system.[1]

It is however difficult to assess the value of reliability. The value of reliability can be quantified by the avoided cost of customers at risk of losing electricity service. This can be gauged from their willingness-to-pay for different types of interruption events at different time of day, day of week, season and geographical regions. These avoided costs can vary widely among different electricity customers. There have not been recent surveys that collect this type of data, so reliability values would be difficult to quantify. The most recent comprehensive study on reliability benefits were documented in an LBNL report in 2009 that uses data from 1989 to 2005[4].

2.3 Behind-the-meter Use Cases

2.3.1 Customer Bill Savings

The primary benefit for cost-effectiveness modelling and evaluation of behind-the-meter use cases is customer bill reduction through removal or reduction of demand charges applicable to some general commercial and industrial rate categories, and shifting PV output to reduce energy related charges. When installed alongside PV generation, energy storage capacity can be used to shift PV output to maximize coincident reduction in net load demand. Given that the benefits for this use case are strictly from the perspective of the retail customer, any incentives available to retail customers to encourage deployment of PV/storage systems also enter the benefits calculation as a reduction in capital expenditure (CAPEX) initial investment cost. Three common incentive programs for Californian customers include:

1. The California Self Generation Incentive Program (SGIP), applicable to energy storage
2. The California Solar Initiative (CSI), applicable to PV, for the Use Case sensitivities that include customer-sited PV
3. The Federal Investment Tax Credit (FITC), applicable to energy storage and PV, for the Use Case sensitivities that include customer-sited PV

[4] Michael J. Sullivan, Matthew Mercurio, Josh Schellenberg, "*Estimated Value of Service Reliability for Electric Utility Customers in the United States*," *LBNL,* June 2009

There are commercial tools available that can calculate customer bill savings, including DNV GL's Microgrid Optimization Tool and LBNL's DER-CAM. These tools typically calculate customer bill savings using the customer's load shape, electric tariffs, PV generation, and storage operation algorithm to calculate demand and energy charge savings.

2.3.2 Capacity Dispatch

Capacity dispatch is another commercially popular benefit category. The storage system could perform in utility or ISO capacity dispatch programs such as Demand Response, Local Capacity Resource (LCR), or Forward Capacity Market (FCM). Under these programs, the storage system would be notified ahead of time of the volume and duration of capacity required and the price of that service. Capacity dispatch may involve storage discharging (equivalent to load reduction) during peak or congested hours of the day such as early or late evening. Storage may also provide capacity service by charging (equivalent to load increase) to mitigate renewables over-generation. Such programs are being piloted in California.

Due to the deterministic nature of capacity dispatch scheduling, this application can be easily bundled with the Demand Charge Reduction (DCR) application. Storage control algorithm would need to co-optimize storage operation between these two applications to maximize revenue potential over the day. Commercial tools such as Microgrid Optimizer can model these bundled applications to demonstrate cost-effectiveness.

2.3.3 Other Customer benefits

In addition to customer bill savings and capacity dispatch revenue, storage can offer additional value in improving power quality and reliability. As noted above, these benefits are difficult to quantify and may vary widely depending on the individual customer's electrical needs.

2.4 Storage ES-Select

DNV GL acknowledges the difficulty for an industry newcomer to make decisions about storage given the complexity of the storage costs and benefits. To this end, DNV GL developed ES-Select for decision makers new to the industry to understand the broad landscape of storage. Instead of requiring accurate inputs to provide accurate answers, it is designed to work with the uncertainties of storage and applications characteristics, costs, and benefits and provides answers in some reasonable "ranges." ES-Select applies the Monte Carlo analysis to randomly choose hundreds of possible values within the provided ranges of input parameters, assuming a normal distribution. Consequently, the provided answers also have a range but the probability of occurrence of the answer within the provided range does not necessarily have a normal distribution.

To further educate and help decision makers on their options for energy storage or their applications and markets, ES-Select offers a wide variety of charts to compare the "ranges" of answers over a wide set of criteria, such as price and cost components, cycle life, size, efficiency, cash flow, payback, benefit range, and market potential.

The key characteristic that needs to be kept in mind when using ES-Select is that in developing this educational/consulting/screening tool, "simplicity" had far more priority than "accuracy." This decision support tool is made for the initial screening purpose when most facts are still unknown to the user, but some decisions still need to be made based on what is already known.

Another design principle in ES-Select is not to confuse the user by asking hard to answer questions upfront, but rather assume the most likely answers and allow the user to overwrite them if s/he has different answers. In other words, every question has a default answer that is often in the form of a range that would cover most, if not all, cases. The objective behind this design principle is to make the tool useful to both a beginner who needs to be educated on “reasonable” values as well as an experienced user who knows exactly what the problem is and has all of his or her numbers ready for input.

ES-Select was demonstrated to NCPA and SCPPA members in a workshop/webinar on November 2016. A public version of the tool can be downloaded from the US Department of Energy website[5]. The workshop presentation is available in Appendix A of this report.

3 STORAGE APPLICATIONS

A common challenge in developing comprehensive energy storage valuation methodologies is the relatively large number of potential storage applications. Each of these applications can take on varying magnitudes of value depending on the location of the storage device and corresponding system needs. In addition, some storage systems can perform multiple applications that can accrue a number of benefits. In this section, we provide a list of most commonly-cited energy storage applications, bundled applications, and the appropriateness NCPA’s selected technologies for a particular application.

3.1 Application Definitions

The following list in Table 1 provides definitions, collated from number of public sources, for the most commonly cited energy storage applications, some of which were covered in more detail earlier in this memo:

Table 1: Energy Storage Application Segments

Wholesale/Transmission Connected	Distribution-Connected	Behind-the-meter

[5] http://www.sandia.gov/ess/tools/es-select-tool/

1. Provide frequency regulation services 2. Provide spin / non-spin reserves 3. Provide ramping 4. Provide Black Start 5. Avoid renewable curtailment and/or minimum load issues 6. Shift energy 7. Provide capacity 8. Smooth intermittent resource output 9. "Firm" renewable output 10. Improve transmission system operation (short duration performance, inertia, system reliability) 11. Avoid congestion fees	12. Defer system upgrades 13. Improve distribution system operation (Voltage Support/VAR Support) 14. Mitigate outages	15. Customer bill-management: Time-of-use (TOU) energy and demand charge management 16. Maintain power quality 17. Provide uninterruptible power supply

1. Provide frequency regulation services

Frequency regulation services available to storage include conventional regulation market products, fast regulation, as well as primary frequency response. Regulation involves managing interchange flows with other control areas to closely match scheduled interchange flows and momentary variations in supply or demand within the control area. The primary reason for including regulation in the power system is to maintain the grid frequency by reconciling momentary differences caused by fluctuations in generation and loads.

Typically, regulation is provided by generating units that are online and ready to increase or decrease power as needed. Their output is increased when there is a momentary shortfall of generation relative to demand and reduced when there is a momentary excess of generation.[1]

In most markets today, energy storage devices are now allowed to compete with generators in offering regulation services. Due to the fast ramp rate capability of most storage systems, a storage device can be quite valuable as a fast regulation device. In the fast regulation market, conventional plants such as gas turbine units would not be able to participate. CAISO controls the participating devices, which are dispatched according to optimal market operation.

2. Provide spin / non-spin reserves

Operation of an electric grid requires reserve capacity that can be called upon when some portion of the online supply resources become unavailable unexpectedly. Generally, reserves are sized to be at least as large as the single largest supply resource (e.g., the single largest generation unit) serving the system and reserve capacity is equivalent to 15% to 20% of the normal electric supply capacity. Spinning Reserve refers to generation capacity that is online (and synchronized to the grid system) but unloaded and that can respond within 10 minutes when needed to compensate for generation or transmission outages. Non-Spinning Reserve refers to generation capacity that may be offline or that comprises a block of curtailable and/or interruptible loads and that can be ramped to the required level (and synchronized to the grid system) within 10 minutes.[1]

3. Provide ramping

Conventional generation-based load following resources will increase output to follow demand up as system load increases and decreases output to follow demand down as system load decreases. Additionally, when renewables are present the demand on the conventional units to increase or decrease output increases with intermittency of the renewable supplies. In either case, the generator action to increase/decrease output is referred to as ramping. To enable ramping service, a generation unit must be operated at partial load, which is inefficient and requires more fuel per MWh, resulting in increased emissions per MWh relative to the generation unit operated at its design output level. Varying the output of generators will also increase fuel use and air emissions, as well as the need for more generator maintenance and thus higher variable operations and maintenance (O&M) costs. Storage is a well-suited alternative resource to provide ramping because it can operate at partial output levels with relatively modest performance penalties and respond very quickly when output modulation is needed for load following.[1]

4. Provide Black Start

Black Start is the procedure to recover from a shutdown of the bulk transmission system which has resulted in major loss of power supply. The black start process involves the starting of individual, isolated power stations (using on-site power that is not dependent on the bulk system to operate, such as a diesel genset) that can then serve to restore power to the ISO balancing authority area following a system outage.[2] A black-start unit provides energy to help other units restart and provide a reference frequency for synchronization. CAISO obtains black start services from generating units under interim black start agreements or reliability must-run contracts.

Energy storage systems can also provide an active reserve of power and energy within the grid and can be used to energize transmission and distribution lines, as well as provide station power to bring power plants on line after a large failure of the grid. Storage can provide startup power to larger power plants, if the storage system is suitably sited and there is a clear transmission path to the power plant from the storage system's location.[1]

5. Avoid energy curtailment and/or minimum load issues

Electricity generation and demand must be kept in balance at all times. When demand drops, it is necessary to ramp down and/or turn off generators. With higher penetration of variable renewable generation, there may be periods of excess generation (supply exceeds demand) which could lead to stability issues, overload, or over voltage constraints. Base-load units can only be ramped down to a minimum generation level in order to keep them online and avoid incurring an extended start-up time if forced to shut off completely. If an excess generation situation still persists after the ramp down of conventional units, it is then necessary to curtail non-firm renewable sources which may otherwise be producing power causing the excess supply condition. Energy storage can be employed as a sink to absorb excess generation during these low net-load (gross demand minus the renewable output) periods, storing energy which would otherwise be curtailed (wasted), and then supplying the energy back to the system during peak hours.

6. Shift energy

At the transmission and distribution level, electric energy time-shift involves purchasing inexpensive electric energy, available during periods when prices or system marginal costs are low, to charge the storage system so that the stored energy can be discharged or sold at a later time when the prices or costs are high. Alternatively, storage can provide similar time-shift service by storing excess energy production, which would otherwise be curtailed, from renewable sources such as wind PV[1] Operationally, this application is similar to avoiding curtailing excess energy as energy shifting on the transmission scale is performed during periods of over-generation.

7. Provide capacity

Capacity refers to the making power and energy available to given a electric market to serve current and future demand. Resource adequacy capacity requirements ensure sufficient resources are available in the CASIO market for safe and reliable operation of the grid in real time. Resource adequacy capacity is also designed to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future. For a given capacity resource, the net qualifying capacity is the qualifying capacity of a resource adjusted, as applicable, based on: (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions. Flexible capacity is defined as the quantity of resource capacity as specified by CAISO to meet maximum three hour ramping and contingency reserves. Depending on the circumstances in a given electric supply system, energy storage can be used as an alternative to buying new central station generation capacity and/or purchasing capacity in the wholesale electricity marketplace.

8. Smooth intermittent resource output

Smoothing intermittent resource output applies to circumstances involving renewable energy-fueled generation whose output change rapidly (over timescales ranging from seconds to minutes) due to transient cloud shadows on the PV array or short-term wind speed variability. With high renewable penetration, power output fluctuation may cause problems like voltage fluctuation and large frequency deviation in electric power system operation.[5]

Energy storage can be used to mitigate rapid output changes from renewable generation due to: a) wind speed variability affecting wind generation and b) shading of solar generation due to clouds. The resulting smooth renewable output offsets the need to purchase or rent highly dispatchable and fast-responding generation such as a simple cycle combustion turbine. Depending on location, smooth renewable energy output may also offset the need for transmission and/or distribution equipment.[4]

9. To "firm" renewable output

Firming is generally referred to renewable intermittency management over a longer time duration than smoothing. Renewables capacity firming applies to circumstances involving renewable energy-fueled generation whose output changes throughout the day due to change of solar insolation or wind speed.[4] The objective is to use additional dispatchable resources so that the combined output from renewable energy generation plus dispatchable resources is constant throughout the day.[4]

Storage can firm-up renewables output so that electric power can be used when needed, not just when the renewable resource is available.[3] The resulting firmed capacity offsets the need to purchase or rent additional dispatchable electric supply resources. Depending on location, firmed renewable energy output may also offset the need for transmission and/or distribution equipment.[4]

10. Improve transmission system operation (short duration performance, inertia, system reliability)

Energy storage used for transmission support improves the transmission system performance by rapidly compensating for real-time electrical anomalies and disturbances such as voltage sag, unstable voltage, and sub-synchronous resonance, resulting in a more stable system. Benefits from transmission support are situation- and location-specific. Transmission Stability Damping increases load-carrying capacity by improving dynamic stability. Sub-synchronous resonance damping increases line capacity by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies. For transient power quality and stability applications, storage systems must be capable of sub-second response times.[1]

11. Avoid congestion fees

Transmission congestion occurs when available, least-cost energy cannot be delivered to all or some loads because transmission facilities are not adequate to deliver that energy. When transmission capacity additions do not keep pace with the growth in peak electric demand, the transmission system becomes congested. Thus during periods of peak demand, the need and cost for more transmission capacity increases along with transmission access charges. Locational pricing of electricity is employed as a tool to account for congestion when managing supply and demand of electric power in a specific area.[1]

Electricity storage can be used to avoid congestion-related costs and charges, particularly when the costs become prohibitive due to significant transmission system congestion. In this service, storage systems would be installed at locations that are electrically downstream from the congested portion of the transmission system. Energy would be stored when there is no transmission congestion, and it would be discharged (during peak demand periods) to reduce peak transmission capacity requirements.[1]

12. Defer system upgrades

Upgrade deferral refers to delaying, or avoiding, of a utility investments in required system upgrades, by using energy storage. Energy storage can enable upgrade deferral on the transmission or distribution network. For transmission, installing energy storage downstream from a nearly overloaded transmission node can defer the need for the upgrade by reducing the peak demand seen at the constrained location. A key consideration is that storage can be used to provide enough incremental capacity to defer the need for a large lump investment in transmission equipment. Doing so could reduce overall cost to ratepayers, improve utility asset utilization, allow use of the capital for other projects, and reduce the financial risk associated with lumpy investments. Additionally, the storage device is available to provide other applications when not reserved for deferral operations.[1]

Distribution upgrade deferral involves using storage to delay or avoid upgrade investments that would otherwise be necessary to maintain adequate distribution capacity to serve all load requirements. Upgrade deferral may include replacement of an aging or over-stressed existing distribution transformer at a substation or re-conductoring distribution lines with larger wire. When a transformer is replaced with a new, larger transformer, its size is selected to accommodate future load growth over the next 15-year to 20-year planning horizon. Thus a large portion of this investment is underutilized for most of the new equipment's life. The upgrade of the transformer can be deferred by using a storage system to offload it during peak periods, extending its operational life by several years. If the storage system is containerized, then it can be physically moved to other substations where it can continue to defer similar upgrade decision points and further maximize the return on its investment.[1]

13. Improve distribution system operation (Voltage Support/VAR Support)

Utilities regulate voltage within specified ANSI standard limits by installing and operating tap changing transformers and voltage regulators at the distribution substation and by switching feeder capacitors downstream to follow load changes. This need is pronounced on long, radial lines with high loading or on feeders with high penetration of intermittent residential PV systems which may be causing unacceptable voltage deviations for neighboring customers. Placing distributed storage closer to load can improve network voltage profile, mitigate fluctuations, and reduce network power losses. [1]

14. Mitigate outages

A storage system can effectively support customer loads when there is a total loss of power from the source utility. This system can be installed at the feeder level, such as community energy storage devices, or customer-sited behind the meter to pick up load when utility service is lost. This support requires the storage system and customer loads to island during the utility outage and resynchronize with the utility when power is restored. The energy capacity of the storage system relative to the size of the load it is supplying determines the time duration that the storage can serve that load. This time can be extended by supplementing the storage system with on-site diesel gen-sets that can continue supporting the load for long-duration outages that are beyond the capacity of the storage system.[1]

15. Customer bill management: Time-of-use (TOU) energy and demand charge management

At the customer-sited level, electric storage can be employed to reduce customer energy bills when operating under a time-of-use energy tariff. Customers can charge storage during off-peak time periods when the retail electric energy price is low, then discharge the energy during times when on-peak time of use (TOU) energy prices apply. This application is similar to electric energy time-shift, although electric energy prices are based on the customer's retail tariff, whereas at any given time the price for electric energy time-shift is the prevailing wholesale price.[1]

16. Maintain power quality

Energy storage can be applied to protect and compensate for on-site customer loads. Short-term power quality events such as voltage spikes, sags, surges, and frequency deviations, which can damage customer equipment, can be mitigated through proper operation of energy storage. Reactive power compensation can also be employed to improve customer power factor.

17. Provide uninterruptible power supply

Even momentary outages or power quality events can result in large-scale customer financial losses when sensitive electronic or process equipment loads are present. The electric supply to these pieces of equipment can be backed up to an uninterruptible power supply which can seamlessly switch from the utility power supply to energy storage backup when a power quality event or momentary outage occurs. For long-term outages, the UPS enables ride-through capability ensuring continuous supply of power to critical loads while other conventional back-up generation is brought on-line.

3.2 Shared Applications

One effective way to increase the value of an energy storage asset is to use it in multiple applications such that its capacity, power, or time could be “shared” among them in a coordinated, overlapping manner. If the shared capacities are not overlapping, such as dedicating certain percentages of the capacity to different functions (for example, 20% for back up and 80% for peak shaving), the total value is not necessarily increased and almost the same result can be obtained by buying two smaller storage units. Overlapping shared capacity, power, or time, is what can help stack up different benefits, but proper controls are required to assure the priority of access.

Some of the most common shared applications include:

- Customer bill management combined with capacity dispatch applications such as Demand Response
- Utility upgrade deferral combined with capacity dispatch applications or ISO services such as participation in wholesale markets

3.3 Application Ranking for NCPA’s Selected Storage Technologies

DNV GL developed a ranking system for the various applications that battery energy storage systems may be utilized for within NCPA territory. Within this ranking system, information about each technology is used to ascertain its appropriateness for a particular application. The battery type’s typical size and technical parameters influenced these rankings.

Each considered application was defined by its requirements for power, energy, cycling, and response time. These Application Requirements were scored on a comparative scale. For instance, in the case of the application of Electric Energy Time Shift, the energy capacity of the system is paramount and thus ranked highly. Alternatively, in the case of the application for Frequency Response, the energy capacity of the system is of lesser importance while response time and power capability are the prioritized requirements. Each technology was then defined by its capabilities to meet these requirements for power, energy, cycling, and response time. These technology capabilities were similarly scored on a comparative scale. For instance, Li-ion technology provides nearly instantaneous response time and was thus ranked highest in that parameter. Flow batteries, on the other hand, scored highest for cycling as they are capable of fully discharging daily with less impact on lifetime and degradation.

The Application Requirements and Technology Capability scores were then compared, defining how well-matched a specific technology was for a given application. For instance, if an application required fast response time, the technologies that provide a fast response time would score highest. Scores across each property were then averaged to provide a Technology Application score for each technology providing each application.

This assessment resulted in the application ranking show below, on a scale from 1 – 10, with 10 (indicated by dark green) demonstrating high correlation between application requirements and technology characteristics. Generally, DNV GL finds that a score of 6 or higher will allow a technology to sufficiently meet the requirements of an application. DNV GL’s discussion and additional opinion around these results follows the table.

	Li-Ion NCM	Li-Ion LFP	Li-Ion LTO	VRB	Flywheel	CAES	TES
Electric Energy Time Shift	8	7	7	8	5	8	7
Electric Supply Capacity	8	7	8	8	5	8	6
Regulation	8	8	9	8	8	6	5
Spinning, Non-spin, Supplemental reserves	8	8	9	7	7	6	4
Voltage support / Power Quality	8	9	9	8	9	5	5
Load following / ramping support for renewables	8	8	9	8	7	6	5
Frequency response	8	9	10	7	9	5	4
Transmission and distribution congestion relief	8	7	8	8	6	8	6
Black Start	Y	Y	Y	Y	Y	Y	N
Reliablity	Y	Y	Y	Y	N	Y	N

	Li-Ion BTM
Bill management - DCM	9
Bill management - TOU	9
Bill management - Self-supply	9
Customer back up	8

Figure 2 Application Ranking of NCPA's Selected Storage Technologies

Under appropriate conditions, Li-Ion technologies are generally well-suited for all of the applications discussed. NCM and LTO specifically are highly rated across all applications reviewed here. LFP's lower cycle life and energy capacity reduces its ratings for repeated deep discharge usage, as seen in energy time shift and electric supply capacity. LTO, while being highly rated is, however, the most expensive of the three chemistries. As such, NCM is currently the most commonly implemented chemistry. Developments and research are, however, closing these gaps.

Similarly, VRB technology is well suited for all of the applications reviewed. While the system's ability to serve long duration makes it especially attractive for energy applications, VRBs can also support shorter, high power applications. Although the technology is less established than Li-ion, if the deployed systems prove performance to these operational characteristics and costs fall with further development, the technology will be attractive for long duration, utility-scale storage.

Flywheels have very fast response times, high power ratings, and show no degradation for high amounts of cycling. As such, this technology is most useful and cost effective for power applications. Although there are flywheel systems developed to serve for up to an hour at a lower power rating, most flywheels are designed for under a minute of use at a time at very high power. For this reason, energy applications all receive lower ratings in DNV GL's quantitative analysis.

In contrast, CAES systems are designed to support extremely long duration energy applications, in some cases, over a day of continuous energy. Due to this, DNV GL's quantitative assessment ranked CAES highly for the energy applications reviewed. CAES systems, purely based on their design mechanics, have a slow response time, requiring up to 10 minutes to respond to controls and serve the demand. As such, although CAES systems have large power values due to their scale, they are not well suited for applications that require quick responses such as voltage support, frequency response, or ramping for renewables.

Finally, ice energy storage is appropriate for energy time shift and reduction in peak demand due to space cooling. Further, when leveraged and coordinated in a single sub-load area, aggregated systems can provide both T&D congestion relief as well as be supportive for supply capacity application. Since peak cooling is highly seasonal and aligns with peak demand hours, wide-spread utilization of this technology can also help to delay infrastructure upgrades otherwise required to meet these concentrated peak periods.

4 STORAGE USE CASE STUDIES

It is difficult to determine cost-effectiveness for storage in general because determining benefits for storage often require modelling a specific technology at a specific location. The costs and benefits can vary depending on three main factors:

1. Location of the device on the grid. The device can be installed on the transmission grid, distribution grid or behind the meter. The benefits would vary based on the market prices or tariffs available at that location, as well as the condition of the grid at that location.
2. Storage technology. Storage technologies vary widely from duration, cycle times, efficiency, and physical configuration and constraints. In addition, different vendors offer the same storage technology in very different packages and functionalities. These factors affect the device cost, and the applications it can perform.
3. Applications. Storage technologies can perform 17 applications as outlined in Section 3. Most of these applications would require analysis using a modelling tool with proper time-scale and fidelity. For stacked applications, multiple analytical tools may be needed.

Providing a general value for storage will likely be wrong. Instead, the storage industry has opted to assess storage on an use case basis. The use cases would have defined assumptions such as location, technology, market, and tariffs. The most comprehensive energy storage cost-effectiveness use cases were completed under the CPUC storage proceeding by DNV GL and EPRI in 2013. Subsequently, new storage technologies have become available, storage costs have come down, renewables penetration has increased, and market conditions have changed. The 2013 results could be updated using the same cost-effectiveness methodologies; however, without additional analysis, it is safe to assume that the cost-effectiveness in general are more favorable now than in 2013.

The following sections provide examples of energy storage use cases in the transmission side, distribution side, and customer side level. The value basis for these findings are storage costs versus benefits, such as market revenue potential, avoided transmission and distribution (T&D) investment and customer bill savings versus storage cost. For each of the use cases, it shows that energy storage is cost effective for a specific subset of assumptions under a range of benefits versus a range of costs. The cost-effectiveness reaches a breakeven point when the value side of the equation being at the upper end of the assumed value range, and the storage cost being at the lower end of the assumed cost range.

4.1 Use Case #1: Transmission-connected storage to provide frequency regulation

Under CPUC's AB 2514 proceeding, DNV GL simulated the cost-effectiveness of a transmission-connected fast-responding providing frequency regulation under a performance payment regime. The frequency regulation market requires devices to match 4-second signals. The benefit of this use case is market revenue from CAISO. The case studies found that the breakeven point of the simulation is $882/kW

($3528/kWh) cost for the device. Any storage devices with costs below this level are even more cost competitive and any devices with costs higher are estimated to be not cost effective. Although this study is done for battery device, the operating characteristics are also representative of a flywheel, pumped hydro, or other fast acting storage device. The breakeven cost, that is benefit cost ratio (BCR) of 1, for a flywheel storage device is $6.44 million ($965/kW or $3,860/kWh). The study has assumed FR costs to increase 3% every year, but this has not been observed in the California Independent System Operator (CAISO) market. If regulation costs are twice what they were estimated to be, then the breakeven cost for a battery storage device participating in the CAISO regulation market is $40.78 million ($2,039/MW or $8,156/MWh).

The primary benefit used in the cost-effectiveness modeling and evaluation is market revenue. For the Frequency Regulation Only Use Case modeled, the form of market revenue quantified as a “benefit” is market-based payment for provision of Regulation Up (RegUp) and Regulation Down (RegDown) services sold into the CAISO market. The market pays devices in two ways: capacity payment for the opportunity cost of the committed capacity, and the performance of actual up and down movement of the resource following the signal (mileage).

DNV GL used high resolution production simulation modeling tool PLEXOS with DNV KEMA Renewable Market Integration Tool (KERMIT) tool to estimate the potential revenue stream in a future market scenario that includes Pay for Performance. Production simulation was used to determine the dispatch and related hourly base clearing price for RegUp and RegDown payments for a sample set of days that were then extrapolated for a representative year’s 8760 market hours. The KERMIT tool was then used for the inter-hour resolution needed to estimate the associated Pay for Performance Benefit Factor applied to the Production Simulation (production cost based) RegUp and RegDown base clearing prices.

The benefit cost analysis is a pro-forma style analysis that estimates break-even capital costs for the 20 MW, 5 MWh storage device based on a 20 year revenue stream from CAISO regulation market and listed project financing assumptions. In addition, system benefits are estimated by determining the change in California production costs estimated by PLEXOS for the simulations with and without the storage device. Sensitivity analyses examining the influence of the primary factors are reported as well.

For the base case, the breakeven cost (a benefit-cost ratio of 1) for a 20 MW, 5MWh storage device participating in CAISO regulation markets from 2015 to 2035 is $17.6 million. This represents an $882/kW ($3528/kWh) cost for the device. Any storage devices with costs below this level are even more cost competitive and any devices with costs higher are estimated to be not cost effective. For example, a battery storage device with a capital cost of $600 per kW is estimated to have a 20 NPV of $7.50 million whereas a battery storage device with a capital cost of $1,000 per kW is estimated to have a 20 NPV of negative value of $3.14 million.

The breakeven cost, that is benefit cost ratio (BCR) of 1, for a flywheel storage device is $6.44 million ($965/kW or $3,860/kWh) and the BCR for a flywheel with a capital cost of $1,500 is 0.66. This is a 9.4% increase in breakeven capital cost compared to the battery storage device indicating higher capital cost projects are feasible. This is because the flywheel device has lower variable O&M costs and does not need to replace a battery stack every 10 years.

If regulation costs are twice what they were estimated to be, then the breakeven cost for a battery storage device participating in the CAISO regulation market is $40.78 million ($2,039/MW or $8,156/MWh). This is a

232% increase compared to the base case results. Using the capital costs CESA provides, the BCR for a battery is 2.18 and 1.33 for a flywheel.

From an operations point of view, the most important factor determining the breakeven cost is the performance of the storage device as that determines what fraction of the approximately $3 million the storage device is able to obtain. If the performance of the storage device is reduced by 10% (from 98% to 88% for up regulation performance and from 95% to 86% for down regulation performance) then the BCR decreases by 0.11 for a battery and 0.06 for a flywheel. The break-even cost decreases by 14%. The table below summarizes the simulation results of battery and flywheel under the base case and sensitivity cases.

Table 2 Summary Table of Benefits Costs for Scenarios for Regulation Markets

Scenario	Asset Type	Capex ($/kW)	Regulation Price Multiplier	Performance Multiplier	Benefit to Cost
Base Case	Battery	$750	1	1	1.09
	Flywheel	$1,500	1	1	0.66
2x Regulation Price	Battery	$750	2	1	2.18
	Flywheel	$1,500	2	1	1.33
P4P Performance Score (Pay for Performance)	Battery	$750	1	0.9	0.98
	Flywheel	$1,500	1	0.9	0.6

4.2 Distribution-Connected substation upgrade deferral

Substation upgrade deferral is the delayed investment of additional substation transformer capacity. Storage enables this deferral by reducing substation transformer peak loading during the hours of the years for which the respective equipment would have been overloaded without energy storage. In addition to peak shaving, the storage device can output reactive power to reduce voltage drops and losses across the substation transformer. Lastly, by reducing peak demand overloads on the substation transformed, the useful life of the substation transformer can be extended.

Distributed energy storage is typically not a cost-effective solution when a voltage deviation issue can be solved with traditional distribution voltage regulation equipment such as adding additional capacitors or voltage regulators. As shown in the case study done for the SDG&E (Section 4.2.1), relatively low cost of this traditional solutions as compared to utility scale energy storage at current prices made storage not a cost-effective solution. However, traditional voltage regulation solutions may not be viable or effective at addressing all voltage regulation issues, such as those arising in cases of high PV penetration on constrained feeders. In such cases, if circuit reconductoring is otherwise required, the associated avoided-cost benefit can make energy storage a cost-effective solution. An example of a cost-effectiveness analysis for distributed energy storage being employed to avoid circuit re-conductoring is shown in section 4.2.2.

4.2.1 Use Case #2: SDG&E distribution upgrade deferral

SDG&E contracted DNV GL to perform an independent cost-effectiveness analysis on the highest ranked bid from the 2014 Storage RFP. DNV GL applied its proprietary ES-GRID[6] modeling tool to assess the cost-

[6] The ES-GRID tool is an advanced modeling and simulation tool designed to assess the cost-effectiveness of energy storage connected on the distribution system. The tool is customized to a specific system and can assess the cost and benefits of single or bundled storage

effectiveness of the capacity upgrade deferral for each of the defined scenarios. DNV-GL simulated a total of 36 scenarios. As documented in details below, SDG&E found that 35 of 36 scenarios were not reasonably cost effective after applying both quantitative and qualitative evaluation criteria. The NPV savings of the lone cost effective scenario is $700,000. This NPV in savings is approximately 5% of the total installed cost for the highest ranked storage solution, and approximately 1% of the estimated substation costs, which includes a 30% contingency. This means the entire quantitative value of pursuing the storage solution rests on that solution's actual costs being almost exactly its estimated costs. If the actual costs exceed the estimated costs by 5% or more, the immediate value to customers is entirely eroded. However, if the substation's actual costs are only 1% less than estimated costs – not an implausible outcome give that the substation's estimated costs include a 30 % contingency – there is no immediate value to customers in having installed storage to defer construction of the planned substation. Given these objectively thin margins, SDG&E elected to not pursue the storage solution in this particular instance.

SDG&E identified a planned substation as a potential candidate for deferral by a cost-effective energy storage project. The planned substation is needed to accommodate expected growth of end-use load in one area of SDG&E's distribution service territory, maintain substation and circuit reliability, and reduce area substation loading to optimum operating conditions. The 2014 Storage RFP was designed to determine whether (i) an energy storage project could inject enough power, at the right times of the day and year and at the low voltage side of the existing transformers (where the distribution feeder circuits connect) to reduce power flows across the existing transformers to delay the point in time when the planned substation would need to be constructed, and (ii) the savings associated with deferring the construction of the planned substation would offset the cost of the energy storage project; i.e., would be cost-effective for SDG&E customers.

SDG&E worked with DNV GL to define a set of scenarios and inputs for the ES-GRID model runs. This scenario based approach allows for the cost-effectiveness of the energy storage project to be assessed over the range of bid pricing options, storage power and energy configurations, substation upgrade costs, and transformer bank overload triggers. To compute the number of years of deferral that each energy storage configuration can provide, the model used SDG&E's hourly SCADA load data and forecast load for each of the identified transformers. For each scenario, and across all 10 years of the simulation horizon, ESGRID computed the optimal hourly energy storage dispatch schedule for peak shaving on the impacted transformer bank. For each scenario, the ES-GRID analysis produces the hourly storage dispatch profiles, number of years of deferral, and days that storage would be dispatched for peak shaving. Using the computed deferral period, the model next calculated the net present value (NPV) based on various benefit and cost elements such as capital expenditure, installation cost, fixed and variable O&M costs, storage charging cost, deferral benefit, and deferred/avoided tax payments.

DNV-GL simulated a total of 36 scenarios and found that 35 of 36 scenarios were not reasonably cost effective after applying both quantitative and qualitative evaluation criteria. For the scenarios with 4 MW / 12 MWh storage solution and a 100% loading trigger, the model determined that 12 scenarios were cost effective (i.e., had a positive NPV), and concluded it is possible to defer the planned substation for three years, starting in 2018. For these scenarios, storage is dispatched in a limited number of hours on three

applications. Through scenario development, the tool allows for the direct comparison of multiple scenarios of a particular energy storage use case.

days in 2018, 2019, and 2020. However, at a closer look at these “cost-effective” scenarios, most of them require one or a combination of the following unrealistic characteristics:

- The planned substation cost to fall within the “high” cost category, or 20% over the engineering budget.
- The storage device contained warranty options that were significantly less than the asset’s useful life

Only two scenarios were cost effective using the mid-case substation costs, and a 10-year warranty option. One scenario has an estimated NPV savings of $700,000, and another has an estimated NVP savings of $3,000 which is essentially a breakeven case. Removing the breakeven case, the only cost-effective scenario under reasonable assumptions has an NPV savings of $700,000. This amount is equivalent approximately 5% of the total installed cost for the highest ranked storage solution, and approximately 1% of the estimated substation costs, which includes a 30% contingency. To put this in perspective, the entire quantitative value of pursuing the storage solution rests on that solution’s actual costs being almost exactly its estimated costs. If the actual costs exceed the estimated costs by 5% or more, the immediate value to customers is entirely eroded. Similarly, if the substation’s actual costs are only 1% less than estimated costs – not an implausible outcome give that the substation’s estimated costs include a 30 % contingency – there is no immediate value to customers in having installed storage to defer construction of the planned substation. Given these objectively thin margins, SDG&E elected to not pursue the storage solution in this particular instance.

4.2.2 Use Case #3: CPUC avoided distribution system upgrade for PV integration

For a different distribution-connected use case, storage is found cost-effective for PV integration when re-conductoring costs were high. Distribution upgrades avoidance, including re-conductoring and avoided regulator costs, accounted for the majority of the storage benefits. Distribution system loss savings were found to be only a small portion of the overall benefit. As shown in Figure 3, DNV GL ran 250 cases that were simulated for the distributed energy storage for PV integration Use Case. The break-even case reflects a correctly sized battery with high re-conductoring costs, low deferral value, and medium range storage costs. Sizing storage greater than the line limit needs increases costs with only small incremental benefit, resulting in non-economic cases. Additional benefits not valued here include improved power quality potential and potential improvements to system reliability.

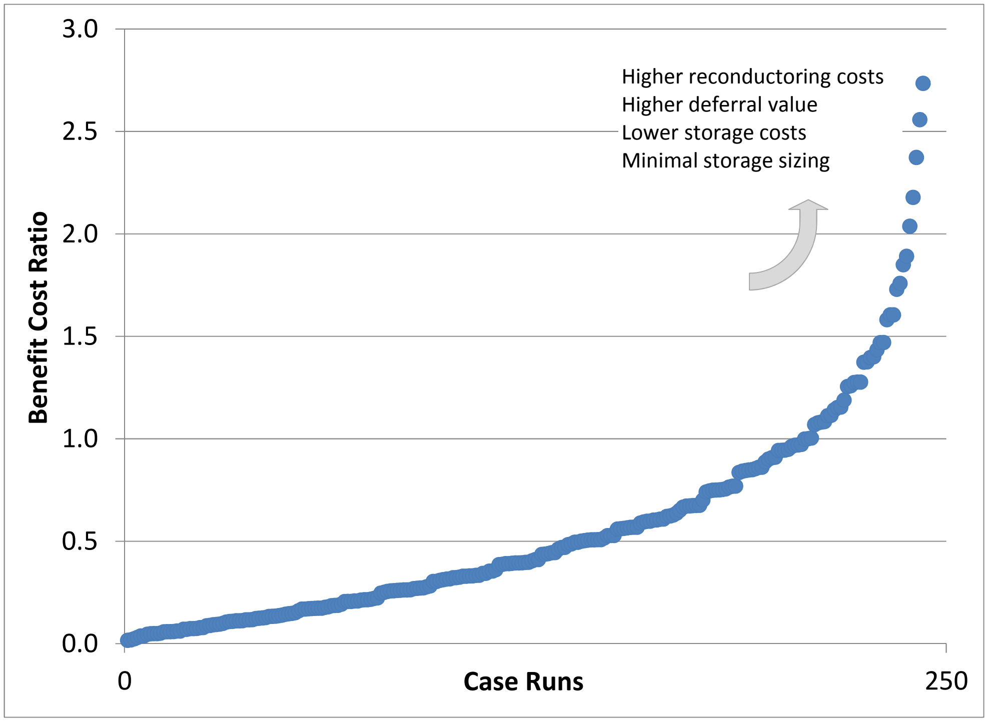


Figure 3 Benefits-Costs for Substation-sited Distributed Energy Storage for PV Integration

Energy storage can be employed by utilities to facilitate the integration of PV generation and mitigate possible negative impacts on the distribution system by:

1. avoiding system upgrades required for PV integration
2. mitigating voltage fluctuations at the primary distribution side resulting from intermittent distributed PV generation
3. reducing distribution system losses through improved utilization of distributed generation
4. deferring upgrade of substation equipment by time-shifting peak PV generation to coincide with system load peak

In the Use Case presented here, the avoided system upgrade is reflected as an avoided investment to re-conductor distribution equipment that would have become overloaded in the presence of reverse power flows from downstream PV generation. Energy storage is presented as an alternative to this equipment upgrade. The cost-effectiveness of energy storage for this Use Case is evaluated based on engineering modeling. In particular, the costs and benefits account for system-wide impacts, observed via time series power flow simulation. Also, the modeling results guide assumptions and evaluate the degree to which energy storage can meet the needs of the stated applications (at different energy storage sizes, for example). For this Use Case, the model simulates power flow over a sample multi-phase distribution test feeder, publicly available from the Institute of Electrical and Electronics Engineers (IEEE) as IEEE 123 Node

Test Feeder.[7] Simulation results for these systems are obtained using DNV GL's distribution energy storage valuation tool, ES-GRID.

Table 3 summarizes the engineering analysis results for IEEE 123 Node Feeder with PV generation. The results provided for the base case, represent the distribution system performance with PV and without energy storage. The columns to the right present distribution system performance with energy storage. Each column represents performance for the same distribution system, but with the corresponding size and duration of energy storage installed. The engineering analysis results illustrate the ability of energy storage to mitigate overloads of the capacity constrained lateral, eliminate both high and low voltage exceptions, reduce system losses, reduce system peak demand, and reduce voltage regulation tap changed operations.

Table 3: Summary Results for Distribution System Performance with PV and Energy Storage

Metric	Base case	500 kW, 2 HR	500 kW, 4 HR	1000kW, 2HR	1000kW, 4HR	2000kW, 2HR
Peak real power demand (kW)	4,369	4,341	4,341	4,259	4,259	4,145
Line capacity overload (Hours)	662	46	0	0	0	0
Maximum line flow (kW)	405	369	341	341	332	332
Total energy demand (MWh)	16,422	16,453	16,464	16,508	16,511	16,646
Total Losses (MWh)	605	581	568	572	568	622
Tap changes (#)	10,706	10,198	9,998	10,002	9,990	11,723
Maximum voltage (per unit voltage)	1.0568	1.0522	1.0492	1.0492	1.0473	1.0703
Overvoltage events (#)	123	11	0	0	0	356
Minimum voltage (per unit voltage)	0.94487	0.94699	0.94699	0.95178	0.95178	0.94433
Undervoltage events (#)	172	35	24	0	0	30

Drawing on the results of the engineering analysis, a cash flow analysis was run for a series of scenarios, using combinations of the key sensitivities: storage size, storage duration, storage costs, cost of re-conductoring, deferral value, and load growth rate. Six illustrative scenarios are shown in Table 4.

Table 4: Select Financial Results

Scenario #	Size	Deferral	Benefits	Costs	NPV	BCR
150	0.5 MW 4 hr	$309/kW	2,584	-2,392	192	1.1
177	1 MW 4 hr	$309/kW	2,867	-4,753	-1,887	0.6
138	0.5 MW 4 hr	$70/kW	2,399	-1,880	519	1.3
153	0.5 MW 4 hr	$538/kW	2,761	-2,392	369	1.2
147	0.5 MW 4 hr	$70/kW	2,399	-2,392	7	1.0

Figure 4 illustrates a cost-effective case, Scenario 150, on the left. The majority of the benefits are due to avoided re-conductoring upgrades. Additional benefit comes from substation upgrade deferral and some loss reduction. Larger energy storage investment, illustrated with Scenario 177, on the right, shows a slight

[7] "IEEE 123 Note test Feeder," IEEE Power Engineering Society, Power System Analysis, Computing and Economics Committee, Distribution System Analysis Subcommittee.

increase in value. However, the case is not cost-effective, as the incremental cost of sizing energy storage beyond the re-conductoring avoidance application is greater than the incremental benefits.

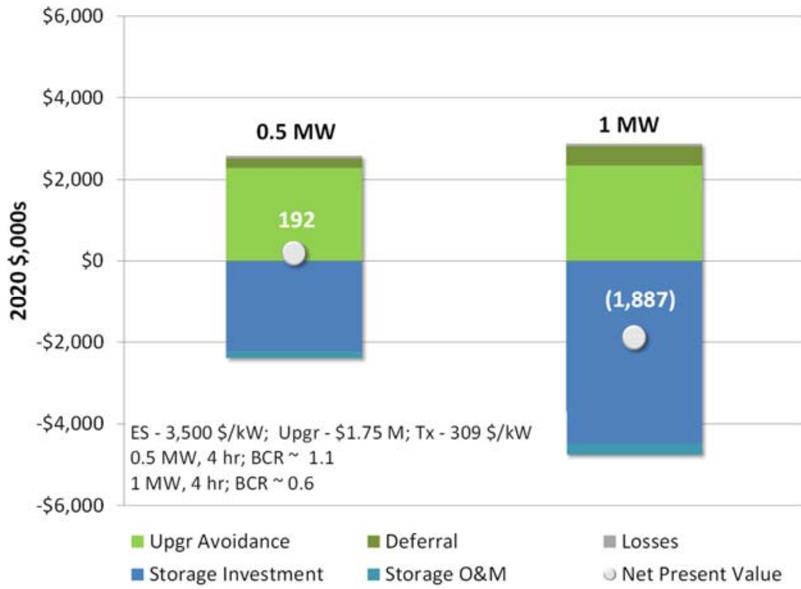


Figure 4: Cost, Benefits and NPV for Scenarios 150 and 177

Though re-conductoring is the primary benefit of this application, higher substation upgrade costs (and therefore higher deferral values) enable cost-effective cases with higher energy storage costs. Figure 5 illustrates two cases that are cost-effective, one with lower energy storage cost and deferral value (Scenario 138, on the left) and the other with higher energy storage cost and deferral value (Scenario 153, on the right).

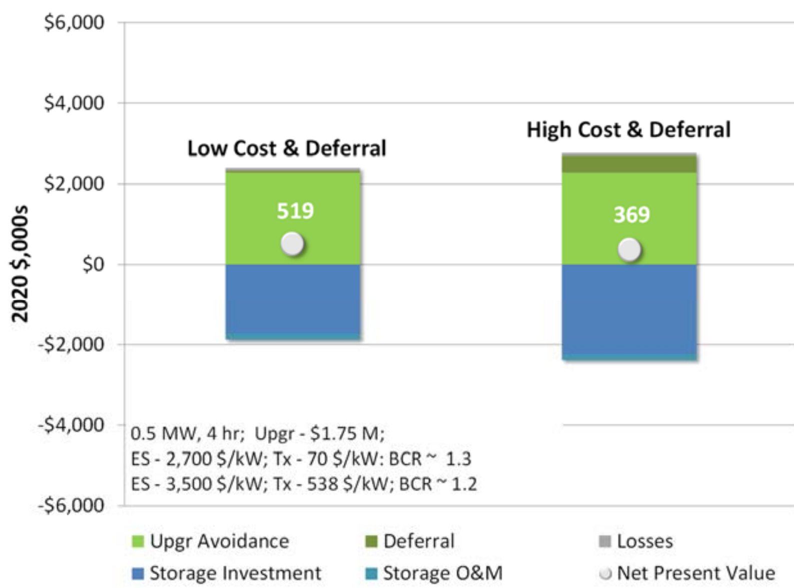


Figure 5 Cost, Benefits and NPV for Scenarios 138 and 153

4.3 Use Case #4: Behind the Meter Storage for Bill Reduction

The primary use of behind the meter storage is for peak demand reduction. DNV GL modelled common area meter of multi-family residence and a school in SDG&E's territory. For the common area meter scenario, tariff switching gives an estimated Internal Rate of Return (IRR) of around 18%-27% depending on storage costs, while maintaining the facility on the same tariff gives an estimated IRR of around 9% -15%. For the school scenario, the best simulated IRR for a combined installation of solar PV and storage is around 17%-23%. The scenario with only storage installation in the school has an estimated IRR of 14%-38%.

Table 5: Financial Results for Different Customer Use Case Scenarios

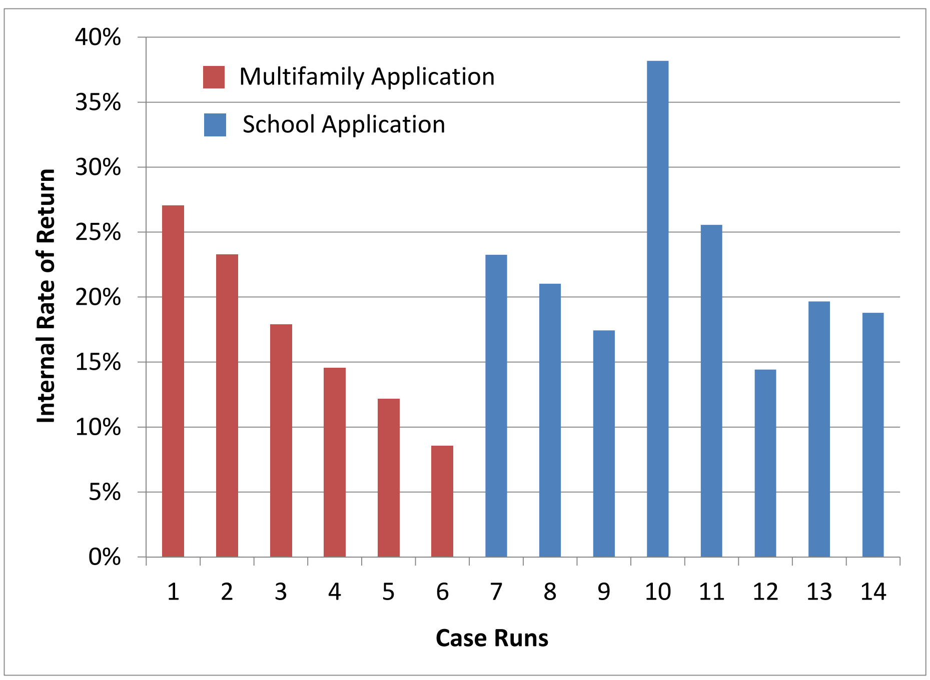
Storage cost ($/KW)	Installation			Incentives					Financial Results	
	Facility Peak	Installed Storage	Installed PV	SGIP	CSI	FITC		Acc dep	IRR	NPV
						PV	Storage			
Scenario 1: Storage and Solar PV dc-coupled Customer Type: Common area meter of multi-family residence Primary Function: Demand reduction to shift to different tariff										
Low - $3000/KW	21	5 KW, 10 KWhr	5 KW	YES	YES	YES	YES	YES	27.03%	$13,363
Med - $3500/KW									23.29%	$12,110
High - $4500/KW									17.90%	$9,602
Scenario 2: Storage and Solar PV dc-coupled Customer Type: Common area meter of multi-family residence Primary Function: Demand and energy charge reduction										
Low - $3000/KW	22.5	5 KW, 10 KWhr	5 KW	YES	YES	YES	YES	YES	14.55%	$4,692
Med - $3500/KW									12.17%	$3,438
High - $4500/KW									8.56%	$931
Scenario 3: Storage and Solar PV dc-coupled Customer Type: School Primary Function: Demand and energy charge reduction										
Low - $3000/KW	900	50 KW, 100 KWhr	50 KW	YES	YES	YES	YES	YES	23.26%	$164,918
Med - $3500/KW									21.02%	$152,382
High - $4500/KW									17.43%	$127,310
Scenario 4: Only Storage Customer Type: School Primary Function: Demand and energy charge reduction										
Low - $3000/KW	900	50 KW, 100 KWhr	50 KW	YES	NA	NA	No	YES	38.18%	$91,391
Med - $3500/KW									25.56%	$75,215
High - $4500/KW									14.41%	$42,864

For demand-side use cases the customer savings due to bill reduction required the ability to calculate the specific amount of demand reduced and energy shifted against a sample demand shape that has enough detail to adequately estimate the electric bill impacts. When other customer-side assets like PV are introduced, the control of energy storage within the model also required substantial controls logic (implemented via linear programing optimization) to answer the deceptively simple question - by how much can electric bill charges be reduced through a given storage system. DNV GL's Microgrid Optimization (MGO) tool was used to perform both the storage use optimization against an annualized demand shape to lower customer electric bill charges.

For the Demand Energy Storage category Use Cases, the primary benefit used in the cost-effectiveness modeling and evaluation is customer electric bill reduction through removal or reduction of Demand Charges applicable to some general commercial and industrial rate categories, and shifting PV output to reduce energy related bill charges. On-site PV was also included in several sensitivities which was added to the bill minimization optimization scheme by using available storage capacity to shift PV output for energy savings and account for any coincident reduction in net load demand. Given that the benefits for this Use Case are strictly from the perspective of the retail customer, retail customer incentives also enter into the 'benefits' calculation as a reduction in capital expenditure (CAPEX) initial investment cost.

Customer owned and operated storage is cost-effective for facilities with high peak demand to base load ratio, under tiered time-of-use (TOU) tariffs with high demand charges. In these cases, the current Self Generation Incentive Program (SGIP) incentives played a significant role in storage cost-effectiveness.

Figure 6: Internal Rate of Return for Multifamily and School Applications



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[4] Jim Eyer, Garth Corey, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide,* February 2010

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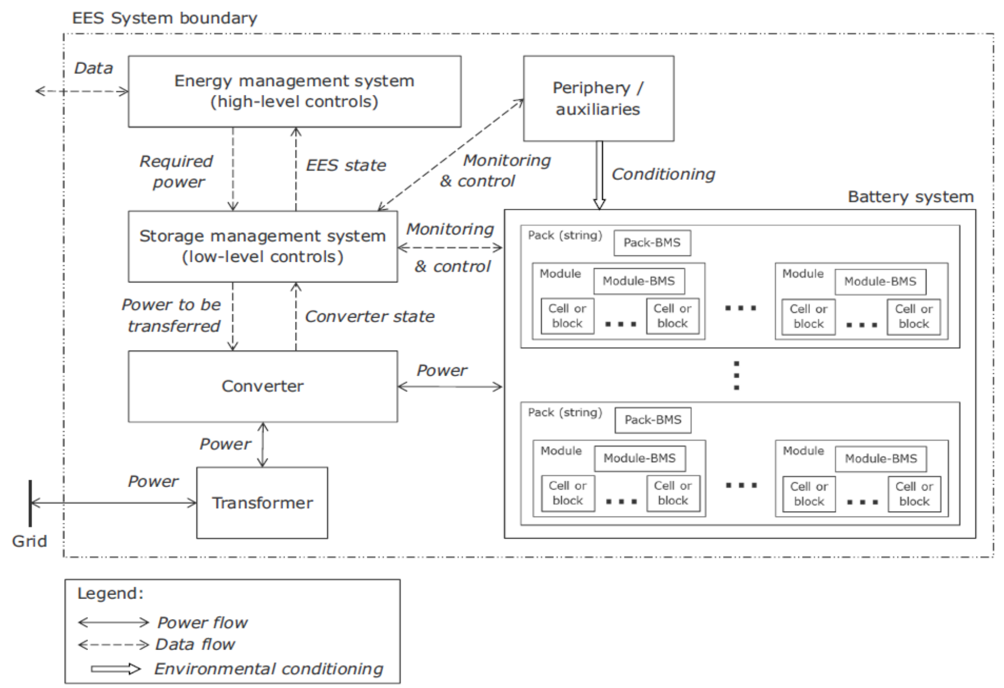
Lithium Ion

Lithium-Ion (Li-Ion) batteries utilize the exchange of Lithium ions between electrodes to charge and discharge the battery. Li-ion is a highly attractive material for batteries because it has high reduction potential, i.e., a tendency to acquire electrons (-3.04 Volt versus a standard hydrogen electrode), and it is lightweight. Li-Ion batteries are typically characterized as power devices capable of short durations (approximately 15 minutes to 1 hour) or stacked to form longer durations (but increasing costs). Rechargeable Li-ion batteries are commonly found in consumer electronic products, such as cell phones and laptops, and are the standard battery found in electric vehicles. In recent years this technology has developed and expanded its portfolio of applications considerably into utility-scale applications which, despite having very different requirements and features from consumer applications, benefit from the scale of manufacturing which lowers costs across markets. Because of its characteristics, Li-Ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term (30-minutes or less) spinning reserve applications.

As with all energy storage technologies, Li-Ion batteries do carry some safety risk. Extreme over-heating or thermal runaway could cause fire and the release of toxic or reactive gases. This risk is strongly mitigated by various methods of cooling, including natural convection, forced air cooling, and liquid cooling, which keep the batteries not only at a safe temperature, but also at a temperature optimal for operation.

These risks are being regulated at an industry level, with the development, testing, and updates to safety standards, including recommendations for the appropriate response to fires. All Li-Ion systems being purchased and installed should be certified to such standards.



Parameter/ Technology		Li-Ion BTM		Li-Ion NCM	Li-Ion LFP	Li-Ion LTO
		Residential	C/I			
Power capacity	**Minimum**	2 kW	250 kW	1 MW	1 MW	1 MW
	Maximum	10 kW	1 MW	35 MW	35 MW	40 MW
Energy Capacity	**Minimum duration**	20 min	20 min	20 min	20 min	10 min
	Maximum duration	4 hr	4 hr	2 hr	2.5 hr	2 hr
Recharge rates		1C	1C	1C	2C-1C	3C-1C
Round trip efficiency		90%	82-83%	77 - 85%	78-83%	77-85%
Availability	**Up-time**	97%	97%	97%	97%	96%
	Carve Outs	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr
Response time		ms	ms	ms	ms	ms
Degradation - Percent of initial capacity lost after 10 years	**Energy Applications**	40%	30%	30-40%	20-40%	15-25%
	Power Applications	10-20%	10-20%	10-20%	15-25%	5-15%
Expected life (100% DOD, 25*C, 1C)	**Years**	10	10	10	10	10
	Cycles	3,500	5,000	3,500	2,000	15,000

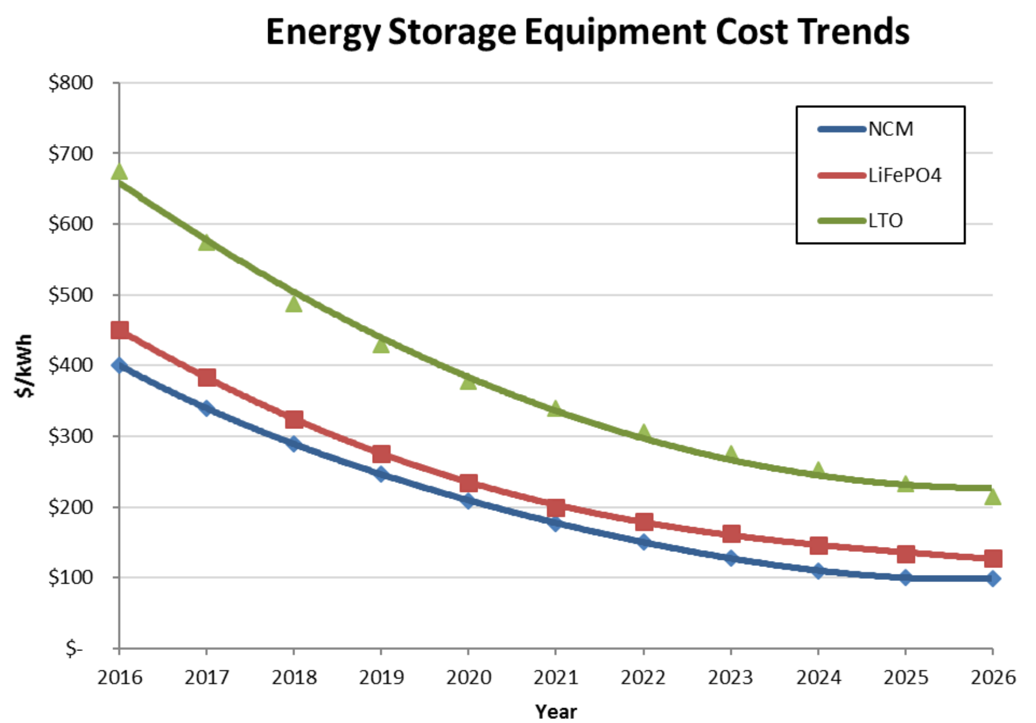
Lithium Ion

Lithium Ion energy storage systems, while differing across battery chemistries (as detailed later in this document), are generally appropriate for serving energy applications, moderate power applications, and applications requiring a short response time. Further, if charged at the time of the outage, Li-Ion systems can support a black start. Across the board, with an increase in adoption, Li-Ion technologies have reduced in price and improved in operation. However, of the technologies reported on in this project, Li-Ion batteries are some of the most sensitive to temperature. As such, Li-Ion systems are generally installed with cooling and heating systems, which may consume a portion of the useable system capacity.

Li-Ion is, in the current market, the dominating technology found in behind-the-meter (BTM) installations due in part to it's ability to scale to residential and commercial needs with a minimal physical footprint. BTM is used at the customer site to provide back up and bill management services. Bill management applications include electric time shift, to charge during lower time of use (TOU) periods and discharge during more expensive TOU periods; demand charge management (DCM), to discharge the battery in order to reduce peak load; and self-supply, to regulate the use of renewables thus more closely matching the renewable generation to the user load profile. Li-Ion technology is well suited for these applications due to its fast response time and recharge rate. Many systems are currently being designed with limited to no planned customer input or maintenance, but constant monitoring, controls, and service deployment as needed.

Utilities are beginning to investigate the aggregation of BTM storage to support grid services. The burgeoning demand for small scale distributed energy storage highlights the sometimes conflicting needs and requirements of utilities and end use customers, when high demand periods coincide. This poses an interesting controls and contracting challenge, but the flexibility of Li-Ion storage technology is appropriate for these broader and more intricate controls.

Based on DNV GL's quantitative assessment, under appropriate conditions, Li-Ion technologies are generally well-suited for all of the applications discussed. NCM and LTO specifically are highly rated across all applications reviewed here. LFP's lower cycle life and energy capacity reduces its ratings for repeated deep discharge usage, as seen in energy time shift and electric supply capacity. LTO, while being highly rated is, however, the most expensive of the three chemistries. As such, NCM is currently the most commonly implemented chemistry. Developments and research are, however, closing these gaps. The differences in chemistries are discussed further on the following page.



Cost Parameter/ Technology	Li-Ion NCM	Li-Ion LFP	Li-Ion LTO
Energy storage equipment cost ($/kWh)	$325-$450	$350-$525	$500-$850
Power conversion equipment cost ($/kW)	$350-$500	$350-$500	$350-$500
Power control system cost ($/kW)	$80-$120	$80-$120	$80-$120
Balance of system ($/kW)	$80-$100	$80-$100	$80-$100
Installation ($/kWh)	$120-$180	$120-$180	$120-$180
Fixed O&M cost ($/kW yr)	$6-$11	$6-$11	$6-$11
Major Maintenance ($/kW)	$150 - 400	$150 - 400	$150 - 400
Years between major maintenance	5	5	5

Li-Ion BTM	Residential	C/I
Total installed cost $/kWh	$530 - $765	$525-$700

Lithium Ion – Nickel Manganese Cobalt

$LiNiMnCoO_2$ (NCM or NMC) is one of the most commonly used chemistries in grid-scale energy systems. This technology demonstrates balanced performance characteristics in terms of energy, power, cycle life, and cost.

Nickel by itself has a high specific energy and poor stability whereas manganese offers low internal resistance with a low specific energy. Combining the two elements enables a high discharge current and leads to a better product. The cathode in this battery typically has a ratio of nickel to cobalt to manganese of 1-1-1 respectively but other combinations are also possible. The three active materials in NCM batteries can be easily blended and offer an economically viable solution for various applications. The NCM chemistry is most beneficial in applications where high battery cycle life, power and stability is required.

NCM batteries have a nominal charge of 4.10V/cell instead of 4.20V/cell, providing a lower energy capacity than Lithium Cobalt Oxide ($LiCoO_2$) batteries but higher energy density and longer life. NCM chemistry is very common due to these features as it provides an engineering compromise.

Lithium Ion – Iron Phosphate

$LiFePO_4$ (LFP) can be purchased at a low cost for a high power density, and its chemistry is considered one of the safest available within Li-ion batteries. Due to its very constant discharge voltage, the cell can deliver essentially full power to 100% DOD. However, $LiFePO_4$ batteries are typically applicable to a more limited set of applications due to its low energy capacity and elevated self-discharge levels.

LFP batteries offer low resistance, high current rating and long cycle life. They also perform well when kept at high voltages for a long time and have higher rates of discharge compared to other Li-ion batteries. The nominal voltage of a LFP cell is 3.20V and has a round-trip efficiency of 92%. Compared to other technologies, a LFP battery can still retain a 90% efficiency when discharge rates are low.

LFP batteries do not need to be fully charged which offers flexibility in installations where multiple cells are connected in parallel. In other words, battery operation is not compromised if multiple batteries in a system have different levels of charge. LFP battery chemistry is not prone to thermal runaway and thus reduces the risk of combustion. LFP batteries have low internal resistance, are more stable when overcharged and can tolerate higher temperatures without decomposing.

Lithium Ion – Titanate

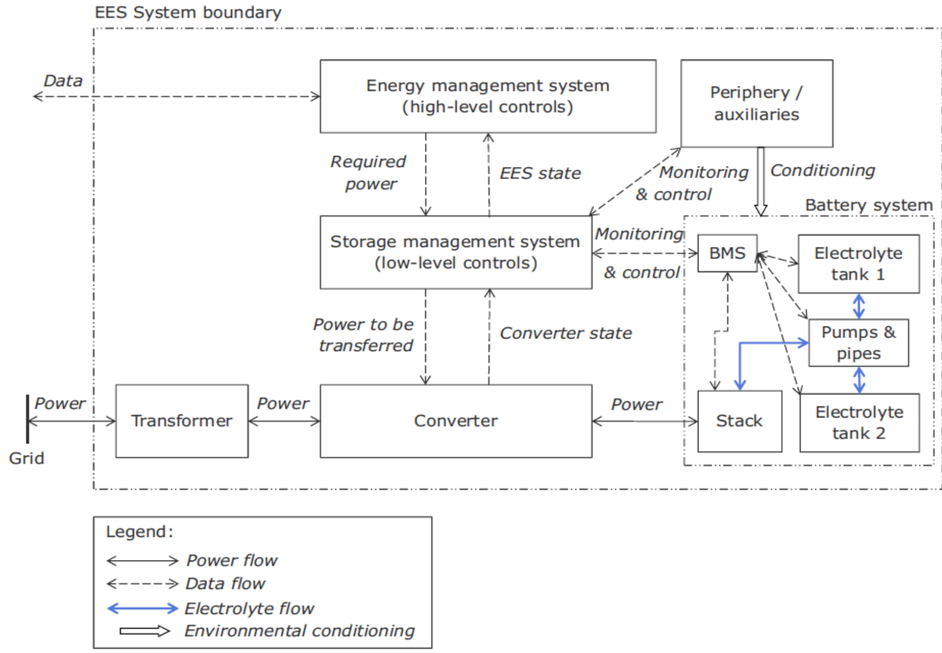
Lithium Titanate ($Li_4Ti_5O_{12}$ or LTO) offers a stable Li-ion chemistry, one of the highest cycle lifetimes reported for Li-Ion batteries, and a high power density. LTO battery cells take advantage of nanocrystals that allow the anode to have a larger surface area than other Li-ion battery technologies. The LTO nanocrystals result in an anode with a surface area of 100 m^2/gram, a large increase from traditional carbon or graphite materials with surface areas of 3 m^2/gram. This characteristic allows electrons in an LTO battery to enter and leave the anode quickly and provide a lifecycle that is upwards of 15,000 cycles.

The large anode surface area in LTO batteries also allows them to have a recharge efficiency of 98% which is relatively high. This enables LTO batteries to be charged quickly, requiring less electricity and power compared to other rechargeable batteries. The nanocrystals used in LTO batteries also allow better performance at low temperatures and can be beneficial to customers in areas with cold winters.

LTO cells have a nominal voltage of 2.40V allowing them to have a higher discharge rate than other Li-ion batteries. Their lower operating voltage also results in increased safety. Additionally, because LTO batteries do not use carbon, they do not overheat and significantly reduce any chance of fires. Their low operating voltage as well as cooler operating temperatures make them some of the safest rechargeable battery technologies in the market.

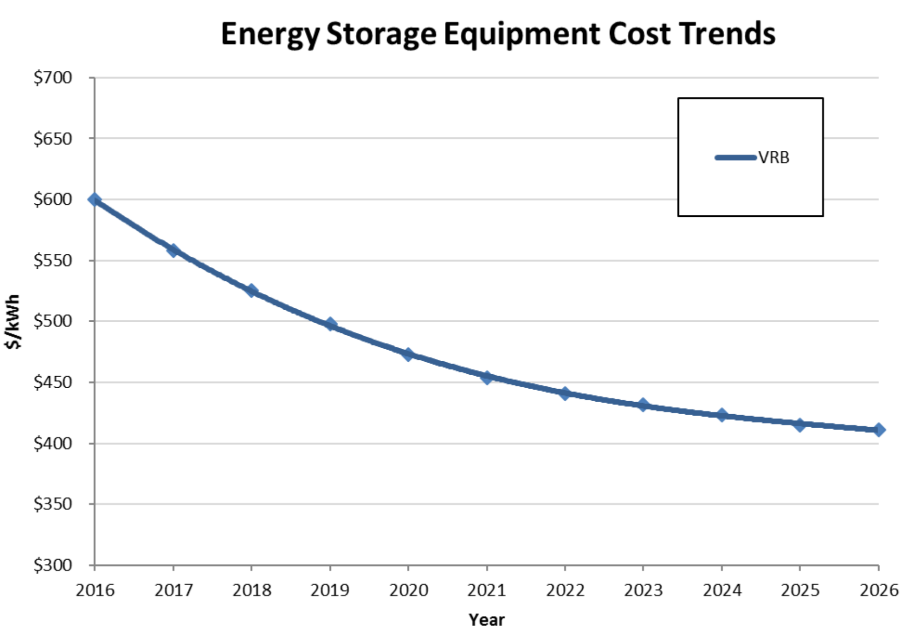
Vanadium Redox

Vanadium Redox batteries (VRB), or Vanadium flow batteries, are based on the redox reaction between the two electrolytes in the system. "Redox" is the abbreviation for "reduction-oxidation" reaction. These reactions include all chemical processes in which atoms have their oxidation number changed. In a redox flow cell, the two electrolytes are separated by a semi-permeable membrane. This membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. A general VRB system includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves. An important advantage of VRB technology is that it can be "stopped" without any concern about maintaining a minimum operating temperature or state of charge. This technology can be left uncharged essentially indefinitely without significant capacity degradation.



In VRBs, the liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. This allows the energy capacity of the battery to be increased at low cost. Energy and power are decoupled, since energy content depends on the amount of electrolyte stored. VRB systems are unique in that they use one common electrolyte, which provides opportunities for increased cycle life. These large, liquid solution containers do however limit the VRB to utility or large industrial installations.

Based on DNV GL's quantitative assessment, VRB technology is well suited for all of the applications reviewed. While the system's ability to serve long duration makes it especially attractive for energy applications, VRBs also support shorter, high power applications. VRB's chief limiting factor is cost, requiring more expensive equipment, installations, and maintenance. Additionally, the technology is less mature than Li-Ion systems, but is solidifying its place in the market. As such, the current claimed efficiencies, degradation rates, and expected life will continue to be updated with field data. If the deployed systems prove performance to these operational characteristics and costs fall with further development, the technology will be attractive for long duration, utility-scale storage.



Cost Parameter/ Technology	VRB
Energy storage equipment cost ($/kWh)	$500-$700
Power conversion equipment cost ($/kW)	$500-$750
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100-$125
Installation ($/kWh)	$140-$200
Fixed O&M cost ($/kW yr)	$7-$12
Major Maintenance ($/kW)	$600 - $800
Years between major maintenance	8

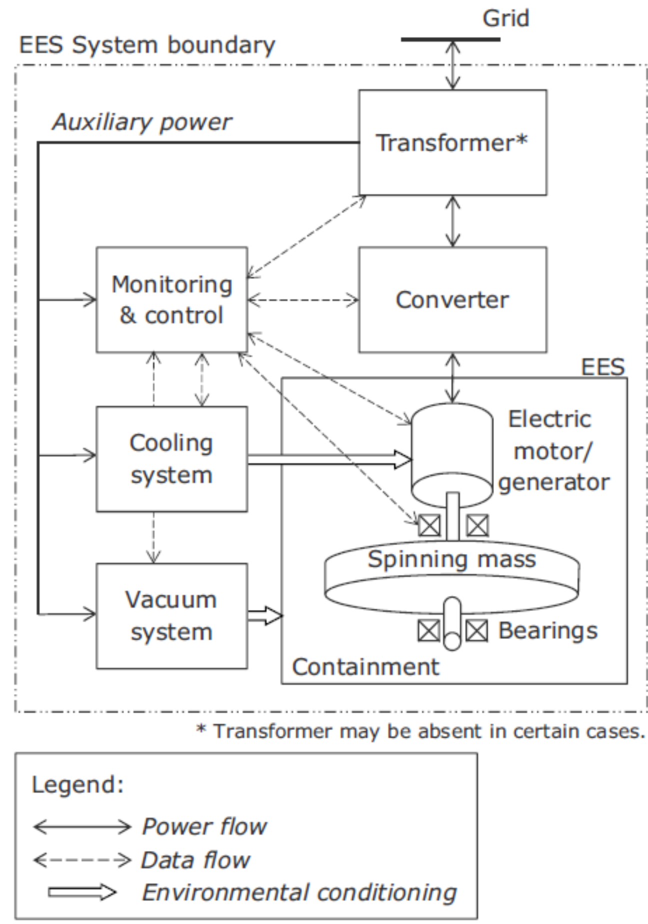
Flywheel Energy Storage

A flywheel stores energy as the rotational kinetic energy of a spinning mass, i.e. the rotor. The rotor is accelerated by an electric machine acting as a motor during charging, and decelerates when energy is extracted (discharging mode) by the same machine acting as a generator. To reduce friction losses during rotation, in general the rotor spins in a vacuum and magnetic bearings are used to keep the rotor in position.

The amount of energy that can be stored is proportional to the mass, the square of the rotational speed and the square of the radius of the rotor. Power rating is determined by the electric motor/generator. Flywheels require external power to maintain its rotational velocity. These idling losses incur a relatively high self-discharge rate. Self-discharge rate is mainly influenced by the bearing technology and the quality of the vacuum.

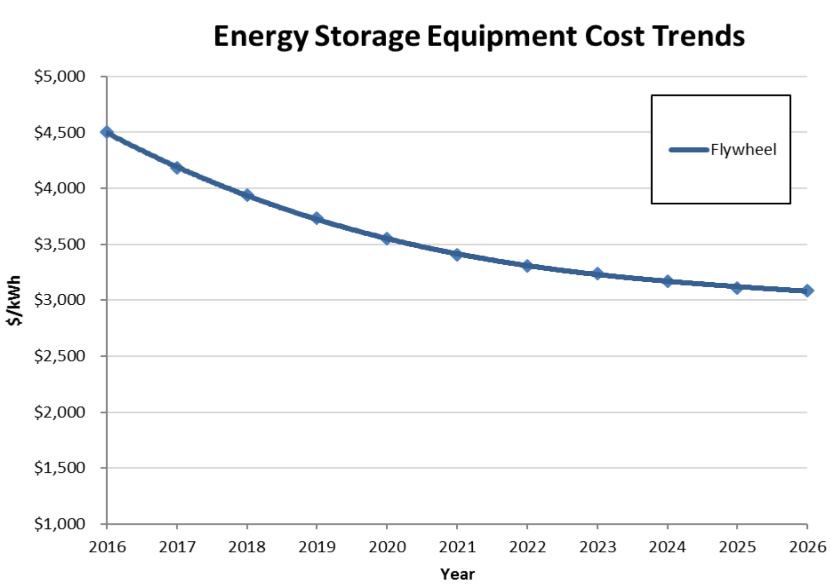
To stabilize the rotating mass bearings are needed. Modern flywheels often operate fully contact-free levitated by magnetic bearings or a combination of magnetic bearings and high speed roller bearings. Often the bearing system requires peripheral systems like an electronic controller for the active magnetic bearing system. The flywheel-mass rotates under low pressure (often vacuum or even high vacuum) in a containment to reduce friction losses. On the one hand the containment acts as the low pressure vessel, on the other hand it acts as a safety measure in case of a disintegration of the flywheel.

In a flywheel-based energy storage system, each flywheel has its own converter. Multiple converters may then be connected to one transformer.



Flywheels have very fast response times, high power ratings, and show no degradation for high amounts of cycling. As such, this technology is most useful and cost effective for power applications. Although there are flywheel systems developed to serve for up to an hour at a lower power rating, most flywheels are designed for under a minute of use at a time at very high power. For this reason, energy applications all receive low ratings in DNV GL's quantitative analysis.

Due to the short design duration of flywheel systems, the $/kWh values are much larger in comparison to other storage technology reviewed here. However this is not true of the total system costs, which trend closer to that of the other technologies. Flywheels do not require significant or expensive maintenance, which further positively affects their overall cost. However, systems do vary widely in cost and maintenance, depending on what materials are being used and which of the configurations discussed above are utilized.

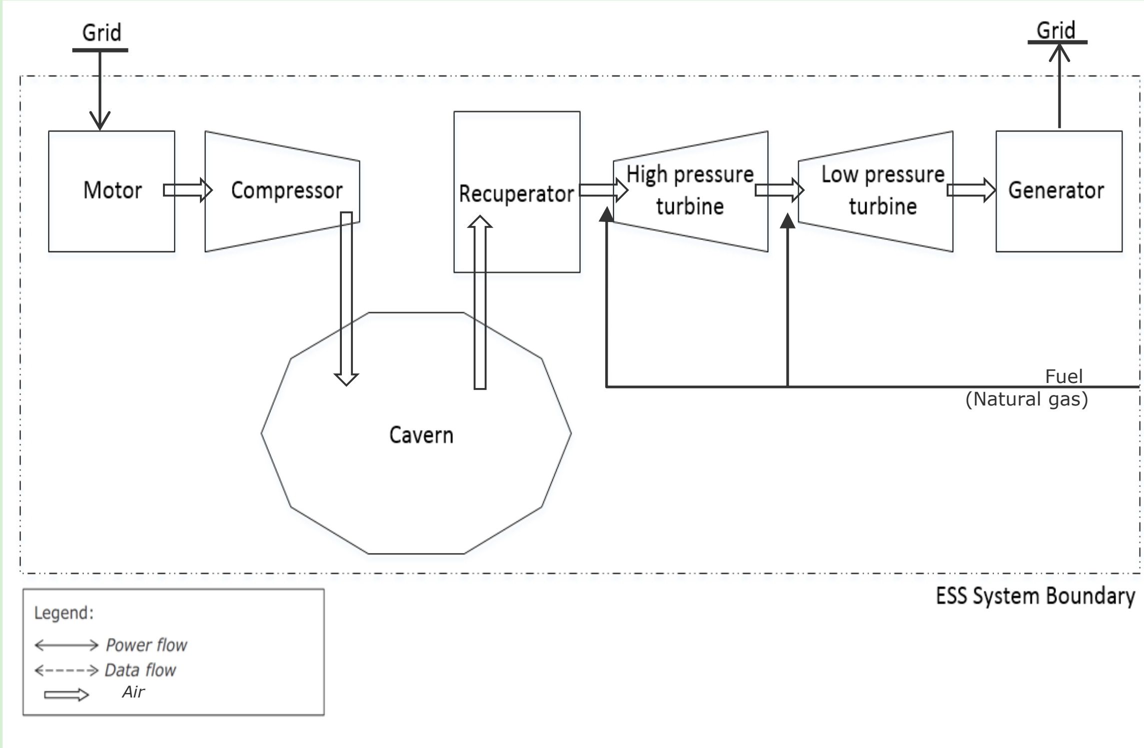


Cost Parameter/ Technology	Flywheel
Energy storage equipment cost ($/kWh)	$3,500 - $5,500
Power conversion equipment cost ($/kW)	$350 - $500
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100-$125
Installation ($/kWh)	$2,000 - $3,000
Fixed O&M cost ($/kW yr)	$4 - $6
Major Maintenance ($/kW)	$200 - $300
Years between major maintenance	5

Compressed Air Energy Storage

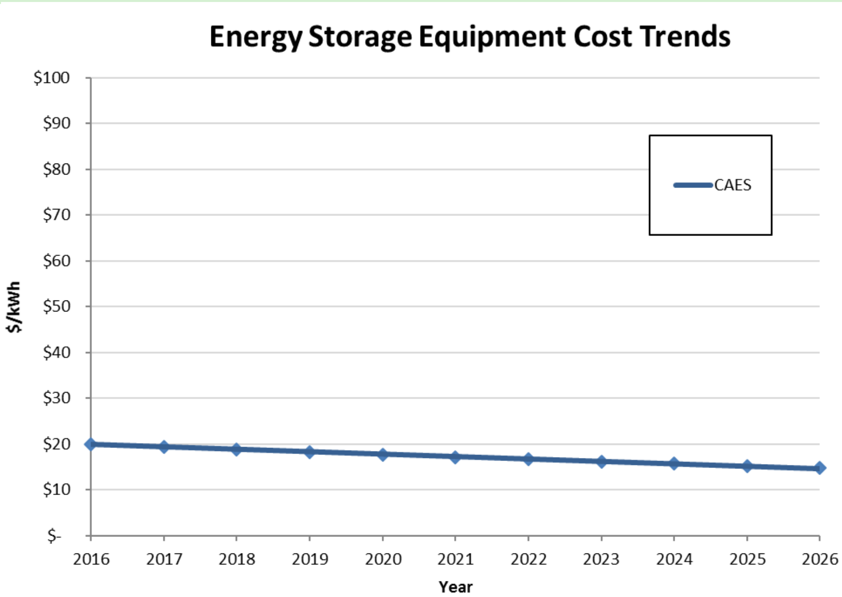
Compressed air energy storage (CAES) stores electricity by compressing air into a reservoir and generates electricity by expanding the compressed air in a gas turbine. The compression is performed by a compressor unit. Depending on the type of CAES, the heat produced during the compression is stored or released into the atmosphere. The compressed air is stored in a suitable geological formation such as salt domes, aquifers or depleted gas fields. The air is released for power generation; it is heated by combustion of natural gas and then expanded in the gas turbine.

The generation capacity of the CAES is determined by the size of the gas turbines. The compressor and the gas turbines can be dimensioned independently. The size of the geological formation determines the amount of energy that can be stored. Due in part to geological feasibility limitations, CAES has only been permanently successfully implemented in a handful of installations world-wide. Beyond the large-scale cavern systems, CAES is in the developmental and demonstration stages for underwater systems and smaller above-ground tank-based systems. These systems were not examined in detail as they are not yet commercialized.



CAES systems are designed for to support extremely long duration energy applications, in some cases, over a day of continuous energy. Due to this, DNV GL's quantitative assessment ranked CAES highly for all of the energy applications reviewed. CAES systems, purely based on their design mechanics, have a slow response time, requiring up to 10 minutes to respond to controls and serve the demand. As such, although CAES systems have large power values due to their scale, they are not well suited for applications that require quick responses such as voltage support, frequency response, or ramping for renewables.

CAES systems, again due to their large capacities, have a very low $/kWh cost. However, when the system scale is taken into consideration, the total system cost follows similar trends to other storage technologies. Underground CAES is limited in scope, but has well proven and documented performance, with two systems in operation for over 25 years. As such, the technology has been refined, with any significant cost reductions focused in the newer, developmental technologies.



Cost Parameter/ Technology	CAES
Energy storage equipment cost ($/kWh)	$10 - $30
Power conversion equipment cost ($/kW)	$400 - $500
Power control system cost ($/kW)	$100-$140
Balance of system ($/kW)	$100 - $160
Installation ($/kWh)	$5 - $10
Fixed O&M cost ($/kW yr)	$3 - $5
Major Maintenance ($/kW)	$70 - 100
Years between major maintenance	4

Thermal Energy Storage

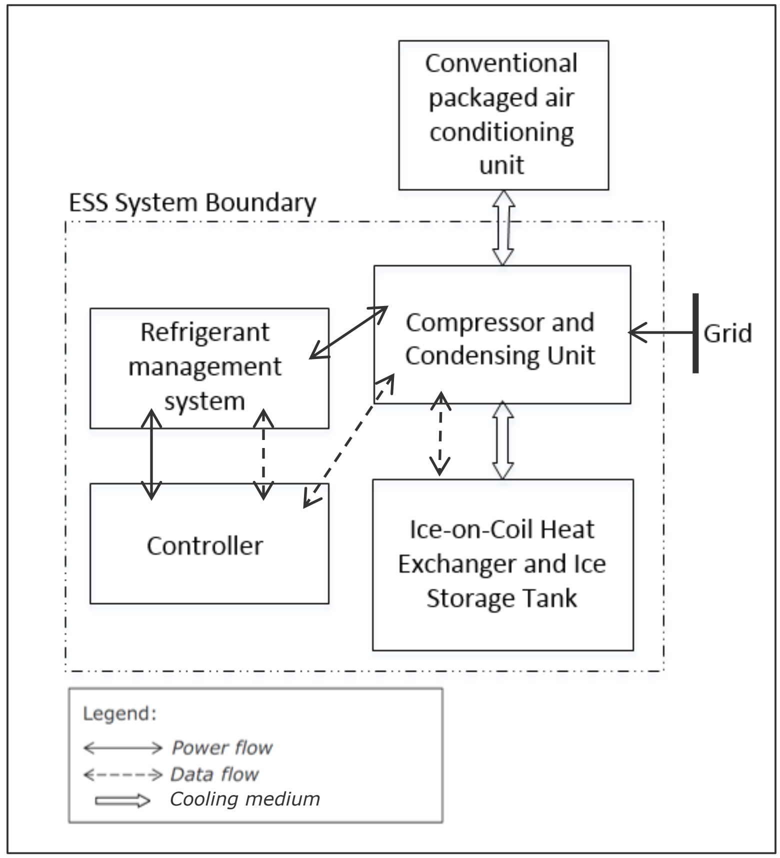
Thermal energy storage is a broad term for a variety of energy storage devices. It covers a wide range of very different technologies, wherein a medium is heated or cooled, and that energy is used at a later time. The energy to heat or cool the medium can come from the grid during off-peak times, renewable production that exceeds current demand, waste heat, or other sources. For the purposes of this report, the thermal energy storage discussed is ice energy storage.

Ice energy storage entails freezing water, or a water-based solution, at night to support space cooling during the day. The freezing process is conducted at night because lower ambient temperatures allow the ice to be made under thermodynamically beneficial conditions. Additionally, energy prices drop during the off-peak night hours. During the day, when temperatures and energy prices rise, the ice is melted and the cool air is circulated in the space. This can either reduce or eliminate the need for a conventional packaged air conditioning unit, dependent on the needs of the space and the local conditions.

An ice energy storage system is comprised of a compressor and condensing unit, which serves to create and melt the system's ice, an ice storage tank with a heat exchanger, and a control and management system. Often, it is paired with a conventional packaged air conditioning unit, which will send the ice-cooled air into the connected space, controlled in concert with the packaged unit's functions. In cases where no conventional air conditioning unit is in place, a fan installed with the system will directly feed the air into the space.

Ice energy storage is appropriate for energy time shift and reduction in peak demand due to space cooling. DNV GL's quantitative assessment thus gave TES an acceptable rating for this application. This rating is not as high comparatively as observed with other technologies due to its limitations in application to exclusively space cooling and the associated load reduction.

TES is, however, cost competitive, with low initial cost and minimal required maintenance. As such, it may be a good option for facilities, or utilities who host facilities, with the greatest source of demand originating from cooling loads. Since peak cooling is highly seasonal and aligns with peak demand hours, this can further help to delay infrastructure upgrades otherwise required to meet these concentrated peak periods.



Cost Parameter/ Technology	TES
Energy storage equipment cost ($/kWh)	$200-$300
Power conversion equipment cost ($/kW)	N/A
Power control system cost ($/kW)	$80-120
Balance of system ($/kW)	$80-100
Installation ($/kWh)	$120-$180
Fixed O&M cost ($/kW yr)	$5-$7
Major Maintenance ($/kW)	$100 - $125
Years between major maintenance	5