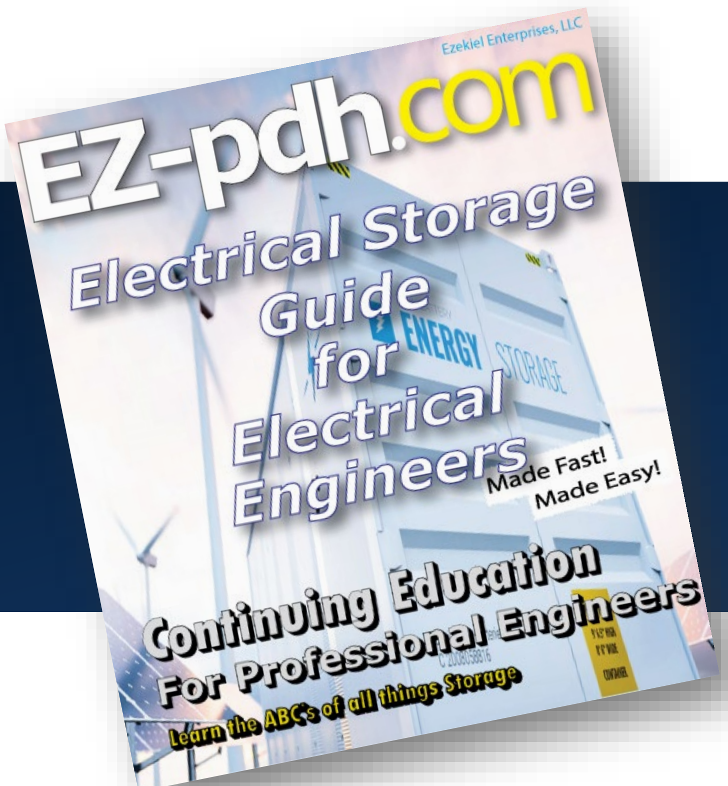

Electrical Storage Guide for Electrical Engineer

Five (5) Continuing Education Hours
Course #EE1465

Approved Continuing Education for Licensed Professional Engineers

EZ-pdh.com
Ezekiel Enterprises, LLC
301 Mission Dr. Unit 571
New Smyrna Beach, FL 32170
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Course Description:

The Electrical Storage Guide for Electrical Engineer course satisfies five (5) hours of professional development.

The course is designed as a distance learning course that provides a thorough overview of current electrical storage technologies including batteries, flywheels, compressed air energy storage (CAES), and pumped storage hydropower (PSH).

Objectives:

The primary objective of this course is to enable the student to understand current electrical storage technologies for application in the selection, procurement, installation, and/or operation of stationary energy storage systems in today's electric grid.

Grading:

Students must achieve a minimum score of 70% on the online quiz to pass this course. The quiz may be taken as many times as necessary to successful pass and complete the course.

A copy of the quiz questions are attached to last pages of this document.

Table of Contents

Electrical Storage Guide for Electrical Engineer

ENERGY STORAGE 101

What is energy storage? Energy storage mediates between variable sources and variable loads. Without storage, energy generation must equal energy consumption. Energy storage works by moving energy through time. Energy generated at one time can be used at another time through storage. Electricity storage is one form of energy storage. Other forms of energy storage include oil in the Strategic Petroleum Reserve and in storage tanks, natural gas in underground storage reservoirs and pipelines, thermal energy in ice, and thermal mass/adobe.

Electricity storage is not new. In the 1780s Galvani demonstrated "animal electricity" and in 1799 Volta invented the modern battery. In 1836 batteries were adopted in telegraph networks. In the 1880s, lead-acid batteries were the original solution for night-time load in the private New York City area direct current (dc) systems. The batteries were used to supply electricity to the load during high demand periods and to absorb excess electricity from generators during low demand periods for sale later. The first U.S. large-scale electricity storage system was 31 megawatts (MW) of pumped storage in 1929 at the Connecticut Light & Power Rocky River Plant. As of 2011, 2.2% of electricity was stored world-wide, mostly in pumped storage.

In this course, a complete electricity storage system (that can connect to the electric grid or operate in a stand-alone mode) comprises two major subcomponents: storage and the power conversion electronics. These subsystems are supplemented by other balance-of-plant components that include monitoring and control systems that are essential to maintain the health and safety of the entire system. These balance-of-plant components include the building or other physical enclosure, miscellaneous switchgear, and hardware to connect to the grid or the customer load. A schematic representation of a complete energy storage system is shown in Figure 1 with a generic storage device representing a dc storage source, such as a battery or flywheel.

In battery and flywheel storage systems, the power conversion system is a bidirectional device that allows the dc to flow to the load after it is converted to alternating current (ac) and allows ac to flow in the reverse direction after conversion to dc to charge the battery or flywheel. The monitoring and control subcomponents may not be a discrete box as shown in the figure below, but could be integrated within the power conversion system (PCS) itself.

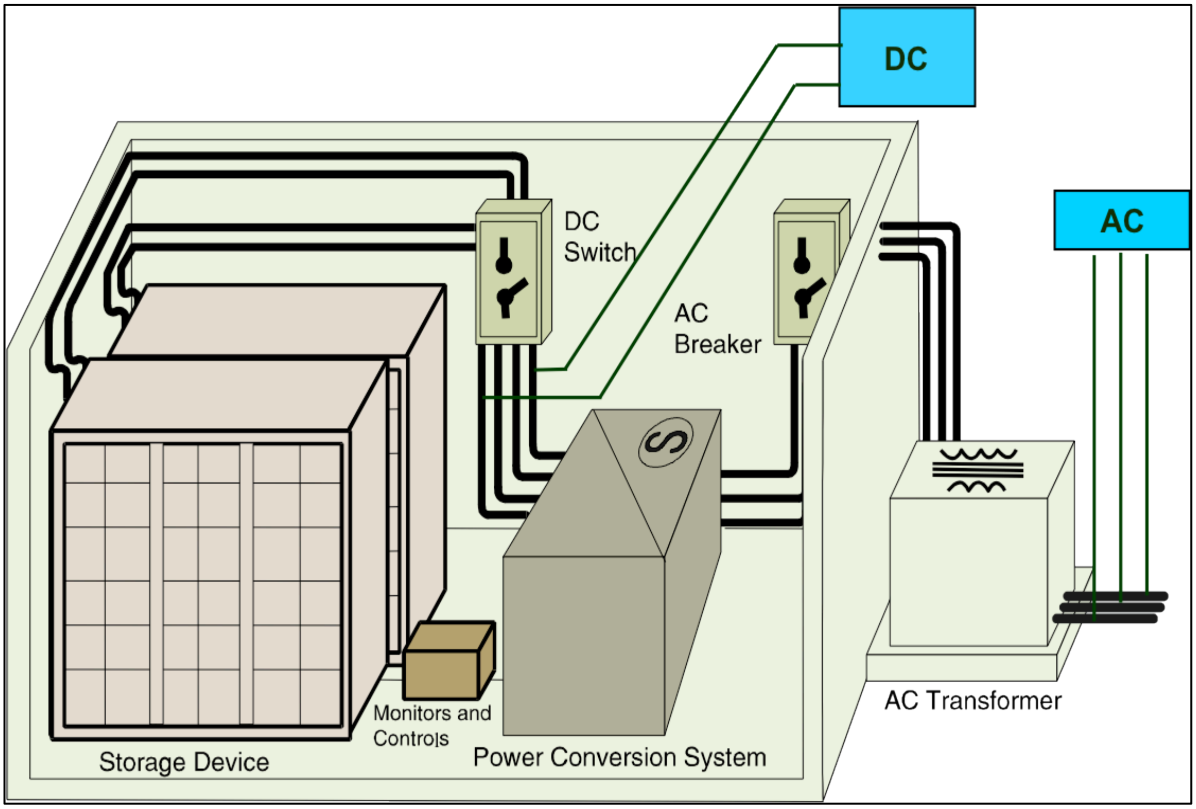


Figure 1. Schematic of a Battery Energy Storage System
(Source: Sandia National Laboratories)

CAES involves high-pressure air stored in underground caverns or above-ground storage vessels (e.g., high-pressure pipes or tanks). In pumped hydroelectric energy storage (PHES), energy is stored by pumping water to an upper reservoir at a higher elevation than the system’s lower reservoir.

CHAPTER 1. ELECTRICITY STORAGE SERVICES AND BENEFITS

Operational changes to the grid, caused by restructuring of the electric utility industry and electricity storage technology advancements, have created an opportunity for storage systems to provide unique services to the evolving grid. Regulatory changes in T&D grid operations, for instance, impact the implementation of electricity storage into the grid as well as other services that storage provides. Although electricity storage systems provide services similar to those of other generation devices, their benefits vary and are thoroughly discussed in this chapter.

Until the mid-1980s, energy storage was used only to time-shift from coal off-peak to replace natural gas on-peak so that the coal units remained at their optimal output as system load varied. These large energy storage facilities stored excess electricity production during periods of low energy demand and price and discharged it during peak load times to reduce the cycling or curtailment of the coal load units. This practice not only allowed the time-shifting of energy but also reduced the need for peaking capacity that would otherwise be provided by combustion turbines. The operational and monetary benefits of this strategy justified the construction of many pumped hydro storage facilities. From the 1920s to the mid-1980s, more than 22 gigawatts (GW) of pumped hydro plants were built in the United States. After this period, the growth in pumped hydro capacity stalled due to environmental opposition[3] and the changing operational needs of the electric grid, triggered by the deregulation and restructuring of the electric utility industry.

By the mid-1980s, the push was stronger to develop battery and other storage technologies to provide services to the electric grid. However, these technologies could not match the ability of pumped hydro to provide large storage capacities. In the late 1980s, researchers at DOE/SNL and at EPRI were identifying other operational needs of the electric grid that could be met in shorter storage durations of 1 to 6 hours rather than the 8 to 10+ hours that pumped hydro provided.

Two SNL reports[4,5] in the early 1990s identified and described 13 services that these emerging storage technologies could provide. A more recent report, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*[6] expanded the range of the grid services and provided significantly more detail on 17 services as well as guidance on estimating the

[3] From the 2003 Handbook: ‘‘the addition of pumped hydro facilities is very limited, due to the scarcity of further cost-effective and environmentally acceptable sites in the U.S.’’ *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003.

[4] "*Battery Energy Storage: A Preliminary Assessment of National Benefits (The Gateway Benefits Study)*," Abbas Ali Akhil; Hank W Zaininger; Jonathan Hurwitch; Joseph Badin, SAND93- 3900, Albuquerque, NM, December 1993.

[5] "*Battery Energy Storage for Utility Applications: Phase I Opportunities Analysis*," Butler, Paul Charles, SAND94-2605, Albuquerque, NM October 1994..

[6] "*Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*," Eyer, James M. – distributed Utility Associates, Inc., Garth Corey – Ktech Corporation, SAND2010-0815, Albuquerque, NM and Livermore, CA, February 2010.

benefits accrued by these services.[7] Other works have also documented use cases and services that storage provides to the grid. Most notably, EPRI's Smart Grid Resource Center Use Case Repository contains over 130 documents that discuss various aspects of storage.[8] Similarly, California Independent System Operator (CAISO) also describes eight scenarios supplemented by activity diagrams to demonstrate the use of storage for grid operations and control.[9]

This course combines that knowledge base and includes the description and service-specific technical detail of 18 services and applications in five umbrella groups, as listed in Table 1.

Table 1. Electric Grid Energy Storage Services Presented in This Course

Bulk Energy Services	
	Electric Energy Time-Shift (Arbitrage)
	Electric Supply Capacity
Ancillary Services	
	Regulation
	Spinning, Non-Spinning and Supplemental Reserves
	Voltage Support
	Black Start
	Other Related Uses

Transmission Infrastructure Services	
	Transmission Upgrade Deferral
	Transmission Congestion Relief
Distribution Infrastructure Services	
	Distribution Upgrade Deferral
	Voltage Support
Customer Energy Management Services	
	Power Quality
	Power Reliability
	Retail Electric Energy Time-Shift
	Demand Charge Management

1.1 Bulk Energy Services

1.1.1 Electric Energy Time-shift (Arbitrage)

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 used or sold at a later time when the price or costs are high. Alternatively, storage can provide similar time-shift duty by storing excess energy production, which would otherwise be curtailed, from renewable sources such as wind or photovoltaic (PV). The functional operation of the storage system is similar in both cases, and they are treated interchangeably in this discussion.

[7] An application, or grid service, is a use whereas a benefit connotes a value. A benefit is generally quantified in terms of the monetary or financial value.

[8] EPRI Smartgrid Resource Center: Use Case Repository, http://smartgrid.epri.com/Repository/Search.aspx?search=storage, last accessed May 9, 2013.

[9] "*IS-1 ISO Uses Energy Storage for Grid Operations and Control*," Ver 2.1, California ISO, Folsom, CA, November 2010, http://www.caiso.com/285f/285fb7964ea00.pdf, last accessed May 9, 2013.

Technical Considerations

Storage System Size Range: 1 – 500 MW
Target Discharge Duration Range: <1 hour
Minimum Cycles/Year: 250 +

Storage used for time-shifting energy from PV or smaller wind farms would be in the lower end of the system storage size and duration ranges shown above, whereas storage for arbitrage in large utility applications or in conjunction with larger wind farms or groups of wind and/or PV plants would fall in the upper end of these ranges.

Both storage variable operating cost (non-energy-related) and storage efficiency are especially important for this service. Electric energy time-shift involves many possible transactions with economic merit based on the difference between the cost to purchase, store, and discharge energy (discharge cost) and the benefit derived when the energy is discharged.

Any increase in variable operating cost or reduction of efficiency reduces the number of transactions for which the benefit exceeds the cost. That number of transactions is quite sensitive to the discharge cost, so a modest increase may reduce the number of viable transactions considerably. Two performance characteristics that have a significant impact on storage variable operating cost are round-trip efficiency of the storage system and the rate at which storage performance declines as it is used.

In addition, seasonal and diurnal electricity storage can be considered as a bulk service. It can be very useful for wind or PV if there are significant seasonal and diurnal differences.

1.1.2 Electric Supply Capacity

Depending on the circumstances in a given electric supply system, energy storage could be used to defer and/or to reduce the need to buy new central station generation capacity and/or purchasing capacity in the wholesale electricity marketplace.

The marketplace for electric supply capacity is evolving. In some cases, generation capacity cost is included in wholesale energy prices (as an allocated cost per unit of energy). In other cases, market mechanisms may allow for capacity-related payments.

Technical Considerations

Storage System Size Range: 1 – 500 MW
Target Discharge Duration Range: 2 – 6 hours
Minimum Cycles/Year: 5 - 100

The operating profile for storage used as supply capacity (characterized by annual hours of operation, frequency of operation, and duration of operation for each use) is location-specific. Consequently, it is challenging to make generalizations about storage discharge duration for this service. Another key criterion affecting discharge duration for this service is the way that generation capacity is priced. For example, if capacity is priced per hour, then storage plant duration is flexible. If prices require that the capacity resource be available for a specified duration for each occurrence (e.g., five hours), or require operation during an entire time period (e.g., 12:00 p.m. to 5:00 p.m.), then the storage plant discharge duration must accommodate those requirements.

The two plots in Figure 2 illustrate the capacity constraint and how storage acts to compensate the deficit. The upper plot shows the three weekdays when there is need for peaking capacity. The lower plot shows storage discharge to meet load during those three periods and also shows

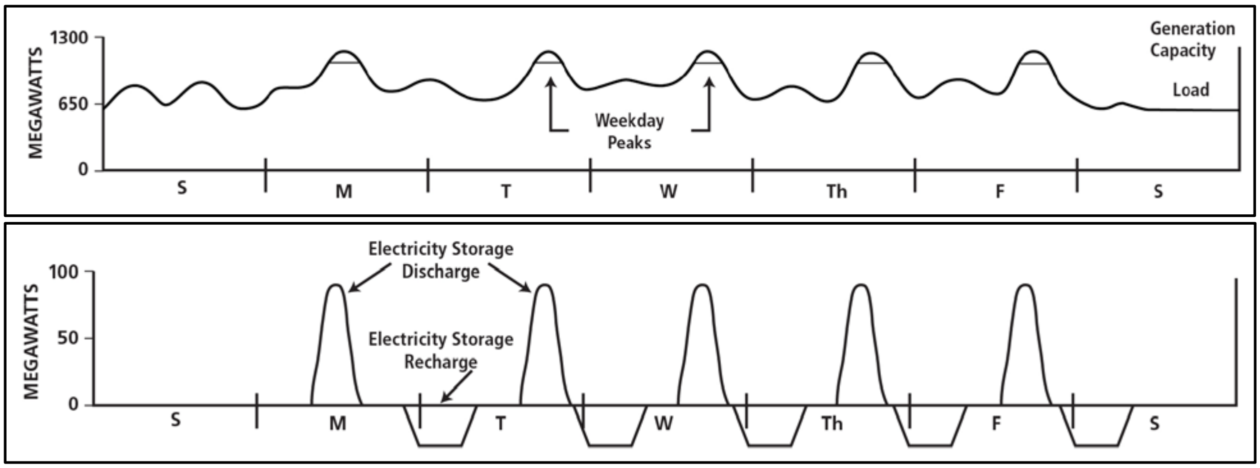


Figure 2. Storage for Electric Supply Capacity

that the storage is charged starting just before midnight and ending late at night during the times when system load is lower.

1.2 Ancillary Services

1.2.1 Regulation

Regulation is one of the ancillary services for which storage is especially well-suited. Regulation involves managing interchange flows with other control areas to match closely the scheduled interchange flows and momentary variations in demand within the control area. The primary reasons for including regulation in the power system are to maintain the grid frequency and to comply with the North American Electric Reliability Council's (NERC's) Real Power Balancing Control Performance (BAL001) and Disturbance Control Performance (BAL002) Standards.

Regulation is used to reconcile momentary differences caused by fluctuations in generation and loads. Regulation is used for damping of that difference. Consider the example shown in Figure 3. The load demand line in Figure 3 shows numerous fluctuations depicting the imbalance between generation and load without regulation. The thicker line in the plot shows a smoother system response after damping of those fluctuations with regulation.

Generating units that are online and ready to increase or decrease power as needed are used for regulation and their output is increased when there is a momentary shortfall of generation to provide up regulation. Conversely, regulation resources' output is reduced to provide down regulation when there is a momentary excess of generation.

An important consideration in this case is that large thermal base-load generation units in regulation incur significant wear and tear when they provide variable power needed for regulation duty.

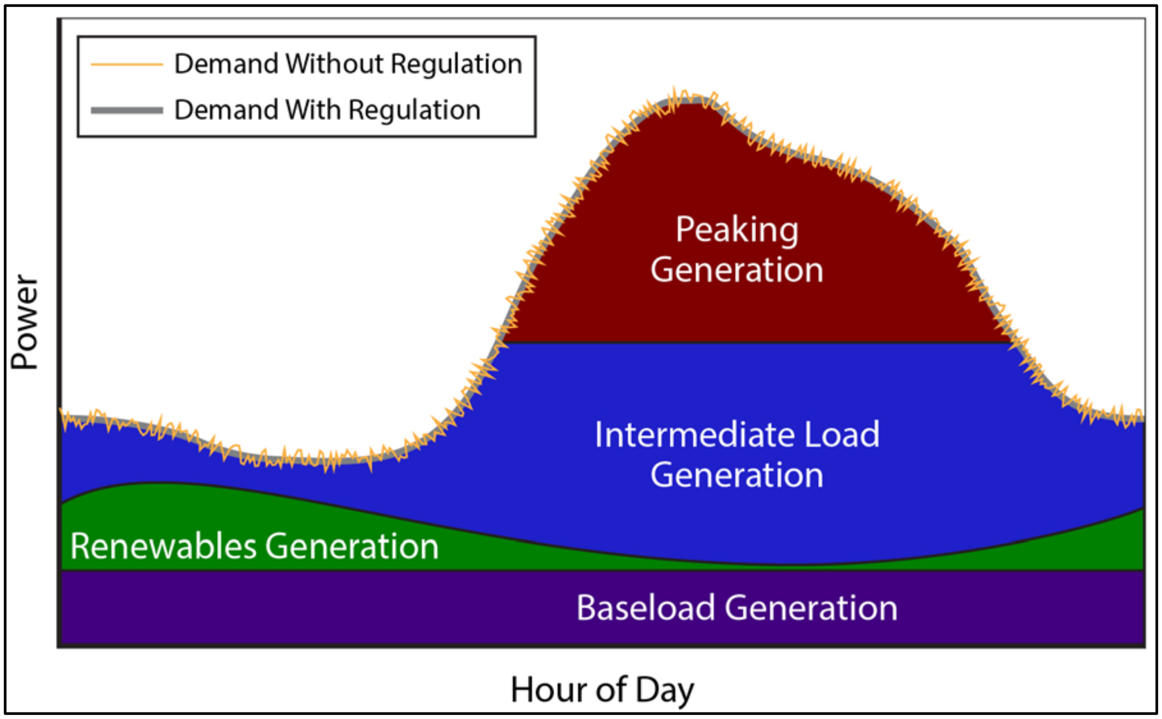


Figure 3. System Load Without and With Regulation
(Source: Sandia National Laboratories)

Two possible operational modes for 1 MW of storage used for regulation and three possible operational modes for generation used for regulation are shown in Figure 4. The leftmost plot shows how less-efficient storage could be used for regulation. In that case, increased storage discharge is used to provide up regulation and reduced discharge is used to provide down regulation. In essence, one-half of the storage's capacity is used for up regulation and the other half of the storage capacity is used for down regulation (similar to the rightmost plot, which shows how 1 MW of generation is often used for regulation service). Next, consider the second plot, which shows how 1 MW of efficient storage can be used to provide 2 MW of regulation – 1 MW up and 1 MW down – using discharging and charging, respectively.

When storage provides down regulation by charging, it absorbs energy from the grid; the storage operator must pay for that energy. That is notable – especially for storage with lower efficiency – because the cost for that energy may exceed the value of the regulation service.

Technical Considerations

Storage System Size Range: 10 – 40 MW

Target Discharge Duration Range: 15 minutes to 60 minutes
Minimum Cycles/Year: 250 – 10,000

The rapid-response characteristic (i.e., fast ramp rate) of most storage systems makes it valuable as a regulation resource. Storage used for regulation should have access to and be able to respond to the area control error (ACE) signal or an automatic generation control (AGC) signal if one is available from the Balancing Authority in which the storage system is located, as opposed to conventional plants, which generally follow an AGC signal. The equivalent benefit of regulation

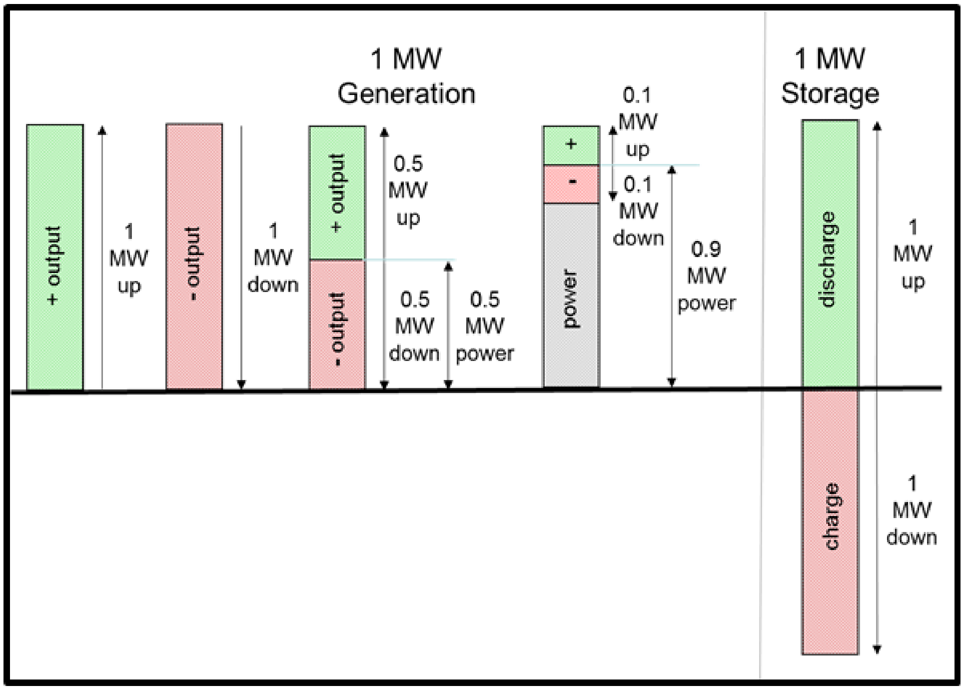


Figure 4. Storage and Generation Operation for Regulation
(Source: E&I Consulting)

from storage with a fast ramp rate (e.g., flywheels, capacitors, and some battery types) is on the order of two times that of regulation provided by conventional generation,[10] due to the fact that it can follow the signal more accurately and thus reduce the total wear and tear on other generation.

Figure 5 shows two plots to illustrate the storage response for a regulation requirement. The upper plot is an exaggerated illustration of the generation variance in response to fluctuating loads. The lower plot shows storage either discharging or charging to inject or absorb the generation as needed to eliminate the need for cycling of the generation units.

[10] "*Assessing the Value of Regulation Resources Based on Their Time Response Characteristics*", Makarov YV, S Lu, J Ma, TB Nguyen, PNNL-17632, Pacific Northwest National Laboratory, Richland, WA, June 2008.

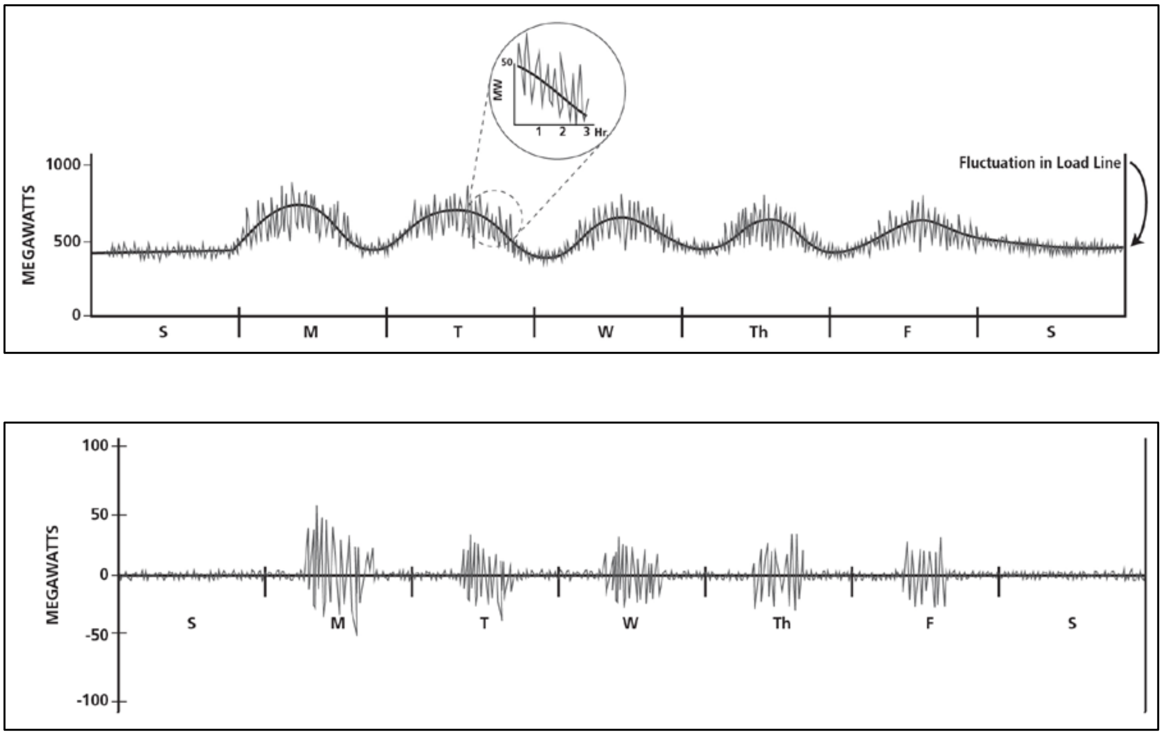


Figure 5. Storage for Regulation

1.2.2 Spinning, Non-Spinning, and Supplemental Reserves

Operation of an electric grid requires reserve capacity that can be called upon when some portion of the normal electric supply resources become unavailable unexpectedly.

Generally, reserves are at least as large as the single largest 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. NERC and FERC define reserves differently based on different operating conditions. For simplicity, this course discusses three generic types of reserve to illustrate the role of storage in this service:

Spinning Reserve[11] (Synchronized) – Generation capacity that is online but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. 'Frequency- responsive' spinning reserve responds within 10 seconds to maintain system frequency. Spinning reserves are the first type used when a shortfall occurs.

[11] Spinning reserve is defined in the NERC Glossary as "Unloaded generation that is synchronized and ready to serve additional demand."

Non-Spinning Reserve[12] (Non-synchronized) – Generation capacity that may be offline or that comprises a block of curtailable and/or interruptible loads and that can be available within 10 minutes.

Supplemental Reserve – Generation that can pick up load within one hour. Its role is, essentially, a backup for spinning and non-spinning reserves. Backup supply may also be used as backup for commercial energy sales. Unlike spinning reserve capacity, supplemental reserve capacity is not synchronized with grid frequency. Supplemental reserves are used after all spinning reserves are online.

Importantly for storage, generation resources used as reserve capacity must be online and operational (i.e., at part load). Unlike generation, in almost all circumstances, storage used for reserve capacity does not discharge at all; it just has to be ready and available to discharge when needed.

Technical Considerations

Storage System Size Range: 10 – 100 MW
Target Discharge Duration Range: 15 minutes – 1 hour
Minimum Cycles/Year: 20 – 50

Reserve capacity resources must receive and respond to appropriate control signals. Figure 6 shows how storage responds to spinning reserve requirements. The upper plot shows a loss of generation and the lower plot shows the immediate response with a 30-minute discharge to provide the reserve capacity until other generation is brought online.

[12] Non-spinning reserve is not uniformly the same in different reliabiity regions. It generally consists of generation resources that are offline, but could be brought online within 10 to 30 minutes and could also include loads that can be interrupted in that time window.

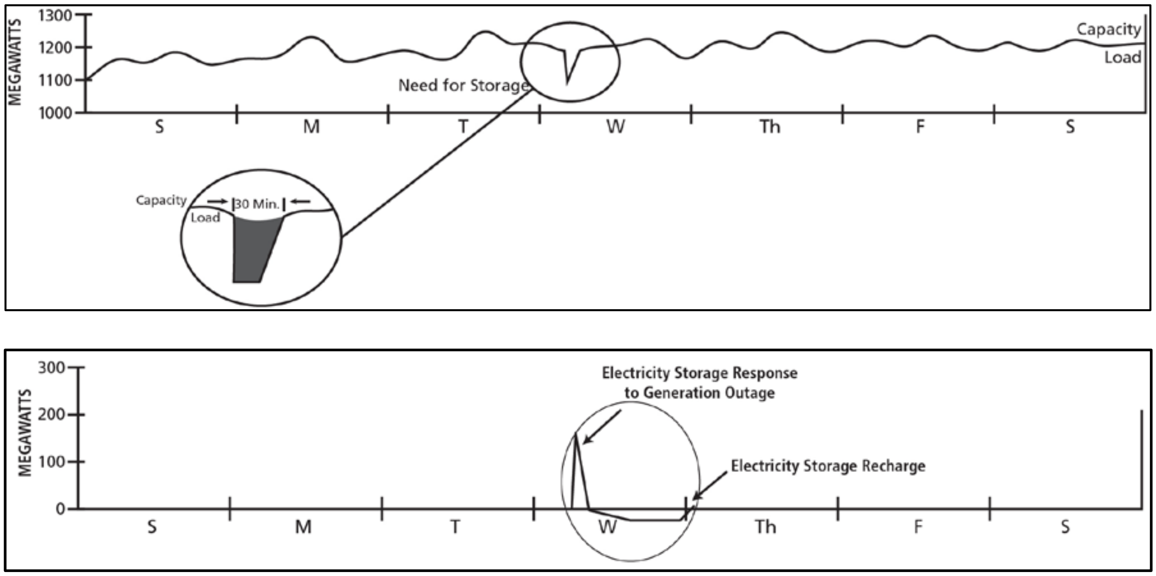


Figure 6. Storage for Reserve Capacity

1.2.3 Voltage Support

A requirement for electric grid operators is to maintain voltage within specified limits. In most cases, this requires management of reactance, which is caused by grid-connected equipment that generates, transmits, or uses electricity and often has or exhibits characteristics like those of inductors and capacitors in an electric circuit. To manage reactance at the grid level, system operators need voltage support resources to offset reactive effects so that the transmission system can be operated in a stable manner.

Normally, designated power plants are used to generate reactive power (VAR) to offset reactance in the grid. These power plants could be displaced by strategically placed energy storage within the grid at central locations or taking the distributed approach and placing multiple VAR-support storage systems near large loads.

Technical Considerations

Storage System Size Range: 1 – 10 mega volt-ampere reactive (MVAR)
Target Discharge Duration Range: Not Applicable
Minimum Cycles/Year: Not Applicable

The PCS of the storage systems used for voltage support must be capable of operating at a non-unity power factor, to source and sink reactive power or volt-ampere reactive (VARs). This capability is available in all PCSs used in today's storage systems. Real power is not needed from the battery in this mode of operation and thus discharge duration and minimum cycles per year are not relevant in this case.

The nominal time needed for voltage support is assumed to be 30 minutes — time for the grid system to stabilize and, if necessary, to begin orderly load shedding to match available generation. Figure 7 shows three discharges of storage: with active injection of real power and

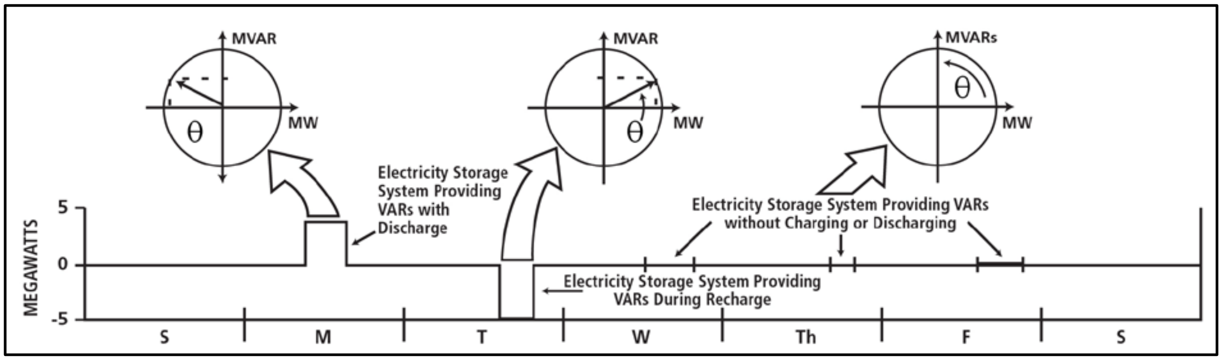


Figure 7. Storage for Voltage Support Service

VARs, with absorbing power to balance voltage while providing VARs, and providing VARs only without real power injection or absorption as needed by the grid.

1.2.4 Black Start

Storage systems provide an active reserve of power and energy within the grid and can be used to energize transmission and distribution lines and provide station power to bring power plants on line after a catastrophic failure of the grid. Golden Valley Electric Association uses the battery system in Fairbanks for this service when there is an outage of the transmission intertie with Anchorage. The operation of the battery is illustrated in Figure 8, which shows its discharge to provide charging current to two transmission paths as needed, as well as start-up power to two diesel power plants that serve Fairbanks until the intertie is restored.

Storage can provide similar 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.

Technical Considerations

Storage System Size Range: 5 – 50 MW
Target Discharge Duration Range: 15 minutes – 1 hour
Minimum Cycles/Year: 10 – 20

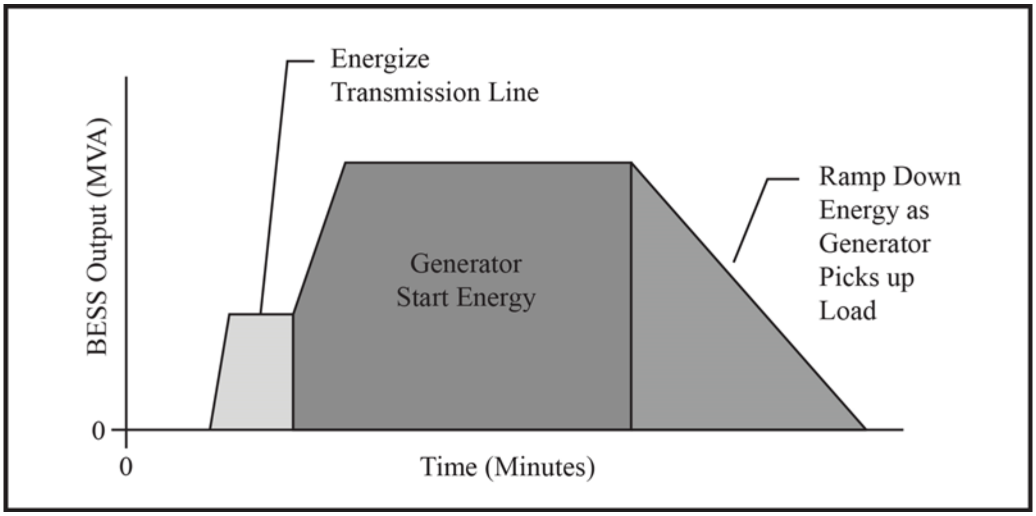


Figure 8. Black Start Service by Storage
(Courtesy: Golden Valley Electric Association)

1.2.5 Other Related Uses

1.2.5.1 Load Following/Ramping Support for Renewables

Electricity storage is eminently suitable for damping the variability of wind and PV systems and is being widely used in this application. Technically, the operating requirements for a storage system in this application are the same as those needed for a storage system to respond to a rapidly or randomly fluctuating load profile. Most renewable applications with a need for storage will specify a maximum expected up- and down-ramp rate in MW/minute and the time duration of the ramp. This design guidance for the storage system is applicable for load following and renewable ramp support; this course therefore treats them as the same application.

Load following is characterized by power output that generally changes as frequently as every several minutes. The output changes in response to the changing balance between electric supply and load within a specific region or area. Output variation is a response to changes in system frequency, timeline loading, or the relation of these to each other that occurs as needed to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.

Conventional generation-based load following resources' output *increases* to follow demand *up* as system load increases. Conversely, load following resources' output *decreases* to follow demand *down* as system load decreases. Typically, the amount of load following needed in the up direction (load following up) increases each day as load increases during the morning. In the evening, the amount of load following needed in the down direction (load following down) increases as aggregate load on the grid drops. A simple depiction of load following is shown in Figure 9.

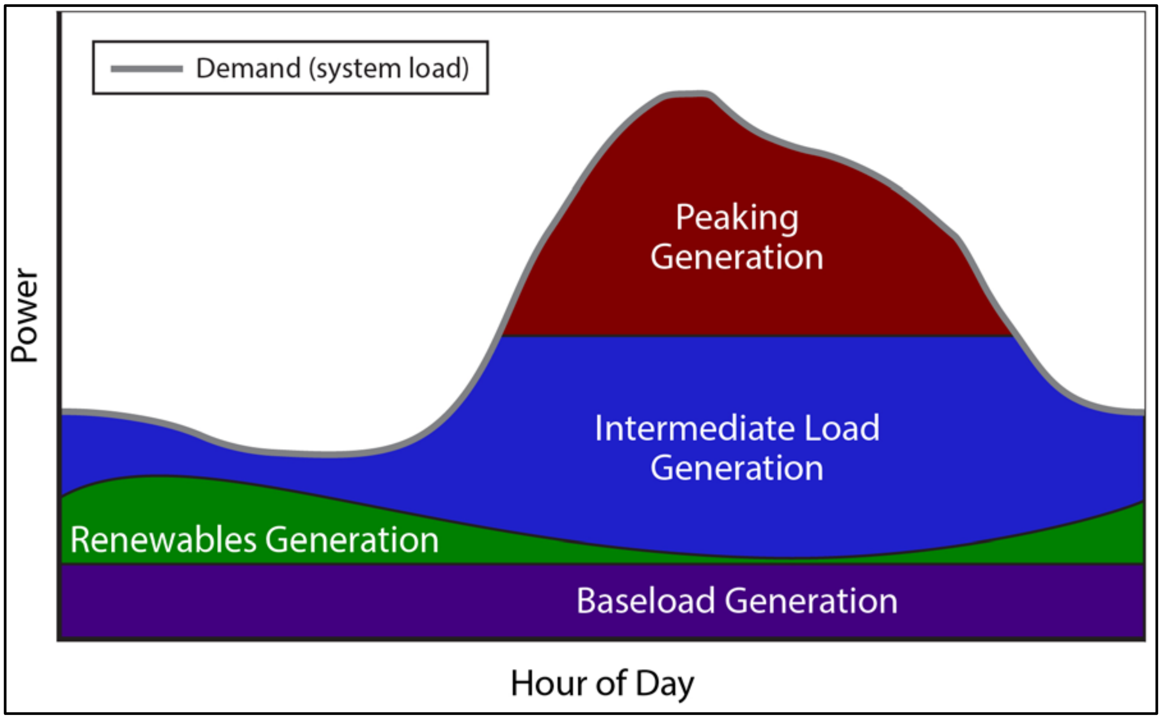


Figure 9. Electric Supply Resource Stack

Normally, generation is used for load following. For load following up, generation is operated such that its output is less than its design or rated output (also referred to as 'part load operation'). Consequently, the plant heat rates, fuel cost, and emission are increased. This allows operators to increase the generator's output, as needed, to provide load following up to accommodate increasing load. For load following down, generation starts at a high output level, perhaps even at design output, and the output is decreased as load decreases.

These operating scenarios are notable because operating generation at part load requires more fuel per megawatt hour (MWh) and results in increased air emissions per MWh relative to generation operated at its design output level. Varying the output of generators (rather than operating at constant output) will also increase fuel use and air emissions, as well as the need for generator maintenance and thus variable operations and maintenance (O&M) costs. In addition, if a fossil plant has to shut down during off-peak periods, there will be a significant increase in fuel use, O&M, and emissions. Plant reliability will also deteriorate, resulting in the need for significant purchases of replacement energy.

Storage is well-suited to load following for several reasons. First, most types of storage can operate at partial output levels with relatively modest performance penalties. Second, most types of storage can respond very quickly (compared to most types of generation) when more or less output is needed for load following. Consider also that storage can be used effectively for both load following up (as load increases) and for load following down (as load decreases), either by discharging or by charging.

In market areas, when charging storage for load following, the energy stored must be purchased at the prevailing wholesale price. This is an important consideration, especially for storage with lower efficiency and/or if the energy used for charging is relatively expensive, because the cost of energy used to charge storage (to provide load following) may exceed the value of the load following service.

Conversely, the value of energy *discharged* from storage to provide load following is determined by the prevailing price for wholesale energy. Depending on circumstances (i.e., if the price for the load following service does not include the value of the wholesale energy involved), when discharging for load following, two benefits accrue – one for the load following service and another for the energy.

Note that in this case, storage competes with central and aggregated distributed generation and with aggregated demand response/load management resources including interruptible loads and direct load control.

Technical Considerations

Storage System Size Range: 1 – 100 MW
Target Discharge Duration Range: 15minutes – 1 hour
Minimum Cycles/Year: Not Applicable

Storage used for load following should be reliable or it cannot be used to meet contractual obligations associated with bidding in the load following market. Storage used for load following will probably need access to AGC from the respective independent system operator (ISO). Typically, an ISO requires output from an AGC resource to change every minute.

Other considerations include synergies with other services. Large/central storage used for load following may be especially complementary to other services if the charging and discharging for the other services can be coordinated. For example, storage used to provide generation capacity mid-day could be charged in the evening, thus following diminished system demand down during evening hours.

Load following could have good synergies with renewables capacity firming, electric energy time-shift, and possibly electric supply reserve capacity applications. If storage is distributed, then that same storage could also be used for most of the distributed applications and for voltage support.

1.2.5.2 Frequency Response

Frequency response is very similar to regulation, described above, except it reacts to system needs in even shorter time periods of seconds to less than a minute when there is a sudden loss of a generation unit or a transmission line. As shown in Figure 10,[13] various generator response actions are needed to counteract this sudden imbalance between load and generation to maintain the system frequency and stability of the grid. The first response within the initial seconds is the primary frequency control response of the governor action on the generation units to increase their power output as shown in the lower portion of the figure. This is followed by the longer duration secondary frequency control response by the AGC that spans the half a minute to several minutes shown by the dotted line in the lower portion of Figure 10. It is important to note that the rate at which the frequency decays after the triggering event – loss of generator or transmission – is directly proportional to the aggregate inertia within the grid at that instant. The rotating mass of large generators and/or the aggregate mass of many smaller generators collectively determines this inertia.

The combined effect of inertia and the governor actions determines the rate of frequency decay and recovery shown in the arresting and rebound periods in the upper portion of Figure 10. This is also the window of time in which the fast-acting response of flywheel and battery storage systems excels in stabilizing the frequency. The presence of fast-acting storage assures a smoother transition from the upset period to normal operation if the grid frequency is within its normal range. The effectiveness of fast-acting storage in this application has been successfully utilized by utilities[14] and also described in other reports and papers.[15]

[13] "*Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation*," Joseph H. Eto (Principal Investigator) et al., LBNL-4142E, Lawrence Berkeley National Laboratory, Berkeley, CA, December 2010, http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf), last accessed on March 25, 2013.

[14] See BEWAG and PREPA projects

[15] "*Energy Storage – a Cheaper, Faster and Cleaner Alternative to Conventional Frequency Regulation*," a white paper by the California Energy Storage Alliance (CESA), Berkeley, CA, (http://www.ice-energy.com/stuff/contentmgr/files/1/76d44bfc1077e7fad6425102e55c0491/download/cesa_energy_storage_for_frequency_regulation.pdf), last accessed March 25, 2013.

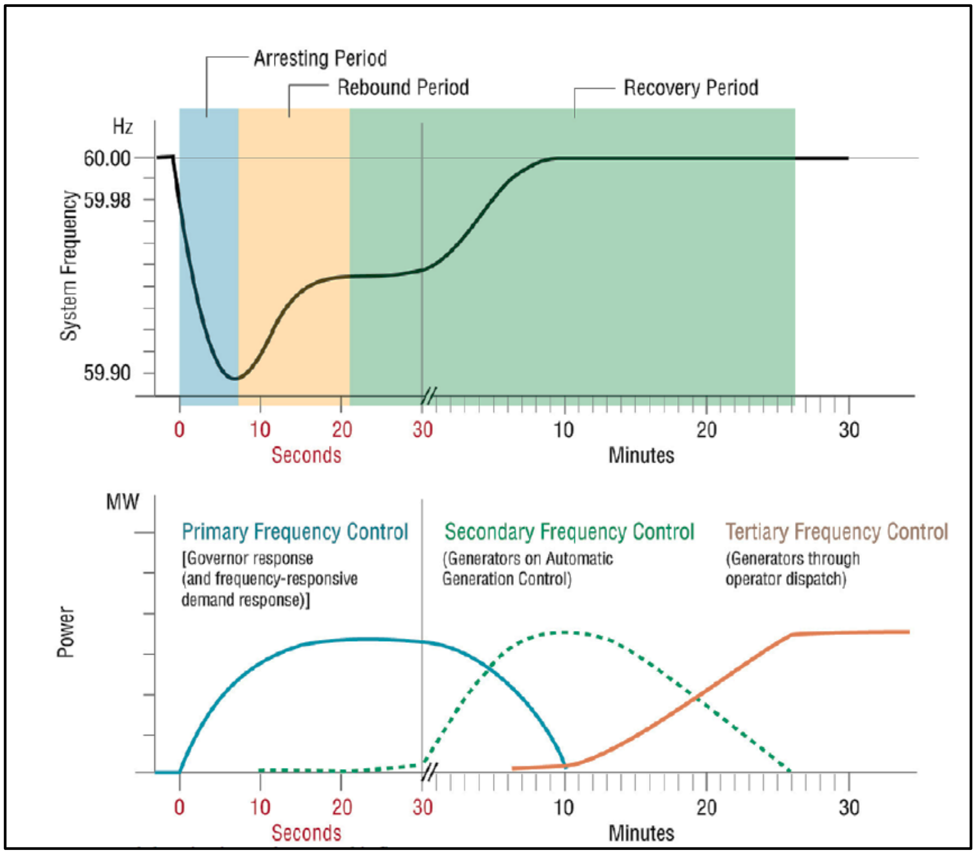


Figure 10. The Sequential Actions of Primary, Secondary, and Tertiary Frequency Controls Following the Sudden Loss of Generation and Their Impacts on System Frequency

The size of storage systems to be used in frequency response mode is proportional to the grid or balancing area in which they are needed. Generally, storage systems in the 20 MW and greater size can provide effective frequency response due to their fast action; some studies[16] have shown that the response is twice as effective as a conventional fossil-fueled generator, including combustion turbines (CTs) and coal units. However, location of the storage system within the grid with respect to other generation, transmission corridors, and loads plays a crucial role in the effectiveness as a frequency response resource.

1.3 Transmission Infrastructure Services

1.3.1 Transmission Upgrade Deferral

Transmission upgrade deferral involves delaying – and in some cases avoiding entirely – utility investments in transmission system upgrades, by using relatively small amounts of storage.

[16] Ibid.

Consider a transmission system with peak electric loading that is approaching the system's load-carrying capacity (design rating). In some cases, installing a small amount of energy storage downstream from the nearly overloaded transmission node could defer the need for the upgrade for a few years.

The key consideration is that a small amount of storage can be used to provide enough incremental capacity to defer the need for a large lump investment in transmission equipment. Doing so reduces overall cost to ratepayers, improves utility asset utilization, allows use of the capital for other projects, and reduces the financial risk associated with lump investments.

Notably, for most nodes within a transmission system, the highest loads occur on just a few days per year, for just a few hours per year. Often, the highest annual load occurs on one specific day with a peak somewhat higher than any other day. One important implication is that storage used for this application can provide significant benefits with limited or no need to discharge. Given that most modular storage has a high variable operating cost, this may be especially attractive in such instances.

Although the emphasis for this application is on transmission upgrade deferral, a similar rationale applies to transmission equipment life extension. That is, if storage use reduces loading on existing equipment that is nearing its expected life, the result could be to extend the life of the existing equipment. This may be especially compelling for transmission equipment that includes aging transformers and underground power cables.

Technical Considerations

Storage System Size Range: 10 – 100 MW
Target Discharge Duration Range: 2 – 8 hours
Minimum Cycles/Year: 10 – 50

Energy storage must serve sufficient load, for as long as needed, to keep loading on the transmission equipment below a specified maximum.

Figure 11 illustrates the use of storage for transmission deferral. The lower plot shows storage being discharged on Wednesday afternoon to compensate for the high load on the substation transformer, as shown in the upper plot. The storage is recharged when the feeder load reduces in the late evening. Alternatively, the storage can be recharged during the late night as long as it is available to serve the peak load that the transformer is likely to see the following day(s).

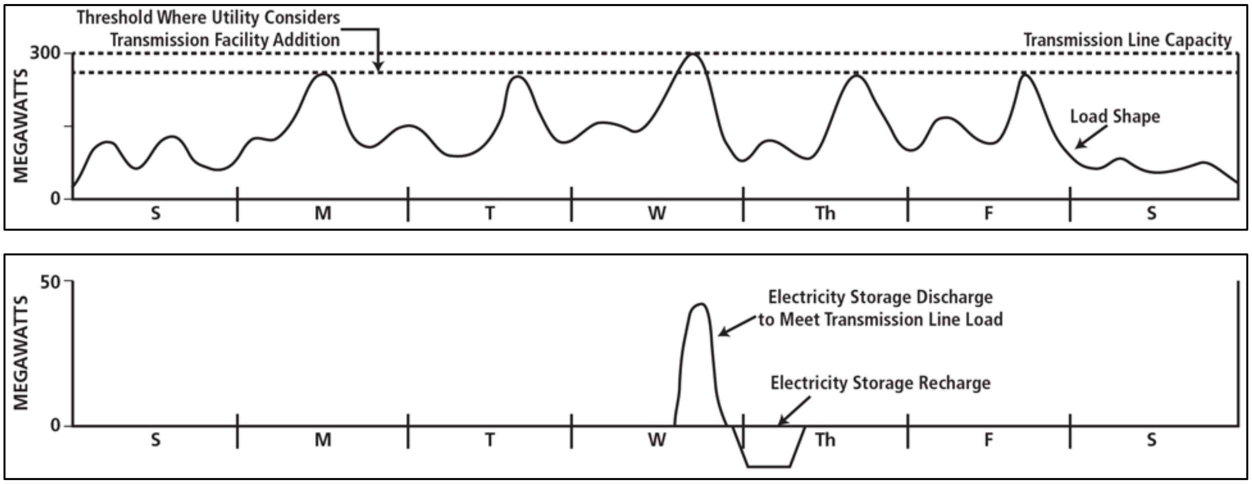


Figure 11. Storage for Transmission and Distribution Deferral

1.3.2 Transmission Congestion Relief

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 systems become congested. Thus during periods of peak demand, the need and cost for more transmission capacity increases along with transmission access charges. Transmission congestion may also lead to increased congestion costs or locational marginal pricing (LMP) for wholesale electricity at certain transmission nodes.

Electricity storage can be used to avoid congestion-related costs and charges, especially if the costs become onerous 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.

Technical Considerations

Storage System Size Range: 1 – 100 MW
Target Discharge Duration Range: 1 – 4 hours
Minimum Cycles/Year: 50 - 100

The discharge duration needed for transmission congestion relief cannot be generalized easily, given all the possible options. As with the Transmission upgrade deferral service, it may require only a few hours of support during the year when congestion relief is required. Generally, congestion charges apply for just a few occurrences during a year when there are several consecutive hours of transmission congestion.

Figure 12 illustrates the storage response in transmission congestion relief service. The upper plot shows four instances in which load exceeds the capacity of the transmission line. The lower plot shows storage discharge during those four events and a recharge during the late night when the system load is lower and the transmission line is lightly loaded.

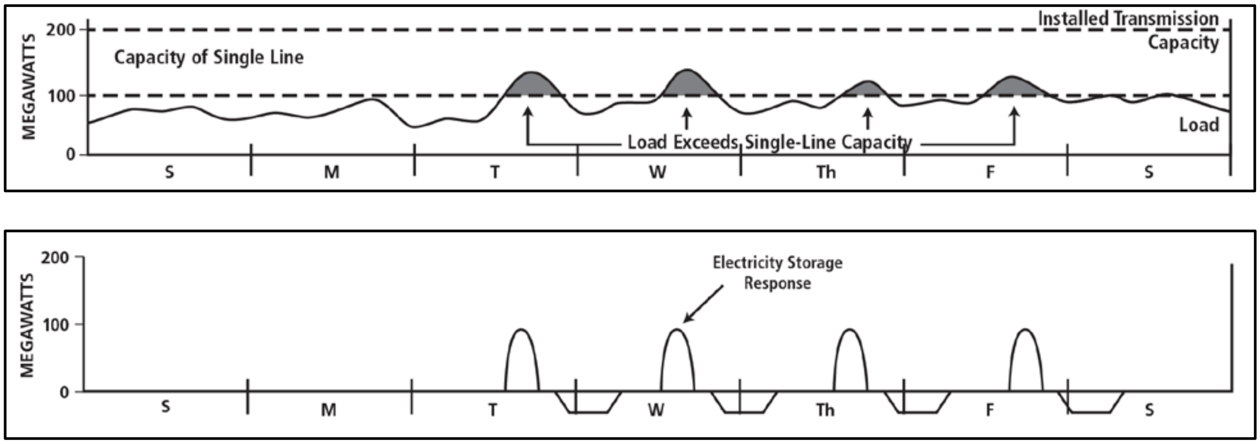


Figure 12. Storage for Transmission Congestion Relief

1.3.3 Other Related Uses

Energy storage used for transmission support improves the transmission system performance by compensating for electrical anomalies and disturbances such as voltage sag, unstable voltage, and sub-synchronous resonance. The result is a more stable system. It is similar to the network stability ancillary service that is not addressed in this course. Benefits from transmission support are highly situation-specific and site-specific. Two cases are briefly described:

Transmission Stability Damping: Increase load-carrying capacity by improving dynamic stability.

Sub-synchronous Resonance Damping: Increase line capacity by allowing higher levels of series compensation by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies.

Technical Considerations

Storage System Size Range: 10 – 100 MW
Target Discharge Duration Range: 5 seconds – 2 hours
Minimum Cycles/Year: 20 - 100

Energy storage must be capable of sub-second response, partial state-of-charge operation, and many charge-discharge cycles. For storage to be most beneficial as a transmission support resource, it should provide both real and reactive power. Typical discharge durations for transmission support are between one and 20 seconds.

Figure 13 shows two plots that illustrate the storage response to momentary voltage sag and a deviation in the phase angle that persists for a few seconds, as shown in the upper plot. The storage response is a quick discharge and recharge to damp the oscillation caused by the voltage

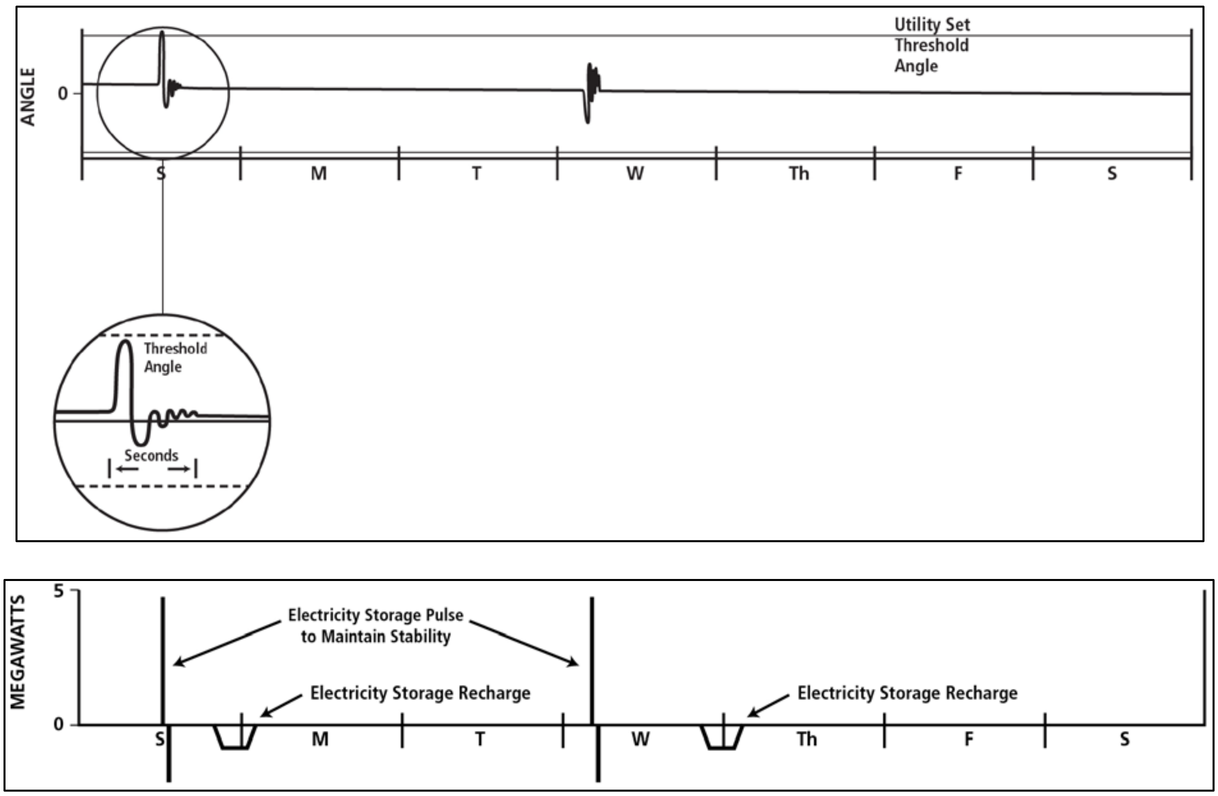


Figure 13. Storage for Customer-side Power Quality

sag and phase angle deviation. As shown in the lower plot, the storage response needs to be very fast and requires high power but lower energy capacity.

1.4 Distribution Infrastructure Services

1.4.1 Distribution Upgrade Deferral and Voltage Support

Distribution upgrade deferral involves using storage to delay or avoid investments that would otherwise be necessary to maintain adequate distribution capacity to serve all load requirements. The upgrade deferral could be a replacement of an aging or over-stressed existing distribution transformer at a substation or re-conductoring distribution lines with heavier 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, thus 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.

A corollary to this strategy is that it also minimizes the ever-present risk that planned load growth does not occur, which would strand the investment made in upgrading the transformer or re-conductoring the line. This could be the case when a large load, such as a shopping mall or a residential development, did not materialize because the developer delayed or cancelled the project after the utility had performed the upgrade in anticipation of the new load. A storage system allows not only deferring the upgrade decision point, but also allows time to evaluate the certainty that planned load growth will materialize, which could be a two-year to three-year window.

Notably, for most nodes within a distribution system, the highest loads occur on just a few days per year, for just a few hours per year. Often, the highest annual load occurs on one specific day with a peak somewhat higher than any other day. One important implication is that storage used for this application can provide significant benefits with limited or no need to discharge.

A storage system that is used for upgrade deferral could simultaneously provide voltage support on the distribution lines. Utilities regulate voltage within specified limits[17] by tap changing regulators at the distribution substation and by switching capacitors to follow load changes. This is especially important on long, radial lines where a large load such as an arc welder or a residential PV system may be causing unacceptable voltage excursions on neighboring customers. These voltage fluctuations can be effectively damped with minimal draw of real power from the storage system.

Technical Considerations

Storage System Size Range: 500 kilowatts (kW) – 10 MW
Target Discharge Duration Range: 1 – 4 hours
Minimum Cycles/Year: 50 - 100

Figure 14 illustrates the use of storage for T&D deferral. The lower plot shows storage being discharged on Wednesday afternoon to compensate for the high load on the substation transformer, as shown in the upper plot. The storage is recharged when the feeder load reduces in the late evening. Alternatively, the storage can be recharged during the late night, as long as it is available to serve the peak load that the transformer is likely to see the following day(s).

[17] ANSI C84.1 "American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hz)" establishes nominal voltage ratings for utilities to regulate the service delivery and operating tolerances at the point of use.

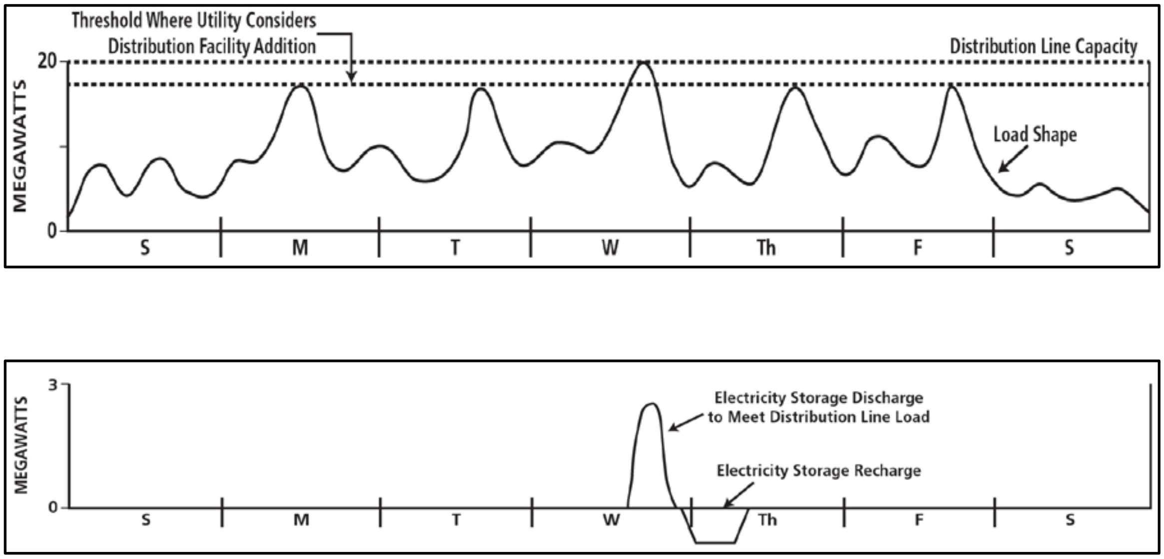


Figure 14. Storage for Distribution Upgrade Deferral

1.5 Customer Energy Management Services

1.5.1 Power Quality

The electric power quality service involves using storage to protect customer on-site loads downstream (from storage) against short-duration events that affect the quality of power delivered to the customer's loads. Some manifestations of poor power quality include the following:

- Variations in voltage magnitude (e.g., short-term spikes or dips, longer term surges, or sags).
- Variations in the primary 60-hertz (Hz) frequency at which power is delivered.
- Low power factor (voltage and current excessively out of phase with each other).
- Harmonics (i.e., the presence of currents or voltages at frequencies other than the primary frequency).
- Interruptions in service, of any duration, ranging from a fraction of a second to several seconds.

Technical Considerations

Storage System Size Range: 100 kW – 10 MW
Target Discharge Duration Range: 10 seconds – 15 minutes
Minimum Cycles/Year: 10 - 200

Typically, the discharge duration required for the power quality use ranges from a few seconds to a few minutes. The on-site storage system monitors the utility power quality and discharges to smooth out the disturbance so that it is transparent to the load.

The upper plot in Figure 15 shows a voltage spike of 50 volts (V) and the lower plot shows storage absorbing the 50V-spike to maintain a constant 480V to the load. These anomalies in the electric supply to the customer, which can occur several times in quick succession due to events

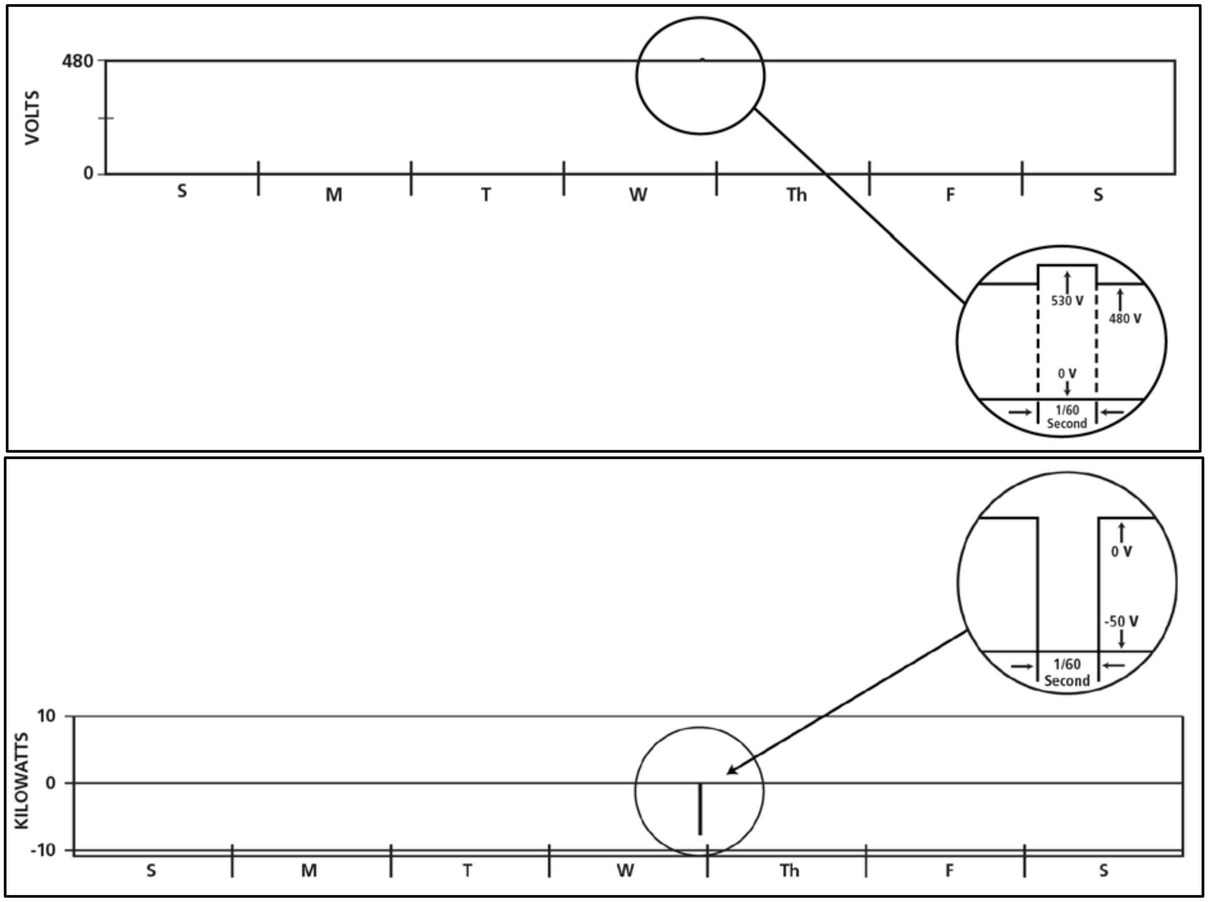


Figure 15. Storage for Customer-side Power Quality

in the T&D network that supplies the customer, need to be corrected to protect sensitive processes and loads at the customer site.

1.5.2 Power Reliability

A storage system can effectively support customer loads when there is a total loss of power from the source utility. 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 protecting 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.

The storage system can be owned by the customer and is under customer control at all times. An alternate ownership scenario could be that the storage system is owned by the utility and is treated as a demand-side, dispatchable resource that serves the customer needs as well as being available to the utility as a demand reduction resource.

1.5.3 Retail Energy Time-Shift

Retail electric energy time-shift involves storage used by energy end users (utility customers) to reduce their overall costs for electricity. Customers charge the 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.

For example, a hypothetical TOU tariff is shown in Figure 16. It applies to Commercial and Industrial electricity end users from May to October, Monday through Friday, whose peak power requirements are less than or equal to 500 kW.

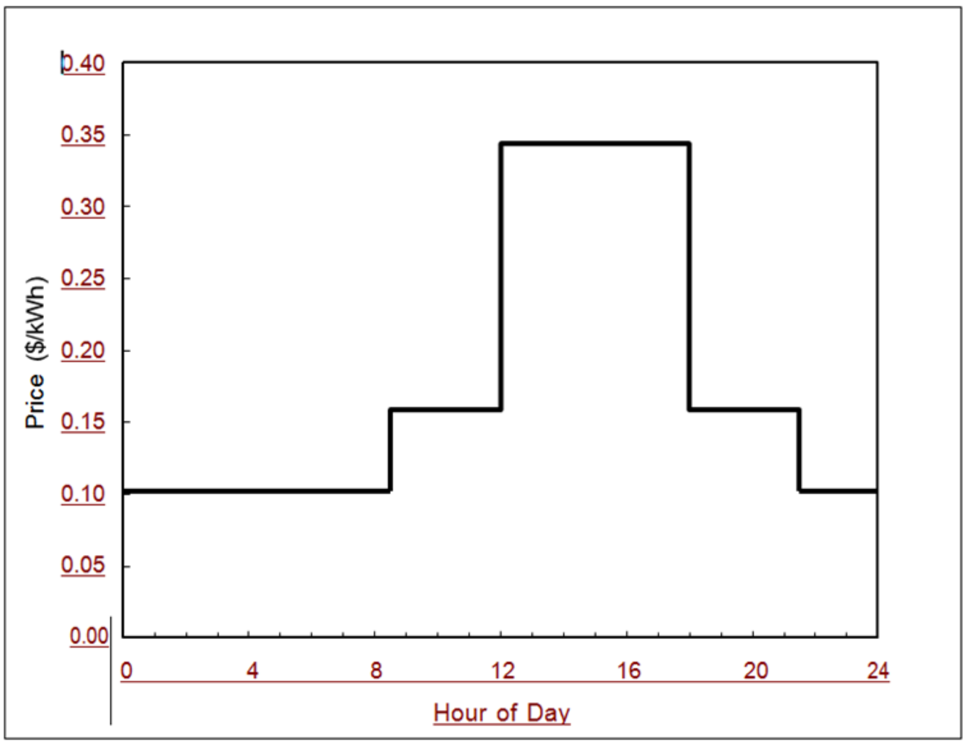


Figure 16. Time of Use Summer Energy Prices for Small Commercial/Industrial Users

As shown in Figure 16, energy prices are about 32¢/kilowatt hour (kWh) on-peak (12:00 p.m. to 6:00 p.m.). Prices during partial-peak (8:30 a.m. to 12:00 p.m. and 6:00 p.m. to 9:30 p.m.) are about 15¢/kWh, and during off-peak (9:30 p.m. to 8:30 a.m.), prices are about 10¢/kWh.

Technical Considerations

Storage System Size Range: 1 kW – 1 MW
Target Discharge Duration Range: 1 – 6 hours
Minimum Cycles/Year: 50 - 250

The maximum discharge duration in this case is determined based on the relevant tariff. For example, for the assumed hypothetical tariff, there are six on-peak hours (12:00 p.m. to 6:00 p.m.). The standard value assumed for this case is five hours of discharge duration.

1.5.4 Demand Charge Management

Electricity storage can be used by end users (i.e., utility customers) to reduce their overall costs for electric service by reducing their demand during peak periods specified by the utility.

To avoid a demand charge, load must be reduced during all hours of the demand charge period, usually a specified period of time (e.g., 11:00 a.m. to 5:00 p.m.) and on specified days (most often weekdays). In many cases, the demand charge is assessed if load is present during just one 15-minute period, during times of the day and during months when demand charges apply.

The most significant demand charges assessed are those based on the maximum load during the peak demand period (e.g., 12:00 p.m. to 5:00 p.m.) in the respective month. Although uncommon, additional demand charges for 1) part peak or (partial peak) demand that occurs during times such as shoulder hours in the mornings and evenings and during winter weekdays and 2) base-load or facility demand charges that are based on the peak demand no matter what time (day and month) it occurs.

Because there is a facility demand charge assessed during charging, the amount paid for facility demand charges offsets some of the benefit for reducing demand during times when the higher peak demand charges apply. Consider a simple example: The peak demand charge (which applies during summer afternoons, from 12:00 p.m. to 5:00 p.m.) is $10/kW-month, and the annual facility demand charge is $2/kW-month. During the night, when charging occurs, the $2/kW facility demand charge is incurred; when storage discharges mid-day (when peak demand charges apply), the $10/kW-month demand charge is avoided. The net demand charge reduction in the example is

$$\$10/\text{kW-month} - \$2/\text{kW-month} = \$8/\text{kW-month}$$

Note that the price for electric energy is expressed in $/kWh used, whereas demand charges are denominated in $/kW of maximum power draw. Tariffs with demand charges have separate prices for energy and for power (demand charges). Furthermore, demand charges are typically assessed for a given month; thus demand charges are often expressed using $/kW per month ($/kW-month).

To reduce load when demand charges are high, storage is charged when there are no or low demand charges. (Presumably, the price for charging energy is also low.) The stored energy is discharged to serve load during times when demand charges apply. Typically, energy storage can discharge for five to six hours, depending on the provisions of the applicable tariff.

Consider the example illustrated in Figure 17. The figure shows a manufacturer's load that is nearly constant at 1 MW for three shifts. During mornings and evenings, the end user's direct load and the facility's net demand are 1 MW. At night, when the price for energy is low, the facility's net demand doubles as low-priced energy is stored at a rate of 1 MW, while the normal load from the end user's operations requires another MW of power. During peak demand times

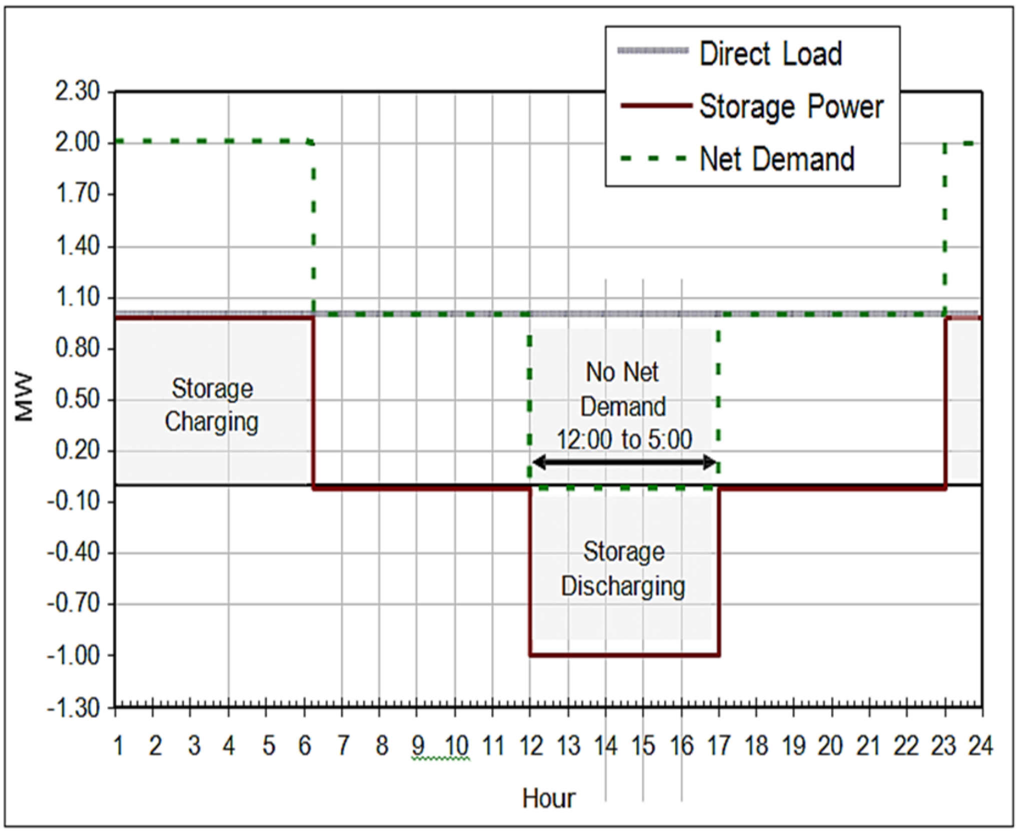


Figure 17. On-peak Demand Reduction Using Energy Storage

(12:00 p.m. to 5:00 pm in the example), storage discharges (at the rate of 1 MW) to serve the end user's direct load of 1 MW, thus eliminating the real-time demand on the grid.

In the above example, storage is 80% efficient. To discharge for 5 hours, it must be charged for

$$5 \text{ hours} \div 0.8 = 6.25 \text{ hours.}$$

The additional 1.25 hours of charging is needed to offset energy losses. If a facility demand charge applies, it would be assessed on the entire 2 MW (of net demand) used to serve both load and storage charging.

Although it is the electricity customer who internalizes the benefit, in this scenario, it may be that the design, procurement, transaction cost, etc. could be challenging for many prospective users, especially those with relatively small peak loads.

Technical Considerations

Storage System Size Range: 50 kW – 10 MW
Target Discharge Duration Range: 1 – 4 hours
Minimum Cycles/Year: 50 – 500

In this example, the storage plant discharge duration is based on a hypothetical applicable tariff. For example, a hypothetical Medium General Demand-Metered TOU tariff defines six on-peak hours from 12:00 p.m. to 6:00 p.m. It is assumed that this requires five hours of storage duration.

Figure 18 shows an example where the peak loads exceed the threshold set by the first peak of the month on Monday afternoon. That sets the level for the remaining month; loads must remain below that threshold to avoid demand charge penalties.

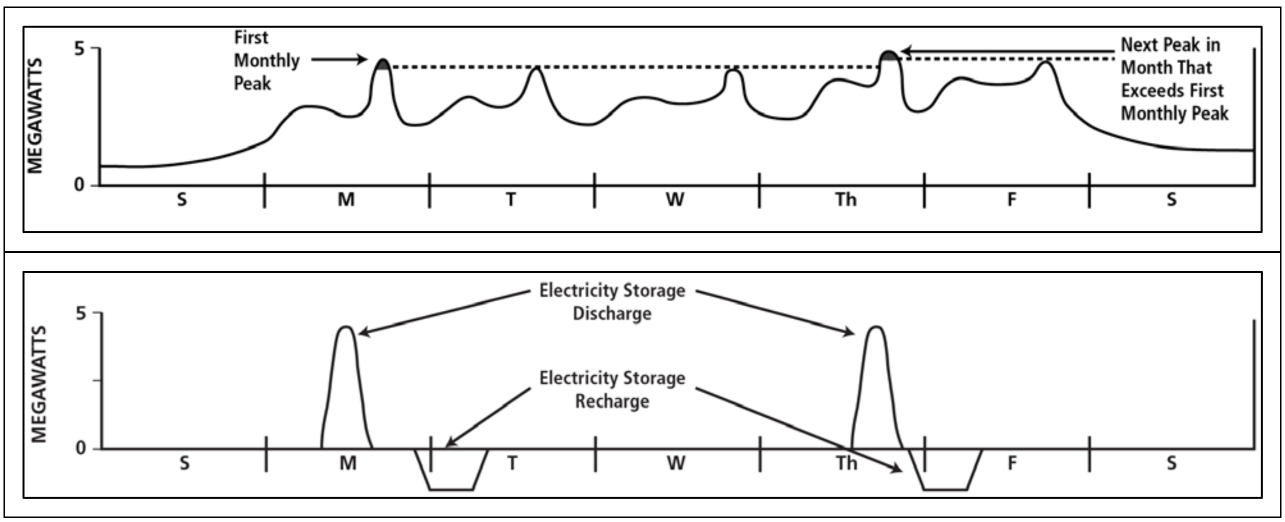


Figure 18. Storage for Customer-side Demand Management

1.6 Stacked Services—Use Case Combinations

Electricity storage can be used for any of the services listed above, but it is rare for a single service to generate sufficient revenue to justify its investment. However, the flexibility of storage can be leveraged to provide multiple or stacked services, or use cases, with a single storage system that captures several revenue streams and becomes economically viable. How these services are stacked depends on the location of the system within the grid and the storage technology used. However, due to regulatory and operating constraints, stacking services is a process that requires careful planning and should be considered on a case-by-case basis.

In the California Public Utility Commission’s (CPUC’s) energy storage proceeding R1012007, a series of electricity storage use cases was considered and studied by multiple stakeholders. CPUC divided the use cases into three general categories based on the location of the storage as shown in Table 2. When connected to the grid at the transmission level, energy storage can provide grid-related service to ancillary markets under the control of ISOs while bidding into the energy market. Energy storage can also act as a peaker to provide system capacity. When placed on the distribution circuits, energy storage can help solve local substation-specific problems (mitigating voltage problems, deferring investment upgrades, etc.) while providing ancillary services to the grid. On the customer side of the meter, energy storage system can shave the customer's peak load and reduce the electricity bill while improving power quality and reliability. Detailed documents about the CPUC-defined electricity storage use cases can be found on the CPUC website.[18] As part of the CPUC proceeding's effort to understand better the cost-effectiveness of different electricity storage use cases, EPRI conducted cost-benefit analyses using the Energy Storage Valuation Tool (ESVT), discussed in Chapter 3, for a subset of the CPUC use cases, including the bulk storage peaker substitution use case, the ancillary services only use case, and the distributed peaker use case. The results of the EPRI analyses[19] were presented in a public workshop in March 2013.

Table 2. Illustration of California Public Utility Commission Use Cases

(Source: EPRI presentation in CPUC Storage OIR Workshop, March 25, 2013[20])

Use Case	Categories
Transmission-Conneced Energy Storage	Bulk Storage System
	Ancillary Services
	On-Site Generation Storage
	On-Site Variable Energy Resource Storage
Distributed-Level Energy Storage	Distributed Peaker
	Distributed Storage Sited at Utility Substation
	Community Energy Storage
Demand-Side (Customer-Sited) Energy Storage	Customer Bill Management
	Customer Bill Management w/ Market Participation
	Behind the Meter Utility Controlled
	Permanent Load Shifting
	EV Charging

A detailed discussion of the methodology to determine and evaluate viable electricity storage use cases can be found in Chapter 3 of this course. Various business models for acquiring storage systems can be found in Chapter 4.

[18] http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm, last accessed March 15, 2013.

[19] "*Energy Storage Valuation Tool Draft Results—Investigation of Cost Effectiveness Potential for Select CPUC Inputs and Storage Use Cases in 2015 and 2020*," EPRI Energy Storage Program, CPUC Storage OIR Workshop (R.10-12-007), http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm ; last accessed March 25, 2013.

[20] Ibid.

CHAPTER 2. ELECTRICITY STORAGE TECHNOLOGIES: COST, PERFORMANCE, AND MATURITY

2.1 Introduction

This chapter presents a review of the currently available and emerging electricity storage technologies that are anticipated to be available within the next two to three years. Emerging technologies still in the early research and development (R&D) development stage are noted in the last section of this chapter but are not reviewed in detail. The sections in this chapter are organized by technology and provide a snapshot of the status, trends in deployment, data sheets on performance, and design features. Estimates of life-cycle costs for each technology are also provided, along with the key assumptions.

2.2 Storage Technologies Overview

The portfolio of electricity storage technologies can be considered for providing a range of services to the electric grid and can be positioned around their power and energy relationship. This relationship is illustrated in Figure 19, which shows that compressed air energy storage (CAES) and pumped hydro are capable of discharge times in tens of hours, with correspondingly high sizes that reach 1000 MW. In contrast to the capabilities of these two technologies, various electrochemical batteries and flywheels are positioned around lower power and shorter discharge times. *In Figure 19, these comparisons are very general, intended for conceptual purposes only;* many of the storage options have broader duration and power ranges than shown.

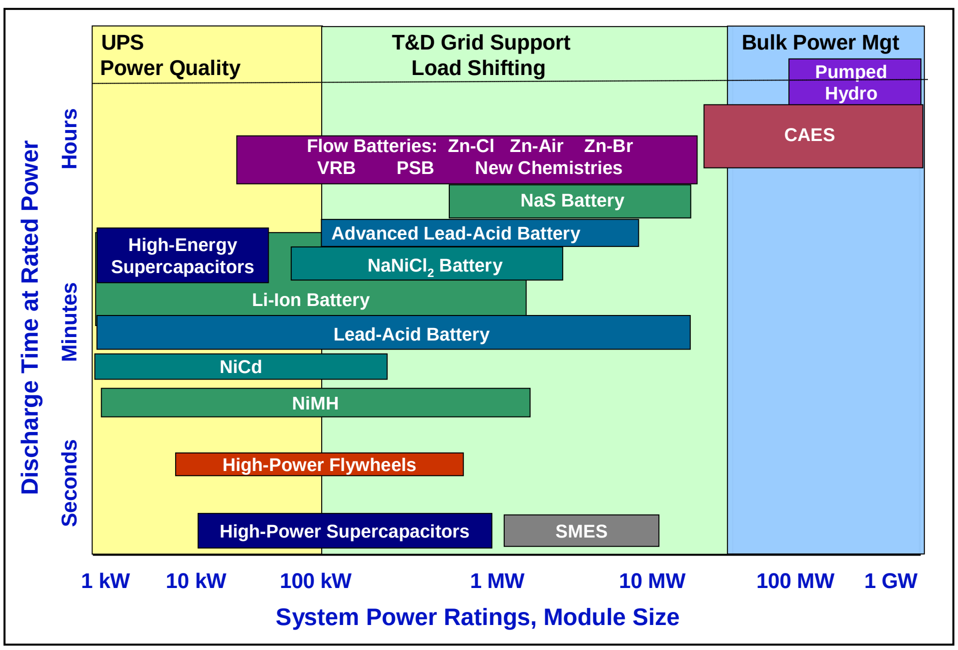


Figure 19. Positioning of Energy Storage Technologies

Traditionally, economies of scale have dictated that pumped hydro be sized for storage times that exceed 8 to 10 hours – necessary to amortize the cost of large storage reservoirs, dams, and civil engineering work that are integral to this technology. For example, Rocky Mountain Hydroelectric Plant, the last pumped storage plant built in the United States, has over 10 hours of storage capacity and is rated at 1095 MW. Similarly, CAES requires developing large underground (naturally occurring or man-made caverns) or large steel above-ground storage reservoirs to store the compressed air. In contrast to these large sizes, flywheels and the family of batteries cluster in the lower end of the discharge duration spectrum, ranging from a few seconds to 6 hours (delivered by sodium sulfur battery systems and potentially certain flow battery systems).

2.3 Approach

All costs shown are in 2012 dollars and do not reflect regional cost differences across the United States. More than 50 battery original equipment manufacturers (OEMs), power electronics system providers, and system integrators were surveyed and asked to provide performance, cost, and O&M data for energy systems they could offer for various uses of storage. Reference electrical one-line diagrams and installation assessments were drawn for each use considered. Vendor responses to this survey provided the basis for the information in the data sheets provided in the subsequent sections. An iterative approach was used to review scope of supply, cost data, and operation and performance data. Given the lack of credible O&M data for some technologies, proxies were developed to estimate fixed, variable, and periodic battery replacement costs shown in affordably.

Given that certain energy storage technologies are still in the R&D stage and have not been fully developed or have not been demonstrated in the specifically intended service, process and project contingencies costs were added to develop installed costs, given the uncertainty in those cases.

Installed cost estimates were developed for the specific services and are presented per kilowatt of discharge capacity installed ($/kW installed). Levelized cost of energy (LCOE) or lifecycle cost estimates are expressed per kilowatt-hour ($/kWh) of delivered energy and per kW of discharge capacity ($/kW-yr). For technology screening-level studies, these cost estimates are conceptual estimates that will differ from site-specific project estimates for the following reasons:

Project estimates are more detailed and based on site-specific conditions and use cases. Individual companies' design bases may vary. Actual owner costs as well as site-specific costs in project estimates are generally higher. Site-specific requirements, such as transportation, labor, interconnection, and permitting, also have an impact.

[21] Energy Storage Technology and Application-Cost and Performance Data Base, EPRI ID: 1024279, EPRI, Palo Alto, CA, November 2012.

[22] Electricity Energy Storage Technology Options 2012 System Cost Benchmarking, EPRI ID: 1026462, EPRI, Palo Alto, CA, December 2012.

As presented in Table 3, a rating system is used to define an overall confidence level for data presented in technology screening studies. One rating approach is based on a technology's development status; the other is based on the level of effort expended in the design and cost estimate. The confidence levels of the estimates presented in this report reflect technology development statuses ranging from early demonstration trials to mature development, with a preliminary or simplified level of effort. The rating system indicates the level of effort involved in developing the design and cost estimate.

Table 3. Confidence Rating Based on Cost and Design Estimate

Letter Rating	Key Word	Description
A	Actual	Data on detailed process and mechanical designs or historical data from existing units
B	Detailed	Detailed process design (Class III design and cost estimate)
C	Preliminary	Preliminary process design (Class II design and cost estimate)
D	Simplified	Simplified process design (Class I design and cost estimate)
E	Goal	Technical design/cost goal for value developed from literature data

Accuracy

Because of the impact of local site-specific conditions, energy storage system estimates in this report necessarily fall into the simplified or preliminary classifications. When compared with finalized or detailed cost estimate values, these may vary by 10% to 30%. However, because a consistent methodology is used for developing installed capital and levelized lifecycle cost estimates, these costs are useful in performing screening assessments for comparing various alternative storage technologies according to the service they provide.

Estimates of the range of accuracy for the cost data presented in this section are shown in Table 4, which is based on the confidence ratings described previously.

Table 4. Accuracy Range Estimates for Technology Screening Data*

		Percent Accuracy in Technology Development Rating				
	Estimate Rating	A Mature	B Commercial	C Demo	D Pilot	E & F Lab & Idea
A	Actual	0	–	–	–	–
B	Detailed	-5 to +8	-10 to +15	-15 to +25	–	–
C	Preliminary	-10 to +15	-15 to +20	-20 to +25	-25 to +40	-30 to +60
D	Simplified	-15 to +20	-20 to +30	-25 to +40	-30 to +50	-30 to +200
E	Goal	–	-30 to +80	-30 to +80	-30 to +100	-30 to +200
This table indicates the overall accuracy for cost estimates. The accuracy is a function of the level of cost-estimating effort and the degree of technical development of the technology. The same ranges apply to O&M costs.						

* Ranges in percent (%).

2.4 Pumped Hydro

Pumped hydroelectric energy storage is a large, mature, and commercial utility-scale technology currently used at many locations in the United States and around the world. Table 5 is a technology dashboard that shows the status of technology development for pumped hydro systems. Pumped hydro employs off-peak electricity to pump water from a reservoir up to another reservoir at a higher elevation. When electricity is needed, water is released from the upper reservoir through a hydroelectric turbine into the lower reservoir to generate electricity.

Figure 20 shows a cutaway view of a typical pumped hydro plant, and Figure 21 is a picture of the upper reservoir of the Tennessee Valley Authority's (TVA's) Raccoon Mountain pumped storage facility. This storage technology has the highest capacity of all the storage technologies assessed, because its size is limited only by the size of the available upper and lower reservoirs.

Table 5. Technology Dashboard: Pumped Hydro

Technology Development Status	Mature	Numerous New Pumped Hydro FERC Filings in U.S.
Confidence of Cost Estimate	C	Preliminary; Based on planned actual site-specific projects
Accuracy Range	Commercial	-15% to +15%
Operating Stations	40 units (20+ GW) in U.S.	Over 129 GW in operation worldwide
Process Contingency	0%	Variable-speed drive technology being applied to new sites
Project Contingency	10-15%	Uncertainties in sitting, permitting, environmental impact and construction

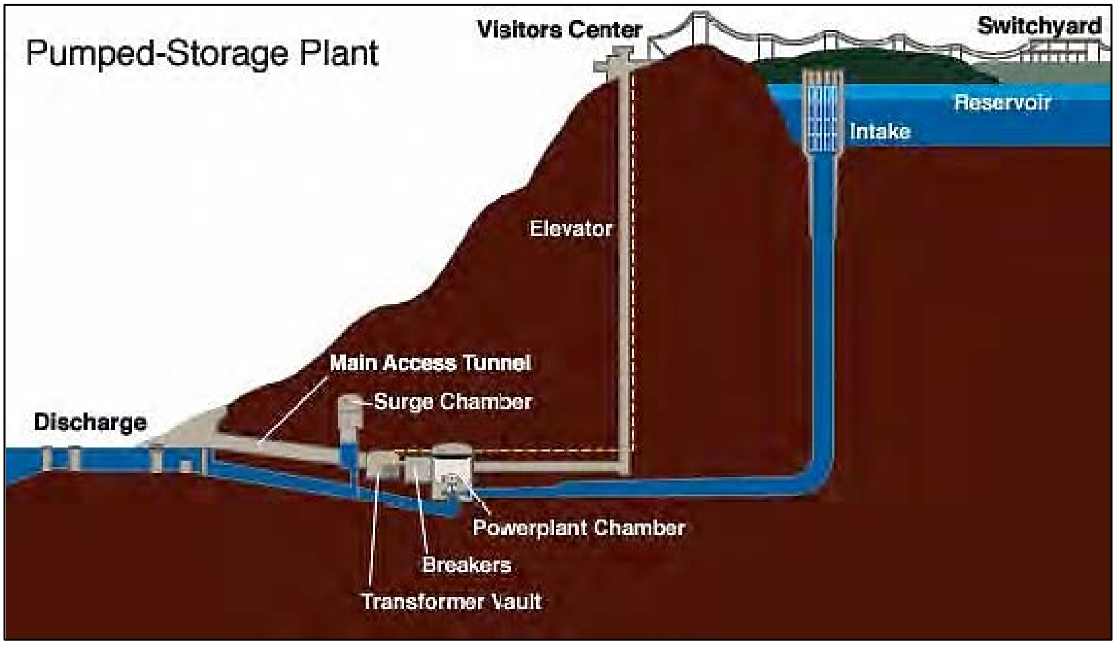


Figure 20. Cutaway Diagram of a Typical Pumped Hydro Plant

Figure 21. Man-made Upper Reservoir of TVA's Raccoon Mountain Pumped Hydro Plant
(Operational in 1979, the facility can generate 1620 MW for up to 22 hours.)

Projects may be practically sized up to 4000 MW and operate at about 76%–85% efficiency, depending on design. Pumped hydro plants have long lives, on the order of 50-60 years. As a general rule, a reservoir one kilometer in diameter, 25 meters deep, and having an average head of 200 meters would hold enough water to generate 10,000 MWh.

The earliest plant in the U.S. was built in the late 1920s, and the last pumped storage plant commissioned was in the 1980s, when environmental concerns over water and land use severely limited the ability to build additional pumped hydro capacity. Figure 22 provides a list of Pumped Storage Preliminary Permits/Proposed Projects in the United States. In Europe, over 15 GW of new pumped hydro facilities are expected to be installed by 2020, and future deployments in Asia are also expected to grow during this time period.

While the siting, permitting, and associated environmental impact processes can take many years, there is growing interest in re-examining opportunities for pumped hydro in the United States, particularly in view of the large amounts of wind generation and new nuclear power generation that may be deployed over the next few decades. A list of licensed pumped storage facilities and pending permits is maintained by FERC at http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp.

A 2011 EPRI study developed updated estimates for construction of new pumped hydro facilities.[23] Data from this study are reproduced in Figure 23 and Figure 24.

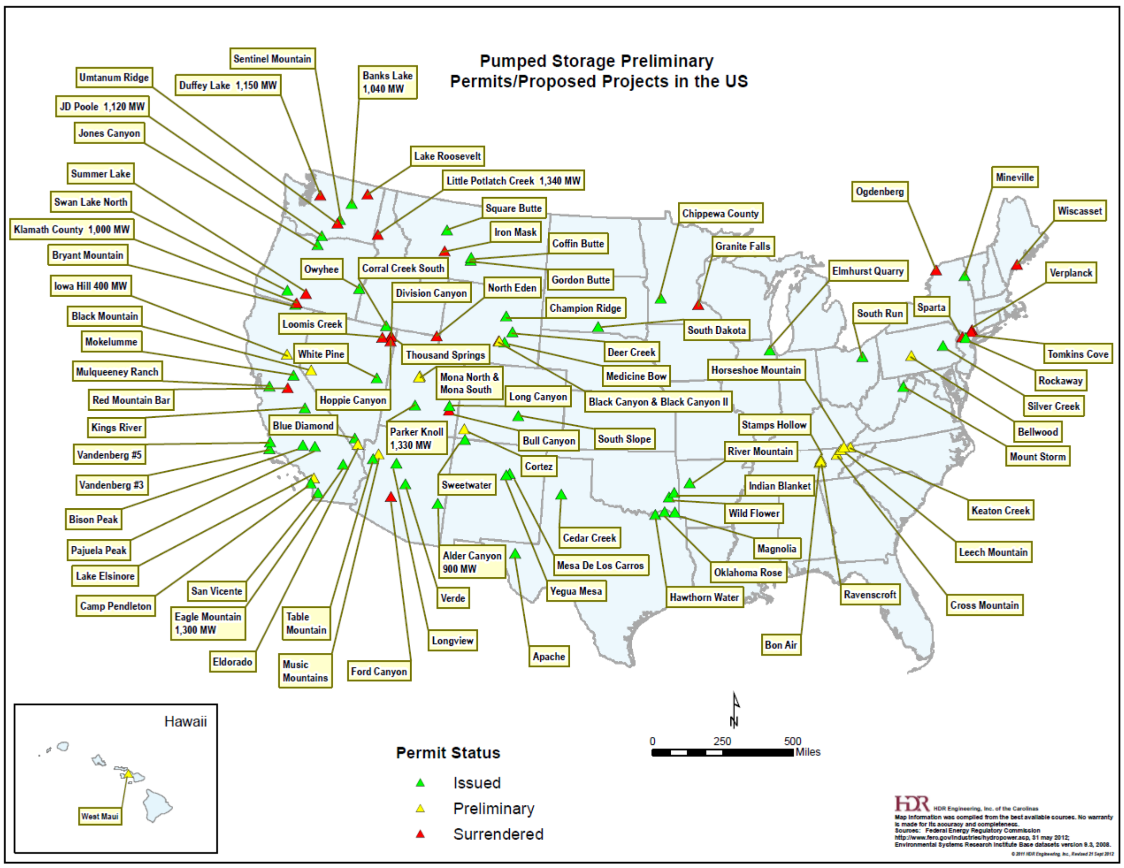


Figure 22. Pumped Storage Preliminary Permits/Proposed Projects in the United States

[23] *"Quantifying the Value of Hydro Power on the Electric Grid: Plant Cost Elements"*, Principal Investigators: s. Brown, J. Gibson, R. Grady, R. Miller, A. Roth, J.Sigmon, D. Summers; EPRI Report 1023140, EPRI, Palo Alto, CA, November 2011.

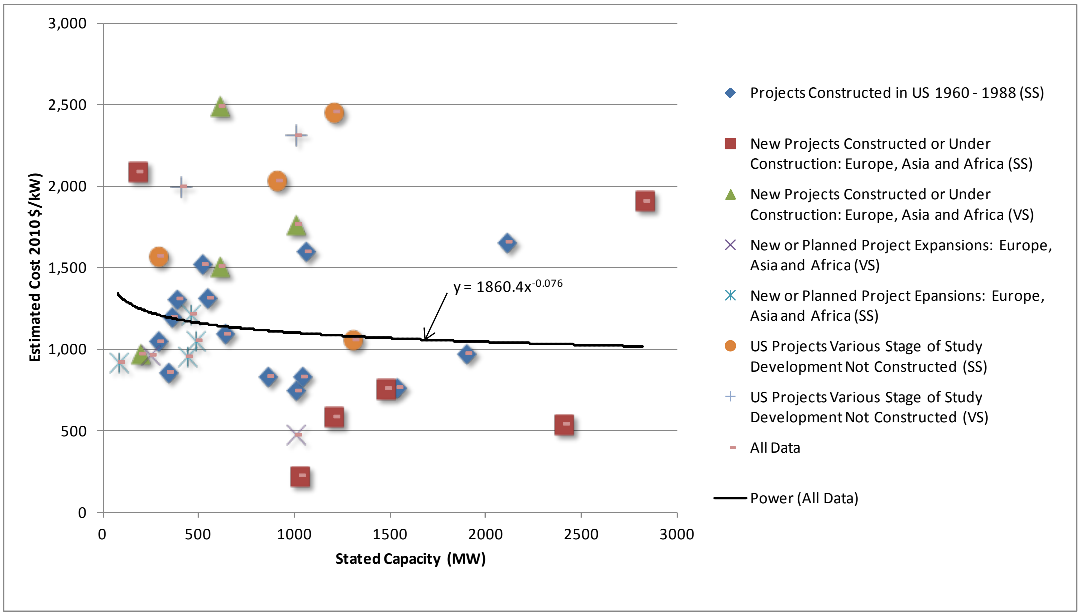


Figure 23. Cost Data ($/kW) for Historical and Proposed Pumped Hydro Projects As a Function of Capacity

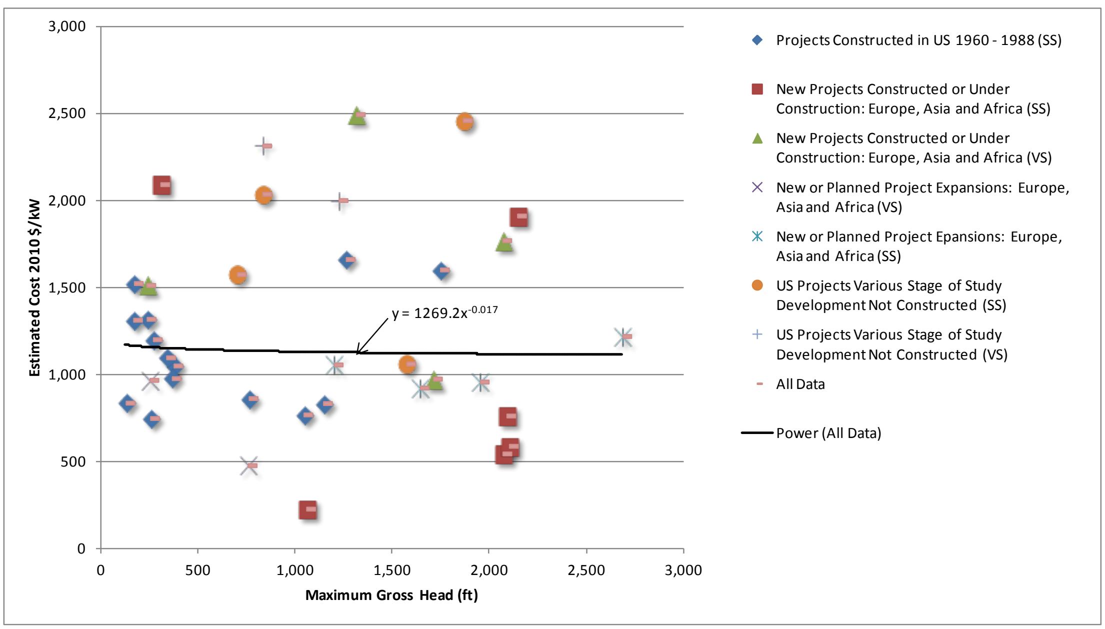


Figure 24. Cost Data ($/kW) for Historical and Proposed Storage Systems

Pumped hydro systems are assumed to be located at greenfield sites where site-specific project costs are included in the cost estimates. This site would be typical of an unprepared or new site for a utility or a private developer that includes all the listed site-specific project costs. These estimates, then, represent an installed total plant cost (TPC) less the owner's financial costs. The utility and owner interconnection transmission line costs for pumped hydro systems are also not included in the cost estimates; however, site-specific generator step-up transformers and the site substation are included in the site-specific costs.

Pumped Hydro Life-Cycle Cost Analysis

Figure 25, Figure 26, and Figure 27 summarize present value of installed cost, the LCOE in $/MWh, and the levelized cost of capacity in $/kW-yr for pumped hydro facilities. These are based on round-trip efficiency of 81%, 365 cycles per year, and plant life of 60 years. Project-specific parameters with a more detailed economic dispatch would have different life-cycle estimates.

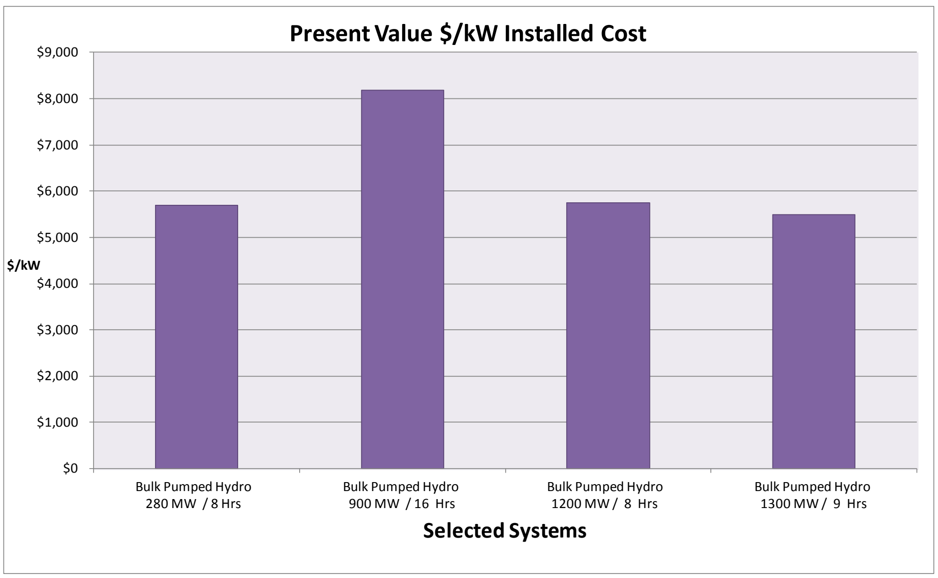


Figure 25. Present Value Installed Cost in $/kW for Pumped Hydro

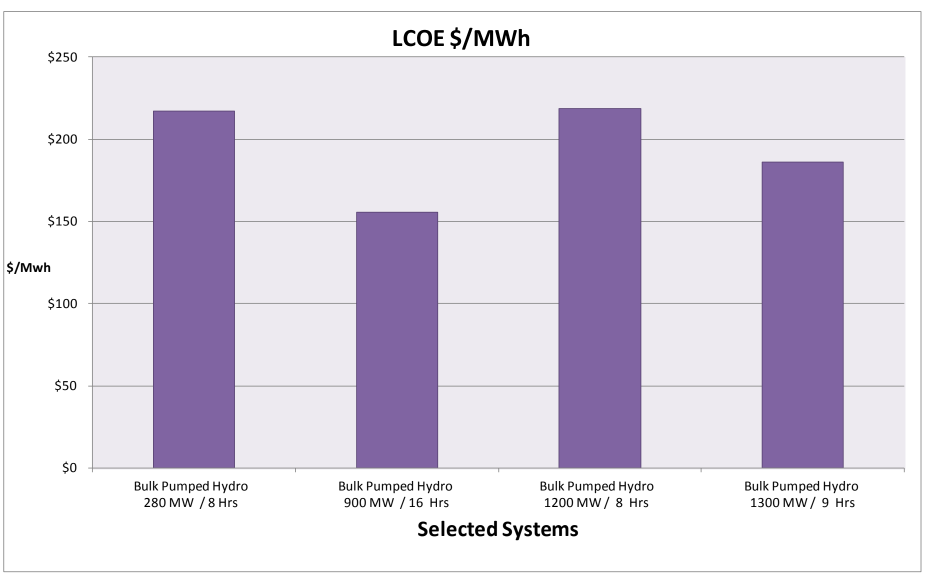


Figure 26. Levelized Cost of Energy in $/MWh for Pumped Hydro

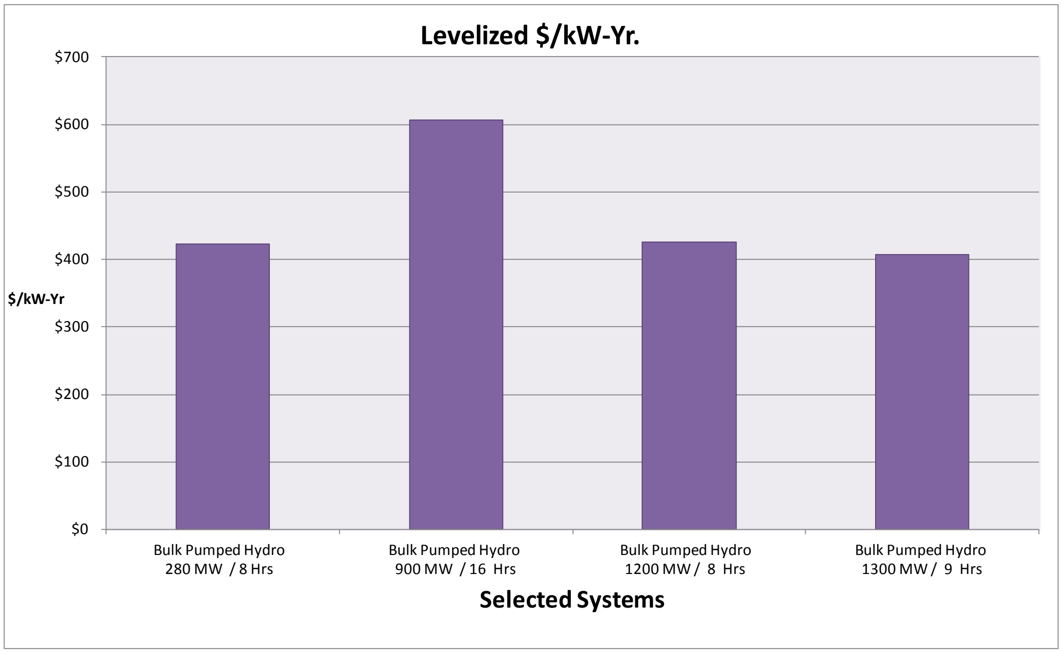


Figure 27. Levelized Cost of Capacity in $/kW-yr for Pumped Hydro

Additional Pumped Hydro Resources

1. *Quantifying the Value of Hydro Power on the Electric Grid: Plant Cost Elements*, EPRI Report 1023140, EPRI, Palo Alto, CA, November 2011.

2. *Application of Adjustable-Speed Machines in Conventional and Pumped-Storage Hydro Projects, EPRI ID TR-105542, EPRI, Palo Alto, CA, February 1996.*

3. *Operation and Maintenance Experiences of Pumped-Storage Plants, EPRI ID GS-7325, EPRI, Palo Alto, CA, May 1991.*

4. *Results from Case Studies of Pumped-Storage Plants, EPRI ID 1023142, EPRI, Palo Alto, CA, September 2012.*

2.5 Compressed Air Energy Storage

Technical Description

CAES systems use off-peak electricity to compress air and store it in a reservoir, either an underground cavern or aboveground pipes or vessels. When electricity is needed, the compressed air is heated, expanded, and directed through an expander or conventional turbine-generator to produce electricity. Figure 28 is a schematic of a CAES plant with underground storage cavern in a salt dome.

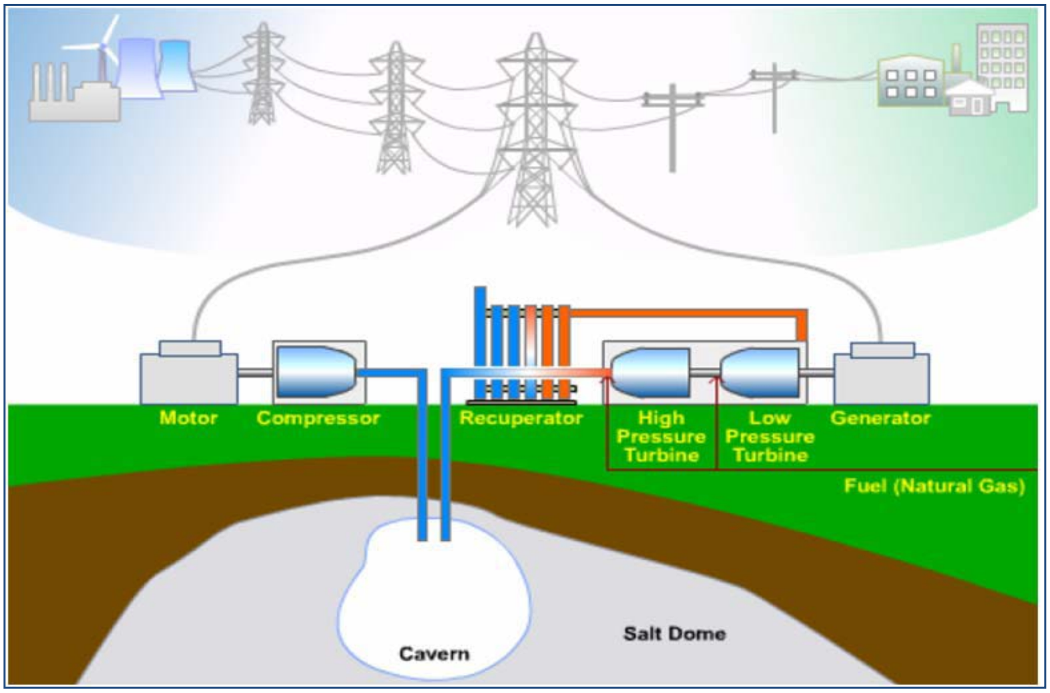


Figure 28. Schematic of Compressed Air Energy Storage Plant with Underground Compressed Air Storage

CAES is the only commercial bulk energy storage plant available today, other than pumped hydro. There are two operating first-generation systems: one in Germany and one in Alabama. In the past few years, improved second-generation CAES system cycles have been defined and are being designed. Second-generation CAES hold the potential for lower installed costs, higher efficiency, and faster construction time than the first-generation systems. In one type of advanced second-generation CAES plant, a natural-gas-fired combustion turbine (CT) is used to generate heat during the expansion process. In such a plant, about two-thirds of the electricity generated is produced from the expansion turbine and about one-third from the CT. New compressor designs and advanced turbo-machinery are also leading to improved non-CT-based CAES systems.

CAES plants employing aboveground air storage would typically be smaller than plants with underground storage, with capacities on the order of 3 to 50 MW and discharge times of 2 to 6 hours. Aboveground CAES plants are easier to site but more expensive to build (on a $/kW basis) than CAES plants using underground air storage systems, primarily due to the incremental additional cost associated with aboveground storage. CAES systems using improved first-generation designs also continue to be evaluated and are being proposed.

Underground CAES storage systems are most cost-effective with storage capacities up to 400 MW and discharge times of 8 to 26 hours. Siting such plants involves finding and verifying the air storage integrity of a geologic formation appropriate for CAES in a given utility's service territory.

Maturity and Commercial Availability

There are two operating first-generation CAES systems: one in Germany and one in the state of Alabama in the U.S. The first-generation CAES plant at PowerSouth Energy Cooperative (formerly Alabama Electric Cooperative) has operated reliably for 18 years and successfully demonstrated the technical viability of this early design. A 290-MW, four-hour CAES plant has been operating in Huntorf, Germany, since December 1978, demonstrating strong performance with 90-percent availability and 99-percent starting reliability. This plant uses two man-made, solution-mined salt caverns to store the air.

EPRI is collaborating with Pacific Gas and Electric (PG&E) in a DOE-awarded grant to support site, design, and demonstration testing of a 300-MW/10-hour CAES plant.

Table 6 is a technology dashboard that shows the status of technology development for second-generation CAES.

Table 6. Technology Dashboard: Compressed Air Energy Storage

Technology Development Status	1st Generation - Mature 2nd Generation - Demonstration	Commercial offer possible System to be verified by demonstration unit
Confidence of Cost Estimate	C	Based on preliminary designs Owners’ costs and site-specific costs not included; these costs can be significant. First-time-engineering costs can be significant.
Accuracy Range	C	-20% to +25%
Operating Field Units	2nd Generation - None	Two of first-generation type
Process Contingency	15%	Key components and controls need to be verified for second-generation systems.
Project Contingency	10%	Plant costs will vary depending upon underground site geology.

CAES Life-Cycle Cost Analysis

Figure 29, Figure 30, and Figure 31 summarize present value of installed cost, the LCOE in $/MWh, and the levelized cost of capacity in $/kW-yr for CAES plants. These estimates are based on heat rate and energy ratio and O&M data from the data sheets for CAES. A simple dispatch was assumed: 365 cycles per year and plant life of 30 years. Investor ownership financial assumptions. Natural gas cost of $3 one million Btu (MMBtu); off peak power costs of $30 megawatt hour (MWh). Project specific parameters with a more detailed economic dispatch would have different life-cycle estimates.

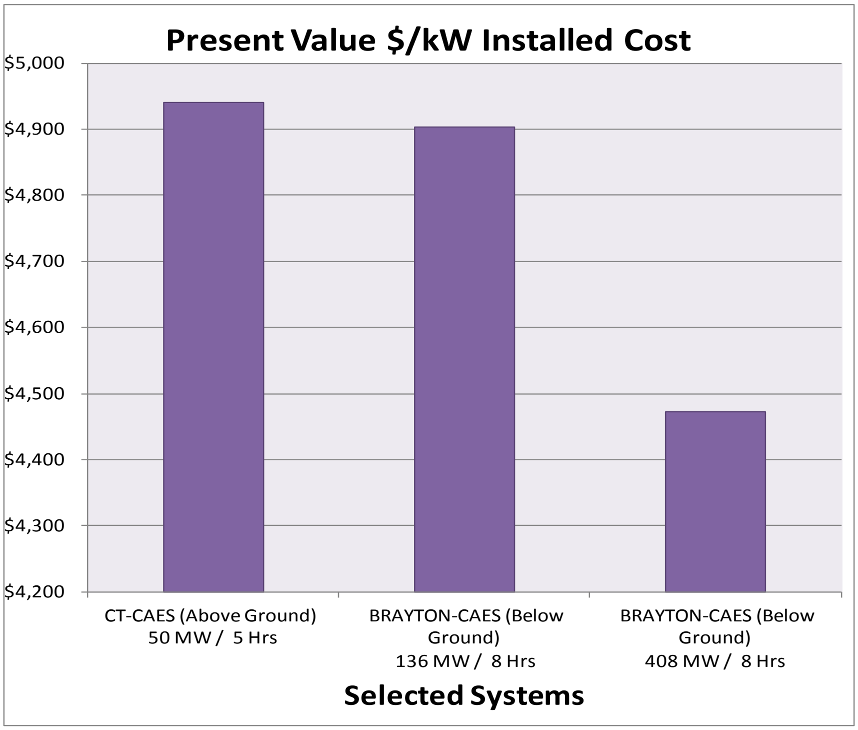


Figure 29. Present Value Installed Cost for Different Sizes of CAES Systems

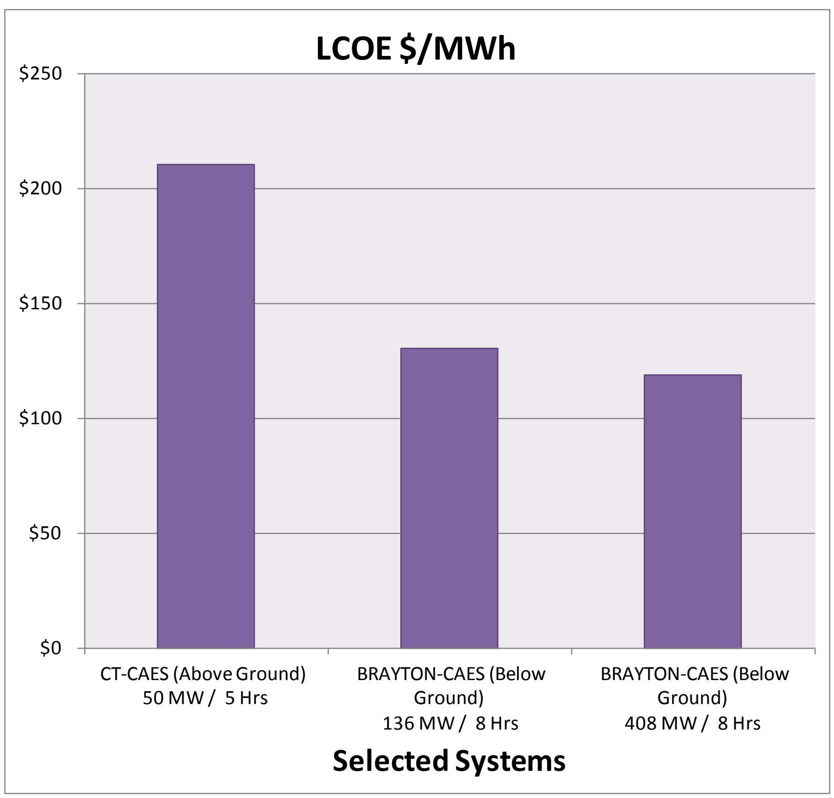


Figure 30. Levelized Costs of Energy in $/MWh for Different Sizes of CAES Systems

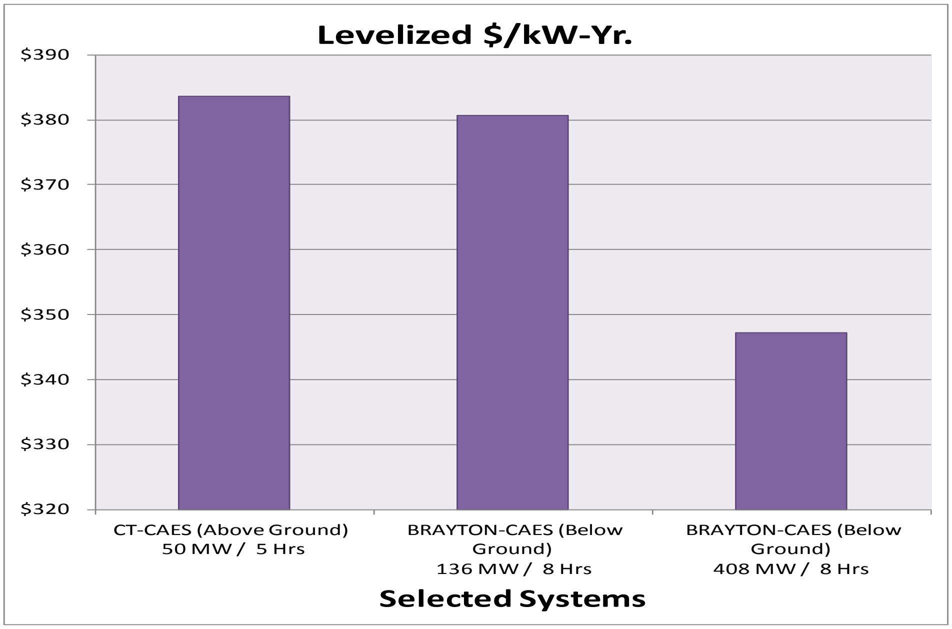


Figure 31. Levelized Costs of Capacity in $/kW-yr for Different Sizes of CAES Systems

Additional CAES Resources

1. *Electricity Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits*. December 2010. EPRI Report 1020676.
2. *History of First U.S. Compressed-Air Energy Storage (CAES) Plant (110 MW 26h): Volume 2: Construction*, EPRI ID TR-101751-V2, EPRI, Palo Alto, CA, May 1994.
3. *History of First U.S. Compressed Air Energy Storage (CAES) Plant (110-MW-26 h): Volume 1: Early CAES Development*, EPRI ID 101751-V1, EPRI, Palo Alto, CA, January 1993.
4. *Midwest Independent Transmission System Operator (MISO) Energy Storage Study,* EPRI ID 1024489, EPRI, Palo Alto, CA, February 2012.
5. *Evaluation of Benefits and Identification of Sites for a CAES Plant in New York State*, EPRI TR-104268,EPRI, Palo Alto, CA, September 1994.

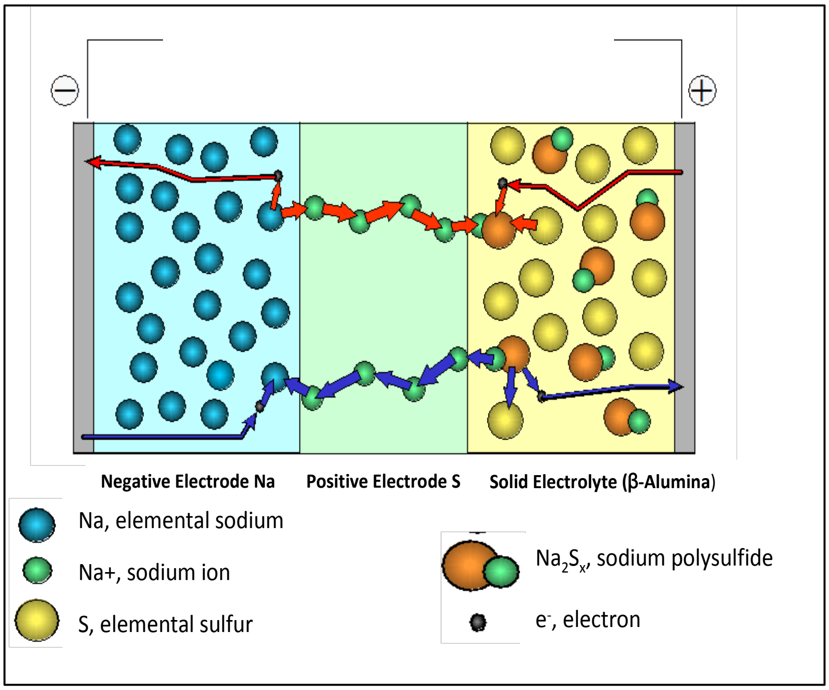
2.6 Sodium-sulfur Battery Energy Storage

Technical Description

Sodium-sulfur (NaS) batteries are a commercial energy storage technology finding applications in electric utility distribution grid support, wind power integration, and high-value grid services. NaS battery technology holds potential for use in grid services because of its long discharge period (approximately 6 hours). Like many other storage technologies, it is capable of prompt, precise response to such grid needs as mitigation of power quality events and response to AGC signals for area regulation.[24]

The normal operating temperature regime of NaS cells during discharge/charge cycles is in the range of 300 ºC to 350 ºC. During discharge, the sodium (negative electrode) is oxidized at the sodium/beta alumina interface, forming Na^+ ions. These ions migrate through the beta alumina solid electrolyte and combine with sulfur that is being reduced at the positive electrode to form sodium pentasulfide (Na_2S_5). The Na_2S_5 is immiscible with the remaining sulfur, thus forming a two-phase liquid mixture. See Figure 32, below.[25]

After all the free sulfur phase is consumed, the Na_2S_5 is progressively converted into single-phase sodium polysulfides with progressively higher sulfur content (Na_2S_{5-x}). Cells undergo exothermic and ohmic heating during discharge. Although the actual electrical characteristics of NaS cells are design-dependent, voltage behavior follows that predicted by thermodynamics.[26]



[24] *Electric Energy Storage Technology Options: A Primer on Applications, Costs and Benefits*, PI: Rastler, Dan, EPRI ID 1020676, EPRI, Palo Alto, CA, September 2010. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001020676

[25] Courtesy of EPRI.

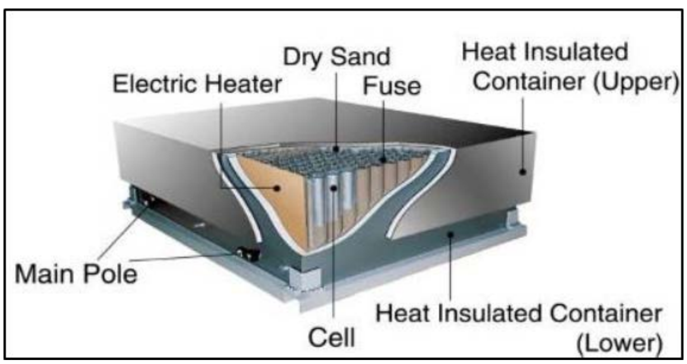
[26] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; EPRI ID 1001834, EPRI, Palo Alto, CA, and the US Department of Energy, Washington, DC, 2003. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001001834

Figure 32. Chemical Structure of a Sodium-sulfur Cell

After all the free sulfur phase is consumed, the Na_2S_5 is progressively converted into single-phase sodium polysulfides with progressively higher sulfur content (Na_2S_{5-x}). Cells undergo exothermic and ohmic heating during discharge. Although the actual electrical characteristics of NaS cells are design-dependent, voltage behavior follows that predicted by thermodynamics.[27]

The NaS batteries use hazardous materials including metallic sodium, which is combustible if exposed to water. Therefore, construction of NaS batteries includes airtight, double-walled stainless-steel enclosures that contain the series-parallel arrays of NaS cells. Each cell is hermetically sealed and surrounded with sand both to anchor the cells and to mitigate fire, as shown in Figure 33. Other safety features include fused electrical isolation and a battery management system that monitors cell block voltages and temperature. The sodium, sulfur, beta-alumina ceramic electrolyte, and sulfur polysulfide components of the battery are disposed of by routine industrial processes or recycled at the end of the NaS battery life. NaS batteries can be installed at power generating facilities, substations, and at renewable energy power generation facilities where they are charged during off peak hours and discharged when needed. Battery modules contain cells, a heating element, and dry sand.

NGK Insulators, Ltd., and Tokyo Electric Power Co. (TEPCO) jointly developed NaS battery technology over the past 25 years. “NAS” is a registered trademark for NGK’s sodium-sulfur battery system, while “NaS” is a generic term used to refer to sodium-sulfur based on those elements’ atomic symbols (“Na” and “S”). Standard units typically used in energy storage installations from NGK Insulators, Ltd., contain five 50-kW NaS modules that include a control unit, heater, heater controller, and voltage and current measurement sensors. Multiple, parallel standard units are used to create multi-megawatt systems.



[27] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; EPRI ID 1001834, EPRI, Palo Alto, CA, and the US Department of Energy, Washington, DC, 2003. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001001834

Figure 33. Sodium-sulfur Battery Module Components[28]

Performance Characteristics

Energy density by volume for NaS batteries is 170kWh/m^3 and by weight is 117kWh/ton. NGK projects its NAS to have a cycle life of 4500 cycles for rated discharge capacity of 6 MWh per installation MW. Rated at 4500 cycles, NaS batteries are projected to have a calendar life of 15 years.

Table 7 summarizes the performance characteristics of NaS batteries provided by the manufacturer.

Table 7. Performance Characteristics of NaS Batteries29

Energy Density (Volume)	170 kWh/m3
Energy Density (Weight)	117 kWh/ton
Charge/Discharge Efficiency – Batteries (DC Base)	> 86 percent
Charge/Discharge Efficiency – System (AC Base)	≥ 74 percent
Maintenance	Low
Cycle Life	4,500 cycles at rated capacity
Calendar Life	15 yr

Based on vendor data the round-trip alternating current (ac)-to-ac efficiency of NaS systems is approximately 75%. The estimated life of a NaS battery is approximately 15 years after 4500 cycles at rated discharge.[30]

Maturity and Commercial Availability

NaS installations providing the functional equivalent of about 160 MW of pumped hydro storage are currently deployed within Tokyo. NaS batteries are only available in multiples of 1-MW/6-MWh units with installations typically in the range of 2 to 10 MW. The largest single installation is the 34-MW Rokkasho wind-stabilization project in Northern Japan that has been operational since August 1, 2008. At this time, about 316 MW of NaS installations have been deployed

[28] *1 MW / 7.2 MWh NaS Battery Demonstration and Case Study Update,*EPRI, EPRI ID: 1017814, EPRI, Palo Alto, CA: December 2009.

[30] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits,* EPRI, EPRI ID: 1020676. EPRI, Palo Alto, CA, September 2010. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001020676

globally at 221 sites, representing 1896 MWh. Customers in the United States include American Electric Power (AEP) (11 MW deployed at five locations), PG&E (6 MW, in progress), and Xcel Energy (1 MW, deployed).

The NAS battery installation provided by NGK Insulators, Ltd., deployed at Xcel in Lucerne, MN, in 2008 contains 20 50-kW modules with 7.2 MWh of storage capacity and a charge/-discharge capacity of 1 MW. See Figure 34 below. Batteries are charged when wind turbines are operating. The batteries then provide supplemental power when the turbines are not operating. Xcel estimates the fully charged NAS facility could power 500 homes for over seven hours.

Table 8 shows the technology dashboard for NaS battery systems.

Figure 34. Xcel Battery Supplementing Wind Turbines, Lucerne, MN

Table 8. Technology Dashboard: Sodium-sulfur Battery Systems

Technology Development Status	A	Significant recent commercial experience.
Confidence of Cost Estimate	A	Data based on installed systems.
Accuracy Range	B	-5% to +8%
Operating Field Units	221 sites	306 MW installed.
Process Contingency	0%	Proven battery performance.

Project Contingency	1-5%	Depending on site conditions.

Sodium-sulfur Batteries Life-Cycle Cost Analysis

Figure 35, Figure 36, and Figure 37 summarize present value of installed cost, the LCOE in \$/MWh, and the levelized cost of capacity in \$/kW-yr for NaS plants. These estimates are based on capital and O&M data from the NaS data sheets. A simple dispatch was assumed: investor-owned utility financials and 365 cycles per year for 15 years. Battery replacement costs for longer service lives were not assumed over and above the O&M estimates.

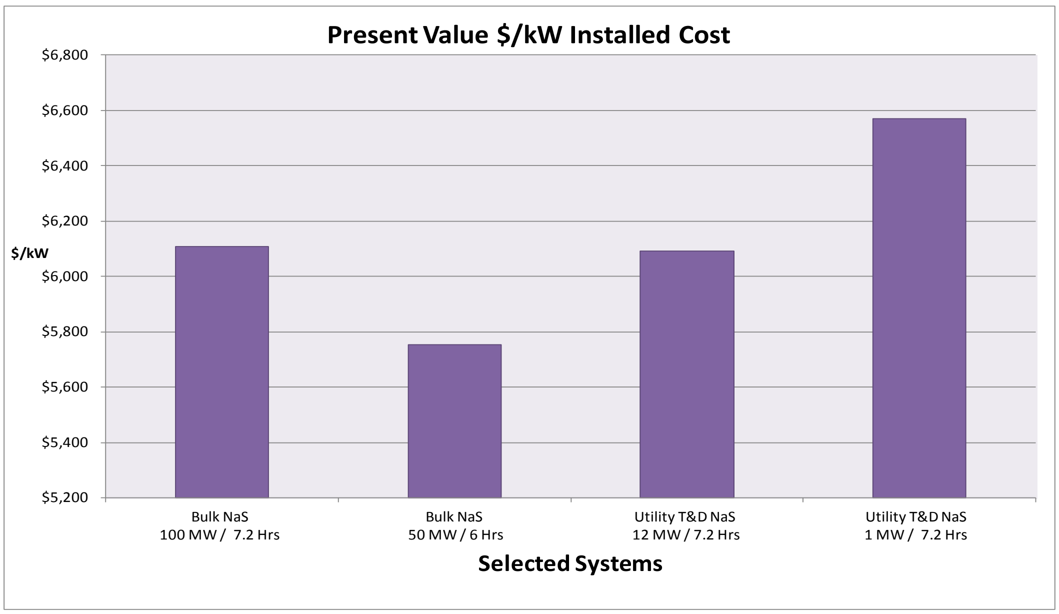


Figure 35. Present Value Installed Cost for Different Sodium-sulfur Systems

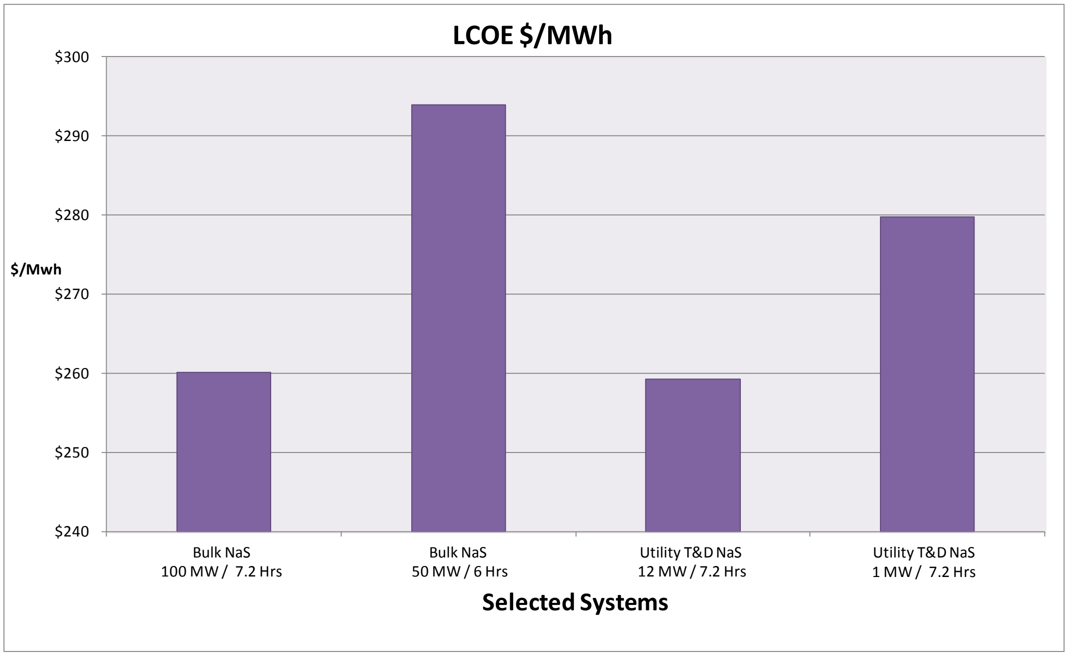


Figure 36. Levelized Cost of Energy in $/MWh for Different Sodium-sulfur Systems

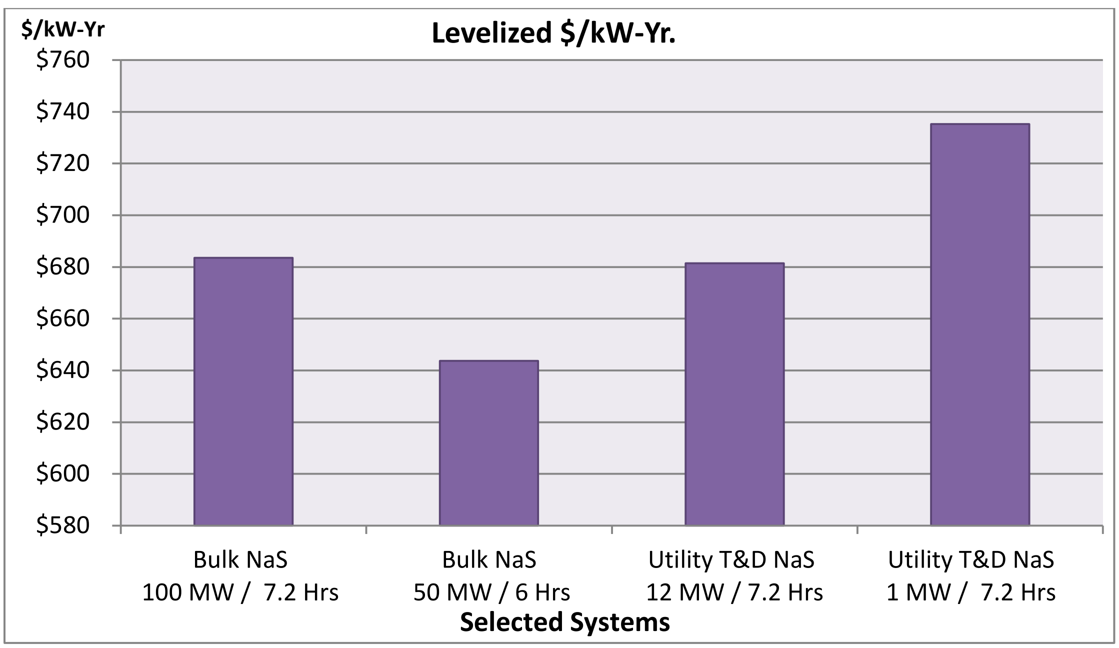


Figure 37. Levelized Costs of Capacity $/kW-yr for Different Sodium-sulfur Systems

Additional Sodium-Sulfur Battery Resources

1. *Program on Technology Innovation: Long Island Bus NaS Battery Energy Storage System*, EPRI ID 1013248, EPRI, Palo Alto, CA, EPRI ID 1013248, March 2006.

2. *Program on Technology Innovation: New York Power Authority Advanced Sodium Sulfur (NaS) Battery Energy Storage System*, EPRI ID 1023626, EPRI, Palo Alto, CA, December 2011.

3. *AEP Sodium-Sulfur (NaS) Battery Demonstration - 2003 Annual Report*, EPRI ID 1009814, EPRI, Palo Alto, CA, August 2004.

4. *AEP Sodium-Sulfur (NaS) Battery Demonstration: Final Report*, EPRI ID 1012049, EPRI, Palo Alto, CA, Jun 2005.

5. *Field Trial of AEP Sodium-Sulfur (NaS) Battery Demonstration Project: Interim Report - Plant Design and Expected Performance*, EPRI ID 1001835, EPRI, Palo Alto, CA, March 2003.

6. *Functional Requirements for Electric Energy Storage Applications on the Power System Grid, What Storage Has to Do to Make Sense*, EPRI ID 1021936, EPRI, Palo Alto, CA, December 2011.

2.7 Sodium-nickel-chloride Batteries

Technical Description

Sodium-nickel-chloride batteries are high-temperature battery devices like NaS. Figure 38 illustrates the design of this battery and key principles. When charging a Sodium-nickel-chloride battery at normal operating temperatures, salt (NaCl) and nickel (Ni) are transformed into nickel-chloride ($NiCl_2$) and molten sodium (Na). The chemical reactions are reversed during discharge, and there are no chemical side reactions. The electrodes are separated by a ceramic wall (electrolyte) that is conductive for sodium ions but an isolator for electrons. Therefore, the cell reaction can only occur if an external circuit allows electron flow equal to the sodium ion current. The porous solid $NiCl_2$ cathode is impregnated with a sodium ion conductive salt ($NaAlCl_4$) that provides a conductive path between the inside wall of the separator and the reaction zone. Cells are hermetically sealed and packaged into modules of about 20 kWh each.

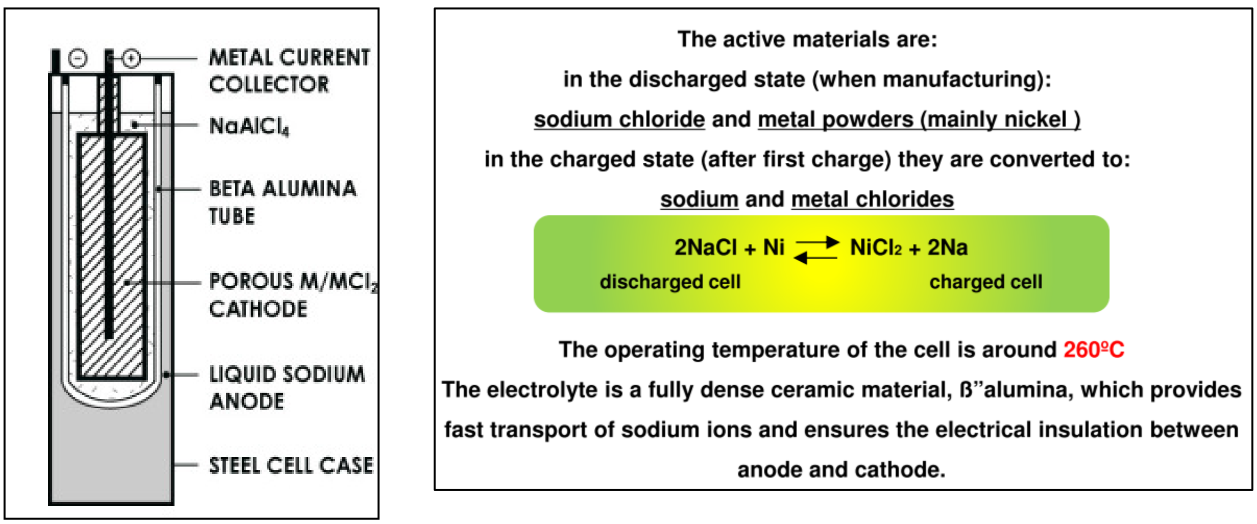


Figure 38. Design and Principal Features of Sodium-nickel-chloride Batteries
(Courtesy FIAMM)

The internal normal operating temperature of 270 °C to 350 °C is required to achieve acceptable cell resistance and must be thermally managed by design features.

Two battery original equipment manufacturer (OEM) suppliers have production facilities operating and are starting to deploy systems in the size range of 50 kW to 1 MW. By the end of 2013, several fully integrated systems are expected to be deployed for utility grid support and renewable integration.

Figure 39 and Figure 40 show two FIAMM-developed containerized systems deployed at utility sites.

Figure 39. FIAMM 222-kWh System Site at the Duke Energy Rankin Substation

Figure 40. Containerized 25 kW/50 kWh FIAMM Battery Unit (large green housing) on Concrete Pad, Next to S&C PureWave CES (small green housing)

Maturity and Commercial Availability

Table 9 presents the technology dashboard for NaNiCl2 stationary storage systems.

Table 9. Technology Dashboard for Sodium-nickel-chloride Batteries

Technology Development Status	Demonstration C	Limited field demonstrations
Confidence of Cost Estimate	D	Vendor quotes and system installation estimates
Accuracy Range	C	-10% to +15%
Operating Field Units	2 or more	Several photovoltaic and distributed storage installations by 2012
Process Contingency	5-10%	Limited testing and filed experience
Project Contingency	5-10%	Limited data on life-cycle costs; limited operation and maintenance cost data

Sodium-nickel-chloride Batteries Life-Cycle Cost Analysis

Life-cycle costs of several selected $NaNiCl_2$ systems are illustrated in Figure 41, Figure 42, and Figure 43. The estimates are based on capital and O&M data from the $NaNiCl_2$ data sheets. A simple dispatch was assumed with investor-owned utility financials and 365 cycles per year for 15 years. Generally, key assumptions are investor owned utility (IOU) ownership with 365 cycles peak-shaving annually for 15 years. Cost metrics for these systems vary by vendor and related assumptions on battery replacement costs of 8 or 15 years.

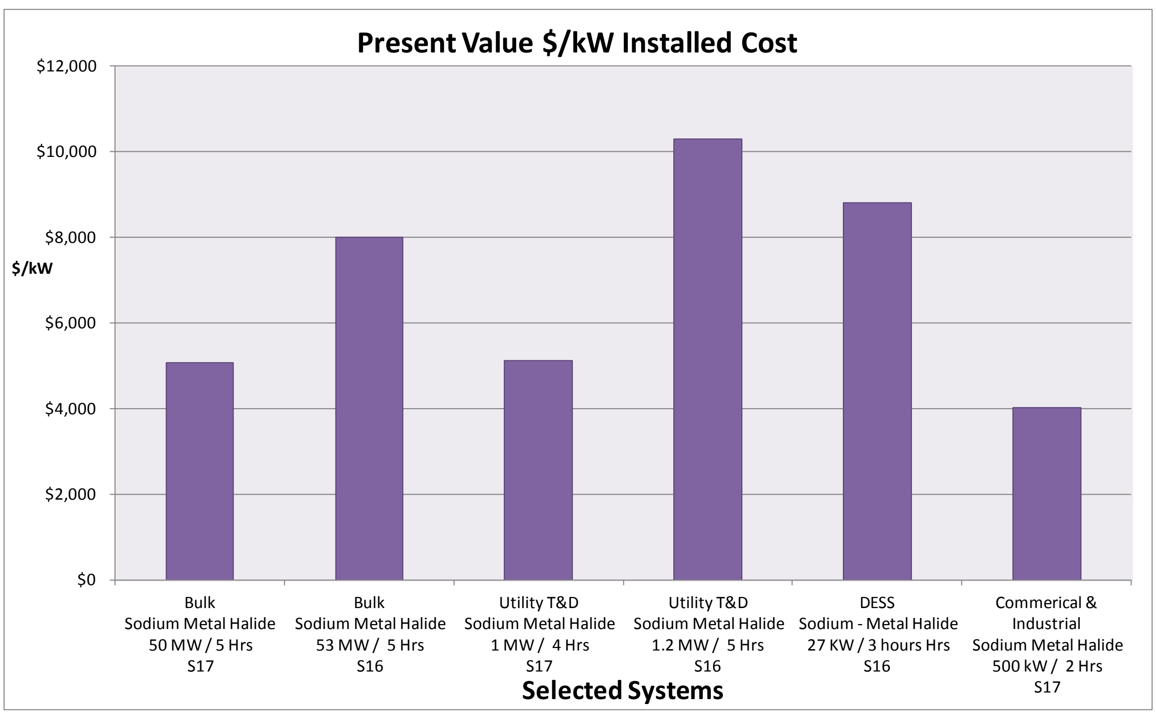


Figure 41. Present Value Installed Cost for Different Sodium-nickel-chloride Batteries
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

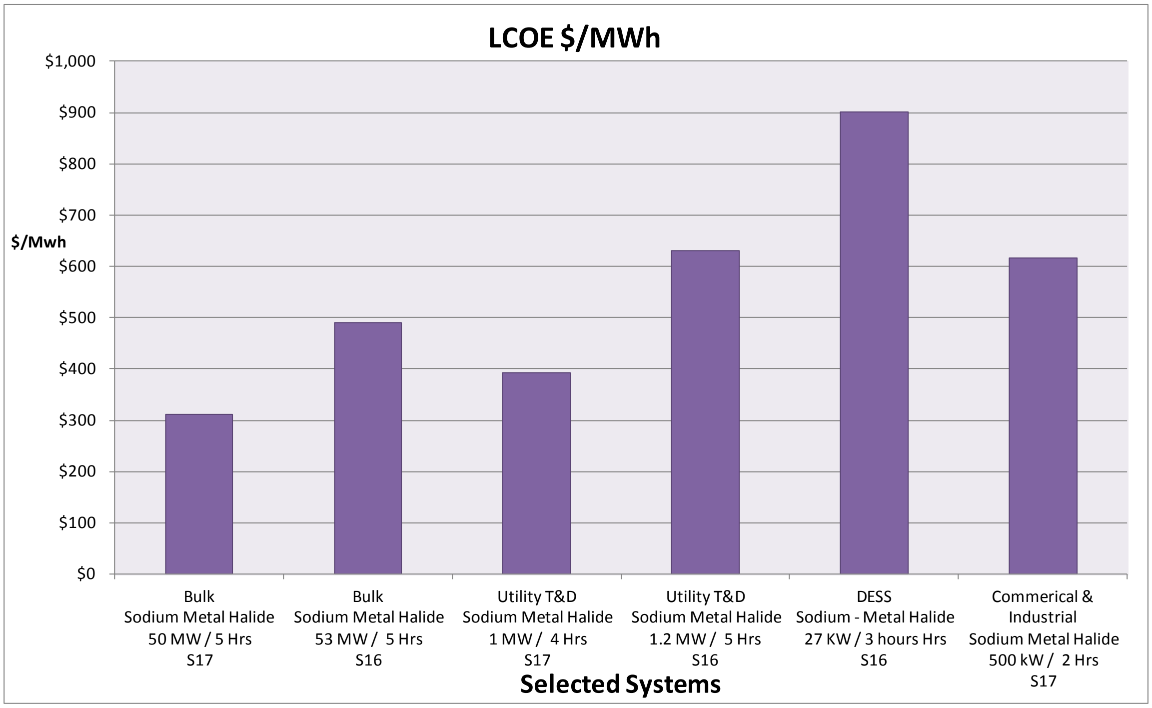


Figure 42. Levelized Cost of Energy
in $/MWh for Different Sodium-nickel-chloride Batteries
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

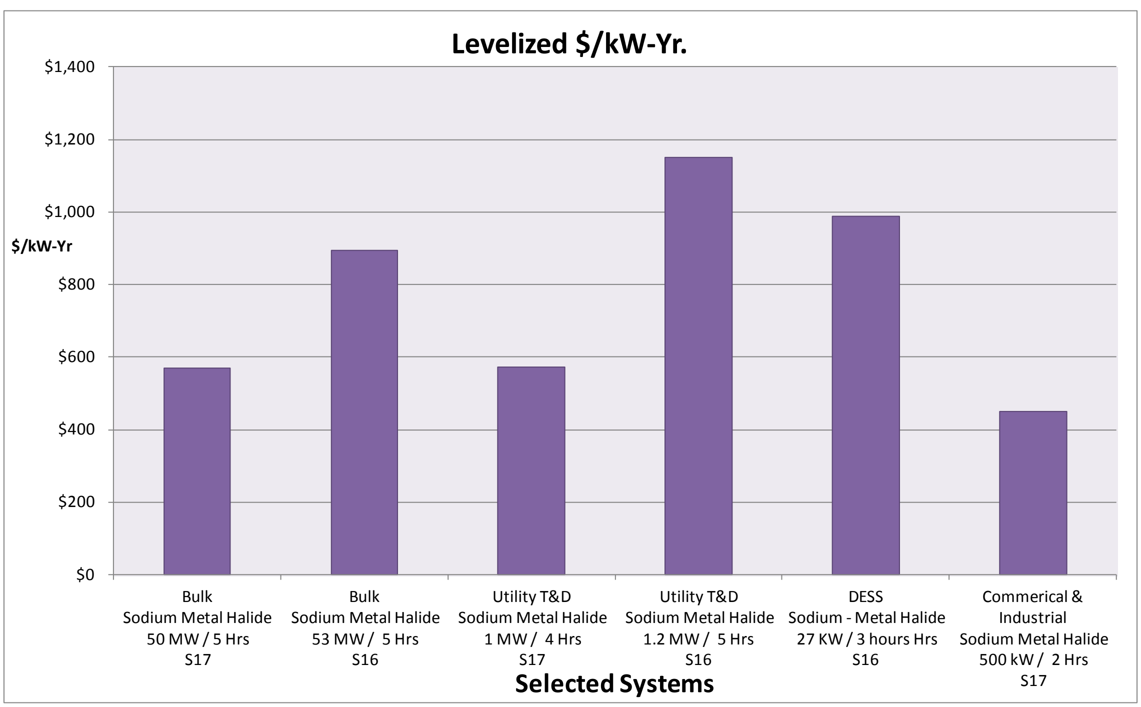


Figure 43. Levelized Cost of Capacity
in $/kW-yr for Different Sodium-nickel-chloride Batteries
(*The S designation under each bar is a vendor code that masks the identity of the vendor.)*

Additional Sodium-nickel-chloride Battery Resource

1. *Technology Review and Assessment of Distributed Energy Resources*, EPRI ID 1012983, EPRI, Palo Alto, CA, February 2006.

2.8 Vanadium Redox Batteries

Technical Description

Vanadium reduction and oxidation (redox) batteries are of a type known as *flow batteries*, in which one or both active materials is in solution in the electrolyte at all times. In this case, the vanadium ions remain in an aqueous acidic solution throughout the entire process.

The vanadium redox flow battery is a flow battery based on redox reactions of different ionic forms of vanadium. During battery charge, V3+ ions are converted to V2+ ions at the negative electrode through the acceptance of electrons. Meanwhile, at the positive electrode, V4+ ions are converted to V5+ ions through the release of electrons. Both of these reactions absorb the electrical energy put into the system and store it chemically. During discharge, the reactions run in the opposite direction, resulting in the release of the chemical energy as electrical energy.

In construction, the half-cells are separated by a proton exchange membrane that allows the flow of ionic charge to complete the electrical circuit. Both the negative and positive electrolytes (sometimes called the anolyte and catholyte, respectively) are composed of vanadium and sulfuric acid mixture at approximately the same acidity as that found in a lead-acid battery. The electrolytes are stored in external tanks and pumped as needed to the cells (see Figure 44).

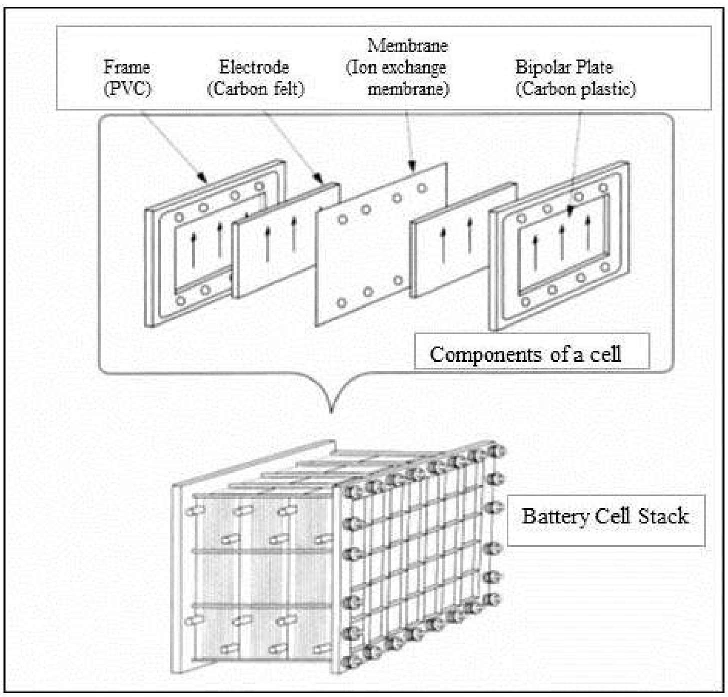


Figure 44. Construction of a Vanadium Redox Cell Stack
(Courtesy Sumitomo Electric Industries)

Individual cells have a nominal open-circuit voltage of about 1.4 V. To achieve higher voltages, cells are connected in series to produce cell stacks. Vanadium redox flow batteries have an important advantage among flow batteries: the two electrolytes are identical when fully discharged. This makes shipment and storage simple and inexpensive and greatly simplifies electrolyte management during operation.[31]

Self-discharge is typically not a problem for vanadium redox systems, because the electrolytes are stored in separate tanks. Self-discharge may occur within the cell stack if it is filled with charged electrolyte, resulting in the loss of energy and heat generation in the stacks. For this reason, the stacks are usually elevated above the tanks, so that electrolyte drains back into the tanks when the pumps are shut down. The battery will then take a short while to come back into operation again. Alternatively, the pumps can operate in an idling state, which would allow charged electrolyte to be available at all times, at the price of a slightly higher parasitic loss.[32]

The life of a vanadium redox system is determined by a number of components. The cell stack is probably the limited life component, with a useful life estimated at ~10 years; however, operational field data are not available to confirm these lifetimes. The tanks, plumbing, structure, power electronics, and controls have a longer useful life. The electrolytes and the active materials they contain do not degrade with time.

Vanadium redox systems are capable of stepping from zero output to full output within a few milliseconds, if the stacks are already primed with reactants. In fact, the limiting factor for beginning battery discharge is more commonly the controls and communications equipment. For short-duration discharges for voltage support, the electrolyte contained in the stacks can respond without the pumps running at all. The cell stack can produce three times the rated power output provided the state of charge is between 50% and 80%.[33]

The physical scale of vanadium redox systems tends to be large due to the large volumes of electrolyte required when sized for utility-scale (megawatt-hour) projects. Unlike many other battery technologies, cycle life of vanadium redox systems is not dependent on depth of discharge. Systems are rated at 10,000 cycles, although some accelerated testing performed by Sumitomo Electric Industries, Ltd., produced a battery system with one 20-kW stack for cycle testing that continued for more than 13,000 cycles over about two years.

When decommissioning a vanadium redox system, the solid ion exchange cell membranes may be highly acidic or alkaline and therefore toxic. They should be disposed of in the same manner as any corrosive material. If possible, the liquid electrolyte is recycled. If disposed of, the

[31] *VRB Energy Storage for Voltage Stabilization: Testing and Evaluation of the PacifiCorp Vanadium Redox Battery Energy Storage System at Castle Valley, Utah*, EPRI ID 1008434, EPRI, Palo Alto, CA, 2005.

[32] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC: 2003. 1001834. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation; http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001001834

[33] Ibid.

vanadium is extracted from the electrolyte before further processing of the liquid. Research is ongoing to determine the exact environmental risk factors for vanadium.

Figure 45[34] illustrates the schematic of a vanadium redox flow battery.

Technical Maturity

Table 10 illustrates a dashboard for a vanadium flow battery system. This type of flow battery is technically the more mature battery of all the flow-type battery systems.

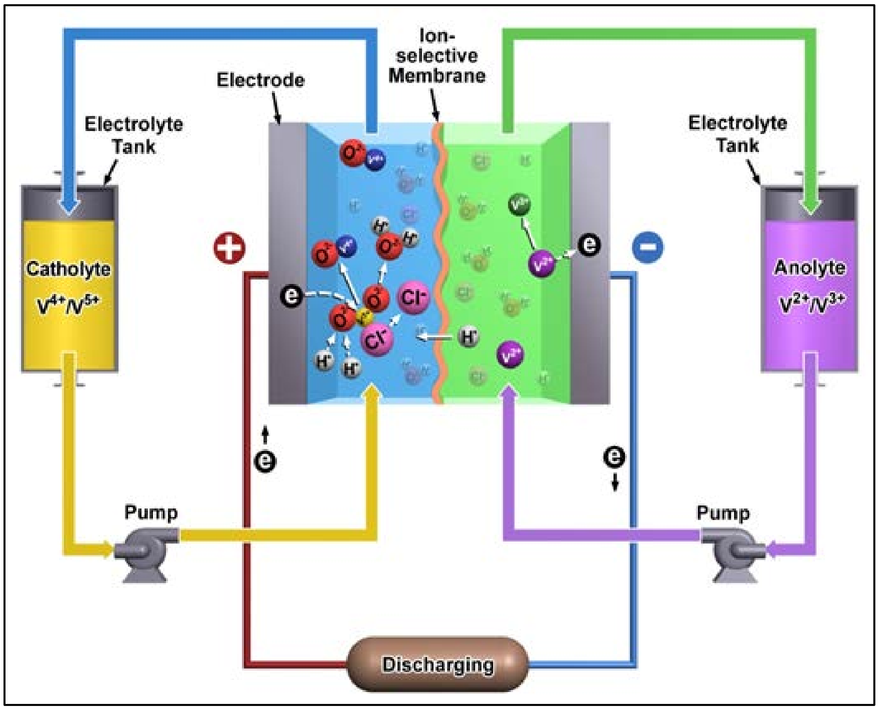


Figure 45. Principles of the Vanadium Redox Battery
(Courtesy of the Pacific Northwest National Laboratory)

Vanadium redox systems have been demonstrated in a number of applications and large-scale field trials (see Figure 46).

[34] *VRB Energy Storage for Voltage Stabilization: Testing and Evaluation of the PacifiCorp Vanadium Redox Battery Energy Storage System at Castle Valley, Utah*, PI: Harash Kamath – EPRI PEAC Corporation, EPRI ID 1008434, EPRI, Palo Alto, CA, March 2005.

Table 10. Technology Dashboard: Vanadium Flow-Type Battery Systems

Technology Development Status	Pre-Commercial C	Systems Verified in Limited Field Demonstrations
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	C	-10% to +15%
Operating Field Units	Units operating in renewable integration, end-user energy management, and telecom applications	Currently 50-kW, 100-kW, 500-kW, 600-kW, and 1000-kW systems in operation. The largest in the U.S. is a 600-kW/3600-kWh system in a customer energy-management application. A 1-MW/5-MWh system is in operation in Japan.
Process Contingency	5-8%	For MW-scale applications
Project Contingency	5-7%	For MW-scale applications Contingency will vary by size of the application. Vendors are offering 10-year energy services contracts.

Figure 46. Prudent Energy 600-kW/3,600-kWh VRB-ESS Installed at Gills Onions, Oxnard, CA

The system consists of 200-kW modules providing a total of 6 hours of electrochemical energy storage.

Vanadium Redox Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 47, Figure 48, and Figure 49. These estimates are based on capital and O&M data from the Vanadium Redox data sheets. A simple dispatch was assumed: an investor-owned utility financials with 365 cycles per year for 15 years. Generally, key assumptions are IOU ownership, with 365 cycles peak-shaving annually for 15 years. Periodic stack replacement costs are assumed every 8 years and range from $615/kW to $746/kW.

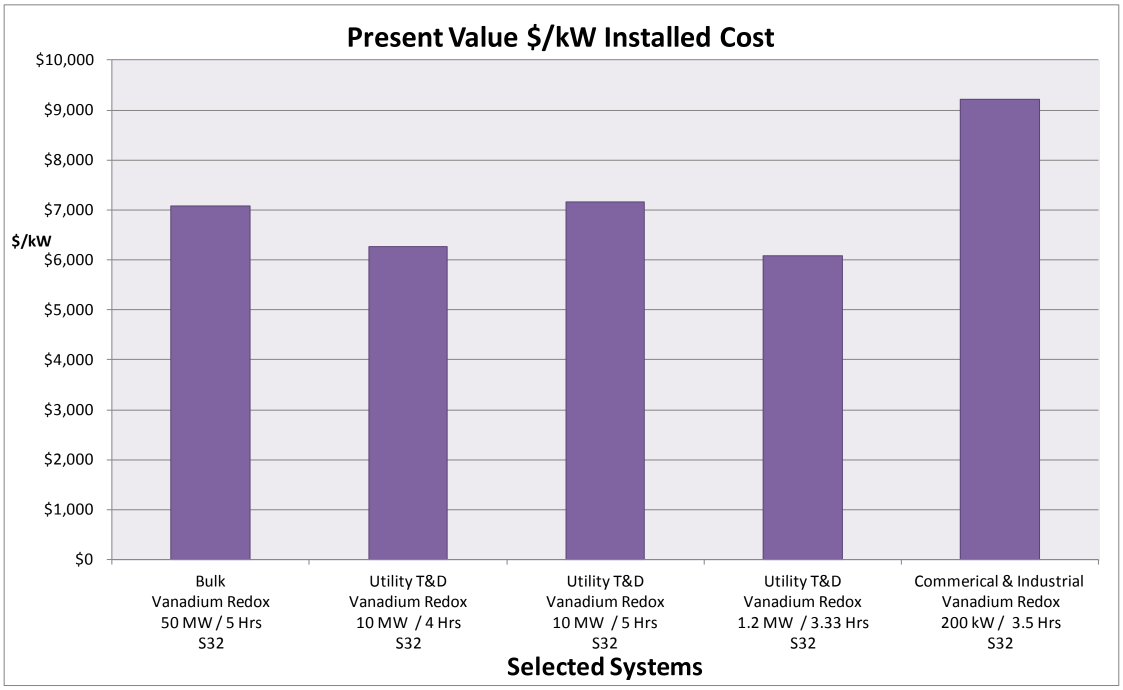


Figure 47. Present Value Installed Cost for Different Vanadium Redox Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

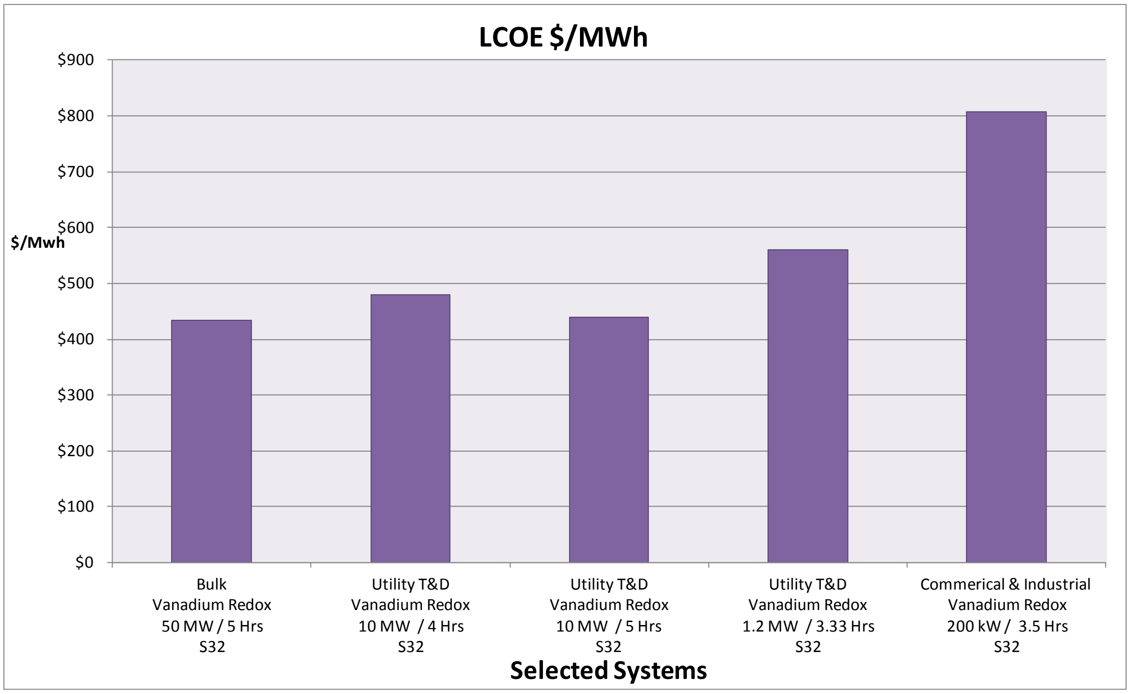


Figure 48. Levelized Cost of Energy in $/MWh for Different Vanadium Redox Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

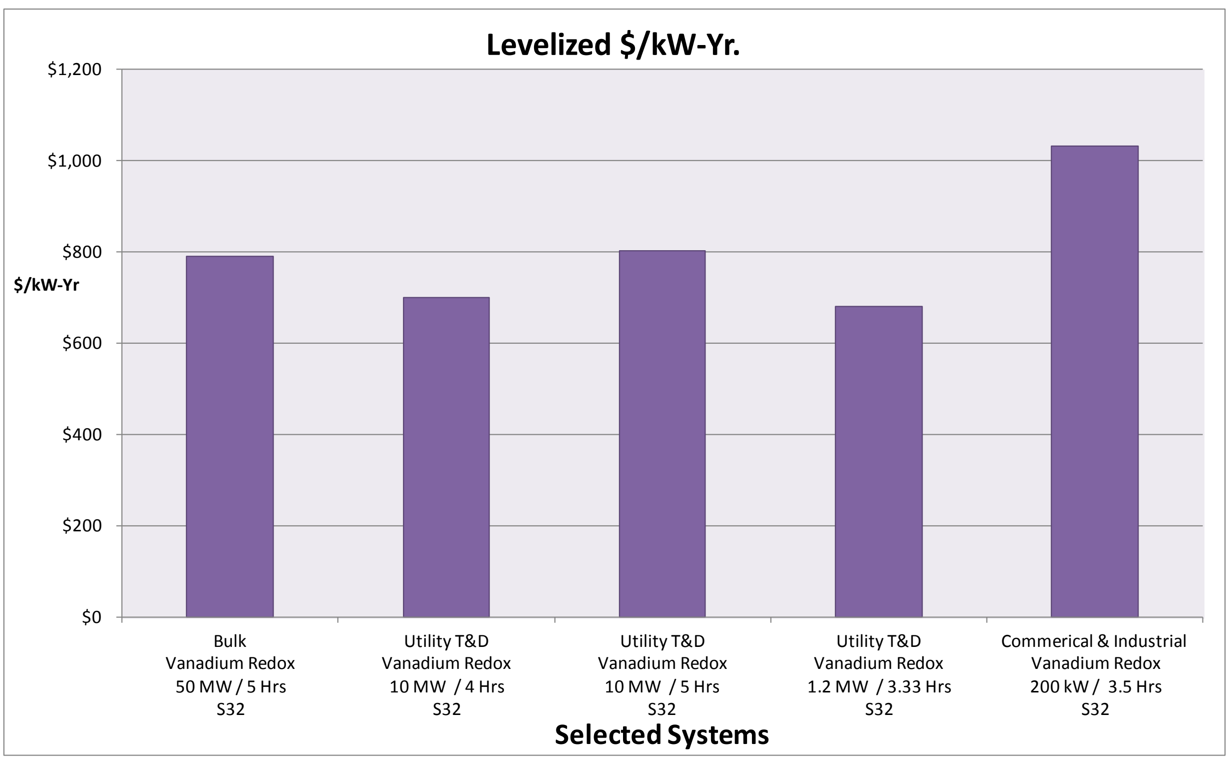


Figure 49. Levelized Cost of Capacity in $/kW-yr for Different Vanadium Redox Systems
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

Additional Vanadium Redox Battery Resources

1. *VRB Energy Storage for Voltage Stabilization: Testing and Evaluation of the PacifiCorp Vanadium Redox Battery Energy Storage System at Castle Valley, Utah*, EPRI ID 1008434, EPRI, Palo Alto, CA, March 2005.

2. *Vanadium Redox Flow Batteries*, EPRI ID 1014836, EPRI, Palo Alto, CA, March 2007.

3. *Assessment of Advanced Batteries for Energy Storage Applications in Deregulated Electric Utilities*, EPRI ID TR-111162, EPRI, Palo Alto, CA, December 1998.

2.9 Iron-chromium Batteries

Technical Description

Iron-chromium (Fe-Cr) redox flow battery systems is another type of flow battery still in the R&D stage but steadily advancing toward early field demonstrations in 2013-2014. The low-cost structure of these systems also makes them worth evaluating for grid-storage solutions. Given the considerable uncertainties in performance and cycle life, process and project contingencies are high. Figure 50 shows the principles of operation for this technology.

Performance Characteristics

Using liquid reactants, only a small volume is electrically active and the cells are hydraulically balanced. Use of dissolved reactants means there is no volume change during cycling. This is in contrast to Li-ion, lead-acid, NaS, Zinc-bromine, and others, which do involve a volume change. This feature results in a less-complex design and simpler controls. The technology may also feature a lower-cost design, materials, and reactants. Figure 51 shows a typical battery Fe-Cr energy storage system concept.

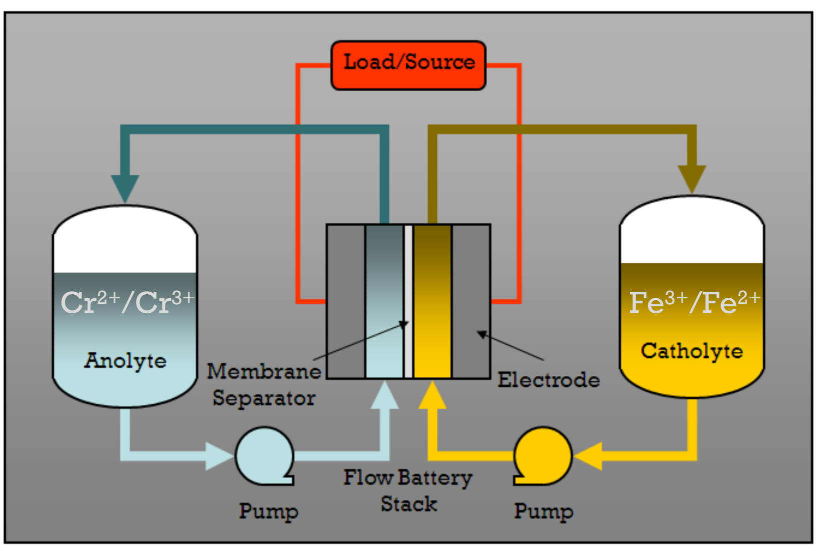


Figure 50. Principles of Operation for an Iron-chromium Battery Energy Storage System

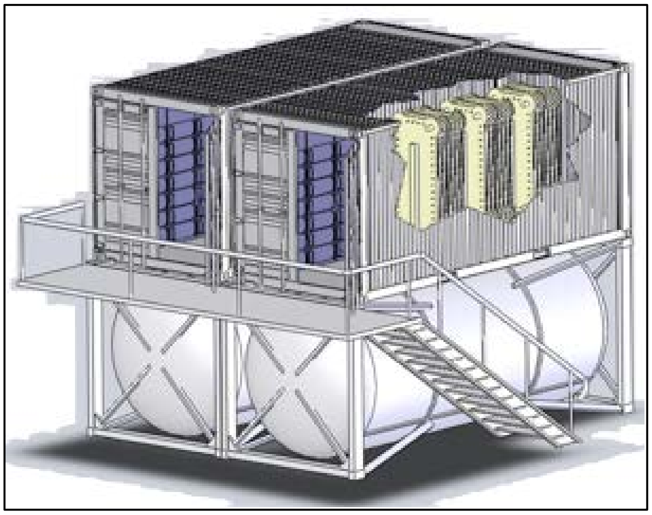


Figure 51. Typical Iron-chromium Battery System
(Photo courtesy EnerVault)

Fe-Cr flow battery systems can be used for time shift on either the utility or customer side of the meter, as well as for frequency regulation services. Figure 52 shows various Fe-Cr system concepts for these applications.

Table 11 is a technology dashboard that shows the status of technology development for Fe-Cr-chromium batteries.

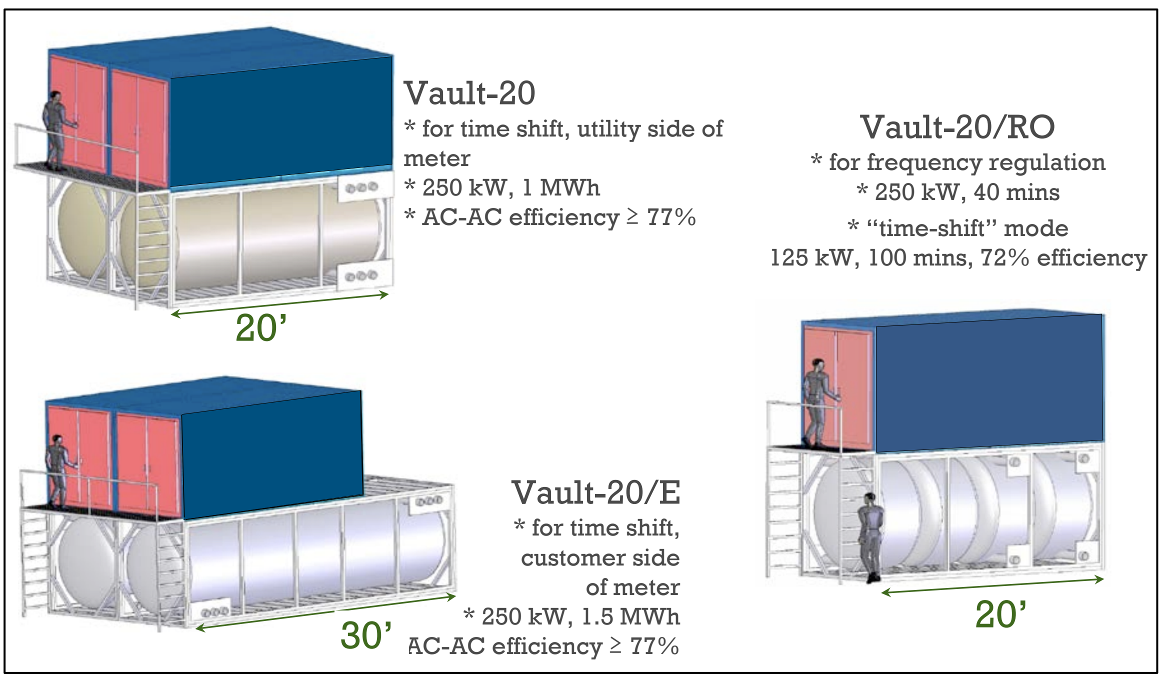


Figure 52. Iron-chromium Battery Storage System Concepts
(Photo courtesy EnerVault)

Table 11. Technology Dashboard: Iron-chromium Battery Systems

Technology Development Status	Laboratory E	Small cells and stack in a lab setting
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	E	-15% to +15%
Operating Field Units	None	None in utility-scale demonstrations Fe-Cr in niche telecom applications
Process Contingency	15-20%	Efficiency and cycle-life uncertain. Scale-up uncertainties
Project Contingency	10-15%	Limited definition of product designs

Iron-chromium Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 53, Figure 54, and Figure 55. The estimates are based on capital and O&M data from the Fe-Cr data sheets. A simple dispatch was assumed, with investor-owned utility financials and 365 cycles per year for 15 years. Generally, key assumptions are IOU ownership, with 365 cycles peak-shaving annually for 15 years. Periodic stack replacement costs assumed every 8 years and start at $194/kW.

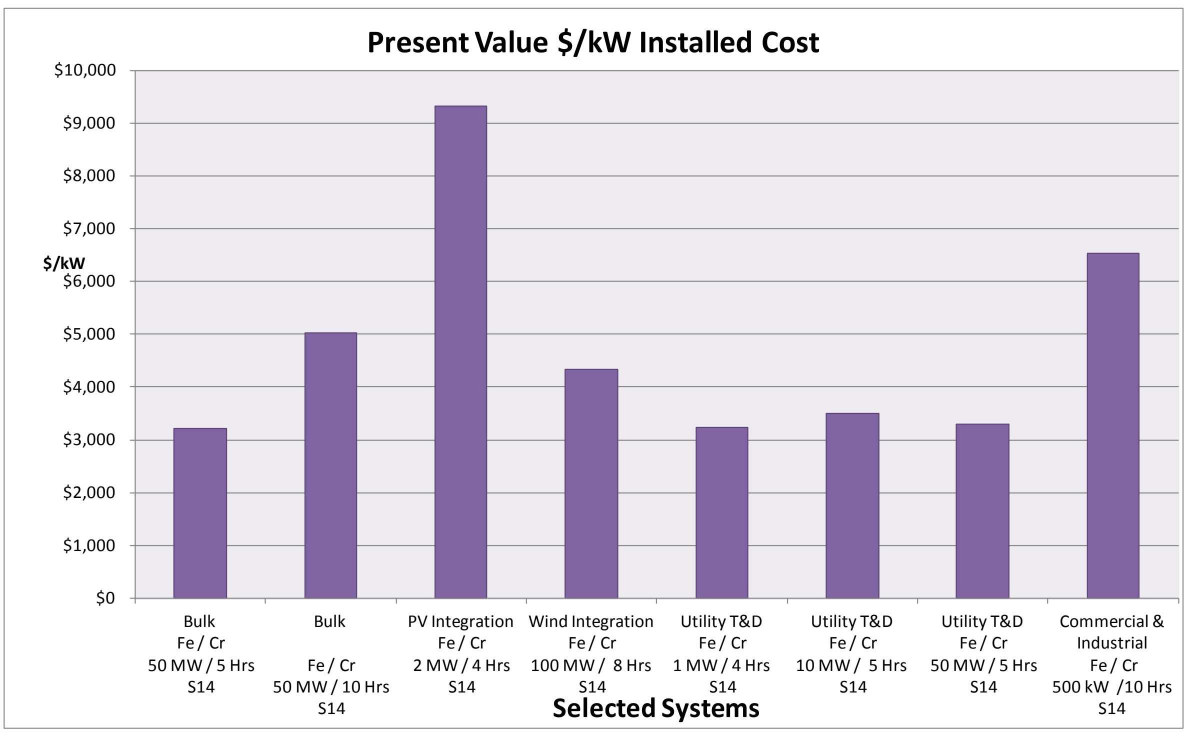


Figure 53. Present Value Installed Cost for Different Iron-chromium Systems
(*The S designation under each bar is a vendor code that masks the identity of the vendor.)*

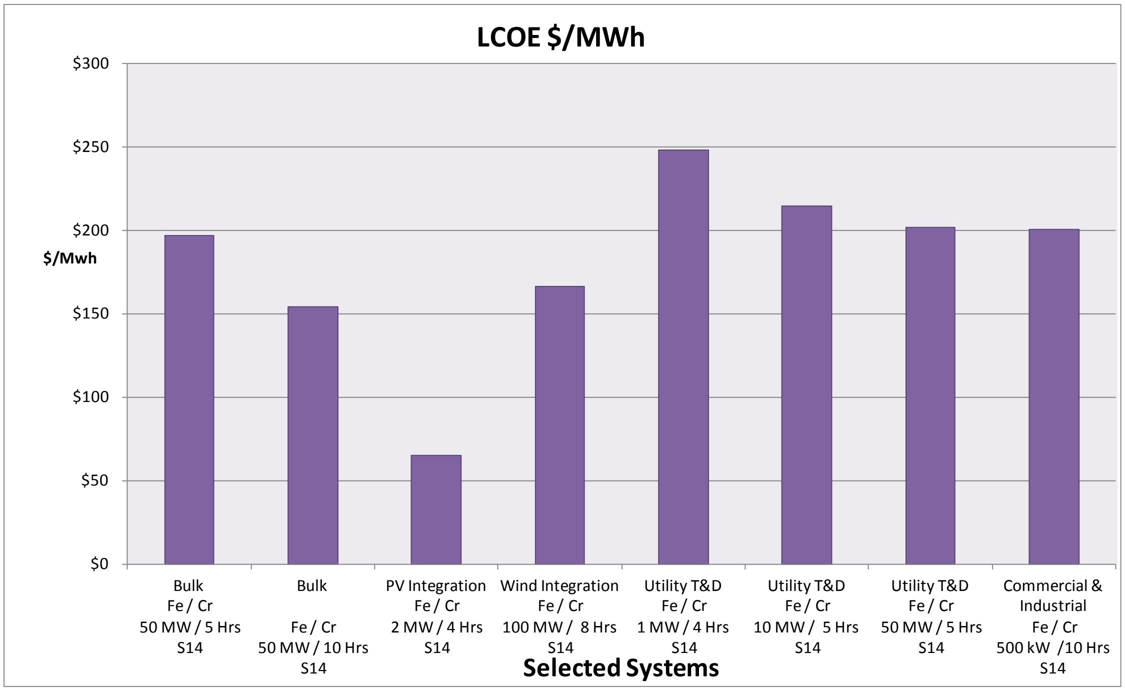


Figure 54. Levelized Cost of Energy in $/MWh for Different Iron-chromium Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

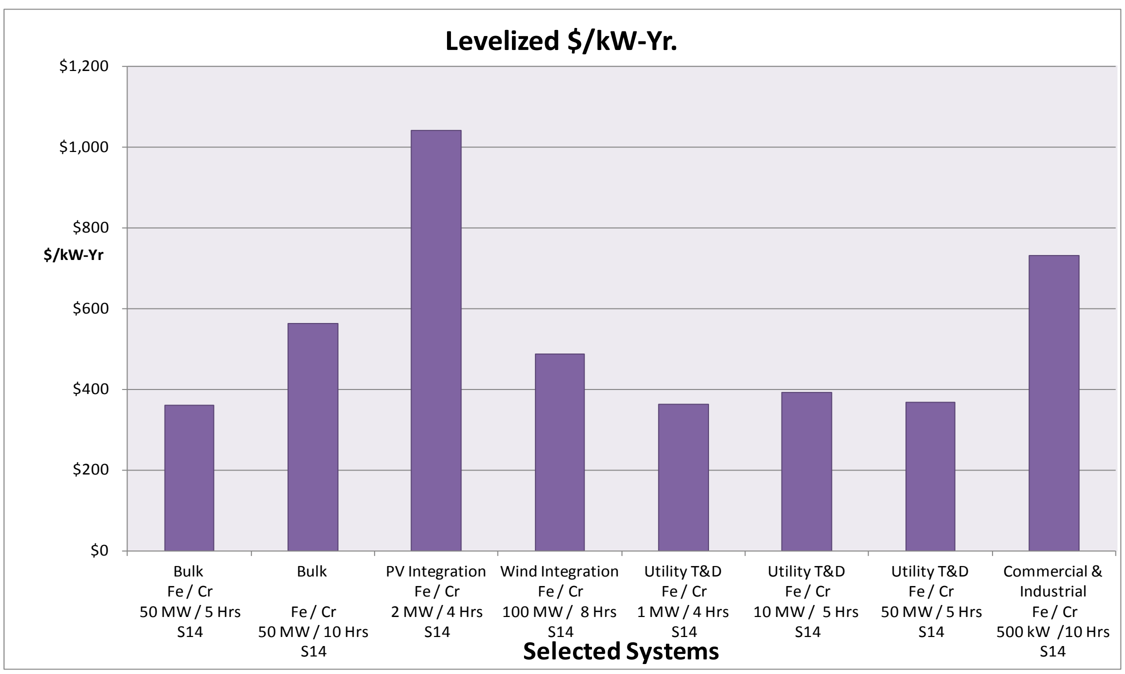


Figure 55. Levelized Cost of Capacity in $/kW-yr for Different Iron-chromium Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

2.10 Zinc-bromine Batteries

Technical Description

The Zinc-bromine battery is another type of flow battery in which the zinc is solid when charged and dissolved when discharged. The bromine is always dissolved in the aqueous electrolyte.

Each cell is composed of two electrode surfaces and two electrolyte flow streams separated by a micro-porous film. The positive electrolyte is called a *catholyte*; the negative is the *anolyte*. Both electrolytes are aqueous solutions of zinc bromine ($ZnBr_2$).

During charge, elemental zinc is plated onto the negative electrode. Elemental bromine is formed at the positive electrode. Ideally, this elemental bromine remains only in the positive electrolyte. The micro-porous separator allows zinc ions and bromine ions to migrate to the opposite electrolyte flow stream for charge equalization (see Figure 56 below). At the same time, it inhibits elemental bromine from crossing over from the positive to the negative electrolyte, reducing self-discharge because of direct reaction of bromine with zinc.

The cell electrodes are composed of carbon plastic and are designed to be bipolar. This means that a given electrode serves both as the cathode for one cell and the anode for the next cell in series. Carbon plastic must be used because of the highly corrosive nature of bromine. The positive electrode surface is coated with a high-surface-area carbon to increase surface area. The two electrolytes differ only in the concentration of elemental bromine; both should have the same zinc and bromine ion concentrations at any given time during the charge/discharge cycle. This can best be accomplished through the use of an ion-selective membrane as the separator. This membrane would allow the passage of zinc and bromine ions without allowing the passage of elemental bromine or polybromine. In practice, such membranes have proven more costly and less durable than nonselective membranes. For these reasons, nonselective micro-porous membranes are usually used for the separator. The electrolyte is circulated for a number of reasons. Circulation serves to remove bromine (in the form of polybromine) from the positive electrode quickly, freeing up the surface area for further reaction. It also allows the polybromine to be stored in a separate tank to minimize self-discharge.

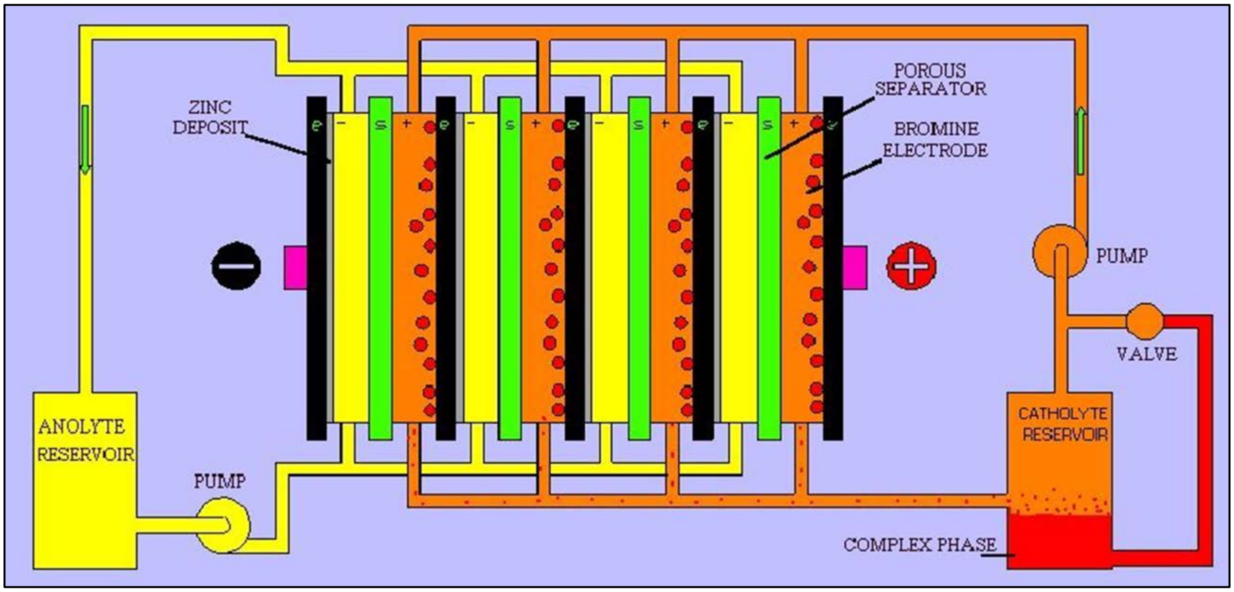


Figure 56. Zinc-bromine Cell Configuration
(Courtesy ZBB Energy Corporation)[35]

On the negative electrode, the flow inhibits the formation of zinc dendrites. Finally, the circulation simplifies thermal management through the use of a heat exchanger. The two electrolytes can flow in the same direction within a cell (co-current), or in opposite directions (counter-current), depending on the design.[36]

Performance Characteristics

Table B-18, Table B-19, and Table B-20 show representative performance characteristics of Zinc-bromine batteries in various storage applications. The most common factor in degradation and potential failure of Zinc-bromine batteries arises from the extremely corrosive nature of the elemental bromine electrolyte. This substance tends to attack all the components of the Zinc-bromine system that are exposed to it. Past failure modes have included damaged seals, corrosion of current collectors, and warped electrodes. The active materials themselves do not degrade. The significance of this fact is that the lifetime is not strongly dependent on the number of cycles or the depth of discharge, but on the number of hours that the system has been operational. During normal operation, Zinc-bromine batteries do not present unusual environmental hazards. They do, however, contain materials that can become environmental contaminants. Bromine is a toxic material and should be recovered in the event of a spill or when the unit is decommissioned. Zinc-bromine is a corrosive and should be handled

[35] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation;
[36] Ibid.

appropriately. Zinc is considered a transition-metal contaminant in some locales and thus should be properly recovered when the unit is decommissioned.[37]

Maturity and Commercial Availability

Zinc-bromine batteries are in an early stage of field deployment and demonstration trials. While field experience is currently limited, vendors claim estimated lifetimes of 20 years, long cycle lives, and operational ac-to-ac efficiencies of approximately 65%. Module sizes vary by manufacturer but can range from 5 kW to 1000 kW, with variable energy storage duration from two to six hours, depending on the service requirements and need. Small projects comprising 5-kW/2-hour systems are being deployed in rural Australia as an alternative to installing new power lines. In the United States, electric utilities plan to conduct early trials of 0.5 – 1.0 MW systems for grid support and reliability by 2014.

Table 12 is a technology dashboard that shows the status of technology development for Zinc-bromine systems.

Table 12. Technology Dashboard: Zinc-bromine Flow-type Battery Systems

Technology Development Status	Demonstration trials	Small systems deployed in limited field demonstrations.
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	C	-10% to +15%
Operating Field Units	3 or more	None in utility-scale demonstrations of 500 kW or larger.
Process Contingency	10%	Efficiency uncertain. Limited life and operating experience at greater than 100 kW.
Project Contingency	10- 15%	Transportable and small systems have lower construction and installation issues.

Figure 57 shows a containerized Zinc-bromine system made by Redflow.

[37] Ibid.

Figure 57. A 90-kW/180-kWh Zinc-bromine Energy Storage System by RedFlow
(Housed in a 20-foot shipping container)

Zinc-bromine Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 58, Figure 59, Figure 60, Figure 61, Figure 62, and Figure 63 for each application. The estimates are based on capital, O&M data and stack replacement costs as shown in the data sheets for Zinc-bromine. A simple dispatch was assumed; generally, key assumptions are IOU ownership, with 365 cycles peak-shaving annually for 15 years.

Additional Zinc-bromine Battery References

1. *Validated Test Data on MWh-Scale Flow and Other Battery Systems: Large Battery Installations 2003*, EPRI ID 1005019, EPRI, Palo Alto, CA, December 2003.

2. *Electricity Energy Storage Technology Options*, EPRI ID 1020676, EPRI, Palo Alto, CA, December 2010.

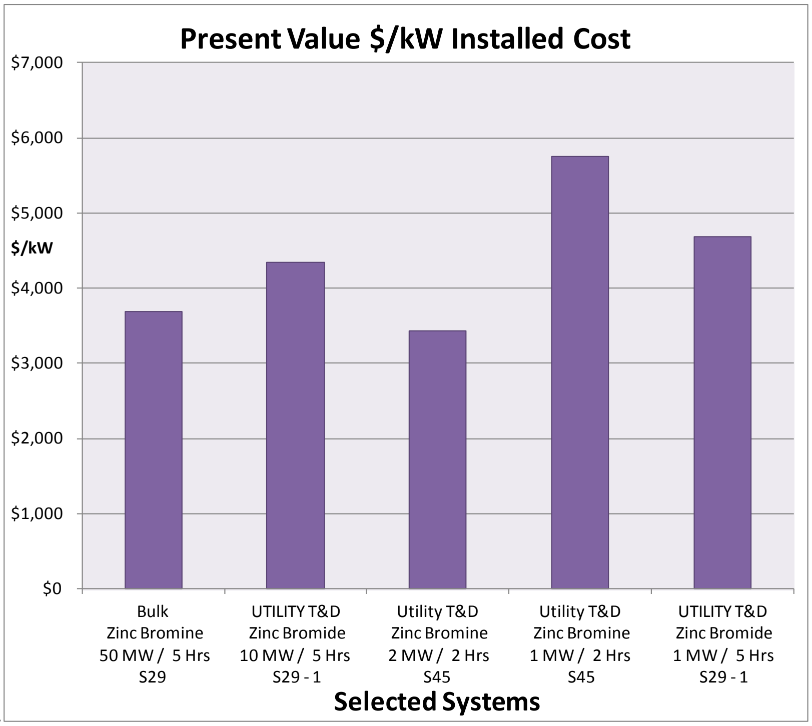


Figure 58. Present Value Installed Cost for Zinc-bromine Systems in Bulk and Utility Transmission and Distribution Service

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

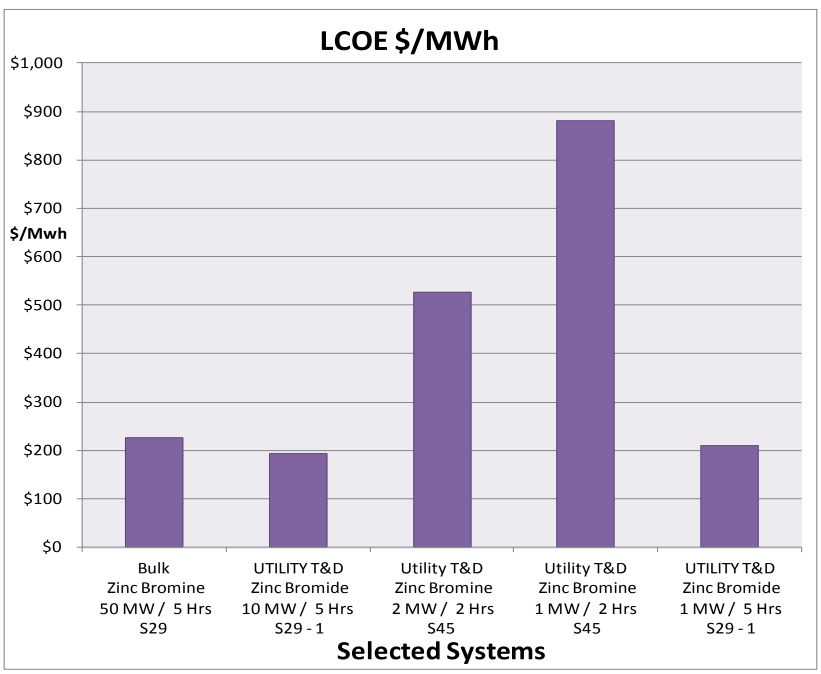


Figure 59. Levelized Cost of Energy in $/MWh for Zinc-bromine Systems in Bulk and Utility Transmission and Distribution Service

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

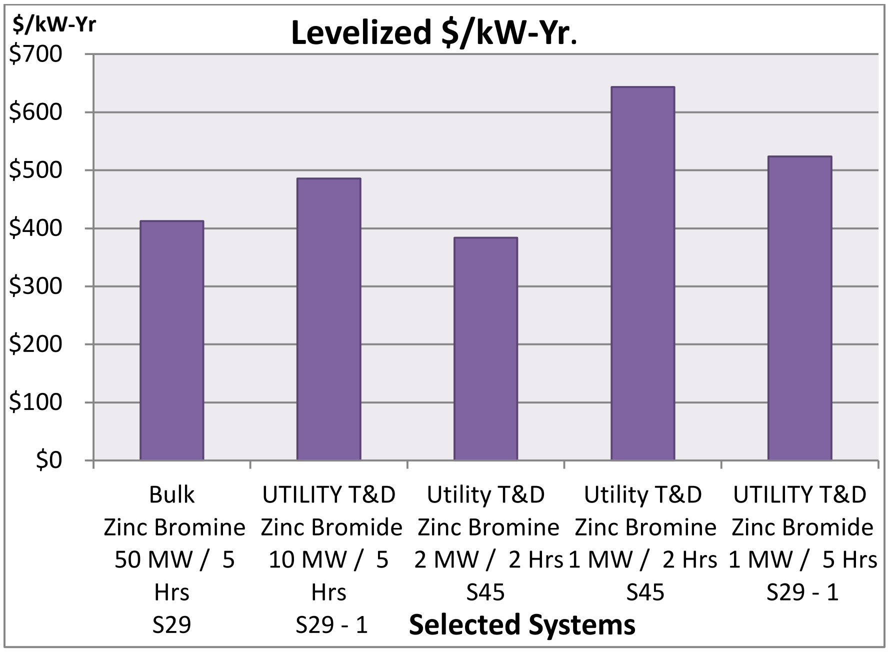


Figure 60. Levelized Cost of Capacity in $/kW-yr for Zinc-bromine Systems in Bulk and Utility Transmission and Distribution Service

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

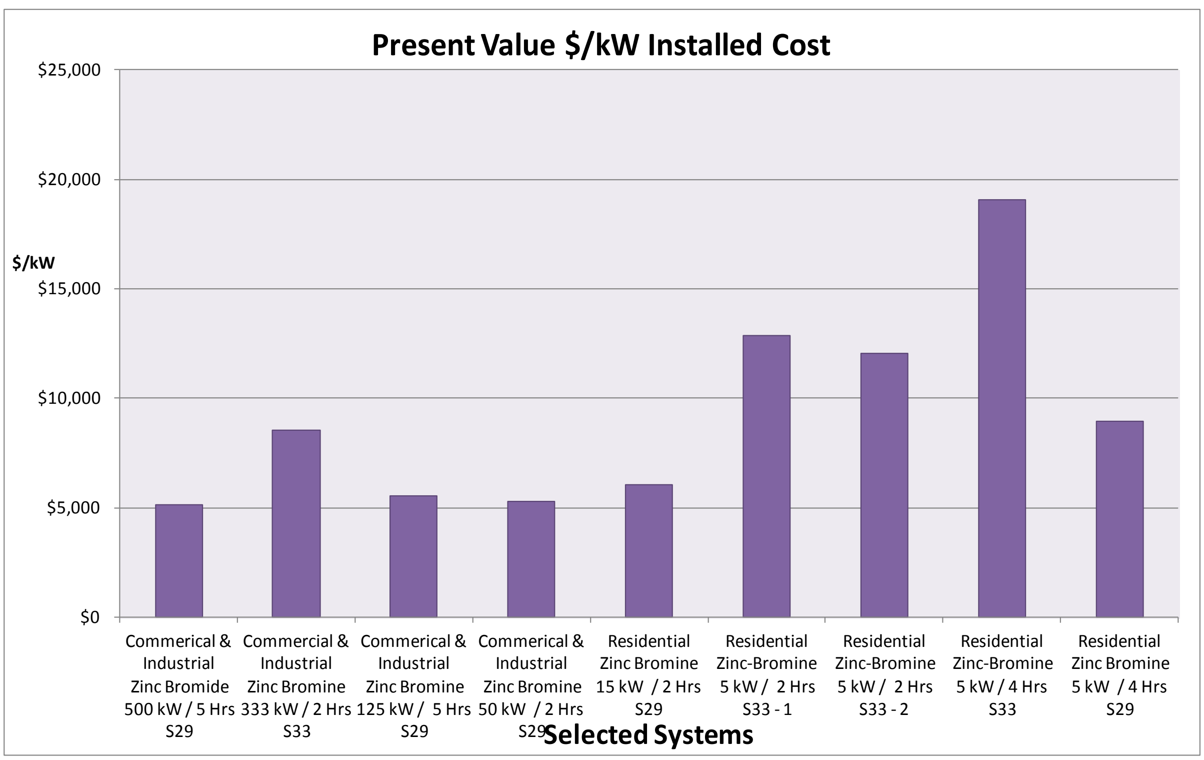


Figure 61. Present Value Installed Cost for Zinc-bromine Systems in Commercial and Industrial and Residential Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

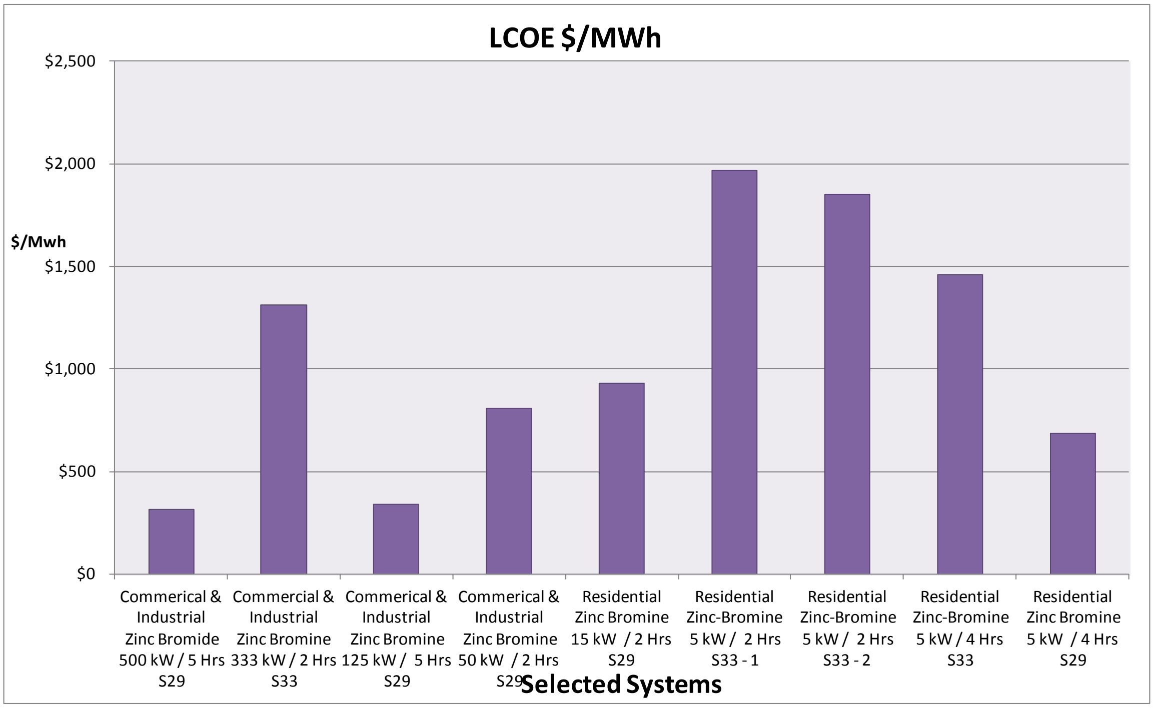


Figure 62. Levelized Cost of Energy in $/MWh for Zinc-bromine Systems in Commercial and Industrial and Residential Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

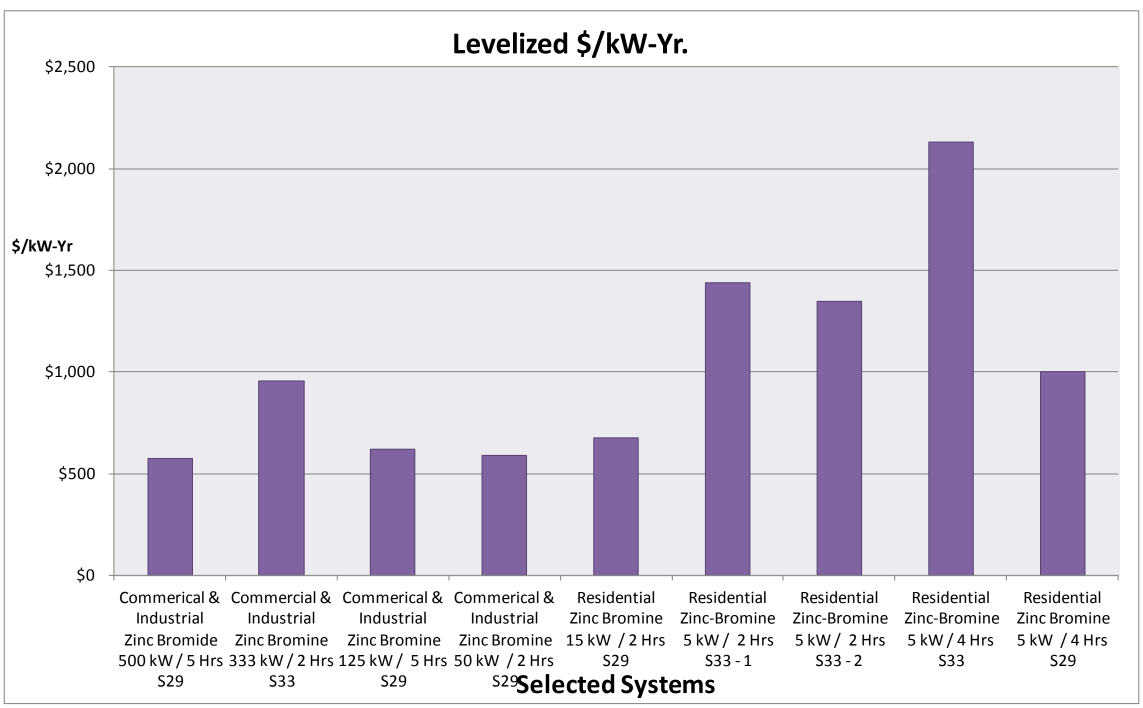


Figure 63. Levelized Cost of Capacity in $/kW-yr for Zinc-bromine Systems in Commercial and Industrial and Residential Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

2.11 Zinc-air Batteries

Technical Description

Zinc-air batteries are a metal-air electrochemical cell technology. Metal-air batteries use an electropositive metal, such as zinc, aluminum, magnesium, or lithium, in an electrochemical couple with oxygen from the air to generate electricity. Because such batteries only require one electrode within the product, they can potentially have very high energy densities. In addition, the metals used or proposed in most metal-air designs are relatively low cost. This has made metal-air batteries potentially attractive for electric vehicle (EV) and power electronics applications in the past, as well as raising hopes for a low-cost stationary storage system for grid services. Zinc-air batteries take oxygen from the surrounding air to generate electric current. The oxygen serves as an electrode, while the battery construction includes an electrolyte and a zinc electrode that channels air inside the battery as shown in Figure 64.

The Zinc-air battery produces current when the air electrode is discharged with the help of catalysts that produce hydroxyl ions in the liquid electrolyte. The zinc electrode is then oxidized and releases electrons to form an electric current. When the battery is recharged, the process is reversed, and oxygen is released into the air electrode.

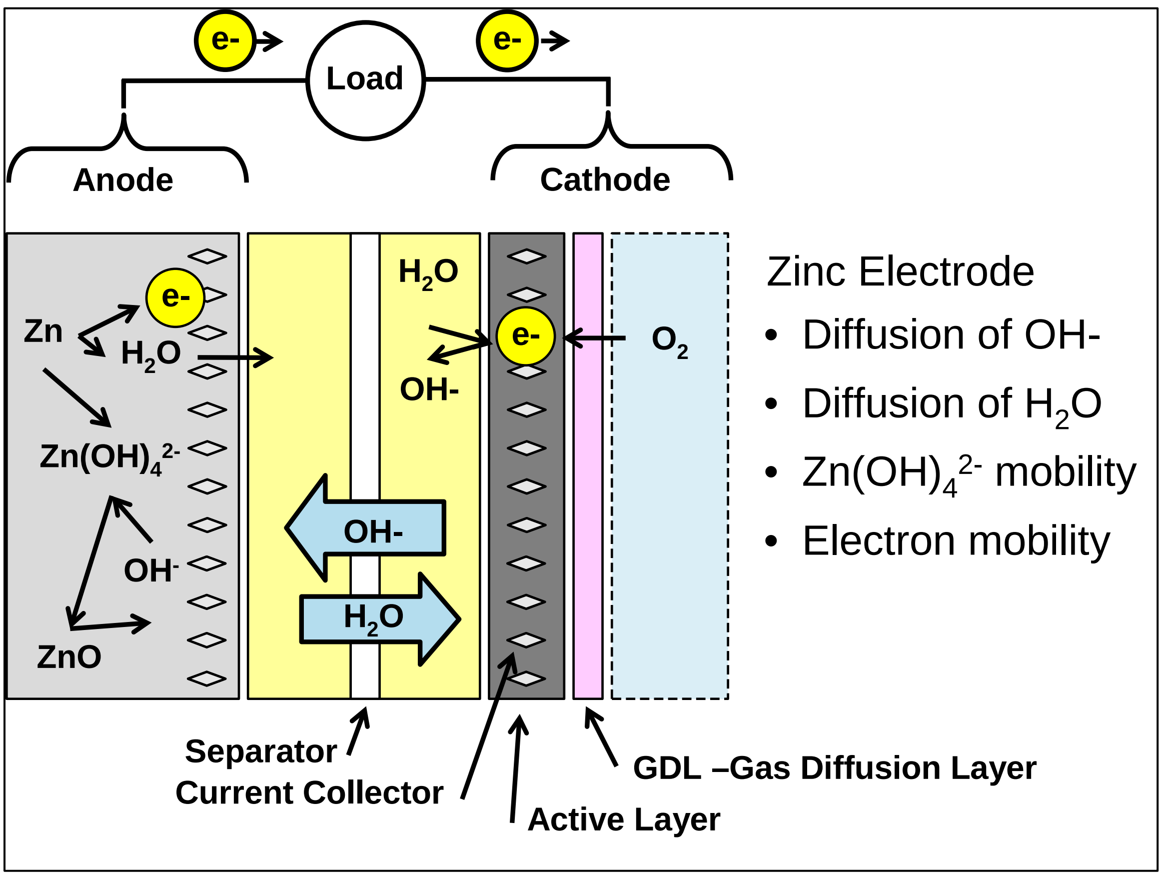


Figure 64. Zinc-air Battery Functional Schematic
(Courtesy ReVolt)

The challenge for researchers has been to address issues such as electrolyte management, avoiding carbon dioxide (CO_2) impacts from the air on the electrolyte and cathode, thermal management, and avoiding Zn dentrite formation. Methods are also being investigated to address issues with the air electrolyte not deactivating in the recharging cycle and slowing or stopping the oxidation reaction. The cessation of the oxidation reaction reduces the number of times that a Zinc-air battery can be recharged.

Despite the many advantages, metal-air batteries also pose several historical disadvantages. The batteries are susceptible to changes in ambient air conditions, including humidity and airborne contaminants. The air electrode – a sophisticated technology that requires a three-way catalytic interface between the gaseous oxygen, the liquid electrolyte, and the solid current collector – has been difficult and expensive to make. However, the technology is far more stable and less dangerous than other battery technologies.

Performance Characteristics

Electric recharge has been difficult and inefficient with metal-air batteries, with typical round-trip efficiencies below 50 percent. Some developers have attempted to overcome this limitation with mechanically rechargeable systems in which the discharged metal anode is replaced with a fresh metal anode and the system continues to operate.

There are currently a few early-stage companies attempting to bring energy-dense, high-operating-efficiency, better depth-of-discharge stationary systems to the market, particularly for utility T&D grid support and renewable energy integration. R&D is underway by several companies, with some research still in the university laboratory stage.

Zinc-air batteries have up to three times the energy density of Li-ion, its most competitive battery technology. Unlike lithium-ion, however, Zinc-air batteries neither produce potentially toxic or explosive gases, nor contain toxic or environmentally dangerous components. Zinc-oxide, which is the main material in a zinc-air battery, is 100-percent recyclable.

Maturity and Commercial Availability

Zinc-air technology is still in early R&D phase for stationary storage systems for grid services markets. Despite substantial technical obstacles faced in the past, this technology holds a great deal of potential because of its low capital cost for grid support and potentially for electric transportation applications.

Table 13 illustrates the technology dashboard for Zinc-air energy storage systems.

Table 13. Technology Dashboard: Zinc-air Battery Systems

Technology Development Status	Laboratory E	Small cells and stacks in a lab setting some bench scale system tests
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	E	-15% to +15%
Operating Field Units	None	None in utility-scale demonstrations
Process Contingency	15-20%	Efficiency and cycle life uncertain. Scale-up uncertainties
Project Contingency	10-15%	Limited definition of product designs.

Figure 65 and Figure 66 show a 1-kW battery prototype and an artist's rendering of a 1-MW/6 MWh system.

Figure 65. 1-kW Zinc-air Prototype
(Photo courtesy of EOS Energy Storage)

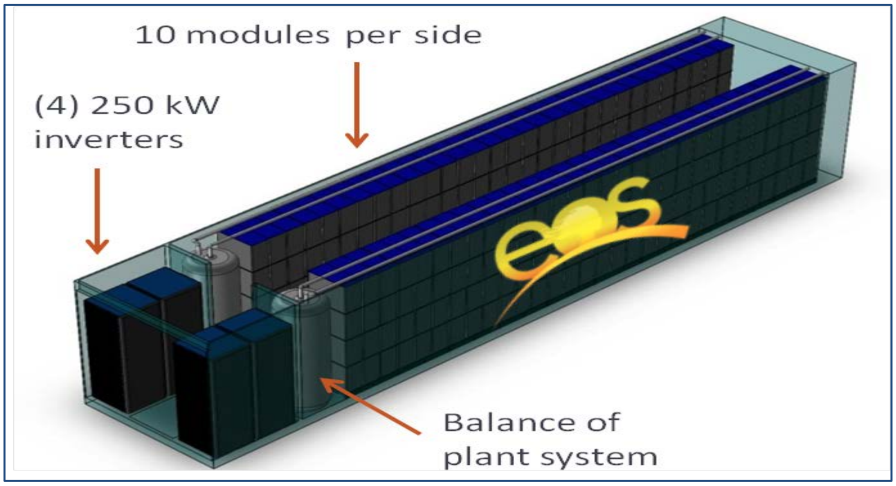


Figure 66. Illustration of 1-MW/6/MWh Eos Aurora Zinc-air Design
(Developed by EOS Energy Storage)

Zinc-air Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 67, Figure 68, and Figure 69 by application. The estimates are based on capital, O&M data, and stack replacement costs from the Zinc-air data sheets. A simple dispatch was assumed, with life-cycle estimates based on IOU financial assumptions of 365 cycles annually for 15 years. There was no periodic stack replacement costs assumed in these figures. If a replacement cost of $200 per kW every 5 years is assumed, the impact on present value installed cost is about a 9% increase.

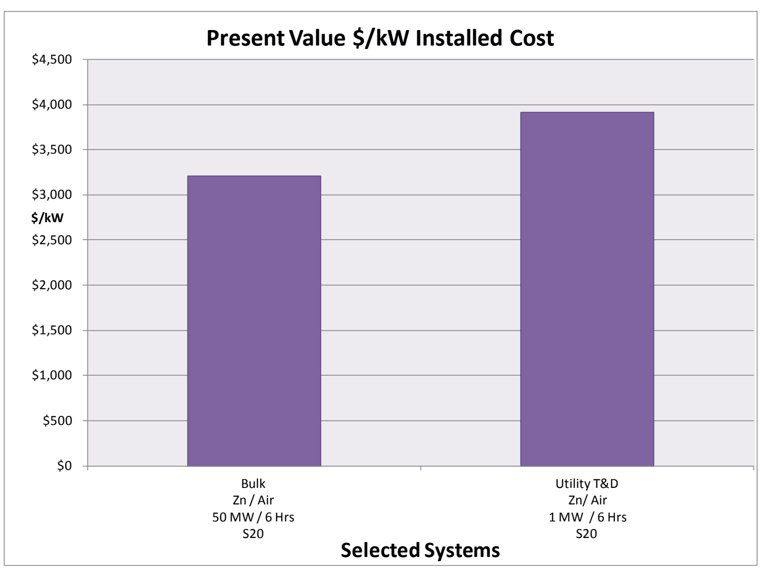


Figure 67. Present Value Installed Cost for Zinc-air Systems in Bulk Services
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

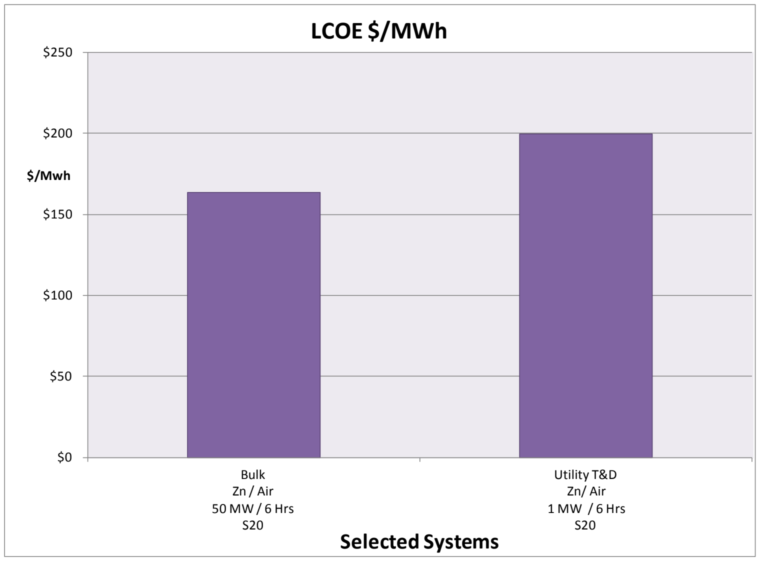


Figure 68. Levelized Cost of Energy in $/MWh for Zinc-air Systems in Bulk Services
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

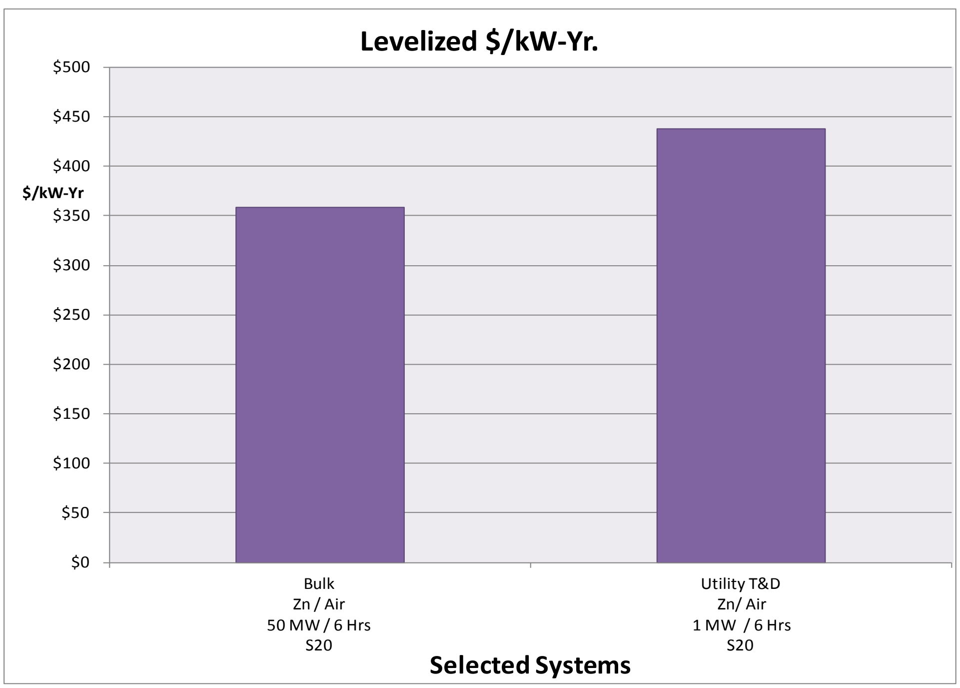


Figure 69. Levelized Cost of Capacity in $/kW-yr for Zinc-air Systems in Bulk Services
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

2.12 Lead-acid Batteries

Technical Description

Lead-acid batteries are the oldest form of rechargeable battery technology. Originally invented in the mid-1800s, they are widely used to power engine starters in cars, boats, planes, etc. All lead-acid designs share the same basic chemistry. The positive electrode is composed of lead-dioxide, PbO_2, while the negative electrode is composed of metallic lead, Pb. The active material in both electrodes is highly porous to maximize surface area. The electrolyte is a sulfuric acid solution, usually around 37% sulfuric acid by weight when the battery is fully charged.

Lead-acid energy storage technologies are divided into two types: lead-acid carbon technologies and advanced lead-acid technologies. Lead-acid carbon technologies use a fundamentally different approach to lead-acid batteries through the inclusion of carbon, in one form or another, both to improve the power characteristics of the battery and to mitigate the effects of partial states of charge. Certain advanced lead-acid batteries are conventional valve-regulated lead-acid (VRLA) batteries with technologies that address the shortcomings of previous lead-acid products through incremental changes in the technology.[38] Other advanced lead-acid battery systems incorporate solid electrolyte-electrode configurations, while others incorporate capacitor technology as part of anode electrode design.

Lead-acid Carbon

Lead-acid carbon technology can exhibit a high-rate characteristic in both charge and discharge with no apparent detrimental effects as are typically experienced in traditional vented lead-acid (VLA) and VRLA batteries. This characteristic allows the lead-acid carbon batteries to deliver and accept high current rates only available with current higher-cost nickel metal-hydride (Ni-MH) and Li-ion batteries.[39]

There are three major lead-acid carbon technologies currently moving into the market. The three developers working on these technologies are Ecoult/EastPenn, Axion Power International, and Xtreme Power. Each developer has a different implementation of carbon integrated with the traditional lead-acid battery negative plate. In general, each variation is targeting a specific niche market.[40]

According to Axion, their proprietary PbC® technology is a multi-celled asymmetrically supercapacitive lead-acid-carbon hybrid battery. The negative electrodes are five-layer assemblies that consist of a carbon electrode, a corrosion barrier, a current collector, a second corrosion barrier, and a second carbon electrode. These electrode assemblies are then combined with conventional separators and positive electrodes. The resulting battery is filled with an acid

[38] "*Energy Storage and Distributed Generation Technology Assessment: Assessment of Lead-Acid-Carbon, Advanced Lead-Acid, and Zinc-Air Batteries for Stationary Application*", EPRI, EPRI ID 1017811, EPRI, Palo Alto, CA, December 2009.
[39] Ibid.
[40] Ibid.

electrolyte, sealed, and connected in series to other cells. Laboratory prototypes have undergone deep-discharge testing and withstood more than 1600 cycles before failure. In comparison, most lead-acid batteries designed for deep discharges deliver 300 to 500 cycles. Application-specific prototypes may offer several performance advantages over conventional lead-acid batteries, including:

- Significantly faster recharge rates,
- Significantly longer cycle lives in deep discharge applications, and
- Minimal required maintenance.[41]

Xtreme Power systems are finding early uses in wind and PV smoothing applications. The Xtreme Power PowerCell™ is a 12-volt, 1-kWh, advanced dry cell battery utilizing a solid-state battery design and chemistry. The uniform characteristics of the PowerCells™ allow thousands to be assembled in massive parallel and series matrices, suited for use in large-scale utility applications requiring many megawatts of power while still maintaining a manageable footprint. Its low internal resistance results in high-power retention, as well as the ability to rapidly charge and discharge large amounts of power[42] . The vendor reports a PowerCell™'s life is based on its depth of discharge (DOD). Cycle life is a log function of DOD and ranges from over 500,000 cycles at 1% DOD to 1,000 cycles at 100% DOD.

Advanced Lead-acid Technologies

While developers of lead-acid carbon technologies are improving the capability of conventional lead-acid technologies through incorporation of carbon in one or both electrodes, manufacturers such as GS Yuasa and Hitachi are taking other approaches. Advanced lead-acid products from these manufacturers focus on technology enhancements such as carbon-doped cathodes, granular silica electrolyte retention systems (GS Yuasa), high-density positive active material, and silica-based electrolytes (Hitachi).

Some advanced lead batteries have supercapacitor-like features that give them fast response, similar to flywheels or Li-ion batteries. Advanced lead-acid systems from a number of companies are currently in early field trial demonstrations.

Performance Characteristics

Traditional VLA and VRLA batteries are typically designed for optimal performance in either a power application or an energy application, but not both. That is, a battery specifically designed for power applications can indeed deliver reasonable amounts of energy (e.g., for operating car lights), but it is not designed to deliver substantial amounts of energy (e.g., 80-percent deep discharges) on a regular basis. In comparison, a lead-acid carbon or advanced lead-acid battery

[41] Axion website: http://www.axionpower.com/profiles/investor/fullpage.asp?f=1&BzID=1933&to=cp&Nav=0&LangID=1&s=0&ID=10298, accessed March 15, 2013

[42] Xtreme Power website: www.xtremepower.com, accessed March 15, 2013

specifically designed for energy applications can deliver high impulses of power if needed, although it is not specifically designed to do so.

There are several lead-acid carbon and advanced lead-acid technologies; the values are an average of currently available systems. Each system will have its own performance characteristics.[43]

Disposal of lead-acid batteries is an important part of the life cycle. The environmental and safety hazards associated with lead require a number of regulations concerning the handling and disposal of lead-acid batteries. Lead-acid batteries are among the most recycled products in the world. Old batteries are accepted by lead-acid manufacturers for recycling. Batteries are separated into their component parts. The lead plates and grids are smelted to purify the lead for use in new batteries. Acid electrolyte is neutralized, scrubbed to remove dissolved lead, and released into the environment. Other component parts such as plastic and metal casings are also recycled.[44]

Maturity and Commercial Availability

Lead-acid batteries are the most commercially mature rechargeable battery technology in the world. VRLA batteries are used in a variety of applications, including automotive, marine, telecommunications, and uninterruptible power supply (UPS) systems. However, there have been very few utility T&D applications for such batteries due to their relatively heavy weight, large bulk, cycle-life limitations, and perceived reliability issues (stemming from maintenance requirements).

As shown in Figure 70, a 1-MW/1.5-MWh lead-acid battery by GNB Industrial Power (now Exide) has been operating for 12 years in Metlakatla, AK. In this project, the battery system exhibited very little visible degradation upon post-test analysis and was replaced in 2008, after 12 years of continuous shallow discharge service. Other lead-acid carbon energy systems have been deployed in sizes of 10 to 20 MW.[45]

[43] *Energy Storage Market Opportunities: Application Value Analysis and Technology Gap Assessment*, EPRI ID 1017813, EPRI, Palo Alto, CA, December 2009.

[44] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Application,* EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003.

[45] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits,* PI: Dan Rastler, EPRI ID 1020676, EPRI, Palo Alto, CA, September 2010.

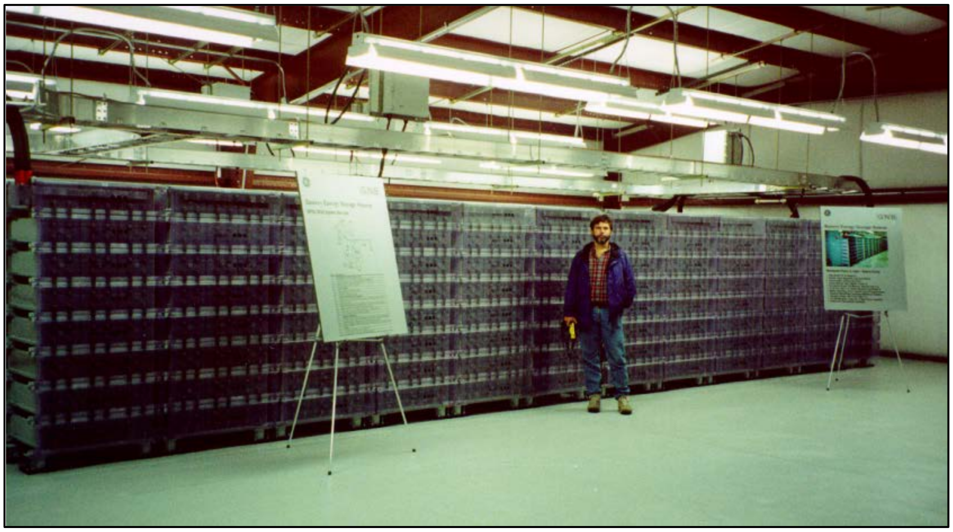


Figure 70. 1-MW/1.5-MWh Lead-acid Carbon System at Metlakatla, AK[46]

Many traditional suppliers and new entrants are seeking to introduce advanced lead-acid technology in U.S. utility markets through products designed for residential, commercial, and industrial use. While each of these cannot be covered in detail in this course, the reader must clearly define the application use case, requirements, and life-cycle expectations during the process of review, assessment, and final selection. Some of the more notable recent field deployments are reviewed here.

Hitachi is developing their advanced lead-acid product for renewable integration and smart grid projects in Japan, with the intent of competing with NaS and Li-ion batteries. Some of their advanced lead-acid batteries have been integrated with wind-generation sites, including the well-known project at Tappi Wind Park installed in 2001 with support from the New Energy Development Organization (NEDO), a Japanese government organization that promotes the development of new energy technologies. The Tappi Wind Park battery system, shown in Figure 71 used an earlier generation of the Hitachi advanced lead-acid battery technology. In August 2009, Hitachi completed a 10.4-MWh battery, built to stabilize a 15-MW wind facility at Goshogawara in northern Japan. A similar plant was installed in late 2010 at another wind-generation site at Yuasa. This battery is now available to companies for integration into the United States, although costing for the United States is unclear at this time.[47]

[46] *Energy Storage and Distributed Generation Technology Assessment: Assessment of Lead-Acid-Carbon, Advanced Lead-Acid, and Zinc-Air Batteries for Stationary Application*, EPRI ID 1017811, EPRI, Palo Alto, CA, 2009.
[47] Ibid.

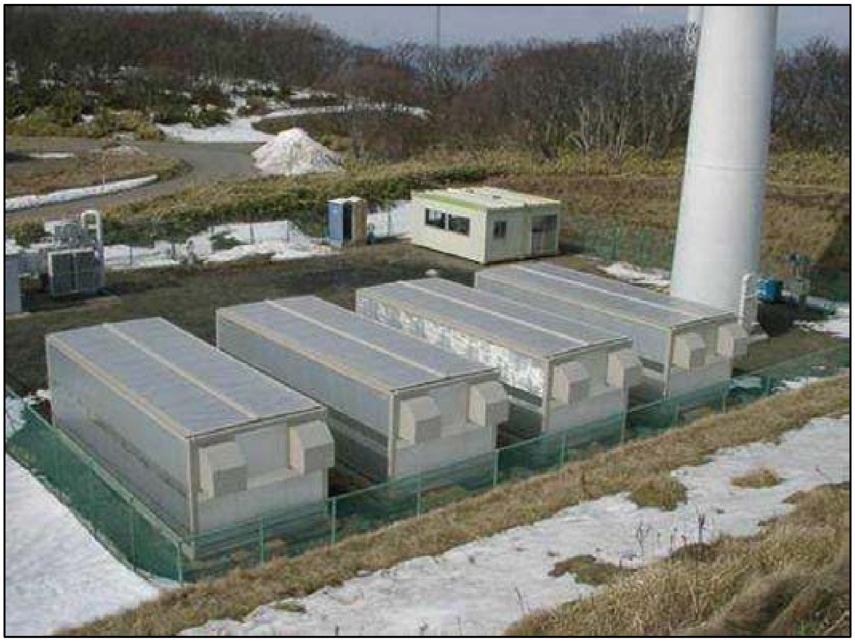


Figure 71. Acid Battery Installation at Tappi Wind Park
(Courtesy Hitachi)[48]

Xtreme Power, Inc., has deployed its advanced lead-acid XP System in multiple services, including wind and PV integration, transmission and distribution applications, and smart grid applications in Hawaii. One of these systems deployed in Maui, HI, is shown in Figure 72. Xtreme Power also plans to offer grid congestion and large-scale power management products for grid-tied services.

Figure 73 shows another advanced lead-acid system made by Ecoult/East Penn installed at a Public Service Company of New Mexico (PNM) project site.

[48] Ibid.

Figure 72. 1.5-MW/1-MWh Advanced Lead-acid Dry Cell Systems by Xtreme Power in a Maui Wind Farm
(Source: Xtreme Power)

Figure 73. 500-kW/1-MWh Advanced Lead-acid Battery for Time-shifting and 900-kWh Advanced Carbon Valve-regulated Battery for Photovoltaic Smoothing
This is a solar energy storage facility that is fully integrated into a utility's power grid.
(Source: PNM Resources)

Table 14 is a technology dashboard that shows the status of technology development for lead-acid batteries.

Table 14. Technology Dashboard: Advanced Lead-acid Battery Systems

Technology Development Status	Demonstration C	Limited field demonstrations Some advanced systems can be classified as commercial
Confidence of Cost Estimate	D	Vendor quotes and system installation estimates
Accuracy Range	C	-10% to +15%
Operating Field Units	5 or more	Several wind and photovoltaic applications expected by 2013
Process Contingency	10-15%	Limited testing and field experience
Project Contingency	5-10%	Cycle life and depth of discharge for application needs careful evaluation; limited operation and maintenance cost data.

Lead-acid Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of several selected systems is illustrated in Figure 74 through Figure 88 for each application. The estimates are based on capital, O&M data, and battery replacement costs from the Lead-acid data sheets. Life-cycle estimates were based on IOU financial assumptions, with 365 cycles annually for 15 years. For the frequency regulation application, a simple dispatch was assumed based on each system operating 5000 cycles per year.

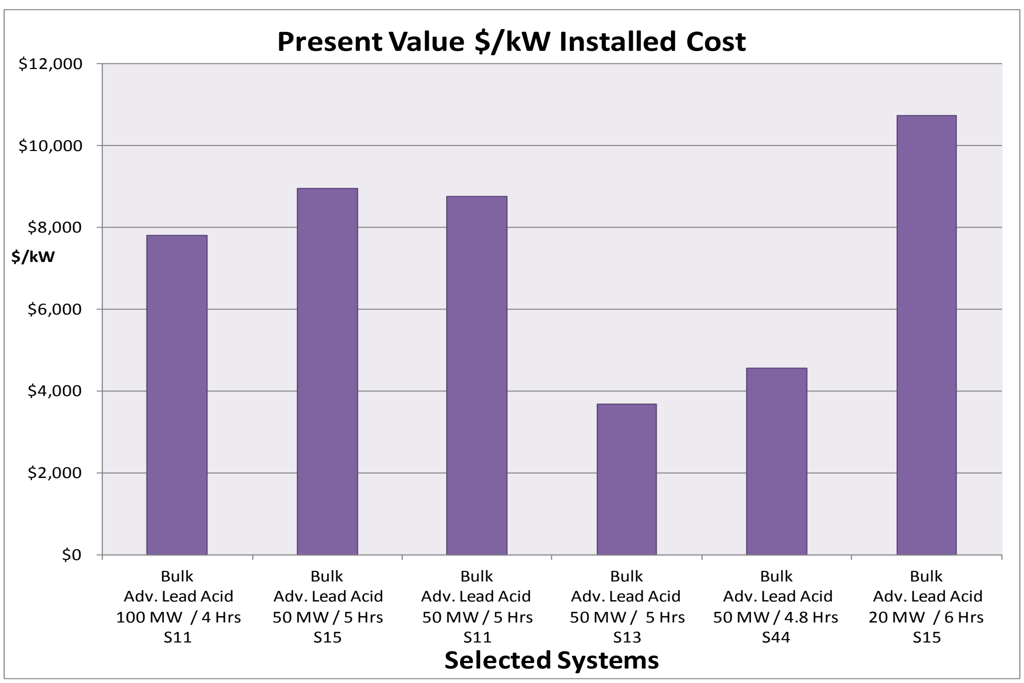


Figure 74. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems Bulk Service Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

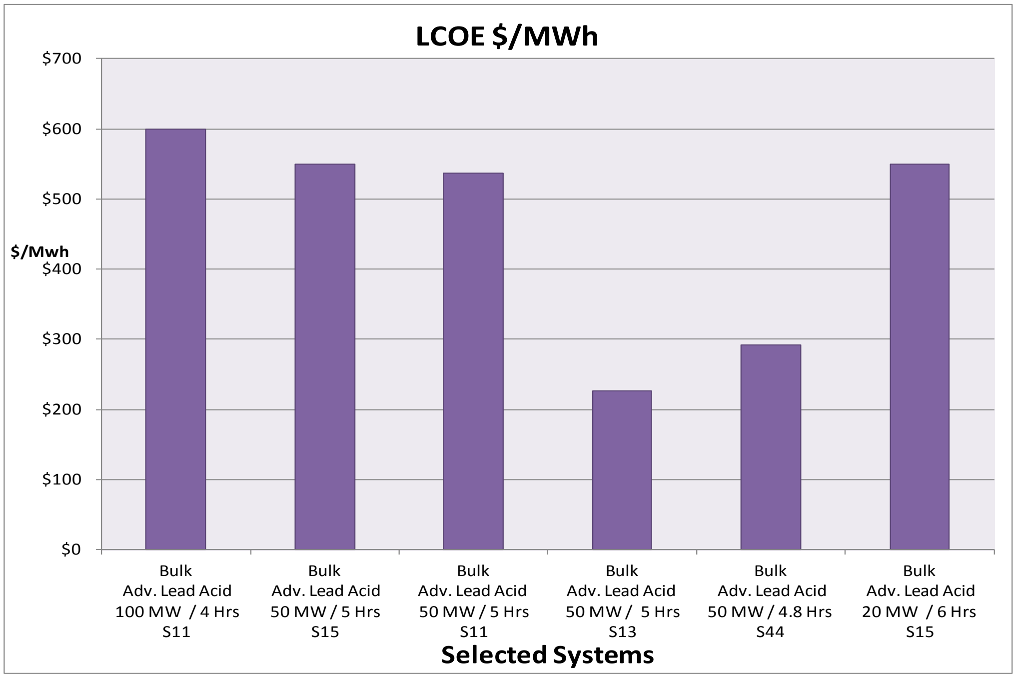


Figure 75. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Bulk Service Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

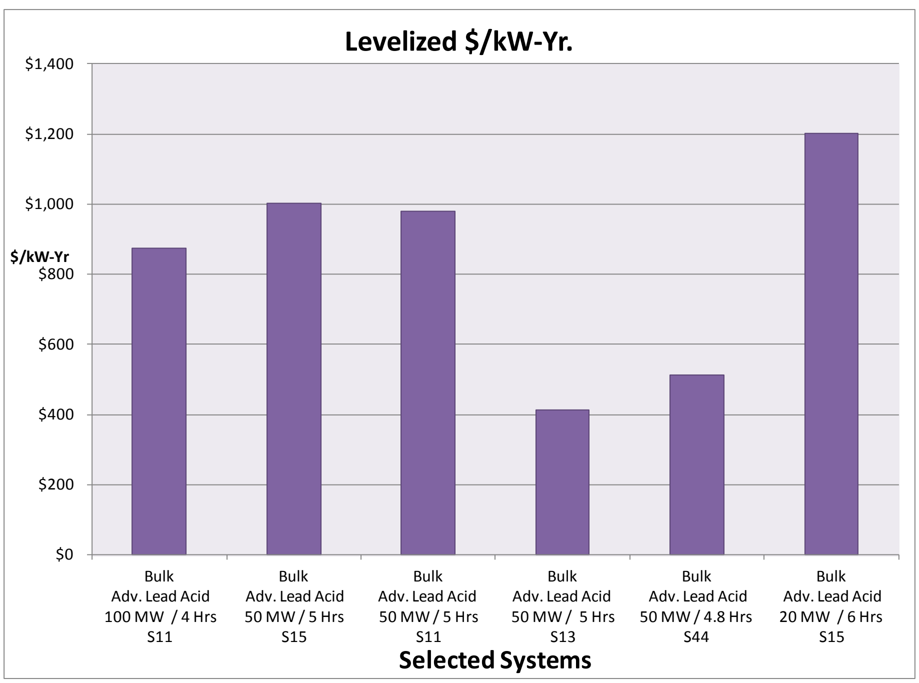


Figure 76. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Bulk Service Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

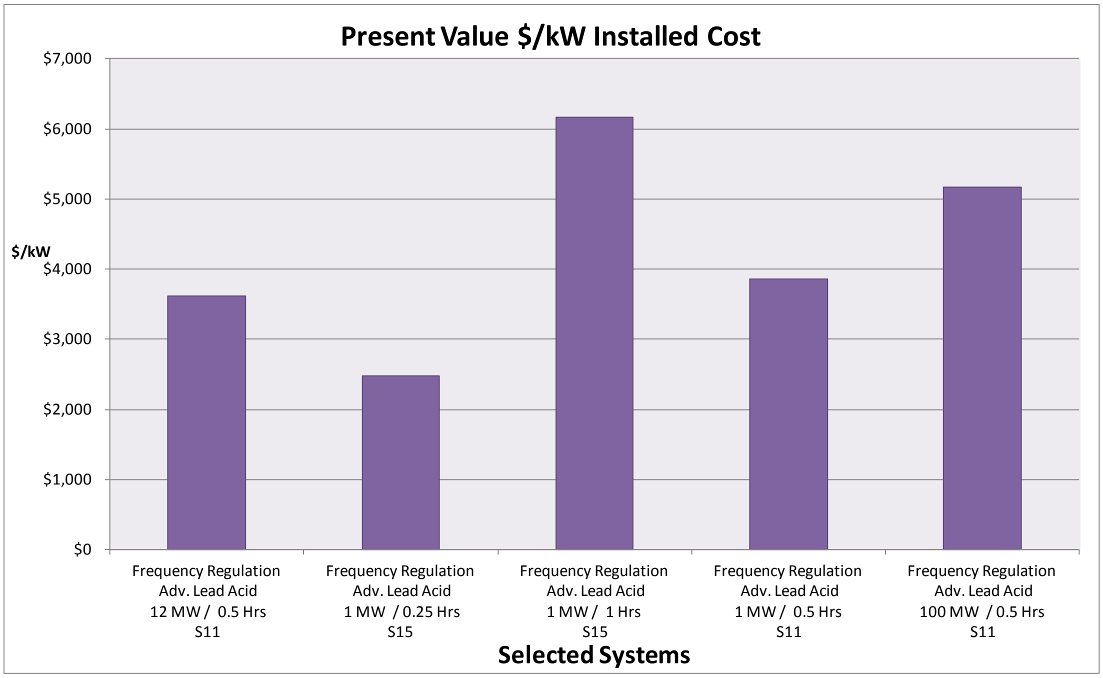


Figure 77. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Frequency Regulation

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

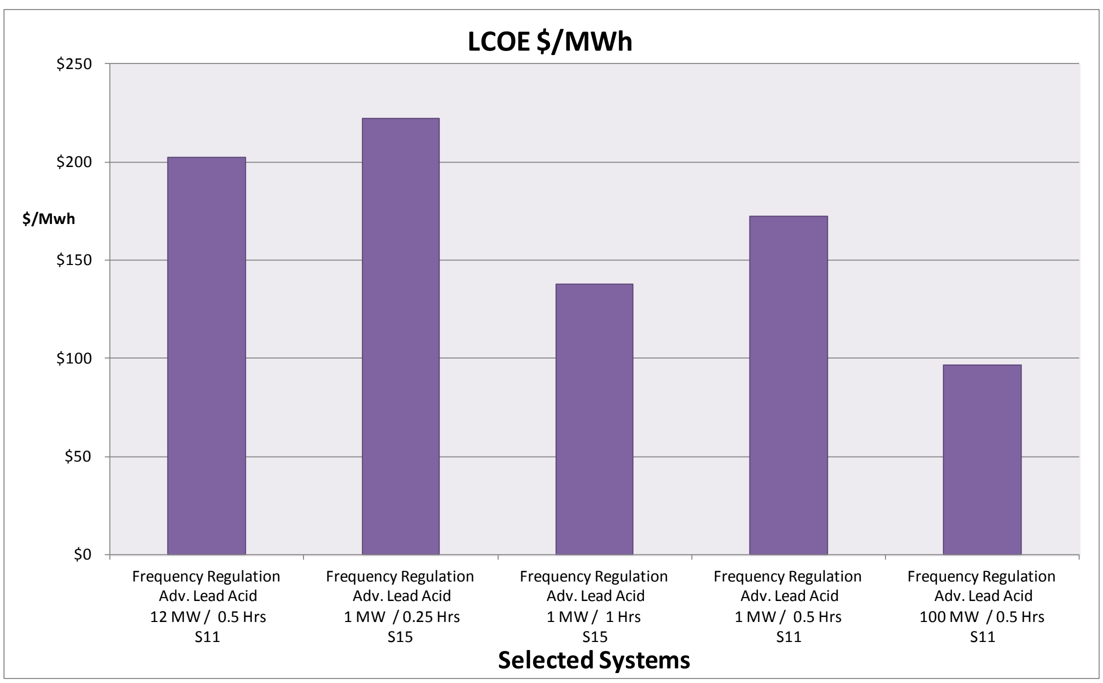


Figure 78. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Systems in Frequency Regulation

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

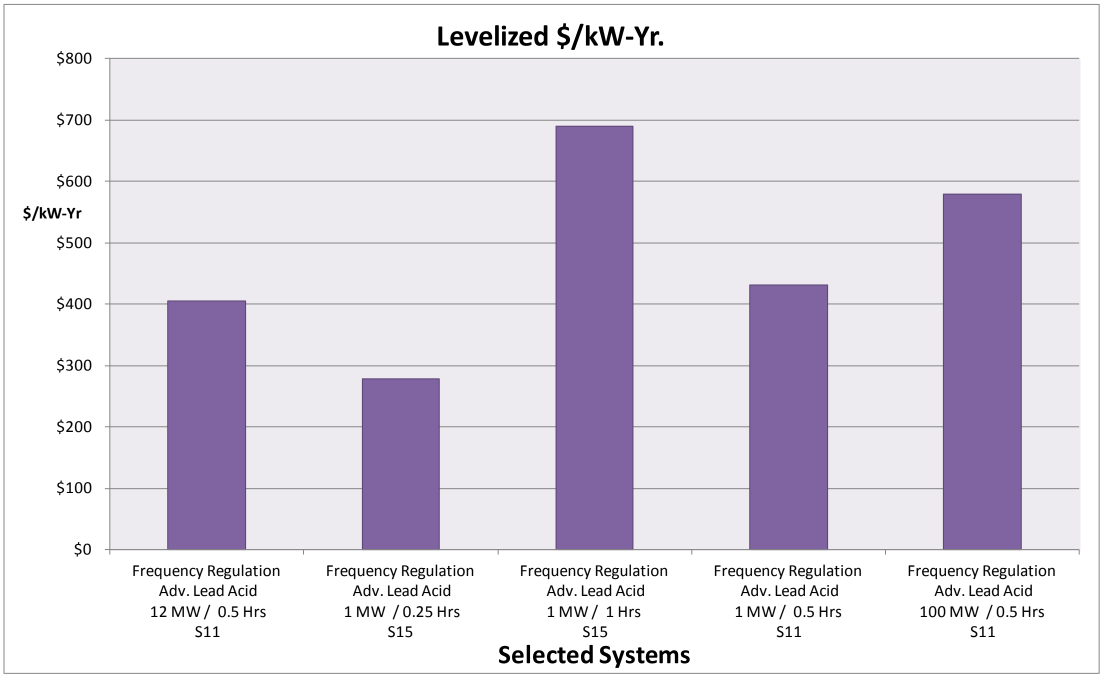


Figure 79. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Frequency Regulation

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

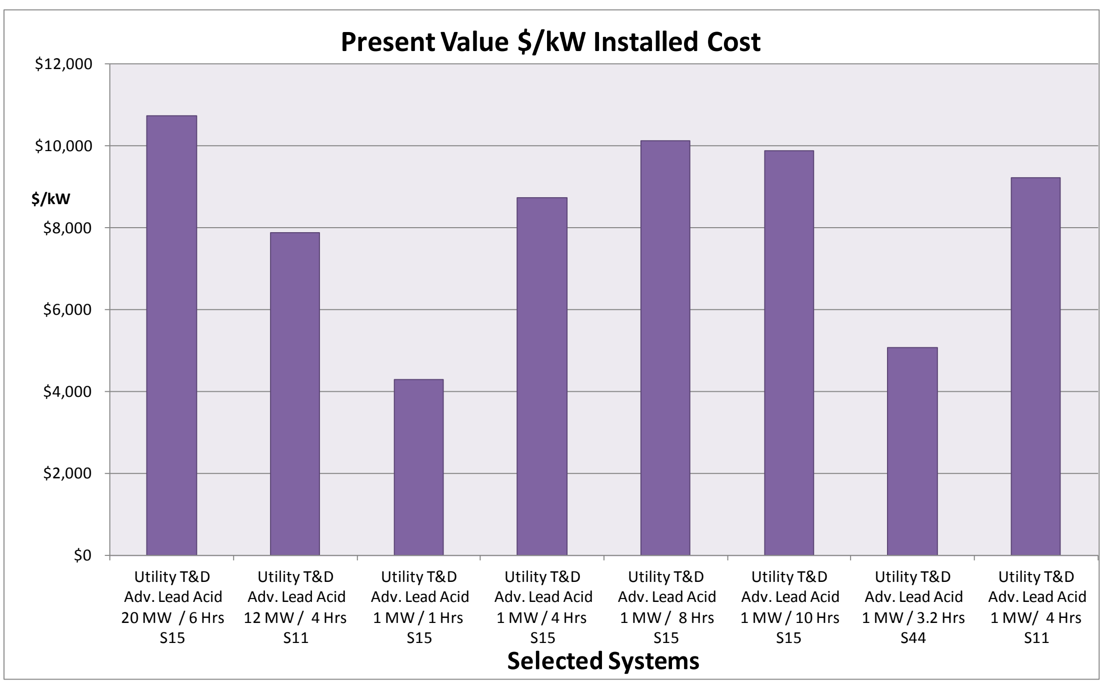


Figure 80. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Transmission and Distribution Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

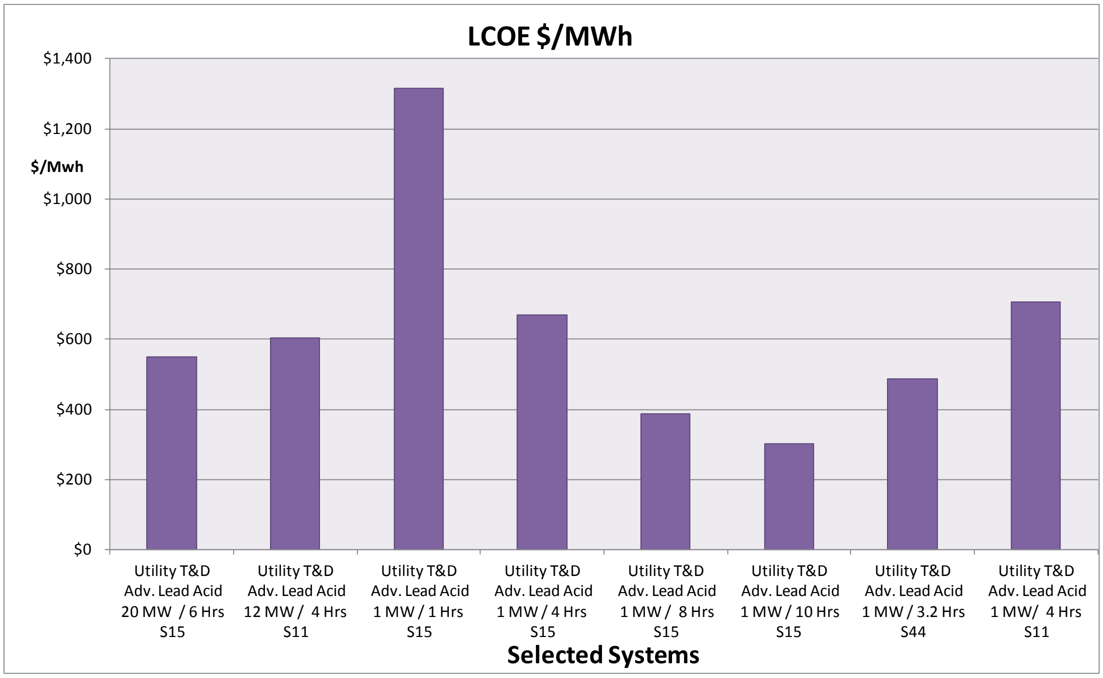


Figure 81. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Transmission and Distribution Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

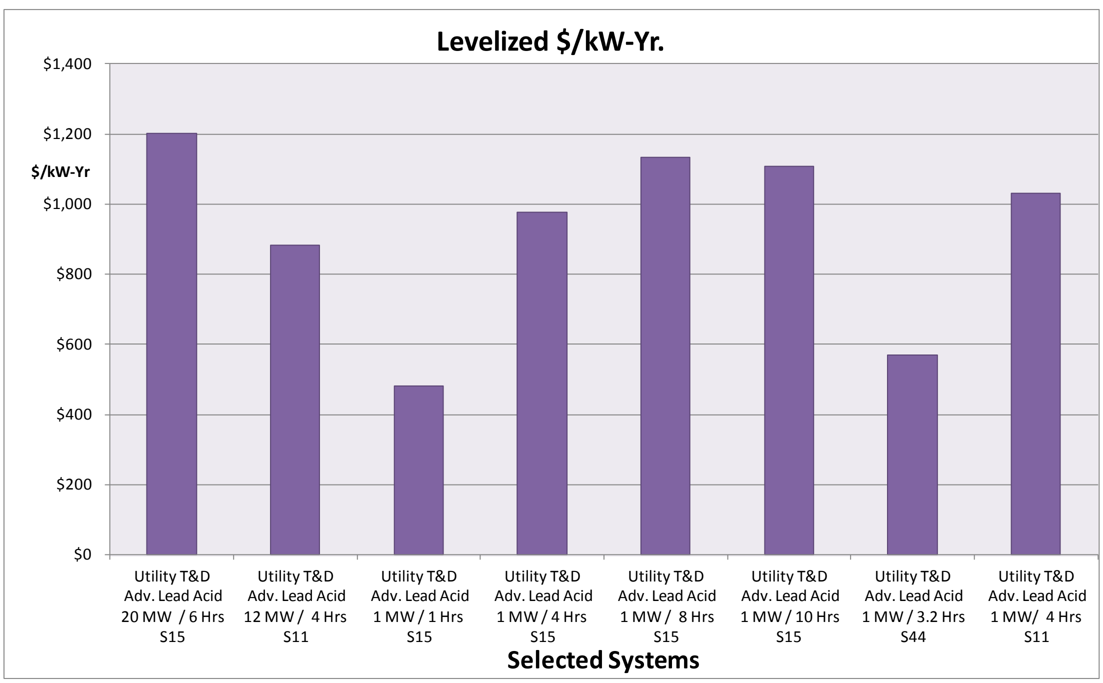


Figure 82. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Transmission and Distribution Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

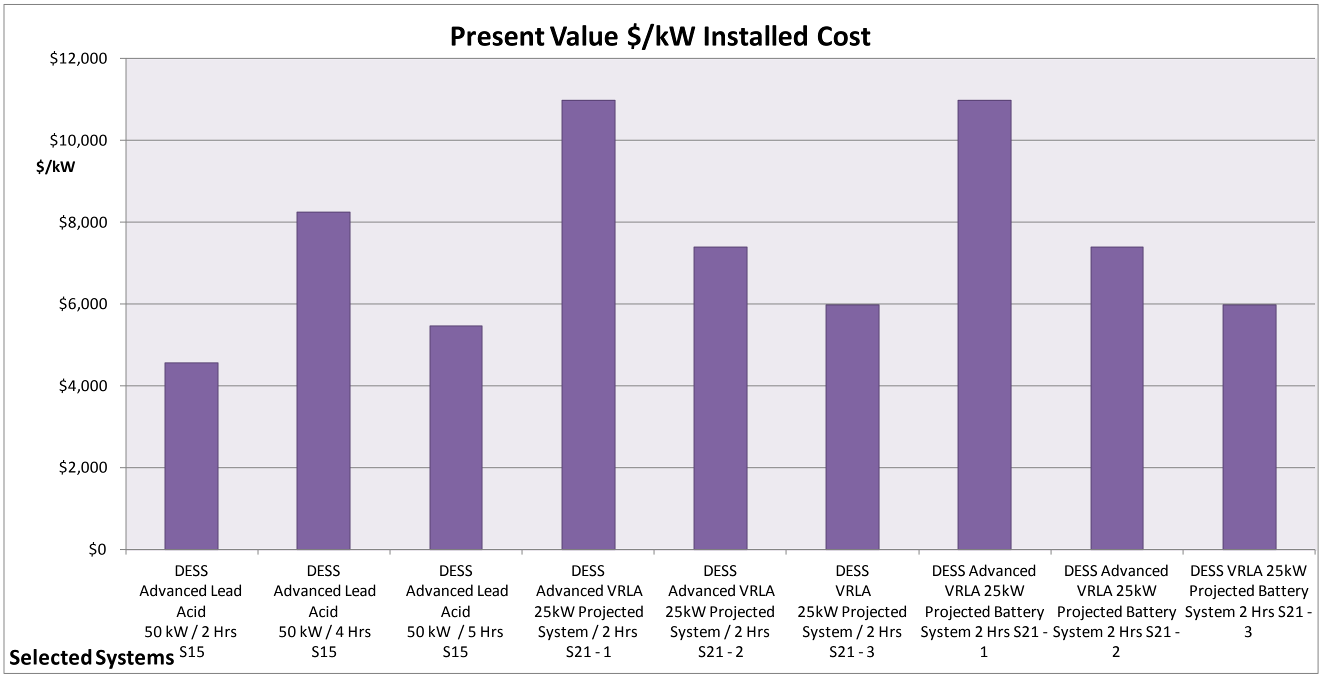


Figure 83. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Distributed Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

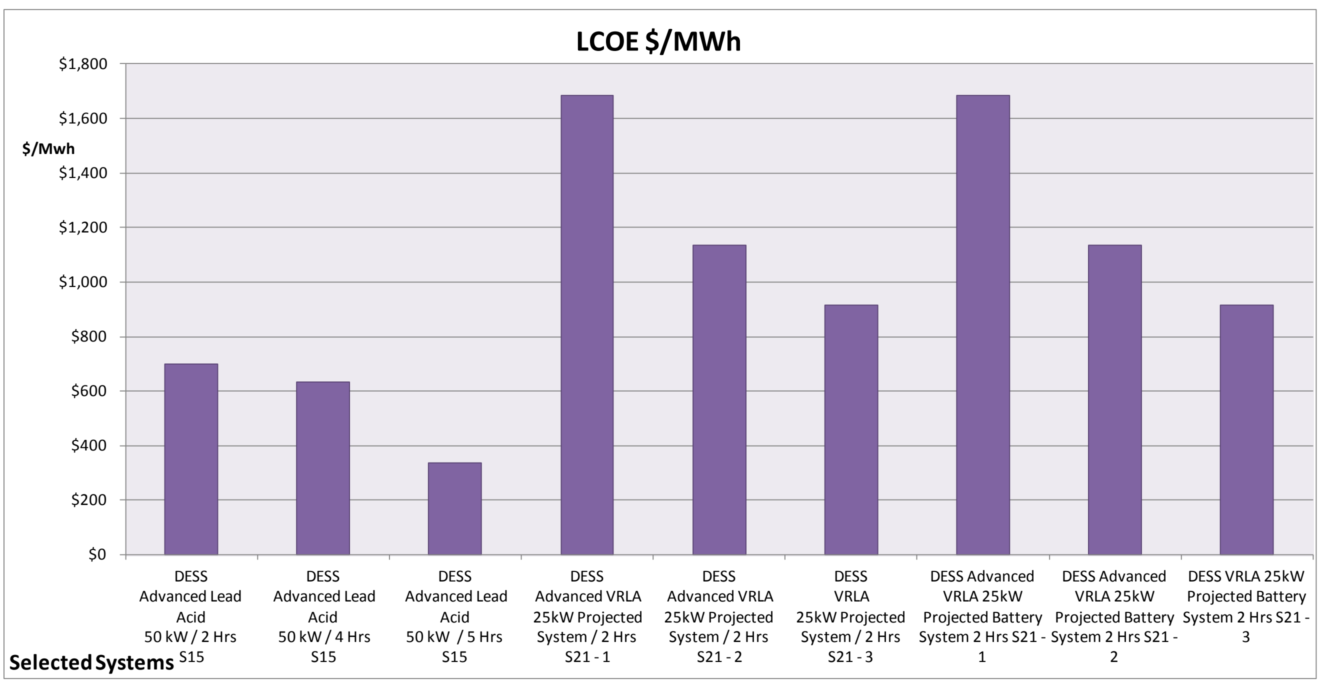


Figure 84. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Distributed Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

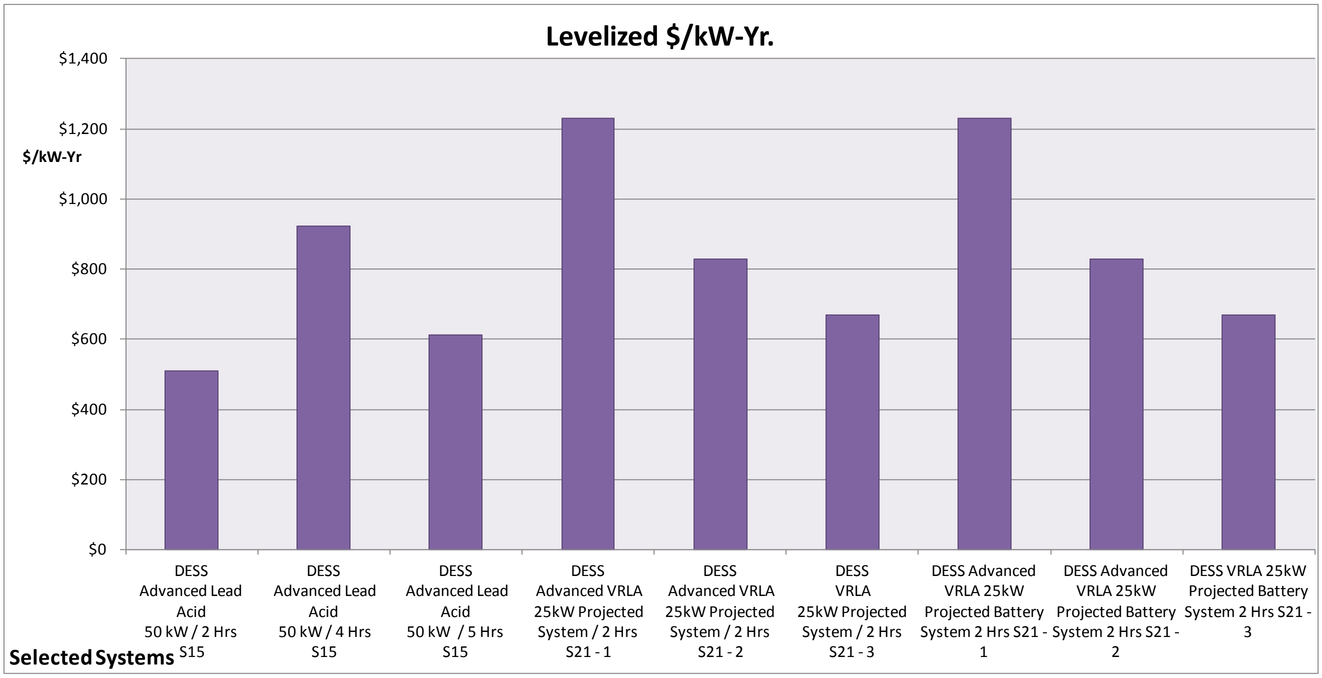


Figure 85. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Distributed Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

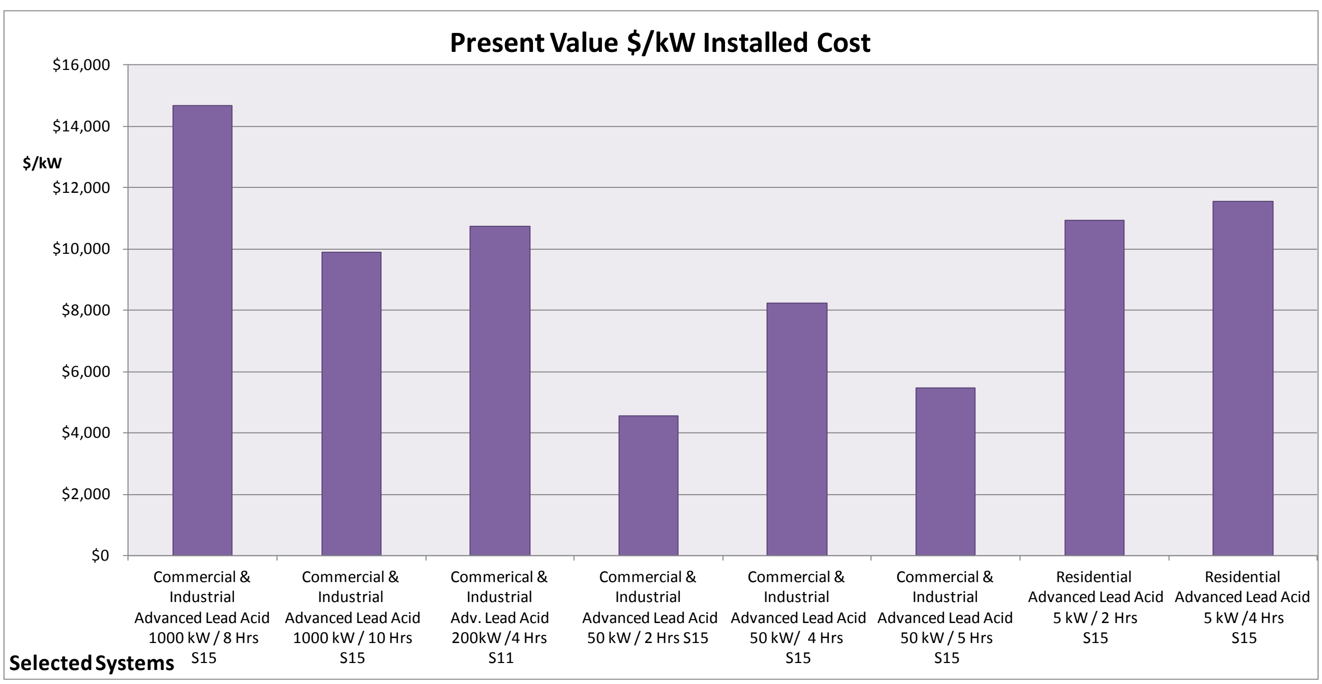


Figure 86. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

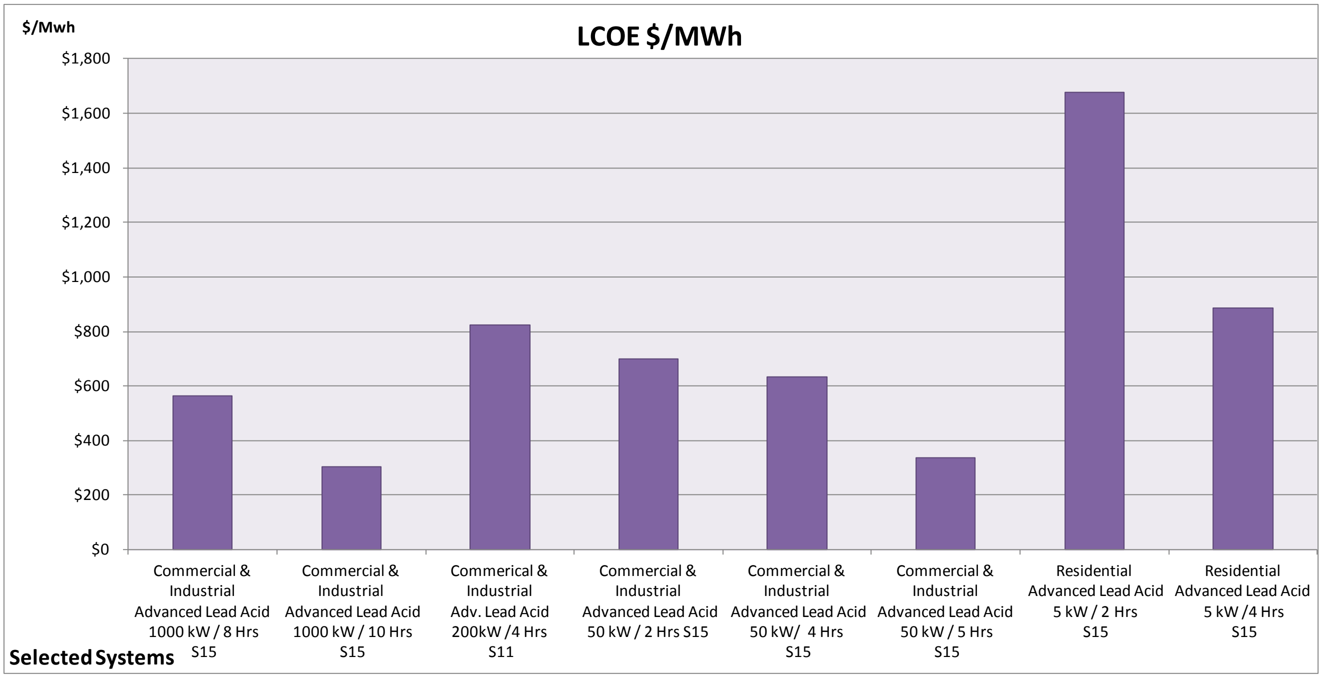


Figure 87. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

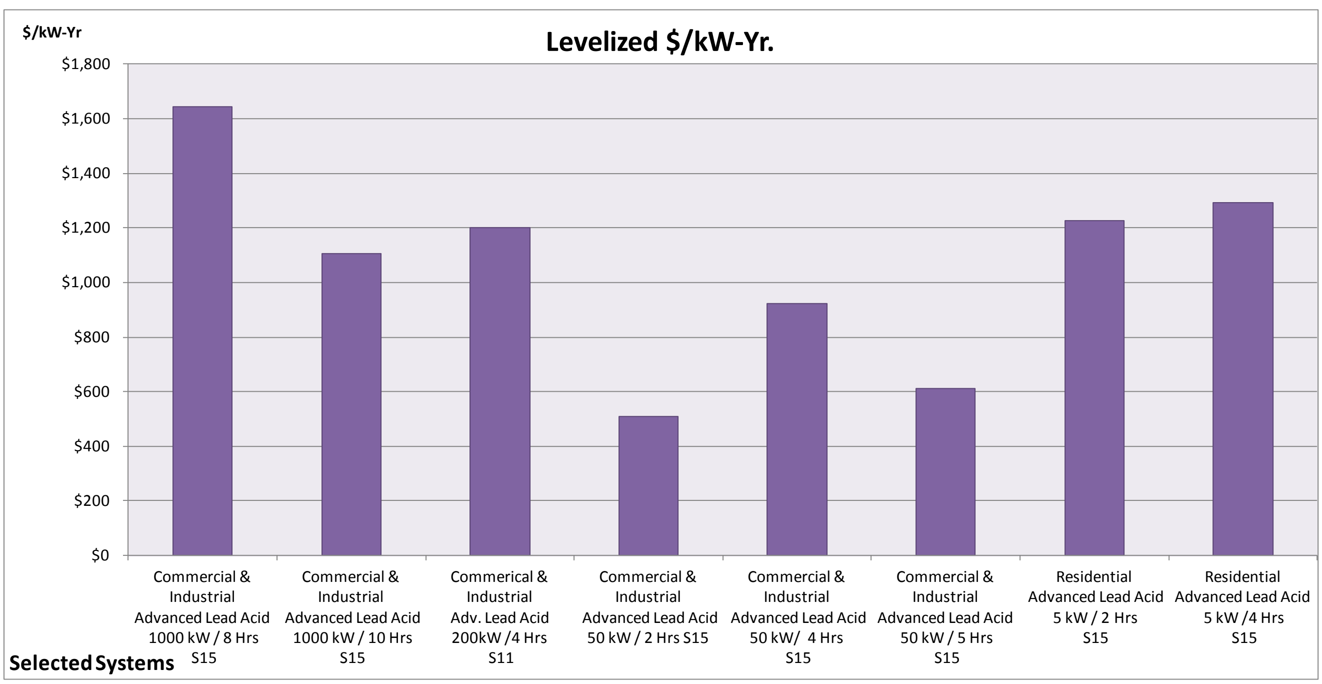


Figure 88. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Lead-acid Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

Additional Lead-acid Battery Resource

1. *New Industry Guidelines for the Maintenance of Stationary Valve-Regulated Lead Acid Batteries*, EPRI ID TR-106769, EPRI, Palo Alto, CA, June 1996.

2. *Valve Regulated Lead Acid (VRLA) Battery Qualification Assessment*, EPRI ID 1019216, EPRI, Palo Alto, CA, November 2009.

3. *Chino Battery Energy Storage Power Plant: Engineer-of-Record Report*, EPRI ID Tr-101787, EPRI, Palo Alto, CA, March 1993.

4. *Chino Battery Energy Storage Power Plant: First Year of Operation*, EPRI ID TR-101786, EPRI, Palo Alto, CA, February 1993.

2.13 Flywheel Energy Storage

Technical Description

Flywheels store energy in the form of the angular momentum of a spinning mass, called a rotor. The work done to spin the mass is stored in the form of kinetic energy. A flywheel system transfers kinetic energy into ac power through the use of controls and power conversion systems.

Most modern flywheel systems have some type of containment for safety and performance-enhancement purposes. This containment is usually a thick steel vessel surrounding the rotor, motor-generator, and other rotational components of the flywheel. If the wheel fractures while spinning, the containment vessel would stop or slow parts and fragments, preventing injury to bystanders and damage to surrounding equipment. Containment systems are also used to enhance the performance of the flywheel. The containment vessel is often placed under vacuum or filled with a low-friction gas such as helium to reduce the effect of friction on the rotor. See Figure 89, below.[49]

[49] Ibid.

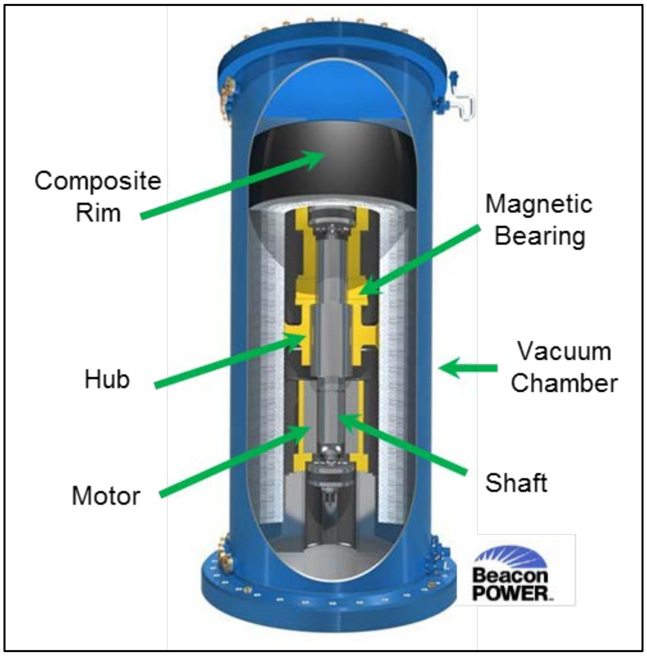


Figure 89. Integrated Flywheel System Package Cutaway Diagram
(Courtesy Beacon Power)[50]

Performance Characteristics

Round-trip efficiency and standby power loss become critical design factors in energy flywheel design because losses represent degradation of the primary commodity provided by the storage system (energy). However, they are largely irrelevant in power flywheel design, although standby losses are a factor in operating cost in comparison with other power technologies that have significantly lower losses. For these reasons, energy flywheels usually require more advanced technologies than power flywheels. These energy flywheels usually have composite rotors enclosed in vacuum containment systems, with magnetic bearings. Such systems typically store between 0.5 kWh and 10 kWh. The largest commercially available systems of this type are in the 2- to 6-kWh range, with plans for up to 25 kWh. All energy flywheels available today are dc output systems. Round-trip efficiencies for energy flywheels are usually between 70% and 80%. The standby losses are very small, typically less than 25 W DC per kWh of storage and in the range one to two percent of the rated output power.[51]

Flywheels can be charged relatively quickly. Recharge times are comparable to discharge times for both power and energy flywheels designs. High-power flywheel systems can often deliver

[50] Ibid.
[51] Ibid.

their energy and recharge in seconds, if adequate recharging power is available. Bidirectional power conversion facilitates this two-way action.[52]

Flywheels generally exhibit excellent cycle life in comparison with other energy storage systems. Most developers estimate cycle life in excess of 100,000 full charge-discharge cycles. The rotor is subject to fatigue effects arising from the stresses applied during charge and discharge. The most common failure mode for the rotor is the propagation of cracks through the rotor over a period of time.[53]

As with any energy storage technology, hazardous conditions may exist around operating flywheels. Considerable effort has gone into making flywheels safe for use under a variety of conditions. The most prominent safety issue in flywheel design is failure of the flywheel rotor while it is rotating. In large, massive rotors, such as those made of steel, failure typically results from the propagation of cracks through the rotor, causing large pieces of the flywheel to break off during rotation. Unless the wheel is properly contained, this type of failure can cause damage to surrounding equipment and injury to people in the vicinity. Large steel containment systems are employed to prevent high-speed fragments from causing damage in the event of failure.[54]

In contrast to many other energy storage systems, flywheel systems have few adverse environmental effects, both in normal operation and in failure conditions. Neither low-speed nor high-speed flywheel systems use hazardous materials, and the machines produce no emissions.[55]

Today's flywheel systems are shorter energy duration systems and not generally attractive for large-scale grid support services that require many kWh or MWh of energy storage. Flywheels charge by drawing electricity from the grid to increase rotational speed and discharge by generating electricity as the wheel's rotation slows. They have a very fast response time of four milliseconds or less, can be sized between 100 kW and 1650 kW, and may be used for short durations of up to one hour. They have very high efficiencies of about 935, with lifetimes estimated at 20 years.

Although flywheels have power densities 5 to 10 times that of batteries—meaning they require much less space to store a comparable amount of power—there are practical limitations to the amount of energy (kWh) that can be stored. A flywheel energy storage plant can be scaled up by adding more flywheel system modules. Typical flywheel applications include power quality and UPS uses, as seen in commercial products. Research is under way to develop more advanced flywheel systems that can store large quantities of energy.

[52] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation;
[53] Ibid.
[54] Ibid.
[55] Ibid.

Because flywheel systems are fast-responding and efficient, they are currently being positioned to provide ISO frequency-regulation services. Analysis of such flywheel services have been shown to offer system benefits, including avoiding the cycling of large fossil power systems and lower CO_2 emissions. Spindle Grid Regulation, LLC (formerly Beacon Power), is currently demonstrating megawatt-scale flywheel plants with cumulative capacities of 20 MW to support the frequency-regulation market needs of ISOs.[56]

There are also a number of applications that now propose using flywheels as an energy storage medium. These include inrush control, voltage regulation, and stabilization in substations for light rail, trolley, and wind-generation stabilization. The majority of products currently being marketed by national and international-based companies are targeted for power quality (PQ) applications. Another high value application in PQ is short-term bridging through power disturbances or from one power source to an alternate source.[57]

In summary, the applications proposed for flywheel energy storage are the following:

- Power quality/regulation,
- UPS, and
- Grid frequency-regulation services.

Maturity and Commercial Availability

Flywheels are currently being marketed as environmentally safe, reliable, modular, and high-cycle life alternatives to lead-acid batteries for UPS and other power-conditioning equipment designed to improve the quality of power delivered to critical or protected loads. Okinawa Power has installed a 23-MW flywheel system for frequency regulation. Fuji Electric has demonstrated the use of flywheel technology to stabilize wind power generation.[58]

Spindle Grid Regulation, LLC, owns a 20-MW flywheel-based frequency-regulation facility in Stephentown, NY, that commenced operations in 2011 and sells frequency-regulation services to New York Independent System Operator (NYISO) under tariff rates. According to empirical testing performed during early trials, flywheels showed that 1 MW of fast-response flywheel storage produced 20 to 30 MW of regulation service, and that flywheel regulation was two to three times better than an average Independent System Operator –New England (ISO-NE) generator.[59] The facility sits on five acres and comprises 200 flywheels, each with a storage

[56] *Large-Scale Energy Storage in Decarbonised Power Grids,* Inage, Shin-ichi, International Energy Agency, Paris, France, 2009.

[57] *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*, EPRI ID 1001834, EPRI, Palo Alto, CA, and the U.S. Department of Energy, Washington, DC, 2003. L. D. Mears, H. L. Gotschall - Technology Insights; T. Key, H. Kamath - EPRI PEAC Corporation;

[58] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits*, PI: Dan Rastler, EPRI ID 1020676, EPRI, Palo Alto, CA, 2010.

[59] *Application of Fast-Response Energy Storage in NYISO for Frequency Regulation Services*, Beacon Power Corporation, Portland, OR, April 2010.

capacity of 100kW. Stephentown was originally developed and built by Beacon Power. Beacon also operates the facility. Spindle is also developing a second 20-MW facility in Hazle Township, PA, with financial assistance from the DOE and the Commonwealth of Pennsylvania.

Figure 90 shows a 1-MW system installed at Beacon Power's headquarters in Tyngsboro, MA.

Figure 90. 1-MW Smart Energy Matrix Plant
(Photo courtesy: Beacon Power)

Table 15 is a technology dashboard that shows the status of technology development for flywheel energy storage systems.

Table 15. Technology Dashboard: Flywheel Energy Storage Systems

Technology Development Status	Demonstration status for Frequency Regulation C	Commercial experience in Power Quality UPS applications Pilots in ISO A/S Market applications
Confidence of Cost Estimate	B	Vendor quotes and system installation estimates.
Accuracy Range	B	-15% to +15%
Operating Field Units	10 or more	In a 20-MW application. Numerous uses in power quality applications.
Process Contingency	1-5%	Uncertain long-term life and performance of the flywheel subsystem
Project Contingency	5-10%	

Flywheel Storage Life-Cycle Cost Metrics

Life-cycle cost analysis is illustrated in Figure 91, Figure 92, and Figure 93. The estimates are based on capital, O&M data, and replacement costs from the data sheets. A simple dispatch was assumed, based on 5000 cycles per year, $290 per kW replacement costs every 5 years, and IOU financing.

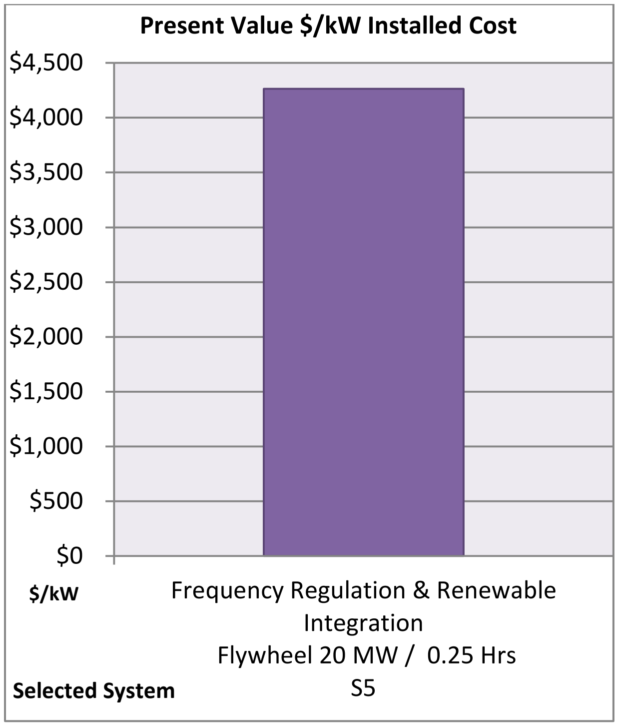


Figure 91. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Flywheel Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

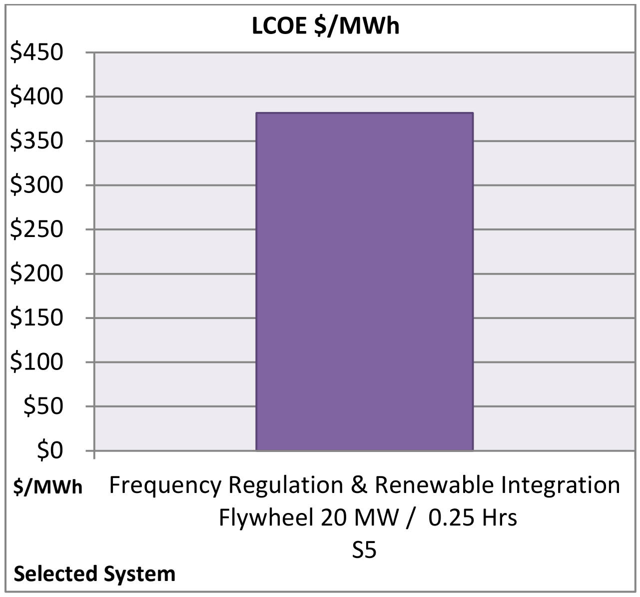


Figure 92. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Flywheel Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

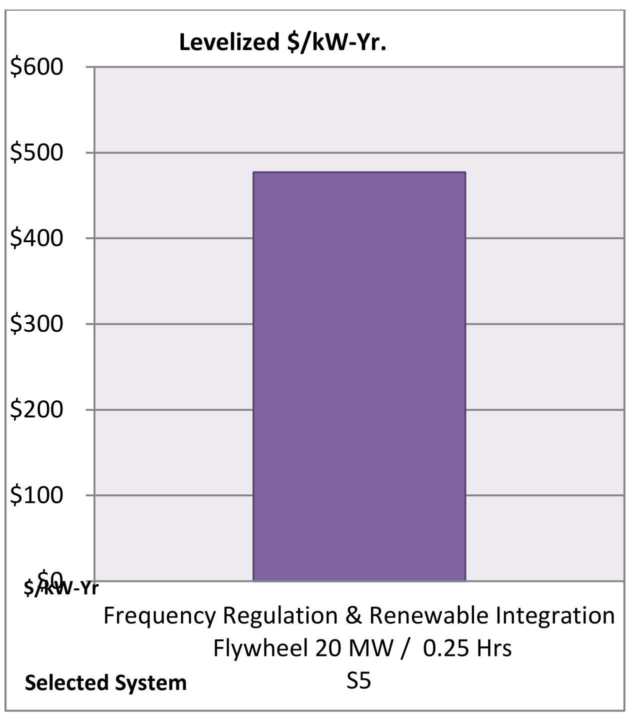


Figure 93. Present Value Installed Cost and Levelized Costs in $/MWh and $/kW-yr for Flywheel Systems

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

Additional Resources for Flywheels

1. *Flywheel Energy Storage*, EPRI ID TR-108378, September 1997.

2. *Flywheels for Electric Utility Energy Storage*, EPRI ID: TR-108889, December 1999.

2.14 Lithium-ion Family of Batteries

Technical Description

In the past two years, Li-ion battery technology has emerged as the fasted growing platform for stationary storage applications. Already commercial and mature for consumer electronic applications, Li-ion is being positioned as the leading technology platform for plug-in hybrid electric vehicles (PHEVs) and all-electric vehicles, which will use larger-format cells and packs with capacities of 15 to 20 kWh for PHEVs and up to 50 kWh for all-electric vehicles.

The most common types of liquid Li-ion cells are cylindrical and prismatic cell. They are found in notebook computers and other portable power applications. Another approach, prismatic polymer Li-ion technology, is generally only used for small portable applications such as cellular phones and MP3 players. Rechargeable Li-ion batteries are commonly found in consumer electronic products, which make up most of the worldwide production volume of 10 to 12 GWh per year. Compared to the long history of lead-acid batteries, Li-ion technology is relatively new. There are many different Li-ion chemistries, each with specific power-versus-energy characteristics. Large-format prismatic cells are currently the subject of intense R&D, scale-up, and durability evaluation for near-term use in hybrid EVs, but are still only available in very limited quantities as auto equipment manufacturers gear up production of PHEVs.[60]

A Li-ion battery cell contains two reactive materials capable of undergoing an electron transfer chemical reaction. To undergo the reaction, the materials must contact each other electrically, either directly or through a wire, and must be capable of exchanging charged ions to maintain overall charge neutrality as electrons are transferred. A battery cell is designed to keep the materials from directly contacting each other and to connect each material to an electrical terminal isolated from the other material's terminal. These terminals are the cell's external contacts (see Figure 94).

[60] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits,* PI: Dan Rastler, EPRI ID 1020676, EPRI, Palo Alto, CA, September 2010.

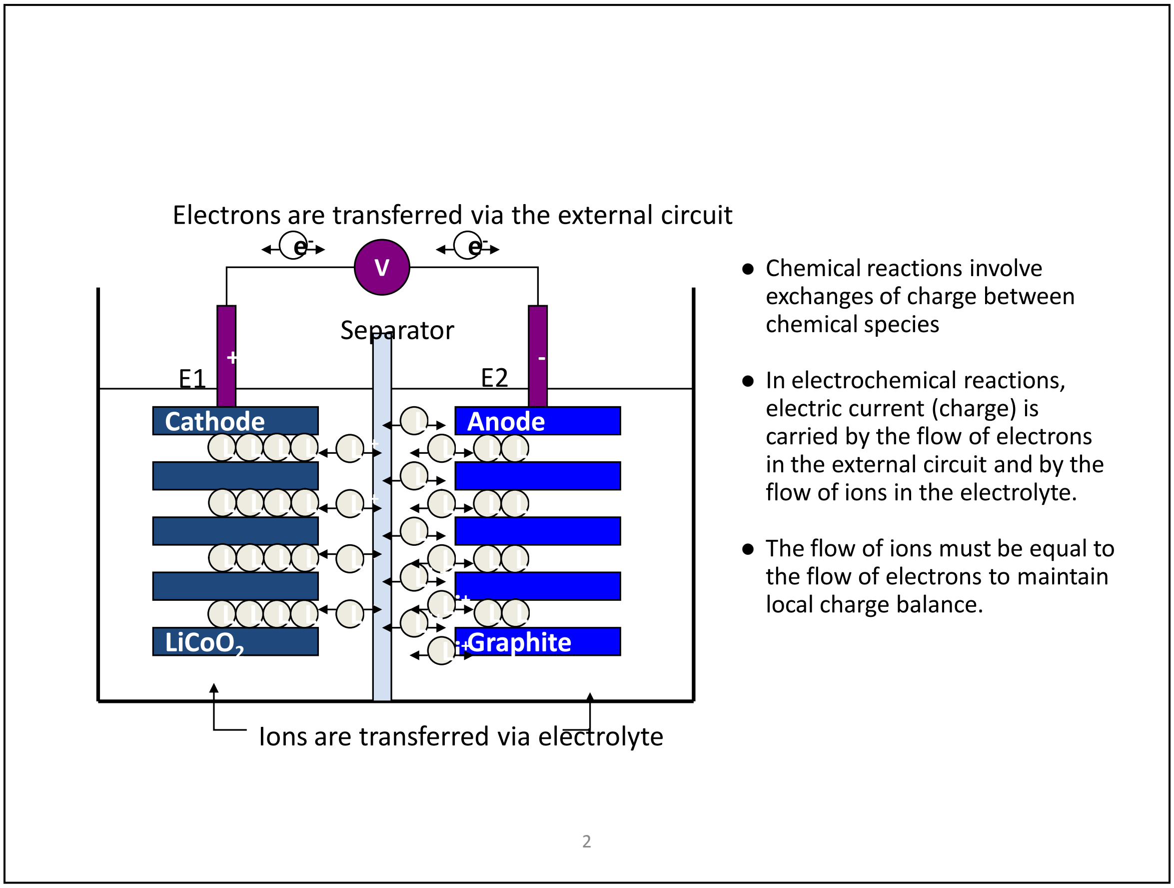


Figure 94. Principles of a Li-ion Battery

Inside the cell, the materials are ionically, but not electronically, connected by an electrolyte that can conduct ions, but not electrons. As shown in Figure 95, this is accomplished by building the cell with a porous insulating membrane, called the separator, between the two materials and filling that membrane with an ionically conductive salt solution. Thus this electrolyte can serve as a path for ions, but not for electrons. When the external terminals of the battery are connected to each other through a load, electrons are given a pathway between the reactive materials, and the chemical reaction proceeds with a characteristic electrochemical potential difference or voltage. Thus there is a current and voltage (i.e., power) applied to the load.[61]

Maturity and Commercial Availability

The large manufacturing scale of Li-ion batteries (estimated to be approximately 30 GWh by 2015) could result in potentially lower-cost battery packs – which could also be used and

[61] Ibid.

integrated into systems for grid-support services that require less than 4 hours of storage. Many stationary systems have been deployed in early field trials to gain experience in siting, grid integration, and operation. Li-ion systems dominate the current deployment landscape for grid-scale storage systems in the United States. Figure 96 illustrates some of the Li-ion energy storage system deployments underway that have accelerated in the past two years. The stars represent the most significant projects; several other Li-ion projects are underway elsewhere.

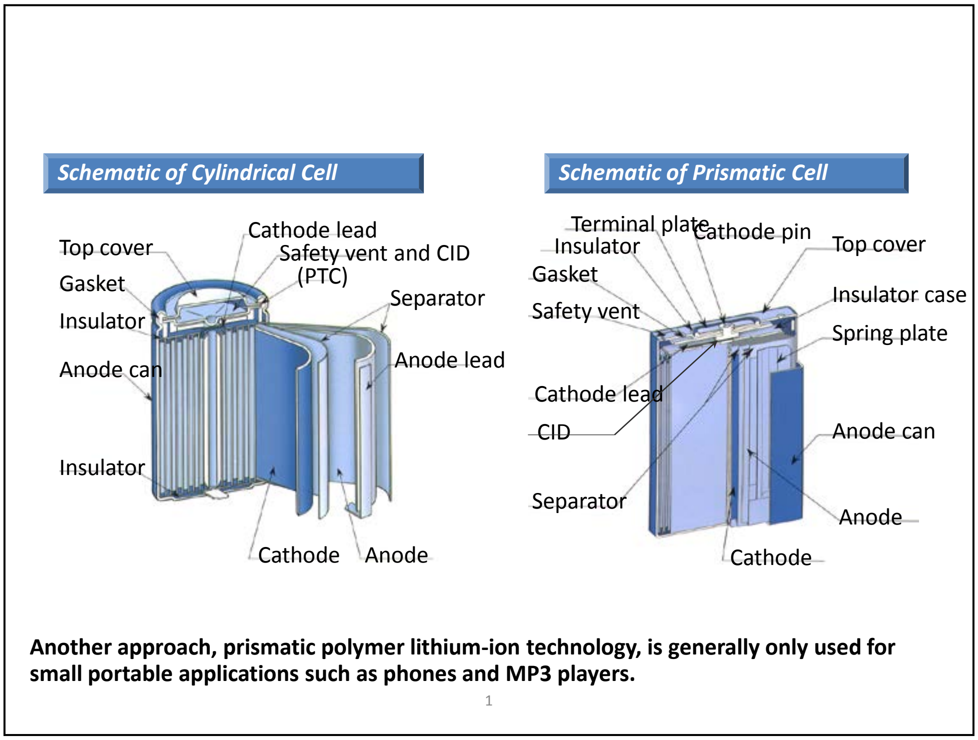


Figure 95. Illustrative Types of Li-ion Cells

Figure 96. Locations of Current and Planned U.S. Li-ion System Grid Demonstrations

Early system trial demonstrations are underway using small 5- to 10-kW/20-kWh distributed systems and large 1-MW/15-minute fast-responding systems for frequency regulation. Several electric utilities are also planning to deploy Distributed Energy Storage Systems (DESSs) in the 25- to 50-kW size range on the utility side of the meter with energy durations ranging from 1 to 3 hours. Some systems have islanding capability, which can keep homeowners supplied with power for 1 to 3 hours if the grid goes down. Several customer-side-of-meter commercial and residential applications are also underway. The first large commercial peak-shaving system (2 MW/4 MWh) has been deployed by Chevron Energy Solutions. AES Energy Storage LLC has deployed more than 50 MW of systems as an independent power producer (IPP) for frequency regulation and spinning reserve services. Utilities are also deploying megawatt-scale units for PV integration and distribution grid support. In addition, several vendors are implementing small residential energy storage systems that when aggregated could provide system and utility benefits. In total, more than an estimated 100 MW of grid-connected advanced Li-ion battery systems have been deployed for demonstration and commercial service.

Several representative Li-ion systems from different suppliers are shown in Figure 97, Figure 98, and Figure 99. Two residential systems are shown in Figure 100. On the left is a 5-kW/7.8-kWh residential energy storage system installed at Sacramento Municipal Utility District's Anatolia all SolarSmart Homes development. The suppliers are Silent Power, GridPoint, and SAFT. On the right is a 2.7-kW 10.8-kWh system supplied by Sunverge Energy with smart grid software that enables aggregation of many units allowing utilities, end users, or third parties to buy and sell electricity and manage energy needs based on individual interests.

Figure 97. AES Storage LLC's Laurel Mountain Energy Storage
(Supplies 32 MW of regulation in PJM using Li-ion batteries supplied by A123 Systems)

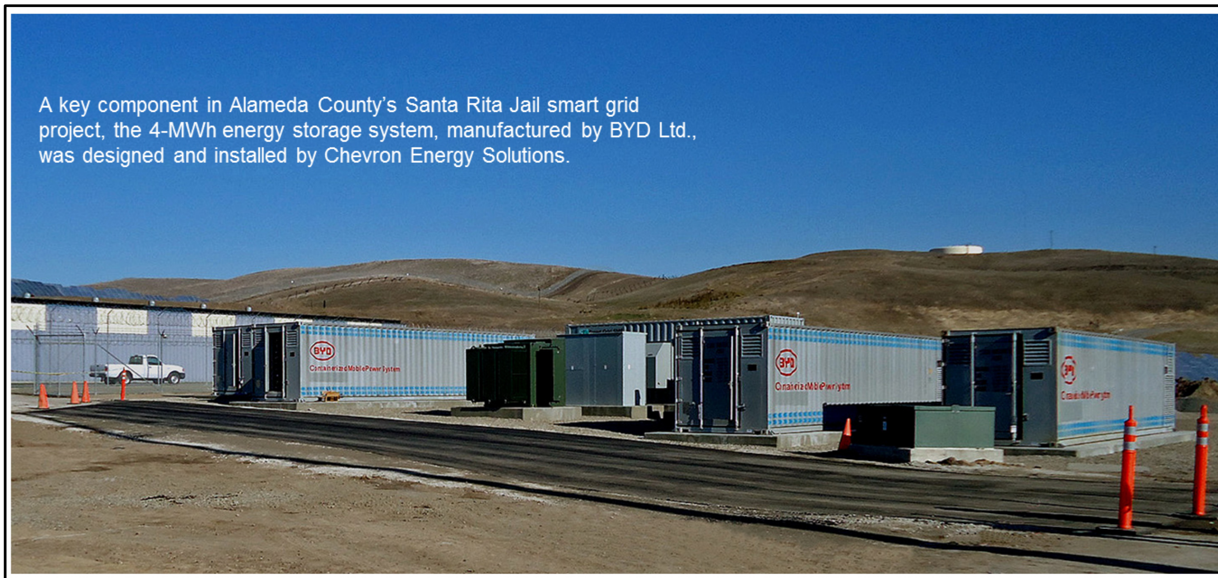


Photo courtesy of Chevron Energy Solutions Company

Figure 98. A 2-MW/4-MWh Li-ion Energy Storage System

Figure 99. A 30-kW/34-kWh Distributed Energy Storage Unit
(Being Installed and Inspected at the Sacramento Municipal Utility District's Anatolia SolarSmart Homes Development. Suppliers are SAFT, Grid Point, and Power Hub)

Figure 100. Residential Energy Storage and Energy Management Systems

Table 16 presents a technology dashboard for Li-ion battery systems for stationary grid services.

Table 16. Technology Dashboard: Lithium-ion Battery Systems

Technology Development Status	Demonstration C	Systems verified in several field demonstrations in a variety of use cases.
Confidence of Cost Estimate	C	Vendor quotes and system installation estimates.
Accuracy Range	C	-20% to +10%
Operating Field Units	32 MW in frequency regulation service 0.5 MW/1 MWh 25-50 kW/2 hr	Numerous small demonstrations in the 5-kW to 25-kW sizes are currently underway. MW-scale short-energy-duration systems are being operated in frequency regulation applications. MW class for grid support and PV smoothing being introduced 2-MW/4-MWh system installed in an end-use customer peak shaving application
Process Contingency	10-15% Depends on chemistry	Battery management system, system integration, and cooling need to be addressed. Performance in cold climate zones needs to be verified.
Project Contingency	5-10%	Limited experience in grid-support applications, including systems with utility grid interface. Uncertain cycle life for frequency regulation applications.

Li-ion Batteries Life-Cycle Cost Analysis

Life-cycle cost analysis of selected systems is illustrated in Figure 101 through Figure 112 for each application. The estimates are based on capital, O&M data, and battery replacement costs from the Li-ion data sheets. A simple dispatch was assumed for bulk, utility T&D, C&I energy management, and residential energy management. Life-cycle estimates are based on IOU financial assumptions of 365 cycles annually for 15 years.

For the frequency regulation applications, a simple dispatch was assumed based on each system operating 5000 cycles per year.

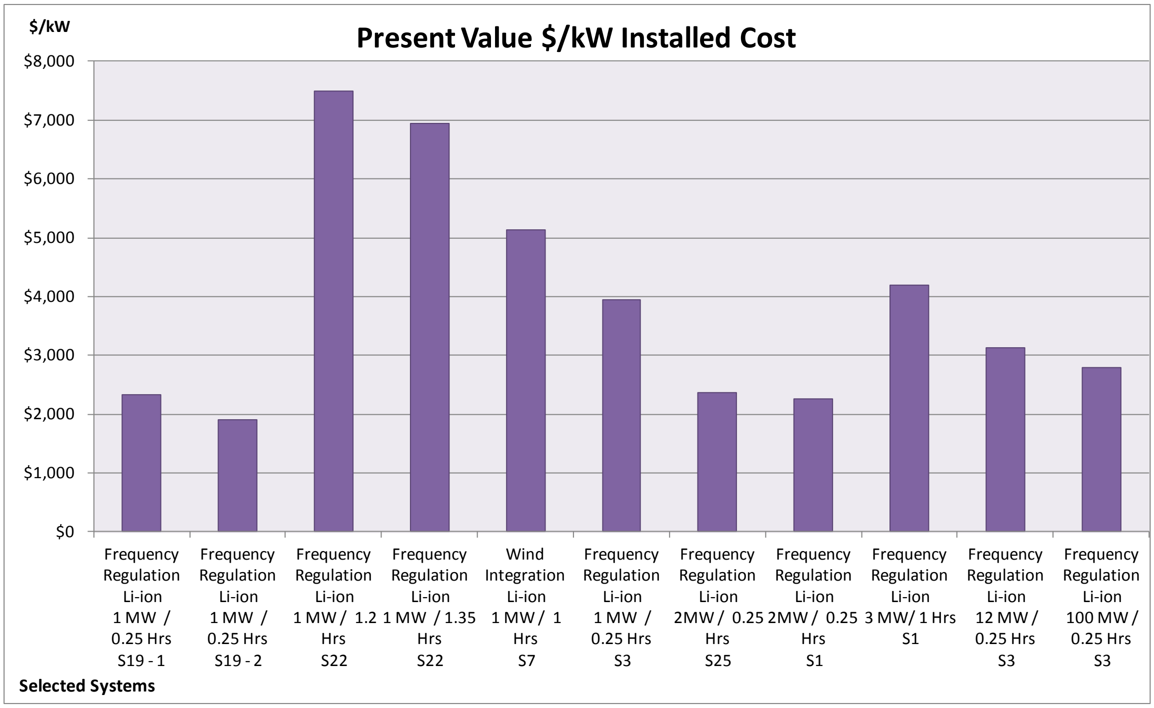


Figure 101. Present Value Installed Cost in $/kW for Li-ion Batteries in Frequency Regulation and Renewable Integration Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

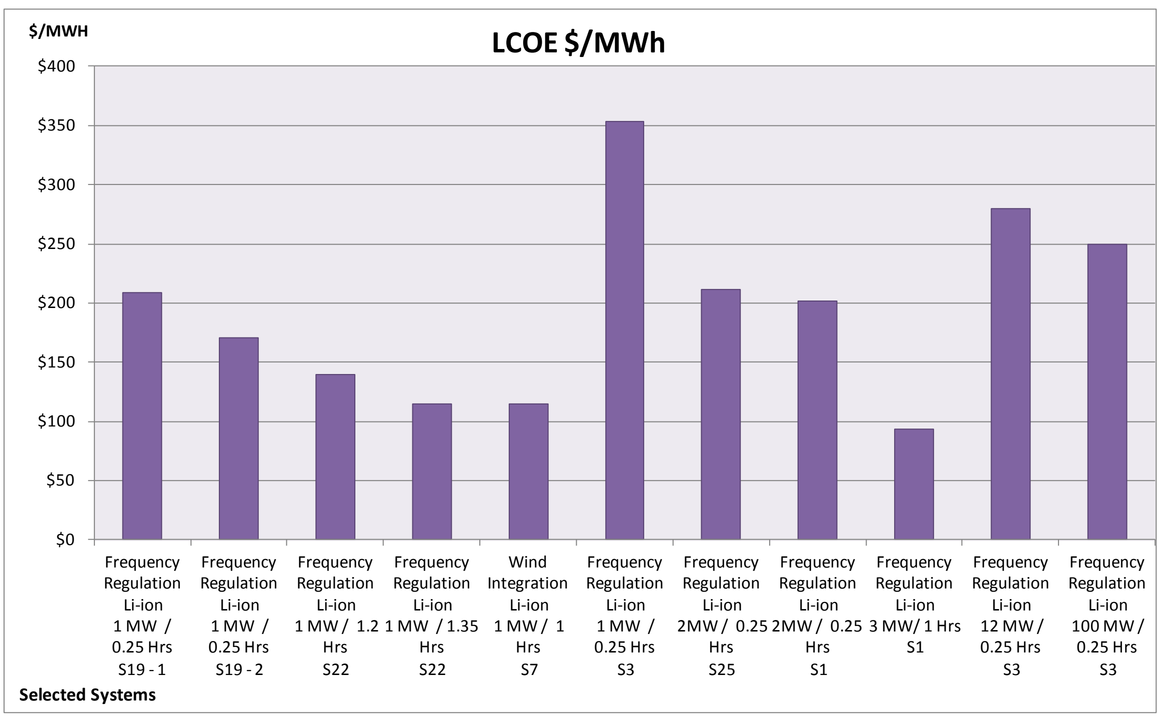


Figure 102. LCOE in $/MWh for Li-ion Batteries in Frequency Regulation and Renewable Integration Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

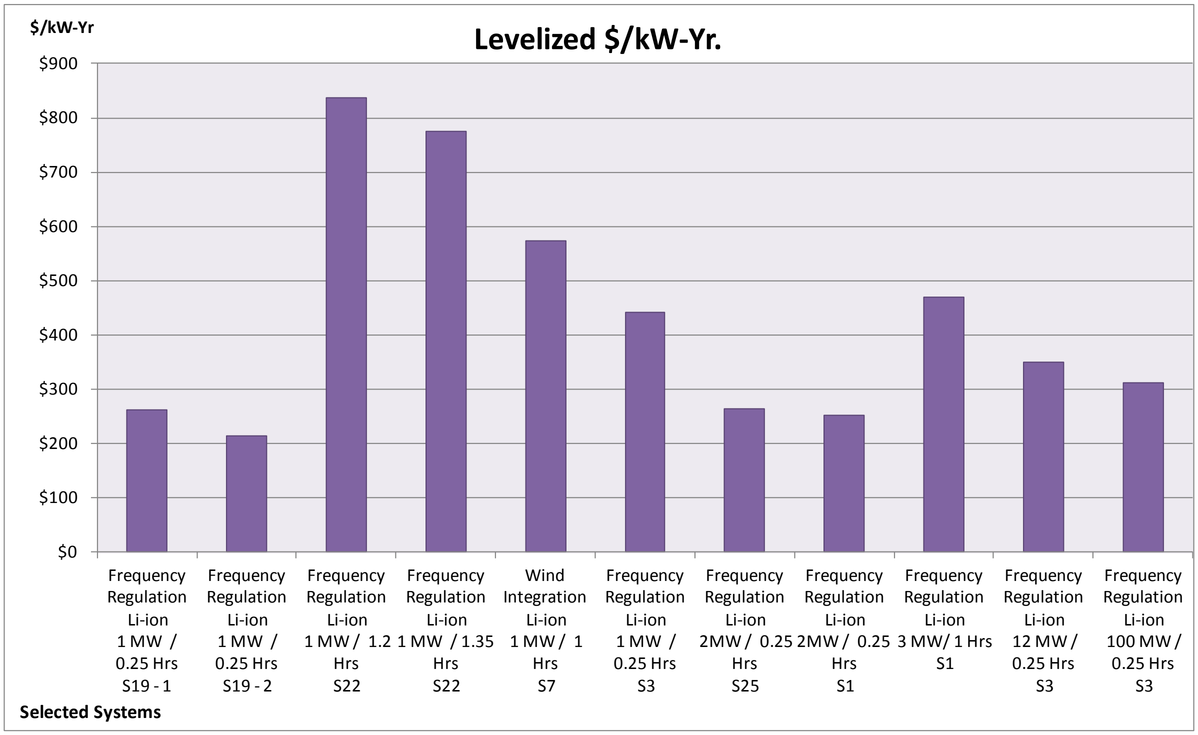


Figure 103. Levelized $/kW-yr for Li-ion Batteries in Frequency Regulation and Renewable Integration Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

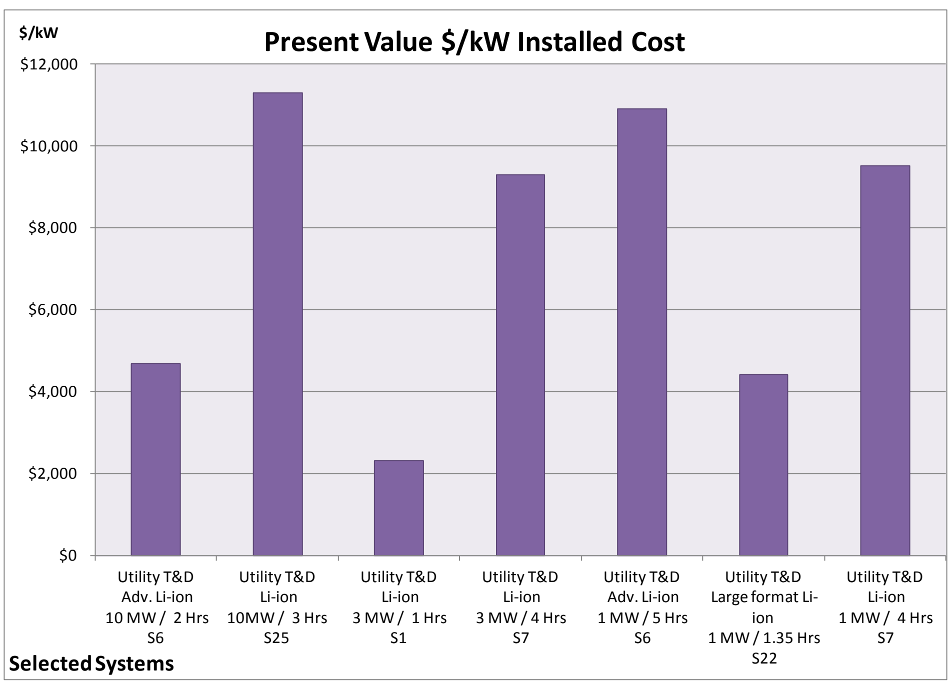


Figure 104. Present Value Installed Cost in $/kW for Li-ion Batteries in Transmission and Distribution Applications
(The S designation under each bar is a vendor code that masks the identity of the vendor.)

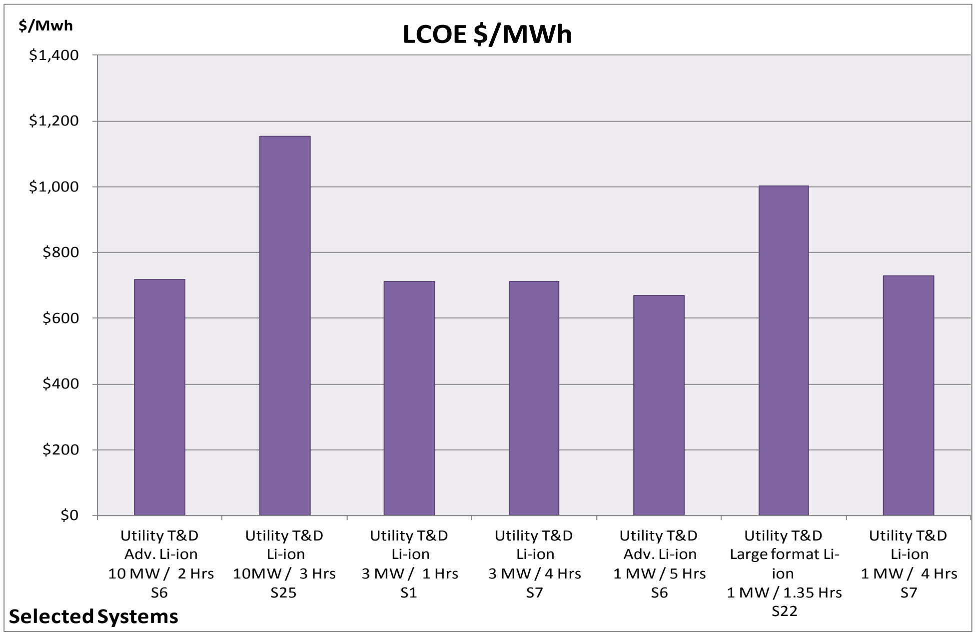


Figure 105. LCOE in $/MWh for Li-ion Batteries in Transmission and Distribution Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

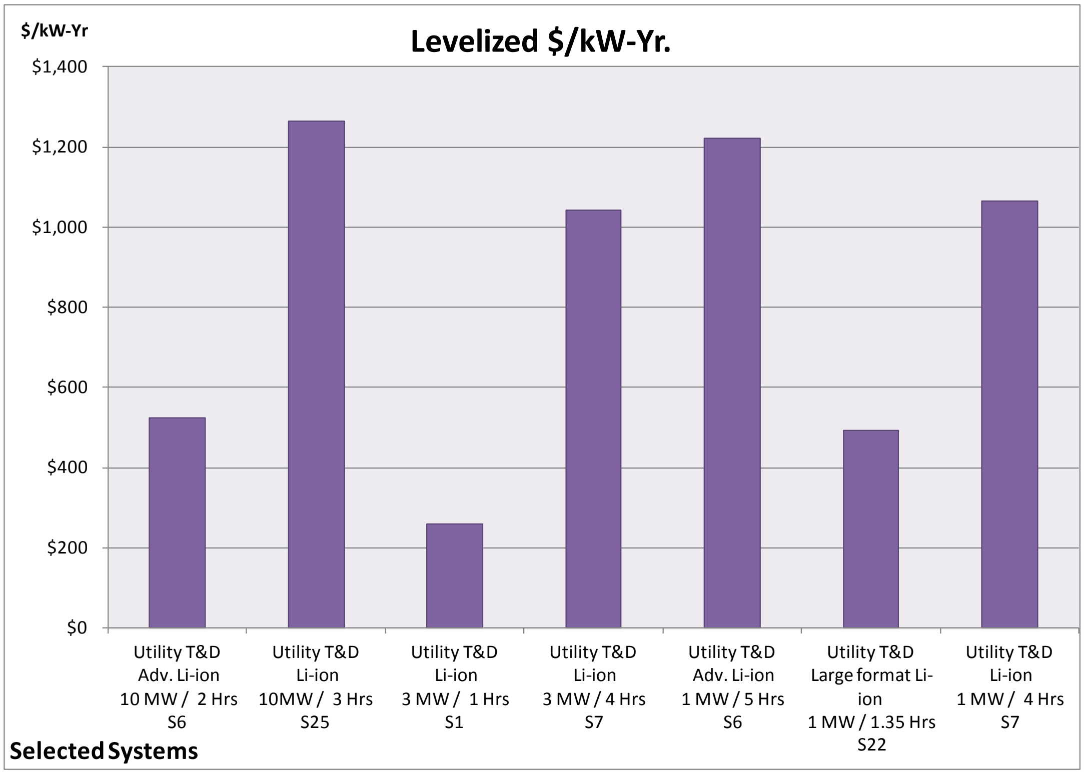


Figure 106. Levelized $/kW-yr for Li-ion Batteries in Transmission and Distribution Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

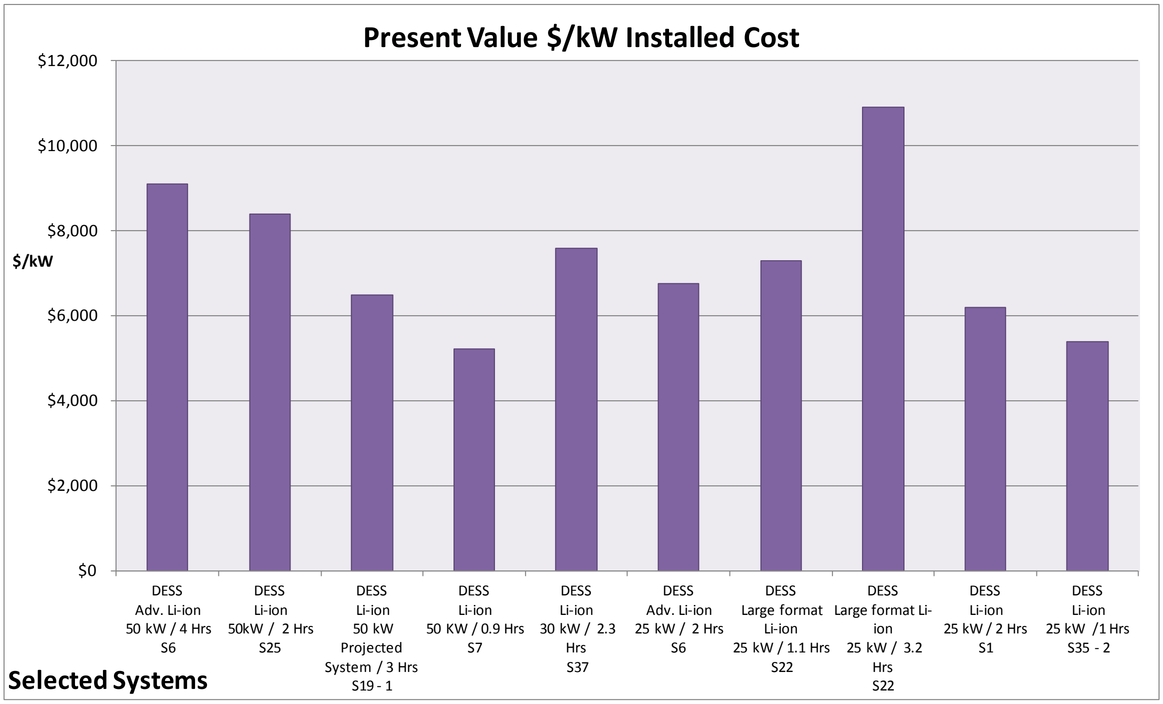


Figure 107. Present Value Installed Cost in $/kW for Li-ion Batteries in Distribute Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

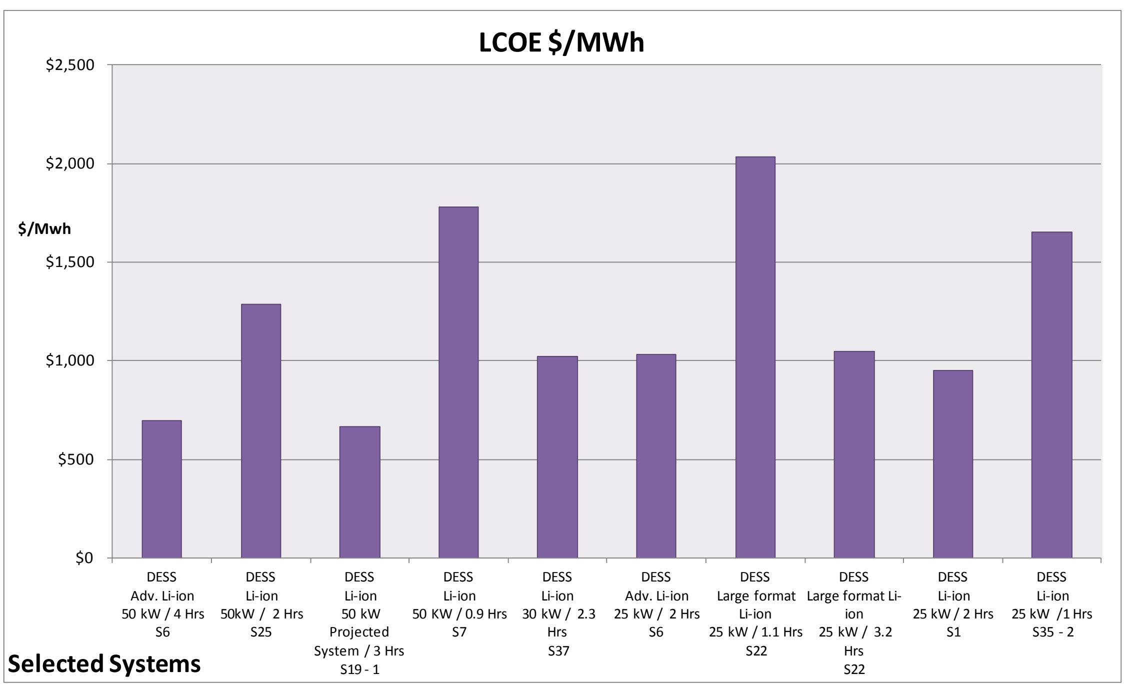


Figure 108. LCOE in $/MWh for Li-ion Batteries in Distribute Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

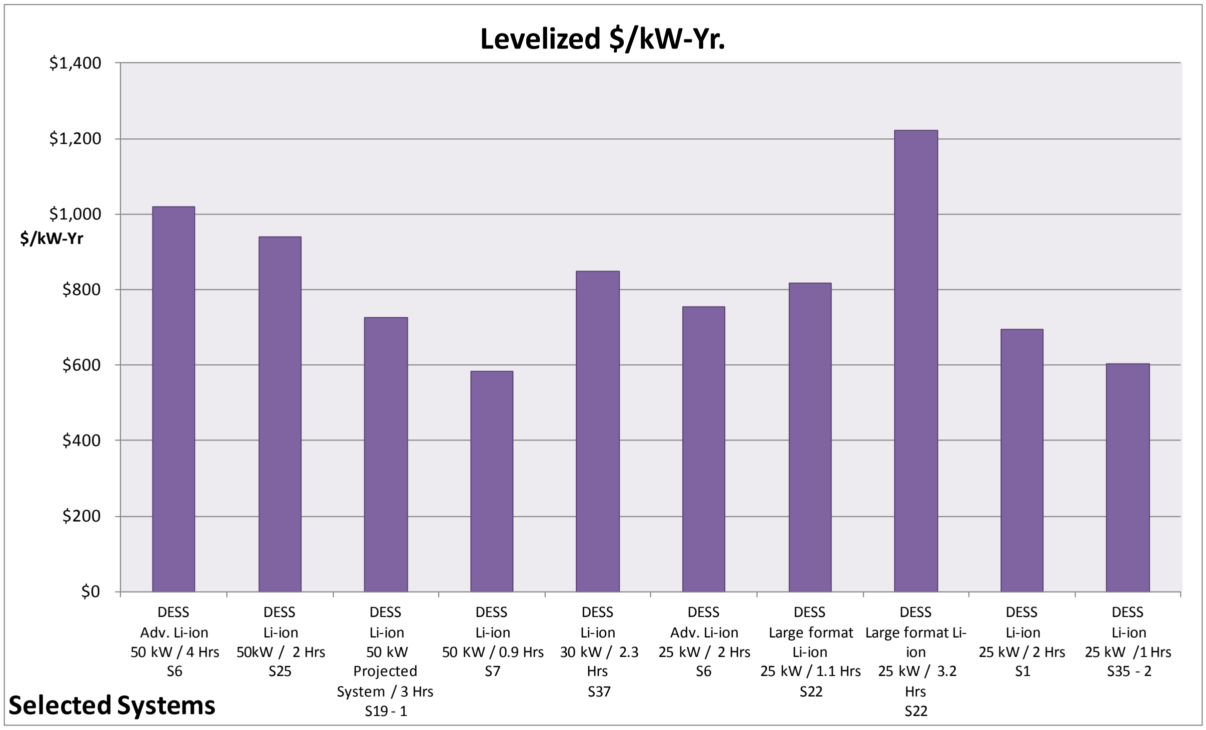


Figure 109. Levelized $/kW-yr for Li-ion Batteries in Distribute Energy Storage System Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

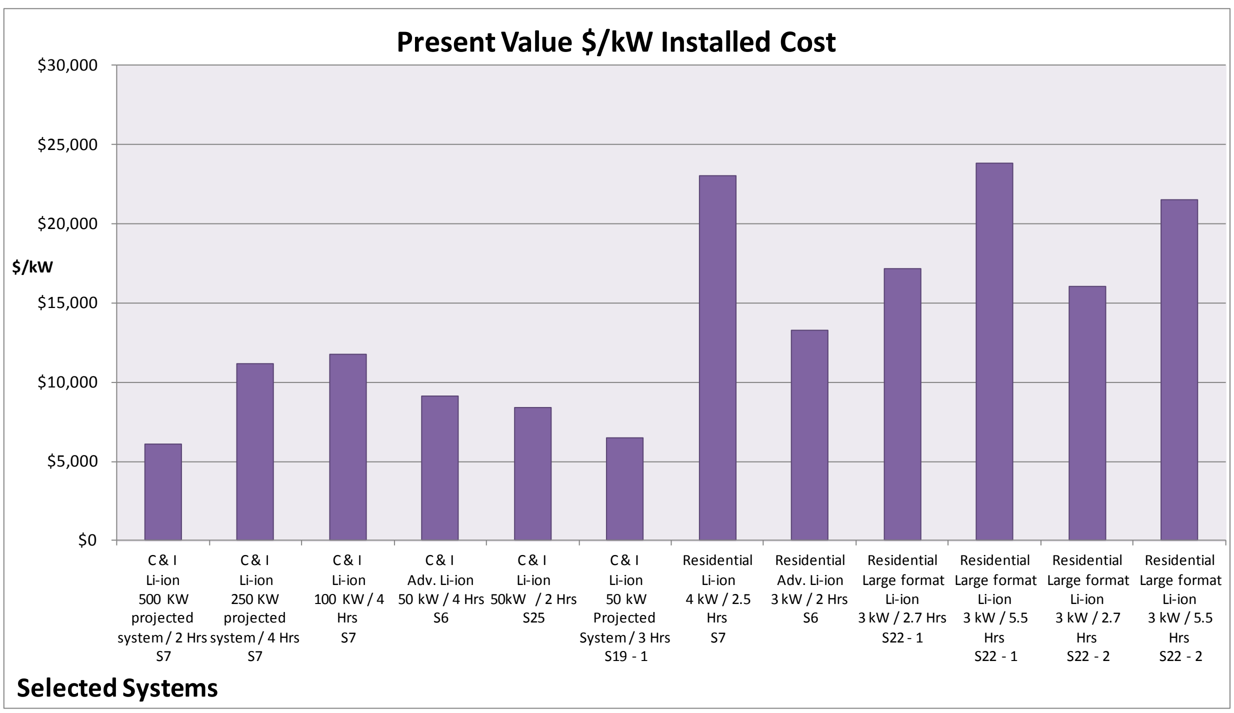


Figure 110. Present Value Installed Cost in $/kW for Li-ion Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

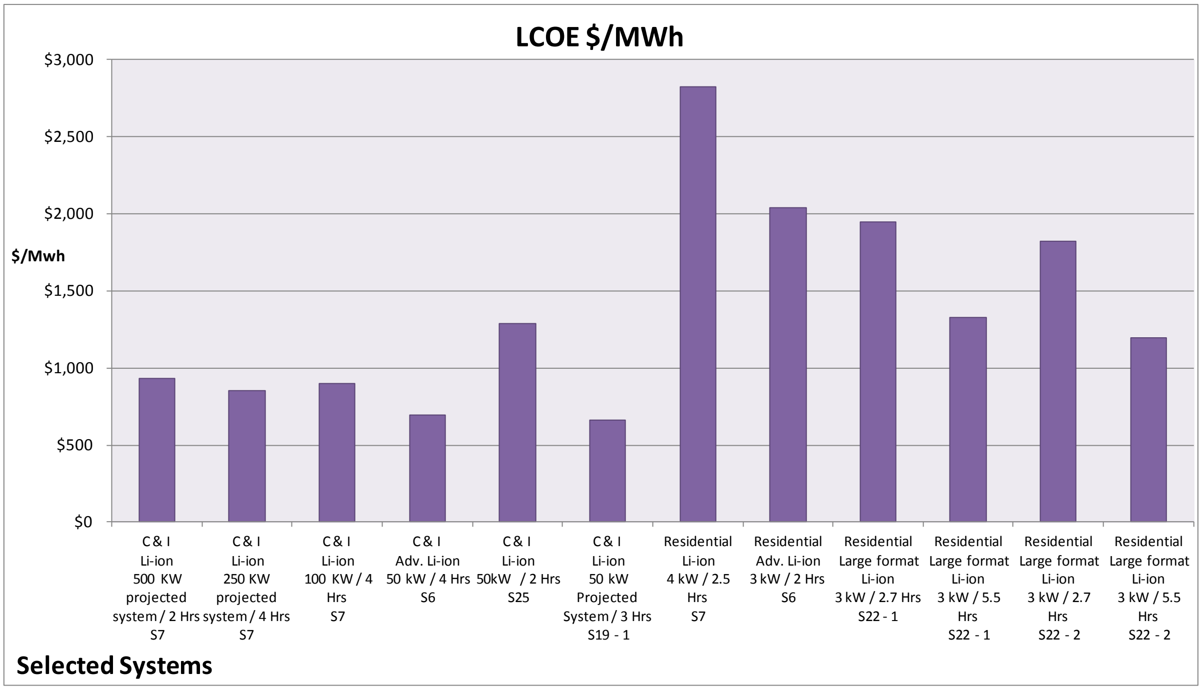


Figure 111. LCOE in $/MWh for Li-ion Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)

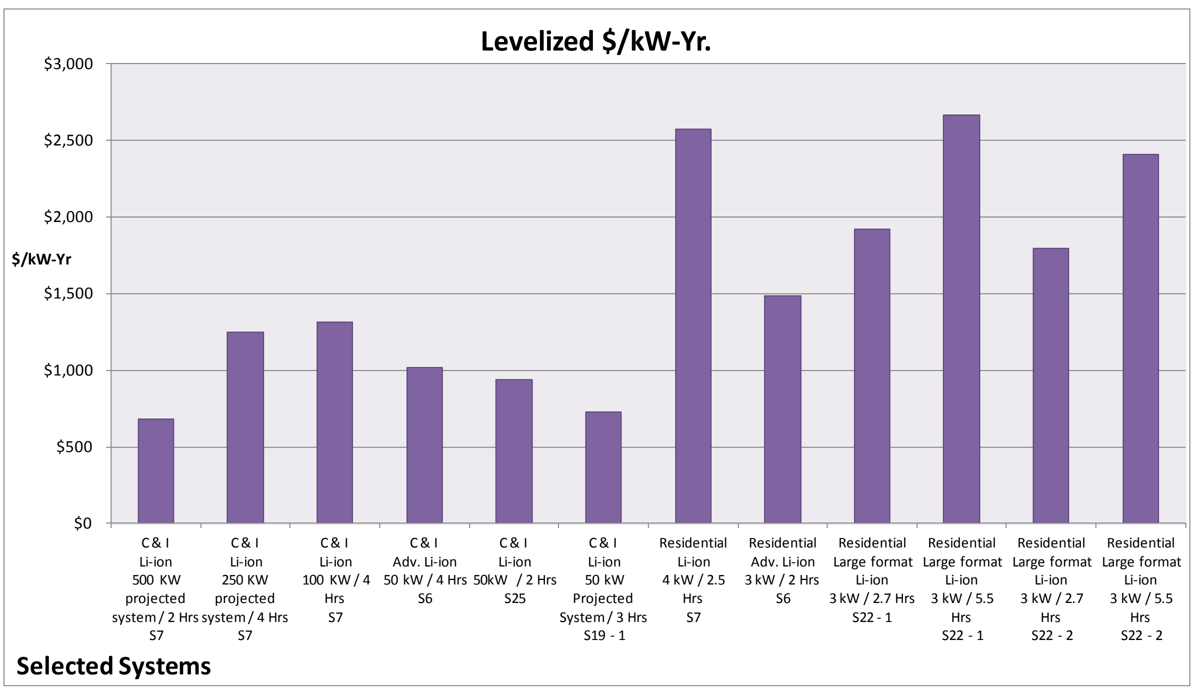


Figure 112. Levelized $/kW-yr for Li-ion Batteries in Commercial and Industrial Applications

(The S designation under each bar is a vendor code that masks the identity of the vendor.)
(All system costs are based on 5000 cycles per year)

Additional Resources for Li-ion Batteries

1. *Technical Specification for a Transportable Energy Storage System for Grid Support Using Commercially Available Li-ion Technology*, EPRI ID 1025573, EPRI, Palo Alto, CA, July 2012.
2. *Demonstration Initiative for a Grid Support Storage System using Li-ion Technology: Phase I Report*, EPRI ID 1025574, EPRI, Palo Alto, CA, August 2012.
3. *Electricity Energy Storage Technology Options*, EPRI ID 1020676, EPRI, Palo Alto, CA, December 2010.

2.15 Emerging Technologies

There are many other types of energy storage technologies, both mature and still in the R&D phase, that are not discussed in this report. Nickel-cadmium and nickel metal hydride (NiMH) batteries are mature and suitable for niche applications. Innovation and R&D continues in many other emerging storage technology options. Stages of R&D and timelines and field deployment timing are summarized in Table 17.

Table 17. Emerging Storage Options Research and Development Timelines for Emerging Energy Storage Options

Storage Type	Status/Innovation	Estimated Deployment Timing
Liquid Air Energy Storage Systems	System studies. Low-cost bulk storage. Small demos underway.	2013-2014 first +MW-scale demo.
Non/Low-Fuel CAES	System studies underway to optimize cycle and thermal storage system. Low-fuel and non-fuel CAES for bulk storage.	2015 pilot demonstration of 5-MW system
Underground Pumped Hydro	System studies. New concepts under development.	Under study.
Nano-Supercapacitors	Laboratory testing. High power and energy density; very low cost.	2013-2015
Advanced Flywheels	System studies. Higher energy density.	Under development. 2015.
H_2/Br Flow	Bench-scale testing. Low-cost storage.	2013-2014 pilot demo.

Storage Type	Status/Innovation	Estimated Deployment Timing
Advanced Lead-Acid Battery	Modules under test. Low cost; high-cycle life.	2013-2015 early field trials.
Novel Chemistries	Bench-scale testing. Very low cost; long-cycle life.	2013-2015 modules for test.
Isothermal CAES	2 MW and 1 MW System Development and Demonstration effort. Non-fuel CAES for distributed storage.	2013 pilot system tests.
Advanced Li-ion Li-air and others	Laboratory/basic science. Lower costs; high energy density.	2015-2020

CHAPTER 3. METHODS AND TOOLS FOR EVALUATING ELECTRICITY STORAGE

3.1 Characteristics of Electricity Storage Systems

There is a fundamental difference in the operational characteristics of traditional generation sources and electricity storage systems operating on the grid. Traditional generation always sends power one way, whereas electricity storage systems require a two-way power flow to function, both charging and discharging states. Other characteristics of storage systems add to this complexity. First, the charging energy could come from a single source or a variety of sources based on the generation portfolio of the grid as a whole; this characteristic could and does change over time. Second, smaller storage could be located anywhere within the grid. While large storage resides on the transmission side, smaller systems could be embedded deep in the T&D network, creating both opportunities and grid integration impacts and concerns. Third, the inherently fast response times measured in fractions of a cycle is its strength and weakness in estimating its value. This characteristic creates a fairly complex computational task for tools and computer models that are required to analyze the financial and technical performance of electricity storage in the grid. Finally, a single storage system could provide multiple services to the grid. Stacking, as this characteristic is called, creates its own set of computational complexities for even robust models.

3.2 Evaluating Electricity Storage Systems

Given these characteristics, a generalized approach for evaluating energy storage includes:

- Assessing storage requirements and value originating from the locational needs of grid operators and planners;
- Avoiding conflation or double-counting of benefits;
- Drawing a distinction between quantifiable and monetizable services and direct and incidental benefits;
- Delaying resource-intensive production simulation analyses until after technically feasible, cost-effective use cases are identified; and
- Delaying deep investigation of policy and regulatory scenarios until after technically sound cost-effectiveness cases are identified and impacts modeled.

The following methodology[62] provides a framework for evaluating electricity storage with the steps described below. Figure 113 provides a visual representation of the evaluation framework.

[62] "*Bulk Energy Storage Value and Impact Analysis: Proposed Methodology and Supporting Tool*," EPRI, EPRI ID: 1024288, Palo Alto, CA, December 2012.

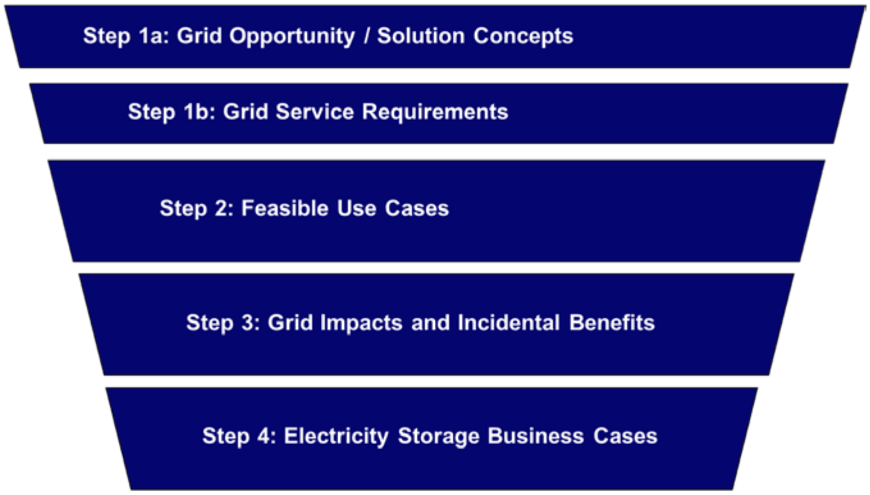


Figure 113. Steps in Electricity Storage Evaluation
(Source: EPRI)

3.2.1 Step 1a: Grid Opportunity/Solution Concepts ("What Electricity Storage Can Do")

Figure 114 illustrates Step 1a.

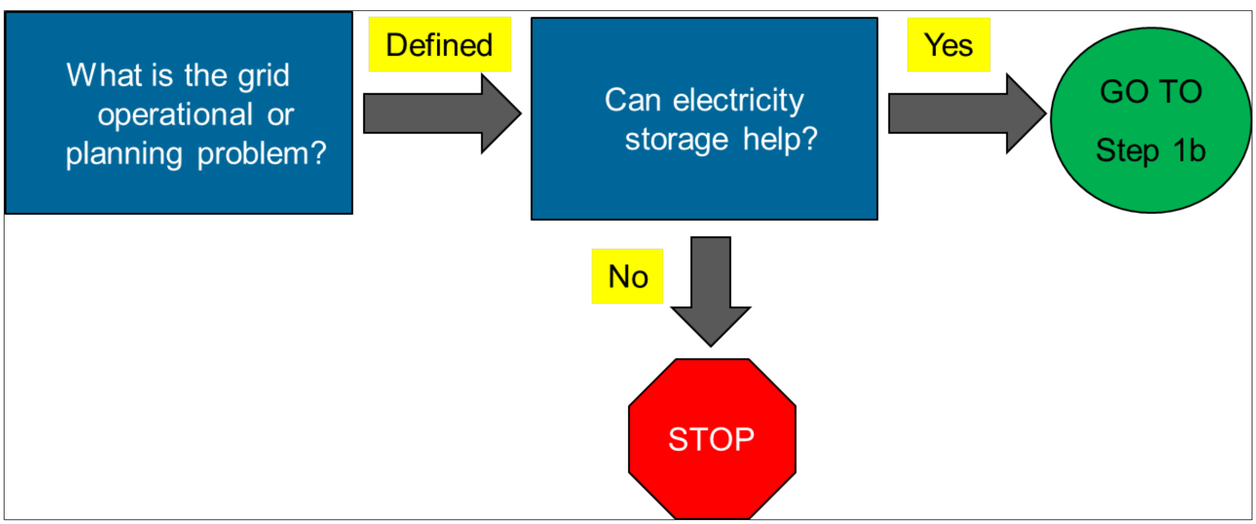


Figure 114. Decision Diagram for Step 1a: Opportunity/Solution Concepts
(Source: EPRI)

3.2.1.1 What Is the Grid Operational or Planning Problem?

Grid operational or planning problems can be anything from a congested transmission line, a sharp load peak, an outage, voltage deviation caused by increased penetration of renewable resources, etc. Some of the services that help relieve those issues are formally categorized in ancillary services and can be procured through markets. Others are site-specific issues that require a unique solution.

3.2.1.2 Can Electricity Storage Help?

Electricity storage fundamentally can store, and later release, energy, effectively moving energy from one time period to another (with losses). When technical and economic opportunities can be created by shifting energy over time periods ranging anywhere from seconds to days (or even seasons), then electricity storage may have value. Additionally, the power electronics in battery systems may have fast response and ramp capability and the ability to operate at non-unity power factors, which can be used to change ac voltage. These characteristics may provide additional opportunities to provide ancillary services, like frequency regulation and voltage support.

The first step of the exploration is to ask the questions: "What is the grid operational or planning issue?" and "Do the unique attributes of storage provide a potential solution?" If the answer is "yes", the second part of the first step is to define the problem and solution with additional technical rigor in Step 1b.

3.2.2 Step 1b: Define Grid Service Requirements (What Must Be Accomplished)

A high-level decision diagram for Step 1b of the methodology is shown in Figure 115.

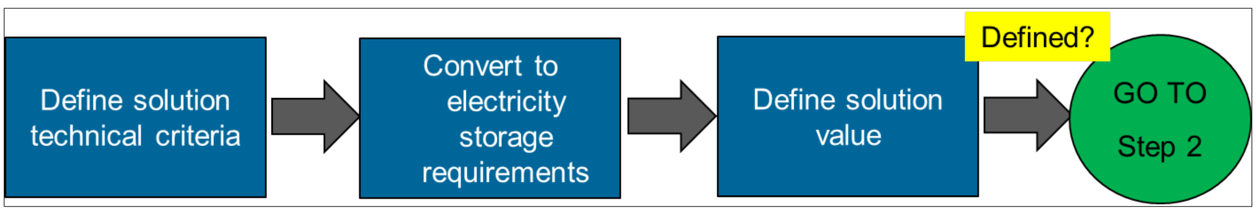


Figure 115. Decision Diagram for Step 1b: Define Grid Service Requirements
(Source: EPRI)

3.2.2.1 Define Solution Technical Criteria

After identifying a conceptual improvement or solution that electricity storage can provide, the next analytical step is to define the grid issue technically and the technical requirements for its resolution. There has historically been some confusion over the terms grid service and application and the terms 'grid service' and 'application' are sometimes used interchangeably. Grid service is used here to indicate that this step considers grid-defined operating requirements and benefits, rather than application of a specific resource.

Convert to Electricity Storage Requirements

Communicating with key stakeholders and decision-makers is critical to determining the appropriate metrics, the minimum operating criteria, and the best available alternative (non-storage) solution to the problem. The technical criteria for an electricity storage-based option can then be determined based on the case-specific information available, including load shapes, market participation rules, generation costs and other time-varying and static characteristics relevant to the grid service under investigation.

3.2.2.2 Define Solution Value

The value of the electricity storage solution can be calculated based on the avoided cost or expected revenue from the chosen grid service. This may require using engineering tools to identify the efficacy of both the electricity storage and the alternative solution to the problem in question. However, the method will be dependent on the grid service under investigation. It may also be considered and documented if either the electricity storage solution or the alternative exceeds the minimum requirements of the service, which may warrant an adjustment in the value of the electricity storage option.

3.2.3 Step 2: Feasible Use Cases

Figure 116 illustrates the generic process for Step 2: Feasible Use Cases.

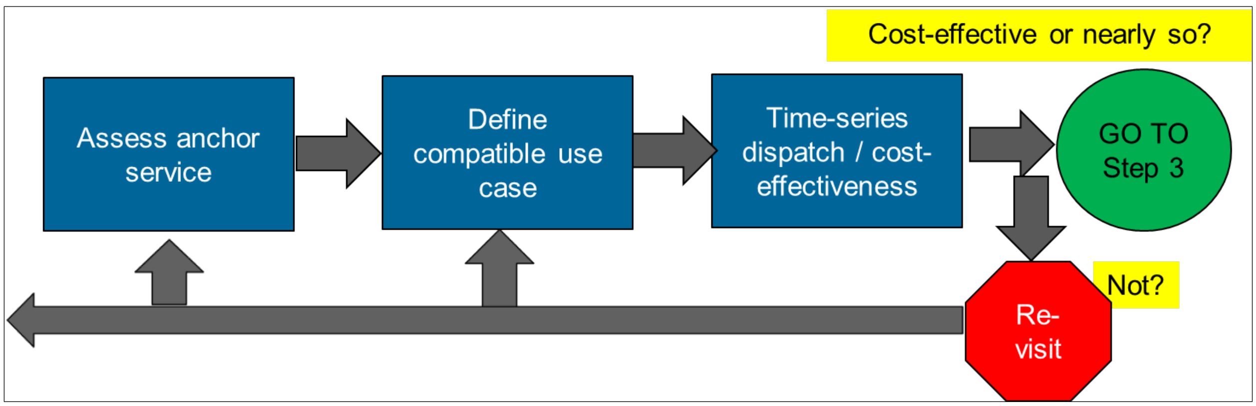


Figure 116. Decision Diagram for Step 2: Feasible Use Cases
(Source: EPRI)

3.2.3.1 Assess Anchor Service

A use case is a technically feasible and monetizable combination of grid services at a particular location. Electricity storage use cases often contain a service of disproportionately high value, which is called anchor service in this course. After requirements have been determined for the anchor grid service in Step 1b, storage technology and configuration options can be investigated. The relative value of the anchor service may then be investigated for different electricity storage options of interest. Assessing the intended anchor service prior to adding additional services may be of value.

In some cases, an anchor service may have location-specific value. For example, the value of providing a distribution upgrade deferral depends on the investment size, load growth rate, and the frequency and duration of peak load events, all of which are unique to each location. In contrast, frequency regulation service may typically be provided from many locations within a region that operates in a synchronous manner (subject to transmission constraints). The electricity storage utilization and value of this anchor service could be estimated with certain operational assumptions or simulated using a time-series simulation.

Typically, a benefit that is 25% to 50% or more of the total storage system cost is a rule of thumb for declaring the potential of a grid service to be an anchor service.

3.2.3.2 Define Compatible Use Case

After the anchor service has been assessed and chosen for further investigation, other compatible grid services, also called secondary services may be considered. Compatibility assessment should occur across multiple dimensions:

- Joint satisfaction of minimum requirements,
- Timing of service (identical, overlapping, or non-overlapping timing), and
- Flexibility of additional services (long-term or short-term commitment?)

3.2.3.3 Joint Satisfaction of Minimum Requirements

The minimum capacity, duration, ramp rate, etc., required to perform the grid services of interest must all be met by the electricity storage system. The secondary services may require longer duration of available storage, or faster response, or another operational parameter that was not considered in the anchor service. If the minimum requirements for the secondary services add significant incremental cost, then the cost of improved electricity storage performance should be reconsidered against the incremental value expected. Identifying additional services for which the initial storage configuration satisfies all minimum requirements is the most beneficial outcome. Failing that, if the upgrade cost of the storage system is lower than the incremental benefit of adding the service, the secondary service may still be considered.

3.2.3.4 Frequency and Duration of Grid Services

The second issue of use-case compatibility is the timing of grid services. The timing and expected operation may coincide identically, overlap, or be non-overlapping in nature. Take, for example, a use case for which electricity storage could be jointly used to shave the transmission transformer peak (transmission upgrade deferral) and the system peak (electric supply capacity). Consider the following three cases: Case 1, in which the transformer and system peaks both occur from 2 p.m. to 6 p.m.; Case 2, in which the transformer peak is from 12 p.m. to 4 p.m. and the system peak is from 2 p.m. to 6 p.m.; and Case 3, in which the transformer peak is from 10 p.m. to 2 a.m. and the system peak is from 2 p.m. to 6 p.m.

In Case 1, shown in Figure 117, the effect of the additional electric supply capacity service to the transmission investment deferral anchor service may be minor, because the storage is performing double duty with a single dispatch, simultaneously unloading a transformer and providing peak generation. (Note that perfect correlation is unlikely between multiple services; this example illustrates an ideal case.)

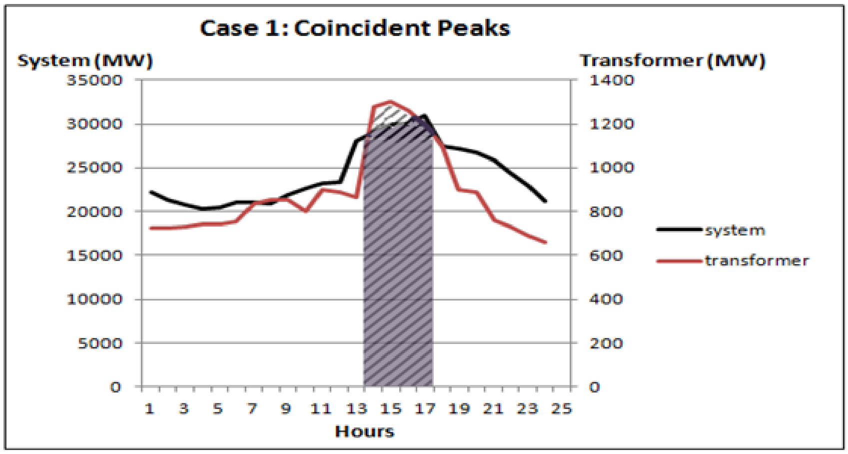


Figure 117. Case 1: Coincident Transformer and System Load Peaks
(Source: EPRI)

In Case 2, shown in Figure 118, the loads are overlapping but not completely coincident (as they were in Case 1). As a result, the cumulative peak that would need to be shaved to satisfy both the transmission investment deferral and system capacity services has now increased from approximately 4 hours to 6 hours, necessitating additional electricity storage duration to accomplish both services.

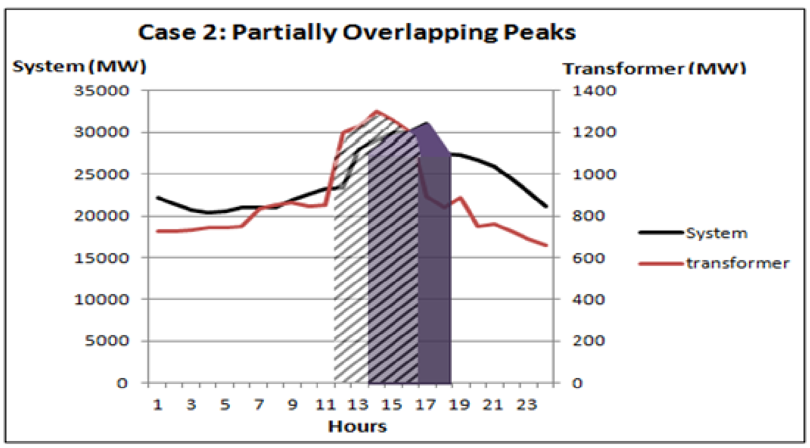


Figure 118. Case 2: Partially Overlapping Transformer and System Load Peaks
(Source: EPRI)

Finally, in Case 3, shown in Figure 119, the peaks are fully non-coincident. As a result, it may be possible to accomplish both services by charging the electricity storage system between the peaks. Therefore, the electricity storage system may not require additional duration, but could require a technology with improved capability for multiple charge-discharge cycles per day. This scenario is possible for situations in which a transformer serves industrial or irrigation loads, which may be timed to coincide with off-peak system hours when these customer time-of-use tariffs charge a low retail price of electricity.

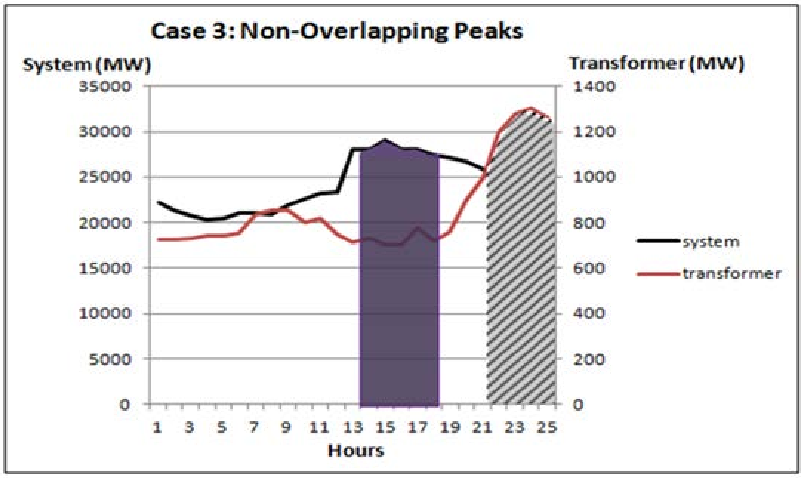


Figure 119. Case 3: Non-overlapping Transformer and System Load Peaks
(Source: EPRI)

3.2.3.5 Hierarchy for Grid Services

Flexibility measured in terms of frequency, duration, and term of commitment is an important consideration for adding secondary grid services to a use case. Certain grid services, such as transmission upgrade deferral, are inflexible. If electricity storage is installed to offset load growth on a transformer, a high degree of availability is required because it is being relied upon in lieu of a capital upgrade. System electric supply capacity may be somewhat more flexible, because there is a greater diversity of resources available to provide capacity within the bulk electricity system. However, capacity payments are often made on a monthly or yearly basis for resource availability during the system peak and penalized when not available. Therefore the flexibility is still relatively low, compared to service that can be committed the day before or even closer to the period of performance. Energy and ancillary service scheduling typically occurs in the day-ahead or real-time, so these services are significantly more flexible and should be easier to add to a use case. When adding two services together, the storage system should always try to meet the operation requirements for the less flexible service and then use the remaining capacity for the more flexible service. Sometimes this approach can lead the value of one service to decline when combined with another service.

When considering secondary grid services, consider the duration of commitment and the control requirements for providing each service, as well as the hierarchy of operation across multiple services. For some technologies, such as flywheels and short-duration batteries, there may not be many choices in what services can be provided. Realistically, due to their short duration, all flywheels and short-duration batteries may be able to provide are regulation services.

After screening for compatibility and value of multi-service use cases, revisit the initial storage system options considered for the anchor service. Optimization between use cases and storage system technology characteristics is currently an iterative process.

3.2.3.6 Time Series Dispatch/Cost-effectiveness

After choosing the use cases including the anchor grid service, compatible secondary services, and other electricity storage systems of interest, an analysis can be designed to quantify the benefits of grid service combinations, locations, and technologies. In some cases, a very simple analysis may be sufficient to screen out those cases with costs that are considerably higher than the benefits. However, due to the complexities of modeling limited energy resources and the importance of time-varying loads and values, more sophisticated tools may be required.

3.2.4 Step 3: Grid Impacts and Incidental Benefits

The summary-level process for Step 3 is displayed in Figure 120.

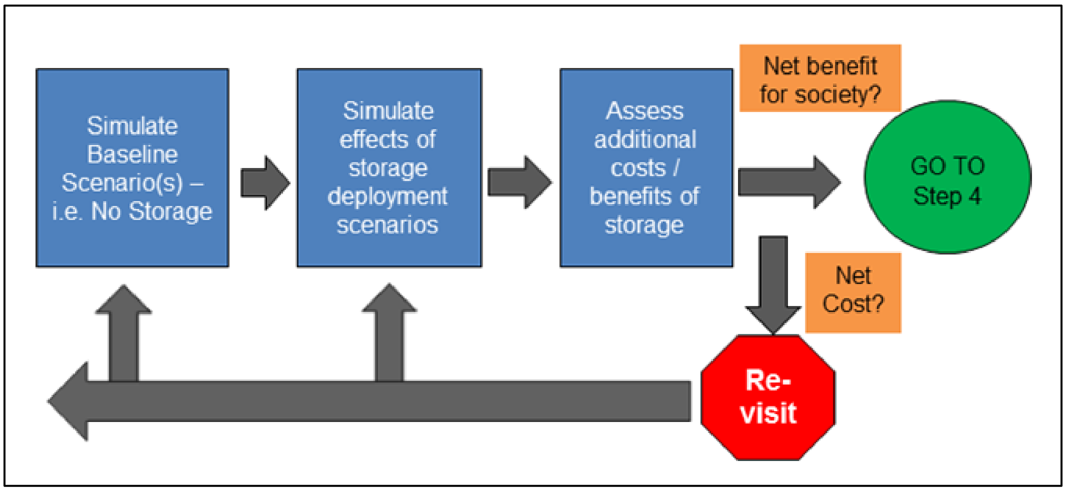


Figure 120. Decision Diagram for Step 3: Grid Impacts and Incidental Benefits
(Source: EPRI)

The purpose of Step 3: Grid Impacts and Incidental Benefits are to determine how the remaining electricity storage deployment scenarios affect system-wide metrics of cost, reliability, and external factors, including:

- Consumer costs,
- System flexibility,
- Transmission asset utilization and generator operation, and
- Environmental impacts, such as greenhouse gas (GHG) emissions.

Step 2 enabled the analyst to assess one or more technically feasible use cases to improve understanding of direct costs and benefits of a storage investment. Steps 1 and 2 may also enable conceptual understanding of how storage may impact the bulk electricity system. The analyst can then form hypotheses to test using production simulation tools, which have the regional perspective required to assess system impacts.

3.2.4.1 Assess Additional Costs/Benefits of Storage

The intent of Step 3 is to investigate impacts and incidental benefits or costs to the electricity system of electricity storage operation. Incidental benefits are not necessarily unintended, but they are not direct benefits explicitly addressed by the operation and control of the storage system. For example, the operation of storage may decrease GHG emissions by providing system capacity during peak demand periods and decreasing the usage of inefficient peaker combustion turbine units. However, if the storage is not directly dispatched with the objective of lower GHG emissions, then this is an incidental benefit. Operation of storage may actually increase the utilization of more carbon-intensive coal-fired base load generators, which could actually increase GHG emissions, but understanding the complex system relationships requires a production simulation. In summary, incidental benefits may result from a combination of the electricity storage system dispatch and other characteristics of the electric system.

If the production simulation shows a significant deviation in energy and AS prices compared to the inputs used in Step 2, the analyst should update the inputs and rerun the price-taker model (such as the EPRI Energy Storage Valuation Tool), as appropriate. Occasionally, the analyst may prefer to go directly to Step 3. For example, if the grid service is regulation, as regulation market is relatively small, a price-taker model may not capture the potentially sizable impact a large electricity storage system could have on a service with low demand (in MW).

3.2.5 Step 4: Electricity Storage Business Cases ("How Storage Can Monetize Benefits")

The simplified process for Step 4: Electricity Storage Business Cases is shown in Figure 121.

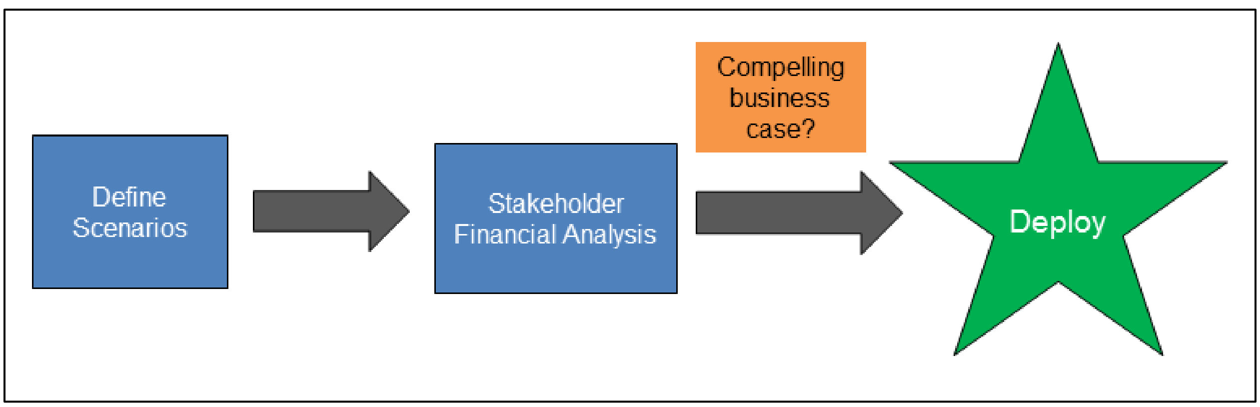


Figure 121. Decision Diagram for Step 4: Electricity Storage Business Cases
(Source: EPRI)

The penultimate phase of assessing electricity storage cost-effectiveness is to investigate real-world business cases. The distinction between this stage of analysis and all previous steps is the inclusion of relevant policy and regulation scenarios, as well as more advanced business-model and financial-analysis considerations. Step 4 is distinct from Steps 2 and 3 in that it focuses on monetization for the energy-storage system owner, rather than considering total value aggregated across all stakeholders.

3.2.5.1 Define Scenarios

Consider the example of a use case involving a transmission investment deferral, energy time-shift (arbitrage), and frequency regulation services. In Steps 2 and 3, the technical capability of the electricity storage system to provide value is evaluated, and the potential value of the electricity storage services is calculated (quantified). However, the avoided cost of the transmission deferral accrues to the transmission system, and the energy and frequency regulation benefits accrue to generation.

Depending on the objectives of the storage valuation analysis, it may be practical to perform Step 4 concurrently with Step 2 to assess both the quantifiable, aggregate value as well as the monetizable value to the storage owner. However, due to the cross-cutting nature of storage and its usefulness to provide a greater diversity of benefits than typical resources, it is important to distinguish “quantifiable value” from “monetizable value.” Over longer periods of time, policies and regulations are fluid, so the analyst considers those issues separately to support forward-looking research into electricity storage valuation.

3.2.5.2 Stakeholder Financial Analysis

Once the scenarios of interest have been identified, the analyst can then review the same use case from multiple stakeholder perspectives. Some issues to consider are:

- Business model(s) of the entity,
- Cost of capital for discounting future cash flows,
- Consideration of transaction costs,
- Taxes,
- Risk appetite,
- Permitting, and
- Insurance.

This is only a partial list; many other issues can be considered for case-specific business decisions. Step 4 is the step in which all of the complex realities of investing, building, and operating an emerging technology enter the analysis.

3.3 Modeling Tools

Specific tools that support energy storage evaluations span the spectrum in the level of detail and complexity – from high-level screening to detailed analysis for site- and service-specific needs. Many of these tools have been identified and are listed in Table 18.

Table 18. Analytical Tools for Use in Electricity Storage Cost-Effectiveness Methodology

Category	Resource Portfolio Planning	Production Simulation	Load Flow/ Stability	Dynamics Simulation	Electricity Storage Technology Screening	Electricity Storage Cost-Effectiveness
Focus	Long-term resource and capacity planning needs	Future-year trans. Grid simulation	Near-term T&D grid resource stability/ engineering needs	Short-term variability and load-balancing	Screening storage technology and service combinations	Assessing storage project cost-effectiveness
Goals	Minimize cost and risk of resource portfolio, maximize social welfare	Least-cost unit commitment and economic dispatch with reliability/ transmission constraints to manage minutes to hours variability and uncertainty	Least-cost planning to meet reliability and tolerance thresholds	Manage seconds to minutes variability and uncertainty	Identify promising technology/ services combinations	Maximize expected NPV of storage investment
Scope	Generation, international trading	Generation, Transmission	Transmission or Distribution	Generation	Generation, T&D, Customer	Generation, T&D, Customer
Examples	NESSIE, RETScreen, NEMS, EGEAS EMCAS	PLEXOS, UPLAN, GridView, PROMOD, Ventyx, GE-MAPS PROBE PSO	**Trans:** PSS/E,PSLF, HOMER, **Dist:**CYMDist, Open DSS, GridLab-D VSAT TSAT POM	Kermit FESTIV PSO	ES-Select ESVT ESCT	ESVT (EPRI) ESCT (Navigant)
Core Strengths	Evaluate range of future, regional scenarios and resource portfolios	One-year system dispatch with zonal/nodal model of regional grid, including market price effects	High resolution power flow, Volt/VAR and fault analysis for specific grid configurations	Short-time-scale dispatch for frequency regulation	Scoping analysis of a wide range of technologies and services	Life-cycle financial and cost-benefit analysis from owner/operator and societal perspectives

CHAPTER 4. STORAGE SYSTEMS PROCUREMENT AND INSTALLATION

4.1 Using Business Models for Storage Systems

Storage services for the grid can be acquired through several business models, as shown in Figure 122. These business models range from contracting for services only without owning the storage system to outright purchase. The specific option chosen depends on the varying needs and preferences of the owner. This chapter provides broad guidelines for acquiring electricity storage systems using different options.

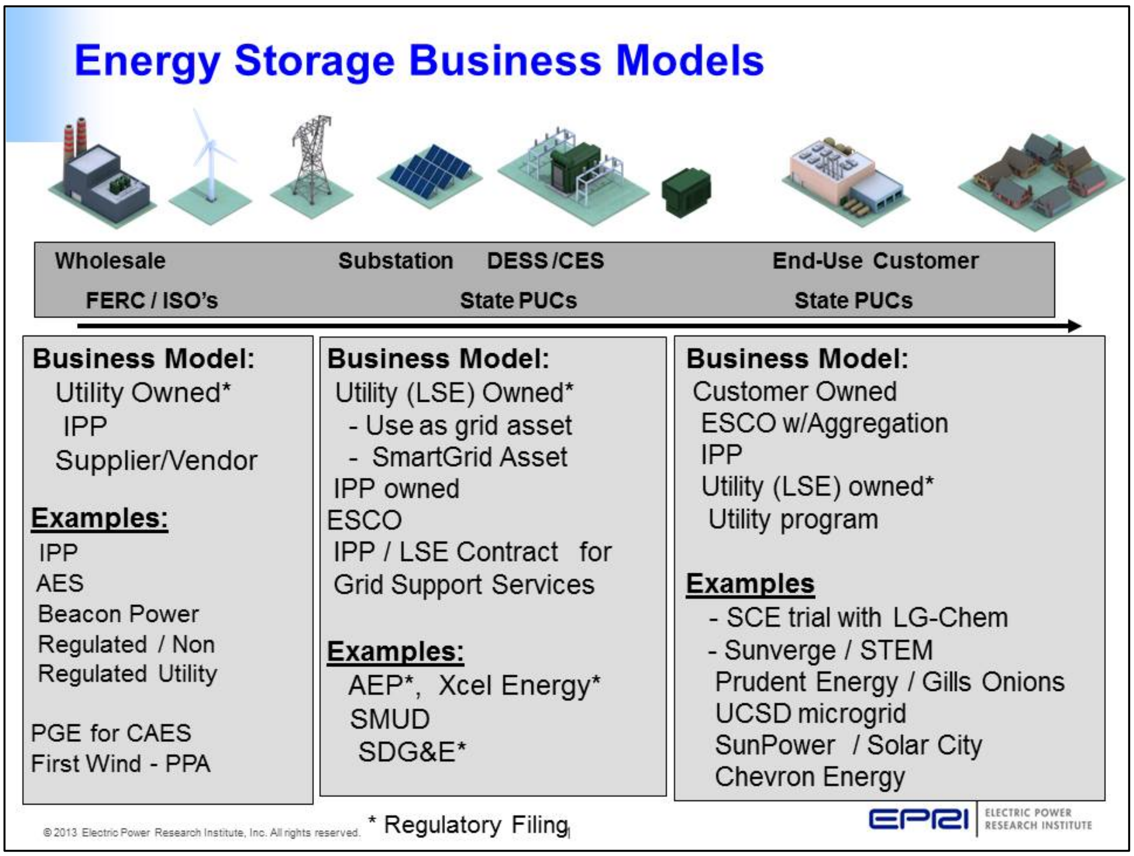


Figure 122. Business Models for Storage Systems
(Source: EPRI)

4.1.1 Third-party Ownership

In this option the storage system is owned, operated, and maintained by a third party who provides specific storage services according to a contractual arrangement. This process is very similar to fossil generating stations' independent power producer agreements. The key terms for fossil plants under such an operating agreement, typically of 20 to 25 years duration, generally include:

- The off taker supplies the fuel, takes the energy, and holds the dispatch rights.
- The seller earns a fixed capacity payment (i.e., $/kW-month) and a variable O&M payment per MWh delivered ($/MWh).
- In return for the capacity payment, the seller assures a certain availability of the plant.
- The seller provides a heat rate guarantee.

The terms of the operating agreement for third-party ownership of a storage facility will be somewhat similar to that of a fossil plant, except the variables for a storage system reflect its unique differences. For example, for a battery storage system, heat rate (MBTU/kWh) is not applicable. It would instead be replaced by a range for round-trip efficiency. The “fuel” would be the cost of off-peak electricity for charging the storage. The complete contract would also include a number of other details such as frequency and number of charge/discharge cycles during the life of the contract, depth of discharge. Similarly, other storage technologies, such as CAES, flywheels and pumped hydro will include operating parameters specific to those technologies that govern their optimal performance during the term of the contractual agreement.

The advantage of third-party ownership is that it shelters the owners - utilities and end-users - from financial and technology risks – both technological obsolescence due to rapid evolution of a particular technology and the inability of the purchased technology to meet projected performance targets. An additional consideration is that the operating costs for a third-party storage plant providing services to an IOU, co-op, municipal utility or end-use customer would be passed through via a bilateral contract.

The third- party ownership model has worked successfully with renewable technologies and in traditional fossil power plant generation projects. It has not, however, been widely adopted by storage technology vendors or investors, especially new entrants to the commercial marketplace who prefer short payback and higher cash flows that outright sales generate.

4.1.2 Outright Purchase and Full Ownership

The alternative option to third-party ownership is full purchase and ownership of a storage system. In this option, the wide range of size and functionality between pumped hydro and CAES technologies, compared to batteries and flywheels, creates a clear distinction between their procurement and installation process. Pumped hydro and CAES are technologies that predominantly provide generation-side services due to their large sizes and long-duration discharge capability. Batteries and flywheels are technologies that predominantly provide grid services that need relatively smaller storage size and shorter duration discharges, as discussed in earlier chapters of the course. Thus the procurement and installation of pumped hydro and CAES is preceded by a far more rigorous analysis to justify their inclusion in the utility system expansion plans, including environmental impact assessments, orders-of-magnitude higher level of civil engineering to develop the sites, and community input in the approval process for the implementation of these projects. This pre-planning takes several years, even before the final procurement of hardware begins. Other reports have detailed the intricacies of navigating the regulatory approval and permitting process for recently proposed pumped hydro and CAES projects.[64] The unique path of each project renders it difficult to identify a common process for procuring and installing these two technologies. Thus the focus of this chapter is on battery and flywheel storage systems, because their procurement and installation lends itself to a more replicable process and is less project-specific.

If the battery or flywheel storage project is solely for a demonstration of the technology for the owning entity, then the procurement process is usually driven by predetermined assumptions of cost, technology preference, and location of the project. On the other hand, if the owning entity is implementing the storage project based on operational needs of the grid, then the choice of storage technology, size, location, and project schedule is governed by the results of analytical tools described in earlier chapters and influenced by system-wide grid and regulatory considerations. In both instances, the owning entity has a choice of procuring the storage system piecemeal, with each subsystem of the storage system acquired separately, or procuring the entire storage system on a turnkey basis.

The current trend in storage system acquisitions has been toward the latter option, which is also facilitated by the commercial availability of several turnkey, modular storage systems with any of the family of battery types or flywheel technology. Turnkey acquisitions relieve the owning entity from specifying each subsystem individually and managing their procurement contracts and installation separately. Before the commercial availability of modular turnkey systems, many of the early utility and cooperative-owned battery storage systems: Noteworthy Projects, were acquired on a piecemeal basis and assembled at the project site. The piecemeal approach of building a battery system placed the burden of managing a complex acquisition and construction project on the owning utility. The first modular, turnkey system appeared in the United States in the mid-1990s with the introduction of the Model PM250, a 250 kW battery storage system designed and built by AC Battery. The PM250 was a factory-assembled, modular, turnkey battery storage system that was delivered to the site in one container-sized package. It demonstrated the advantages of a modular, factory assembled system design over the site-assembled counterparts and laid the foundation for the subsequent availability of today's containerized storage systems.

Battery and flywheel storage system acquisitions can be managed through a two-step process that consists first of issuing an Request for Information (RFI) followed by a Request for Proposals (RFP), as illustrated in Figure 123. Executing the first step to issue an RFI only requires identifying basic functional requirements of the intended use of the energy storage system and identifying a pool of potential vendors who could supply such a system. The functional requirements described in the RFI can include as many characteristics of the desired

[64] *"Evaluating utility owned electric energy storage systems : a perspective for state electric utility regulators",* Bhatnagar, Dhruv and Loose, Verne, SAND2012-9422, Sandia National Laboratories, Albuquerque, NM, 2012.

system as can be identified at the time the RFI is prepared. These requirements usually include the power and energy size of the system, expected charge/discharge cycles, life expectancy, footprint, proposed location, and other characteristics to provide the vendors with a concept of the storage system. A guide[65] is available that provides information that can guide the initial identification of these system characteristics as shown in Table 20 below.

[65] *Electric Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits,*PI: Dan Rastler, EPRI, EPRI ID: 1020676. EPRI, Palo Alto, CA, September 2010. http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001020676

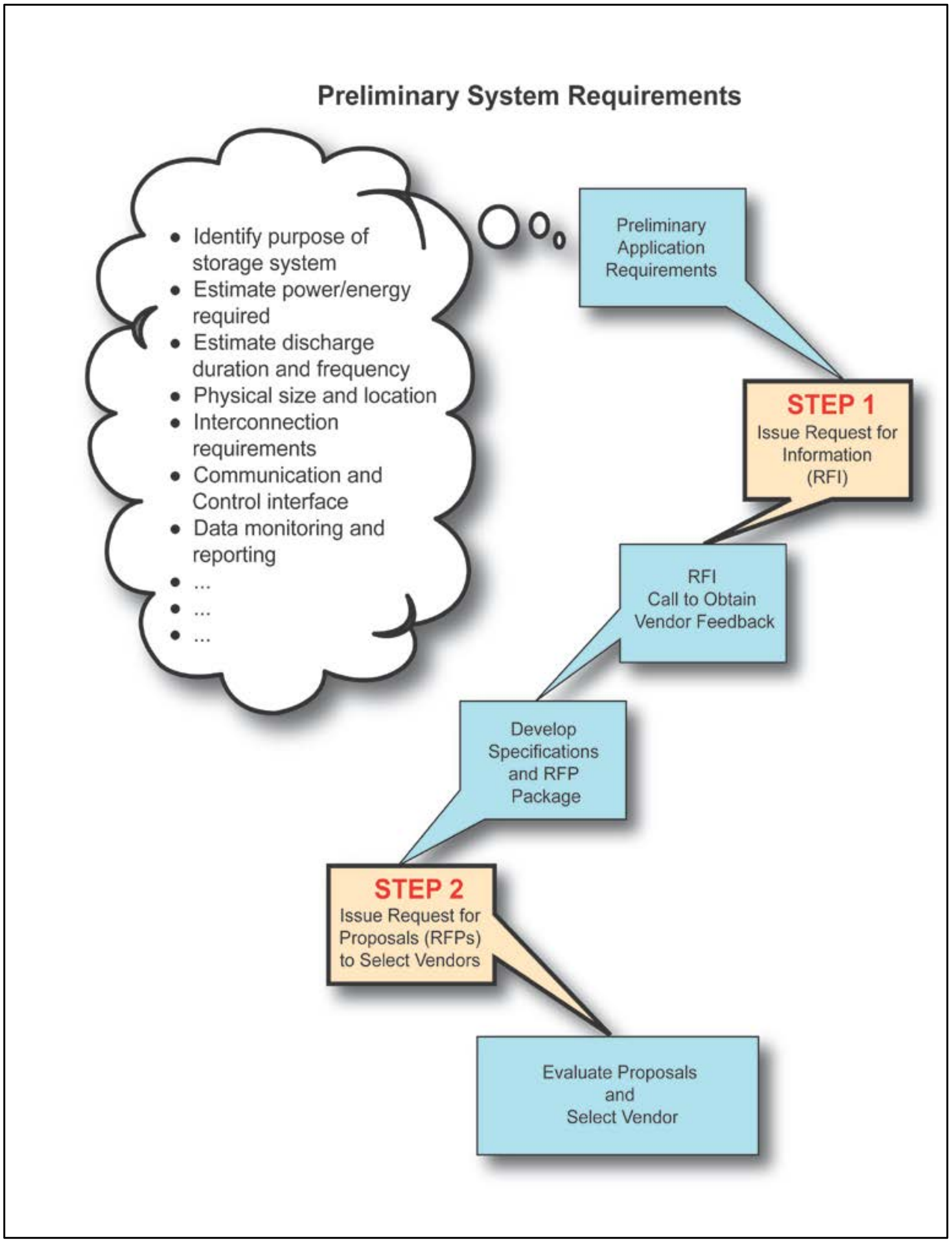


Figure 123. A Process for Storage System Acquisition
(Source: Sandia National Laboratories)

Table 19. Storage System Characteristics for Select Services

Application	Description	Size	Duration	Cycles	Desired Lifetime
Wholesale Energy Services	Arbitrage	10-300 MW	2-10 hr	300-400/yr	15-20 yr
	Ancillary services [2]	See note 2	See Note 2	See Note 2	See Note 2
	Frequency regulation	1-100 MW	15 min	>8000/yr	15 yr
	Spinning reserve	10-100 MW	1-5 hr		20 yr
Renewables Integration	Wind integration: ramp & voltage support	1-10 MW distributed 100-400 MW centralized	15 min	5000/yr 10,000 full energy cycles	20 yr
	Wind integration: off-peak storage	100-400 MW	5-10 hr	300-500/yr	20 yr
	Photovoltaic Integration: time shift, voltage sag, rapid demand support	1-2 MW	15 min-4 hr	>4000	15 yr
Stationary T&D Support	Urban and rural T&D deferral. Also ISO congestion mgt.	10-100 MW	2-6 hr	300-500/yr	15-20 yr
Transportable T&D Support	Urban and rural T&D deferral. Also ISO congestion mgt.	1-10 MW	2-6 hr	300-500/yr	15-20 yr
Distributed Energy Storage Systems (DESS)	Utility-sponsored; on utility side of meter, feeder line, substation. 75-85% ac-ac efficient.	25-200 kW 1-phase 25-75 kW 3-phase Small footprint	2-4 hr	100-150/yr	10-15 yr
C&I Power Quality	Provide solutions to avoid voltage sags and momentary outages.	50-500 kW	<15 min	<50/yr	10 yr
		1000 kW	>15 min		
C&I Power Reliability	Provide UPS bridge to backup power, outage ride-through.	50-1000 kW	4-10 hr	<50/yr	10 yr
C&I Energy Management	Reduce energy costs, increase reliability. Size varies by market segment.	50-1000 kW Small footprint	3-4 hr	400-1500/yr	15 yr
		1 MW	4-6 hr		
Home Energy Management	Efficiency, cost-savings	2-5 kW Small footprint	2-4 hr	150-400/yr	10-15 yr
Home Backup	Reliability	2-5 kW Small footprint	2-4 hr	150-400/yr	10-15 yr

1. Size, duration, and cycle assumptions are based on EPRI's generalized performance specifications and requirements for each application, and are for the purposes of broad comparison only. Data may vary greatly based on specific situations, applications, site selection, business environment, etc.
2. Ancillary services encompass many market functions, such as black start capability and ramping services, that have a wide range of characteristics and requirements.

The RFI does not specify a storage technology type and only includes other desired characteristics of the storage system, unless the owner has a predisposition for a particular storage technology. In the absence of such a preference, it is best to leave the technology selection up to the vendor to ensure that the most suitable storage technology that closely matches the owner's stated requirements is made available.

The complete RFI is then issued to a pool of prospective suppliers with a two-fold purpose. First, it is an opportunity for the vendors to provide feedback to the owners about how they perceive the system requirements and what other pieces of information they need to submit a full proposal when the subsequent RFP is issued. Second, the vendor feedback provides information to refine the system requirements further, based on hardware that is available or could become available within the desired timeframe. This feedback leads to the development of a firm specification for the system that will be part of the RFP issued later in the procurement process. Further, the RFI vendor responses are a good indicator of vendor qualifications to supply a system that meets the owner requirements. It also allows the owners to develop a short list of vendors that will subsequently be included on the RFP requestor list. The smaller pool of vendors will be more likely to have the right technology and qualifications to respond to the subsequent RFP when it is issued. Generally, only one RFI vendor feedback call is needed to move forward on developing the RFP as the next step of the procurement process. A sample RFI used by the Kauai Island Utility Cooperative (KIUC) is provided. Finally, the advantage of the two-step RFI/RFP process is that an RFI provides a means for a non-binding exchange of information between the owners and vendors that allows them to assess each other's needs and capabilities. This provides the basis for developing a RFP that more closely reflects the requirements of the proposed system matched to the hardware and services that vendors can offer.

Another open source document[66] that can be used as a template for a storage system specification is available from American Electric Power (AEP). This specification for a Community Energy Storage (CES) system was written with input from vendors and other utilities, and its development was facilitated by EPRI.

AEP followed a similar RFI process to formulate a comprehensive specification set that describes the desired functionality of the system, yet leaves the selection of the specific storage technology to the vendor. The specification starts with the simple details and goes on to describe very specific features desired by the utility, including electrical requirements, interconnection, controls, and communications.

4.1.3 Electric Cooperative Approach to Energy Storage Procurement

While IOU and electric co-ops (which are not-for-profit) often have similar needs related to electricity storage, they also have differences in corporate and financial structure, as well as infrastructure and customer demographics. These differences could affect the approach that each takes in regard to capital assets.

One of the major differences between the organizational and financial structures of co-ops and IOUs is that co-ops, unlike IOUs, are split into two categories – distribution co-ops that deliver electricity to its consumers/owners and the generation and transmission (G&T) co-ops that are bulk power providers that own and operate generation assets or purchasing power on the market and sell to the distribution co-op. A key aspect of this relationship is that the G&T is owned by the distribution co-ops it serves. Distribution co-ops have an all-requirements contract with the G&T, meaning that special consideration must be made regarding which entity receives the benefits of an energy storage system. For example, a G&T representing distribution co-ops in a regulated market would likely receive significant financial benefits from selling ancillary services like frequency regulation, whereas a distribution co-op likely would not. On the other

[66] American Electric Power, Revision 2.1, http://www.dolantechcenter.com/Focus/DistributedEnergy/docs/CESHubSpecifications_rev2_1.pdf, last accessed on April 25, 2013.

hand, a distribution co-op may find great value in reducing substation congestion, while a G&T likely does not, depending on the terms of the all-requirements contract. A G&T adds electricity storage for peak-shaving leading to load reduction, which will receive a capacity credit based upon avoided future cost, whereas distribution co-ops will receive a much higher reduction in the cost of their demand charges.

Geographically, electric co-op distribution systems typically have longer distribution feeders and serve areas with much lower customer densities than IOUs. Nationwide, co-ops serve an average of 7.4 consumers per mile of line and collect annual revenue of approximately $15,000 per mile of line versus IOUs, which average 34 customers per mile of line and collect $75,500 per mile. This results in greater emphasis by the co-ops on voltage support and mitigation of feeder congestion. Both IOUs and co-ops are likely to seek energy storage systems to defer substation capacity increases or to address transmission issues.

The not-for-profit structure of co-ops typically limits its ability to take advantage of tax credits and accelerated depreciation on capital investments, whereas IOUs can leverage such tax credits and depreciation to benefit the corporate bottom line. As a result of these differences, an IOU may be more likely to invest directly in ownership of energy storage equipment, while a co-op may lean toward a purchase of energy storage services, rather than outright capital investment. For some co-ops, purchasing services, rather than capital investment, allows taxable entities to own the equipment and realize the tax depreciation benefits—often with a portion of those benefits reflected in a lower cost of services charged to the co-op.

Some of the above-discussed differences in financial drivers for capital investments may be offset by an electric co-op’s ability to finance projects at much lower interest rates than IOUs. These lower interest rates would be due to lender perceptions of lower financing risk for co-ops. Electric distribution co-ops are 100-percent debt-financed, with a cost of capital that is 2 to 3 times less than an investor-owned utility, whose financial structure is typically 40 percent equity (with target return on equity of 15 to 20 percent) and 60-percent debt. Thus the electric distribution co-op discount rate is going to be a factor of 2 to 3 times less than for an IOU, which should favor decisions to add energy storage. Consequently electric distribution co-ops may want to own the relatively high capital cost energy storage systems, while an IOU may not. However, capital conservation is important for co-ops, because they are typically smaller organizations with smaller balance sheets. Lenders like the Rural Utilities Service would need to be involved in the decision-making process to permit access to its capital.

4.2 Role of Regulations in Energy Storage Markets, Cost Recovery, and Ownership

Energy storage systems and the services they provide can be sold in regulated and deregulated markets. However, almost all the electrical grid-connected storage services, market opportunities, cost-recovery methods, cost-effectiveness criteria, incentives, and rebates are governed by a well-established regulatory oversight. The rules and regulations that affect storage deployment are enforced by federal and state agencies such as FERC, PUCs, and ISOs. These organizations provide varying oversight and regulation to the industry. ISOs provide oversight of transmission and generation in control areas and FERC regulates interstate transactions and determines rules and tariffs, while PUCs regulate utility management, operations, and capacity acquisition within their State's jurisdiction. Consequently, these rules and regulations impact the growth of the storage industry, because policies can create or inhibit market opportunities for electricity storage and may determine how, and if, they will be compensated.

Figure 124 provides further information into the jurisdictions of the agencies and their influence over the utilization of storage in the grid.

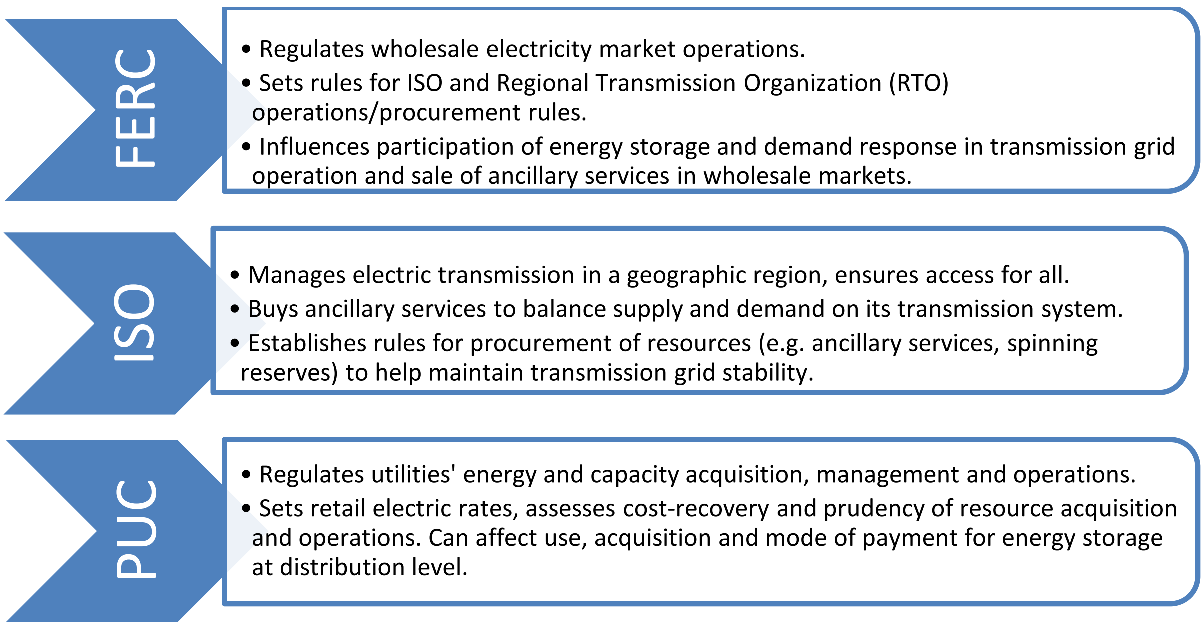


Figure 124. Regulatory Agencies Affecting Electricity Storage Systems

Energy storage industry stakeholders must keep abreast of the myriad activities of regulatory agencies and understand the impacts on energy storage opportunities, pricing, and cost-recovery. Awareness of these rules is important to identify opportunities for energy storage systems. Table 20 presents examples of agency rules that have created opportunities for energy storage deployment. Several of these rules have come about due to proactive involvement in rulemaking by the storage industry associations such as the Electricity Storage Association (ESA), California Energy Storage Alliance (CESA), and storage system vendors. Participation and monitoring rulemaking processes also alerts stakeholders to proceedings that may otherwise lack information on energy storage capabilities and may inadvertently leave it out as a possible option for grid operation.

Table 20. Examples of Regulatory Agency Rules and Their Impacts on Energy

AGENCY	RULE/ACTION	INTENT OF THE RULE OR ACTION	IMPACT
FERC	Rule 755	Directs that ISOs compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the accuracy and speed of responding to the requested level of capacity to rectify frequency.	Fast responding energy storage is paid more because it provides a quicker and more accurate level of power to ISO's set target compared to conventional generation sources.
FERC	Rule 719	Directs ISO/regional transmission organizations (RTOs) to accept bids from demand response resources for certain ancillary services on a basis comparable to other resources.	Opens up possibility for meeting commercial and industrial customers' critical load using storage enabling frequent demand response participation.
FERC	Rule 745	FERC's Market-Based Demand Response (DR) Compensation Rule establishes that electric utilities and retail market operators will be required to pay resources the market price for energy, known as the locational marginal price (LMP), when load reductions will balance the grid's supply and demand as an alternative to a generation resource.	Higher DR rewards may enable use of storage to bid in a larger customer loads for DR participation in a cost effective manner.
FERC	Rule 1000	In an effort to address deficiencies in regional and interregional transmission planning and cost allocations, FERC Order 1000 requires Public Utility Transmission providers to participate in transmission planning at the regional level. These plans must include comprehensive evaluation of transmission solutions in coordination with neighboring region transmission providers to ensure cost effectiveness and must account for public policy requirements. Second, the order requires that the costs of transmission facilities be allocated fairly to estimated beneficiaries. Finally, the order identifies non-incumbent developer requirements.	Because Order 1000 requires alternatives in transmission planning, non-transmission alternatives such as energy storage could potentially see an increase in deployment; and in some instances may provide a more cost-effective solution than other transmission investments.
California Independent System Operator (CAISO)	Modified Rules to Allow Non Generation Resources	Removed resource-type restrictions and reduced minimum rated capacity to 500 kW from 1 MW to provide certain ancillary services. Reduced minimum continuous energy requirement from 2 hours to: Day-Ahead Regulation Up/Down: 60 minutes; Real-Time Regulation Up/Down: 30 minutes;	Allows energy storage resources, such as batteries and flywheels, to provide regulation service by fully utilizing their fast-response, fast-ramping capabilities. Allows new storage technologies to provide regulation energy over a

AGENCY	RULE/ACTION	INTENT OF THE RULE OR ACTION	IMPACT
		Spin and Non-Spin: 30 minutes. Will allow minimum continuous energy measured from the period that the resource reaches the awarded energy output. Measurement starts once resource reaches awarded energy, not end of 10-minute ramp requirement.	continued sustained period that do not have seemingly inexhaustible energy like fossil fuel resources.
CAISO	Flexible Capacity Procurement to Integrate Renewable	CAISO is considering various electricity capacity sources to help manage the steep ups and downs due to wind and solar coming on line under the Renewable Portfolio Standards (RPS) mandate. CAISO defines the characteristics of the acceptable resources to manage steep and sudden ramps.	If superior abilities of energy storage to ramp up quickly in response to needs and reach full capacity are included in the characteristics required, energy storage systems can participate in this market.
CPUC	Energy Storage Rule-making for AB2514	Set up a framework for assessing storage services, cost-effectiveness, and identifying barriers; then possibly setting storage procurement targets if deemed necessary.	May require utilities to procure energy storage to a set target provided cost-effectiveness criteria are met.
CPUC	Self-Generation Incentive Program (SGIP) rules	SGIP offers incentives to customers who produce electricity with wind turbines and fuel cells. Recent revision has made advanced energy storage system eligible for rebate.	Either as stand-alone or combined with other renewable eligible technologies, energy storage initially received $2/watt rebate, declining by 10% in each subsequent years.

4.3 Project Timelines

The larger size of pumped hydro and CAES storage facilities require much longer planning horizons due to the analysis and design activity that precedes their implementation. These planning timeframes typically span seven to ten years or more, depending on public opposition or support for a particular project, the ability to satisfactorily negotiate environmental impact studies, and other approval requirements. The large size and remote location of these projects may also need a new transmission corridor; several years may be required to obtain all the necessary permits and regulatory approvals before it can be constructed (although this activity may be mostly concurrent with storage facility planning).

The relatively smaller battery or flywheel storage projects have been implemented within two to three years from conceptual inception to commissioning. The Fairbanks battery project described earlier, which is representative of a large, site-assembled battery system, took less than four years from its inception to its commissioning date. Smaller storage systems in the 1-MW to 5-MW range have been commissioned in less than two years from initial conception to commissioning. These timeframes are even shorter for the modular containerized systems that can be installed in the field and brought on-line within months after they reach the project site.

A high-level overview of the typical timelines that can be expected for the procurement and installation of a storage technology are shown in Figure 125.

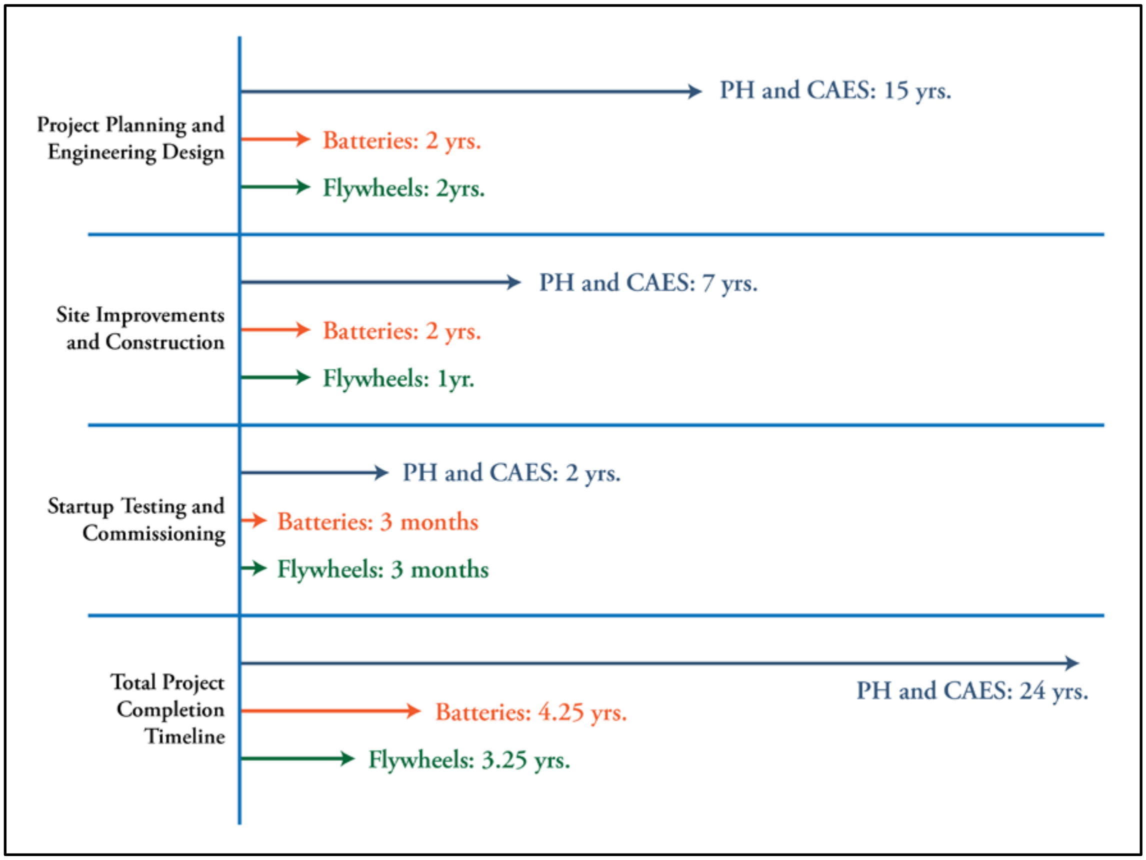


Figure 125. Typical Project Timelines

4.4 RFP or RFQ?

A question frequently asked in the procurement process is whether an RFP or a Request for Quote (RFQ) is more suitable for storage system procurement. An RFP is recommended to acquire a storage system, because the RFP is suitable for a process in which the commodity being acquired has some latitude for variation, as is the case of an energy storage system, whereas an RFQ is used in the instance when the commodity being acquired can be precisely defined and identified. The RFP allows the prospective vendor to propose a system that closely matches the specifications and, in some cases, propose alternatives or add-ons that could offer a superior option. The RFP process generally anticipates that no two proposals will be exactly identical or offer the same commodity. By contrast, the RFQ requires each vendor to quote the exact same commodity, and the quoted price and related support services (if needed) are usually the only criteria for selection of the supplier or vendor.

4.5 Performance Standards and Test Protocols

The duty cycles and other parameters shown for grid services in Table 19 of ELECTRICITY STORAGE SERVICES AND BENEFITS and other places in the course are mostly estimated values derived from computer modeling, limited operational experience with energy storage projects, or the best guess of technical experts in the energy storage community. Using the frequency regulation service as an example, the energy storage system vendors do not offer a standard product for frequency regulation that is designed to exactly match these parameters. Rather, the prevalent industry practice is to offer existing products that most closely match the customer's stated needs, as described in the RFI or RFP. The actual future performance of the storage system, after it is commissioned in the field, is guaranteed through suitable warranties and hard-wired protection features built into the system. Two of these features are hard stops that limit the depth of discharge and/or conservative contingencies on its projected operational life. While such measures have worked reasonably until now, both the vendors and users recognize an urgent need to codify and standardize both performance requirements and test procedures better to stimulate widespread use of energy storage in the grid. Such standardization lends uniformity to product design and performance and is the hallmark of all mature technologies, but formulating a standard is a lengthy process that requires consensus from a broad base of stakeholders. The DOE Energy Storage Systems (ESS) Program, through the support of the Pacific Northwest National Laboratory (PNNL) and SNL, is facilitating the development of protocols to precede and expedite the formulation of subsequent standards. EPRI is collaborating in this effort with DOE with the objective that, in the near term, these protocols will be used to measure and quantify the performance of energy storage systems in select grid services and subsequently could provide the basis of industry-wide standards. The availability of a suite of uniform, service-specific protocols that include integration criteria and performance metrics will allow storage system vendors, utilities, and other storage users to evaluate the performance of storage technologies on a uniform basis. These protocols will differentiate technologies and products for specific service(s) and provide transparency and uniformity in how performance is measured.

The DOE first-year effort in 2013[67] was focused on frequency regulation and peak shifting with additional applications to follow. The project leads at the two laboratories and EPRI were David Conover at PNNL, David Schoenwald at SNL, and Ben Kaun at EPRI.

4.6 Safety Issues Related to Utility Sited Stationary Battery Installations

The following section provides a guide to addressing overall safety and environmental issues surrounding energy storage systems. Particularly noteworthy issues include the following:

[67] "*Protocol for Uniformly Measuring and Expressing the Performance of Energy Storage Systems*," PNNL-22010, Bray KL, DR Conover, MCW Kintner-Meyer, V Viswanathan, S Ferreira, D Rose, and D Schoenwald, Pacific Northwest National Laboratory, Richland, WA, October 2012. http://www.pnnl.gov/publications/default.asp

- Many safety and environmental issues are both *site-specific* and *technology-specific*.
- Electricity storage is fundamentally different from other electrical equipment because *it is always energized* and it cannot simply be turned off. This characteristic requires unique procedures on the part of operators, workers, and linemen to ensure adequate safety measures and procedures are in place for installation, commissioning, and operation.
- In many cases, electricity storage contains exotic materials that may require special handling in routine operation, as well as in emergency conditions such as fire, flooding, or earthquakes. The manufacturer *must* produce materials safety recommendations for routine operation as well as information that can be used to inform first responders about proper protocol in dealing with these systems under emergency situations.

4.6.1 Relevant Codes and Standards

Many storage applications are electric utility-owned and/or utility-operated installations. Typically these systems are governed by the National Electrical Safety Code® (NESC®); however, other codes can influence the design based on equipment type, location, and circuit voltage levels. A sampling of relevant codes and standards for a utility-based, advanced lead-acid battery project includes:

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NESC®	National Electrical Safety Code®
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration
UL	Underwriters Laboratories

This list includes those codes that are applicable to an advanced lead-acid installation, but is by no means all-inclusive. Project developers should be cognizant of all applicable national and local codes, local interpretations of codes, and any code overlap or grey areas where codes conflict or are silent. For example, NEC may have more clarity on lower voltage systems that utilities typically define as customer side, but if these systems are utility-owned and/or utility-operated, the systems will fall under NESC jurisdiction.

4.6.2 Safety in the Design Process

To enable efficient implementation of the storage project, thoroughly review all codes and standards applicable through the utility's specifications and align these with codes and standards used by the storage manufacturer. Storage systems are a new resource option for utilities and are not traditional components of utility systems. Therefore aligning utility substation, distribution, metering, protection, communication, relay, and potentially transmission system standards with the storage system vendor early in the engineering design and procurement phase is prudent.

During the design process, identify the constructing entities of the project. If on-site construction will be performed by utility or outsourced personnel, identify upfront the capabilities of the assigned entity, the voltage and energy source with which they are qualified, and the codes to which their licenses require adherence. A key example would be a licensed contractor installing a 480V ac system in a utility-owned storage project. The contractor's license typically requires adherence to NEC, but the NESC may have jurisdiction in this case and the contractor may need an exemption to install the NESC-based design.

Project developers should also allow adequate clearances for site installation equipment (cranes, lifts), and easy, code-compliant access for safety and fire suppression-related equipment. Obtaining input from local government safety agency (fire departments, local zoning) is a necessary step in the design, construction, and operational processes that provides emergency responders with clear knowledge of how the storage system operates, the embedded safety systems, the chemical contents of the storage system, and the locations of critical system components at the project site.

Material Safety Data Sheets should be provided by the vendor, and copies should be on file with the local fire department. Project equipment should meet all safety labeling requirements. Local safety officials should be made familiar with and briefed on the emergency response protocols at the site both during construction and upon commissioning, so that they are familiar with the layout and location of the higher risk system components at the project site.

4.6.3 Safety in Operations

The electricity storage systems should have built-in safety features that are integrated into the overall system monitoring and performance architecture. These features and their functionality should be reviewed during the design phase to ensure that they meet the owner requirements and can communicate with the existing Supervisory Control and Data Acquisition (SCADA) system as necessary. The storage system safety alarm should be capable of transmitting to appropriate utility/co-op and emergency response personnel over existing communication channels.

Battery storage systems generally monitor temperatures at multiple locations in the battery string(s) and alert the operator of potential hot spots at critical locations. Additional monitoring with infrared (IR) scanners that sweep the battery stack, system enclosure, or inside the battery building at 5- or 10-minute intervals add a greater level of safety and are strongly recommended for high temperature or more energetic chemistries, such as the lithium family of batteries.

Flow battery systems require added measures for on-site containment of electrolyte spills. Such containment may require construction of dams or berms for large, outdoor storage tanks or design features within the building for smaller, indoor systems. Monitoring and alarm systems should be capable of detecting leaks and initiating appropriate shutdown and alarm features.

Emergency response personnel should be involved during the early design phase to ensure that they are adequately trained and prepared for all contingencies.

Similar containment measures are not required of storage systems that do not contain liquid electrolytes or contain electrolytes in insignificant quantities. Examples would be the lithium family or any of the advanced lead-acid batteries. However, secondary containment to hold the water or other chemicals used in extinguishing a fire by the emergency response crews may require containment. This consideration should be addressed with safety personnel and local fire departments early in the project planning phase to ensure compliance with their requirements.

4.6.4 Safety and Environmental Personnel

Dedicated safety and environmental personnel with appropriate training and experience must be involved early in the project development phase to review and develop appropriate safety protocols, review procedures from a safety point of view, and provide guidance in environmental permitting.

After project commissioning, all safety systems should be periodically inspected in accordance with manufacturer specifications and relevant codes and standards. Best-practice safety reviews should be held and any deficiencies noted and corrected.

4.7 Interfacing Storage to the Utility's Existing Communications Network

4.7.1 Front End Communication Control Requirements Definition

As part of the system design, identify the electricity storage system's communication and control needs when interfacing to the utility's existing communication and control architecture. The design should accommodate participant roles and rules, applicable standards (current and emerging), and be compliant with all electric utility interoperability requirements. The architecture and data models along with system requirements should be developed with sufficient specificity to ensure the vendor-supplied equipment works as expected upon commissioning. The contract documents should include specific requirements and specifications to which vendors can successfully respond.

One potential route to successful integration of electricity storage systems and their associated control and communication systems pivots on a requirements analysis, commonly used in systems and software development, that includes determining both functional and non-functional requirements. One possible framework for a requirements analysis can be developed using the IntelliGrid Use Case Template available at EPRI's Smart Grid Resource Center.[68] Functional

[68] EPRI Smart Grid Resource Center: Use Case Repository, http://www.smartgrid.epri.com/Repository/Repository.aspx, last accessed April 25, 2013.

requirements should present a close examination of the process steps and requirements that emerge from use cases, data, and architecture models and document the discreet requirements that allow the processes in the use cases to operate. In addition, requirements should assign ownership and level of criticality for each requirement.

At this stage detailed logical data models and conceptual architecture models can be developed, along with the corresponding data points list(s) (location of data collection points and requirements). The data models describe the data required and how they interrelate. The architecture model describes physical systems, including electricity storage, metering, source of control signals, and physical layers used for communications. In part, data models address the interoperability requirements, including communication protocols, communication rates, and needs for protocol translation. The data points list should be as inclusive as possible, noting the data capture rate and communication protocol. Many extra slots should be reserved for yet-unidentified data points, as further design development may well lead to a requirement for additional data capture points.

All models must also reflect current and emerging cyber security requirements, including required firewalls, intrusion protection, authentication, account management, access management, access logging, and auditing. The security requirements are especially critical and should reflect the latest cyber security best practices.

The contract documents should require that a cyber-security plan be developed that addresses and mitigates the critical vulnerabilities inherent in both the hardware and software that comprise the control system and Data Acquisition System (DAS), including sensors, control actuators, control algorithms, communications channels, and so on. The system and its components should be hardened against willful attack or human negligence. In addition the contract documents should require that the Contractor work closely with the Owner to ensure complementary functionality with the Owner's cyber security policy.

As cyber security is an ever-evolving discipline, the following are current (May 2013) suggested resources:

- Guide for Assessing the High-Level Security Requirements in National Institute of Standards and Technology Interagency Report (NISTIR), NISTIR 7628,[69]
- National Institute of Standards and Technology (NIST), NIST Special Publication 800-53,[70] and
- NERC Critical Infrastructure Protection Requirements.[71]
- Other requirements that may need to be addressed, given varying instances, are business continuity, disaster recovery, and regulatory and legal concerns.

[69] http://csrc.nist.gov/publications/nistir/ir7628/nistir-7628_vol3.pdf, last accessed April 28, 2013.
[70] http://csrc.nist.gov/publications/PubsSPs.html#800-53, last accessed April 28, 2013.
[71] http://www.nerc.com/page.php?cid=6%7C69, last accessed April 28, 2013.

Non-functional requirements should present a similar level of detail. Non-functional requirements address such issues as look and feel, usability, performance, operation, maintainability and support, as well as security.

Finally, the functional and non-functional requirements should address software, hardware, and communication interfaces at an adequate level of detail and should be included in a Requirements Document. The Requirements Document should be a product of the effort of correctly identified and active team members, key stakeholders, potential users of the data, and supporting personnel, who clearly communicate expectations and requirements. The Requirements Document is then issued to prospective vendors and provides a vehicle for relaying not only the project objectives and expected features, but also, most importantly, the technical requirements.

4.8 Other Implementation Considerations

Project implementation, either through outright purchase or through a services agreement, will require addressing other issues and activities. These will generally include environmental impact studies, interconnection studies, PUC approvals, and siting permits. These other considerations are project-specific and site-specific and cannot be generalized in a simplified manner. However, smaller-sized storage systems are simpler to implement, relative to larger pumped hydro or CAES storage projects. For example, a storage system to provide T&D deferral services will likely be utility-owned and located in an existing substation. In such a case, there may be no need for a building permit or an environmental impact study, especially if this is a modular, containerized storage system. Similarly, a storage system installed to provide ramp support or time-shifting of spilled energy that is a retrofit to an existing renewable system, such as a PV or wind farm, could eliminate the need for a building permit and an environmental impact study because the existing facilities provide umbrella coverage. In such a case, the host utility may determine the need for an interconnection study and other stability analyses.

Warranties for electric storage systems are specific to storage technology, intended service requirements and vendor preferences. Cycling frequency, DOD, and operational lifetimes are the governing parameters for battery technologies; some battery technologies also state operating temperature ranges to be maintained for the warranty to be honored. While attention tends to focus on the storage component of the system, the operating conditions of the other sub-systems, such as the power conversion and control system components, also governs the warranty coverage.

Electricity storage systems that support renewable sources, such as wind and solar, require careful consideration of their warranty terms, especially if there is uncertainty on the variability of the renewable resource. Ramp rates that exceed the design specifications will adversely impact the expected operational life of the battery; field operational data should be reviewed at frequent intervals to flag events outside design ranges. Warranty terms may require renegotiation after a one-year period, if the out-of-bound conditions persist.

Electricity storage is a very flexible resource. The owner/operator may apply the system for grid services unspecified in the original procurement. The warranty terms may require renegotiation if such conditions arise.

4.9 Storage System Test Facilities

The recent emergence of new storage technologies and the growth of commercially available turnkey systems uncovered a strong need for facilities at which system developers and vendors can test their systems to desired performance criteria. Four such facilities are available in the United States, where storage components or complete systems can be tested under controlled conditions by independent entities.

4.10 Noteworthy Projects

Pumped hydro projects have been built since the early 1900s, whereas large battery projects have a relatively recent history of deployment in the electric grid. The early and current projects have and will continue to break new ground and expand the use of electricity storage into new areas. Noteworthy projects that validated battery technology capabilities in providing grid services and ongoing projects funded in the United States through the 2009–2011 American Recovery and Reinvestment Act (ARRA) are listed.

4.11 Electricity Storage Trade Associations and Not-for-Profit Conferences

Trade associations, organizations, and not-for-profit conferences that promote electricity storage and provide a venue to network within the energy storage community are listed below.

Electricity Storage Association (ESA)

Originally called the Utility Battery Groups (UBG) until 1996, the ESA is an international trade association working to promote the development, integration, and commercialization of energy storage technologies and systems. The ESA holds an annual meeting to provide the premier industry forum for energy storage leaders.

Website: http://www.electricitystorage.org/about/about_esa

California Energy Storage Alliance (CESA)

CESA is a broad coalition committed to expanding the role of energy storage to promote the growth of renewable energy and a more affordable, clean, and reliable electric power system in California.

[72] DOE International Energy Storage Database, http://www.energystorageexchange.org/projects, last accessed April 28, 2013.

Website: http://www.storagealliance.org

Texas Energy Storage Alliance (TESA)

TESA's membership includes both electrical and thermal energy storage companies in Texas. TESA promotes fair regulatory markets that promote the use of storage in the Electric Reliability Council of Texas (ERCOT) network.

Website: http://texasenergystorage.com

Electrical Energy Storage Applications and Technologies (EESAT)

The EESAT Conference is a biannual event hosted by the DOE's Office of Electricity Delivery and Energy Reliability, SNL, and the ESA. The conference is the premier forum for dissemination, review, and presentation of research and development, demonstrations, and studies conducted around the globe on specific electrical energy storage applications and technologies applied to the electricity grid.

Website: http://www.sandia.gov/eesat/

Electricity storage is also promoted by several overseas organizations. Some of these include:

European Association for Storage of Energy – EASE

Website: http://www.ease-storage.eu/

China Energy Storage Alliance - CNESA

Website: http://www.cnesa.org/indexe.php

India Energy Storage Alliance - IESA

Website: http://www.indiaesa.info/

1. **Electricity storage system comprises of two major subcomponents, which are?**
   - Storage, Power conversion electronics
   - Storage, Infrastructure
   - Generator, Power conversion electronics
   - Generator, Storage

2. **Which of the following services do energy storage systems provide for?**
   - Bulk energy services
   - Ancillary services
   - Transmission infrastructure services
   - Distribution infrastructure services
   - All of the above

3. **True or False. Electricity storage is eminently suitable for damping the variability of wind and PV systems and is being widely used in this application.**
   - True
   - False

4. **For transmission congestion relief, the energy storage system would be installed where in relation to the congested transmission portion?**
   - Upstream
   - Downstream
   - At the congested portion
   - Anywhere, as does not matter

5. **Electricity storage is well suited to ensure quality of power by protecting against which of the following events?**
   - Variations in voltage magnitude
   - Low power factor
   - Harmonics
   - All of the above

6. **True or False. Electricity storage can be used for any of the services listed as it is common for a single service to generate sufficient revenue to justify its investment.**
   - True
   - False

7. **Generally, for a discharge time in hours at rated power of 100 MW, which energy storage system(s) will be capable of this?**
   - Lithium-ion batteries
   - High-power flywheels
   - Pumped storage hydropower
   - All of the above

8. **Which of the following statements is true?**
   - Pumped storage hydropower has the highest capacity of all the storage technologies
   - The last pumped storage plant commissioned in the US was in the 1980s
   - Europe and Asia have new and future deployments of pumped storage hydropower plants
   - All of the above

9. **Compressed Air Energy Storage is a proven bulk energy storage technology but requires what to be cost-effective for capacities up to 400 MW?**
   - Aboveground air storage
   - Underground air storage
   - To operate in conjunction with a natural-gas-fired combustion turbine (CT)
   - None of the above

10. **How many operating field units of Sodium-sulfur Battery Systems are deployed worldwide?**
    - 221
    - 100
    - 12
    - 2

11. **Which of the following is known as a "flow battery", in which one or both active materials are in solution in the electrolyte at all times?**
    - Vanadium Redox
    - Iron-chromium
    - Zinc-bromine
    - All of the above

12. **What is an advantage of iron-chromium flow batteries over Li-ion, lead-acid, zinc-bromine and other technologies?**
    - High energy density
    - Low cycle-life
    - Mature technology
    - Less complex design and simpler controls

13. **True or False. Due to the corrosive nature of the bromine electrolyte in Zinc-bromine batteries, the cycle life of is not strongly dependent on the number of cycles or the depth of discharge, but on the number of hours that the system has been operational.**
    - True
    - False

14. **Zinc-air batteries have up to _____ times the energy density of Li-ion, its most competitive battery technology.**
    - Three
    - Two
    - One half
    - One quarter

15. **Which lead-acid battery can deliver high current rates similar to nickel metal-hydride (Ni-MH) and Li-ion batteries?**
    - Vented lead-acid
    - Valve regulated lead-acid
    - Lead-acid carbon
    - None of the above, lead-acid cannot match the current rates

16. **True or False. Lead-acid batteries are the most commercially mature rechargeable battery technology in the world.**
    - True
    - False

17. **Which of the following is false regarding Flywheel energy storage?**
    - Have long cycle life
    - Have low efficiencies
    - Have fast response times
    - Have power densities 5 to 10 times that of batteries

18. **Which battery systems dominate the current deployment landscape for grid-scale storage systems in the United States?**
    - Lead-acid
    - Zinc-bromine
    - Lithium-ion
    - Redox

19. **True or False. Lithium-ion storage systems cannot be used in Residential Energy Storage due to the complexity and hazards during operation.**
    - True
    - False

20. **Which of the following are emerging technologies?**
    - Liquid air energy storage systems
    - Nano-Supercapacitors
    - Isothermal CAES
    - All of the above