2019 Energy Storage Technology Assessment

Platte River Power Authority

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1 Executive Summary

Platte River Power Authority (PRPA) is investigating energy storage as part of its asset portfolio analysis and Integrated Resource Plan (IRP) activities. This report provides technology characteristics and an estimated cost comparison of several specific types of Energy Storage Systems (ESS) that are suitable for use on Platte River's system.

Characteristics of pumped hydropower energy storage systems (PHES), battery energy storage systems (BESS), and compressed air energy storage (CAES) are discussed in this report. Life cycle cost estimates for PHES and BESS technologies are provided in this report based on four and ten hour storage durations and 400 MW capacities. These energy storage alternatives are analyzed on an indicative 30-year life cycle cost basis considering O&M costs, major maintenance, augmentation, purchased power, and capital recovery costs. CAES is not included in this life cycle comparison because of the current state of technological and commercial development. The results of these calculations for levelized cost of delivered energy or levelized cost of storage (LCOS) are summarized below.

		Lithium Ion Battery Energy Storage		Vanadium Flow Battery Energy Storage		Pumped Hydro Energy Storage	
Capacity	MW	400	400	400	400	400	400
Storage Duration	hrs	4	10	4	10	4	10
30-Year Total Levelized Cost (LCOS)	**$/MWh**	$144	$145	$149	$149	**$151**	**$92**
Engineering and Installation Time	**years**	**0.5 - 1.0**	**1. 3 - 1.7**	**0.7 - 1.3**	**1.0 - 2.0**	**8 - 10**	**8 - 10**

From this comparison it can be observed that for 4-hour storage durations, BESS provides the lowest LCOS and for 10-hour durations PHES provides the lowest LCOS. When considering this result, it is important to keep the assumptions and basis of this calculation in mind. In particular, the evaluation is based on each technology being fully operational and available in year 1 of the 30-year evaluation period. Time required for development and construction is not included in this analysis. In this area, BESS is favored with its shorter 6-24 month timeline as compared to PHES which requires 8-10 years for development and construction. With the protracted development time and more complicated permitting process associated with PHES there is a greater level of risk and uncertainty related to unforeseen schedule delays beyond expectations.

In any case, when selecting an ESS technology, the specifics of the technology must be considered in the context of the user's system parameters such as demand timing, growth projections, generation mix, and grid topology. The user should also be aware of the full spectrum of potential value propositions available with ESS such as capacity credits, frequency regulation, voltage support, and reserves.

2 Introduction

2.1 Scope

Platte River Power Authority (Platte River or PRPA) is investigating energy storage technologies in support of its asset portfolio analysis and is interested in including Energy Storage Systems (ESS) in this analysis. As part of these efforts, this Energy Storage Technology Assessment report is intended to provide technology characteristics and an estimated cost comparison of contemporary generic and non-site-specific utility-scale ESS that are suitable for use on Platte River's system. PRPA has defined the basis for this cost comparison as follows:

- 4-hour and 10-hour energy storage duration
- 400MW power capacity for batteries
- 400MW power capacity for pumped hydro
- 30 year evaluation period
- One full charge/discharge cycle 365 days per year

This information will serve to inform PRPA on characteristics of energy storage resources for further consideration in their IRP.

There are a wide assortment of ESS technologies available for utility-scale applications. A few of these options have reached commercial maturity and are being deployed regularly today. These include pumped hydropower energy storage systems (PHES) and battery energy storage systems (BESS) (lithium ion (Li-ion), sodium sulfur, and vanadium redox flow). These technologies have characteristics and costs that make them suitable for consideration by PRPA and are discussed in depth in this report. Other ESS technologies such as compressed air energy storage, mechanical storage, hydrogen storage, flywheels, other battery chemistries, and liquid air systems are not considered appropriate technologies for PRPA for a variety of reasons including challenges associated with technological maturity, system complexity, storage duration, geographical requirements and commercial availability. Some description is provided in this report, but they are not compared on an economic basis.

Information is provided in this report that illustrates the cost and deployment trends of PHES and BESS. Detailed cost estimates of these technologies are also provided in this report.

There is currently much discussion in the industry over strategies for assigning capacity credits to energy storage resources. This report discusses the results of a capacity credit study to illustrate this relationship.

2.2 Disclaimer

It is not the intention of this report to endorse or promote any specific vendor, but to incorporate a wider picture of the ESS technologies as applied to utilities and specifically to PRPA.

2.3 Storage Technology Overview

The ESS industry is in the midst of significant growth, primarily driven by the increase in deployment of intermittent and renewable generation assets such as wind and solar. The generation from these renewable assets often does not coincide with market demand making storage assets financially attractive in that they allow energy to be stored during periods of excess generation and delivered during periods of high demand. In addition there is a current societal push for greater storage to enable proliferation of carbon-neutral renewable energy resources. Energy storage systems also support load following when intermittent resources experience rapid changes in generation. Energy storage system growth is expected to continue and be further accelerated as costs of ESS are declining and renewables proliferate. Storage systems also offer the following recognized benefits to the transmission grid.

- Energy Arbitrage
- Capacity (Resource Adequacy and Grid Firming)
- Demand Response/Demand Charge Reduction
- Frequency Regulation and Response
- Resilience / Reliability with distributed storage
- Renewables Integration
- T&D System Upgrade Deferral
- Voltage Support
- Contingency / Spinning Reserve

3 Available Technologies

Some of the more prevalent and available ESS technologies are described in this section. As mentioned above, two technologies that have characteristics and costs that are favorable for consideration by PRPA are PHES and BESS. These technologies are useful for storage durations of several hours or more, capable of being deployed at an appropriate scale of several hundred megawatts, technologically proven through the product life cycle, and commercially available from multiple vendors allowing competitive procurement. These technologies are described in some detail in the following sections.

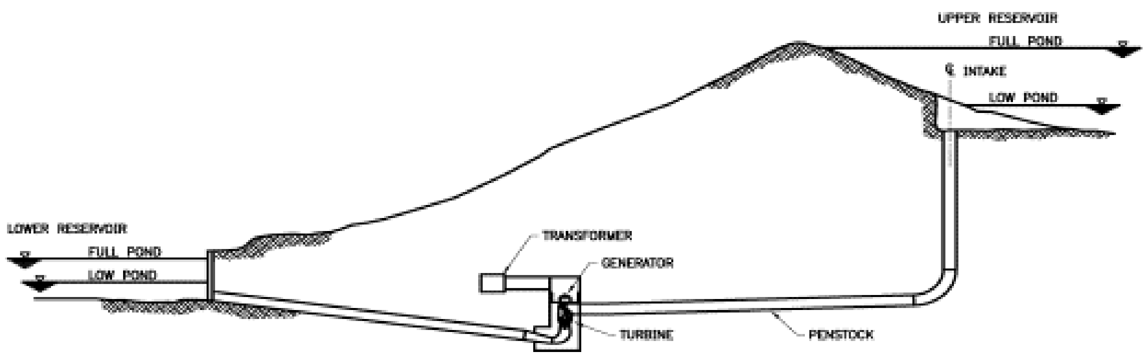
In addition, ESS technologies that are not considered as favorable for PRPA are described in this section. The reasons that these technologies are not considered for more detailed comparison is discussed in the description of each technology.

3.1 Pumped Hydro

Background

PHES is a type of hydroelectric power generation that stores energy in the form of water in an upper reservoir, pumped from a second reservoir at a lower elevation (Figure 1). During periods of high electricity demand, the stored water is released through turbines in the same manner as a conventional hydro station. Excess energy, historically at lower cost during the night and on weekends, but potentially also in the middle of the day when solar generation is maximum, is used to recharge the reservoir by pumping the water back to the upper reservoir. Reversible pump/turbine and generator/motor assemblies act as both a pump and a turbine. PHES stations are unlike traditional hydro stations as they are a net consumer of electricity. PHES plants can be very economical, from an overall system operation perspective, due to on-peak/off-peak price differentials and, more importantly, the provision of ancillary grid services and firming up intermittent solar and wind resources.

Figure 1. Schematic of PHES System



PHES historically has been used to balance load on a system and allow large, thermal generating sources to operate at optimum conditions. PHES is the largest-capacity and most cost-effective form of grid-scale energy storage currently available for longer storage durations. Pumped storage systems also provide ancillary electrical grid services such as network frequency control and reserve generation. This is due to the ability of PHES plants, like other hydroelectric plants, to respond to load changes within seconds and even faster with inertial response.

PHES is now being applied to firm the variability of renewable power sources, such as wind and solar generation. PHES can absorb excess generation at times of high output and low demand, and release that stored energy during peak demand periods, proving to be an enabling technology for the growing renewable power penetration into the United States energy supply system.

Maturity

PHES is the most mature of all energy storage technologies, including mechanical, thermal, chemical, and electrical storage technologies. The total installed capacity of pumped storage in the world exceeds 130 GW and represents almost 99 percent of all energy storage with remaining storage provided by two compressed air energy storage (CAES) projects and batteries. PHES was first used in Italy and Switzerland in the 1890s and reversible pump-turbines became available in the 1930s. In the United States, pumped storage has been providing energy storage and ancillary services since the 1920s. Today, there are 42 operating pumped storage projects in the U.S., providing more than 20 GW of capacity.

Technological Characteristics

PHES is characterized by a round-trip efficiency of roughly 80 percent and negligible performance degradation with time. The reservoirs are generally located above ground and are filled with fresh water, but some unconventional applications adopt the sea as the lower reservoir (seawater pumped hydro energy storage) or underground caverns as lower, and less often, upper reservoirs (underground pumped hydro energy storage). Closed-loop pumped storage projects use two engineered reservoirs with no continuous connection to an existing waterway, whereas open-loop projects are continuously connected to an existing waterway.

Modern pumped storage projects are designed to last beyond a hundred years while being continuously connected to the grid providing either pumping or generation services, as well as load following, ramping and frequency regulation services. Maintenance outage requirements typically are limited to a three week outage every two years, a two month outage every 10 years, and then an extended eight to nine month complete disassembly/overhaul/rewind outage every 20 years. This maintenance cycle can be expected to allow the pumped storage project to have high availability throughout its service life.

Pumped storage systems are more suited for larger storage applications with typical capacities ranging from approximately a few hundred megawatts to over 1000 MW. Gross head differentials range from a few hundred feet to more than 2000 feet. The amount of energy stored varies, but typically correspond to between 8 and 15 hours of operation at full output. Pumped storage plants can be equipped with reversible pump-turbines, which can rotate in both directions to provide generation and pumping capacity, or ternary units, which comprise a separate turbine and a pump coupled along the same shaft. Reversible units are more often used because of their compactness, simplicity, and cost-effectiveness.

To increase the operational flexibility and response time to changes on the grid, reversible pump-turbines have in recent years also been designed with variable-speed generator-motors and sophisticated power electronics (variable-speed pump-turbines), which allows the project to operate over a wider range of operating conditions and provides improved efficiencies in both pumping and generation modes. Converter fed synchronous machines are another modern technology option to provide even greater operational capability in both modes, but there are corresponding tradeoffs due to the size and cost of the full sized converter.

Pumped storage plants can ramp up from 50 percent output to full production capacity in about 15 seconds, from standstill to full production capacity in less than two minutes, or from standstill to full pumping capacity within less than five minutes depending on the plant configuration. Pumped storage projects can typically also shift the mode of operation from generating to pumping, or vice versa, in less than 5 minutes. In addition to providing energy arbitrage, load shifting, and capacity capabilities, pumped storage plants can also provide ancillary services, including for example both primary and secondary load-frequency control, spinning reserve, black start capability, and voltage support.

3.2 Batteries

With growing interest in using batteries for utility scale energy storage applications, there has been significant investment into R&D for a wide array of battery chemistries. A few of these chemistries have emerged as front-runners that are being deployed and utilized at large scale today. The following section provides a brief technical overview of the battery technologies that have demonstrated commercial viability for utility scale applications.

The power input and output of battery energy storage systems are governed by a bidirectional inverter known as a Power Conversion System (PCS). A PCS can respond to a dispatch signal to charge or discharge in milliseconds, allowing a BESS to ramp up from standby mode to full nameplate capacity in less than 2 seconds, including communication latencies. Because there is no rotational inertia, a BESS can change from charging to discharging (and vice versa) nearly instantaneously. This enables the provision of very high performance ancillary services such as frequency regulation. Additionally, battery PCS units have the ability to supply full four-quadrant AC output, which can be utilized to supply voltage and var support.

An appropriately sized BESS can supply the full suite of energy storage services, including energy arbitrage, load shifting, capacity capabilities, ancillary services, including for example both primary and secondary load-frequency control, spinning reserve, black start capability, and voltage support.

3.2.1 Lithium-ion

Background

Li-ion batteries have rapidly become the workhorse of the battery storage industry. Large scale manufacturing and production of multiple chemistries (lithium nickel manganese cobalt oxide ($LiNiMnCoO_2$ or NMC), lithium iron phosphate ($LiFePO_4$ or LFP), lithium manganese oxide (LMO), and lithium titanate ($Li_4Ti_5O_{12}$ or LTO)) have given it a significant portion of the commercial energy storage market. Li-ion's competitive energy density and power density has made it the standard for portable applications. The global demand for portable technologies has played a direct part in Li-ion investment that in turn carries over into large scale Li-ion production.

Maturity

Li-ion is the second-most mature technology in the stationary battery energy storage market, after lead acid (conventional lead acid battery systems are not economical for utility energy storage because of their low energy density, short cycle life, and high cost). The technology was first proposed in 1970, released commercially in 1991, and is now the standard technology for portable electronics and electric vehicles. The same technology used for electric vehicles has become widely accepted for large-scale energy storage applications and also forms the core technology for stationary energy storage.

At the end of 2018, 854 MW (1,372 MWh) of grid-scale battery energy storage systems were operational in the United States. The vast majority of the BESS systems currently in operation are on the order of 10MW or less. It has not been until recent years that larger systems are being constructed. Currently, the largest BESS in operation worldwide is the 100MW (129MWh) Lithium-ion system for Hornsdale Power Reserve in South Australia. As of yet, no single, centralized BESS has been placed into service at the scale being considered by PRPA in this report, however, systems of this size are being contemplated and evaluated.

A large number of vendors produce the technology, including Bosch, Panasonic, Johnson Controls, LG Chem, NEC, Samsung, Saft, BYD, Hitachi, CATL, and GS Yuasa (Mitsubishi). A number of startups with newer lithium technologies went bankrupt in the 2000s and were acquired by larger vendors. Newer startups like Tesla are primarily engaged in the marketing and product development side of the business. Tesla, for example, utilizes batteries manufactured by Panasonic and will continue to do so in its new U.S.-based factory.

All lithium-ion battery systems will gradually degrade in energy capacity over time. The rate of this degradation is heavily dependent on duty cycle, cell chemistry, charge/discharge rates, and other factors. In order to account for this degradation, Li-ion systems can be over-built at the beginning of a project, have modules replaced or added periodically, or some combination of these approaches. The addition of new modules to retain nameplate capacity is known as “augmentation.” Li-ion battery suppliers are now offering capacity maintenance agreements to maintain capacity for at least 20 years using periodic augmentation or full module replacement. These augmentation periods typically are planned for every 5-10 years.

Technological Characteristics

Li-ion batteries consist of a range of technologies varying in size, shape, and chemistry. The primary chemistries in use today are lithium nickel manganese cobalt oxide (NMC), lithium manganese oxide (LMO), lithium iron phosphate (LFP), and lithium titanate (LTO). For stationary applications, the battery industry has thus far moved toward more heavily utilizing NMC. NMC is the most typical chemistry in grid-scale ESS due to its balanced performance characteristics in terms of energy, power, cost, and cycle life.

There has been growing interest in LFP batteries for grid-scale ESS in recent years. In contrast to the NMC battery, the LFP technology is a lower cost battery with a slightly decreased power density, thus requiring more space than NMC for the installation of a similar power rating. LFP technology has a constant discharge voltage, the cell can produce full power to 100 percent depth of discharge (DOD) and its chemistry is seen as safer and less of a fire risk when compared to other Li-ion chemistries due to its reduced energy density. LFP batteries are also prone to a higher degree of self-discharge meaning that the batteries will tend to lose charge faster than other technologies, when not in use.

Li-ion battery cells typically consist of a graphite anode, metal-oxide cathode, and a lithium salt electrolyte gel. For stationary applications these are typically packaged in a flat pouch or rolled up like a jelly-roll (prismatic). Battery cells are integrated into battery modules, which are installed in standard 19-inch-wide racks similar to those used for telecom equipment. The racks are then installed in a building or specially prepared shipping container to function as an integrated battery system.

Li-ion batteries are highly sensitive to temperature. The building or container is typically provided with an active cooling system to maintain the batteries within an optimal temperature range. The system will be de-rated if operated or stored for any significant length of time outside of these optimal temperature ranges. Li-ion batteries are typically designed for operation in an ambient temperature of 70°F, though the optimal point will vary by vendor and intended use.

Due to the temperature sensitivity, fire hazard, and special shipping requirements, many states classify stationary Li-ion systems as hazardous materials. Some jurisdictions have required hazardous material management plans (HMMPs). Careful consideration should be given to fire suppression consisting of either gaseous (dry) systems, which may require air permitting or liquid systems that may cause concerns with the Clean Water Act.

The C-rate of a battery is the ratio of the system’s rated charge/discharge power to its rated energy capacity. Lithium-ion battery systems are inherently best suited for C-rates between 0.25 and 2. This translates to storage charge/discharge durations between 0.5 and 4 hours. Different use-cases necessitate different storage durations, but most recent lithium-ion installations are 1-4 hour systems as this duration is typically sufficient to cover the peak load duration of a utility. To achieve longer durations, more racks or containers can simply be added in parallel while maintaining balance of plant equipment with the same rated power.

Lithium-ion batteries have round trip efficiency (RTE) generally around 90 percent at the AC point of interconnection. The auxiliary power required for system HVAC, controls, and other services is generally self-supplied and included in the RTE number.

3.2.2 Vanadium Redox Flow

Background

Vanadium Redox Batteries (VrBs) are a fundamentally different type of battery energy storage system to the forms previously discussed. A VrB system uses a liquid anode and cathode rather than a single liquid electrolyte. The anode and cathode fluids are circulated through the battery cell into holding tanks.

The systems are relatively new and early versions were complex custom engineered systems. The VrB industry is moving more towards pre-packaged systems in containers to compete with Li-ion systems.

There is much interest in these systems as they have a high cycle life, have large allowable temperature range, operate at low temperature, and have long storage durations.

Maturity

While the first operational system was demonstrated in Australia in the 1980s, there are only a few systems in operation worldwide. A number of vendors make these systems, including UniEnergy Technologies (UET), Gildemeister (American Vanadium), Rongke

Power, Prudent Energy, ViZn Energy, Vionx Energy, and Sumitomo. The industry is currently in a phase of continuous improvement, with three generations of technology available. Only a few systems commercially operate from a worldwide perspective.

VrB systems use electrodes to generate currents through flowing vanadium electrolytes. The size and shape of the electrodes govern power density, whereas the amount of electrolyte governs the energy capacity of the system. The cell stacks are comprised of two compartments separated by an ion exchange membrane. Two separate streams of electrolyte flow in and out of each cell with ion or proton exchange through the membrane and electron exchange through the external circuit.

VrB systems are recognized for their long service life (up to 20,000 life cycles with routine pump maintenance) as well as their ability to provide system sizing flexibility in terms of power and energy. The separation membrane prevents the mix of electrolyte flow, making recycling possible. The end of life can be extended by replacing the electrolyte and the membrane.

The industry, marked by UET and Gildemeister, is moving away from custom systems to prepackaged systems to compete with Li-ion. UET is also offering 2- to 20-year warranties with performance guarantees and long-term service agreements. The industry is currently hampered by the infancy of the companies providing the technology. Many of the vendors are venture-capital backed companies with only a single product line. Additionally, the systems tend to be uneconomic for storage durations less than 3 hours and better suited for longer duration applications. While this technology holds promise, it is still in its early phases of commercialization.

Technological Characteristics

All flow batteries share the common topology of a battery cell with flowable electrolyte pumped between storage tanks. Electrolyte is pumped through the cell for charging or discharging, and is stored in separate tanks for longer duration storage. The volume of the storage tank determines the duration of energy storage. Early systems, and those provided by Prudent Energy and Sumitomo, are still custom engineered with varying durations of storage.

As noted previously, the industry is moving toward containerized systems with pre-determined storage durations of 3 to 8 hours. The prepackaged systems utilized one or more containers per battery. In the case of UET, a 4 MW/16 MWh system utilizes five 20-foot containers, four for the battery and one for the PCS. The containers typically have both secondary and tertiary containment for the electrolyte fluid. Some containerized flow products can be stacked vertically to reduce their footprint.

For larger flow systems on the scale of 50MW or more, it is sometimes advantageous to install the equipment in one large building rather than in modularized containers. This can improve energy density and reduce auxiliary power costs. One such facility is currently under construction in Dalian, China. The 200MW, 800MWh Vanadium redox flow system, provided by Rongke Power, is scheduled to come online in 2020.

VrB batteries are characterized by a high cycle life and insensitivity to temperature. They operate at a low temperature and are only limited by the temperature rating of the auxiliary components (pumps, sensors, etc.). The electrolyte degrades very slowly over time, allowing for a very high cycle life. This allows VrB systems to maintain nameplate capacity for 20+ years without requiring the periodic replacement or “augmentation” that Li-ion systems must undergo. Due to the pumps, they have a high station service load yielding a lower round trip efficiency than other technologies. RTE values for VrB systems are generally around 70 percent[1].

Critical to the design of these systems is that the energy available from the battery depends on the discharge rate. For a continuous discharge at a specified rate (resource adequacy), the storage duration could vary from 2 to 8 hours.

3.3 Compressed Air

Background

Compressed Air Energy Storage systems use motor driven compressors to store compressed air in a storage cavern. Depending on the type, the systems may also store the heat generated by compression of the air. The stored compressed air is delivered to either combustion turbines which are fired with natural gas for power generation or mechanical expanders that convert the compressed air energy directly to electricity with no auxiliary fuel consumption. Utilizing pre-compressed air removes the need for a compressor on the combustion turbine, allowing the turbine to operate at high efficiency during peak load periods but natural gas fuel is still needed, so the technology is not truly carbon free. With mechanical expanders, there is no supplemental fuel used.

Maturity

Two plants are currently in operation, Alabama Electric Cooperative’s (AEC) McIntosh plant (rated at 110 MW) which began operation in 1991 and the Huntorf facility, located in Huntorf, Germany. The Western Energy Hub Project in the U.S. is in active planning stages. Additional CAES plants have been proposed but, as of yet, have not moved forward beyond conceptual design. Some of these proposed projects include, the Norton Energy Storage (NES) project, the PG&E Kern County CAES plant, the ADELE CAES plant in Stassfurt, Germany, the APEX Bethel Energy Center, Chamisa Energy Project, Gaelectric CAES plant in Lame, UK, and the Toronto Hydro UCAES Project

The Western Energy Hub project, promoted by Magnum Energy, LLC (Magnum), is probably the most advanced CAES project under development in the U.S. The salt dome geology has been well characterized, as well as land acquisition and local and state permitting underway. The first phase of the Magnum project is for natural gas liquids (propane and butane) storage which broke ground in April 2013. The second phase of the project under development is construction of four additional solution-mined underground storage caverns capable of storing 54 billion cubic feet of natural gas. Magnum has been granted all the necessary permits for construction and operation of the gas storage facility from the State of Utah.

The final phase of the Western Energy Hub project is CAES, in conjunction with a combined-cycle power generation project. The CAES will utilize additional solution-mined caverns to store compressed air. Off-peak renewable generation will be used to inject air

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[1] AC-to-AC, including auxiliary power.

into the caverns which will be released during periods of peak power demand. The compressed air will be delivered to a combustion turbine. Magnum plans up to 1,200 MW of capacity spread across four 300 MW modules, with two days of compressed air at full load. Magnum anticipates an in-service date of around 2021 for the first module.

Pacific Gas & Electric (PG&E) has been awarded a $25M grant from the Department of Energy (DOE) to research and develop a CAES plant. The California Public Utility Commission (CPUC) has matched the grant and supplied an additional $25M; the California Energy Commission has supplied an additional $1M of support. The proposed project is a 300 MW plant in Kern County, CA with minimum storage duration of 4 hours. The first phase of development involved a reservoir feasibility study that completed in Q4 2015. The estimated in-service date for this project is currently unknown. It has not been stated whether the proposed plant will be diabatic or adiabatic and is likely subject to the outcome of the feasibility study. PG&E issued a Request for Offers on October 9, 2015 to procure products and services related to the CAES project. Potential negotiations with shortlisted bidders commenced in August 2016. A nearly depleted natural gas field in San Joaquin County has been selected for the project site.

The ADELE project is a planned adiabatic (heat generated during compression is stored, then returned to the air when decompressed) CAES plant in Stassfurt, Germany. The project is planned to have a storage capacity of 360 MWh, with a total output of 90 MW and projected efficiency of 70 percent. The project is part of the Federal Government's Energy Storage Initiative and is funded by the German Federal Ministry of Economics and Technology. The initial development phase was funded with $17M and was expected to be completed by 2013. The total project was expected to have a duration of 3.5 years and a cost of $56M.The project development was revised for completion in 2016 however little additional information is available regarding the project.

The equipment utilized in CAES plants, which includes compressors and gas turbines, is well proven technology used in other mature systems and applications. Thus, the technology is considered commercially available, but the complete CAES system lacks the maturity of some of the other energy storage options as a result of the very limited number of installations in operation.

Technological Characteristics

Two primary types of CAES plants have been implemented or are being reviewed for commercial operation: (a) diabatic and (b) adiabatic. In diabatic CAES, the heat resulting from compressing the air is not stored. The air leaving the storage cavern must be reheated prior to expansion in the combustion turbine. Adiabatic CAES stores the heat of compression in a solid (concrete, stone) or a liquid (oil, molten salt) form that is reused when the air is expanded. Due to the conservation of heat, adiabatic storage is expected to achieve round trip efficiencies of 70 percent. Both the McIntosh and Huntorf are diabatic CAES plants with round trip efficiencies of 54 percent and 42 percent respectively.

Varying sources over varying time periods report that the AEC McIntosh plant offers availability from 86 percent to 95 percent. Compressed air energy storage requires initial electrical energy input for air compression and utilizes natural gas for combustion in the turbine. The McIntosh plant offers fast startup times of approximately 9 minutes for an emergency startup and 12 minutes under normal conditions. As a comparison, simple cycle peaking plants consisting of gas turbines also typically require 10 minutes for normal startup. The Huntorf CAES plant has been designed as a fast-start and stand-by plant; it can be started and run at full-load in 6 minutes.

Technological Risks

Because of the limited deployment at scale there is limited potential to competitively bid the major equipment without risk associated with utilizing equipment from an unproven supplier. Another significant risk involves the ability to reliably identify an energy storage geological formation with integrity and accessibility (no proven formations exist in the PRPA territory). Adiabatic designs are under development and introduce new risks into the design of a CAES plant. There are additional heat-storage devices and components in the system that will increase the design complexity of the system. Because of the risks associated with this technology, the uncertainty regarding cost of deployment, limited commercial availability, and limited operating history this technology is not evaluated from an economic standpoint in this report.

3.4 Other Emerging Technologies

There are several other ESS technologies, which are listed below that are not discussed or compared in this report as they are not either not technologically applicable to PRPA bulk-energy storage needs or not sufficiently developed to be considered commercially available. Some of these technologies may be available on a commercial scale, but because of duration limitations, capability limitations, limited supplier base, or limited operating experience they are not considered favorable for PRPA and are not compared from an economic perspective. A brief discussion is presented for each technology summarizing reasons for not including them in the economic evaluation.

- Advanced Lead-Acid, Zinc-Bromine, Zinc-Air flow, and other battery chemistry

There are numerous electrochemical (battery) energy storage solutions with various chemistries in various stages of development and deployment in addition to the Li-ion and VrB technologies detailed in this report. Some of these technologies have the potential to be cost competitive with the established chemistries, but none appear to offer significantly better economics. Therefore, the technologies that were evaluated, Li-ion and VrB can act as proxy for these chemistries that were not evaluated in detail. As these battery chemistries become commercially available, they should be compared with established systems for specific applications on the basis of cost effectiveness, reliability, warranty/guarantee protection, and other factors.

- Liquid Air

Liquid air storage uses electricity to cool air from the atmosphere to the point at which air liquefies, approximately minus 195 °C. The liquid air, which takes up approximately one-thousandth of the volume of air in the gas phase, can be stored for long periods in a vacuum insulated vessel at atmospheric pressure. At times when electricity demanded, the liquid air is pumped into a heat exchanger, which acts as a boiler. Either heat from ambient air or low grade waste heat is used to heat the liquid and turn it back into a gas. The increase in volume and pressure from this is used to drive a turbine to generate electricity. In isolation, liquid air storage systems have a round-trip efficiency of approximately 25 percent. This can be increased to 50-60 percent with the addition of a cold store to capture the energy generated by evaporating the liquid air. There is one pilot facility in operation worldwide, a 2.5 MWh system developed by Universty of Leeds and Highview Power Storage. Because of the low round-trip efficiency and commercial maturity lower than CAES, this technology was not considered favorable for PRPA.

- Hydrogen Storage

Hydrogen energy storage systems use hydrogen as the medium for storage of energy. Hydrogen is generated using electrical energy through electrolysis of water and stored as compressed gas in underground caverns of aboveground tanks. The hydrogen is converted back to electricity through a conventional gas turbine or internal combustion engine or through a fuel cell. Hydrogen systems are capable of storage energy density that is higher than CAES leading to modest costs for the storage portion of the ESS system. This technology is characterized by low round-trip efficiency in the 30 to 40 percent range and high power conversion system cost, approximately two to eight times as expensive as PHES. Given the low round-trip efficiency, lack of commercial scale demonstration, and high cost, this technology was not considered favorable for this PRPA application.

- Flywheels

Flywheel technology is a well-established technology with discharge durations in the scale of seconds to minutes. They are well suited for power related services such as UPS, frequency regulation, and bridging to back-up system. They are not commercially available for bulk-storage applications with discharge durations in the range of multiple hours as required by PRPA.

- Capacitors

Capacitors are a direct method of storing electrical energy, storing energy as electrical charges. They are widely used in power-quality related services such as bridging and ride-through. They have short storage durations on the scale of milliseconds up to a few minutes. Current capacitor technology has energy density that is orders of magnitude lower than state-of-art battery systems. Because of their low energy density and short discharge times they are not favorable for the PRPA bulk-storage needs.

- Magnetic and superconducting magnetic systems

Magnetic and superconducting magnetic energy storage system are a direct method of storing electrical energy, storing energy in the form of a magnetic field created by flowing electrical charges. Because of their fast response time they are suitable for power-quality related services such as bridging and ride-through. They have short storage durations on the scale of milliseconds up to a few minutes. Current magnetic technology has energy density that is higher than capacitors, but is still orders of magnitude lower than state-of-art battery systems. Because of their low energy density and short discharge times they are not favorable for the PRPA bulk-storage needs.

- Mechanical Gravity Energy

Mechanical gravity energy storage systems convert electrical energy into potential energy by raising heavy solid objects in the earth's gravitational field. The stored potential energy can be converted back to electrical energy by a generator coupled to the object that allows the object fall in a controlled way. PHES is a form of mechanical gravity energy storage that uses water as the working medium. Various arrangements have been proposed including railcar systems, crane-based systems, and in-ground systems. There have been a few demonstration projects completed, but no commercial deployment has been made. Because of the lack of any commercial deployment, this technology is not considered favorable for PRPA applications.

4 Deployment Trends

4.1 Pumped Hydro

In the United States, one of the last pumped storage projects to be constructed and commissioned was the 1,065 MW Bad Creek Pumped Storage Project, owned and operated by Duke Energy, in 1991, with Oglethorpe's Rocky Mountain Pumped Storage Project commissioned in 1995. However, many projects are currently in FERC licensing proceedings or in the pre-feasibility or feasibility level engineering definition phases. These projects include the 2,000 MW Big Chino Valley Pumped Storage Project in Arizona, 740 MW Tazewell Pumped Storage Project in Virginia, 1,200 MW Goldendale Energy Storage Project in Washington, 400 MW Swan Lake North Pumped Storage Project in Oregon, and 1,300 MW Eagle Mountain Pumped Storage Project in Southern California.

In Europe, several new pumped storage projects have recently been brought on line, including the 1,000 MW Limmern Pumped Storage Project completed in 2017 and the 900 MW Nant de Drance Pumped Storage Project in Switzerland in 2018.

Variable speed reversible turbine technology has been the typical equipment selected for the new installations in Europe where greater operational flexibility is required by the grid. Similarly, these types of pump-turbines have also been the focus for the projects under study in the U.S., primarily because of the increased operating flexibility, increased operating range and efficiency, and ancillary services that they can provide for a market that is becoming more penetrated by intermittent generation sources like solar and wind.

In the U.S., several of the projects under study and in FERC licensing proceedings are closed-loop facilities, meaning they have no continuous connection with an existing waterway. They, therefore, require construction of two new reservoirs by excavation or damming of suitable valleys as well as identification of a water source for filling up the reservoirs to prepare for commercial operation and to offset any water losses due to evaporation, infiltration, and leakage during operation. However, the environmental issues can be fewer with closed-loop projects, consequently resulting in fewer required environmental studies and lower overall impact to those resources.

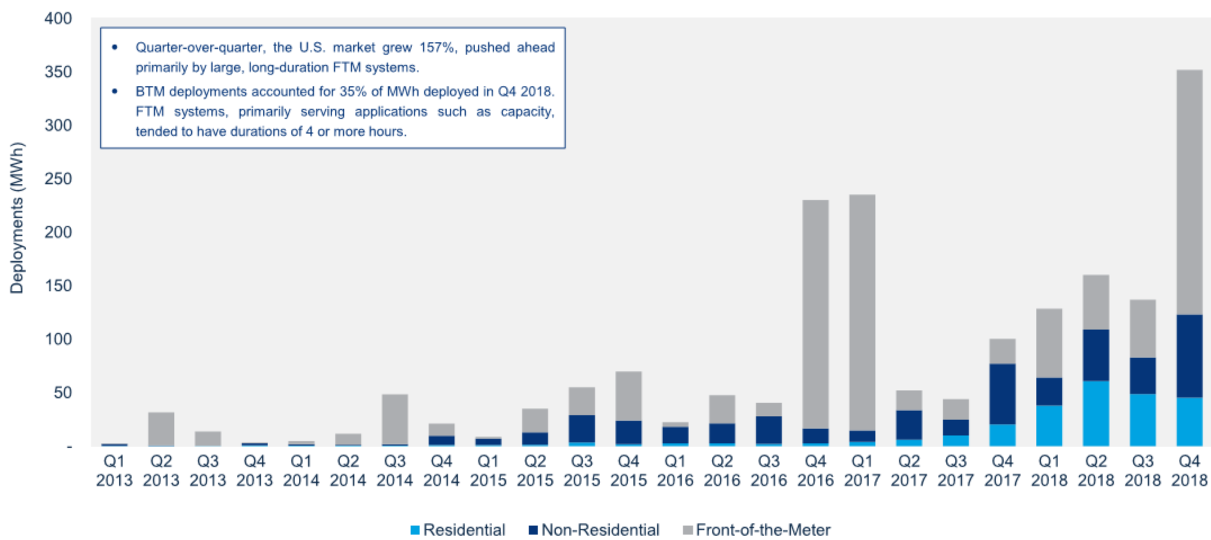
A pumped-storage project is little more than a typical hydroelectric power plant with associated water retaining structures, powerhouse, and water conveyances, but with more complicated rotating generating equipment. The expertise to engineer a pumped storage project exists in the U.S. with the large engineering consulting companies familiar with dam design and construction, underground tunneling, and powerhouse mechanical and electrical components. Teaming arrangements and joint ventures with European engineering firms ensure that the latest advancements in pumped storage powerhouse equipment design are incorporated.

Contractors in the U.S. also have the expertise necessary to construct new pumped storage projects. Specialized contractors may be used for underground construction, transmission, and other specialized project components.

4.2 Batteries

The most significant growth in energy storage installations has been in the area of battery technology. In 2018, it was reported that over 777 MWh[2] of battery capacity was installed in the U.S., the majority of which was Li-ion battery technology. Fourth quarter of 2018 was a record quarter for battery deployment with an increase of 50 percent over the previous record and 100 percent over the previous quarter.

Figure 2. U.S. Energy Storage Deployment in Megawatt-Hours



Source: GTM Research

While the vast majority of energy storage systems installed thus far have capacity (MW) sizes in the single digits, there has been a growing number of centralized, very large scale battery deployments and planned projects in recent months. Currently, the largest BESS in operation worldwide is the 100 MW/129 MWh Lithium-ion system for Hornsdale Power Reserve in South Australia. Florida Power and Light Co. (FPL), for example, recently announced plans to build a 409-MW/900-MWh battery storage facility, called Manatee Energy Storage Center, to begin operations in late 2021. This facility will have

[2] Includes both Front-of-The-Meter (FTM) and Behind-The-Meter (BTM) deployments.

roughly four times the storage capacity of the world's current largest operational battery system in South Australia.

To meet these goals using batteries, land use constraints, the electrical characteristics of PRPA's existing grid infrastructure, and other economic factors would need to be considered. These factors would likely favor deployment of a distributed fleet of BESS projects rather than a large centralized unit. Distributed storage assets could provide multiple services to multiple areas of the grid simultaneously, could use a range of technologies tailored to specific use-cases, and could provide greater redundancy than highly centralized storage assets.

5 Pricing Trends

5.1 Pumped Hydro

In general, cost trends for pumped storage projects tend to follow the general construction cost trends of any large infrastructure project. Pricing for pumped storage is very site specific and strongly dependent on available head and length of any water conveyances. The pump-turbine and related electrical and mechanical balance of plant equipment supply and installation typically represents approximately 25 percent of the total cost of the project for a green field site with no existing infrastructure. If one existing reservoir can be utilized, the cost share of the equipment supply and install can be approximately 30 percent, and if two existing reservoirs are used, then that share may be even higher. Recent equipment budget estimates indicate that variable speed equipment supply and installation costs can vary from approximately $400/kW to $600/kW, depending on size of units, number of units, and the head. Costs for single speed pump-turbine equipment would be less. As the technology is very mature, any future cost variation will likely be more a function of availability of suppliers, cost of steel, and general market conditions than any advancement or innovation in the technology.

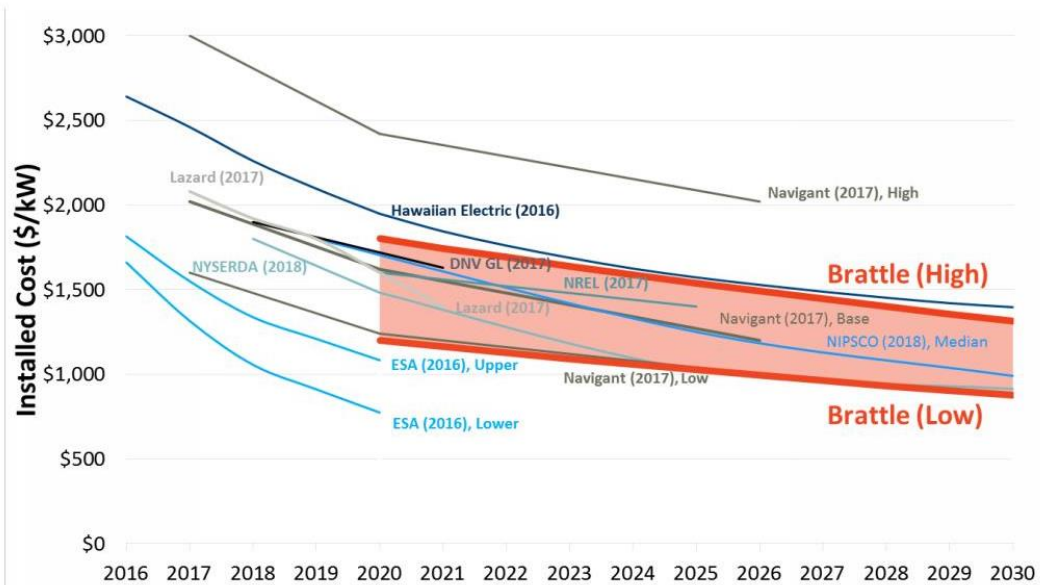
Overall project construction costs are also highly dependent on the project location and availability of the skilled labor needed to construct a pumped storage project. These are large infrastructure projects that require a significant workforce that typically stay in either a nearby town, or, if project is remote, in a camp on site. Regional labor market conditions will affect the construction costs as these projects can employ up to 1000 workers or more. Competition from other large concurrent infrastructure projects in the region will affect the number of qualified bidders, which would also affect the cost.

5.2 Batteries

The costs for battery storage technologies are expected to continue to fall as maturity is gained and the economies of growing market orders are secured. The cost of Li-ion batteries have dropped nearly 90 percent from their commercialization in 1991 and have been trending down at an annual rate of approximately 14 percent over the past 5 years. Most indications show that the downward trend will continue as suppliers continue to improve manufacturing processes and production capacity. In 2018, increasing demand for mineral resources, especially cobalt, slowed the decline in NMC battery prices and increased lead times. This has redirected some attention to LFP technology, a trend which is expected to continue. Less established technologies such as flow batteries will likely see a substantial decline in installed cost if they are able to reach the level of widespread commercialization that Li-ion batteries are now experiencing. Many flow technologies also offer the advantage of a very long cycle life as compared to current Li-ion cell technology. This means they do not require the same periodic augmentation (and the associated costs) that Li-ion batteries do to maintain energy capacity.

Figure 3 below shows the approximate battery installed cost trend out to 2030, based on data assembled by The Brattle Group. HDR recommends using the Brattle (Low) curve as the expected battery storage moving forward.

Figure 3. Cost Projections for 4-hour Battery Energy Storage Systems



Sources and Notes: The Brattle Group, Literature review of Navigant (2017), Hawaiian Electric Companies (2016), NREL (2017), NIPSCO (2018), DNV GL (2017), NYSERDA (2018a), ESA (2016), and Lazard (2017). Installed cost estimates for a 4-hour storage system. All values in nominal dollars.[3]

[3] Brattle cost projections assume a 15 year lifespan. With the report the Brattle Group states the following: *"Our fixed-cost and cost-levelization assumptions include the costs of replacing worn-out battery cells during the 15-year period. We do not assume degradation over time, consistent with the assumption that worn-out battery cells will be replaced throughout the 15-year period."*

6 Cost Comparison

6.1 Pumped Hydro

Construction costs for pumped storage were estimated in Oct 2018 dollars using actual construction cost data published by EPRI[4] for fourteen historical pumped storage projects constructed in the United States between the years 1962 and 1982. The original construction costs were first escalated to Oct 2018 dollars using U.S. Bureau of Reclamation construction and labor cost indexes and then calibrated to the estimated construction costs for five recent feasibility level studies of pumped storage projects with capacities ranging from 400 to 1200 MW and with energy storage ranging from 10 to 12 hours. The 2018 costs were escalated to 2019 dollars using a 3 percent escalation rate for the cost comparison analysis.

The historical cost data included the separated costs attributable to capacity (MW) and to energy storage (MWh). Therefore, the analysis and escalation of the historic data to 2019 dollars provided these cost components, which facilitated the cost estimation of the generic pumped storage projects of interest. Recent supplier quotes for variable speed pump-turbines and associated electrical equipment and costs from recent European experience for balance of plant equipment were used to ensure that the pump-turbine costs and balance of plant electric and mechanical equipment costs were accurately captured. Note that the costs estimated and presented below do not include transmission, land acquisition, or cost of capital during construction (AFUDC) which can be significant due to the large quantities of land and the long project construction durations that are typically required. The cost of AFUDC is not included because it is specific to owner financing parameters. The costs do include indirect costs, such as administration and construction management. Engineering costs were estimated to be 3 percent of total construction cost; planning and FERC licensing costs for an original FERC license were estimated to be $3,000,000. The generic project cost estimates presented below include an assumption of a four-unit powerhouse with no existing reservoirs.

However, although based on historic cost information, the actual construction cost of a pumped storage project is highly site specific. The costs presented below represent completely generic projects assuming completely new infrastructure (two new reservoirs with dams) and must, therefore, be considered with a level of uncertainty of approximately -30 percent to +50 percent. High capacity and energy projects constructed on sites with good access, high head, short water conveyances, in good rock, suitable topography for the reservoirs, and easy access to construction power and water, would result in lower project costs. Similarly, if one or two existing reservoirs could be used for either or both the upper and lower reservoirs, the project cost would be lower by the avoided cost of constructing those dams and the reservoirs. For example, utilizing one existing lake or reservoir for the lower reservoir could reduce total construction costs by

[4] EPRI. 1990. Pumped-Storage Planning and Evaluation Guide. Prepared by Harza Engineering Company, Chicago, Illinois. January 1990.

approximately 10 percent. Projects with the opposite characteristics to those described above would result in higher costs.

In addition to the upfront costs for licensing, permitting, engineering, and construction, we have also estimated operation and maintenance (O&M) costs per the table below. Annual O&M costs were estimated per EPRI (1990) guidance, which provides annual costs based on estimated annual energy generation and include costs for operation (e.g. station service load), maintenance, general expenses, insurance premiums, and other related expenses. For the purpose of this analysis, we assumed the project would complete one full operating cycle at full capacity for 358 days a year, including a total of one week of outage every year. At an interval of every 20 years, the pump-turbines and motor-generators would be refurbished at a cost of approximately $10,000,000 per unit. In addition, the original FERC license is assumed to be issued for 50 years, after which we estimate relicensing costs of $2,000,000 every 40 years after that.

It should be noted that there is still significant value remaining in any hydropower facility, including pumped storage facilities, at the end of its typical service life, which is typically estimated to be between 80 and 120 years. The civil structures would likely have significant service life remaining, although the electro-mechanical equipment would likely need to be replaced. We have not estimated this value, but it should be taken into consideration when comparing pumped storage to other technologies with shorter expected service life and no remaining or salvage value at the end. Decommissioning costs are also not included.

Table 1. PHES Cost Data

Capacity (MW)	400	400
Energy Storage (hrs)	4	10
Engineering, Construction & Commissioning Capital Cost ($M)	$876	$1,107
O&M Cost ($M)[5]		
O&M (annual)[6]	$3.50	$4.90
Insurance[7]	$0.90	$1.10
Bi-Annual 3-week Outage Costs ($)	$0.60	$0.60
Replacement / Major Overhaul (every 20 years)	$30.0	$30.0
Other Factors		
Approximate Footprint Requirements	25-100 ac	50-150 ac
Permitting	See Planning/Original	See Planning/Original

[5] First year costs, later years are escalated

[6] Excludes estimated insurance costs

[7] Assumed equal to 0.1 percent of Construction & Commissioning Capital Costs per EPRI (1990).

	FERC Licensing/ Studies above	FERC Licensing/ Studies above
Time to Develop[8]	8-10 years	8-10 years

6.2 Batteries

Construction costs for battery energy storage systems were estimated in 2019 dollars using a combination of publicly available industry data and information obtained directly from battery manufacturers and vendors. Several reputable organizations routinely track and publish cost and deployment trends for various types of energy storage technology. Considering the pace at which battery system costs are declining, it is important to incorporate data obtained as recently as possible. Therefore, actual bid data from numerous BESS suppliers was also considered. The resulting estimates were calculated based on a cost per MW and/or cost per MWh rate extrapolated from these resources.

Note that the costs estimated and presented below do not include transmission or cost of capital during construction (AFUDC). The costs do include indirect costs, such as administration and construction management. Planning and licensing costs are minor with BESS and are included in the engineering costs.

One key advantage of battery energy storage systems is that they do not require highly specific geographical or geological characteristics to be installed. This potentially reduces costs and time requirements associated with permitting, land acquisition, and site development processes. Additionally, the modular nature of the container-based solutions that most suppliers offer makes relatively rapid deployment of large-scale projects a possibility. Another advantage of this modular is that the cost for half this system size (200-MW, 800 MWh) is half the price of the current evaluated system.

Different battery technologies offer varying degrees of energy density, but in any case the size of BESS discussed in this report would require a considerable amount of land, but much less than an equivalently sized PHES. As a reference, the 100MW/129MWh Lithium-ion system for Hornsdale Power Reserve occupies approximately 2.5 acres of land. This equates to ~0.02 acres/MWh. VrB systems are generally less energy dense: one VrB supplier quotes a footprint of ~0.04 acres/MWh[9]. Estimates for land acquisition costs are not included in this report.

As shown in section 4.2 above, there remains a great deal of uncertainty in predicting future costs associated with BESS. Breakthroughs in technology and associated reductions in costs continue to occur on a regular basis as funding is poured into R&D efforts globally. Given the degree of advancement that has been made in both the capability and cost of battery technology over the last decade, it is difficult to predict what the landscape will look like in 10 years, much less 30 years. The likelihood that costs will flatten out near current levels and no major technological advancements will be made over that time seem very low.

[8] Time to construct 4-5 years

[9] Per VRB Energy Gen2X, 2018

Additionally, much of the data gathered for this report is based on battery system sizes on the order of 10-160 MWh. The scale of deployment that PRPA is considering for this report is greater than this, which creates economies of scale that may reduce specific costs of the system. These potential economies of scale are not explicitly included within this report. They are reflected in the higher negative uncertainty values associated with this estimate of approximately -50 percent to +30 percent.

Requirements for O&M of battery systems vary for different technologies. For Li-ion systems, O&M costs tend to be quite minimal as there are virtually no moving parts aside from HVAC systems. Flow systems, however, require a system of pumps to move electrolyte fluid between storage tanks and across an ion exchange membrane. These pumps require periodic maintenance and replacement, which elevates O&M costs. A major advantage of flow systems is that the energy capacity of a flow system does not degrade over time in the way that Li-ion battery cells do. The rate of capacity degradation of a Li-ion battery depends heavily on duty-cycle, but generally these systems require either augmentation (adding new modules to the existing degraded ones) or full replacement of degraded modules with fresh ones every 5-10 years to maintain adequate capacity. The cost associated with that augmentation and replacement is broken out separately in the table below and are not included in Warranty or O&M estimates. Because cell cycle-life is expected to continue to improve, it is assumed that an average of 2 full module replacements would be required over a 30 year project life.

At the end of the 30 year project life, there are several options an owner could consider as a path forward. If the system is Li-ion, the capacity maintenance agreement could be renewed and another cycle of augmentation or replacement could be undertaken to allow the system to retain its nameplate capacity. Alternatively, the system could simply remain in use at a continuously de-rated capacity. If it is desired that the system be decommissioned and dismantled, there would be costs associated with the recycling and disposal of the equipment. Most suppliers offer a recycling / disposal program with the supply of their equipment. Those costs are not included in this report. Many suppliers of flow systems offer commercial arrangements to lease the electrolyte or a purchase and buy-back option, where the supplier will purchase the electrolyte fluid from the owner at the end of the project. This residual value is also not included in this report.

Estimated Li-ion battery system costs for a 400 MW, 1600 MWh installation and a 400 MW, 4000 MWh installation in 2019 dollars are as follows:

Table 2. Li-ion BESS Cost Data

Capacity (MW)	400	400
Energy Storage (hrs)	4	10
Engineering, Construction & Commissioning Capital Cost ($M)[10]	$502	$1,255
O&M Cost ($M)[11]		
O&M (annual)	$5.12	$12.8

[10] Li-ion capital costs are expected to decline at a rate of 8% per year, per Lazard LCOS V4.0

[11] First year costs, later years are escalated

Replacement / Major Overhaul (every 10 years)	$265	$634
Other Factors		
Footprint Requirements	32 acres	80 acres
Residual Value	Low	Low
Time to Construct[12]	6-12 months	16-20 months

Estimated Vanadium Redox Flow battery system costs for a 400 MW, 1600 MWh installation and a 400 MW, 4000 MWh installation in 2019 dollars are as follows:

[12] Construction only; additional 6-12 months including engineering and licensing

Table 3. Vanadium Redox Flow BESS Costs Data

Capacity (MW)	400	400
Energy Storage (hrs)	4	10
Engineering, Construction & Commissioning Capital Cost ($M)[13]	$551	$1,379
O&M Cost ($M)[9]		
O&M (annual)	$19.9	$49.8
Replacement / Major Overhaul	Not Required for Vanadium Flow	Not Required for Vanadium Flow
Other Factors		
Footprint Requirements[14]	64 acres	160 acres
Time to Construct[15]	8-16 months	12-24 months

6.3 Lifecycle Cost Comparison

Each energy storage alternative was analyzed in an indicative lifecycle cost analysis to establish a levelized cost of storage (LCOS) considering capital costs, fixed O&M costs, major maintenance, augmentation, and purchased power over a 30 year evaluation period. The levelized cost of storage is calculated as the net present value of the annual costs over a 30 year period divided by the annual energy discharged to the grid (MWh). This analysis assumes first year costs in the first quarter of 2019. The lifecycle cost analysis considers one discharge/charge cycle per day.

In addition to the basis described in Section 5.1 and Section 5.2, the following approach and assumptions were utilized to develop the LCOS for each of the options:

- Escalation at 3 percent per year, provided by PRPA.
- Discount rate at 5 percent, provided by PRPA.
- Capital recovery costs are representative of an annualized cost based on the total capital costs discussed in Section 5.1 and Section 5.2. The costs include engineering, planning, regulatory, construction, construction management, and owner's costs.
- O&M costs - include staffing costs and reoccurring equipment maintenance costs. Fixed costs associated with insurances and property taxes were excluded from the analysis.
    - PHES – costs are inclusive of staffing, turbine, generator, and balance of plant and facility routine maintenance and bi-annual outages. No royalty or land lease fees are included in these costs.

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[13] Vanadium Flow Battery capital costs are expected to decline at a rate of 11% per year, per Lazard LCOS V4.0

[14] Footprint Requirements can be reduced significantly using vertical stacking of systems.

[15] Construction only; additional 6-12 months including engineering and licensing.

    - BESS – typical costs include scheduled maintenance activities, inverter replacements, power stack and pump inspection and replacement (flow batteries), remote monitoring and troubleshooting, software licensing and updates, HVAC maintenance, auxiliary electrical loads, periodic chemistry refresh (flow batteries), and mechanical/electrical inspections.

- Major Maintenance/Augmentation
    - PHES – Major maintenance costs are included in year 20 and 21. It is assumed that the units will require 6 months for complete refurbishment.
    - BESS – due to the capacity and round-trip efficiency degradation of Li-ion technology over time, augmentation strategies are included that entail periodic replacement to ensure that the BESS is supplying the necessary MW, MWh, and expected cycle life during the performance period. Lithium Ion augmentation is assumed to occur in year 10 and 20. Vanadium flow batteries do not experience significant performance degradation over time.
- Purchased Power Costs – off-peak electric purchases to charge or pump each ESS option. For example, PHES pumping costs are determined by dividing the discharge generation by the average plant round-trip efficiency of 80 percent and multiplying by the cost of electricity. An off-peak energy price of $18/MWh has been assumed for this analysis.

The total LCOS incorporates estimated capital costs, operating costs, and generation for each option and is summarized in Table 4. In general, the PHES units result in lower levelized costs on a $/MWh basis compared to BESS options. For this analysis, the larger 10 hour storage duration PHES units benefit from economy of scale cost reductions. For the shorter 4-hour duration, the estimated cost of the augmentation and maintenance for the BESS options bring their costs above those for PHES. The cost of the augmentation for the BESS can vary with each OEM. BESS integrators are typically willing to provide a guaranteed equipment life of about 10-15 years and a guaranteed capacity for over 20 years with an appropriate augmentation strategy. Each integrator strategy can be different and there are not set industry standards.

Determining what type of configuration to pursue depends on many factors, but is driven by overall capacity and energy requirements and the associated least cost alternative (capital and lifecycle) associated with such.

Table 4. Energy Storage Systems Lifecycle Cost Comparison[16]

		Lithium Ion Battery Energy Storage		Vanadium Flow Battery Energy Storage		Pumped Hydro Energy Storage	
Capacity	MW	400	400	400	400	400	400
Storage Duration	hrs	4	10	4	10	4	10
Annual Generation							
Discharge	MWh	570,000	1,424,000	570,000	1,424,000	535,000	1,339,000
Charge	MWh	655,000	1,637,000	814,000	2,034,000	669,000	1,673,000
Capital Cost[17, 18]							
Total Capital Cost	$/kW	$1,255	$3,138	$1,379	$3,446	$2,191	$2,768
Levelized Cost of Storage[19]							
Capital Cost Recovery	$/MWh	$57	$57	$63	$63	$107	$54
O&M and Warranty	$/MWh	$13	$13	$50	$50	$10	$6
Major Maintenance/ Augmentation	$/MWh	$44	$45	$0	$0	$2	$1
Purchased Power	$/MWh	$29	$30	$37	$37	$32	$32
Total Levelized LCOS	**$/MWh**	$144	$145	$149	$149	$151	$92

[16] Not including land acquisition, transmission, or AFUDC.

[17] Collected from industry data

[18] Costs in 2019$

[19] The levelized cost of storage is calculated as the net present value of the annual costs over a 30 year period divided by the annual energy discharge to the grid (MWh).

17 PHES values are based on existing dam and powerhouse, without a reservoir

7 Capacity Credit

Assigning capacity credit (CC) values to energy storage systems is a topic of much discussion in the energy storage industry today. The ability of an ESS to provide reliable capacity depends greatly on the characteristics of the ESS itself, particularly the duration of the system. As such, there is no standard CC value that can be attributed to ESS. Several frameworks for assessing CC values for storage systems have been developed, which calculate CC values iteratively based on the storage system parameters and the characteristics of the system on which they are modeled.

In general, there are three main factors that inhibit a storage resource's ability to provide firm capacity during a stress event (Great Britain 2017):

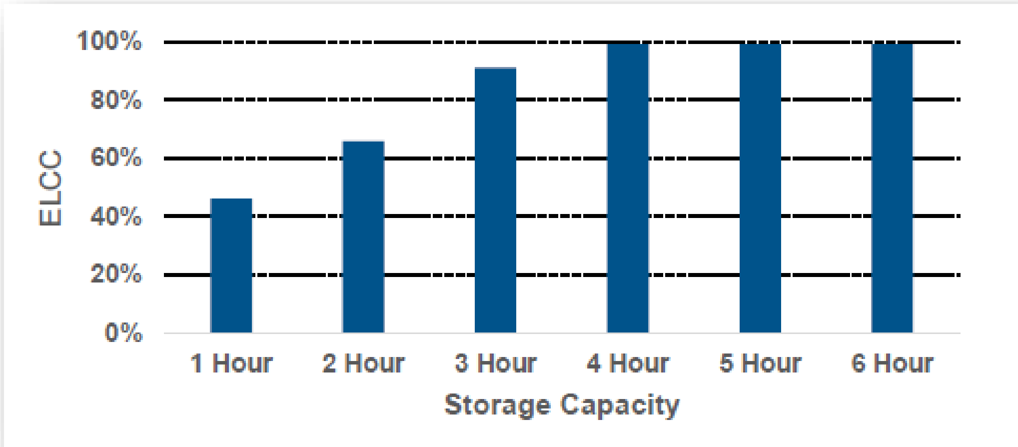
1. Stress events may last longer than the duration of the ESS.
2. The declining performance of ESS over time reduces their contribution to security of supply.
3. Some ESS may be less than fully charged at the start of a stress event if they are simultaneously providing multiple grid services.

Therefore, to some degree, the higher the duration of a storage resource, the higher the CC that can be assigned to it. An energy storage system with a duration of many hours would behave similarly to a thermal generator in terms of its ability to provide firm energy to the grid at the time of need (CC = availability).

In addition, it must be assumed that the resource is available during the period(s) with the highest load at a full state-of-charge. When the resource is being used simultaneously for an alternative application (such as frequency response), this may not be the case. To account for this, an ESS can be over-built to provide multiple services by allocating portions of its energy capacity to each service. For example, a 20 MWh ESS can assign 4 MWh of its energy capacity to frequency regulation, while the remaining 16 MWh can be used for supplying capacity reserves.

A 2016 study by ICF sought to quantify the relationship between duration and CC by modeling energy storage systems of varying durations on the ERCOT grid. The results of the study indicated that a 1-hour energy storage device provides nearly half the capacity value, and a 4-hour energy storage device provides almost full capacity value. Figure 4 shows the relationship between the Electric Load Carrying Capability (ELCC) of an energy storage device and the duration of the device (Johal, Harjeet, et al 2016).

Figure 4. Capacity Value of Storage as a Function of Stored Energy



Source: ICF

The analysis on the modeled grid indicates that smaller duration of energy storage provides partial capacity benefits, while an energy storage system with 4 hours or higher of stored energy could obtain almost 100 percent ELCC. In other words, a 100 MW energy storage system with 1-hour of stored energy can provide 46 MW of firm capacity, while a 100 MW storage resource with 4 hours of stored energy can provide 99 MW of firm capacity (Johal, Harjeet, et al 2016).

In February 2018 FERC (Federal Energy Regulatory Commission) issued order 841 directing regional gird operators to devise new rules for participation of ESS in multiple electricity market services including wholesale energy, capacity, and ancillary services. The deadline for regional grid operators to develop rules for implementation is December 2019. Currently RTOs (regional transmission organizations) have draft rules in varying stages of development. The California Public Utilities Commission has proposed minimal revisions to its 4-hour rule which states that for storage to be eligible it must have the ability to operate for at least four consecutive hours at maximum power output for three consecutive days. NYISO has proposed rules that allow storage to be eligible based on its capability to meet 4-hour run-time requirements with derating based on availability history. PJM has proposed 10-hour requirements for participation in their capacity market.

In the absence of these regulatory requirements, however, the achievable capacity credit ultimately becomes a function of the system that it is serving and more specifically the size and duration of the system's peak period upon which capacity is determined.

8 Conclusion

Platte River Power Authority is investigating energy storage as part of its asset portfolio analysis and Integrated Resource Plan (IRP) activities. This Energy Storage Technology

Assessment report is intended to provide technology characteristics and an estimated cost comparison of contemporary generic and non-site-specific, utility-scale Energy Storage Systems that are suitable for use on Platte River's system.

There is a wide assortment of ESS technologies available for utility-scale applications. A few of these options have reached a sufficient state of technological and commercial development so that they can be considered by PRPA. These include pumped hydropower energy storage systems (PHES) and battery energy storage systems (BESS). These technologies have characteristics and costs that make them suitable for consideration by PRPA and are discussed in depth in this report. Compressed air energy storage (CAES), is discussed in this report but it is not considered favorable for PRPA's application because of the limited commercial experience, system complexity, and geographical requirements of the technology.

Information is provided in this report that illustrates the cost and deployment trends of PHES and BESS. Life cycle cost estimates for these technologies are provided in this report based on four and ten hour storage durations and 400 MW capacity as defined by PRPA. Each energy storage alternative was analyzed in an indicative life cycle cost analysis to establish a levelized cost of storage (LCOS) considering O&M costs, major maintenance, augmentation, purchase power, and capital recovery costs over a 30 year evaluation period. This analysis assumes first year costs in the first quarter of 2019. The lifecycle cost analysis considers one complete discharge/charge cycle per day. The results of this calculation are summarized below.

		Lithium Ion Battery Energy Storage		Vanadium Flow Battery Energy Storage		Pumped Hydro Energy Storage	
Capacity	MW	400	400	400	400	400	400
Storage Duration	hrs	4	10	4	10	4	10
30-Year Total Levelized Cost (LCOS)	**$/MWh**	$144	$145	$149	$149	**$151**	**$92**
Engineering and Installation Time	**years**	**0.5 - 1.0**	**1. 3 - 1.7**	**0.7 - 1.3**	**1.0 - 2.0**	**8 - 10**	**8 - 10**

From this comparison it can be observed that for 4-hour storage durations, BESS provides the lowest LCOS and for 10-hour durations PHES provides the lowest LCOS. When considering this result, it is important to keep the assumptions and basis of this calculation in mind. In particular, the following items should be considered:

- The cost evaluation is based on each technology being fully operational and available in year 1 of the 30-year evaluation period. Time required for development and construction is not included in this analysis. In this area BESS is favored with its shorter 6-24 month timeline as compared to PHES which requires 8-10 years for development and construction.
- With the protracted development time and more complicated permitting process associated with PHES there is a greater level of risk and uncertainty related to unforeseen schedule delays beyond expectations.

- The price uncertainty for PHES (-30 percent to +50 percent) is higher than that of BESS (-50 percent to +30 percent) as a result of:
    - The highly site-specific nature of PHES and,
    - The downward capital cost trends in BESS.
- Transmission and land acquisition costs as well as costs for the allowance for funds used during construction (AFUDC) are not included in the analysis. These costs would be expected to be more favorable for the BESS technology.
- The value of the ESS at the end of the analysis period (30 years) is not included. PHES, with an expected service life of between 80 and 100 years would have significantly more value remaining after 30 years than a BESS system.

In any case, when selecting an ESS technology the specifics of the technology must be considered in the context of the users system parameters such as demand timing, growth projections, generation mix, and grid topology. The user should also be aware of the full spectrum of potential value propositions available with ESS such as capacity credits, frequency regulation, voltage support, and reserves.

9 References

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