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Review

An Evaluation of Energy Storage Cost and Performance Characteristics

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Abstract: The energy storage industry has expanded globally as costs continue to fall and opportunities in consumer, transportation, and grid applications are defined. As the rapid evolution of the industry continues, it has become increasingly important to understand how varying technologies compare in terms of cost and performance. This paper defines and evaluates cost and performance parameters of six battery energy storage technologies (BESS)—lithium-ion batteries, lead-acid batteries, redox flow batteries, sodium-sulfur batteries, sodium-metal halide batteries, and zinc-hybrid cathode batteries—four non-BESS storage systems—pumped storage hydropower, flywheels, compressed air energy storage, and ultracapacitors—and combustion turbines. Cost and performance information was compiled based on an extensive literature review, conversations with vendors and stakeholders, and costs of systems procured at sites across the United States. Detailed cost and performance estimates are presented for 2018 and projected out to 2025. Annualized costs were also calculated for each technology.

Keywords: energy storage; energy economics; batteries; lithium-ion; pumped storage hydro; compressed air energy storage; flywheels; ultracapacitors; combustion turbines

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1. Introduction

The energy storage industry has expanded globally as costs continue to fall and opportunities in consumer, transportation, and grid applications are defined. As the rapid evolution of the industry continues, it has become increasingly important to understand how varying technologies compare in terms of cost and performance. Despite high interest, however, there remain few comprehensive and in-depth analyses of storage costs and performance available to the public. With this background in view, this paper has three objectives:

1. To define and compare cost and performance parameters of six battery energy storage systems (BESS), four non-BESS storage technologies, and combustion turbines (CTs) from sources including current literature, vendor and stakeholder information, and installed project costs.
2. To forecast those cost and performance parameters out to the year 2025.
3. To annualize the values derived so that the cost of each technology may be fairly compared given their varying life cycles.

Along with CT, the following energy storage technologies are evaluated:

- Lithium-ion batteries,
- Lead-acid batteries,
- Redox flow batteries,
- Sodium-sulfur batteries,
- Sodium-metal halide batteries,
- Zinc-hybrid cathode batteries,
- Pumped storage hydropower (PSH),
- Flywheels,
- Compressed air energy storage (CAES), and
- Ultracapacitors.

Cost information for the battery technologies is broken down into four components: (1) capital cost for the battery packs ($/kWh of BESS energy storage capacity), (2) power conversion system (PCS) ($/kW of BESS power capacity), (3) balance of plant (BOP) ($/kW of BESS power capacity), and (4) construction and commissioning (C&C) ($/kWh of BESS energy capacity). For non-BESS technologies, all in capital costs are presented. Fixed and variable operations and maintenance (O&M) are also included.

Understanding the capabilities of each energy storage is as important as understanding its costs. Performance metrics evaluated for each storage technology in this paper include: (1) round-trip efficiency (RTE), (2) annual RTE degradation factor, (3) response time, (4) cycle life, (5) calendar life, (6) manufacturing readiness level (MRL), and (7) technology readiness level (TRL). Each of these parameters is described in greater detail later in this paper.

Cost and performance information were procured for the most recent year for which data are available. Escalation rates are used where appropriate for technologies that have experienced cost growth. The base year used is 2018 and projections for 2025 are provided. All costs are presented in 2018 dollars, unless otherwise noted.

Data collected and analyzed for this report were obtained from a wide range of sources, including academic papers, web articles and databases, conversations with vendors and stakeholders, and summaries of specific projects at sites across the US. For PSH and other competing technologies, input was solicited from various storage vendors through a questionnaire detailing key parameters with regard to their technology. Feedback collected from these vendors was then compiled and summarized.

While the individual technology cost and performance parameters provide a fundamental basis for evaluating the state of each technology, results must also be annualized to establish a fair basis of comparison. By conducting a pro forma analysis of each of the technologies that incorporates financing, each storage project with applicable taxes, and insurance over its usable life, a fair framework is established to compare the storage assets.

This paper builds on a previous report prepared by this research team that assigned value to the services offered by energy storage systems. That article presented a taxonomy of benefit categories, including bulk energy, ancillary service, transmission, distribution, and customer energy-management benefits [1]. This companion article addresses the cost side of the ledger.

2. Technology Cost and Performance Metrics

Reported metrics used in this paper include those related to capital as well as the costs of PCS, BOP, C&C, fixed O&M, and variable O&M. Performance metrics include RTE, response time, cycle life, calendar life, MRL, and TRL. Each of these are described in the subsections that follow, along with methodologies for determining their value from the literature.

2.1. Capital Cost

Capital cost, as defined here, covers different components that vary by technology type. Capital costs for electrochemical storage devices are typically expressed in dollars per kilowatt hour ($/kWh), while those for flywheels, PSH, CAES, and CTs are expressed in dollars per kilowatt ($/kW). This paper remains consistent with the literature for these technologies. While ultracapacitors are electrochemical devices, their total cost can be represented as either $/kW or $/kWh based on the application. The researchers chose to highlight the $/kW cost for this technology and for flywheels in this paper due to their high specific power and power density.

For batteries and capacitors, capital costs pertain to the procurement of the direct current (DC) energy storage unit and do not include PCS, BOP, or C&C costs. For PSH, it includes waterways, reservoirs, pumps, and electrical generators. For CAES, it includes caverns, compressors, and generators.

2.2. Power Conversion System

PCS costs includes those for the inverter and packaging, as well as container and inverter controls. PCS is common across all battery technologies (and ultracapacitors) and will affect all of them similarly. The PCS cost is expected to decrease as system voltages increase [2,3], because higher current for the same power rating leads to higher cost. This decrease is expected to be faster initially, with rate of decrease slowing down as DC voltage increases. The normalized DC voltage for lithium-ion technology was approximately 1.6 times that of other battery technologies. Lithium-ion is expected to have a PCS cost of approximately 82 percent of that for other chemistries due to its higher DC voltage range. For the year 2025, it is assumed that this difference in nominal DC voltage will no longer persist.

In addition to voltage-related costs, which fall under system design, PCS standardization and manufacturing scale are further expected to drive down costs [3]. A 25 percent decrease in cost over present-day lithium-ion PCS cost is assigned to year 2025 because of the benefits of standardization and scalability due to increased volume production [3]. It is additionally based on both the expected growth in installed storage in the US for 2025 and the results of applying a learning curve model used to forecast price based on cumulative production [4,5]. The lower 2025 cost is assigned uniformly to PCS for all battery chemistries. This assumption is supported by developments such as flow batteries efficiently addressing shunt current related issues to increase DC string voltage. Similarly, sodium-based high temperature systems, with their higher unit cell voltage than flow battery cells, are well placed to scale up to higher DC voltage levels in the coming years.

While new technologies may mature by 2025, they may not yet benefit from large-volume production. Silicon carbide (SiC)-based inverters, for example, are making headway in the electric vehicle (EV) space, charging infrastructure, photovoltaic, power supplies, motor drives, and uninterruptible power supplies but there is still room for the market to grow [6]. Wafer supply limitations have been a bottleneck and are expected to be overcome through investments by the lead SiC wafer suppliers. This technology and its impact on cost has not been considered in this report due to lack of sufficient information.

Table 1 provides the system voltages for various BESSs from the literature.

Table 1. System voltages by technology.

Technology	Nominal DC Voltage (V)	Source Year, Author(s)
Lithium-ion	860 [a]	
Lithium-ion	1221	2018, Samsung [7]
Sodium-sulfur	640 [b]	2005, Kishinevsky [8]
Sodium-metal halide	640 [c]	
Zinc-hybrid cathode	768 [d]	2018, EoS [9]
Lead acid	756 [e]	2018, May et al. [10]

[a] Vendor requests that details of this information be kept confidential. [b] 5 modules, each module 64 V or 128 V. [c] Same value assumed as sodium sulfur. [d] EoS Aurora 1000 I 4000. [e] For several projects, the DC voltage was not clearly specified. The number of cells in each parallel string was stated, however, it was not explicitly stated these cells were in series. For example, 1032 cells in a string at Chino corresponds to 2064 V DC, which is too high.

2.3. Balance of Plant

The balance of the energy storage system (ESS), known as the BOP, typically includes components such as site wiring, interconnecting transformers, and other additional ancillary equipment and is measured on a $/kW basis [11].

The literature has information about PCS, BOP, and C&C cost, but the individual component costs are not well documented [12–14]. Zakeri and Syri (2015) provided PCS and BOP costs for various BESS chemistries, but the numbers were grouped together, so separate costs could not be obtained [15]. Hayward and Graham (2017) provided BOP costs in $/kWh, with the cost being $508/kWh for year 2018 and $441/kWh for year 2025 in 2017 Australian dollars [16]. At that high of a cost, the research team believes the estimated cost could include some costs that we would deem to be C&C costs. Clean Energy Grid (2014) provides a wide range of BOP cost, expressed in $/kWh ($120–$600/kWh) [17].

The BOP costs are mainly assigned to electrical wiring and connections. Unit cell voltage plays a role to the extent that for the same ampere-hour (Ah) capacity, the cell count decreases with increasing voltage, with lower numbers of cell-to-cell interconnections needed. However, most battery systems have basic repeating units or modules, which consist of multiple cells. The module cost is already captured in the DC system cost. Hence, in terms of module interconnections for large systems, the number of modules in the system determine the inter-module connection costs. The series-parallel design within the battery system determines the maximum current between adjacent modules, thus determining the current conductor specifications for a specific material (width, thickness, and length).

Even for high cell voltage chemistries such as lithium-ion, some vendors choose cells with small Ah capacity to improve reliability and safety [18]. Hence, the unit cell voltage is not a reliable predictor of the cell count in the BESS.

Due to the aforementioned considerations, the BOP across all battery chemistries has been set at $100/kW, a consensus number from the literature. As a result that no significant technological improvements are anticipated, a nominal 5 percent decrease in BOP costs is assigned for the year 2025 to account for efficiencies associated with scale.

2.4. Construction and Commissioning

C&C costs, also referred to as engineering, procurement, and construction (EPC) costs, consist of site design costs, costs related to equipment procurement/transportation, and the costs of labor/parts for installation [11].

The cost decreases are not expected to be as great for C&C because these costs are more mature than those more directly tied to each technology. For grid integration, the cost is mainly a function of system footprint and weight (with discrete steps in costs), degree of factory assembly vs. onsite assembly (the total cost may be the same regardless of where the assembly occurs), and architecture in terms of open racks vs. containerized systems [19].

For this report, C&C cost was addressed strictly using the system footprint or using the total volume and weight of the BESS. Volume has been used as a proxy for all these metrics. For this work, the normalized volume per watt-hour is used as a metric.

The consensus C&C costs from the literature were increased by 15 percent for the technology with the smallest energy density expressed as largest liters per watt-hour (L/Wh). This value was multiplied by the normalized volume per watt-hour raised to a power of 0.33 to yield a lithium-ion C&C cost of $100/kWh, slightly higher than the $80/kWh estimated by McLaren et al. (2016) [20]. A 5 percent drop was assumed for year 2025 because while gains have been made in recent years, the estimated C&C cost at $100/kWh is on the low end of current estimates with little scope for further cost decrease due to "learning." Additionally, any benefits going further along the learning curve are expected to be partially balanced by higher material and labor costs with increased penetration of storage. Table 2 provides system volume, while Table 3 provides the C&C cost.

Table 2. System volume by battery technology.

Battery Chemistry	Wh/L	Source Year, Author(s)
Redox flow	12.5	2018, UET [21]
Lithium-ion	80	2018, Research Interfaces [22]
Lithium-ion	90–130 [(a)]	2018, Research Interfaces [22]
Sodium-sulfur	40	2009, Gotschall and Eguchi [23]
Sodium halide	65 [(b)]	2011, LCE Energy [24]
Lead acid Chino	16 [(c)]	1990, Rodrigues [25]
Lead acid estimated	22.5 [(d)]	2020, ITP Renewables [26]
Zinc-hybrid cathode	17	2018, EoS [27]

[(a)] Used 100 Wh/L for lithium-ion battery energy storage systems (BESS). [(b)] Large-scale system Wh/L assumed to be 60% of the 9.6 kWh module. [(c)] Large-scale system Wh/L assumed to be 60% of the 30 kWh module. [(d)] Estimated from ratio of lead acid to lithium-ion Wh/L reported in literature.

Table 3. C&C Cost by Technology ($/kWh), 2018 and 2025.

Chemistry	L/Wh Normalized	(L/Wh Normalized) $^{0.33}$	C&C Cost $/kWh, 2018	C&C Cost $/kWh, 2025
Lithium-ion	0.12	0.53	101	96
Sodium halide	0.19	0.61	115	110
Sodium-sulfur	0.31	0.70	133	127
Lead acid	0.78	0.93	176	167
Zinc-hybrid cathode	0.73	0.91	173	164
Redox flow battery	1	1	190	180

2.5. Fixed Operations and Maintenance

Fixed O&M includes all costs necessary to keep the storage system operational throughout the duration of its economic life that do not fluctuate based on energy usage.

It is clear from the available literature that fixed O&M costs for all battery chemistries were in the range of $6–$20/kW-yr, with most in the $6–14/kW-yr range [11,12]. While lithium-ion may have more costs associated with safety and battery management systems (BMSs), the larger size of other battery technologies can result in higher O&M costs, and their relatively safe operational characteristics work toward lowering O&M costs. A fixed O&M cost of $10/kW-yr was assumed for all battery chemistries in this paper.

Fixed O&M costs for non-BESS technologies were found in the literature and are reported in each technology section, respectively.

2.6. Variable Operations and Maintenance

Variable O&M includes all costs necessary to operate the storage system throughout the duration of its economic life and is normalized with respect to the annual discharge energy throughput and is expressed as cents/kWh.

Few resources in the literature provided a concrete variable O&M value [12,28]. Those that did assumed it to be approximately 0.3 cents/kWh-year. This paper uses this number for variable O&M for all battery technologies.

Variable O&M costs for non-BESS technologies were found in the literature and are reported in each technology section, respectively.

2.7. Round-Trip Efficiency

RTE is the ratio of net energy that is discharged to the grid (after removing auxiliary load consumption) to the net energy used to charge the battery (after including the auxiliary load consumption) [29].

Losses for BESSs can be grouped into the following categories:

- Loss of Ah capacity. While Ah loss can be high over the course of the battery life, it is negligible for each cycle. In flow batteries, cross-over-related losses accumulate over several cycles but are negligible for each cycle.
- Internal resistance-related losses reduce discharge voltage while increasing charge voltage.
- Auxiliary loads such as heating, ventilation, and air-conditioning (HVAC), BMS, PCS controls, and pumps (for flow batteries).

While there is no single RTE value for each technology, this work established the DC-DC RTE for each technology and used 0.96 RTE for PCS to compute the overall system RTE for each technology [30].

RTEs for non-BESS technologies are described in the respective sections when appropriate.

2.8. Response Time

Ramp rate is the time (typically in seconds or minutes) that a system takes to change its output level from rest to rated power; faster ramp rates or lower response times are more valuable. Response time, for the most part, is determined by the inverter selection for the application and the overall system design.

Based on an extensive literature review and testing of lithium-ion and flow battery systems conducted by the research team, the response times for the DC battery and ultracapacitor ESSs contained in this report were assumed to be less than one second. However, extensive tests conducted by the research team have shown that inverter response times can range from as little as less than one second to approximately 13 s to reach rated power. Therefore, we assume that the response times for the ultracapacitor and the BESSs contained in this analysis would be one second, subject to PCS limitations that could extend the response time out by an additional 1–13 s.

Flywheel response time provided by vendors was determined to be 250 milliseconds from the information gathered. Lastly, for other technologies, such as PSH and CAES, the time to go from shutdown to full power can be as high as 2–10 min. More information is provided in each technology section where available.

2.9. Cycle Life

The cycle life for conventional batteries, not including redox flow, is a function of its depth of discharge (DoD). Cycle life, where provided in the literature, is listed in each technology's subsection. When cycle life was provided without a DoD, a DoD of 80 percent was assumed. For PSH and CAES, degradation depends on the number of mode changes. Flywheels and ultracapacitors have cycle lives >200,000 because chemical degradation is not an issue.

2.10. Calendar Life

Calendar life is defined strictly as the maximum life of the system when it is not being operated. When a storage system is being cycled, the overall life of the system is dependent on the degradation that takes place per-cycle. Calendar life for batteries is highly dependent on operating conditions. For BESS and ultracapacitors operating at ambient temperatures, the life decreases with an increase in operating and/or ambient temperature. The calendar life used in this work uses data gathered from literature and from vendors.

2.11. Manufacturing Readiness Level

MRL is a measure used for assessing how mature the manufacturing of a product for a technology is and ranges from a scale of 1 (basic manufacturing issues identified) through 10 (high rate production using efficient production practices demonstrated) [31].

2.12. Technology Readiness Level

TRL is a measure used for assessing the phase of development of a technology. TRL indicates how mature the technology is and ranges from a scale of 1 (basic principle observed) through 9 (total system used successfully in project operations) [32]. All of the technologies included in this report are TRL 5 or higher. CTs offer the highest TRL at 9, followed by several technologies at TRL 8.

3. Assumptions

The following assumptions were made when determining the estimates for the cost and performance of each type of technology in the analysis:

- For each technology, unit energy and power costs were obtained from literature and/or vendors. Battery costs were available from vendors, supplemented by literature, in terms of $/kWh, while ultracapacitor costs provided by vendors were in both $/kW and $/kWh. Flywheel, PSH, and CAES costs were provided by vendors, supplemented by literature. Appropriate sources are noted within each technology subsection for values collected.
- The power and energy capacities for each technology used in this report are given in Table 4 along with the energy-to-power (E/P) ratios we used for each when comparing costs between technologies.
- Outliers were removed from cost ranges provided by the literature and the remaining reported values were adjusted for inflation. From the adjusted range, a single value estimate was established. When establishing a single point estimate for each technology, additional weight was given to values reported for systems with E/P ratios closer to the baseline values used in this report.
- Adjustments to 2018 US dollars (USD) were made using consumer price index data from the US Bureau of Labor Statistics for the Producer Price Index-Industry Data for Electric Power Generation, Transmission, and Distribution Sector [33].

Table 4. Assumed energy, power, and energy-to-power ratios by technology type.

Technology	MW	MWh	E/P
BESS	1	4	4
Ultracapacitor	1	0.0125	0.0125
CAES	250	4000	16
Flywheel	20	5	0.25
PSH	2000	32,000	16

3.1. Forecast Methodology

Predictions regarding cost estimates for the year 2025 were obtained using performance improvement forecasts, which allow developers to extract more energy per unit mass, and economies of scale.

Data on future cost predictions was collected from DNV GL (2016) and used to form the basis of the forecasts within this paper [11]. The drop in lithium-ion prices were estimated to be 67 percent and in zinc air to be 60 percent, while sodium-sulfur and redox flow batteries dropped by 9 percent and 18 percent, respectively [11]. A 31 percent drop in lithium-ion prices was used in this paper due to the assumption that economies of scale would be balanced by an increase in demand for nickel, cobalt, and lithium.

For the vanadium redox battery, this paper assumed that the drop in cost between 2018 and 2025 would be 29 percent. This value is greater than the 18 percent estimated by the literature because as demand increases, electrode and membrane costs within the stack are expected to decrease [11,34,35]. Improvement in performance is also expected to increase the power density, allowing for use of fewer stacks to provide the same power, thereby further decreasing cost. For energy intensive applications, for the same power density, a larger DoD (or State of Charge (SoC) range) can be expected for redox flow battery systems, thereby dropping the unit energy costs.

While a 60 percent drop in a zinc-air system was estimated by the vendor, our work is a bit more conservative, and estimates a 28 percent drop from the already low cost of the zinc-hybrid cathode (or zinc air) battery system.

For the sodium-sulfur system, so far deployments have been mainly in Japan. With some of the safety issues resolved, if the deployment of this technology increases globally, a 24 percent drop in cost is anticipated in this work for this technology.

Sodium-metal halide batteries have not gained significant traction in the energy storage space and are deployed mainly in bus fleets. Hence, there is more room for cost reduction; a reduction of 30 percent has been used in this work. The 30 percent reduction has been applied to the average low cost and high cost for sodium-metal halide based on information gathered from the literature and vendors.

Lead-acid batteries are a mature technology, especially in the context of starting lighting ignition batteries used in automobiles. Hence, a 15 percent cost reduction is assumed as this technology gains penetration in the energy storage space. Cost decreases are shown in Table 5.

Table 5. Cost Decrease from 2018 to 2025 by Battery Technology.

Chemistry Type	2018 to 2025 Cost Decrease
Lithium-ion (NMC)	31%
Vanadium redox	29%
Zinc air	28%
Sodium sulfur	24%
Sodium-metal halide	30%
Lead acid	15%

For PSH, CAES, flywheels, and ultracapacitors, 2025 capital costs were assumed to be the same as those estimated for 2018. These are more mature technologies; hence, this study assumed the 2025 costs to be unchanged. Further, while technology innovation has potential to further reduce costs, PSH and CAES involve long-range development timelines and, therefore, a substantial reduction in costs is unlikely to be experienced in a relatively short number of years.

3.2. Degradation-Related RTE Reduction Methodology

As part of this analysis, annual degradation in RTE was also calculated. Degradation of batteries results in Ah capacity loss and an increase in the battery cell internal resistance [36–38]. The DC-DC RTE is affected simply by the ratio of the following:

$$\mathrm{V_d \times Ah_d / (V_c \times Ah_c)} \tag{1}$$

where,

V_d = average discharge voltage,
Ah_d = Ah capacity during discharge,
V_c = average charge voltage, and
Ah_c = charge capacity

For most batteries, the coulombic efficiency, defined as the ratio of Ah_d/Ah_c is > 0.999, and can be assumed to be nearly equal to 1. That is, while the batteries do lose Ah capacity over time, it can be assumed that for each cycle, the charge and discharge capacity are equal to each other. Hence, the RTE depends only on the average discharge and charge voltage.

For any battery cell, the operating voltage is simply the open circuit voltage:

$$(\mathrm{OCV}) + (\mathrm{I} \times \mathrm{R_i}) \tag{2}$$

where I is the current in amperes and is negative for discharge and positive for charge and *R* is resistance. As a battery loses capacity (due to loss of lithium for example in lithium-ion), the internal resistance builds up. When active material degrades (loss of active material), this increases charge transfer resistance. Typical end of life is when Ah capacity falls to 80 percent of rated. Based on chemistry and mode of degradation, this is accompanied by a 1.3–2× change in resistance. The RTE degradation calculations conducted for this paper assume that each battery type will have an increase in internal resistance of 50 percent over its useful life.

The voltage of the ultracapacitor decreases linearly with discharge time after a drop in voltage associated with its internal resistance, and a corresponding increase in voltage during charge. The RTE for ultracapacitors is estimated in a way similar to estimating RTE for batteries [39]. When the ultracapacitor is cycled between its maximum voltage and half the maximum voltage, 75 percent of its energy content can be withdrawn [40]. For non-aqueous systems, the nominal voltage rating is 2.70 volts (V) [41], hence the voltage range of operation is 2.70 V to 1.35 V, which corresponds to an average voltage range of 2.02 V.

Flywheels have extremely low degradation; some claim "zero degradation over time" [42]. The degradation rate of RTE for flywheels was assumed to be the same as that for ultracapacitors—both of them at a low value of 0.14 percent per year. For all practical purposes, their degradation rates can be considered negligible.

The RTE for a pumped storage hydro system can be approximated by the product of pumping efficiency and generating efficiency, excluding losses due to evaporation [43]. However, there was no methodology available to estimate the precise degradation of pumping and generating efficiency over time. Three losses overall are typically accounted for in PSH plants: electrical, mechanical, and hydraulic. When looking at mechanical and hydraulic losses, the degradation of PSH plants can be accelerated by factors such as trash rack fouling—when debris clog at the hydropower intake location [44,45], or cavitation—the scenario in which a cavity is generated in a pump due to a partial pressure drop of flowing liquid [46]. While hydraulic losses from water flow through the tunnels remain unchanged, the performance of machinery itself may decrease over time through deterioration of machine parts, which may require more water to produce the same power—higher flow rate leads to more hydraulic losses. Transformer and turbine/generator losses may increase over time as well. Despite these factors, refurbishments are expected to recover performance [45]. For example, changing out the transformer oil brings it back to working condition. Typically, PSH plants are evaluated every five years for refurbishment of equipment, which corrects the degradation factors described.

Some of the degradation factors defined in the previous paragraph also apply to other technologies. Cavitation can also occur through liquefaction within supercritical CAES units that involve liquid air [47]. Deterioration of transformers and turbines for CAES and CTs can be addressed in a similar manner to the procedure described for PSH.

Batteries were found to have more methods and data for calculating RTE degradation within the literature Table 6 shows the RTE loss per year for each battery chemistry. The calendar life and other parameters used in the calculation of degradation were determined by the literature and information on each is described in higher detail in the individual technology sections that follow.

Table 6. Annual round-trip efficiency (RTE) loss by battery chemistry.

Chemistry	Final RTE/Initial RTE	Calendar Life (Years)	Annual RTE Loss
Lithium-ion loss	0.959	10	0.50%
Sodium sulfur	0.956	13.5	0.34%
Lead acid	0.898	3	5.40%
Zinc-hybrid	0.878	10	1.50%
Redox flow battery	0.847	15	0.40%
Sodium-metal halide	0.956	12.5	0.35%
Ultracapacitor	0.979	16	0.14%
Flywheel	N/A	>20	0.14%

4. Results Summary

Tables 7 and 8 provide a summary of the cost and performance characteristics of the technologies compiled in this report. Primary estimates represent 2018 values; numbers in brackets represent 2025 forecast values. In Table 7, total project costs are estimated for a hypothetical 1 MW/4 MWh BESS. To determine the total project costs for the lithium-ion battery technology, for example, the product of the capital and C&C costs and its energy capacity (4000 × $372) is taken. We then add that value to the product of the PCS and BOP costs and the unit's power capacity (1000 × $388). Those calculations yield a total project cost of $1.9 million for a 1 MW/4 MWh lithium-ion BESS, which would translate into costs of $1876/kW or $469/kWh.

BESS are listed separately because they require a PCS. All the other technologies do not have a separate PCS, except ultracapacitors. While ultracapacitors also require a PCS, they have been listed with flywheels in Table 8 because both technologies have low specific energies.

Total $/kWh project cost is determined by the sum of capital cost, PCS, BOP, and C&C where values measured in $/kW are converted to $/kWh by multiplying by four (given the assumed E/P ratio of four) prior to summation. Total $/kW project cost is determined by dividing the total $/kWh cost by four following the same assumption.

5. Technology-Specific Findings

The following sections discuss the cost and performance data of each individual technology considered within this paper.

5.1. Combustion Turbines

Among conventional power generation technologies, CTs offer a high degree of operational flexibility in terms of start/stop time and ramping speed, and therefore are often used as the next best alternative to more flexible resources (e.g., ESSs).

5.1.1. Capital Cost

The basic components of an operational CT unit are the turbine itself, gearbox, electrical generator, air inlet system including filter assembly, exhaust gas system including the duct and silencer, and start-up system. Depending on the fuel and emission compliance requirements, additional costs may be incurred for fuel compression systems and emission control systems that are not included in the basic package cost.

Capital cost estimates found in various technology reports are presented Table 9. A capital cost of $940/kW was used in this report.

Table 7. Summary of compiled 2018 findings and 2025 predictions for cost and parameter ranges by technology type—BESS [(a)(b)].

	Lithium-Ion		Lead Acid		Redox Flow		Sodium-Sulfur		Sodium-Metal Halide		Zinc-Hybrid Cathode	
Parameter	**2018**	**2025**	**2018**	**2025**	**2018**	**2025**	**2018**	**2025**	**2018**	**2025**	**2018**	**2025**
Capital Cost–Energy Capacity ($/kWh)	271	(189)	260	(220)	555	(393)	661	(465)	700	(482)	265	(192)
Power Conversion System ($/kW)	288	(211)	350	(211)	350	(211)	350	(211)	350	(211)	350	(211)
Balance of Plant ($/kW)	100	(95)	100	(95)	100	(95)	100	(95)	100	(95)	100	(95)
Construction and Commissioning Cost ($/kWh)	101	(96)	176	(167)	190	(180)	133	(127)	115	(110)	173	(164)
Total Project Cost ($/kW)	1876	(1446)	2194	(1854)	3430	(2598)	3626	(2674)	3710	(2674)	2202	(1730)
Total Project Cost ($/kWh)	469	(362)	549	(464)	858	(650)	907	(669)	928	(669)	551	(433)
O&M Fixed ($/kW-yr)	10	(8)	10	(8)	10	(8)	10	(8)	10	(8)	10	(8)
System RTE	0.86		0.72		0.675	(0.7)	0.75		0.83		0.72	
Annual RTE Degradation Factor	0.50%		5.40%		0.40%		0.34%		0.35%		1.50%	
Response Time (limited by PCS)	1 s		1 s		1 s		1 s		1 s		1 s	
Cycles at 80% DoD	3500		900		10,000		4000		3500		3500	
Life (Years)	10		2.6	(3)	15		13.5		12.5		10	
MRL	9	(10)	9	(10)	8	(9)	9	(10)	7	(9)	6	(8)
TRL	8	(9)	8	(9)	7	(8)	8	(9)	6	(8)	5	(7)

[(a)] An E/P ratio of 4 h was used for battery technologies when calculating total costs. [(b)] Variable O&M estimates, a proxy for wear and tear, have not been included in the table as the cost is considered negligible. MRL = manufacturing readiness level; O&M = operations and maintenance; TRL = technology readiness level.

Table 8. Summary of compiled 2018 findings and 2025 predictions for cost and parameter ranges by technology type—non-BESS [(a)].

<table>
<tr><th>Cost Parameter</th><th>Combustion Turbine</th><th colspan="4">PSH [(b)]</th><th>Flywheel [(c)]</th><th>CAES [(b)]</th><th>Ultracapacitor [(d)]</th></tr>
<tr><td>Capital–Energy Capacity ($/kW)</td><td>940</td><td colspan="4">2638</td><td>2400</td><td>1669</td><td>400</td></tr>
<tr><td>Power Conversion System ($/kW)</td><td>N/A</td><td colspan="4">Included in Capital Cost</td><td>Included in Capital Cost</td><td>N/A</td><td>350 (255)</td></tr>
<tr><td>Balance of Plant ($/kW)</td><td></td><td colspan="4"></td><td></td><td></td><td>100 (95)</td></tr>
<tr><td>Construction and Commissioning ($/kW)</td><td></td><td colspan="4"></td><td>480 [(e)]</td><td></td><td>80 [(e)]</td></tr>
<tr><td>Total Project Cost ($/kW)</td><td>940</td><td colspan="4">2638</td><td>2880</td><td>1669</td><td>930 (835)</td></tr>
<tr><td>Total Project Cost ($/kWh)</td><td></td><td colspan="4">165</td><td>11,520</td><td>105</td><td>74,480 (66,640)</td></tr>
<tr><td>O&M Fixed ($/kW-year)</td><td>13</td><td colspan="4">15.9</td><td>5.6</td><td>16.7</td><td>1</td></tr>
<tr><td>System RTE</td><td>0.328</td><td colspan="4">0.8</td><td>0.86</td><td>0.52</td><td>0.92</td></tr>
<tr><td>Annual RTE Degradation Factor</td><td></td><td colspan="4"></td><td>0.14%</td><td></td><td>0.14%</td></tr>
<tr><td rowspan="7">Response Time</td><td rowspan="7">From cold start: 10 min
Spin ramp rate: 8.33%/min
Quick start ramp rate: 22.2%/min</td><td></td><td>FS</td><td>AS</td><td>Ternary</td><td rowspan="7">0.25 s</td><td rowspan="7">From cold start: 10 min

From online to full power: 5 min

From full speed no load to FL: 3.33 min

From offline to FL: 4 min</td><td rowspan="7">0.016 s</td></tr>
<tr><td>SIA to FLG</td><td>5–70 s</td><td>60 s</td><td>20–40 s</td></tr>
<tr><td>Shutdown to FG</td><td>75–120 s</td><td>90 s</td><td>65–90 s</td></tr>
<tr><td>SIA to FL</td><td>50–80 s</td><td>70 s</td><td>25–30 s</td></tr>
<tr><td>Shutdown to FL</td><td>160–360 s</td><td>230 s</td><td>80–85 s</td></tr>
<tr><td>FL to FG</td><td>90–220 s</td><td>280 s</td><td>25–60 s</td></tr>
<tr><td>FG to FL</td><td>240–500 s</td><td>470 s</td><td>25–45 s</td></tr>
<tr><td>Cycles at 80% DoD</td><td>N/A</td><td colspan="4">15,000</td><td>200,000</td><td>10,000</td><td>1 million</td></tr>
<tr><td>Life (Years)</td><td>20</td><td colspan="4">>25</td><td>>20</td><td>25</td><td>16</td></tr>
<tr><td>MRL</td><td>10</td><td colspan="4">9 (10)</td><td>8 (9)</td><td>8 (9)</td><td>9</td></tr>
<tr><td>TRL</td><td>9</td><td colspan="4">8 (9)</td><td>7(8)</td><td>7 (8)</td><td>8</td></tr>
</table>

[(a)] Variable O&M estimates, a proxy for wear and tear, have not been included in the table as the cost is considered negligible. [(b)] E/P = 16 h. [(c)] E/P = 0.25 h. [(d)] E/P = 0.0125 h. [(e)] 20 percent of capital cost. AS = adjustable speed; FS = fixed speed. SIA = Spinning-in-air; FLG = Full load generation; FG = Full generation; FL = Full load.

Table 9. Capital cost estimates—CT technology.

Capital Cost ($/kW)	Notes	Source Year, Author(s)
1176	44.5 MW net capacity unit	2014, Darrow et al. [48]
825	Recommended value based on review of integrated resource planning (IRP) documents	2014, Olson et al. [49]
1193	40.5 MW net capacity unit	2016, US DOE [50]
1101	100 MW facility, 2 units	2016, US EIA [51]
678	237 MW single unit	2016, US EIA [51]
903–1012	Cost of new entry (CONE) study in five US regions	2018, Newell et al. [52]
651	Cost and performance projection for a 211 MW gas turbine power plant	2012, Black and Veatch [28]

5.1.2. Fixed and Variable O&M Costs and Performance Metrics

Major components of a CT facility's fixed O&M costs are fixed components of inspection and maintenance costs at intervals recommended by the original equipment manufacturer (OEM).

More often these services are provided by the OEM or by their affiliated third-party service providers against a long-term service agreement. Costs of day-to-day operation manpower, general and administrative costs, permit fees, property taxes, and insurance are also included in fixed O&M costs. Values from the literature are summarized in Table 10. A fixed O&M cost of $13/kW-yr was used in this report.

Table 10. Fixed and variable O&M costs—CT technology.

Fixed O&M ($/kW-yr)	Variable O&M ($/kWh)	Notes	Source Year, Author(s)
9		Recommended value based on IRP documents	2014, Olson et al. [49]
17.50 6.8	0.0035 0.0107	100 MW facility, 2 units 237 MW single unit	2016, US EIA [51]
13.7–25.6	0.00425–0.00429	CONE study in 5 US regions	2018, Newell et al. [52]
5.26	0.03	Cost and performance projection for a 211 MW gas turbine power plant	Black and Veatch (2012) [28]

Variable O&M cost components include consumables for day-to-day O&M, including inspections and overhauls. Variable O&M costs were assumed to be $0.0105/kWh in this paper.

The efficiency of CT units is typically expressed using heat rate (Btu/kWh). The US Environmental Protection Agency published a combined heat and power (CHP) technology catalog in which technical performance and costs of CT units with various sizes were studied [48]. Heat rates were found to vary in the literature from 9488 to 14,247 Btu/kWh (23.96–35.97 percent in terms of efficiency). For example, the heat rate for a 211 MW CT plant was 10,390 Btu/kW [28], corresponding to an RTE of 32.8 percent using a conversion factor of 3412 Btu/kWh [53]. An RTE of 30 percent was used in the report. Its spin ramp rate was 8.33 percent per minute, while the quick start ramp rate was 22.2 percent per minute, and it takes 10 min to reach rated power from cold start.

5.1.3. Technology and Manufacturing Readiness Levels

CT technology is one of the proven power generation technologies that has been in field application for decades. As of 2016, 28 percent of total installed natural gas-fired power generation capacity in the US (449 GW) was based only on CT technology and 53 percent was based on combined cycle technology [51]. With such wide-scale commercial deployment, this technology has had the opportunity to be tested to the highest level of TRL and MRL criteria. Therefore, a TRL of 9 and MRL of 10 are assigned to CT technology.

5.2. Lithium-Ion Batteries

More than 500 MW of stationary lithium-ion batteries had been deployed worldwide by the year 2015, which increased to 1629 MW by 2018. Given their commercialization start in the early 1990s, lithium-ion batteries are prevalent across a variety of industries due to their high specific energy, power, and performance. Due to the increased demand from the electric automobile industry and the energy storage market, the price of this chemistry is expected to reduce further [54]. For this reason, it is a typical choice for large installments and there have been successful deployments for grid support of distributed renewables up to several megawatts [54–56].

5.2.1. Capital Cost

The primary components of a lithium-ion battery contain modules composed of an assembly of cells, which include electrodes, electrolyte, and separators. The battery system as a whole is built of a multitude of modules as well as a BMS and a PCS. Between 2010 and 2017, battery prices decreased by

80 percent, reaching approximately $200/kWh, and it is predicted the price will reach approximately $96/kWh within the next eight years [54].

Table 11 summarizes DC battery capital cost estimates from the literature for grid-scale battery energy storage systems. Lahiri (2017) estimated the cost range for the DC-Side Modules and BMS to be in the range of $325–$700/kWh, keeping the values broad to accommodate technology differences [13]. Aquino et al. (2017a) placed the value in a tighter range at $340–$450/kWh for a 4 MW/16 MWh lithium-ion NMC system and a fully installed cost estimate of between $9.1 million and $12.8 million [12]. They also provide price estimates for li-phosphate (LFP) and lithium-titanate (LTO) systems at $340–$590/kWh and $500–$850/kWh, respectively. Curry (2017) and Watanabe (2017) provided estimates that were at the lower end of the range in Table 11 [57,58]. However, some estimates were for only the battery packs [57,59]. Damato (2017) estimated an installed cost of $335–$530/kWh, which includes the PCS, grid integration and equipment, tax, fees, and General and Administrative (G&A) costs [60]. For a representative 4-h case, the DC battery cost was 60 percent of total installed cost. Using this multiple, the DC battery cost was estimated.

Table 11. Capital cost estimates—lithium-ion technology.

Capital Cost ($/kWh)	Notes	Source Year, Author(s)
$325–$700	Includes DC-Side Modules and BMS	2017, Lahiri [13]
$325–$450	NMC system	2016, DNV GL [11]
$350–$525	LFP system	2016, DNV GL [11]
$340–$450	NMC system	2017, Aquino et al. [12]
$340–$590	LFP system	2017, Aquino et al. [12]
$273	Includes cell and pack cost only	2017, Curry [57]
$285		2017, Watanabe [58]
$540		2014, Wright [61]
$400		2017, Greenspon [62]
$573		2014, Manuel [63]
$300	Balance of system was $570/kW or $143/kWh	2015, DiOrio et al. [64]
$409–$662		2017, DNV GL [65]
$180–$520	2015 cost NMC	2016, Kamath [66]
$180–$520	2015 cost NCA	
$300–$450	2015 LFP	
$209–$343	Calculated from installed costs of $335–$530/kWh by subtracting PCS, grid integration and equipment, tax, fees, and G&A costs	Damato (2017) [60]
$209		2018, Morris [59]

Many of the sources identified for estimating costs provided costs as total project averages rather than broken down to estimate the costs of different components of the batteries. The average installed cost was $932/kWh, significantly higher than the Damato (2017) estimates [60]. One explanation is that the higher average installed costs corresponds to systems that were smaller compared to Damato's work, and hence did not experience savings through economies of scale. For this work, costs for LTO were not considered.

As a result that lithium-ion battery costs have dropped significantly over the last 10 years, the high-end values have not been used in our estimation of DC battery system cost. Costs earlier than year 2016 were not considered and costs for years 2016 and 2017 were multiplied by 0.95 and 0.95^2 respectively, assuming a 5 percent decrease in cost per year. While 5 percent appears low, this approach is appropriate because only the low end of the cost range observed in the literature was considered. These storage DC battery packs averaged $296/kWh.

To compare the DC battery cost for grid-scale storage with reported costs for EV battery packs, a survey of EV battery pack cost was conducted (Table 12.). The EV battery pack unit energy cost on average was 10% lower than grid-scale storage costs.

Table 12. Lithium-ion EV battery costs, 2016–2018.

Cost ($/kWh)	Component	Year	Source Year, Author
$250–300	Pack	2018	2018, Evertiq [67]
$200	Pack	2018	2018, Posawatz [68]
$209	Pack	2017	2017, Chediak [69]
$236 [(a)]	Pack	2017	2018, Eckert [70]
$190	Pack	2018	2018, Safari [71]
$250	Pack	2016	2018, Safari [71]
$227	Pack	2016	2017, Lambert [72]
$200–250	Pack	2016	2016, Lacey [73]

[(a)] industry-wide average (16% annual decline).

EV pack costs were multiplied by a factor of 1.1 to reflect an estimated 10 percent increase in cost for containerization of the packs used in storage applications. This assumption is based on an analysis of costs broken down by their individual components, such as labor, material, and overhead [74,75]. Only costs for years 2016–2018 were considered, and the 2016 and 2017 costs were multiplied by 0.95 and 0.95^2, respectively. EV packs with the three lowest costs were removed from the analysis. The average of the adjusted EV pack costs was $256/kWh. The weighted average of the storage and adjusted EV battery cost was $271/kWh. Using the PCS, BOP, and C&C costs, the lithium-ion battery system cost for 2018 was estimated to be $469/kWh.

5.2.2. Fixed and Variable O&M Costs and Performance Metrics

Lithium-ion systems have a typical usable life of approximately 10 years and usually require major maintenance every 5 to 8 years to remain operational [76]. Aquino et al. (2017a) estimates the fixed O&M cost to be in the range of $6–$14/kW-yr for their 4 MW/16 MWh NMC system and the variable cost to be $0.0003/kWh for a system of the same size [12]. Lahiri (2017) provides a similarly close estimate for fixed O&M and additionally estimates major maintenance costing in the range of $150–$400/kW [13]. A fixed O&M cost of $10/kW-yr and variable O&M cost of $0.0003/kWh have been used in this study for all battery technologies, with a reduction of fixed O&M costs to $8/kW-yr by 2025.

Table 13 provides collected information about the fixed and variable O&M costs of lithium-ion battery systems.

Table 13. Fixed and variable O&M costs—lithium-ion technology.

Fixed O&M Cost ($/kW)	Variable O&M Cost ($/kWh)	Notes	Source Year, Author(s)
$6–$12	$0.0003	Excludes major maintenance cost	2017, Lahiri [13]
$6–$14	$0.0003	Excludes major maintenance cost	2017, Aquino et al. [12]
$10			2014, Manuel [63]
$20			2015, DiOrio et al. [64]
£10			2016, Newbery [30]

5.2.3. Cycles, Lifespan, and Efficiency

While lithium-ion technology is considered the most mature of battery storage technologies, improvements will continue to be made that will increase the calendar life, energy density, and number of cycles the technology can provide. Table 14 shows estimations for different efficiency and life parameters across a range of cited studies. On average, most of the literature places the life years in the range of 10–20 years; more of the literature estimates life years on the lower end and indicates the need for major maintenance and battery replacement to keep the system operational. A range of cycle estimates was provided throughout the literature from a low of 400 to a high of 5475 cycles when a 70 percent DoD is assumed [62,64]. Pacific Northwest National Laboratory (PNNL) testing of grid-scale batteries yielded an AC-AC RTE of 83–87 percent over 1.5 years of testing, while RTE for a battery >5 years old was 81 percent [77–79]. While each of these are different chemistries, this is an example of the deterioration of RTE over time. A system RTE of 86 percent was used in this work. A cycle life of 3500 at 80 percent DoD and calendar life of 10 years were also assumed. A PCS RTE of 96 percent was assumed for all technologies.

Table 14. Cycles, life years, and RTE—lithium-ion technology.

Cycles	Life Years	DC-DC RTE	Notes	Source Year, Author(s)
2500	15			2018, May et al. [10]
3500	10	77–85%		2017, Aquino et al. [12]
	10	83%		2014, Manuel [63]
400–1200		80–90%		2017, Greenspon [62]
	9	89%	Based on an AC-AC RTE of 85% and 0.96 factor	Newbery (2016) [30]
5475		92%	70% DoD	2015, DiOrio et al. [64]
2000–10,000	15–20	90–98%	Not including auxiliary loads	2016, EASE [54]
		87–91%	Three different battery chemistries AC-AC RTE of 83–87%	2018, Viswanathan et al. [77] 2019, Crawford et al. [78,79]

5.2.4. Technology and Manufacturing Readiness Levels

The commercialization of lithium-ion batteries began in the early 1990s through a wide variety of applications and sizes. With the scale of deployment reaching the level it has, the technology has been tested thoroughly across deployments of all scales up to the higher levels of both the TRL and MRL scales. For this reason, lithium-ion batteries receive a TRL of 8 and an MRL of 9. It is predicted that by 2025, those numbers will rise to 9 and 10, respectively.

5.3. Lead-Acid Batteries

Lead-acid batteries are used across a wide variety of applications but are not typically found in small, portable systems. Lead-acid batteries are of two main types of design: flooded (vented lead-acid [VLA]) and valve-regulated lead-acid (VRLA). The technology typically has a power range of up to a few megawatts and an energy range of up to 10 MWh. A benefit of the VRLA technology option is its lack of maintenance requirements compared to the VLA counterpart. Other benefits stated by industry include having high cumulative energy throughput, high cycle life in a partial SoC cycling regime at various rates, good charge acceptance leading to faster recharge, and uniform cell-to-cell behavior [80]. Overall, the technology offers efficient performance at a relatively low cost and its adoption is expected to become more widespread over the coming years [54].

Information gathered from Enersys, an additional battery manufacturer, indicated that while lead-acid batteries may not be the best technology for applications such as frequency regulation, which have highly volatile signals, they are a cost-effective solution for applications such as load following and time shifting. Furthermore, lead-acid batteries have a 99% recyclability rate, which offers another incentive over competing technologies [81].

5.3.1. Capital Cost

Both of the subtypes of lead-acid batteries consist of a grid plate for the positive electrodes and either copper or lead grids for the negative electrodes. The battery cells can be interconnected to form large battery systems. Just as with the lithium-ion battery, the lead-acid system also requires a PCS as one of the components necessary for operation.

Table 15 lists capital cost estimates for the lead-acid technology. Aquino et al. (2017b) estimated the battery cost to be in the $200–$500/kWh range, while also reporting BOP and C&C costs [82]. The lower end of the cost was in the $120–$180/kWh range [10,83,84], with usable energy content as low as 50% of rated energy [83]. Capital cost of $260/kWh was assumed for this work.

Table 15. Capital cost estimates—lead acid technology.

Battery Capital Cost ($/kWh)	Notes	Source Year, Author(s)
$200–500	$150–$350/kW for PCS, $80–120/kW BOP, $150–180/kW C&C	2017, Aquino et al. [82]
$183 [(a)]	100 kWh installed; 50 kWh usable.	2015, PowerTech Systems [83]
$120		2014, Anuphjappharadorn et al. [84]
$400–$700		2016, Kamath [66]
$160–$240	$400-$600/kWh installed. Remove PCS, BOP, and C&C costs.	2018, May et al. [10]
$130–$260 [(a)]	For up to 10 MWh	2016, EASE [54]
$240	12 V, >150 Ah module	Vendor specifications [(b)]

[(a)] Values obtained from converting euros to US dollars at $/euro exchange for appropriate year. [(b)] Vendor requests that details of this information be kept confidential.

5.3.2. Fixed and Variable O&M Costs and Performance Metrics

A benefit of the VRLA technology is the lack of maintenance requirements; however, Aquino et al. (2017a) estimated the fixed O&M cost for an advanced lead-acid battery combined with an asymmetric supercapacitor to be in the range of $7–$15/kW-yr with variable cost at an estimated $0.0003/kWh [12]. Note that fixed and variable O&M were kept the same for all battery technologies, as described in the lithium-ion O&M section.

5.3.3. Cycles, Lifespan, and Efficiency

Lead-acid systems are stated as having a shorter economic life than lithium-ion batteries. According to Aquino et al. (2017), they are primarily used for resource adequacy or capacity applications due to their short-cycle life and their higher degradation rates [12]. Table 16 shows the battery parameter data collected for this technology.

The cycle life at 80 percent DoD of lead-acid batteries is in the 600 to 1250 range, and the higher values reported in Table 16 have less reliability. Assuming 350 cycles per year—an assumption from the literature supporting one full DoD for 350 days each year [85]—this leads to a life in the range of 1.4 to 3.6 years. While lead-acid batteries can have longer life when subjected to lower DoD or for float applications, for this report, a life of 2.6 years has been assigned. While spirally-wound lead-acid cells have greater RTE due to lower internal resistance due to higher cost, this work assumes an energy-dense cell design and an associated lower RTE. Hence, a DC-DC RTE of 75 percent is assumed.

Table 16. Cycles, life years, and RTE—lead acid technology.

Cycles	Life Years	RTE	Source Year, Author(s)
500 (at 50% DoD)	5.2		2015, PowerTech Systems [83]
	1.5–2	75%	2014, Anuphjappharadorn et al. [84]
600 (at 80% DoD)			2015, DiOrio et al. [64]
1250 (at 80% DoD)			2011, BAE [86]
2000	15	79–84%	2018, May et al. [10]
600			2012, C&D Technologies, Inc. [87]
1200	20	95%	2015, C&D Technologies, Inc. [88]

Note that the values observed by May et al. (2018) in Table 16 are outliers in comparison to what is seen elsewhere in the literature and have been left out of the values used to derive the resulting values presented in this report [10]. Nevertheless, they have been included in the table below. A system RTE of 72 percent was used in this work, while cycle life was assumed to be 900 cycles. At a rate of 350 cycles per year, this translated to 2.6 years of battery life.

Thus, while lead-acid systems are lower in initial capital cost relative to all the battery technologies considered in this report, their full life-cycle costs are comparable to lithium-ion battery systems.

5.3.4. Technology and Manufacturing Readiness Levels

Traditional lead-acid technology is one of the more mature electrochemical systems available; however, numerous changes made to create improvements over the years have led to more advanced but less mature systems. Typically, the lead-acid system has low cost over other systems, but also lower calendar and cycle lives especially at high DoD in comparison to the prevalent lithium-ion technology, as well as a low energy density, which makes it less competitive as a product. However, due to the long timespan over which research and upgrades have been made, it is assigned TRL and MRL levels of 8 and 9, respectively, the same as those of the lithium-ion technology.

5.4. Redox Flow Batteries

Redox flow batteries offer a very different type of system than the other battery systems described in this report. The flow battery is composed of two tanks of electrolyte solutions, one for the cathode and the other for the anode. Electrolyte is then passed by a membrane to store and generate energy. The technology is still in the early phases of commercialization compared to more mature battery systems such as lithium-ion and lead-acid; however, redox flow batteries offer advantages over competitive systems such as long lifecycles, low temperature ranges for operation, and easy scalability.

Vanadium redox flow batteries are primarily commercialized by a few companies: the US-based UniEnergy Technology (UET) and Vionx Energy, the German-based Gildemeister, and Sumitomo Electric from Japan. To compete with lithium-ion, these manufacturers have begun moving toward off-the-shelf systems as opposed to custom ones. UET also offers warranties between 2 and 20 years with performance guarantees [82].

5.4.1. Capital Cost

The capital component of a flow battery includes the electrolyte solution, membrane, and the hydraulic pumps necessary to push the solution from each tank to the corresponding electrode. The battery system can be composed of different design variants that can be stacked together to build systems that have larger capacities.

RedT Energy Storage (2018) and Uhrig et al. (2016) both state that the costs of a vanadium redox flow battery system are approximately \$490/kWh and \$400/kWh, respectively [89,90]. Aquino et al. (2017a) estimated the price at a higher value of between \$730/kWh and \$1200/kWh when including PCS cost and a \$131/kWh performance guarantee [12]. Removing these costs led to a range of \$542–\$952/kWh. Zinc-bromide flow battery systems were not considered in this analysis due to lack of available information and stability related to zinc plating with associated dendrite growth. Volterion estimated 800 euros/kW for their stack modules inclusive of control units [91]. Our internal work indicates for a 4-h system, the stacks are 35 percent of the DC system cost. Hence, the system cost is estimated to be \$676/kWh after converting euros to USD and using the E/P ratio of four. Near-term stack costs were estimated to be €500/kW, translating to \$488/kWh assuming stacks cost 30% of DC system. Stack costs were estimated to be 250 €/kW, which corresponds to \$293/kWh assuming stack costs are only 25 percent of DC system cost.

An average cost of \$555/kWh was used for year 2018, with a 30 percent reduction to \$393/kWh anticipated for 2025.

Table 17 shows the capital costs from a selection of literature.

Table 17. Capital cost estimates—redox flow technology.

Capital Cost ($/kWh)	Notes	Source Year, Author(s)
$490	5 kW, 20 kWh	2018, RedT Energy Storage [89]
$444	400 Euros	2016, Uhrig et al. [90]
$463		2016, Noack et al. [92]
$730–$1200	Includes PCS cost and $131/kWh performance guarantee	2017, Aquino et al. [12]
$542–952	After removing PCS and performance guarantee costs	2017, Aquino et al. [82]
$500–$700		2016, DNV GL [11]
$468		2017, Selmon and Wynne [93]
$490	5 kW, 20 kWh	2018, RedT Energy Storage [89]
$444	400 Euros	2016, Uhrig et al. [91]
$463		2016, Noack et al. [92]
$730–$1200	Includes PCS cost and $131/kWh performance guarantee	2017, Aquino et al. [12]
$542–952	After removing PCS and performance guarantee costs	2017, Aquino et al. [82]
$500–$700		2016, DNV GL [11]
$468		2017, Selmon and Wynne [93]
$435–584	PNNL calculations–increased energy cost by 10% to account for lower DoD than the 80% DoD used for the calculations. Increased cost by 15% to account for container, DC controls, BMS.	2014, Viswanathan et al. [34]; 2015, Crawford et al. [35]
$357–552	$570-$910 for installed cost. Removed PCS, grid integration and equipment tax, fees, and G&A costs.	2017, Damato [60]
$676	Volterion stack costs including control units was 800 Euros/kW. Conversion to US dollars and using stack costs as 35% of DC system cost.	2018, Seipp [91]
$488	Volterion mid-term stack costs—mid-term was not specified, it may be assumed to be 2021	2018, Seipp [91]
$293	Based on stack cost of $250/kW, a 69% reduction due to research & development	2018, Seipp [91]

5.4.2. Fixed and Variable O&M Costs and Performance Metrics

Aquino et al. (2017a) estimates that the fixed O&M for a vanadium redox flow battery system is somewhere between $7–$16/kW-yr and that the variable O&M cost is the same as other systems at $0.0003/kWh [12]. Due to lack of information and reliability for O&M costs, the same O&M costs were used across all battery technologies as mentioned previously. The O&M costs are at least as high as other battery technologies due to the "growing pains" associated with a newly emerged technology.

5.4.3. Cycles, Lifespan, and Efficiency

Redox flow systems typically have a longer lifespan than other electrochemical battery systems due to their lack of sensitivity to temperatures and the fact that charge transfer reactions occur as redox reactions in solution, with the solid electrodes simply providing a path for electron transport, thus avoiding the stress experienced by conventional battery electrodes during cycling. Aquino et al. (2017a) estimates the life to be 15 years with an RTE of 65–78 percent [12]. EASE (2016), on the other hand, places the ranges capable for a generic flow battery slightly higher when battery system auxiliary load is included in the DC-DC calculation [54]. Testing of UET flow batteries by PNNL has shown an all-inclusive RTE of 65 percent at the 4-h rate [77–79]. An AC-AC RTE of 67.5 percent has been assigned to this system.

For flow batteries, there is an optimal spot for operation that changes with stack design and E/P ratio. While stack performance improves at lower power levels, the nearly fixed overhead due to pumping operation results in varying RTE as a function of SoC, stack design, and E/P ratio.

Vanadium redox flow batteries have a cycle life of >10,000 cycles and an anticipated life of >15 years [10,62]. EASE (2016) states that they expect redox flow batteries to be capable of providing >12,000 cycles at an unknown DoD [54]. Aquino et al. (2017) provide much more conservative estimates at 5000 and 3000 cycles for vanadium and zinc-bromide, respectively [12]. While the electrolyte is non-degradable when used properly, the stack may need replacement as time goes on.

For this work, a cycle life of 10,000 cycles at 80 percent DoD, a calendar life of 15 years, and a system RTE of 67.5 percent were assumed for 2018, and the system RTE is expected to increase to 70 percent by 2025.

Table 18 shows cycle, lifespan, and RTE from the literature for redox flow batteries.

Table 18. Cycles, life years, and RTE—redox flow technology.

Cycles	Life Years	RTE	Source Year, Author(s)
5000	14	65–78%	2017, Aquino et al. [12]
10,000	15	70%	2018, May et al. [10]
>12,000	10–20	70–75%	2016, EASE [54]
		70.5%	2016, Uhrig et al. [90]
>10,000	20–30	75–80%	2017, Greenspon [62]
10,000	15	70%	2018, May et al. [10]

5.4.4. Technology and Manufacturing Readiness Levels

In recent years, redox flow batteries have gained high prominence due to their flexible characteristics and long cycle lives [94,95]. They were originally developed in the 1970s and recent innovations and improvements have been made to further address components that could increase the RTE to make the systems more competitive than lithium-ion systems given their current high cost [94,95]. Redox flow batteries have been assigned a TRL of 7 and an MRL of 8 after a review of the literature and the state of commercialization.

5.5. Sodium-Sulfur Batteries

Sodium-sulfur batteries are mature electrochemical energy storage devices with high-energy densities. According to Aquino et al. (2017), they are primarily provided by a single Japanese-based vendor—NGK Insulators—which, to date, has installed 450 MW of the technology worldwide [12]. The NGK battery typically consists of a set of twenty 50 kW and 100 kWh modules for one battery, allowing for systems that reach into several megawatts. It is a well-demonstrated technology and the largest installation to date is a 34 MW/245 MWh system located in Aomari, Japan, which was installed for wind stabilization. To maintain the molten state of the battery, the system is typically kept at a temperature between 300 °C and 350 °C. Due to these high operating temperatures and the associated safety requirements, this technology is typically suitable for non-mobile applications [54].

5.5.1. Capital Cost

The basic components of a sodium-sulfur battery unit include a system built from a large combination of modules, a control system, and a PCS. A variety of literature was consulted to estimate the current capital cost. For this system, the estimated cost appears to be approximately $750/kWh when results were averaged across the collected literature.

Aquino et al. (2017a) provided a range of capital cost values for a 4 MW/16 MWh system with the low end being $500/kWh to $1000/kWh for just the battery cost [12]. PCS and power control system costs were estimated to be between $580/kW and $870/kW. Kamath (2016) estimated the battery system cost range to be slightly lower between $400–$1000/kWh, while DNV GL (2016) estimated it to be higher at $800/kWh–$1000/kWh [11,66]. The PCS cost was in the $580–$870/kW range, while the costs for lithium-ion was twice as low [11].

For this work, a PCS cost range of $230–$470/kW was used for 2018, because there is no compelling reason to assume PCS costs will not reach a balance across all DC battery technologies. Viswanathan et al. (2014) reported a cost of $415/kWh for a 7-h system [34]. As a result that limited information was available since then, this value is also used as a data point, with a 10 percent increase accounting for the lower E/P ratio (or higher rate of discharge). An average cost of $661/kWh was determined for 2018 sodium-sulfur costs, with a 2025 cost of $465/kWh assuming a decrease of 30 percent.

Table 19 provides capital cost estimates for sodium-sulfur batteries from the literature.

Table 19. Capital cost estimates—sodium-sulfur technology.

Capital Cost ($/kWh)	Notes	Source Year, Author(s)
$500–$1000	4MW/16 MWh	2017, Aquino et al. [12]
$400–$1000		2016, Kamath [66]
$800–$1000		2016, DNV GL [11]
$500		2011, Crowe [96]
$319		2014, Liu et al. [97]
$455		2014, Viswanathan et al. [34]

5.5.2. Fixed and Variable O&M Costs and Performance Metrics

A limited number of sources provided estimates for the O&M costs for a sodium-sulfur battery system. Among those that were found include an estimate by Aquino et al. (2017) of $7–15/kW-year for fixed O&M and no estimate was provided for variable [12]. Other sources estimated that the fixed cost range was narrower to be between $7–$12/kW-year [11].

5.5.3. Cycles, Lifespan, and Efficiency

DNV GL (2016) and Aquino et al. (2017a) both estimated the lifespan of a sodium-sulfur system to be 15 years, putting it at a longer usable life than lithium-ion but shorter than redox flow [11,12]. The estimates for cycle life were all in the same approximate range of 4000 to 4500 cycles except for EASE (2016) [54]. The sodium-sulfur battery was assumed to have a cycle life of 4000 cycles at 80 percent DoD.

Regarding RTE, the ranges found in the literature were tighter than for other technologies [11,12,54]. Assuming a DC-DC RTE of 80 percent, this corresponds to an RTE of 77 percent on an AC-AC basis. Further, adjusting for 4-h discharge, we have assigned an AC-AC RTE of 0.75 for the sodium-sulfur system to account for higher electrochemical losses at a higher rate. The reasoning behind this is that the NGK sodium-sulfur battery is a 7-h system and its reported efficiency is based on a 7-h discharge. Hence, using this battery at the 4-h rate is expected to drop the efficiency.

While the DC response time is on the order of several milliseconds for most batteries, the AC response time was set to 1, determined by PCS response time.

Table 20 shows cycle, lifespan, and RTE from the literature for NaS batteries.

Table 20. Cycles, life years, and RTE—sodium-sulfur technology.

Cycles	Life Years	RTE	Source Year, Author(s)
	15	77%	2016, DNV GL [11]
4500	15	77–83%	2017, Aquino et al. [12]
4000	10	77%	2018, May et al. [10]
2000–5000	15	75–85%	2016, EASE [54]

5.5.4. Technology and Manufacturing Readiness Levels

Sodium-sulfur batteries have been manufactured in Japan since the early 1990s. Since then the technology has been demonstrated at over 190 sites with over 350 MW of capacity installed. In addition to Japan, in 2010 there was 9 MW worth of sodium-sulfur capacity installed just within the US to be used for peak shaving, wind capacity firming, and other applications [54]. Due to the multiple decades of development for this technology, the TRL and MRL levels can be estimated at 8 and 9, respectively, with estimates for 2025 rising to 9 and 10.

5.6. Sodium-Metal Halide Batteries

Sodium-metal halide batteries, also known as sodium-nickel-chloride or zebra batteries, have primarily been introduced into the electrical storage market for EV usage. The battery sizes themselves have a smaller range than some of the other electrochemical storage systems; the former fall in the capacity range of between a few kWh to a few MWh and have a high level of scalability and flexibility. Compared to other batteries such as sodium sulfur that run at high temperatures, the sodium-metal halide battery has a lower temperature range between 270 °C and 350 °C; however, the system still requires independent heaters to maintain the molten state necessary for operation [98]. Overall, the technology has a high performance and durability level with low sensitivity to ambient temperature, which makes it an attractive energy storage option. Due to their flexibility, sodium-metal halide batteries are capable of being used across a large variety of applications, including EVs and public transportation, residential and commercial buildings, renewable generation smoothing, and others [54].

5.6.1. Capital Cost

The sodium-metal halide system consists of a positive electrode made of nickel and sodium chloride and a sodium anode. These components are separated by a ceramic wall. The battery systems are composed of modules that are assembled together to scale the battery up to the desired capacity value. Like other electrochemical systems, the sodium-metal halide battery also requires a PCS.

EASE (2016) estimates the cost of this system to be approximately $550–$750/kWh for a typical system that is several megawatts [54]. May et al. (2018) estimated the range for the average project cost to be somewhere between $750–$1000/kWh [10]. Miraldi (2018) provided a cost estimate for their BESS SPRING164 570 kW, 1.2 MWh DC system of €500/kWh, which converted at the rate of $1.1676/€ (as of 12 July 2018) amounts to $584/kWh [99]. For this work, $700/kWh was used for 2018 capital cost, with an anticipated 31 percent drop to $482/kWh by 2025.

PNNL has developed planar cells that are expected to drive cost down to $150/kWh, while use of iron (Fe) instead of nickel (Ni) is expected to drive cost down further to $100/kWh [100]. The TRL for the PNNL technology is considered to be at 5, hence it has not been included. However, if the manufacturability of this planar design can be demonstrated, the sodium-metal halide battery could be a leading candidate for storage.

5.6.2. Fixed and Variable O&M Costs

No estimates were found for this technology in the literature.

5.6.3. Cycles, Lifespan, and Efficiency

A variety of estimates were provided for RTE for this type of battery technology with most between 80 and 92 percent [54,100,101]. Miraldi (2018) reported an RTE of 79 percent at rated power and 88 percent at rated energy [99]. As a result that this report focuses on a 4-h application and discharge at rated power corresponds to 2 h, it is appropriate to use 88 percent as the relevant number. This work uses a DC-DC RTE of 86.5 percent and an associated AC-AC RTE of 83 percent.

Regarding cycles, most of the literature reviewed estimated the value to be in the 3500 to 4500 cycle range [54,102]. A cycle life of 3500 cycles was assumed. The life of this system ranged from 10 years [99,100] to 15 years [101]. A life of 12.5 years was assumed for this work.

Table 21 provides cycles, life years, and RTE for sodium-metal halide batteries found in the literature.

Table 21. Cycles, life years, and RTE—sodium-metal halide technology.

Cycles	Life Years	RTE	Source
4500	15	88%	2018, Miraldi [99]
4500	<15	80–95%	2016, EASE [54]
4500	15	89%	2015, Benato et al. [101]
4000	10	75%	2018, May et al. [10]
		92%	2018, Li [100]
3500			2018, Solarquotes [102]

5.6.4. Technology and Manufacturing Readiness Levels

Sodium-metal halide batteries have only been in use since 1999. Since then they have primarily been manufactured in Europe and the US with projects taking place in other continents as well. There is still a substantial amount of potential for development of the technology given the short amount of time it has been manufactured compared to other systems. The TRL for this technology is slightly lower than other electrochemical counterparts at TRL 6 and is expected to rise to TRL 8 by 2025. This technology is considered to be MRL 7 and have the potential to rise to MRL 9 by 2025.

5.7. Zinc-Hybrid Cathode Batteries

The zinc-hybrid cathode battery, named "Znyth" battery by its developing and commercializing entity EoS, is a high-energy density storage technology that uses inexpensive and widely available materials, and therefore could be supplied at a low cost [103]. It uses non-flammable, near-neutral pH aqueous electrolyte, which is non-dendritic, and does not absorb carbon dioxide (CO_2), eliminating carbonate clogging issue. There are a number of manufacturers exploring this technology, including Urban Electric Power (Zn-Mno2), ZAF Systems, ZincFive (Zn-Ni), and NantEnergy (zinc-air). Limited information on these systems was available regarding cost or performance; however, information on the EoS system was most complete and served as the primarily source of information for this technology.

5.7.1. Capital Cost

According to the EoS website cost calculator, the DC battery system is priced at $263/kWh as of 2018 for a 1 MW/4 MWh system, including the batteries mounted and wired, the energy stack outdoor-rated enclosure, BMS, and a one-year warranty [104]. It does not include PCS, C&C, or shipping estimates. The calculator also estimates cost for various multiples of the 250 kW/1000 kWh units. Up to 750 kW/3000 kWh, the capital cost was projected to be $263/kWh, followed by a drop to $212/kWh at 1000 kW and higher.

Correspondence with EoS showed that a 500 kW/2 MWh zinc-hybrid cathode system costs $225/kWh for the energy stack that includes batteries, racking, container, and building provided the following information regarding and that the DC control box is $40/kWh [105].

A cost of $265/kWh was used for 2018 in this analysis. In subsequent communication, the 2022 cost was projected to be $160/kWh. For this work, the researchers have used $192/kWh for 2025, a drop of 24 percent.

5.7.2. Fixed and Variable O&M Costs and Performance Metrics

Regarding variable O&M, discussions with EoS gave a cost of $2/kWh for the year 2022 [105]. For this work, the research team have aligned O&M costs with other battery technologies.

5.7.3. Cycles, Lifespan, and Efficiency

EoS claims an RTE of more than 75 percent at 100 percent DoD. It is projected to endure 5000 cycles at 100% DoD, or a 15-year calendar life. The DC-DC RTE projections for 2022 was stated to be 75 percent from Yang (2018), while the DC response time was a few milliseconds to rated power [105]. For this work, the AC-AC RTE was assumed to be 72 percent, while AC response time was assumed to be 1 s.

5.7.4. Technology and Manufacturing Readiness Levels

Thus far, EoS-manufactured Znyth batteries have been installed at only two sites, both in 2017. Based on the number of installations and length of operating experience, a TRL value of 5 and MRL value of 6 are assigned to this technology.

5.8. Pumped Storage Hydropower

PSH units are resources that are sought for their ability to provide bulk power and ancillary services to the grid at a low $/kW rate. PSH is a well-established technology that has existed over a century. With that noted, the technology continues to evolve, as highlighted in this section.

PSH offers quick synchronization, short response time, and the versatility to serve as both a load and a generator. Despite these benefits, however, deployments of the technology have stalled in the US and some other markets in recent years due to large total capital costs requiring funding of hundreds of millions of dollars, the uncertainty of future market demand conditions, and environmental considerations that arise from the nature of the technology [106].

PSH is very efficient in ensuring renewable energy supply is smoothed out over periods of peak energy demand. Solar and wind energy require availability of certain climatic conditions to ensure uninterrupted supply, which is not always present [107]. PSH can store the electricity generated by these resources and supply it when there is peak load energy demand, thus providing balancing services [108].

Despite the lack of recent deployments, PSH provides more than 97 percent of all installed capacity of energy storage [109]. Internationally, PSH capacity is expected to increase 26 GW between 2018 and 2023 [110].

PSH can be used to reduce or eliminate wind curtailment in areas with significant wind power and low amounts of grid-scale storage. There was a 147 percent increase in renewable curtailment in California in spring 2017 from a year earlier. The California Independent System Operator expects this trend to continue unless there is significant grid-scale storage to address it [111]. The 2016 Hydropower Vision Report states that PSH may not be fully valued in the wholesale electricity and ancillary services markets, thus slowing down project deployment [112]. The report also states that there is growth potential of 16.2 GW by 2030, and another 19.3 GW by 2050 under favorable market conditions, to increase deployments from the present 21.6 GW (2016) to 56 GW by 2050 [112]. Hence, state and federal regulatory and market policy changes are essential for enhancing the viability of new PSH projects, especially in regions where renewable penetration lacks grid-scale storage.

PSH plants generally fall within three categories of technology: fixed, variable, and ternary. Fixed speed (also referred to as single-speed) involves a PSH plant that is only capable of pumping water in "blocks" of power that are non-adjustable. Variable-speed PSH units, on the other hand, were introduced to incorporate the technological capability of adjusting the rate at which water is pumped in order to provide regulation services—a use case that is unattainable with fixed speed [113]. Ternary technology consists of a PSH unit that allows for higher flexibility and improved efficiency by incorporating a separate turbine and pump on a single shaft along with the generator [114]. Recent years have brought new approaches to the technology.

Per the US Hydropower Market Report 2017 Update, by the end of 2016 there were 38 PSH projects in some stage of development, 32 of which were in the process of completing feasibility studies [115].

5.8.1. Capital Cost

The capital components of a conventional PSH facility include two water reservoirs, a waterway to connect them, and a power station that includes a pump and turbine. Given the typically large footprint of the system, the cost of an average project is commonly higher than other ESSs given the construction, commissioning, and potential environmental reviews. Aquino et al. (2017) estimated the cost to be $1500–$4700/kW for a single-speed unit, further estimating that an adjustable-speed unit would come with a 10–20 percent higher cost [12]. Most PSH projects were developed in the 1970s and 1980s and, according to a US Bureau of Reclamation report on the Mt. Elbert Pumped Storage Power Plant, they cost around $2020/kW [116]. Oak Ridge National Laboratory (ORNL) estimated two values for the technology, the first between $1800 and $3200/kW for an adjustable-speed PSH unit and the second estimate of $2230/kW from a Black and Veatch report [117].

Cost is typically expressed in $/kW for PSH plants. However, sometimes it is expressed in $/kWh. In both cases, the total cost is divided by the power or energy to get $/kW or $/kWh, respectively. While there is currently insufficient data to do this, it would be useful to separate out the power component cost and the energy component costs such that the total plant cost can be estimated for any E/P ratio. As described later in this section, the cost breakdown among various categories can be difficult because cost is determined by site-specific conditions. For example, the geography/terrain determines the type of reservoir to be built, which directly affects reservoir cost. Tunnel excavation cost also depends on the terrain. For a 10-h, 300 to 1000 MW plant, the 2017 costs were estimated to be within the wide range of $1700–$5100/kW [118].

When evaluating capital cost on a $/kWh basis, Kamath (2016) placed the value at $70–$230/kWh for an average project cost, while May et al. (2018) had a higher range of $250–$350/kWh [10,66].

A discussion with McMillan Jacobs Associates indicated that for a $700/kW transmission upgrade, land costs and civil engineering costs of $460/kW need to be added to target PSH costs. Excluding these costs, for a project to be economical, the target cost was proposed to be in the $1500–$2000/kW range. There were some locations with a projected cost of $3000/kW for a 50 MW system, and some with a projected cost of $2000/kW. Based on a conversation with HDR, our calculations indicate that the land cost is only $6/kW, assuming $250,000 per acre [119]. However, some plants have to purchase two orders of magnitude higher acreage than required for the project, depending on the length of the transmission line being serviced. This work assumes land required does not include the additional acreage and overall these costs are not considered, because they are site-specific.

Project costs for most sites are not broken down into various components. While the Black and Veatch (2012) report provides a breakdown for various categories for a specific case—500 MW, E/P of 10, and lower reservoir being a natural lake or river (hence no additional cost)—such information is typically not provided [28]. In this report, the electrical and mechanical costs for the powerhouse were stated to be $835/kW.

Per International Renewable Energy Agency (IRENA), the $/kW for electrical and mechanical equipment decreases with increasing power and is estimated to be $570/kW for a 4 MW system, $485/kW for a 48 MW system, and $245/kW for a 500 MW system [120]. There appears to be an inflection point at approximately 50 MW. From 4.3 MW to 48 MW, the $/kW decreased by 15%, while from 48 MW to 500 MW, the drop is 50%. This is shown in Figure 1. The unit power cost for the electrical and mechanical equipment in this report is approximately 30 percent of the $835/kW, thus highlighting the challenge associated with arriving at a single cost number for each category. While several projects have been planned with associated cost estimates, cost data for various components are not available.

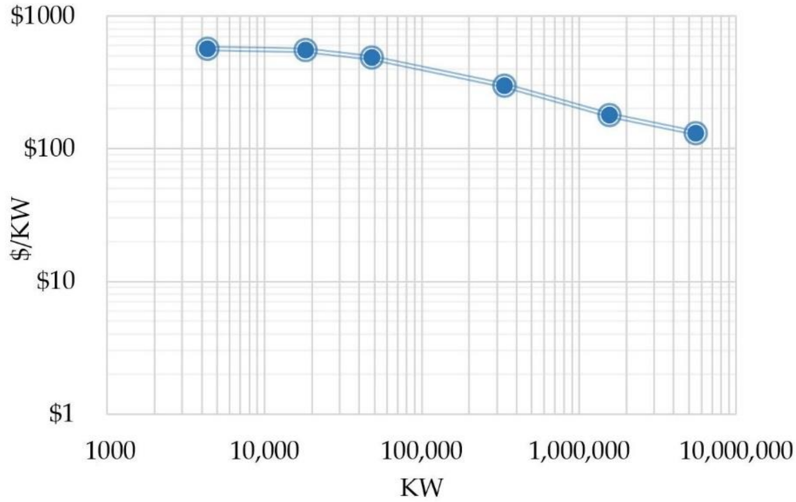

Figure 1. $/kW cost of electromechanical equipment for hydro plants by power capacity.

Steffen (2012) listed the investment cost for 11 announced PSH projects in Germany, which consisted of "land acquisition, civil works, and the hydraulic steel structure" and the "mechanical and electrical machines," with the latter estimated to be 20 to 30 percent of total cost [121]. The cost decreased linearly with increasing PSH power capacity. The cost for a 500 MW system was estimated to be $1840/kW, with the electrical and mechanical equipment, at 25 percent, corresponding to $460/kW. However, once the two projects with existing reservoirs and one project with high leverage were removed, there was no correlation between the project cost per kilowatt hour and the capacity of the project. That is, site-specific conditions affected costs more than the MW capacity of the PSH plant. This is an example of the complexity of trying to break out the PSH cost among various components, because site-specific conditions may dominate costs [122].

Retrofitting of older plants to improve performance includes major upgrades such as expansion of the powerhouse and hydraulic redesign [123–125]. There are plans to convert fixed speed to adjustable-speed or variable-speed PSH; however, doing so results in a 20 to 30 percent increase in cost for the electrical and mechanical equipment, along with potential increases in powerhouse volume and evaluation of civil structure to accommodate larger and heavier machinery [122]. Such upgrades need to be considered on a case-by-case basis for their economic feasibility. An overall project cost increase of 7 to 15 percent is estimated for adjustable-speed PSH over fixed speed, and the electromechanical equipment cost is estimated to be 60 to 100 percent higher [126,127].

Table 22 shows the breakdown for the various line items, including estimated cost for the lower reservoir set equal to that for the upper reservoir [128]. The powerhouse electrical and mechanical equipment cost is $825/kW, while the powerhouse excavation (civil engineering) cost is $80/kW. Depending on the terrain, the costs for tunnels, upper reservoir, and lower reservoir can vary. This list does not include transmission upgrade costs, which can be as high as $700/kW [128].

Table 22. Line item cost breakdown for a 16h pumped storage hydropower (PSH) plant.

Item	$/kW
Total Cost $/kW	2640
Owner's cost	370
EPC	390
Tunnels	135
Powerhouse excavation	80
Powerhouse	835
Upper reservoir	420
Estimated lower reservoir	420

Existing plants have a high E/P ratio of 30 h (h), but 12–16 h plants are in development and some are reaching as low as 8 h in duration. Based on this, 16 h was selected as the duration for this report, which covers the higher end of the E/P ratio for plants that are coming up. From available data, the PSH cost was determined to be $2638/kW for a 16-h plant [129].

Table 23 shows different total $/kW capital costs from collected literature for PSH technology.

Table 23. Capital cost estimates—PSH technology.

Capital Cost ($/kW)	Notes	Source Year, Author(s)
$1500–$4700		2017, Aquino et al. [82]
$70–$230/kWh		2016, Kamath [66]
$2020	$762/kW in 1985 converted to 2018 dollars using 3% escalation rate	2018, US Bureau of Reclamation [116]
$250–$350/kWh		2018, May et al. [10]
$1500–$2000	Target cost for project to be economical. Excludes transmission upgrade cost of $700/kW and civil and infrastructure cost of $460/kW	2018, Manwaring [128]
$3000	For 50 MW system	2018, Manwaring [128]
$1300	Projected cost for Eagle Mountain PSH in Southern California	2018, Manwaring [128]
$1800–$3200	Adjustable-speed PSH	2018, Shan and O'Connor [117]
$2230		2012, Black and Veatch [28]
$1500–$5100		2017, Damato [60]

To estimate the initial capital cost (ICC) to develop a greenfield PSH facility, prior research conducted by ORNL and documented in Witt et al. (2016) was leveraged [130]. Witt et al. (2016) documents the development of a scalable, comprehensive cost modeling tool capable of simulating the ICC for a variety of modular PSH projects and deployment scenarios [130]. Based on a few input site characteristics (storage volume, storage time, design head, and optional variables), the tool provides a reference design, categorical project cost estimates, and ICC estimates. The research considered various test case scenarios, including one in which construction of new upper and lower reservoirs is required and no existing infrastructure is available. In this report, a similar approach is used to estimate ICC.

In general, the default tool settings as documented in Witt et al. (2016) were used in the present study [130]. A few key additional assumptions made include RTE, a penstock length-to-head ratio, and the use of a Pelton turbine with standard pump arrangement. In addition, the escalation techniques used in the original tool were extended out to 2018 using the same cost indexes. Thus, all ICC estimates provided herein are in current year of 2018.

To consider a wide range of utility-scale greenfield PSH development, ICC estimates were calculated across different head (300 to 1500 ft) and installed capacity (100 to 1500 MW) ranges for 6-, 8-, and 10-h design storage times. The cost per kW increase with higher E/P ratios though the cost per kWh decline across the same range. When measured on a cost per kWh basis, PSH compares favorably with other energy storage methods. Importantly, some of the design and cost methods used in the tool may not be intended for application at the high-head and high-capacity scales considered in the present study; however, the general patterns found are deemed reasonable.

The ICC estimates are provided as shown on a cost per kilowatt ($/kW) basis. As shown in the plots, $/kW is lower for high-head development, which reflects the fact that for a project of the same installed capacity and same storage time, smaller reservoir storage capacity and smaller, less-expensive electromechanical equipment is required as head increases. The general trend is consistent with a major finding in Witt et al. (2016) that PSH projects tend toward greater economic viability when developed at a high head greater than 500 ft. For head above 1000 ft, $/kW is roughly the same [130].

The plots also reveal economies of scale associated with PSH development (i.e., $/kW decreases as installed capacity increases). This effect is relatively muted for capacities above 500 MW, as $/kW values generally show little change. At smaller scale (e.g., 100 MW and lower), the $/kW becomes much higher.

A final trend noticeable among the plots in Figure 2 is the tendency for $/kW to increase for larger storage times. This trend is attributed to the fact that for a project of the same installed capacity and same head, larger reservoir storage capacity is required. Additional revenue-related considerations may influence a decision to design for larger reservoir capacity.

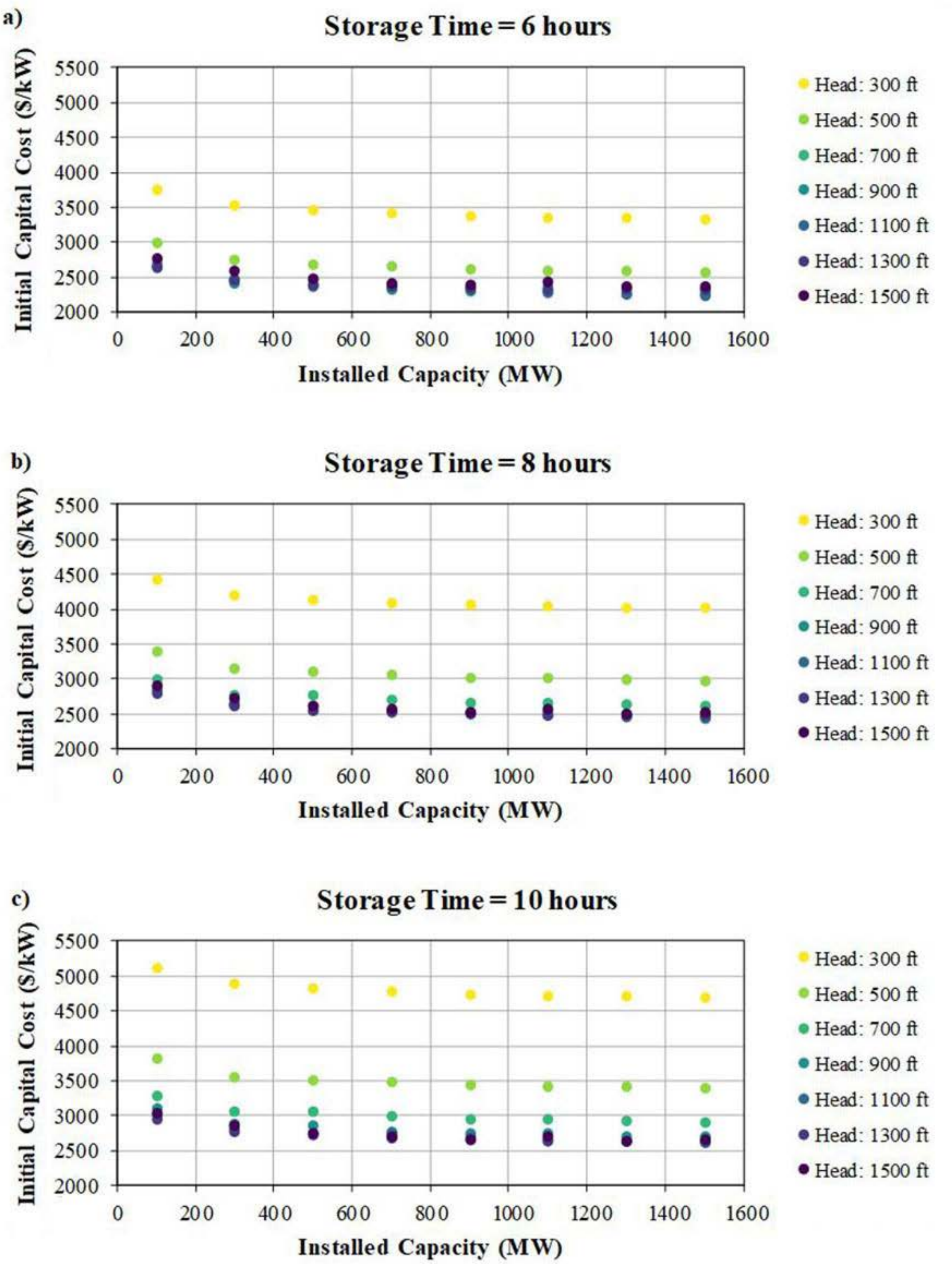

Figure 2. Initial capital cost estimates for greenfield PSH development for (**a**) 6-h, (**b**) 8-h, and (**c**) 10-h storage durations.

In general, for a 6-h storage time, the estimated ICC of a high-head (700+ ft), large-capacity (500+ MW) project is $2200 to $2500/kW. For a project with similar head and installed capacity, the estimated ICC increases to $2400 to $2800/kW for an 8-h storage time and $2600 to $3100/kW for a 10-h storage time.

Capital cost and the potential for the reduction of this cost have been discussed in previous literature without consensus. Some studies point to increasing costs in the next 20- to 40-year time period and some indicate a decline in costs. IRENA stated that since a significant amount of research has been undertaken with respect to hydropower, hydropower is unlikely to exhibit a downward sloping supply curve in the medium term [120]. This is primarily because all the lower cost opportunities and potential have been exploited and the increase in supply of hydropower will be accompanied at higher cost [120,131].

However, since then, additional research has been undertaken in the sphere and ORNL can be credited with the development of Ground Level Integrated Distributed Energy Storage or GLIDES. GLIDES stores air in high-pressure vessels as compressed air and is stated to be a low-cost energy generation technology with higher RTE. Hydraulic pumps are used to drive water into these vessels, leading to a higher air compression [132].

Other significant improvements in PSH are reversible pump-turbines with improved efficiencies, adjustable-speed pump-turbines, improved equipment controls (static frequency converters, generator insulation systems), and improved underground tunneling methods. These have higher capital costs but may lead to greater life-cycle cost reduction. According to MWH (2009), an increase of up to 5% in pumping efficiency has been caused by improvement in the pumping/turbine technology during the 25 years preceding the publication of the report [113,133].

As another example, Shell Energy North America (SENA) is developing a small, modular PSH plant with a 5 MW, 30 MWh capacity. The cost of the plant is estimated to be $22.3 million or $4400/kW ($743/kWh). SENA has estimated a two-year project development cycle consisting of licensing activities in Year 1 and capital costs in Year 2. Licensing costs for the first system are estimated to be $3 million, with costs reduced to $1 million for all subsequent plants. The capital cost for the system, excluding the floating membrane that makes up the lower reservoir, is estimated to be $18.7 million [134]. The conceptual floating membrane system is being developed and the estimated costs are about $600,000 with uncertainty at +100 percent/−50 percent [135]. Annual O&M costs are estimated to be $408,993 in Year 1 [106].

Outside of the SENA project, the literature has had a variety of estimates of how costs may decrease or increase over time for PSH. IRENA (2012) for example, states that they expect lower cost opportunities have already been exploited [120]. Similarly, Barbour et al. (2016) state that because costs are biased toward civil engineering requirements that fluctuate on a project-by-project basis, there are limits to the overall cost reduction that can be gained through the supply chain [136].

5.8.2. Fixed and Variable O&M Costs and Performance Metrics

Regarding fixed O&M costs, Aquino et al. (2017) estimated the range to be between $6.20–$43.30/kW-yr [12]. ORNL averaged the O&M costs for 11 PSH plants in the 2014–2016 period and found the O&M costs ranged from $20/kW-yr at 200 MW to $5/kW-yr at 2,800 MW [116]. Black & Veatch (2012) shows an O&M cost of $30.8/kW-yr [28]. The numbers indicated in Table 24 are averaged (excluding the highest value of 43.3) to arrive at an O&M cost of $15.9/kW-yr. The fixed costs include labor, insurance, and taxes.

Table 24 shows a compilation of the fixed O&M costs found in the literature. O&M cost for hydropower projects have also been estimated to be one percent of the construction and equipment procurement costs [133].

The variable costs for PSH are a function of the number of starts and stops. The variable costs include rehabilitation or repairs to welding joints, circuit breakers, and runners. ORNL estimated unit start cost in the $300–$1000 range [117]. Assuming the plant is sized at 100 MWh, and goes through

20 cycles in a year, this amounts to the 0.000094 to 0.0003 cents/kWh range. Considering the very low value, PSH variable costs have been set to zero in this report.

Table 24. Fixed O&M costs—PSH technology.

Fixed O&M ($/kW-yr)	Notes	Source Year, Author(s)
$6.2–43.3		2017, Aquino et al. [82]
$17.6	2007 costs	2018, US Bureau of Reclamation [116]
$5–20	Fixed decreases from $20/kW-yr at 200 MW to $7.5/kW-yr at 2000 MW to $5/kW-yr at 2800 MW	2018, Uría-Martínez et al. [137]; 2018, Shan and O'Connor [117]
$30.8	500 MW plant	2012, Black and Veatch [28]

5.8.3. Cycles, Lifespan, Response Time, and Efficiency

When evaluating the performance of different units, the RTE for PSH can be approximated by the product of pumping and generating efficiency, excluding losses due to evaporation [43]. The RTE varies from 60 percent for older systems to 80 percent for newer designs [138]. The RTE of 80 percent noted in this report is all-inclusive. The cycle efficiency is a function of DoD, head loss, friction loss in the conveyor tunnel, turbine efficiency, generator efficiency, and pump efficiency. A ramp rate of 20 to 35 MW/s is possible per unit. For some projects, one tunnel feeds two units, thus reducing ramp rate by a factor of two. Typically, the equipment vendors, such as General Electric Company or VOITH, provide their input to tunnel design and construction to ensure their power components can provide the necessary power [138].

May et al. (2018) estimates that a PSH unit is capable of lasting up to 50 years with an RTE of 80 percent and up to 20,000 cycles [10]. ORNL estimates the usable life to be closer to 20 years, and an RTE range of 82 percent and 70–87 percent, respectively [117]. An RTE of 80 percent has been used in this report. Lifetime is assumed to be >25 years, and 15,000 cycles are assumed. Table 25 lists PSH cycles, life years, and RTE.

Table 25. Cycles, life years, and RTE of PSH.

Cycles	Life Years	RTE	Source Year, Author(s)
20,000	20	82%	2017, Aquino et al. [82]
	50	80%	2018, May et al. [10]
	>20	70–87%	2018, Shan and O'Connor [117]

Typical ramp rates for PSH systems are 25 to 50 MW/s [128]. The ramp rate is a function of tunnel design to move water, so for a 4-unit plant, the ramp rate is 200 MW/s. While most of the time there is one tunnel per unit, sometimes one tunnel serves two units, thus decreasing ramp rates to 12 to 25 MW/s per unit. The time for various mode changes depends on whether the PSH is ternary or not. For ternary PSH, mode changes are quicker. Table 26 shows the time in seconds for various mode changes. For fixed-speed (FS) units, pumping is done at fixed load consumption, hence ramp rate is not applicable for the pumping mode. For generation, FS units take 5 to 15 s to reach rated power from online status. Hence, the ramp rate is 7 to 20 percent of rated power per second [117,139].

When ramp rate is defined as the time from spinning to rated power, for the pumping mode, the duration is 25 to 80 s. Ternary systems, having the fastest ramp rate of 4 percent rated power per second, take 25 s for this, while fixed-speed systems take 80 s. Using the same definition for ramp rate during generation, again, the ternary systems achieve this in 20 s, while FS systems achieve this in 5 to 15 s or 7 to 20 percent of rated power/s [117] and 70 s or 1.4 percent rated power/s [140].

Table 26. Ramping ability of PSH.

Status	Shan and O'Connor (2018) [117]	General Electric (2018) [139]
Shutdown to online (generating mode)	60–90 s	220 s
Online generating to shutdown		220 s
Online to full-load generating	5–15 s	60 s
Shutdown to full generation		120 s
Spinning-in-air to full-load generating	5–15 s	
Online to full load		80 s
Shutdown to normal pumping	6 min	300 s
Spinning-in-air to normal pumping	60 s	
Full load to online		60 s
Full generation to shutdown		250 s
Full pumping to shutdown		150 s
Full load to full generation		220 s
Full generation to full load		500 s

Table 26 has been regenerated below (as Table 27), with additional information provided for FS, advanced FS, adjustable speed, and ternary PSH with two different turbine types. While it would be preferable to provide ramp rates for each of these types to allow differentiation among them, there is not enough information to provide ranges for each mode change and category of PSH.

5.8.4. Technology and Manufacturing Readiness Levels

PSH is considered to be the most mature energy storage technology; a majority of the projects operational today originate from the 1970s and 1980s and the concept originated long before that time. More than 170 GW of the technology are installed internationally and are operational [53]. Different design variants are still being developed to improve parameters such as efficiency and response time, and other developments are investigating ways to reduce environmental impacts and the costs associated with avoiding them. These developments might include ideas such as closed-loop solutions that avoid impacting natural waterways. Given the long range of time across which PSH has been developed and installed, it is considered to have a TRL of 8 and an MRL of 9. These values are expected to rise to TRL 9 and MRL 10 by 2025.

5.9. Flywheels

Flywheels are an electromechanical energy storage technology that has a short duration of only a handful of minutes, which makes them suitable for applications that only require a short time of use or that are used as backup power that can bridge between the grid and larger backup sources. Their structure consists of rotating cylinders connected to a motor that stores kinetic energy. The conversion of electric to kinetic energy is achieved through the use of a variable-frequency motor or drive. Energy is stored by using the motor to accelerate the flywheel to higher velocities. The motor of the flywheel works to accelerate the unit to a higher velocity in order to store energy. Subsequently, it is able to draw electrical energy by slowing the unit down [12]. Given the short duration associated with the technology, although the storage system is fairly mature, it is typically not seen in utility applications. The manufacturers of the product in the US include Beacon Power and Helix Power. The latter is currently working on a development with the US DOE around absorption of energy from the regenerative braking and acceleration support to train cars in New York [141]. Flywheel systems can also be suitable for rapid power fluctuations on an industrial-level and for renewable smoothing. A large benefit that flywheels offer as a technology is their long lifecycles, their fast response times, and a typically large RTE value. They require low maintenance over the course of their lifetimes and are capable of running for a large number of cycles without the associated side effects that you would see with electrochemical storage.

Table 27. Ramping ability of PSH plants by technology type.

	Fixed Speed		Advanced Fixed Speed	Extra Fast Fixed Speed	Adjustable Speed	Ternary with Horizontal Francis Turbine	Ternary with Horizontal Pelton Turbine
Source:	**Shan and O'Connor (2018) [117]**	**GE (2018) [139]**	**Fisher et al. (2012) [140]**	**Fisher et al. (2012) [140]**	**Fisher et al. (2012) [140]**	**Fisher et al. (2012) [140]**	**Fisher et al. (2012) [140]**
Shutdown to online (generating mode)	60–90						
Online to full generation	5–15						
Spinning-in-air to full-load generating	5–15	60	70	20	60	40	20
Shutdown to full generation		120	90	75	90	90	65
Full generating to spinning-in-air		80					
Full generation to shutdown		150					
Shutdown to spinning-in-air		220					
Spinning-in-air to shutdown		220					
Shutdown to full-load pumping	360	300	340	160	230	85	80
Spinning-in-air to full-load pumping	60	80	70	50	70	30	25
Full-load pumping to spinning-in-air		60					
Full pumping to shutdown		150					
Full load to full generation		220	190	90	280	60	25
Full generation to full load		500	420	240	470	45	25

5.9.1. Capital Cost

As previously described, flywheels consist of a rotating cylinder connected to a motor that relies on kinetic energy. Flywheels that are installed as a source of uninterruptible power supply and have a much smaller comparable footprint. Aquino et al. (2017) places the capital cost of a 20 MW, 15-min Beacon Power flywheel plant at an estimated $50 million, resulting in a cost estimate of $2400/kW [12]. Piller, an additional flywheel manufacturer, estimates the price to be closer to $600/kW for a 2.7 MW unit [12]. Information gathered from Kinetic Traction, a flywheel manufacturer, placed the cost at a similarly low level of $600/kW for a 333 kW, 1.5 kWh system, not including installation costs [142]. However, the E/P ratio was only 0.27 min. Helix Power has a 1 MW, 0.0074 MWh system that is estimated to cost $1 million or $1000/kW, with an additional $50,000 or $50/kW for installation [141].

Table 28 shows the capital costs found in the literature for flywheel systems.

Table 28. Capital cost estimates-flywheel technology.

Capital Cost ($/kW)	Notes	Source Year, Author(s)
$2400	20 MW/5 MWh Beacon Power flywheel plant	Aquino et al. (2017a) [12]
$600	333 kW, 1.5 kWh system excluding installation	2018, Goodwin [142]
$1050	1 MW, 0.0074 MWh system including installation	2018, Lazarewicz [143]

One way to estimate the unit energy cost is to determine the average of the $/kWh cost from the above table, with $/kWh calculated from the $/kW and E/P ratio for the Beacon, Kinetic Traction, and Helix Power systems [141]. Doing so resulted in $61,533/kWh at an average E/P ratio of 0.093 h, corresponding to $5733/kW. The flaw in this method is the overweighting of the high $/kWh value at a low E/P ratio. A better approach is to use the same power capacity for each system at 1000 kW to determine individual system cost. Using the E/P ratio for each system, the total power and energy for all three systems are calculated along with total cost. The total cost divided by total energy is the average $/kWh, while the total cost divided by the total power is the average $/kW. The results are $1333/kW and $14,309/kWh. The E/P ratio for this total system is 0.093 h, the same as the average E/P arrived at earlier. However, this time, the overweighting of the high $/kWh value at low E/P ratio is not present.

A better approach is to plot the $/kW vs. E/P ratio to get the $/kW value at any required E/P ratio. Extrapolation of the straight-line fit provides the $/kW at E/P ratio > 0.25. The $/kW at E/P ratio of 0.093 was $1312, corresponding to a $/kWh of $14,573. This is shown in Figure 3. It should be noted that the limited data from the literature may result in underfitting the relationship between E/P ratio and capital cost. As more data points are observed, a more accurate fit is possible.

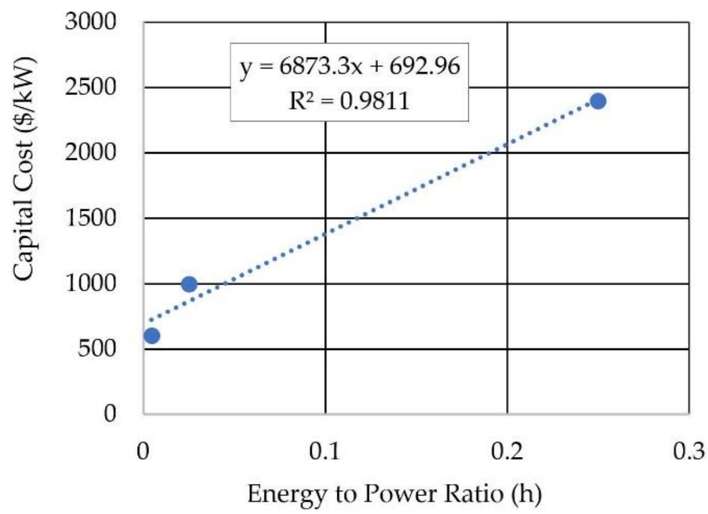

Figure 3. Capital Cost by energy-to-power ratio (h).

Table 29 provides the capital cost in $/kW for various E/P ratios and the associated $/kWh cost. Using the straight-line fit from the vendor values, we are able to calculate the cost for additional E/P ratios. For example, at an E/P ratio of 1, the $/kW and $/kWh is $7566, while at an E/P ratio of 4, the numbers are $28,186/kW and $7047/kW, respectively. As a result that Beacon Power's 20 MW, 5 MWh flywheels have been operating for >3 years, this work will assume an E/P ratio of 0.25, with an associated $/kW cost of $2400/kW for the flywheel system [12].

Table 29. Cycles, life years, and RTE—flywheel technology.

Cycles	Life Years	RTE	Source Year, Author(s)
Unlimited	20	70–80%	2017, Aquino et al. [12]
100,000	20	81%	2014, Manuel [63]
	20	98%	2017, Active Power [144]
<4 million	20	85–90%	2018, Helix Power [141]
	20	86%	2018, Goodwin [142]
		85%	2018, Stornetic [145]
175,000–200,000			2017, Aquino et al. [82]

5.9.2. Fixed and Variable O&M Costs and Performance Metrics

Only a small number of sources provided O&M information regarding this technology category. Among them were Aquino et al. (2017) and Manuel (2014), who estimated fixed O&M to be $5.56/kW-yr and $5.80/kW-yr, respectively [12,63]. Manuel (2014) also provided a variable O&M estimate around $0.30/MWh [63]. Helix Power estimates the maintenance costs to be minimal, while Kinetic Traction estimates (<$1500 per year for a 333-kW system) [141,143].

5.9.3. Cycles, Lifespan, and Efficiency

Flywheels as an energy storage technology are sought after due to their long lifecycles and high RTE levels. Active Power (2017) estimates the RTE at a value as high as 98 percent [144]. Aquino et al. (2017) give a range that is lower—between 70–80 percent [12]. Manuel (2014) for a 30 MW system estimates the RTE to be 81 percent [63]. Helix Power estimates a DC-DC RTE of 88 percent [141], while an 85 percent RTE was reported for the Stornetic Durastor 1000 system [145].

The duration of these systems range from 1–30 min. Regarding usable life, given that the system is a mechanical storage technology, the expected lifetime is capable of being twice as long as some electrochemical counterparts. All literature obtained for this report estimated the usable life of a flywheel system to be approximately 20 years [142,143,145].

Another attractive quality of the technology is the number of cycles it is capable of completing. Helix Power estimates that this value can be as high as 4 million [141], while Aquino et al. (2017) estimate 175,000–200,000 cycles [82]. The system is estimated to ramp to 100 percent of rated power in 250 milliseconds [141] and 5 milliseconds [142].

Table 30 lists flywheel cycles, life years, and RTE.

Table 30. Capital cost for various e/p ratios for flywheel technology.

Vendor	kW	kWh	$/kW	Cost $	$/kWh	E/P (h)	$/kW from Fit	$/kWh Calculated
Beacon [12]	1000	250	2400	2,400,000	9600	0.25	2411	9645
Helix [141]	1000	25	1000	1,000,000	40,000	0.025	865	34,592
Kinetic [142]	999	4.5	600	599,400	133,200	0.004505	724	160,710

5.9.4. Technology and Manufacturing Readiness Levels

The products discussed by the vendors mentioned above are primarily for high-speed flywheels, which have seen only a limited number of installations [12]. Given the newness and development of this technology, its maturity levels are not as high as some of the other energy storage counterparts discussed in this report. This is especially true considering the limited number of applications for which flywheels are ideally suited compared to other technologies, which can limit the amount of investment in this category. For these reasons, the current TRL for this technology is considered to be 7 and the MRL is expected to be 8. Both of these values are expected to increase by one level by 2025.

5.10. Compressed Air Energy Storage

CAES consists of filling a cavern with compressed air during the hours when energy prices are low and later, when the energy is needed, the air is heated and expanded and passed through a turbine that generates electricity. The configuration of CAES plants may also include a combustion chamber through which the air is fed into where it is ignited along with natural gas prior to reaching the turbine. This last component helps to increase both pressure and temperature of the air extracted from the storage which can "boost" output from the plant [146,147].

There are multiple varieties of CAES systems including adiabatic and diabatic. In diabatic systems, the heat from compression is released as waste. For adiabatic systems, the heat from compression is stored and later reused during air expansion—generating a larger amount of power output [148].

Projects of note include one being developed by Burbank Water and Power. The project will result in a 300 MW plant called the Pathfinder CAES in Utah that would utilize underground salt domes. A second phase of the project would add 1200 MW of capacity. When completed, the project as described would have a total of 1500 MW/25,000 MWh for an E/P ratio of slightly over 16. Pacific Gas & Electric, a California-based utility, has also shown interest in investing in CAES through funding provided by the American Recovery and Reinvestment Act. Analysis was begun regarding the development a project in a depleted natural gas reservoir in San Joaquim County. With US natural gas production having increased significantly over the last five years, more such reservoirs are expected to be available in the near future for CAES development [149].

Regarding established CAES plants, the McIntosh, Alabama, power plant has been operating for 27 years. The 110 MW plant has a rate of 400-pound mass/s, while the 55 MW corresponds to 197-pound mass/s [150]. The project has a salt dome capacity of 18.9 MM ft^3, and a pressure range of 650– 1100 psia. Dresser-Rand/Siemens has provided technical and field service support since 1991. Calculations show that at 110 MW generation, the cavern capacity corresponds to 31 h or 3.37 GWh, while at 55 MW compression, it takes 62 h to fill the cavern from 650 pounds per square inch absolute (psia).

5.10.1. Capital Cost

The capital cost of CAES plants includes equipment, construction, installation, engineering, and other costs necessary to build the grid-level storage system. According to Siemens AG (2017) [150], the equipment consists of:

- A 110 MW CAES train,
- Two W501F gas turbines,
- Two V84.2 gas turbines,
- A T300 plant-wide control system,
- Fuel gas booster compressors,
- An RG3 brushless excitation system,
- A D3000 vibration monitoring package for all units, and
- A D4 static excitation systems and start-up frequency converters for V84.2s

The 110 MW McIntosh project, commissioned in 1991, cost $65 million or $590/kW ($1310/kW in 2018 dollars) [151]. The estimated cost for the Iowa Storage Park, a 270 MW project that was terminated due to site limitations, came to $1481/kW [12]. Aquino et al. (2017) offer a range for the plant cost of between $1600 and $2300/kW for a 300 to 500 MW diabatic system, not including storage cavern cost [12]. The system would also include 12 to 48 h of solution-mined storage capacity. They expect that an adiabatic system will likely come at a higher cost given the additional equipment necessary to store the heat from compression, but the values cannot be projected given the low maturity level of the technology. Siemens estimates the cost for a 150 MW/48-h CAES system using the SXT-800 powertrain at a capital cost of between $1050 and $1400/kW or $22–$29/kWh [150]. For our work, an E/P ratio of 16 was assumed for this technology, and this corresponds to $66–$88/kWh. The capital cost for a 16-h plant was estimated to be $1669/kW using all the available data. Table 31 lists the capital costs of CAES systems.

Table 31. Capital cost estimates—compressed air energy storage (CAES) technology.

Capital Cost ($/kW)	Notes	Source Year, Author(s)
$1105	$590/kW in 1991 US dollars	2017, Siemens [150]
$1481		2017, Aquino et al. [82]
$1600–2300	Includes 12 to 48 h of solution-mined storage capacity	2017, Aquino et al. [12]
$1050-$1400		2018, Bailie [152]; 2018, Siemens [153]
$1047	900$/kW in 2010 US dollars	2012, Black and Veatch [28]

Some sources provided individual component costs. Table 32 provides the cost breakdown for a CAES system from Black and Veatch (2012) [28].

Table 32. CAES capital cost breakdown by component, Black and Veatch (2012) [28].

Item	Cost ($/kW)	Percent of Total Cost
Turbine	270	30%
Compressor	130	14%
Balance of Plant	50	6%
Cavern	50	6%
EPC	30	3%
Owner's cost	360	40%

Similarly, the breakdown for the $1050–$1400/kW estimate provided by Siemens [150] was described in Table 33.

Table 33. CAES capital cost breakdown by component, Siemens (2017) [150].

Item	Cost ($/kW)	Percent of Total Cost
Power island	550–650	49%
BOP/EPC	450–550	41%
Cavern Cost	50–200	5–14%

The power island costs are in line with the Black and Veatch (2012) costs for turbine and compressor [28]. The BOP/EPC costs depend on location, labor rates, building/site permitting, transmission interconnection, natural gas pipeline, etc. [152]. In this context, the BOP costs appear to be power related, and included BOP, EPC, and owners cost as listed by Black and Veatch (2012), which add up to 49 percent of total costs [28]. The 5 to 14 percent of total system costs due to the cavern is found when we divide the low cavern cost by the low system cost of $1050/kW (50/1050) and the high cavern cost by the high system cost of $1400/kW (200/1400), respectively. For an E/P ratio of 16, this translates to $3–$12.5/kWh. The cost varies with reservoir type–salt, aquifer, or hard rock mine, new or existing. The cost is also related to the level of solution mining required [152].

The cavern costs, which were listed as $50–$200/kW in Siemens (2017) [150], were converted to $/kWh [152]. For 48 h of storage, these costs were $3.5/kWh, and for 24 h of storage, the costs were estimated to be $4.50/kWh. Using linear fitting, energy-related costs in $/kWh can be assumed to be $-0.0417 \times (E/P) + 5.5$. The cavern cost for a 16-h plant was estimated to be $5.08/kWh using this relationship. From the Black and Veatch (2012) report, the cavern cost for a 15-h plant was 6 percent of system cost [28]. Using cavern cost as 6 percent for a 16-h plant, the cost for the rest of the plant was estimated to be 0.94*$1,667/kW, or $1567/kW. Keeping this constant across various E/P ratios, Table 34 lists costs that were estimated for CAES plants with various E/P ratios.

Table 34. CAES plant costs in $/kW and $/kWh for various e/p ratios or durations.

E/P (h)	10	16	20	30	40
$/kW	1567	1567	1567	1567	1567
$/kWh for cavern	5.1	4.8	4.7	4.2	3.8
Total cost $/kW	1618	1644	1660	1694	1720
$/kWh	162	103	83	56	43

5.10.2. Fixed and Variable O&M Costs

Aquino et al. (2017) estimates that for a 100 MW CAES plant, fixed O&M costs will be approximately $19/kW-yr for either a diabatic or adiabatic system [12]. They believe that variable O&M costs that do not include fuel-related costs for a plant of the same size to be around $2.3/MWh-yr. For the Iowa Stored Energy Park, fixed O&M cost was estimated to be in a similar range at $18.7/kW-yr and the variable O&M estimate at $2.28/MWh-yr [12]. Black and Veatch (2012) estimated a fixed O&M cost of $11.6/kW-yr and variable O&M cost of $0.00155/kWh based on 2010 USD [28]. This translates to $14.7kW-yr and $0.00196/kWh, respectively. The average of these values was used for this work: $16.7/kW-yr for O&M fixed, and $0.00212/kWh for O&M variable.

5.10.3. Cycles, Lifespan, and Efficiency

May et al. (2018) estimate that a CAES system has a usable life of 25 years and is capable of providing 10,000 cycles at an RTE of 65 percent [10]. Others state that a usable life of >30 years is possible and that an RTE is higher at >70% for adiabatic systems [12,54,150]. For diabatic systems, Aquino et al. (2017) and EASE (2016) both place the RTE at approximately 50 percent due to the need to reheat the cavern; however, EASE (2016) believes that diabatic systems still have a usable life greater than 30 years [12,54]. The lower RTE of the diabatic system is in line with Gyuk (2012), which estimates 54 percent [154]. The remainder of the literature consulted places the RTE range at higher values than this—Bailie (2018) stated 73 percent [152] and Li et al. (2016) 67.12 percent [155].

In communication with Dresser-Rand, the RTE was calculated by dividing the electrical output by the sum of electrical input to the compressor and the amount of energy that could have been generated by the natural gas fuel, assuming a 49 percent efficiency for conversion of natural gas to electricity [152]. Based on this formula, the RTE was estimated to be 74.6 percent. Note that their system includes heat capture in the compression cycle. It should further be noted that if the actual lower heating value of the natural gas fuel was used in the denominator, the RTE would be 51.9 percent. The latter appears to be a fair way to account for fuel usage, because in CT, the fuel lower heating value is used to estimate efficiency. Hence, an RTE of 52 percent was used in this work for CAES.

Response times and ramp rates were collected from Siemens (2018) [153] as the following:

- 10 min from cold start to full generation
- 5 min from online to full power
- 3.33 min from full speed no load to full load
- 4 min from offline to full load.

Regarding other operational parameters, Table 35 lists the CAES cycles, life years, and RTE.

Table 35. Cycles, life years, and RTE—CAES technology.

Cycles	Life Years	RTE	Notes	Source Year, Author(s)
10,000	25	65%		2018, May et al. [10]
		50%	Diabatic system	2017, Aquino et al. [12]
	>30	>70%	Adiabatic system	2016, EASE [54]
	>30	>70%	Adiabatic system	2017, Aquino et al. [12]
		54%		2012, Gyuk [154]
		73%		2018, Bailie [152]
		67.12%		2016, Li et al. [155]
		69%	RTE based on heat rate of 4910 Btu/kWh for CAES	2012, Black and Veatch [28]

5.10.4. Technology and Manufacturing Readiness Levels

Only two projects have been implemented in the US and internationally, and additional projects are under development. As with PSH, CAES faces environmental restrictions when constructing the caverns that will store the compressed air. Barriers for implementation have limited the development of projects despite the fact that the compressors and gas turbines used are considered to be a mature technology [12]. For this reason, CAES systems are considered to have a TRL of 7 and an MRL of 8, meaning that the system has been implemented but it is not as developed or mature as other technologies. By 2025, CAES is expected to be TRL 8 and MRL 9.

5.11. Ultracapacitors

Ultracapacitors are typically paired with battery systems to provide and absorb pulse power, and they have extremely fast ramp rates. The charge is stored in the double layer on the electrode, and hence can be released instantaneously when needed. According to Maxwell, a developer and manufacturer of ultracapacitors, when ultracapacitors are used in a hybrid battery system they are capable of performing photovoltaic smoothing, peak shaving, time shifting of energy, and load following [156]. The capacitor used was rated at 277 kW/8 kWh and was paired with a 50 kW/300 kWh aqueous battery for solar integration at Duke Energy's Rankin Substation. The capital expenditure and operating expenditure savings over the battery-only option were estimated to be 10–15 percent and 30 percent, respectively.

An 800-kW system was used to absorb braking energy and provide propulsion in the South-eastern Pennsylvania Transportation System for an average of 90 min per day, with each braking event lasting 15–20 s [156]. The remaining time was spent providing frequency regulation to the grid operator (PJM). The power consumption savings were estimated to be 10–20 percent of the 400 MW used for propulsion, while the frequency regulation provided an annual revenue of $200,000. A 3 MW, 17.2 kWh system is used at the Yangshan deep water port near Shanghai to mitigate a 10- to 15-s voltage sag during crane operation [157]. This resulted in a 38 percent reduction in peak demand. The E/P ratio for this system is 20 s. The system design assumption was 1 million cycles for 8000 h of operation for 10 years. This corresponds to 6000–9000 s for a 10–15 s per sag, assuming a charge time equal to the discharge time [157]. This work does not consider hybrid capacitors, with specific energy of 20–30 Wh/kg and energy density of 40–50 Wh/L such as a li-ion electrode paired with a double layer capacitor electrode, since these are still at a pouch level, and are at low TRL and MRL levels [158,159].

5.11.1. Capital Cost

Capacitors can consist of multiple cells/modules to scale to the desired capacity range of a project in a way similar to electrochemical systems such as lithium-ion. Ioxus energy provided details about their 250 kW DC capacitor and stated that the entire system cost is $40,000, corresponding to $160/kW [160]. Given the low specific energy and energy density of ultracapacitors, they are not competitive on a $/kWh basis with battery technologies. However, on the $/kW power level, they are more competitive due to their high specific power and power density. Maxwell provided a cost of $241,000 for a 1000 kW/7.43 kWh system, while a 1000 kW/ 12.39 kWh system cost $401,000 [161]. This corresponds to $32,565/kWh for the 7.43 kWh system and $32,365/kWh for the 12.39 kWh system, with the $/kW increasing from $241/kW to $401/kW for fixed rated power as the energy increases from 7.43 kWh to 12.39 kWh. While the energy content of the Ioxus system was not disclosed, their $160/kW estimate is on the same order of magnitude as the Maxwell capacitor costs. Clearly, because the power rating of the system is kept constant at 1000 kW, the cost scales with energy, and the unit energy decreases very slightly as energy increases.

For individual cells and modules, the ratio of energy density to power density was 0.001 h or 3.6 s. Maxwell proposed a 60-s duration as a potential use case for its capacitors. The cost estimates provided were for systems with durations of 27 and 45 s [157]. This work assumes an E/P ratio of 0.0124. The capital cost is $401/kW or $32,365/kWh at an E/P ratio of 0.0124. Note that assuming a maximum of 4.5 Wh/kg, for 45-s storage, the maximum power density is 360 W/kg. Since ultracapacitors have a specific power of approximately 2000 W/kg, they have to be used at less than rated power for durations >8 s, where 8 s is simply the ratio of 4 Wh/kg to 2000 W/kg. In other words, the $/actual usable power for large durations will be higher, while the $/kWh is expected to be stable at around $32,500/kWh.

5.11.2. Fixed and Variable O&M Costs and Performance Metrics

Capacitors, unlike other energy storage devices, require very little maintenance to keep their operational abilities over the entire duration of their usable life. For this reason, their O&M costs are considered to be so small to the point of being negligible. A nominal fixed O&M cost of $1/kW-yr, an order of magnitude lower than battery storage O&M costs, was assigned to ultracapacitors, with variable costs the same as batteries of $0.0003/kWh.

5.11.3. Cycles, Lifespan, and Efficiency

An attractive quality that capacitors are able to offer compared to longer-duration storage units is their long usable life. Capacitors are typically quoted as having a lifespan of at least 20 years with some reaching as long as 40 years, which is only rivaled by some PSH plants [159]. Atmaja (2015) compares three different types of capacitors (Electric Double Layer Capacitor, Pseudo-Capacitor, and Hybrid Capacitors) and states that all three are capable of a 40-year usable life and of achieving a 95 percent or higher RTE [162]. Sahay and Dwivedi (2009) place the usable life of supercapacitors at 25–30 years, the RTE at 95 percent, and state that their power density is 10× greater than that of batteries [163]. Maxwell estimates that their ultracapacitors have a slightly shorter DC life of only 10–15 years, but they are capable of running for 1,000,000 duty cycles. Additional details, specific to their 1000 kW/7.43 kWh and 1000 kW/12.39 kWh systems, state that their systems have a response time under 16 milliseconds or >60 MW/second and have a DC-DC RTE of 96 percent [161]. The Ioxus system has a calendar life of 20 years, can sustain 1,000,000 cycles, and has a DC-DC RTE of 98 percent [160].

For this work, the capacitors are assigned 1,000,000 cycles, a 16-year calendar life, and an AC-AC RTE of 94 percent.

5.11.4. Technology and Manufacturing Readiness Levels

Capacitors have been implemented across a wide range of projects like those described previously with regard to Maxwell, demonstrating their effectiveness and maturity as a technology. For this reason, they are believed to have a TRL of 8 and an MRL of 9. These values are expected to be the same by the year 2025.

6. Annualized Costs of Technologies

While the individual technology cost and performance parameters outlined previously provide a fundamental basis for evaluating the state of each technology individually and the predicted path forward regarding maturity and capability, to be able to fairly and objectively compare technologies, these results must be annualized. By conducting a pro forma analysis of each of the technologies incorporating the requirements for financing each storage project with applicable taxes and insurance over its usable life, an adequate framework is provided for comparison.

6.1. Approach

To achieve a comparable annualized cost, technology-specific findings for capital cost, BOP, PCS, C&C, fixed O&M, and variable O&M were run through a pro forma that incorporates assumptions surrounding the required costs of financing a project over the duration of its expected life. This total long-run revenue requirement is then evaluated as an annualized payment in 2018 USD based on an assumed weighted cost of capital for discounting. The assumptions used in this analysis are provided in Table 36.

Table 36. Annualization pro forma assumptions and parameters.

Parameter	Value
Discount rate/weighted cost of capital	7.6%
Annual O&M escalation rate	2.5%
Insurance rate	0.479%
Property tax rate	0.56%
Federal and State income tax rate	24.873%
Annual energy output	1,772,690 kWh

The assumptions listed in Table 36 were adapted from a battery storage project analysis by PNNL located in the Pacific Northwest, US. It is believed that these are adequately representative of a typical storage system within the US.

6.2. Findings and Comparative Analysis

By conducting the annualization calculation outlined in the previous section we are able to compare technologies laterally to get a better understanding of cost components and the economics of each system. Figure 4 shows the comparison if all technologies are evaluated on a $/kW-yr basis. Looking at the results from this perspective shows that battery technologies are less economical when a storage technology is being selected for a large power capability rather than energy. With that noted, lithium-ion technology and the zinc-hybrid cathode are only slightly higher in cost than flywheels on an annualized $/kW-basis. Individual component values are presented in Table 37.

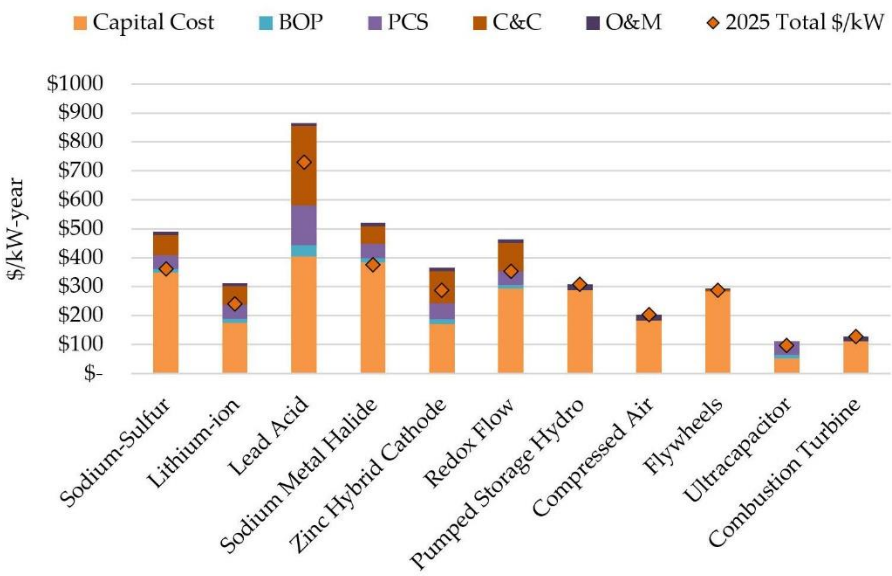

Figure 4. Annualized costs for each technology by cost component.

Table 37. Annualized costs for each technology, 2018 and 2025 ($/kW).

Technology	Year	Capital Cost	BOP	PCS	C&C	O&M	Total
Sodium-sulfur	2018	$349	$13	$46	$70	$12	$490
	2025	$246	$13	$28	$67	$9	$362
Lithium-ion	2018	$174	$16	$46	$65	$11	$312
	2025	$121	$15	$34	$62	$9	$241
Lead Acid	2018	$405	$39	$136	$274	$11	$866
	2025	$343	$37	$82	$260	$9	$731
Sodium-Metal Halide	2018	$385	$14	$48	$63	$11	$521
	2025	$265	$13	$29	$60	$9	$377
Zinc-Hybrid Cathode	2018	$170	$16	$56	$111	$11	$365
	2025	$123	$15	$34	$105	$9	$287
Redox Flow	2018	$293	$13	$46	$100	$12	$464
	2025	$207	$13	$28	$95	$10	$352
Pumped Storage Hydro	2018	$288	$0	$0	$0	$20	$308
	2025	$288	$0	$0	$0	$20	$308
Compressed Air	2018	$182	$0	$0	$0	$21	$203
	2025	$182	$0	$0	$0	$21	$203
Flywheels	2018	$284	$0	$0	$5	$4	$293
	2025	$284	$0	$0	$0	$4	$288
Ultracapacitor	2018	$51	$13	$45	$0	$0	$109
	2025	$51	$12	$33	$0	$0	$96
Combustion Turbine	2018	$111	$0	$0	$0	$16	$127
	2025	$111	$0	$0	$0	$16	$127

Figure 5 has been provided to show each technology cost on a $/kWh basis. This shows how non-battery technologies that are of low cost on a $/kW basis are of substantially higher cost when evaluated on a $/kWh basis. Note that the figure is shown under a log-scale and, therefore, ultracapacitors are approximately one hundred times as costly at over $14,000/kWh-yr than battery storage technologies when observed under this scenario. Flywheels are also of high cost at approximately $3000/kWh-yr. Individual annualized values by component are also shown in Table 38.

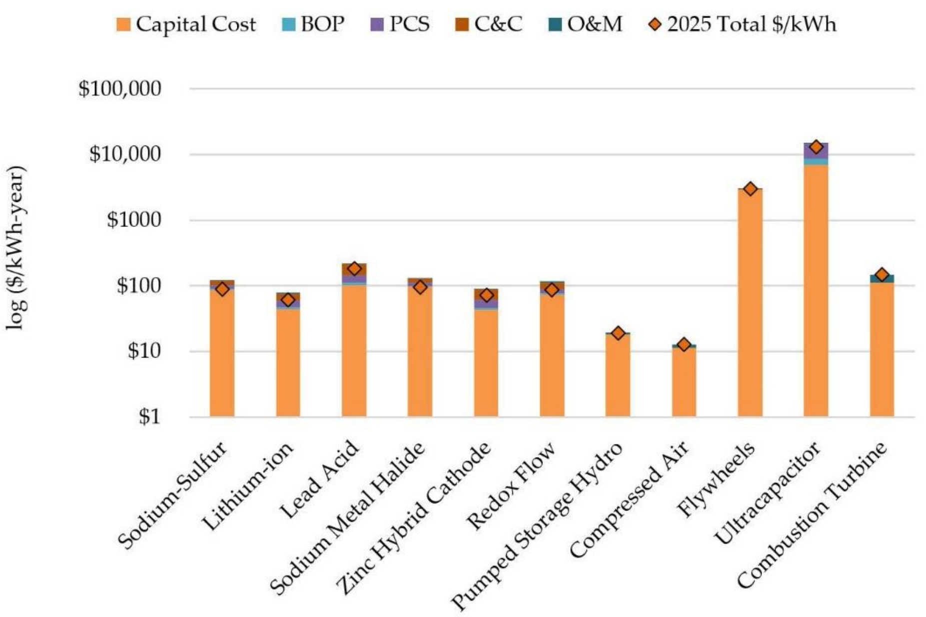

Figure 5. Annualized costs for each technology by cost component, 2018 and 2025 ($/kWh).

Table 38. Annualized costs for each technology, 2018 and 2025 ($/kWh).

Technology	Year	Capital Cost	BOP	PCS	C&C	O&M	Total
Sodium-sulfur	2018	$87	$3	$12	$18	$3	$123
	2025	$61	$3	$7	$17	$2	$91
Lithium-ion	2018	$43	$4	$12	$16	$3	$78
	2025	$30	$4	$8	$15	$2	$60
Lead Acid	2018	$101	$10	$34	$69	$3	$216
	2025	$86	$9	$21	$65	$2	$183
Sodium-Metal Halide	2018	$96	$3	$12	$16	$3	$130
	2025	$66	$3	$7	$15	$2	$94
Zinc-Hybrid Cathode	2018	$43	$4	$14	$28	$3	$91
	2025	$31	$4	$8	$26	$2	$72
Redox Flow	2018	$73	$3	$12	$25	$3	$116
	2025	$52	$3	$7	$24	$2	$88
Pumped Storage Hydro	2018	$18	$0	$0	$0	$1	$19
	2025	$18	$0	$0	$0	$1	$19
Compressed Air	2018	$11	$0	$0	$0	$1	$13
	2025	$11	$0	$0	$0	$1	$13
Flywheels	2018	$2936	$0	$0	$57	$76	$3069
	2025	$2936	$0	$0	$0	$76	$3012
Ultracapacitor	2018	$6894	$1719	$6017	$10	$240	$14,880
	2025	$6894	$1633	$4418	$0	$240	$13,185
Combustion Turbine	2018	$111	$0	$0	$0	$38	$149
	2025	$111	$0	$0	$0	$38	$149

7. Conclusions

This paper defined and evaluated cost and performance parameters of six BESS technologies—lithium-ion batteries, lead-acid batteries, redox flow batteries, sodium-sulfur batteries, sodium-metal halide batteries, and zinc-hybrid cathode batteries—and four non-BESS storage technologies—PSH, flywheels, CAES, and ultracapacitors—as well as CTs. The literature collected and analyzed to compile the technology comparisons in this report included academic papers, web articles and databases, conversations with vendors and stakeholders, and summaries of actual costs provided from specific projects implemented for a specific technology.

The key findings from the analysis conducted for this paper are as follows:

- For a 4-h BESS, lithium-ion batteries offer the best option today in terms of cost, performance, calendar and cycle life, and technology maturity.
- Redox flow batteries, which have several installations, appear to be well positioned, coming in second in terms of overall cost, performance, life, TRL, and MRL. While their RTE is low, there is room for improvement with stack optimization and better flow battery management algorithms.
- For longer-term storage, PSH and CAES give the lowest cost in $/kWh if an E/P ratio of 16 is used at $165/kWh and $104/kWh, respectively, inclusive of BOP and C&C costs.
- In the year 2025, next to the zinc-hybrid cathode system, lithium-ion is still the most cost-effective battery technology.
- On a 16-h basis, PSH and CAES are more cost-effective compared to battery storage technologies in year 2025, while on a 4-h basis batteries are competitive.
- On an annualized basis, lithium-ion has the lowest total annualized $/kWh value of any of the BESS technologies at $74/kWh, and ultracapacitors offer the lowest annualized $/kW value of the technologies included.
- An attempt was made to determine the cost breakdown among the various categories for PSH and CAES. While the cost for these technologies is typically reported in $/kW, the breakdown among EPC, BOP, power trains, and caverns from literature for CAES was compared with the numbers provided by a vendor and was found to align nicely. Based on vendor input,

a relationship was found for cavern cost in $/kWh, such that cost for a CAES system of any power and energy combination could be estimated.

- Comparing various storage technologies with different E/P ratios can lead to misleading results. A framework has been developed to compare costs across a range of E/P ratios for PSH, CAES, and redox flow batteries.

Overall, on a $/kWh basis, PSH and CAES are the most cost-effective energy storage technologies evaluated within this report. However, PSH is a more mature technology with much higher performance with regards to usable life, RTE, and other parameters. Energy storage technologies, though more expensive, serve a useful purpose by offering flexibility in terms of targeted deployment across the distribution system.

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Acronyms and Abbreviations

Acronym	**Definition**
AC	alternating current
Ah	ampere-hour
BESS	battery energy storage system
BMS	battery management system
BOP	balance of plant
Btu	British thermal unit
C&C	construction & commissioning
CAES	compressed air energy storage
CHP	combined heat and power
CONE	cost of new entry
CPUC	California Public Utility Commission
CT	combustion turbine
DC	direct current
DoD	depth of discharge and U.S. Department of Defense
DOE	U.S. Department of Energy
E/P	energy-to-power (ratio)
EIA	Energy Information Association
EPC	engineering, procurement, and construction
EPRI	Electric Power Research Institute
ESS	energy storage system
EV	electric vehicle
FG	full generation
FL	full load generation
FLA	full load generation

FS	fixed speed
G&A	general & administrative
GLIDES	Ground Level Integrated Distributed Energy Storage
GW	gigawatt(s)
h	hour(s)
HVAC	heating, ventilation, and air-conditioning
ICC	installed capacity cost
IRP	integrated resource planning
kW	kilowatt
kWh	kilowatt-hour
LFP	lithium iron phosphate
Li	lithium
LTO	lithium titanate oxide
MRL	manufacturing readiness level
MW	megawatt
MWh	megawatt-hour
NA	not applicable
NHA	National Hydropowper Association
NMC	nickel manganese cobalt oxide
NREL	National Renewable Energy Laboratory
O&M	operations & maintenance
OCV	open circuit voltage
OEM	original equipment manufacturer
ORNL	Oak Ridge National Laboratory
PCS	power conversion system
PG&E	Pacific Gas & Electric
PNNL	Pacific Northwest National Laboratory
PSH	pumped storage hydropower
PV	photovoltaics and present value
RTE	round-trip efficiency
s	second(s)
SENA	Shell Energy North America
SIA	spinning-in-air
SOC	State of Charge
TRL	technology readiness level
UET	UniEnergy Technology
V	volt(s)
VLA	vented lead-acid
VRLA	valve-regulated lead-acid
yr	year(s)

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