2020 Grid Energy Storage Technology Cost and Performance Assessment

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Acronyms

AC	alternating current
Ah	ampere-hour
BESS	battery energy storage system
BLS	U.S. Bureau of Labor Statistics
BMS	battery management system
BOP	balance of plant
BOS	balance of system
C&C	controls & communication
C&I	civil and infrastructure
CAES	compressed-air energy storage
DC	direct current
DOD	depth of discharge
DOE	U.S. Department of Energy
E/P	energy to power
EPC	engineering, procurement, and construction
EPRI	Electric Power Research Institute
ESGC	Energy Storage Grand Challenge
ESS	energy storage system
EV	electric vehicle
GW	gigawatts
HESS	hydrogen energy storage system
hr	hour
HVAC	heating, ventilation, and air conditioning
kW	kilowatt
kWe	kilowatt-electric
kWh	kilowatt-hour
LCOE	levelized cost of energy
LFP	lithium-ion iron phosphate
MW	megawatt
MWh	megawatt-hour
NHA	National Hydropower Association
NMC	nickel manganese cobalt
NRE	non-recurring engineering
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PCS	power conversion system
PEM	polymer electrolyte membrane
PNNL	Pacific Northwest National Laboratory
PSH	pumped storage hydro
PV	photovoltaic
R&D	research & development
RFB	redox flow battery
RTE	round-trip efficiency

SB	storage block
SBOS	storage balance of system
SCADA	sensors, supervisory control, and data acquisition
SM	storage module
SOC	state of charge
USD	U.S. dollars
V	volt
Wh	watt-hour

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Pumped Storage Hydropower

PSH is a mature technology that includes pumping water from a lower reservoir to a higher one where it is stored until needed. When released, the water from the upper reservoir flows back down through a turbine and generates electricity. There are various configurations of this technology, including open-loop (one or more of the reservoirs are connected to a natural body of water) and closed loop (reservoirs are separate from natural waterways). Existing turbine technologies also offer different features and capabilities, including fixed speed, advanced speed, and ternary.

Indirect vs. Direct Costs

The average MW capacity level for PSH plants has increased from 600 MW in 1973, to 1,400 MW in 1991, to > 2,000 MW today, with the current largest plant in the US being 3,000 MW (Bath County Pumped Storage Station, Virginia). Several factors may be responsible for this trend, the main ones being permitting for location and size, and possibly the extent of variable renewable penetration on the grid.

Fixed-speed PSH units are the most commonly deployed type, with frequency regulation ancillary service provided only in the generation mode and spinning reserve in both generation and pumping mode. Adjustable-speed units, on the other hand, provide ancillary services in both pumping and generation mode, and cost about 25-30% more than fixed-speed units (Key, 2011). Ternary units offer higher operational flexibility in terms of faster switching between charge and discharge (Miller, 2020b). However, ternary units cannot match the ramp rates needed for load following and frequency regulation offered by variable-speed units with modern power electronics. Since most regions in the US need switching between pumping to generation mode in < 10 minutes, the fast switching speed offered by ternary units is not needed in the US. There are two PSH plants using ternary units in Europe, where the grids do not offer much flexibility in terms of generation sources, increasing the need for fast switching between modes (Miller, 2020b). While ternary units are known for their fast switching of < 30 seconds, switching times of < 10 minutes are sufficient for the US, with a greater need for fast ramping capability related to load following and frequency regulation, which adjustable-speed units offer. Despite the advanced features described above, no adjustable-speed or ternary units are in operation in the US today and only two adjustable-speed units internationally, and it has been stated that regional transmission organizations are less interested in this technology as there is enough flexibility in generation to meet the needs of the US system (Miller, 2020a).

A hypothetical 1,000 MW PSH system is made up of four units, each rated at 250 MW, with operating range of 125-250 MW. While durations in the past have been 10-20 hours with weekend recharge, going forward, PSH plant duration is expected to be between 8-10 hours with daily recharge (Miller, 2020a). However, there is renewed interest in long-duration storage of > 24 hours.

Capital cost for PSH plants is typically split between direct and indirect costs, also referred to as contingency (HDR Inc., 2014; Manwaring, Mursch, & Erpenbeck, 2020; Miller, 2020a). Indirect costs are typically considered to be 15-33% of direct costs (HDR Inc., 2014; Manwaring et al., 2020; Miller, 2020a). Table 1 shows what is typically included under each of these two categories (HDR Inc., 2014).

Escalation rates corresponding to the Electric Power Distribution for Industrial Electric Power Index were used to get 2020 prices from historical data. In the next phase, escalation factors specific to categories such as civil and infrastructure (C&I), construction material, and powertrains will be used to estimate 2020s price from historical data (Key, 2011).

Table 1. Direct and Indirect PSH Cost Components

Direct Costs	Indirect Costs
Materials	Preliminary engineering and studies (planning studies, environmental impact studies, and investigations)
Construction of project features (tunnels, caverns, dams, roads, etc.)	License and permit applications and processing
Equipment cost	Detailed engineering and studies
Labor for construction of structures	Construction management, quality assurance, and administration
Supply and installation of permanent equipment	Bonds, insurances, taxes, and corporate overheads
Procurement of water rights for reservoir spill and make up water	

The direct capital component of a conventional PSH facility includes two water reservoirs, a waterway to connect them, and a power station with one or more pumps/turbines. Reservoir costs can consist of various components including roller-compacted concrete, cleaning, emergency spillways, excavation and grout, and inlet/outlet structures and accessories (Bailey, 2020). Reservoir costs are addressed in greater detail in the next section.

Placing indirect costs in the range of 15-33% of direct costs from HDR is consistent with information provided from Absaroka Energy, the developer of the 400 MW, 3,400 MWh Gordon Butte PSH Project (Bailey, 2020). The electromechanicals were $1,044/kW and C&I was $1,666/kW for a total of $2,710/kW direct cost. Indirect costs comprised engineering and construction management, financial costs such as project contingency and insurance, and development costs including permitting, licensing, and site acquisition. Indirect costs amounted to 24% of direct cost (Bailie, 2020) and included preliminary engineering studies as well as engineering and design management as part of their total estimated indirect costs. Regardless of nomenclature for specific items, indirect costs are expected to fall somewhere in the stated range and differ between the upper and lower values based on project complexity.

It should be noted that land price is typically not considered within O&M costs, since land cost varies depending on who owns the land. PSH O&M costs are estimated in the section that follows reservoir costs.

Capital Costs

A 2012 report from Black & Veatch estimated a wide total cost range of $1,349/kW to $4,048/kW for PSH and gave an average cost of $2,698/kW for a 500 MW, 10-hour plant in 2010 USD (Black & Veatch, 2012). The breakdown of costs in the report has been reproduced in Table 2. Note that, in order to provide both upper and lower reservoir costs in the table, the upper reservoir cost of $520/kW (2020 USD) was doubled to account for the lower reservoir since its cost was not explicitly provided (Black & Veatch, 2012) and that if there is an existing reservoir, the total reservoir cost will be half of the costs used in this study.

Table 2. Breakdown of PSH Capital Cost Components for a 500 MW, 10-hr Duration Project, Adapted from Black & Veatch (2012)

Cost Component	$/kW (2010 USD)	$/kW (2020 USD)	Percent of Total Direct Costs	Percent of Total Installed Cost
Upper and lower Reservoir	840	1,016		32.2%
Tunnels	135	163		5.1%
Powerhouse excavation	80	97		3.0%
Powerhouse structure, equipment, BOP	835	1,010		31.3%
Total direct costs	**1,910**	**2,311.12**		**71.5%**
EPC management services (project management, construction management, and contingency fees)	390	472	20.4%	14.6%
Owners' cost	370	448	34.4%	13.9%
Total indirect costs	**756**	**915**	**54.8%**	**28.5%**
Total installed cost	**2,650**	**3,07**		

For a 10-hour plant, the reservoir cost was found to be $104/kWh, higher than the $77/kWh without contingency fee and very close to the $103/kWh inclusive of contingency fees obtained from conversations with a PSH developer (Miller, 2020a).

The cost for tunnels as well as powerhouse excavation shown in Table 2 are each a small percentage of total installed cost at approximately 5% and 3%, respectively. Powerhouse structure and electromechanical equipment, on the other hand, which include costs related to tunnels, excavation, structure, and electromechanicals, is higher at 31% of total cost. This amount is in line with estimates provided by Miller (2020a); however, EPC and owner's costs combined are higher than Miller's estimates at approximately 55% of direct costs and 28.5% of total installed costs (Manwaring et al., 2020; Miller, 2020a).

In the same 2012 report, the authors additionally provided a more detailed breakdown of costs for a similar 500 MW PSH plant where the costs for each category were shown to be 89% of those in Table 2. Table 3 shows the breakdown details. The indirect costs in the additional estimates were found to be only 25% of direct costs, thus showing a wide range of indirect costs as a percent of direct cost (25-55% in the 2012 report). Indirect costs in the additional plant analysis include project management and design engineering at 5% of direct cost, construction management and startup support at 5%, and contingency at 15%. Due to lower direct and indirect costs, the total project cost of $2,565/kW was found to be only 85% of the cost shown in Table 2. This range of $2,565/kW to $3,231/kW provided by the two analyses within the same report gives an idea of how costs can vary in one study (Black & Veatch, 2012), based on assumptions of direct and indirect costs.

Table 3. Cost Breakdown for a Representative 500 MW, 10 hour PSH Plant, Adapted from Black & Veatch (2012)

	Value	Value ($/kW)
Rated capacity (MW)	500	
Duration (h)	10	
Total reservoir cost ($M, 2020 USD)	457	
Reservoir cost ($/kWh) (without contingency)	91	
Tunnels ($M)	73	145
Powerhouse excavation	42	85
Powerhouse structure, equipment, and BOP	454	908
Total direct project cost ($M)	1,026	2,052
Project management and design engineering at 5% of total direct cost ($M)	51	103
Construction management and startup support at 5% of total direct cost ($M)	51	103
Contingency at 15% of total direct cost ($M)	154	308
Total project cost ($M)	**1,283**	**2,565**

Conversations with HDR Engineering provided a breakdown of costs for PSH in both 8-10 hour and 18-20 hour duration ranges as shown in Table 4 (Miller, 2020a). Note that minor adjustments made to individual component costs allow values to sum to the total costs provided.

Table 4. Low and High PSH Cost Estimates by Category, Adapted from Miller (2020a)

Cost Category	Low Estimate ($/kW)	High Estimate ($/kW)
Total cost	$2,500	$3,500
Electromechanical cost	$585	$659
C&I	$1,915	$2,841
Contingency fees (25% of total cost)	$625	$875
Total cost without contingency fees	$1,875	$2,625

In order to also estimate the reservoir cost from the above values, it was assumed that the lower $2,500/kW total cost corresponds to a project with an average of the lower duration range (9 hours) while the higher $3,500/kW total cost corresponds to a project at the average of the higher duration range (18 hours). Following this assumption, the $/kWh reservoir cost with contingency was calculated to be $103/kWh based on the relationship between the total cost and the assumed duration of each system. This value is in line with earlier estimates for reservoir cost of $104/kWh (Black & Veatch, 2012).

Subtracting the estimated $103/kWh reservoir cost from the total C&I cost, the powerhouse-related C&I cost was estimated at $988/kW. The sum of the powerhouse C&I and electromechanical costs comes out to $1,500/kW and is greater than the $1,260/kW reported in the 2012 Black & Veatch report, but the total project cost is similar as the latter assumed indirect costs to be 55% of direct costs (Black & Veatch, 2012). Note that these costs include a 33% contingency fee on direct costs (or 25% of project total). Table 5 shows the cost breakdown for individual components without contingency fee added.

Table 5. PSH C&I Cost Components without Contingency Fees

Cost Component	Value
Reservoir cost ($/kWh)	77
Electromechanical cost ($/kW)	467
C&I for powerhouse ($/kW)	742
Contingency fees (% of above costs)	33%

According to Miller (2020a), the non-civil electromechanical part costs $550 to $650/kW depending on head. The greater the head, the smaller the electromechanical components need to be to provide same power. It should be noted that the head also affects C&I costs. The higher the head, the smaller the reservoir needed to get the same energy output. The smaller electromechanical size lends itself to lower C&I for powerhouse. The Goldendale Energy Storage Project has a head of 2,400 feet and is expected to cost $1,800/kW for C&I. Higher head for the project also reduced tunnel excavation costs due to the fact the pump/turbine centerline depth below the lower reservoir bottom decreased with increasing head (Miller, 2020a).

HDR Engineering performed an analysis in 2014 of three PSH projects: Swan Lake North, JD Pool, and Black Canyon (HDR Inc., 2014). Plant details and costs estimated by both the original project developer and HDR's own estimates for the specific plants have been reproduced in Table 6.

Table 6. Project Details and Cost Estimates for Three PSH Plants, Adapted from HDR Inc. (2014)

Component	Swan Lake North	JD Pool	Black Canyon
Head (feet)	1,253	2,000	1,063
Power capacity (MW)	600	1,500	600
Energy duration (hours)	8.8	11	9.5
Energy capacity (MWh)	5,280	12,100	5,700
Project developer cost estimate ($/kW) (2014 USD)	$2,300	$2,100	$1,500
HDR cost estimate ($/kW) (2014 USD)	$2,250	$2,500	$2,150
HDR cost estimate ($/kW) (2020 USD)	$2,406	$2,674	$2,299

An estimate of reservoir cost was derived from the information provided in Table 6. The relationship between total $/kW plant cost and plant duration was examined across the three sites. It is assumed that the change in total cost for an increase in duration is a good proxy for determining the $/kWh reservoir cost for a plant given that increasing duration consists of increasing reservoir size. This calculation gave an estimated $142/kWh for reservoir cost using this data set. Ultimately, this estimate was determined to be a high outlier when compared to reservoir costs estimated or provided from other sources and was excluded from the overall calculation in this analysis. Note that reservoir costs are affected by head and duration. Higher head lends itself to lower reservoir size for the same amount of stored energy, while longer duration benefits from scale, as the fixed costs related to equipment procurement and planning becomes less important, with incremental cost for additional stored energy dominating. It should be noted that, due to limited data availability, the relationship would likely be more robust with estimates from additional projects with a wide range of durations. From the data available, for an 8-11 hour duration range, the total plant cost was estimated to be between $2,300 and $2,637/kW following the relationship established. Assuming these costs do not include substation/switchgear and transmission lines, the total costs are at the lower end of the $2,500 to 3,500/kW range provided in conversations with developers (Manwaring et al., 2020; Miller, 2020a).

An analysis by Black and Veatch for the same three sites analyzed in the 2014 HDR report, except with adjusted MW capacities, showed total project cost to be in a much tighter range of $2,844-2,954/kW compared to the range estimated above (Black & Veatch, 2016). An earlier HDR analysis from 2010 of representative PSH projects, on the other hand, gave a higher total project cost range of $3,025-3,307/kW, inclusive of an assumed 5-mile transmission line. Excluding the transmission line cost the range amounted to a total project cost of $2,915-3,217/kW.

Scaling for PSH with respect to MW capacity was completed using data from Davitti (2018). This resulted in a 35% drop in system cost for every 10x increase in power. The scale factor was adjusted to reflect a 16% drop in system cost in $/kW for every 10x increase in power to be conservative and not overestimate the effect of scaling. This is because there are several factors that affect cost, including tunnel length to storage head ratio, storage head, geology of the location. The scaling factor for various power levels was determined by setting the 100 MW value to 1. For PSH, the capital cost and is multiplied by 0.9 and 1.1 respectively to get the low and high end of the year 2020 price range. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrains.

Using drilling techniques from the oil industry, vertical shafts are drilled to house the submersible pump-turbine, eliminating excavation costs for the powerhouse, with associated reduction in contingency fees for pumphouse construction. This offers a potential 33% cost reduction.

Reservoir Cost

The estimated reservoir cost of $142/kWh derived from the values provided in in Table 6 is higher than the $104/kWh cost found in the 2012 Black & Veatch report, inclusive of contingency (Black & Veatch, 2012). Note that both the reservoir cost from the 2014 HDR study in Table 6 and the reservoir cost from Miller (2020a) in Table 4 are derived from cost differences between projects of various durations. The reservoir cost from Miller (2020a), however, involves even more assumptions, where, as noted previously, the lower end of the total project cost range was assigned to 9-hour storage and the upper end to 18-hour storage, since storage durations were grouped into 8-10 hour and 18-20 hours (Miller, 2020a). Eliminating the high outlier reservoir cost range estimate of $142/kWh from the 2014 HDR report, reservoir costs were assumed to be $100/kWh, in line with the literature and conversations with developers (Black & Veatch, 2012; Miller, 2020a).

As with the power-scaling factor, for the reservoir to be conservative, the scale was adjusted using data from Davitti (2018). Scale was set to 1 for 800 MWh of storage, with a 16% drop in price for every 10x increase in storage MWh capacity (Davitti, 2018).

Table 7 shows the summary of capital and reservoir costs from various sources, and the costs assumed for this work. Note that some sites provide contingency fees as a percentage of total project cost, while others provide breakdown of contingency fees into categories such as EPC management services, project management, construction management, and contingency. In the generic PSH example, the term contingency refers only to construction management, while in this study contingency fees are used as a catch-all category that includes items such as EPC management services, project management, construction management, and other components. While indirect costs and contingency fees can be grouped together, Key (2011) assigns 15-30% of direct costs as indirect costs, which include planning studies, licensing and permitting, design, and construction management. An additional 20-25% contingency fee was also recommended for unanticipated costs.

Table 7. Summary of Cost Estimates from Literature and Developer Interviews

	Generic PSH Site	Generic PSH Site	Swan Lake North[a]	JD Pool[a]	Black Canyon[a]	Generic PSH Site	Generic PSH Site	Generic PSH Site
Reference	Black & Veatch (2012)		HDR Inc. (2014)			HDR Inc. (2010)		Manwaring et al. (2020)
Power (MW)	500	500	600	1,100	600	1,050	1136	1,000
Duration (h)	10	10	8.8					10
Reservoir ($/kWh)	104	91.5						77
Reservoir ($/kW)	1,040	915						770
Tunnels ($/kW)	163	145						
Powerhouse excavation ($/kW)	97	85						
Tunnels, excavation, powerhouse structure, and BOP ($/kW)								742
Powerhouse structure, BOP electromechanical ($/kW)	1,010	908						
Electromechanical ($/kW)								467
Total ($/kW)	**2,310**	**2,053**						**1,979**
EPC management services (project management, construction management, contingency) ($/kW)	472	513						653.07
Owner's cost ($/kW)	448	513						
Total with EPC and owner's cost ($/kW)	**3,230**	**3,079**	**2,406**	**2,674**	**2,299**	**2,603**	**2,121**	**2,632**
Contingency as percentage of total project cost	28%	33%	15-30%	15-30%	15-30%			25%

[a] Unspecified if indirect costs are included in estimates

Since the costs in Table 7 are in agreement, the detailed breakdown provided in Table 5 has been used, coupled with the scaling described earlier, to arrive at system costs for various power and durations. Table 8 provides a detailed category cost breakdown for a 100 MW, 1,000 MWh PSH plant, with references for each category.

Table 8. Price Breakdown for Various Categories for a 100 MW, 1000 MWh PSH

Cost Category	Nominal Size	2020 Price	Content	Additional Notes	Source(s)
Electromechanical powertrain	100 MW	$467/kW		Direct costs	Black & Veatch (2012); Davitti (2018);

Cost Category	Nominal Size	2020 Price	Content	Additional Notes	Source(s)
Powerhouse C&I	100 MW	$742/kW	Electromechanical and powerhouse C&I costs		HDR Inc. (2014); Manwaring et al. (2020); Miller (2020a)
Reservoir	1000 MWh	$76/kWh	Direct costs	Assumes need for upper and lower reservoirs	Bailey (2020); Black & Veatch (2012); Davitti (2018); Miller (2020a)
Contingency	100 MW, 1000 MWh	$656/kW	Indirect costs	33% of direct costs	Bailie (2020); Key (2011); Miller (2020a)
O&M		$30.4/kW-year	Fixed O&M	Deep repair and refurbishments every 20 years	Aquino, Zuelch, and Koss (2017); Black & Veatch (2016); Manwaring et al. (2020); Miller (2020a); R. Shan and O'Connor (2018); Uría-Martínez, Johnson, and O'Connor (2018)
Performance metrics			Calendar life of 50 years	Assumed 40-year life	May, Davidson, and Monahov (2018)
Performance metrics			RTE 70-87%	Assumed 80%	Aquino et al. (2017); May et al. (2018); R. Shan and O'Connor (2018)
Performance metrics			Ramp rates 12-50 MW/s per unit	Ramp rate decreases by 2X when one tunnel serves two units	Fisher et al. (2012); General Electric (2018); Koritarov et al. (2013); Manwaring (2018); R. Shan and O'Connor (2018)

For PSH, the capital cost is multiplied by 0.9 and 1.1 respectively to get the low and high end of the 2020 price range. No learning rates were assigned for 2030 due to maturity of the technology related to reservoirs.

O&M Costs

O&M costs were described in Miller (2020a) for a 1,000 MW plant consisting of four 250 MW units. Table 9 shows the various O&M labor-related costs. Note that labor costs do not change significantly as MW capacity increases, resulting in a lower $/kW-year, while parts and refurbishments have a constant $/kW-year. O&M costs were assigned 0.9 and 1.1 multipliers to establish the range. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrain and reservoirs.

Table 9. Estimated Labor Required for a 1,000 MW PSH Plant, Adapted from Miller (2020a)

Labor Component	Staff Required
Electromechanical controls	6

Electronics-related repair	3
Rotary equipment repair	3
HVAC, smoke and heat rejection	3
Outdoor maintenance of dams, roads	15
Supervisors	8

Variable O&M for PSH plants consist of multiple components including parts and overhaul of pumps/turbines. Parts are estimated at 40% of labor costs and are a constant $/kW across all power levels. Overhauls are expected to be required every 10 years at a cost of $16/kW-year ($40 million per 250 MW unit) and is not expected to be a function of plant size.

There is not a substantial amount of data available on adjustable-speed units in the US given that deployed units are fixed-speed technology. It is projected that O&M costs for adjustable-speed units may be either the same or less than for fixed speed. For fixed O&M, labor would typically require 25 operators to cover a 24/7 operation schedule. For variable O&M, the same source estimated that repairs are required every five years and should be assumed to cost 1% of electromechanical cost (Manwaring et al., 2020).

A deeper repair, in which the turbine is pulled out and seals are replaced, is required every 10 years. This repair is labor-intensive and the bearings and gaskets will often be replaced as well. This can require the plant to be shut down for about a month and costs 5% of electromechanical cost (Manwaring et al., 2020). Lastly, every 20 years parts like the rotor must be replaced and the stator rewired. These changes can cost between 10-20% of the electromechanical cost (Manwaring et al., 2020). These numbers align with details provided in Key (2011).

The fixed O&M defined by Miller and the National Hydropower Association (NHA) (Manwaring et al., 2020) corresponds to yearly fixed labor costs, while variable O&M corresponds to deep repair and refurbishments.. However, both costs are related to labor, maintenance, and repair, and have been denoted as total fixed O&M in this study. The O&M costs combining Miller (2020a) and Manwaring et al. (2020) are shown in Table 10. Note that labor costs are assumed to double for every 10x increase in power.

Table 10. PSH O&M Costs by Category

Component	100 MW System	1,000 MW System
Duration (hrs)	10	10
Labor-related fixed O&M ($/kW-year)	15.7	3.1
Parts-related fixed O&M ($/kW-year)	5.6	5.6
Refurbishment-related fixed O&M ($/kW-year)	9.0	9.0
Total fixed O&M ($/kW-year)	30.4	17.8
Percentage of capital cost	2.0%	1.4%

The O&M costs for PSH plants, measured in $/year, have typically been estimated using the following relationship (Black & Veatch, 2016):

$$O\&M\ Cost = 34{,}730 \times P^{0.32} \times AE^{0.33} \qquad [1]$$

Where,

P = plant capacity (MW)
AE = annual energy throughput (MWh)

Note that the choice of capacity factor affects results. Also, it is assumed that this formula accounts for charge energy as well, based on the known RTE. For a 1,000 MW plant operating at a capacity factor of 25% (Aquino 2017), fixed O&M is estimated to be $8.29 million which corresponds to $8.29/kW-year and puts it in line with the above result of $8.7/kW-year at 1,000 MW. However, at a lower power capacity level of 100 MW, this formula does not adequately account for a larger contribution of labor at this lower power capacity level with a fixed O&M of $18.6/kW-year, much lower than $78.7/kW-year from Table 10. The same study also set aside $280,000 every two years for repairs, which corresponded to $0.14/kW-year. Costs associated with overhaul such as restoration of bushings and bearings in the wicket gate operation, rehabilitation of servomotors, pump-turbine bearings, and similar amounted to $0.32/kW-year. The sum of these numbers is much lower than the $9/kW-year estimated in Table 10. The O&M costs are in line with the literature values (Aquino et al., 2017; R. Shan & O'Connor, 2018; Uría-Martínez et al., 2018). However, the numbers in Table 10 provide more realistic estimates as a function of PSH MW capacity.

For basic variable O&M, there is inconsistent nomenclature regarding what this category consists of. Due to the lack of detailed justification regarding what comprises basic variable O&M for each technology, this work sets the basic variable O&M to be $0.5125/MWh and is derived here based on the average across various technologies (Table 11). Depending on duty cycle, the energy throughput will vary, thus affecting total basic variable O&M costs.

Table 11. Variable O&M Estimate Calculation for Energy Storage Systems

Reference(s)	Technology	Value ($/MWh)
Raiford (2020)	Lead Acid	1
Hunter et al. (In Press)	Hydrogen	0.5
Aquino et al. (2017); Wright (2012); Black & Veatch (2012)	CAES	0.25
Mongird et al. (2019)	Non-specific	0.30
	Average	**0.5125**

Performance Metrics

May et al. (2018) estimate that a PSH unit is capable of having a calendar life of 50 years with up to 20,000 cycles with deep repair and refurbishments needed after 20 and 40 years (Aquino et al., 2017; R. Shan & O'Connor, 2018). Assuming a calendar life of 40 years, with 5% of that time allocated to downtime, this corresponds to a total cycle life of 13,870 cycles for one cycle per day.

The RTE found in the literature typically ranges from a low of 70% to a high of 87% for the technology (Aquino et al., 2017; May et al., 2018; R. Shan & O'Connor, 2018). A middle-ground estimate of 80% RTE is assumed for this analysis.

Typical ramp rates for PSH systems are estimated at 25 to 50 MW/s (Manwaring, 2018). Unlike other storage technologies, the ramp rate is a function of tunnel design to move water between reservoirs. Configuration can also play a significant role in ramp rates and response times. For a four-unit PSH plant with one tunnel per unit, the ramp rate is estimated to be 200 MW/s. However, in configurations where one tunnel has the capability to serve two units, ramp rates decrease to 12 to 25 MW/s per unit (General Electric, 2018; R. Shan & O'Connor, 2018). For spinning in air to full generation, the ramp rate for fixed-speed systems ranges from 1.4 to 20% of rated power per second, while it is 1.7% of rated power per second for adjustable-speed systems. The ramp rate from spinning in air to full load is 1.3 to 2% of rated power per second for fixed-speed systems, while it is 1.4% of rated power per second for adjustable-speed systems.

The time for various mode changes also depends on the choice of turbine. For ternary PSH, which uses a separate turbine and pump on a single shaft, mode changes are quicker (Koritarov et al., 2013). For fixed-speed unit, which are only capable of pumping water in non-adjustable “blocks” of power, pumping is done at fixed-load consumption, thus, ramp rate is not applicable in pumping mode, while for generation mode they can take 5 to 15 seconds to reach rated power from online status (NHA, 2017). Response times across various mode changes for fixed-speed, adjustable-speed, and ternary were found based on the literature and conversations with PSH experts and developers (Fisher et al., 2012; General Electric, 2018; R. Shan & O'Connor, 2018).

Losses due to RTE were estimated based on an assumed electricity cost of $0.03/kWh and an RTE of 80%. Following these two items, it can be determined that the cost due to RTE losses is $0.0075/kWh for PSH.

R&D Trends in PSH

The following trends are anticipated for PSH power plants:

- Migration to adjustable-speed technology. The power electronics cost has decreased over the last few decades, with cost for adjustable-speed electromechanicals and powerhouse about 20% higher than fixed-speed technology (Manwaring et al., 2020; Miller, 2020c). The higher efficiency, superior load following, and ability to provide frequency regulation ancillary service in pumping mode make an adjustable-speed option more attractive.
- Migration to ternary technology is not anticipated due to higher cost and sufficient flexible generation present in the US grid (Miller, 2020b). The fast switching time of approximately 30 seconds is not needed since load following requires switching time of not faster than 10 minutes (Miller, 2020d).
- The PSH plant capacity has been trending higher over the last two decades and this trend is expected to continue (Manwaring et al., 2020; Miller, 2020b).
- The duration is region-dependent, with trend to 12-24 hour storage in regions where renewable generation is dominated by wind (Farley, 2020).
- Quantification of the effects of head and tunnel length to head ratio on system cost and performance for a fixed rated power level. Currently, the relationship developed does not account for differences in power levels. Hence there is a need to perform multilinear regression to relate capital cost to parameters such as power capacity, duration, head, and tunnel length to head ratio. For example, higher head lowers reservoir volume needed for a fixed amount of stored energy. Higher head also reduces the depth below lower reservoir level for the electromechanicals, lowering powerhouse construction cost.

- As long-duration energy storage (diurnal and seasonal) becomes more relevant, it is important to quantify the cost for incremental storage in the reservoir. Estimation of this incremental cost for storage beyond a certain duration such as 10 hours would be useful in addressing long-duration energy storage needs.
- Work is ongoing to adapt oil well drilling techniques to drop in the powertrain, saving powerhouse construction costs and reducing associated contingency fees (Obermeyer, George, & Wells, 2019; Stark, 2020).
- Escalation factors specific to categories such as C&I, construction material, and powertrains have been found higher than the rates used in this work (Key, 2011) and could increase costs.
- Deep repair and refurbishment costs are estimated as fixed costs every 5, 10, or 20 years. There is a need to estimate these costs as a function of operating conditions such as percent of rated power, capacity factor, and cumulative energy throughput.

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