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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Compressed-Air Energy Storage

Capital Cost

CAES involves using electricity to compress air and store it in underground caverns. When electricity is needed, the compressed air is released and expands, passing through a turbine to generate electricity. There are various types of this technology including adiabatic systems and diabatic systems. The difference between these two configurations is that adiabatic systems capture and store the heat generated through the compression process to re-use later in the air expansion process in order to generate a larger amount of power output. For diabatic systems, the heat generated during compression is simply released. Newer applications of this technology include the development of isothermal CAES. This technology attempts to use a different process by removing heat across multiple stages of compression in order to reach a temperature closer to ambient, making it easier and more economic to store.

CAES is designed to fill markets where longer duration (12-24 hours) is needed, especially in regions with higher variable renewable energy penetrations (Farley, 2020d). For example, in Texas renewable generation is dominated by wind and curtailment is as high as 7% of total production. The curtailment is related to 1) a transmission bottleneck and 2) price going to zero. For these reasons, the average duration for wind integration in Texas needs to be around 8 hours. While CAES has been demonstrated to deliver longer duration storage, its cost effectiveness is limited by the availability and design of the caverns used for compressed-air storage.

While CAES technology has been demonstrated on a large scale, there are several reasons why early deployments did not keep pace with PSH, and why the future may be brighter:

- Hydropower generation is a mature and proven form of generation, allowing PSH plants to leverage upon the available knowledge base in hydraulic turbine design, installation and operation (Bailie, 2020d; Naeve, 2020). CAES technology, on the other hand, requires a unique design for the compressors and expanders. While compression equipment is a mature technology in chemical processing, compressor design has multiple variables such as molecular weight of gas and desired discharge pressure and investments have only been recently made to develop compressor technology for this specific application. Similar developments are being made for high pressure expanders based on steam turbines, with redesign needed to account for the molecular weight difference between air and steam (Naeve, 2020).
- CAES systems were designed as an optimized gas turbine (Baxter, 2020). Low natural gas prices made it difficult for CAES to compete with natural gas-powered plants in the past. Migration towards long duration storage of greater than 24 hours is expected to favor CAES, since salt cavern costs are lower than PSH reservoir costs (Farley, 2020a).
- Major turbine manufacturers have started to invest in CAES turbines only recently, since they didn’t have an incentive to do this in the past due to high demand for conventional turbines (Ridge Energy Storage, Undated).
- The performance of CAES process equipment for compression and expansion has improved considerably, along with a drop in price (Farley, 2020a).

- While low cost storage in suitable salt formations is a reality, the electric utility industry has limited experience with the design, development and operation of underground gas storage caverns (Naeve, 2020).
- The high cost of disposing salt brine coupled with risk of locations being unsuitable geologically (Seltzer, 2017) prevented deployment for shorter duration systems. However, recovery of chemicals such as sodium, chlorine, potassium and magnesium from brine may provide some benefits to defray this high cost, especially for locations that are far from the ocean (Delgado, Beach, & Luzzadder-Beach, 2020).

Power Island Capital Costs

There are only two CAES plants currently in operation internationally: the 290 MW plant in Huntorf, Germany, and the 110 MW McIntosh Plant in Alabama, USA. The 270 MW Iowa Stored Energy Park (estimated at a total cost of $1,480/kW), which would have been the third CAES plant, was discontinued in 2011 due to the storage reservoir ultimately being unsuitable for the envisioned scale of the project (Aquino, Zuelch, & Koss, 2017; Schulte, 2011).

The McIntosh Plant was deployed in 1991 and cost $591/kW at installation, which corresponds to $1,068/kW in 2020 USD; however, external funding was provided so the actual cost estimate may be higher. When improvements in performance of the powertrain for the McIntosh Plant are factored into the provided estimate, the total installed cost amounts to $1,200/kW. This cost includes additional permitting requirements over 1991 regulations along with selective catalyst reduction of nitrogen oxide costing a combined $90/kW in 2020 USD (HDR Inc., 2014). Additional site-specific costs for the substation and switchgear[1] as well as a 5-mile transmission line[2] were added and resulted in a total cost of $1,348/kW if the plant was built today (Wright, 2012).

The Electric Power Research Institute (EPRI) conducted an analysis of CAES plants at two different power levels (135 MW and 405 MW) as well as for a low fuel CAES system, hiring an EPC company to provide costs for installation and balance of plant (BOP) and a geologic company to provide air storage costs. Storage type in the analysis included a salt dome, bedded storage, depleted natural gas cavern, and an aquifer. The salt dome cost was noted to decrease with increase in depth in the report. Hence, even as duration increased, using a deeper cavern, the $/kW decreased. This made it difficult to parse out the individual $/kWh cost for the salt cavern. For bedded storage, the correlation of $/kW capital cost was found to be weak as a function of duration and therefore, $/kWh could also not be easily estimated. The total system cost for depleted natural gas caverns was the lowest, thus demonstrating these are the most cost-effective storage options (Wright, 2012). Table 1 has been adapted from the EPRI report (Wright (2012) and shows a detailed breakdown of costs of the 110 MW McIntosh Plant from 1991 as well as the same values adjusted to 2020 USD, including the additional substation/switchgear and transmission costs described earlier. The same report also provided a detailed cost breakdown for a 316 MW CAES system based on the Siemens SGT6-3000E. The total 2020 direct cost was $871/kW, while indirect costs added 21%, bringing the total to $1,052/kW. Adding $150/kW for substation and 5 miles of transmission brings the estimated 2020 cost to $1,202/kW.

[1] $91/kW (2012 USD)
[2] Assumes $1.2M/mile for 138 kV ($44/kW in 2012 USD)

Table 1. CAES Cost Component Breakdown

Cost Component	$/kW (1991 USD)	$/kW (2020 USD)
Major equipment, power island: Compression, expansion, motor-generators recuperator	$468	$520
Mechanical, electrical, and control procurement and construction	$175	$194
Civil procurement and construction	$116	$129
Indirects: EPC fees, engineering, heavy hauls, commissioning, and training	$218	$242
Air storage in domal salt (26 hours)	$101	$112
Storage ($/kWh)	$3.9	$4
Subtotal ($/kW)	**$1,078**	**$1,198**
Substation/switchgear ($12M for 138 kV/150 kVA)	$91	$101
Transmission (5 miles at $1.2M/mile 138 kV)	$44	$49
Grand total ($/kW)	**$1,213**	**$1,348**

For comparison, a report by Black & Veatch broke down the cost for a 262 MW, 15-hour plant as shown in Table 2 (Black & Veatch, 2012). The $1,091/kW (2020 USD) cost is on the lower side, likely due to low EPC (3.7% of direct costs) and owner's cost (7.1% of direct costs). The cavern cost of $29/kWh, obtained by dividing the reported $/kW by the duration, is on the higher side, while the powerhouse costs appear to be lower compared to other estimates. This highlights the complexity in cost assessment and breakdown of CAES. Adding $150/kW for substation/switchyard development and a 5-mile transmission line to the numbers in Table 2 brings the total cost to $1,241/kW in 2020 USD.

Table 2. Cost Component Breakdown for a 262 MW, 15-hour CAES Plant

Cost Component	$/kW (2012 USD)	$/kW (2020 USD)	$/kWh (2020 USD)	Percent of Direct Costs (%)	Percent of Total Cost (%)
Turbine	$270	$327			30.0%
Compressor	$130	$158			14.4%
BOP	$50	$61			5.6%
Cavern	$360	$436	$29		40.0%
EPC management	$30	$36		3.7%	3.3%
Owners' cost	$60	$73		7.1%	6.7%
Subtotal ($/kW)	**$900**	**$1,091**			
Substation/switchgear ($12M for 138 kV/150 kVA)	$91	$101			
Transmission (five miles at $1.2M/mile 138 kV)	$44	$49			
Grand total ($/kW)	**$1,213**	**$1,241**			

Siemens provided cost metrics for a CAES plant with numbers on the low end of the range investigated that were interpreted as future target costs, and have been reproduced in Table 3. These values provide additional insight into the individual cost share of categories. The target cost range was indicated to be between $875-1,375/kW (2020 USD) and, for the purposes of this study, the lower end of this range was not included in final estimate calculations for the reason described (Bailie, 2020a). The higher end of the range was assumed to include transmission interconnection costs. Bailie (2020g) indicated that a turnkey CAES plant will cost anywhere from $850-$1,250/kW depending on configuration and location-related factors. With typical durations < 24 hours, the $/kWh is < $50/kWh, assuming "a high-pressure holding reservoir can be used to store air (salt, depleted gas field, aquifers, hard rock mines)."

Table 3. CAES Cost Component Breakdown – Target Estimates

Cost Component	Description	Low Estimate ($/kW)	High Estimate ($/kW)
Power Island	Powertrain and equipment build	$400	$600
BOP/EPC	Location, labor rates, building/site permitting, transmission interconnection, natural gas pipeline, construction contingency	$425	$575
Reservoir	Salt cavern, aquifer, or hard rock mine	$50	$150
	Total	**$875**	**$1,325**

The same Siemens reference also provided values representing currently achievable estimates and have been reproduced in Table 4. The total project cost is 13 to 1.5x the previously mentioned target costs, which appears more realistic. Note that the cavern cost, which is discussed in more detail after capital cost, is considered to be on the high side at $14-22/kWh (Bailie, 2020a).

Table 4. CAES Cost Component Breakdown – Achievable Estimates

Cost Category	10-hour Duration (Low)	30-hour Duration (High)	20-hour Duration (Average)
160 MW expansion train ($/kW)	$309	$378	$344
115 MW compression train ($/kW)	$197	$241	$219
Core powertrain equipment total ($/kW)	**$506**	**$619**	**$563**
BOP ($/kW) including engineering, procurement, transmission interconnection, natural gas pipeline, and permitting	$159	$216	$188
Construction ($/kW) including labor, construction, and contingency to house powertrain	$375	$563	$469
Power island total ($/kW)	$1,097	$1,341	$1,219
Salt dome cavern ($/kW)	$219 ($22/kWh)	$406 ($14/kWh)	$313 ($16/kWh)
Total project cost ($/kW)	**$1,316**	**$1,747**	**$1,531**
Total project cost ($/kWh)	**$132**	**$58**	**$77**

The cost breakdown for the Bethel Energy Center 324 MW, 48-hour CAES plant was provided by Farley (2020d) and is shown in Table 5. Project development cost was 1.9% of direct cost, while estimated substation and 5-mile transmission line cost was $150/kW. At $131/kW, the substation and transmission amounted to 12.4% of costs including project development and was in line with the $150/kW estimated by (Wright, 2012).

Table 5. Capital Cost Breakdown for a 324 MW CAES Plant

Cost Category	Value ($/kW)
Above ground power island ($/kW)	1038
Project development ($/kW)	20
Powerhouse total ($/kW)	**1058**
Substation/switchgear and 5 miles of transmission	131
Powerhouse total + substation and five miles of transmission ($/kW)	**1189**

Cost Category	Value ($/kW)
Salt dome cavern ($/kW)	131 ($2.73/kWh)

Final capital cost for this analysis was estimated based on an average of those found in the literature described above and was $1,153/kW. Values for highly specific technologies, such as low fuel CAES and those considered to be outliers or target costs, were excluded from the estimation process. Table 6 provides a summary of the capital costs found in the literature and details which values were included in the estimation process to achieve the final result. Note that for most sites, all-in costs were provided without substation/switchyard or 5 miles of transmission line costs. For additional reference, the final capital cost estimate for CAES with the addition of the substation/switchyard and transmission, estimated at $150/kW (Wright, 2012), would be $1,303/kW.

Table 6. Summary of CAES Capital Cost Estimates from Literature

Reference	Site/System	MW	Duration (hours)	Study Year	$/kW Capital Cost (Study Year USD)	$/kW Capital Cost (2020 USD) [(a)]
Aquino et al. (2017)	McIntosh Plant	110	26	1991	$1,068	$1,218
Wright (2012)	McIntosh Plant	110	26	1991	$1,198	$1,348
		136	26	2012	$1,042	$1,189
	Dresser-Rand SMARTCAES	135	8-24	2012	$1,204	$1,354
	Dresser-Rand SMARTCAES	405	8-16	2012	$983	$1,133
	Low fuel CAES	369	8-16	2012	$1,311	$1,461[(b)]
HDR Inc. (2014)	ADELE – Adiabatic CAES for Electricity Supply, Germany	90		2014	$712	$762[(c)]
		300-500	10	2014	1,758	$1,882[(d)]
Bailie (2020a)	Siemens	400-600		2020		$9,500[(c)]
		160	10-30	2020		$1,381

[(a)] Inclusive of substation/switchgear and five-mile transmission costs.
[(b)] Excluded from average calculation – special technology case.
[(c)] Excluded from average calculation – target cost estimate or low outlier.
[(d)] Excluded from average calculation – high outlier.

CAES plants may require a substation and transmission line to be built due to potential plant locations being located away from existing lines. For a 168 MW, 48-hour plant in Texas, these additional costs add up to $40-45 million (Farley, 2020b). These values are consistent with the numbers from Black & Veatch (2012). In Texas, the utility builds these costs into the rate base and the project owner has to put down collateral during construction in case of project incompletion. There is inconsistency in the literature as to whether these costs were included in estimated totals and additional substation/switchgear costs were integrated into those for which it was not explicitly included. Therefore, estimates from references that do not explicitly state whether these costs are included are arrived at by including these additional substation and transmission costs.

Information on scaling for CAES with respect to power capacity is not commonly available and has been adapted for this analysis based on estimates for scaling for PSH using data from the literature (Davitti, 2018). For PSH a 16% drop in system cost in $/kW for every 10x increase in power was estimated. An assumption has been made that the drop in system cost with scaling for CAES is approximately half that of PSH at 8%, since PSH benefits more from scaling due to the nature of the excavation and requirements for underground powerhouse expansion. The scaling factor for various power levels was determined by setting a 100 MW value to 1. For the CAES cavern, the scale was set to 1 for 800 MWh of storage based on data provided in the literature, with a similar 8% drop in price for every 10x increase in storage MWh capacity (Davitti, 2018).

Cavern Costs

Salt dome caverns are typically the most cost-effective option for CAES based on the fact they are both deep and wide, while bedded caverns, which have a shallower depth, are more expensive. The compressed-air storage pressure increases with depth and has an associated decrease in $/kWh (Farley, 2020b). For example, at 3,500 feet deep, 3,000 pounds per square inch is attained. With the right depth and width of salt domes, the cavern cost can be as low as $2/kWh, but oftentimes differs based on geology and region. Caverns in West Texas, for example, typically have shallow depth and need more wells for the same amount of storage, thus increasing cost. Caverns in Michigan, Arizona, and Colorado are bedded salt caverns, with costs > $10/kWh (Farley, 2020b).

Most salt caverns are 800 to 900 feet deep with a typical diameter of 70 to 85 feet. The maximum storage pressure is measured in pounds per square inch and is calculated as 0.8 multiplied by the cavern depth when the typical diameter range mentioned previously is assumed. Examining this type of cavern is relevant as midstream oil companies (those responsible for processing, transporting, and marketing oil) in the US often own salt caverns[3] and if natural gas were to be replaced by hydrogen over time, these caverns may be repurposed for both CAES and hydrogen storage. Experts in this field estimate that there are enough existing caverns to meet CAES and hydrogen storage needs in the future following these assumptions. For this analysis, natural gas fuel supplied from pipes is considered but the costs are not explicitly stated in any report; hence, it is assumed that these costs are accounted for in BOP, EPC, and owner's cost (Bailie, 2020b). Bailie (2020g) noted that salt, depleted gas fields, aquifers, and hard rock mines are all different types of potential reservoirs that can be used for CAES. The "pressure holding capability" of the reservoir determines its storage capacity and cost. For gas fields, it is important to minimize any remaining entrained hydrocarbons.

For CAES using salt caverns, the cost is initially estimated to be $3.5-4/kWh (Bailie, 2020c), although a cavern cost of $2/kWh was estimated in a 2012 report by EPRI (Wright, 2012). A detailed breakdown of the 110 MW McIntosh Plant in the same report, however, showed a cavern cost of $4.3/kWh, which is in line with the number provided by Siemens (Bailie, 2020c). It is unclear if this also includes the cost of dissolving existing salt and disposing of the resultant brine. To be conservative, a 50% adder is used in this analysis to arrive at a total estimated cavern cost of $6/kWh, which is midway between the $2-10/kWh estimated by Luo et al. (Luo, Wang, Dooner, Clarke, & Krupke, 2014), while cavern cost was estimated at $2.7/kWh for the for the 324 MW, 15500 MWh Bethel Energy Center plant of 48-hours duration (Farley, 2020d). Note that this study does not consider bedded salt caverns, which are more

[3] These caverns are predominantly located on the gulf coast of the US.

expensive. Cavern costs for salt domes were estimated in the $2-4/kWh range, while they were expected to be > $10/kWh for bedded salt caverns. The cost depends on depth of the cavern, since higher compression pressures are possible at increasing depth, and also on the salt formation thickness or width (Farley, 2020b). Hunter et al. (In Press) reported $2/kWh for salt caverns. While the cavern cost for 24-hour storage was estimated at $4.50/kWh, this dropped to $3.5/kWh for 48-hour storage (Bailie, 2020e). One of the cost drivers is solution mining. For caverns that already are solution mined, the costs can drop further (Bailie, 2020f).

An average of these numbers ($6/kWh, $3/kWh, and $2/kWh) yields $3.66/kWh for salt dome caverns and is the final estimate for cavern cost provided in this analysis. For historical comparison, an estimate from the 1980s placed CAES cavern cost at $18/kWh (Willett, 1981). It is unclear if this is due to significant decrease in cavern costs or simply to site-specific issues. Table 7 provides a detailed category cost breakdown for a 100 MW, 1,000 MWh CAES plant, with a comprehensive reference list for each category.

Table 7. Price Breakdown for Various Categories for a 100 MW, 1,000 MWh CAES

Cost Category	Nominal Size	2020 Price	Component	Additional Notes	Source(s)
Power island and BOP	100 MW	$1,153/kW	Power island and BOP capital cost	Includes powertrain, labor, permitting, transmission interconnection, natural gas pipeline, construction contingency	Aquino et al. (2017); Bailie (2020a); Bailie (2020g); Black & Veatch (2012); Farley (2020b, 2020d); HDR Inc. (2014); Wright (2012)
Cavern	1000 MWh	$3.66/kWh	Cavern capital cost	Salt dome	Bailie (2020b, 2020c, 2020e, 2020f, 2020g); Farley (2020b, 2020c); Wright (2012); Hunter et al. (In Press)
Indirect costs (owner, engineering, construction management, contingencies)		45% of direct costs, included in above numbers		All prices referenced include indirect costs; reference is from 1981, hence probably needs to be updated	Aquino et al. (2017); Bailie (2020f)
O&M		$10.30/kW-year	Fixed O&M cost		Aquino et al. (2017); Farley (2020b); HDR Inc. (2014); Industry Stakeholder (2020); Wright (2012)
Performance metrics			Calendar life		Aquino et al. (2017); EASE (2016); May, Davidson, and Monahov (2018)
Performance metrics			RTE		Aquino et al. (2017); EASE (2016); May et al. (2018); Bailie (2018);Black & Veatch (2012); Li et al. (2017)

To determine the 2020 price range, the powertrain-related costs are multiplied by 0.9 and 1.1, respectively, to get the low and high end of the price range, with cavern cost of $2/kWh and $10/kWh, respectively. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrain and caverns.

There is a trend in Europe to replace natural gas usage in CAES with green hydrogen produced by renewables. A current Siemens CAES project in Denmark uses hydrogen produced by renewables as fuel instead of natural gas. It is worth noting that the country has a larger interest in using hydrogen in all gas turbines, not just CAES, and is pushing for 100% conversion to hydrogen by the year 2030. The European Union is also making a push for green electricity generation by incentivizing renewable-generated hydrogen for storage, including CAES. In discussion with Siemens, it was noted that for fossil-fuel-free CAES using hydrogen storage, 10 gigawatts (GW) with 30 hours of storage was the suggested system size (Bailie, 2020b).

CAES plants that use hydrogen instead of natural gas can store the gas in cylindrical salt caverns, so there is no reason to assume the hydrogen cavern cost would be different from cavern cost for compressed air.

EPC and Owner's Cost

Total plant cost for CAES is typically heavily influenced by non-trivial components including the choice of design, procurement of the BOP, construction and installation, contingency fees, and specific costs associated with both the site and owner. These components can oftentimes be the most dominating costs, even over major plant equipment. Additionally, costs associated with EPC fees, overhead, construction, and contingencies are typically multipliers or percentages of other costs. If other cost items are overestimated or if equipment costs are increased, these costs will rise as well (Aquino et al., 2017).

Design choices play a large role in determining EPC fees and contingencies due to perceived risks in a less prominent technology. Project management is argued to be of crucial importance and helps to achieve higher cost effectiveness for CAES investment. Oftentimes, risk and responsibility for EPC can be split between the plant owner, the EPC contractor, and various engineers, contractors, and construction management firms under contract. If the project is not well-designed prior to contracting an EPC, costs may increase as alterations are made or risk increases (Aquino et al., 2017).

EPC is estimated to be approximately 20% of overall project costs. Fees and overhead make up 7%, contingency is 6%, and the remaining 7% includes profit (Aquino et al., 2017). In this model, EPC is not controlled by the plant owner. In other models, the plant owner takes more control over project execution, with the EPC managing specific contracts. The plant owner may also choose to have total control over project execution by handing out prime contracts to multiple contractors. This gives a range of project management approaches that may be useful for cost reduction and shifting risk.

An EPRI report from 1981 looking at the design of underground CAES shows the breakdown for indirect cost as percentage of total direct cost provided in Table 8 (Willett, 1981). Based on these numbers there is significant room for cost adjustment.

Table 8. Percent of Total Direct Costs by CAES Cost Component

Cost Component	% of Direct Cost
Owner's cost	15%
Engineering	5%
Construction management	10%
Contingencies	15%
Total	**45%**

O&M Costs

Fixed O&M, measured in $/kW-year, for CAES typically includes labor, safety, site maintenance, communications, training, office and administration, and other similar expenses. A plant will typically require two to three full-time staff depending on the size (referred to here as labor-related fixed O&M) and major maintenance, which is dependent on the number of operating hours each year and can vary year to year (referred to as maintenance-related fixed O&M). Variable O&M costs, measured in $/MWh, include chemical treatment and makeup water for the cooling tower, catalyst replacement, and other non-fuel consumables (Wright, 2012).

Estimates for both fixed and variable O&M components are typically not provided in great detail in the literature. General estimates place total fixed O&M in the range of $12.3-$20.1/kW-year and variable O&M costs to be in the range of $1.7-2.5/MWh (Aquino et al., 2017; Black & Veatch, 2012; HDR Inc., 2014). EPRI conducted a detailed analysis of O&M costs for CAES, described in higher detail later in this section, and estimated basic non-fuel variable O&M to be slightly lower than the other literature at $1.6/MWh (Wright, 2012). Conversation with a CAES developer indicated that basic variable cost was $0.25/MWh. Note that, to remain consistent across technologies in this report, the basic variable O&M was determined from the average of multiple values reported in the literature (described in detail in the lithium-ion section) and is set to $0.5125/MWh for all technologies in this analysis.

Table 9 provides O&M information from a few CAES sites found in the literature where the size of the plant was included. Note that fixed O&M in this table is inclusive of both labor-related fixed O&M costs and maintenance-related fixed O&M costs. More granularity for labor and maintenance-related O&M costs was found in an EPRI study (Wright, 2012), details are shown in Table 10.

Table 9. Fixed and Variable CAES O&M Costs from Various Literature Sources

Reference	Estimate Year	MW	Duration (hours)	Fixed O&M ($/kW-year) [(a)]	Variable O&M ($/MWh) [(a)]	Fixed O&M ($/kW-year) (2020 USD)	Variable O&M ($/MWh) (2020 USD)
Aquino et al. (2017)	2017	100		$19	$2.3	$18.38	$2.22
Black & Veatch (2012)	2017	262	15	$11.6	$1.55	$12.89	$1.72
HDR Inc. (2014)	2014	300-500	10	$18.78	$2.3	$20.08	$2.46

[(a)] Values measured in study year USD

As previously mentioned, there is also an annual fixed O&M cost that is associated with maintenance required for a plant and is determined as a function of the plant's total energy generated each year. The literature reported this as a non-annual cost, unlike in this analysis, and provided an estimate of $3.7/MWh (2012 USD) for this component (Wright, 2012). From the total number of plant starts per year and the hours required per start, the capacity factor was calculated to be 45.6%. Conversation with a CAES developer indicated that long-term service contracts are typically acquired for maintenance and that, for a system with a 130 MW compressor train and 324 MW generator train, the hourly rate is typically $168/hour for generation and $43/hour for the compressor (Farley, 2020b). Depending on operating power during generation, this translates to different $/MWh, with increasing values at lower power levels. The average $/MWh for generation power in the 41-100% range corresponds to $1.71/MWh, while the average for compression was found to be $0.39/MWh. For every 1 MWh generated, only 0.56 MWh of electricity is needed for compression on average (Farley, 2020b) so the charging maintenance O&M is $0.22/MWh generated. Adding values for generation and compression, and applying a 45.6% capacity factor, the maintenance O&M is estimates to be $4.32/MWh. This value is in line with the estimate provided in Wright (2012). Since maintenance cost is a fixed hourly cost, the $/MWh value is converted to $/kW-year taking power generation into account at 60% of maximum output. Using an average value of $4.21/MWh, the maintenance-related O&M comes out to $10.30/kW-year. The numbers were verified from the long-term service agreement hourly rate for generation and compression, incorporating the capacity factor and generation power. For this study, the $10.30/kW-year estimated is used for annual fixed O&M cost related to maintenance.

Note that the compressor and generator efficiencies vary with power, affecting fuel and air costs and the RTE. In other words, for CAES the operating conditions significantly affect RTE, which makes RTE-related losses relevant for the annualized cost analysis included at the end of this report. Heat rate and air compression costs as a function of generator output were provided from discussions with a CAES developer (Farley, 2020c). At the average generation of 41% of maximum output range, the costs added up to $14.4/MWh, assuming a 82% discount of electricity prices net of spinning reserves credit, close to the $15.1/MWh provided (Farley, 2020b). The discrepancy can be attributed to the fact that the heat rate and air consumption per unit energy output varies with output power.

Fixed O&M overall, including both labor and maintenance components, was provided in the literature for two CAES plants: a 100 MW system and a 408 MW system (Wright, 2012). Details from this report are reproduced in Table 10. It is assumed that the smaller plant requires two full-time staff and three are required for the larger. The labor component of fixed O&M is estimated at $6/kW-year for the 100 MW system and $2.2/kW-year for the 408 MW system in 2012 USD based on information shown (Wright, 2012).

Table 10. O&M Costs and Operational Parameters for Multiple CAES Plants

O&M Cost Component	Parameter	100 MW Plant	408 MW Plant
Variable O&M ($/MWh)		1.78	1. 78
Maintenance-related fixed O&M	Major maintenance cost ($/MWh)	4.10	4.10
	Operation hours per year	4,000	4,000
	Plant starts per year	350	350
	Hours per start	11.43	11.43
	MWh annual	400,000	1,632,000
	Total maintenance-related fixed O&M ($/year)	1,476,000	6,022,080
	Total ($/kW-year) (2012 USD)	14.76	14.76
	Total ($/kW-year) (2020 USD)	16.40	16.40
Labor-related fixed O&M	Labor (persons per shift)	2	3
	Shifts per day	3	3

O&M Cost Component	Parameter	100 MW Plant	408 MW Plant
	Total labor per day (persons x shifts)	6	9
	Salary per persons	$100,000	$100,000
	Total labor cost	$600,000	$900,000
	Labor-related fixed O&M ($/kW-year) (2012 USD)	6	2.21
	Labor-related fixed O&M ($/kW-year) (2020 USD)	6.67	2.45
Total fixed O&M	**Total Fixed O&M ($/kW-year) (2012 USD)**	**20.76**	**16.97**
	Total Fixed O&M ($/kW-year) (2020 USD)	**23.07**	**18.85**

Note that the EPRI study increases labor required by 50% when plant capacity increases from 100 MW to 408 MW. For our study, similar to the PSH labor-related O&M approach, an assumption has been made that labor costs double for every order of magnitude increase in plant power. This yields labor-related fixed O&M costs of $6/kW-year at 100 MW, $1.2/kW-year at 1,000 MW, and $0.48/kW-year at 10,000 MW.

Table 11 shows the final estimated O&M costs across various plant sizes for this analysis. The costs were assigned 0.9 and 1.1 multiples to establish the range. No learning rates were assigned for year 2030 due to maturity of the technology related to powertrain and caverns.

Table 11. Fixed and Variable O&M CAES Cost Estimates by Power Capacity

Component	100 MW System	1,000 MW System	10,000 MW System
Full-time staff	2	4	8
Total labor cost ($M)	$600,000	$1,200,000	$4,800,000
Labor-related fixed O&M ($/kW-year)	6	1.2	0.48
Maintenance-related fixed O&M ($/kW-year)	10.30	10.30	10.30
Total fixed O&M ($/kW-year)	16.30	11.50	10.78
Total variable O&M ($/MWh)	0.5125	0.5125	0.5125

Performance Metrics

Resources from the literature that provided calendar life and total cycle life for CAES systems estimated they are capable of 10,000 cycles and have an approximate 30-year usable life (Aquino et al., 2017; EASE, 2016; May et al., 2018). Assuming a calendar life of 30 years, with 5% of that time allocated to downtime, this corresponds to a total cycle life of 10,403 cycles.

With regards to RTE, the stated range from the literature was typically between 50% and 70%, with higher estimates being more common (Aquino et al., 2017; Bailie, 2018; Black & Veatch, 2012; Li et al., 2017; May et al., 2018). For adiabatic systems specifically, RTE is estimated to be higher (> 70%) due to not having to reheat the cavern as the heat generated from compression is reutilized (Aquino et al., 2017; EASE, 2016). Conversations with Dresser-Rand/Siemens provided a method to estimate the RTE by dividing the electrical output of the system by the sum of the electrical input to the compressor and the energy that could have been alternatively generated through the natural gas used. This calculation assumes a 49% conversion efficiency when going from natural gas to electricity. Following this methodology, if heat capture in the compression cycle is assumed, the RTE is expected to be 74.6%. However, if the same system instead utilizes the actual lower heating value of the natural gas fuel, the RTE is calculated to be lower at approximately 52%. This analysis assumes the lower RTE value to be a more accurate representation as, if one were to compare the same system to a combustion turbine unit, the lower heating value would be used to determine efficiency (Bailie, 2018).

Conversations with representatives from Siemens provided a range of response times for CAES systems between 3.33 and 10 minutes depending on mode change (Siemens Energy, 2018).

Losses due to RTE were estimated based on an assumed electricity cost of $0.03/kWh and an RTE of 52%. Following these two items, it can be determined that the cost due to RTE losses is $0.028/kWh for CAES.

R&D Trends in CAES

Future focus areas for CAES are expected to be the following:

- Improvements in powertrain performance are expected to lower unit power costs. For example, the 110 MW McIntosh Plant capacity was upgraded to 136 MW using the same powertrain (Wright, 2012).
- To increase operational flexibility, specifically ramp rate, independent operation of compressors and expanders enable 33% higher ramp rate (Bailie, 2020a; Farley, 2020b). Development and refinement of control systems that enable such operation while taking into account impact on system efficiency and O&M costs are expected to be an area of continued investment.
- Improving system efficiency by lowering heat rate and improvements in heat recuperation over a wide range of operating conditions are also expected to be focus areas for the future.
- Using electricity generated by renewables for air compression.
- Existing natural gas caverns are a logical choice for compressed-air storage, hence technology for removal of entrained natural gas may become important.
- Salt caverns with the optimal depth and width cost $2/kWh, while bedded salt caverns, prevalent in Michigan, Arizona and Colorado, cost > $10/kWh due to lack of depth (Farley, 2020b). In areas such as Texas, where wind dominates, 12-24 hour storage is needed to avoid curtailment related to transmission bottleneck or electricity price going to $0, with utilities preferring combustion turbines at lower duration. Therefore, efforts to reduce the cost of storage via engineering design are expected to gain traction.
- As long-duration energy storage (diurnal and seasonal) becomes more relevant, it is important to quantify cost for incremental storage in the cavern. The incremental cost for CAES storage is estimated to be $0.12/kWh. For example, the cavern for the 324 MW, 16,000 MWh Bethel Energy Center project has a capacity of 4 million barrels. To increase the size by 20%, a 63-day leaching at 3,000 gallons per minute is needed, estimated to cost $383,000 including electricity, water, and labor (Naeve, 2020), which amounts to $0.12/kWh, or $1.2/kW for the 324 MW plant. Hence, as long duration storage becomes prevalent, increasing the storage capacity of existing salt domes by solution mining is expected to gain traction due to its cost-effectiveness.

  - The largest existing cavern has a volume of 17 million barrels (Naeve, 2020), which corresponds to about 64,000 MWh of storage. The Bethel Energy Center cavern can be expanded to 10 million barrels, while ATMOS Energy is developing a 10-million-barrel cavern on the west of the existing Bethel dome, corresponding to nearly 40,000 MWH of storage. As demand for long-term storage increases, it is expected that caverns of similar size will be developed.
  - There are about 130 caverns at Mt. Belview constructed on a large salt done, with web thickness between caverns much less than the 250 to 300 ft required today. For large projects, it is expected that multiple caverns within a single salt dome will be developed and connected in parallel.
  - Long-term service contracts are based on number of operating hours; therefore, operating the system at low power levels where efficiency may be higher increases O&M costs. The efficiency for compression and generation depends on operating power level. Flattening the efficiency curve such that high efficiency is obtained in a wider operating range would be useful and is expected to be a priority.
- Migration to green hydrogen produced from renewables to replace natural gas is a trend in Europe, while in the US natural gas prices are low. If there are regulations that account for carbon footprint in the overall cost, green hydrogen may dominate in the US as well. Hence, locating CAES plants near electrolyzer plants powered by renewables and coupled with hydrogen storage in salt or natural gas caverns may gain traction (Bailie, 2020e).

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