Energy Storage for Solar and Wind Power

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Mark Rossow, PhD, PE, Retired

Continuing Education and Development, Inc.
22 Stonewall Court
Woodcliff Lake, NJ 07677

P: (877) 322-5800
info@cedengineering.com

Chapter 12. Energy Storage Technologies

12.1 Introduction

Energy storage is one of several potentially important enabling technologies supporting large-scale deployment of renewable energy, particularly variable renewables such as solar photovoltaics (PV) and wind. Although energy storage does not produce energy—in fact, it is a net consumer due to efficiency losses—it does potentially allow greater use of variable renewables by shifting energy from periods of low demand to periods of high demand, which reduces curtailment and eases integration challenges. Energy storage can also provide a variety of high value services such as firm capacity and multiple ancillary services.

Energy storage is used in electric grids in the United States and worldwide. It is dominated by pumped-storage hydropower (PSH), with about 20 GW[164] deployed in the United States and more than 127 GW deployed worldwide (EIA 2008; Ingram 2010). In the United States, PSH was built largely in response to market conditions in the 1970s, including high oil and natural gas prices, regulatory restrictions on plants burning oil and gas, dependence on low-efficiency steam plants for peaking power, and anticipated "build-out" of a largely inflexible nuclear fleet (Denholm et al. 2010). In addition to PSH, a single, 110-MW compressed air energy storage (CAES) facility has been constructed in the United States (EPRI/DOE 2003). CAES is described in Section 12.3.2.3.

Deployment of storage in the United States over the past two decades has been limited by low natural gas prices, availability of high-efficiency and flexible gas turbines, and limited cost reductions in storage technologies. In addition, the regulatory treatment of storage, costly licensing and permitting, challenges with storage valuation, as well as utility risk aversion (including market uncertainty) have also limited storage development (EAC 2008). Figure 12-1 shows the installations of bulk energy storage in the United States.

Interest in energy storage technologies, which has reemerged over the past decade, has been motivated by at least five factors:

- Advances in storage technologies
- Volatility of fossil fuel prices
- The development of deregulated energy markets, including markets for high-value ancillary services[165]
- Challenges to siting new transmission and distribution facilities
- The perceived need and opportunities for storage with variable renewable generators and their role to reduce carbon dioxide emissions.

[164] Estimates for the total installed capacity for PSH in the United States range from 20 GW to 22 GW. This range is partially due to the use of different plant ratings. For example, the EIA lists the total nameplate capacity of PSH as of 2008 at 20.4 GW, while the summer capacity is listed at 21.9 GW.

[165] Areas in the United States with wholesale energy markets typically also include markets for both spinning contingency reserves and regulation reserves.

Along with this interest, there have been a number of new proposals and demonstration projects. Table 12-1 lists several proposed or installed projects (since 2000). Although there is significant interest in batteries and CAES, PSH continues to be the dominant proposed storage technology.

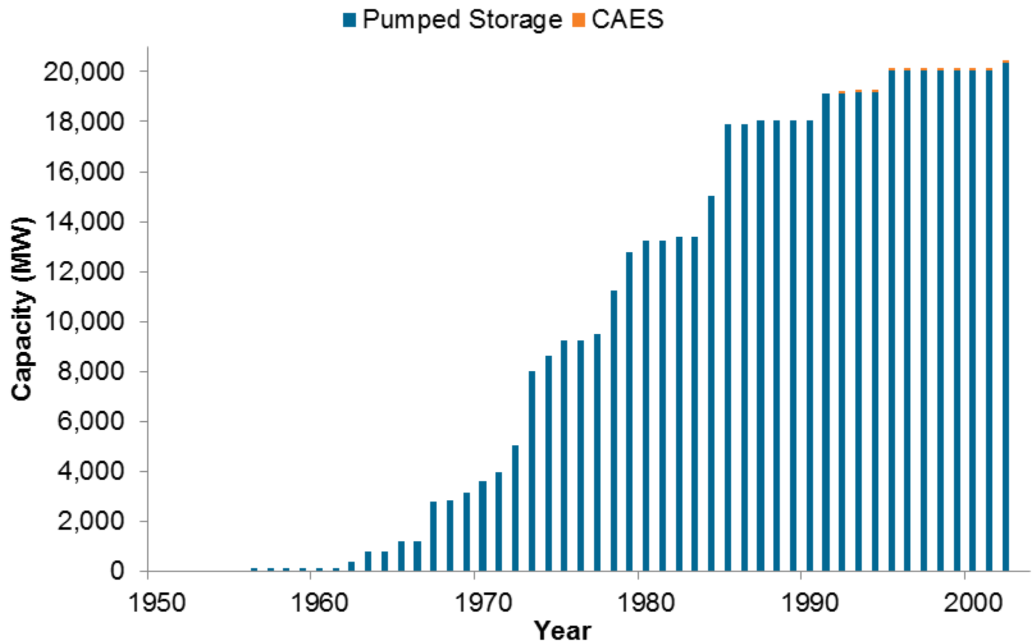

Figure 12-1. Capacity of bulk energy storage systems in United States, 1956–2003

Source: EIA 2008

Table 12-1. U.S. Electricity Storage Facilities Installed or Proposed Since 2000

Technology	Primary Application	Size (MW)	Owner/Developer	Location(s)	Status
PSH	Load leveling/firm capacity/ancillary services	>40,000	Various	Various (see Figure 12-9)	Proposed[a]
CAES	Load leveling/firm capacity/ancillary services				
		300	PG&E[c]	Kern County, California	Proposed
		150	NYSEG[d]	Reading, New York	Proposed
		2,700	FirstEnergy[e]	Norton, Ohio	Proposed
Sodium-sulfur (NaS) battery	T&D deferral/congestion relief	1	AEP[f]	North Charleston, West Virginia	Installed (2006)
		2	AEP	Bluffton, Ohio Balls Gap, West Virginia East Busco, Indiana	Installed (2008)
		4	AEP	Presidio, Texas	Installed (2009)
		1	Xcel Energy[g]	Luverne, Minnesota	Installed (2009)
Vanadium redox battery	T&D deferral/congestion relief	0.25	Pacificorp	Moab, Utah	Installed (2004)
Lithium-ion battery	Frequency regulation	1	AES/PJM Interconnection	Valley Forge, Pennsylvania	Installed (2008)
Flywheel	Frequency regulation	20	Beacon[h]	Stephentown, New York	Installed (2011)
		1	Beacon	Groveport, Ohio	Installed (2008)
		1	Beacon	Tyngsboro, Massachusetts	Installed (2009)

[a] As of December 2011, FERC had issued preliminary permits for 4d plants, representing approximately 35 GW of capacity. The capacity of proposed plants (including those with issued and pending preliminary permits exceeds 40 GW) (FERC n.d.). A map of proposed locations is provided in Figure 12-9.
[c] H. LaFlash "Compressed Air Energy Storage" slide presentation, Pacific Gas and Electric Company, November 3, 2010, http://www.sandia.gov/ess/docs/pr_conferences/2010/laflash_pge.pdf
[d] J. Rettberg, "Seneca Advanced Compressed Air Energy Storage (CAES) 150MW Plant Using an Existing Salt Cavern," slide presentation, November 3, 2010, http://www.sandia.gov/ess/docs/pr_conferences/2010/rettberg_nyseg.pdf NYSEG.
[e] Norton Energy Storage (2000)
[f] Parfomak (2012)
[g] Xcel Energy, http://www.gridpoint.com/Libraries/Featured_Media_Coverage_PDFs/wind-to-battery_-_Xcel_Energy_Brochure.sflb.ashx
[h] Beacon Power Corporation, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDY1Mjd8Q2hpbGRJRD0tMXxUeXBlPTM=&t=1, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MjAxNTh8Q2hpbGRJRD0tMXxUeXBlPTM=&t=1, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9ODI0OXxDaGlsZElEPS0xfFR5cGU9Mw==&t=1, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MzczNDQxfENoaWxkSUQ9MzcxMjE1fFR5cGU9MQ==&t=1, http://www.beaconpower.com/company/news.asp

12.2 Resource Availability Estimates

The ability to site certain storage technologies (conventional PSH and CAES) is based on specific geologic characteristics. These issues are discussed in the technology-specific sections (Section 12.3 and 12.4).

12.3 Technology Characterization

12.3.1 Technology Overview and Applications

Energy storage technologies are typically characterized by their applications, often in terms of discharge time. Three common categories are provided in Table12-2.

Table 12-2. Three Classes of Energy Storage

Common Name	Example Applications	Discharge Time Required
Power quality and regulation	Transient stability, reactive power, frequency regulation	Seconds to minutes
Bridging power	Contingency reserves, ramping	Minutes to ~1 hour
Energy management	Load leveling, firm capacity, T&D deferral	Hours

The first two categories of energy storage applications in Table 12-2 correspond to a range of ramping and ancillary services but do not typically require continuous discharge for extended periods. Storage technologies can provide local power quality benefits, such as voltage stability and provision of reactive power, and can increase the stability of the system as a whole by providing real or virtual inertia. As discussed in Chapter 4 (Volume 1), a high variable-generation grid will require increased operating reserves for frequency regulation due to short-term variability of the wind and solar resources; it will also require reserves covering forecast errors. Forecasting errors, especially over-prediction of wind or solar, requires time to allow fast-start thermal generators to come online. Hydropower and thermal units operating at part load typically provide operating reserves, but operating reserves can also be provided by energy storage technologies, often more efficiently or at a lower cost. Frequency regulation, for example, requires rapid response, and storage devices may provide faster response than traditional generators (Makarov et al. 2008). Storage technologies also have the unique ability to potentially provide reserves greater than their rated output while charging. A device charging at 1 MW can actually provide 2 MW of reserve capacity by stopping charging and rapidly switching to discharging; however, this ability is potentially limited by the technology-dependent switchover time. Previous analysis has demonstrated the potential benefits of providing fast ramping with energy storage to address the increase in sub-hourly variations resulting from large-scale deployment of variable generation (KEMA 2010).

The third category of services in Table 12-2 (energy management) corresponds to energy flexibility—the ability to shift bulk energy over several hours or more—which is the focus of storage deployment in the RE Futures scenarios.[166] An energy management device stores energy during periods of low demand (and correspondingly low energy prices) and discharges energy

[166] However, in the ReEDS and GridView modeling, storage devices also contribute to ancillary services (e.g., forecast error, contingency, and frequency regulation reserves).

during periods of high demand and prices. In a high renewables scenario, this operation would be the same, and the charging and discharging periods would be driven by the combination of normal demand patterns and the supply of available variable generation. This includes storing energy when it might otherwise need to be curtailed due to low demand or constrained transmission. Storage devices sized for energy management can provide an alternative (or supplement) to developing new transmission capacity. Use of dedicated long-distance transmission for wind or solar power will be limited by the relatively low capacity factor of the resource. Storage could help reduce curtailment due to transmission constraints by co-locating storage with variable-generation sources and allowing them to increase use of transmission lines (Desai et al. 2003). This could also decrease the amount of new transmission needed, but represents a trade-off between the most cost-effective use of storage, and the cost of new transmission (Denholm and Sioshansi 2009). Figure 12-2 provides one example of the range of technologies available for these three classes of services and shows that many technologies can provide services across the timescales shown. Many energy management storage devices can provide fast response and provide power quality and bridging power services (the discharge times shown represent the continuous discharge capability as opposed to the response time).

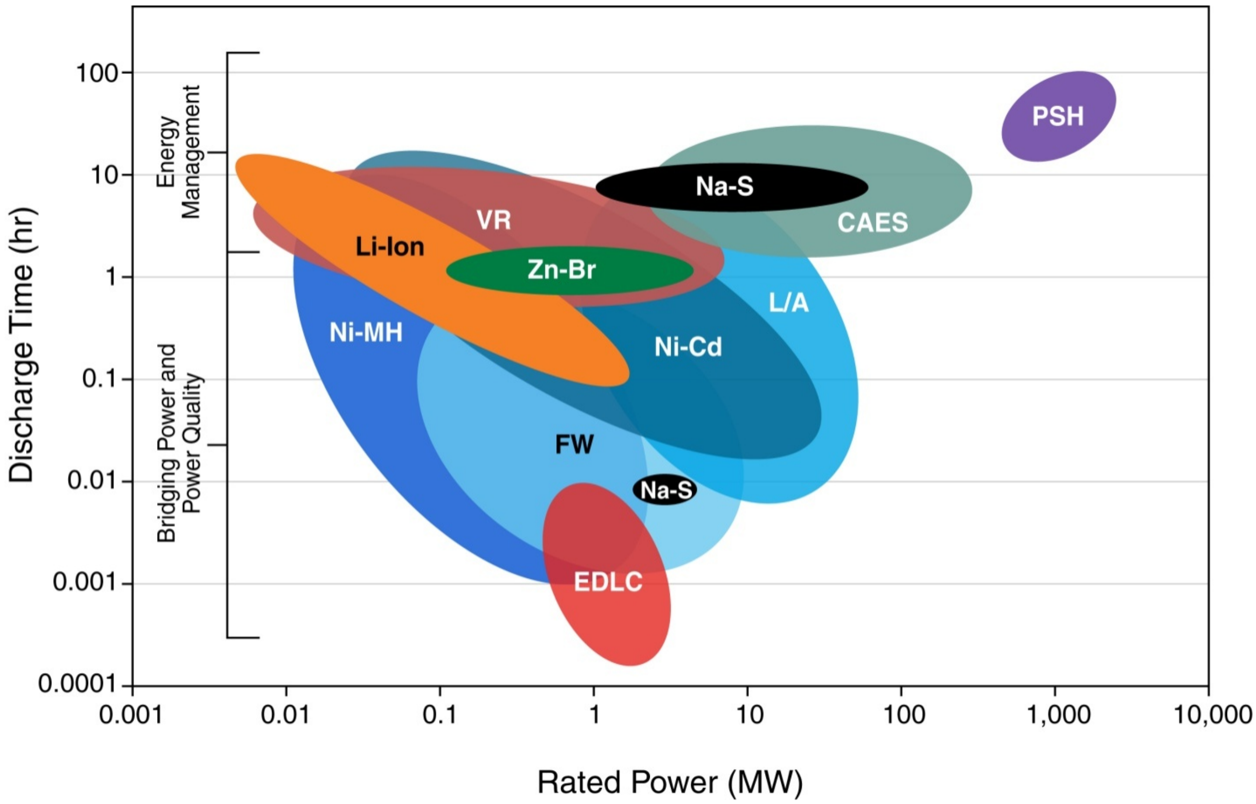

Figure 12-2. Energy storage applications and technologies

Source: Electricity Storage Association (ESA 2011)

System Ratings: Installed or proposed systems as of November 2008. This chart is meant to represent a general range of storage technologies and is not inclusive of all technologies, applications, and possible sizes.

CAES	Compressed air	Ni-Cd	Nickel-cadmium
EDLC	Dbl-layer capacitors	Ni-MH	Nickel-metal hydride
FW	Flywheels	PSH	Pumped-storage hydropower
L/A	Lead-acid	VR	Vanadium redox
Li-Ion	Lithium-ion	Zn-Br	Zinc-bromine
Na-S	Sodium-sulfur		

Figure 12-2 does not include thermal energy storage, which would cover a power range of a few kilowatts for thermal energy storage (TES) in buildings to more than 100 MW in concentrating solar power (CSP) plants, with a discharge time of minutes to several hours.

12.3.2 Technologies Included in RE Futures Scenario Analysis

Utility-scale electricity storage is modeled in the Regional Energy Deployment System (ReEDS) model to provide three services: firm capacity, energy supply shifting, and operating reserves. However, the primary grid integration challenge in a high renewable penetration scenario is the limited coincidence of renewables supply with normal electricity demand. Consequently, storage modeling for RE Futures focused on energy storage technologies that can provide energy management services or can store and discharge continuously for several hours (defined here as

8–15 hours, depending on the technology). This allows energy storage to u se otherwise potentially curtailed energy from variable-generation sources during periods of high generation and low load. As discussed later in this section, the modeling assumptions inherently undervalue shorter term and distributed storage devices, and they restrict their adoption; therefore, RE Futures cannot be used as an indicator of the opportunities for energy storage of all types.

Three technology groups meeting the criteria of being able to provide energy management services were included in the ReEDS modeling: high-energy batteries, pumped-storage hydropower, and compressed air energy storage. These technologies and their implementation in ReEDS are described in the following sections.

Notably absent from the modeling effort were short discharge and power quality applications such as flywheels and high power batteries. The most economic application for these devices appears to be fast-responding frequency regulation markets (Walawalkar et al. 2007). The ReEDS model combines frequency regulation and other reserves (for forecast error and contingency reserves), for example, into a single operating reserve constraint that can be provided by multiple technologies. Although RE Futures captures the increased need for operating reserves as greater levels of variable generation are deployed, it does not explicitly treat sub-hourly or sub-minute events (e.g., frequency regulation), and therefore cannot capture the high value of a regulation reserve device in isolation. As a result, although RE Futures can identify the overall need for reserves and the corresponding possible increase in the role of storage for operating reserves, it does not currently disaggregate the market and identify opportunities for individual reserve technologies. Recognizing this limitation, no attempt was made to estimate deployment of any individual reserve supplying storage technology.

In addition, because ReEDS is essentially a "bulk planning" model, it does not identify the potential value and opportunities of storage sited in the distribution system. In particular, it cannot evaluate opportunities to relieve local transmission or distribution congestion, or the value of T&D deferral. These applications are a primary application for current high-energy batteries such as flow batteries or NaS (Nourai 2007). This is also a primary application for end-use TES (ADM 2006). As a result, ReEDS will undervalue these and restrict their adoption into the marketplace.

Furthermore, the role of V2G was not explicitly evaluated in RE Futures. The RE Futures study included the value of controlled charging; however, uncertainty in the ultimate acceptance among original equipment manufacturers (OEMs), utilities, and consumers of V2G led to the conservative assumption to not include the potentially very large role of V2G.

Finally, limited deployment of hydrogen as a storage medium, and large uncertainty of cost-reduction and performance improvements of hydrogen storage, led to its exclusion as a core energy storage technology evaluated in RE Futures.

For these reasons, the ReEDS storage results are aggregated to show the total amount of storage deployed, as opposed to the deployment of individual storage technologies. RE Futures was used more to indicate the amount of bulk storage that may be beneficial to the grid (within the cost ranges and availability modeled) as opposed to evaluating particular storage technology types.

The particular energy storage technology deployed by ReEDS could actually be any of a number of storage technologies or an emerging technology not evaluated.

12.3.2.1 High-Energy Batteries

For many batteries, there is considerable overlap between energy management and shorter-term applications. Furthermore, batteries can generally provide rapid response, which means that batteries “designed” for energy management can potentially provide services over all applications and timescales discussed.

Several battery technologies have been demonstrated or deployed for energy management applications. The commercially available batteries targeted to energy management include two general types: high-temperature batteries and liquid electrolyte flow-batteries. Other commercially available battery types are generally targeted towards high-power applications and discussed in Section 12.3.4.

High-temperature batteries operate above 250ºC and use molten materials to serve as the positive and negative elements of the battery. The most mature high-temperature battery as of 2011 is the sodium-sulfur battery (NaS), which has worldwide installations that exceed 270 MW (Rastler 2008). Several utilities have deployed the NaS battery in the United States.

Alternative high-temperature chemistries have been proposed and are in various stages of development and commercialization. One example is the sodium-nickel chloride battery (Baker 2008). The second class of high-energy batteries is the liquid electrolyte “flow” battery. This battery uses a liquid electrolyte separated by a membrane (EPRI/DOE 2003). The advantage of this technology is that the power component and the energy component can be sized independently, with the electrolyte held in large storage tanks. As of 2011, there has been limited deployment of two types of flow batteries—vanadium redox and zinc-bromine. Other combinations such as polysulfide-bromine have been pursed, and new chemistries are under development (Yang et al. 2011).

In the United States, a primary focus of energy management batteries has been T&D deferral; however, demonstration projects have been deployed for multiple applications (Nourai 2007; EPRI/DOE 2003).

For RE Futures, batteries were combined into a single technology type, with performance based on a NaS battery; however, given the multiple battery types, and with uncertain cost reductions and technology improvements, the RE Futures battery technology should be considered a generic “high-energy” battery with 8 hours of discharge time. This could include technologies currently under various stages of development and deployment such as advanced lithium-based batteries. As with certain supply technologies, such as solar PV with multiple technology options, the goal was not to “pick winners” because the market will ultimately determine technology pathways based on cost and performance.

12.3.2.2 Pumped-Storage Hydropower

PSH is the only energy storage technology deployed on a gigawatt scale in the United States and worldwide. In the United States, about 20 GW is deployed at 39 sites, and installations range in capacity from less than 50 MW to 2,800 MW (EIA 2008). This capacity was largely built during the 1960s, 1970s, and 1980s (ASCE 1993). While there are a number of proposed plants, there has been no large-scale PSH development in the United States since 1995; however, development has continued in Europe and Asia (Deane et al. 2010). Lack of construction of new U.S. facilities has been largely been due to cost, market issues, and regulatory issues discussed in Section 12.1.

Pumped-storage hydropower stores energy by pumping water from a lower-level reservoir (e.g., a lake) to a higher-elevation reservoir using lower-cost, off-peak electric power. During periods of high electricity demand, the water is released to the lower reservoir to turn turbines to generate electricity, similar to the way in which conventional hydropower plants generate electricity.

Many existing PSH plants store 8 hours or more of energy, making them useful for load leveling, and providing firm capacity. PSH can also ramp rapidly while generating, making it useful for load following and providing ancillary services including contingency spinning reserves and frequency regulation (Phillips 2000).

Figure 12-3 shows a representative conceptual configuration of a PSH plant.

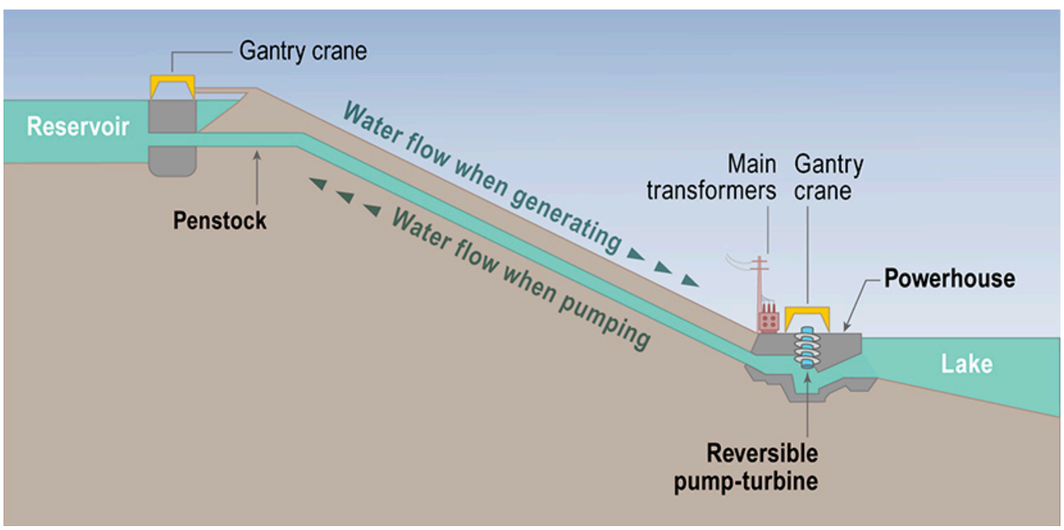

Figure 12-3. Simplified pumped-storage hydropower plant configuration

Pumped-storage hydropower plants often make use of an existing river or lake, avoiding the need for—and cost of—construction of a separate (usually the lower) reservoir. This is called an *open-cycle* PSH plant. In an instance in which a suitable natural water body is not available for use as one of the reservoirs, both the upper reservoir and the lower reservoir must be constructed. This type of construction is known as a *closed-cycle* plant, inasmuch as it has minimal interaction with natural water bodies. A water source is needed for a closed-cycle plant to provide water to initially fill the reservoir and compensate for losses during operation due to leakage and evaporation. Nearby rivers or streams are typical sources; treated municipal grey water or groundwater (wells) can also be used (Yang and Jackson 2011). Of the 45 PSH plants with preliminary permits from FERC, which include a total or more than 35 GW of capacity, at least nine have proposed closed-cycle PSH plants, and these exceed 9 GW of capacity (FERC n.d.).

12.3.2.3 Compressed Air Energy Storage

CAES stores energy by compressing air in an airtight underground storage cavern. To extract the stored energy, compressed air is drawn from the storage cavern, heated, and then expanded through a high-pressure turbine that captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, and the exhaust is expanded through a low-pressure gas turbine. The turbines are connected to an electrical generator (Succar and Williams 2008).

CAES is based on conventional gas turbine technology and is considered a hybrid generation and storage system because it requires combustion in the gas turbine.[167] Instead of a round-trip efficiency number, the performance of a conventional CAES plant is based on its energy ratio (energy in/energy out) and its fuel use (typically expressed as heat rate in Btu/kWh). (Succar and Williams 2008).

The first CAES plant was completed in 1978 in Huntorf, Germany. It was designed primarily to provide “black start” (provide a source of power to start conventional generators after a system-wide failure), and it was rated at 290 MW with 2 hours of capacity (Crotogino et al. 2001). A second plant was built in 1991 in McIntosh, Alabama (Schalge and Mehta 1993). It has a rating of 110 MW for 26 hours, providing firm capacity and load-leveling services. Both plants inject air into underground caverns solution mined from salt formations (Succar and Williams 2008). This plant has a single turbo-machinery drive train using a common motor-generator set connected to the compressor and expander via clutches. This results in turnaround times from compression to expansion of approximately 30 minutes, limiting its use in providing operating reserves and other services requiring fast response.

Proposed CAES plants include a dedicated motor drive compressor and expander-generator that would eliminate the single turbo-machinery train (Norton Energy Storage 2000). This would allow for faster switchover from compression to generation, thus increasing its usefulness for providing ancillary services and responding to increased variability of net load. Once operating, CAES plants can provide rapid ramp rates; the McIntosh plant is capable of ramping at approximately 18 MW (16% of full output) per minute, or rates that are more than 50% greater than a typical gas turbine (Succar and Williams 2008).

[167] The compressed air can be considered a method to assist conventional natural gas turbines by providing the compressed air that typically requires about two thirds of the energy generated by a gas turbine. This reduces the natural gas fuel used by a gas turbine by more than 50%, reducing the heat rate from approximately 10,000 Btu/kWh to approximately 4,000 Btu/kWh (Succar and Williams 2008).

Figure 12-4 shows a representative conceptual configuration of a CAES plant.

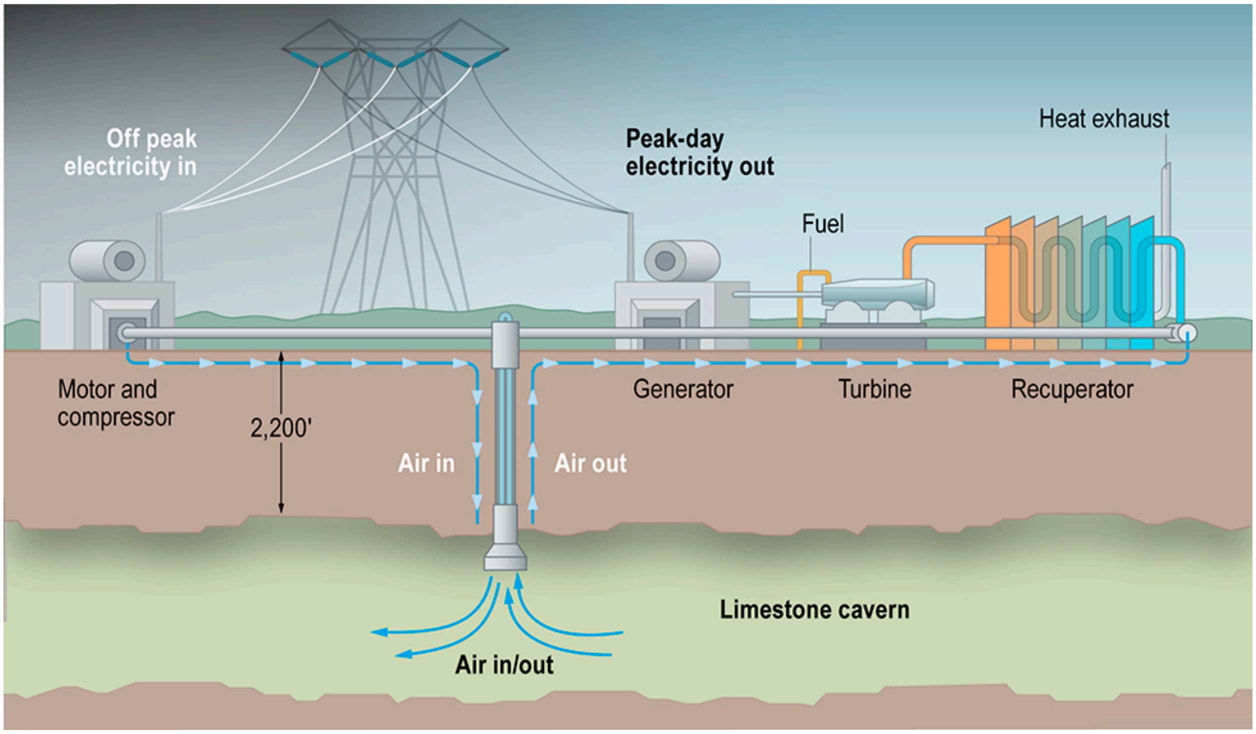

Figure 12-4. Configuration of a compressed air energy storage plant

The large volume of air storage required for CAES is most economically provided by geological structures (Allen 1985; Korinek et al. 1991). The two existing CAES facilities use salt domes, where the cavity is formed by solution mining: fresh water is pumped into the formation to dissolve the salt, and brine is pumped to the surface for disposal or other use (Thoms and Gehle 2000). Domal salt formations are self-healing, meaning pores on the cavity walls seal themselves with available air moisture, virtually eliminating the possibility of air leakage.

Other proposed formations for CAES include bedded salt, which features thinner "layers" of salt. CAES can also potentially be deployed using aquifers, depleted natural gas formations, and hard-rock caverns. A variety of alternative and advanced CAES cycles have been proposed, and these are discussed in Section 12.1.4.3.

12.3.3 Technologies Not Included in RE Futures Scenario Analysis

The following technologies offer substantial potential benefits in many applications, but were not included in the Renewable Electricity Futures modeling as they either provide services not explicitly evaluated in the analysis or have not yet been significantly commercialized in grid storage applications.

12.3.3.1 Flywheels

Flywheels store energy in a rotating mass. Flywheels feature rapid response and high efficiency, making them well suited for frequency regulation. Several flywheel installations have been planned or deployed in locations where frequency regulation markets exist in the United States (Parfomak 2012).

12.3.3.2 Capacitors

Capacitors (including supercapacitors and ultracapacitors) are devices that store energy in an electric field between two electrodes (EPRI/DOE 2003). Capacitors have among the fastest response time of any energy storage device, and they are typically used in power quality applications such as providing transient voltage stability. However, their low energy capacity has restricted their use to short time-duration applications. A major research goal is to increase their energy density and increase their usefulness in the grid (and potentially in vehicle applications) (Hadjipaschalis et al. 2009).

12.3.3.3 Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) stores energy in a magnetic field in a coil of superconducting material. SMES is similar to capacitors in its ability to respond extremely fast, but it is limited by the total energy capacity. This has restricted SMES to "power" applications with extremely short discharge times (Luongo 1996; Feak 1997). Several demonstration projects have been deployed (Ali et al. 2010), and reducing costs by using high-temperature superconductors is a major research goal (Fagnard et al. 2006).

12.3.3.4 High-Power Batteries

High-power batteries are associated with the provision of contingency reserves, load following, and additional reserves for issues such as forecast uncertainty and unit commitment errors. This set of applications generally requires rapid response (in seconds to minutes) and discharge times in the range of up to approximately 1 hour.

These applications are generally associated with several battery technologies, which include lead-acid, nickel-cadmium, nickel-metal hydride, and (more recently) lithium-ion. With their rapid response, batteries can provide power quality services such as frequency regulation, but the continuous cycling requirement can limit life of current technologies (Peterson, Apt, and Whitacre 2010). Lithium-ion batteries are currently the primary candidate for large-scale deployment in battery electric vehicles (EVs) and *plug-in hybrid electric vehicles* (PHEVs), and improvements in batteries designed for vehicles could be applied to stationary applications (Wadia et al. 2011). Several demonstration projects have been built using these technologies to provide operating reserves. Details of cost and performance are provided in EPRI/DOE (2003) and EPRI (2010).

12.3.3.5 Electric Vehicles and the Role of Vehicle-to-Grid

EVs (used here to represent both "pure" electric vehicles and plug-in hybrid electric vehicles) are a potential source of flexibility for variable-generation applications. Charging of EVs can potentially be controlled and can provide a source of dispatchable demand and demand response. Controlled charging can be timed to periods of greatest variable-generation output, while charging rates can be controlled to provide contingency reserves or frequency regulation reserves. Vehicle-to-grid (V2G) (where EVs can partially discharge stored energy to the grid) may provide additional value by acting as a distributed source of storage. EVs could potentially provide all three grid services discussed previously. Most proposals for both controlled charging and V2G focus on short-term response services such as frequency regulation and contingency. Their ability to provide energy services is more limited by both the storage capacity of the battery and the high cost of battery cycling. This could restrict their ability to provide time shifting (energy arbitrage) beyond their ability to perform controlled charging.[168] The role of V2G is an active area of research, and because EVs in any form have yet to achieve significant market penetration, assessing their potential as a source of grid flexibility is difficult. However, analysis has demonstrated potential system benefits of both controlled charging and V2G (Denholm and Short 2006). The role of EVs as an enabling technology requires additional analysis of their unique temporal characteristics of availability, unknown battery costs and lifetimes, and the availability of smart charging stations to maximize their usefulness while parked.

12.3.3.6 Hydrogen Energy Storage and Fuel Production

A hydrogen energy storage system consists of an electrolyzer, storage tanks or underground cavern storage, and either a fuel cell[169] or combustion technology to produce electricity from hydrogen. Hydrogen has been produced industrially via electrolysis since the 1920s. There are currently no utility-scale installations using hydrogen as an energy storage medium; however, electrolyzers and fuel cells are commercially available, and electrolysis is used in a variety of industrial processes (Suresh et al. 2010).

Megawatt-scale hydrogen energy storage systems—using both above-ground storage (in tanks) and below-ground storage in formations similar to CAES—have been proposed (Kroposki et al. 2006). Because compressed hydrogen has a higher energy density than air, a storage cavern could store more energy in the form of hydrogen than could compressed air.

The primary disadvantages of hydrogen energy storage are the relatively low round-trip efficiency (between 28% and 40% depending on electrolyzer and fuel cell efficiencies) and the high cost of fuel cells and electrolyzers (Steward et al. 2009). Recent research has focused on cost reduction and efficiency improvements for fuel cells and electrolyzers, as well as on combining the electrolysis and fuel cell functions in a single "reversible" fuel cell device (Hauch et al. 2006; Milliken and Ruhl 2003; TMI 2001). This could increase efficiency and lower costs for hydrogen storage system (TIAX 2002).

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[168] This conclusion depends on the anticipated cycle life and cost of EV batteries. See Sioshansi and Denholm (2010) and Peterson, Whitacre, and Apt (2010) for a discussion of the impact of battery life and cycling on the value of V2G. However, controlled charging (without V2G) is still a potentially significant source of flexibility, with the ability to raise the minimum load and avoid curtailment.

[169] A full cell is a device capable of generating an electrical current by converting the chemical energy of a fuel (e.g., hydrogen) directly into electrical energy. Fuel cells differ from conventional electrical (e.g., battery) cells in that the active materials such as fuel and oxygen are not contained within the cell but are supplied from outside. It does not contain an intermediate heat cycle, as do most other electrical generation techniques (http://www.eia.doe.gov/glossary/).

A hydrogen energy storage facility could provide increased flexibility and unique revenue opportunities to utilities, which could sell or use the hydrogen for other applications. Hydrogen could be mixed with natural gas for additional flexibility in power generation from the storage system, but this has yet to be demonstrated on a commercial scale. The use of hydrogen as a transportation fuel represents a potentially large market (Greene et al. 2008). In addition to hydrogen, there are pathways to use electricity to produce liquid or gaseous fuels for vehicles or energy storage (Sterner 2009).

12.3.4 Technology Cost and Performance

Limited deployment of many emerging energy storage technologies makes the estimation of costs challenging when deployed at scale. Even more mature technologies, such as PSH and CAES, have not been built in the United States in some time,[170] so the cost of the next plant is somewhat uncertain. Furthermore, PSH and CAES depend on site-specific geologic conditions, which make costs difficult to generalize. When considering costs of all storage technologies, the different applications must be considered. Storage technology costs include both an energy component and a power component, and the total cost of a storage device includes both components, within the limits of the target application. (This is discussed in more detail in Text Box 12-1.) Because the RE Futures modeling considered only bulk applications, only devices with multiple hours of discharge were evaluated. For uniform comparison, total costs were reported on a cost-per-kilowatt basis, where this cost includes both the power component and the energy component.

Text Box 12-1. Defining the Cost of Electricity Storage

A critical issue when discussing the costs of storage technologies is that storage devices in electric applications have both a power component (kW of discharge capacity) and an energy component (kWh of discharge capacity, which may also be expressed as hours of discharge at rated output). The total cost of a storage application must account for the ratings of both components, and it may be expressed differently depending on the application or audience. For example, because utilities universally define the cost of power plants only in terms of rated power ($/kW), they would expect to see costs in these terms, with the hours of storage (kWh capacity) expressed separately. A grid storage plant therefore might be expressed as costing $2,000/kW for a device with eight hours of discharge capacity. On the other hand, the battery community typically expresses costs in terms of rated energy ($/kWh), and it may or may not include the power component in the cost. So the cost of a battery might be stated as $500/kWh with the power capacity of the battery established separately. When evaluating the economics of storage technologies, care must, therefore, be taken to ensure that the costs for meeting both kW and kWh specifications are included and that both components are “sized” properly for any specific application.

12.3.4.1 High-Energy Batteries

Present and future costs for many battery types are uncertain, particularly for flow batteries, due to the relative immaturity of the technology. Table 12-3 provides several estimates for the cost of several battery technologies providing energy services (with an energy capacity of at least 4 hours of continuous discharge).

[170] There is one small PSH facility under construction as of November 2011 (the 40-MW Olivenhain-Hodges project) with completion expected in 2012 (SDCWA 2011).

Table 12-3. Battery Cost Estimates for Grid Storage Applications

Type	BOP[a] ($/kW)	Battery ($/kWh[b])	Storage Hours	Total/$/kW	Source
Vanadium	606	155–251	10	2,600–3,110	EPRI/DOE (2004)
Flow Battery (Several Technologies)	423–1,300	280–450	4	1,545–3,100	Rastler (2009)
NaS	450–550	350–400	4	1,850–2,150	Rastler (2009)
NaS	–	–	7.2	2,590	Nourai (2007)
Li-Ion	350–500	400–600	4	1,950–2,900	Rastler (2009)

[a] Balance-of-plant including power conversion system
[b] Although this column implies only the energy component, these estimates include the power component of the battery. As a result, the values in this table cannot be adjusted for more or less energy (hours of storage). Each cost assessment must be examined individually to determine the component costs.

Cost breakdowns for battery systems, including the balance of systems, installation, and other components, are provided by EPRI/DOE (2004) and Nourai (2007). The assumed cost for high-energy batteries (8–10 hours of discharge capacity) was $3,990/kW in 2010,[171] decreasing roughly linearly to $3,200/kW by 2050. Details about battery cost assumptions are provided in Black & Veatch (2012).

With battery efficiency, it is important to consider the alternating current (AC)-to-AC round-trip efficiency—battery efficiencies are often reported on a direct current (DC) basis without power conversion efficiencies—and to include the effect of “parasitic” loads, such as heating and cooling of batteries and power-conditioning equipment. Typical total AC-to-AC round-trip efficiencies for flow batteries and NaS are in the range of 65%–75%, including parasitic loads (Rastler 2008; Nourai 2007). Higher round-trip efficiencies for lithium-ion batteries have been reported in the range of 90% (KEMA 2008); however, this value does not include certain parasitic loads that can be considerable. A net roundtrip efficiency of 75% was assumed in this report.

12.3.4.2 Pumped-Storage Hydropower

Figure 12-5 provides historical cost data for U.S. PSH plants, inflated to 2009 dollars. There is a general trend toward increasing costs, with the last three plants constructed costing more than $1,000/kW.

[171] All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise; all dollar amounts presented in this report are presented in U.S. dollars unless otherwise noted.

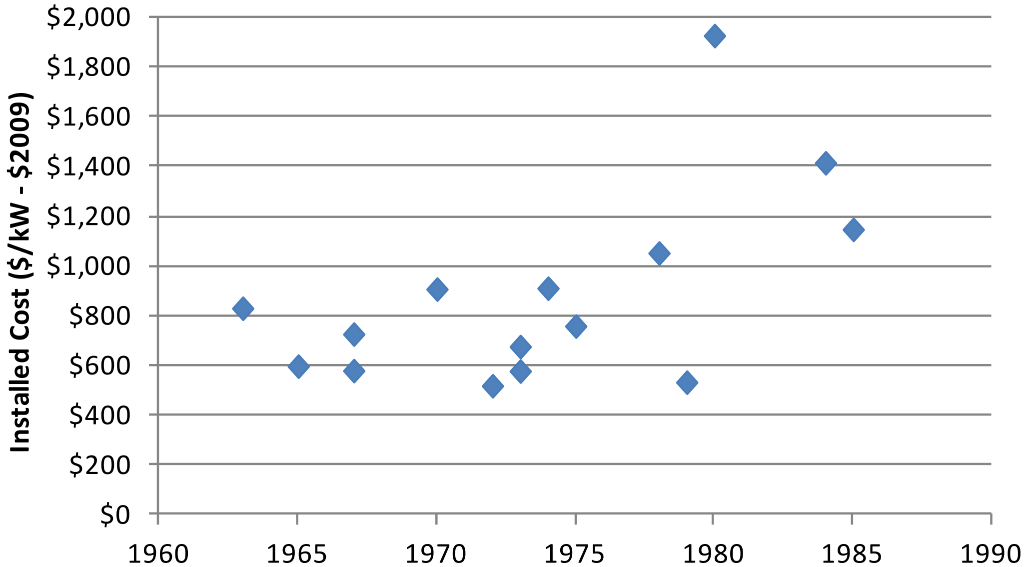

Figure 12-5. Installed cost of pumped-storage hydropower plants in United States

The cost of new PSH plants will vary. The geotechnical and geological characteristics and complexity of site are major factors in PSH development costs. Typically, the largest costs are for development of a project's upper and lower reservoirs and for underground components. One example is the Helms pumped hydropower plant, which was completed in 1984 at a cost of $1,411/kW (2009 dollars), with approximately 50% of the cost being the reservoir, and 28% being the powerhouse (ASCE 1993). No large projects have recently been built in the United States; however, a number of projects have been completed worldwide in the last decade, and there are a significant number of proposed plants both in the United States and internationally.

Table 12-4 lists several recently completed plants in Europe (Deane et al. 2010), along with proposed plants in the United States; capital costs (in dollars-per-kilowatt) are adjusted to 2009 dollars (NWPCC 2008). There are also a large number of proposed plants in Europe, with costs estimated in the range of $700/kW to more than $3,000/kW.

Table 12-4. Recently Completed or Proposed Pumped-Storage Hydropower Plants[a]

Location	Plant Name	Capacity (MW)	$/kW	Date of Completion
United States				
California	Eagle Mountain	1,300	1,019	Proposed
California	Iowa Hills PS	400	1,344	Proposed
California	Lake Elsinore	500	1,500	Proposed
California	Red Mountain	900	1,900–2,100	Proposed
Utah	North Eden PS	700	1,011	Proposed
Utah	Parker Knoll PS	800	1,215	Proposed
Austria	Feldsee	140	750	2009
Austria	Reisseck_II	430	1,091	2008
Germany	Goldisthal	1,060	1,321	2003
Slovenia	Avce	180	711	2009

[a] This represents a small subset of the proposed plants in the United States

Deane et al. (2010) provides a more comprehensive discussion of recent and projected future costs. Recent engineering estimates of new PSH construction costs per kilowatt in the United States include $2,100–$4,000 (Rastler 2009), $2,000–$4,000 (Black & Veatch 2012), and $5,595 (EIA 2010). A large component of this very large range is due to the variation in local conditions—low-price estimates may assume the availability of existing reservoirs (including abandoned mines or other formations), while the high estimates may assume “green field” development or modification of both reservoirs. Generating a supply curve would require evaluation of each individual potential site. Efforts have been initiated to characterize potential new PSH development at scale, but additional data were unavailable at the time of this analysis.

As a result, cost estimates were based on a combination of proposed plant costs described above and engineering estimates, focusing on lower-cost PSH opportunities. Two cost points were identified, at $1,500/kW and $2,000/kW.

One of the primary challenges associated with PSH development is the long construction time, as well as associated risks and uncertainty. State and local application and permitting (including obtaining water rights), FERC permitting, and construction require 10–12 years based on current schedules. Closed-cycle plants could reduce licensing and construction times to 6–8 years. These times (and resulting costs) can be increased due to siting opposition and environmental regulations (Strauss 1991).

Existing PSH facilities in the United States—most of which were constructed during the 1960s, 1970s, and 1980s—have high availability and few forced outages. The great majority of U.S. plants have multiple reversible pump-turbine motor-generator units. Reversible units operate as a motor and pump in the “pumping” mode, and as a turbine and generator in the “generating” mode. Having multiple units per plant allows for scheduling maintenance on one unit while keeping the other units available, typically minimizing effects on overall plant availability.

Figure 12-6 provides the round-trip efficiencies for existing U.S. PSH plants. There has been a trend toward increased efficiencies, and proposed plants have efficiencies that exceed 80% on an AC-to-AC basis (ASCE 1993). Assumed efficiency for new PSH for this study was 80%. There is little loss of performance due to age or throughput. Plants are upgraded through efficiency improvements and life extension on a project-by-project basis, and most U.S. projects have been modernized through runner (turbine) replacements, generator rewinds, control system upgrades, and other incremental improvements. Lifetimes of PSH plants can exceed 60 years (ASCE 1993).

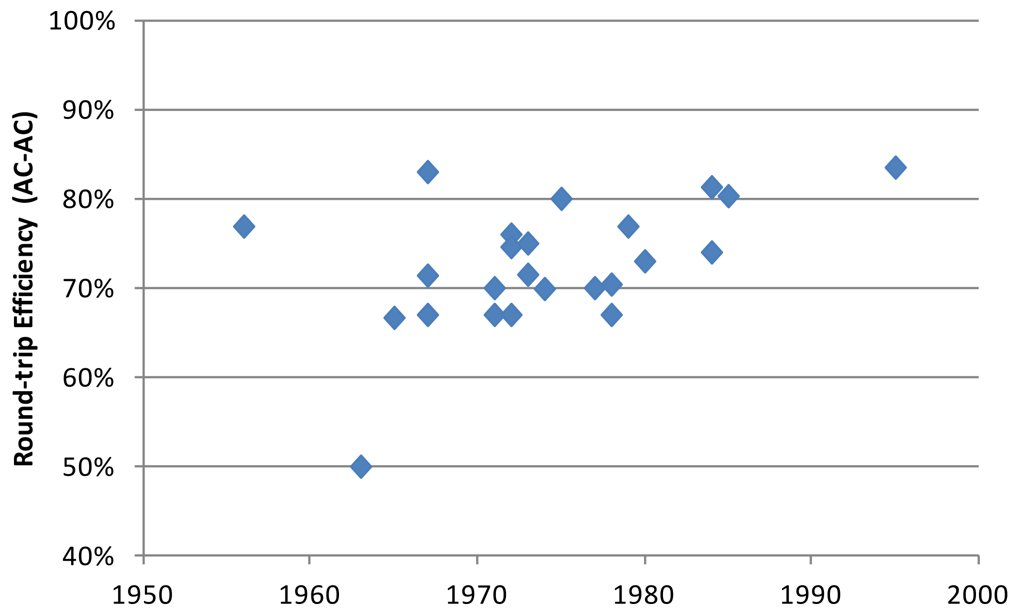

Figure 12-6. Historical efficiencies for pumped-storage hydropower plants in United States

Source: Performak 2012

Older PSH plants can require up to 30 minutes to switch between pumping and generation. However, modern PSH plants enable fast ramping rates in both pumping and generation modes and can begin pumping or generating within seconds.

RE Futures assumed that new PSH deployments would include variable speed (also referred to as "adjustable speed") operation. This technology has not yet been applied in a major U.S. installation, but has been used in several international plants (Yasuda 2000). Among the benefits of variable speed operation are faster response to grid requirements, higher efficiencies, ability to accommodate greater ranges of "head," and wider unit and plant operating ranges (i.e., an ability to operate with a lower minimum load in megawatts).

12.3.4.3 Compressed Air Energy Storage

The cost of CAES plants is driven by aboveground components, including compressors and the expander/generator equipment, as well as by belowground components. Aboveground equipment components are based largely on standard components, with the uncertainty in cost based largely on large swings in commodity prices and the general cost of capital-intensive projects. The largest uncertainty associated with CAES is related to underground cavern development and is especially associated with unproven approaches such as development in bedded salt and aquifers.

Salt caverns are generally the most economical excavated formations for siting CAES plants. Excavation costs for salt caverns, which are constructed by solution mining, can be kept extremely low compared to the costs for bedded salt formations, aquifers, and hard rock mining. Based on current experience with the construction of natural gas storage reservoirs and the Big Hill strategic petroleum reserves in Texas, costs can be maintained at approximately $2/m^3 of excavated cavern for solution mining compared to $20/m^3 in aquifers, and $300/m^3 in hard rock granite.

Table 12-5 provides several cost and performance estimates for proposed CAES plants. Table 12-6 breaks down costs for a conventional CAES system deployed with a salt cavern.

Table 12-5. Cost and Performance Estimates for Four Proposed Compressed Air Energy Storage Plants[a]

Name	Location	Cavern Type	Capacity (MW)	Cost ($/kW)	Heat Rate (Btu/kWh)	Energy Ratio[b]
Iowa Stored Energy Park	Dallas Center, Iowa	Aquifer	–	933–1,014	4,420	0.77–0.89
Norton Energy Storage	Norton, Ohio	Depleted hard-rock mine	2,700	–	3,860–4,300	0.7
PG&E	Kern County, California	Porous rock	300	1,187	–	–
Seneca (NYSEG/Iberdrola)	Schuyler County, NY	Bedded salt	150	833	–	–

[a] Performak 2012

[b] The energy ratio is defined as the amount of electrical energy in per unit of generation. Note that this number is less than 1 because CAES is a hybrid system that uses natural gas. The efficiency of a conventional CAES plant cannot be easily defined as a single number because it uses two different energy sources.

Table 12-6. Cost Breakdown for a Conventional Compressed Air Energy Storage System Deployed in a Salt Cavern

Component	Cost ($/kW)	Fraction of Total
Compressor	87	11%
Heat exchanger	34	4%
High pressure expander	62	8%
Low pressure expander	144	19%
Electrical	45	6%
Construction, labor, indirect costs	324	42%
Cavern development	77	10%
Total	774	100%

Source: CEC 2008

For RE Futures, the aboveground costs were based on a "reference plant" with a capacity of 220 MW. This reference plant assumes a multi-stage compressor, with the first stage using an axial flow compressor with a discharge pressure of 160 pounds-force per square inch gauge (psig) and requiring a power input of 90 MW. The discharge air is passed through an intercooler, which reduces the air's specific volume and temperature in preparation for the second stage of the compression process in which the air is compressed to its final storage pressure of 1,250 psig.

Three installed costs were assumed for new CAES development for RE Futures: $900/kW for deployment with salt domes, $1,050/kW in bedded salt, and $1,200/kW in aquifers. These values are based on engineering estimates, discussed in detail in Black & Veatch (2012), and are within the range cost estimates in Table 12-5 of $730/kW to $1,200/kW for deployment in salt and aquifers. Hard rock caverns that must be excavated were not included in RE Futures, although opportunities for CAES deployments exist in depleted mines.

RE Futures assumed a CAES energy ratio of 0.8 kWh_{in}/kWh_{out} and a heat rate of 4,910 Btu/kWh. These estimates were based on expected performance of the proposed (and subsequently cancelled) Iowa Stored Energy Park (Black & Veatch 2005; Schulte et al. 2012). The reference plant for RE Futures assumed dedicated motor and generators to allow fast switchover times and provision of operating reserves. RE Futures assumed a very high availability, based on both the similarity of CAES to natural gas turbines and the historical performance of the McIntosh Power Plant in Alabama. Plant lifetimes are expected to be similar to conventional gas turbine plants, typically exceeding 20 years with normal maintenance (Crotogino et al. 2001). Additional discussion of CAES cost and performance assumptions is provided in Black & Veatch (2012).

12.3.5 Technology Advancement Potential

12.3.5.1 Batteries

There is considerable opportunity for cost reduction and improvements in many battery technologies. EPRI/DOE (2003 and 2004) describe several cost reductions that could result from engineering and manufacturing scale-up of flow batteries and NaS batteries. Historical "learning curves" show continued progress of both "mature" battery technologies and newer technologies such as lithium-ion. Figure 12-7 and Figure 12-8 illustrate the historical increases in energy density as well as cost for a variety of energy storage devices.

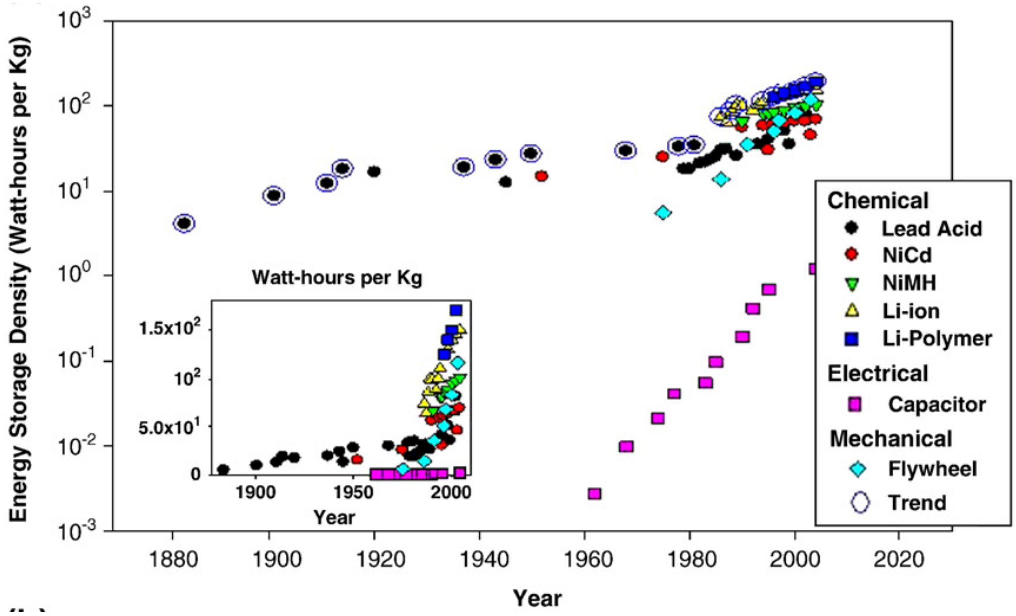

Figure 12-7. Historical improvements in storage energy density

Source: Koh and Magee 2008

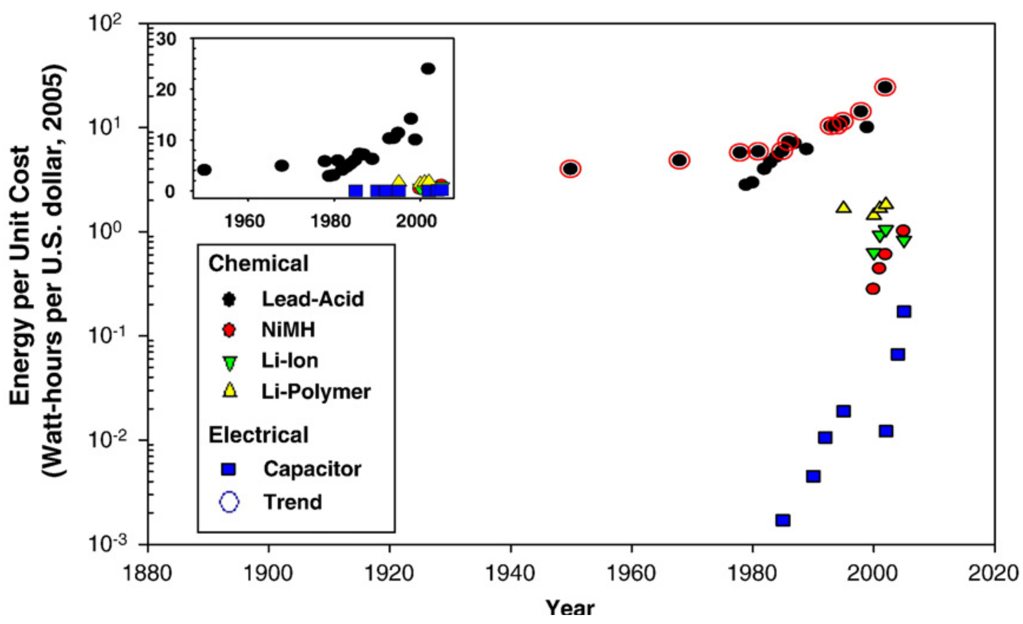

Figure 12-8. Historical improvements in energy storage cost

Source: Koh and Magee 2008

The emergence of nano-scale science provides opportunities for entirely new battery structures that could dramatically improve the power and energy density of several types of batteries. DOE

(2007) provided a detailed discussion of the potential opportunities for batteries. The target for the Advanced Research Projects Agency-Energy (ARPA-E) stationary storage program is $100/kWh.[172] In addition to research on stationary batteries, efforts to reduce the cost of transportation batteries could have significant impact on their application for grid services. RE Futures did not consider the impact of fundamental breakthroughs in battery science on reduced costs and subsequent deployment, nor did it evaluate the distribution level benefits of battery deployment.

12.3.5.2 Pumped-Storage Hydropower

Pumped-storage hydropower is considered a mature technology. However, incremental improvements in efficiency are possible, and the flexibility of existing and future plants may be improved using variable speed drive technologies. Other possible developments include use of saltwater PSH facilities in coastal regions and underground PSH (Tanaka 2000). Resource availability or detailed cost estimates of these alternative configurations were not available, so they were not considered for RE Futures.

12.3.5.3 Compressed Air Energy Storage

Although CAES is based on mature technologies, there are several possible advancements in conventional CAES. Previous CAES plants used components that were not optimized for the unique characteristics of the CAES expansion cycle. This is partially due to the small market for which developing dedicated equipment would not be worthwhile. A large CAES market could drive development of custom turbo-machinery, improving the efficiency of CAES components. Alternatively, several proposed CAES configurations use standard combustion turbines, potentially lowering cost significantly (Nakhamkin 2008). At least one proposed plant has considered an advanced CAES cycle (NYSEG 2009; Rettberg 2010).

Several other advanced CAES concepts were not included in RE Futures. These include aboveground CAES using pipes or other containers (which would have only a few hours of storage) or alternative fuels (such as liquid or gas biofuels). Other configurations not included in RE Futures include several proposed concepts that do not require natural gas. These include adiabatic CAES, which stores the heat of compression and uses this stored energy during expansion. This type of configuration has yet to be constructed, with cost and performance estimates based only on engineering studies (Grazzini and Milazzo 2008). However, at least one demonstration plant has been proposed in Europe (RWE 2010). Another approach being explored is isothermal CAES, which maintains constant temperature (Kepshire 2010).

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[172] The ARPA-E goal of $100/kWh includes both the power and energy component, including power conditioning equipment, installation, and other balance of system components. This corresponds to $800/kW for a device with 8 hours of storage capacity. This would require battery costs of well below $100/kWh, considering balance of system is currently a considerable fraction of $800/kW (U.S. DOE 2010b).

12.4 Resource Cost Curves

12.4.1 Batteries

Batteries do not have the geologic constraints of CAES or PSH. They also do not have fuel or water requirements, so they were assumed to be deployable at scale within each region.

12.4.2 Pumped-Storage Hydropower

New PSH development requires sufficient land for construction of the two requisite reservoirs, with a sufficient elevation difference between the reservoirs to enable economical generation.

Many areas of the United States offer suitable topography, and the technical potential of PSH is extremely large. Although there is no recent comprehensive estimate of PSH potential, older studies indicate the availability of hundreds of conventional PSH sites, more than 1000 GW of potential capacity in just six western states (Allen 1977), and more than 100 GW of potential in the Eastern Interconnection (Dames and Moore 1981). This capacity is roughly equivalent to the installed generation capacity for all of the United States (EIA n.d.). These older assessments include some areas that would be very difficult (or impossible) to develop based on current environmental restrictions. However, the capacity of recently proposed plants (exceeding 40 GW) is greater than the existing installed U.S. storage capacity and suggests there are considerable opportunities for new PSH capacity. RE Futures used an estimate for PSH availability based solely on the location and sizes of proposed plants for which data could be obtained (FERC n.d.). As a result, the developable potential of new PSH was fixed at 35 GW. Although this is much smaller than the technical potential of more than 1,000 GW, there are no data to estimate current development costs of this potential beyond engineering estimates that are as high as $5,595/kW. (Cost estimates are actually provided for much of this potential in the original assessment documents from the 1970s, but these costs are unlikely to reflect current market conditions.) The 35 GW of proposed capacity likely represents lower-cost opportunities as reflected in proposed costs, and reviews of these proposals were used to generate the two price points of $1,500/kW and $2,000/kW discussed in Section 12.1.3.2. Based on the reviews of proposed plants, the lower-cost value ($1,500/kW) was assigned to 10 GW of potential, while the higher cost ($2,000/kW) was assigned to 25 GW of potential. Figure 12-9 provides a map of the existing and proposed plants in the United States. The proposed plants were used to create a supply curve for new development (Figure 12-10), with the two cost points spread uniformly across the resource. Overall, the fact that costs could only be assigned to less than 4% of the technical potential indicates a fundamental need for understanding the potential of new PSH development.

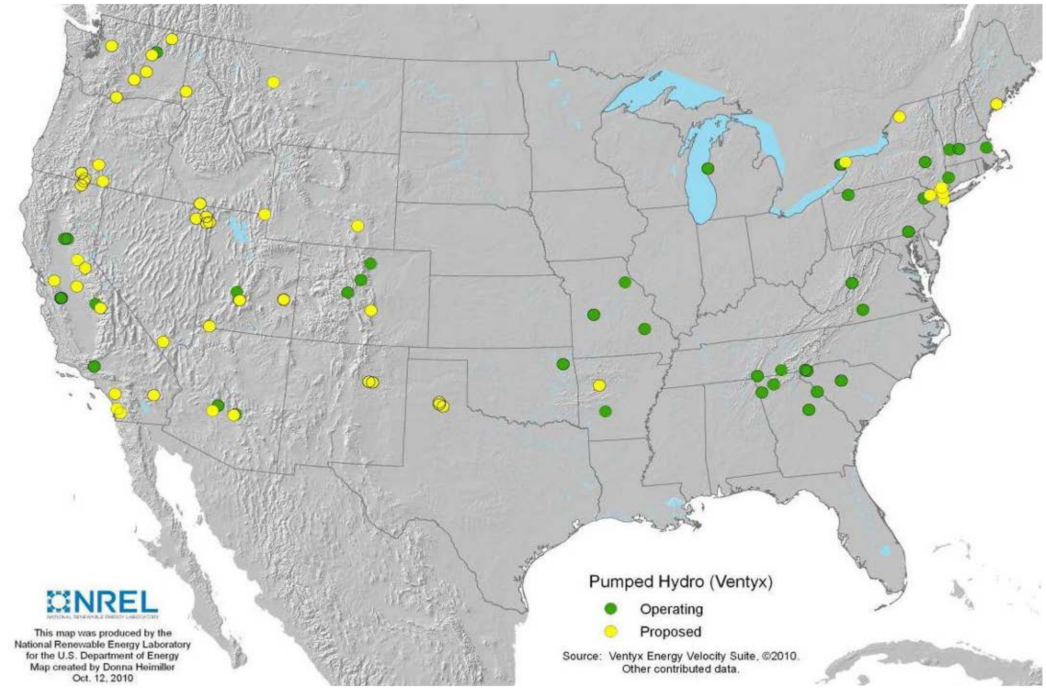

Figure 12-9. Location of existing and proposed (with Federal Energy Regulatory Commission preliminary permits) pumped-storage hydropower installations in the contiguous United States

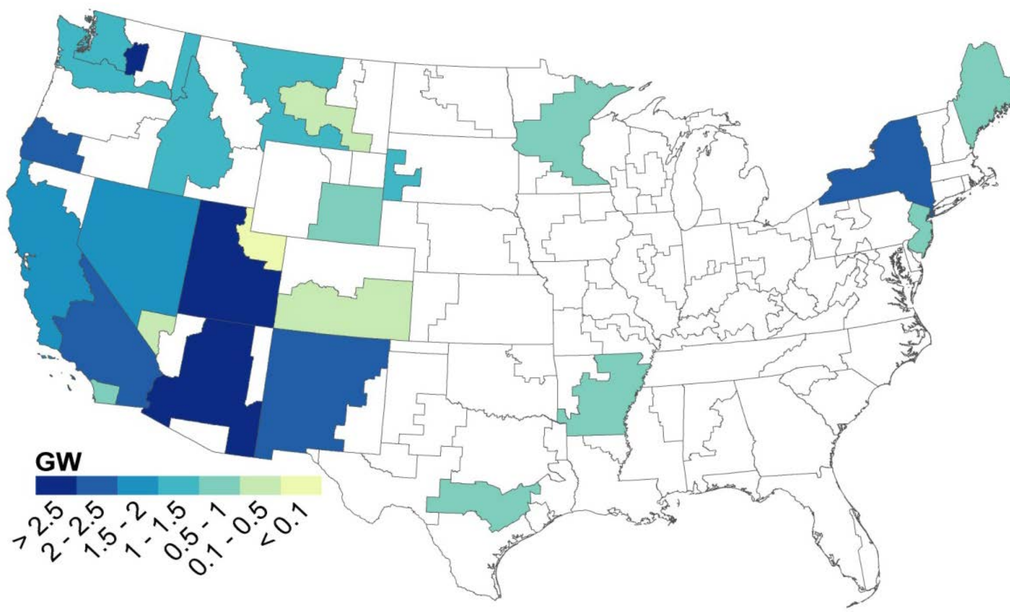

Figure 12-10. Pumped-storage hydropower resource potential used in the ReEDS modeling

12.4.3 Compressed Air Energy Storage

Estimating the amount of underground formations available for CAES is very difficult. Some estimates indicate that more than 75% of the land area of the United States could provide suitable geology for CAES projects (Allen 1985; Mehta 1992). However, each potential site must be individually screened, and this has proved challenging. For RE Futures, CAES deployment was limited to three options: domal salt, bedded salt, and porous rock (primarily aquifers).

Aquifer storage caverns are composed of permeable or fractured rock, and these formations are currently used to store natural gas. The identification of the necessary rock types and formations requires extensive geological testing to ensure the appropriate conditions exist for storage of compressed air. The major criteria for successful aquifer storage caverns are:

1. The existence of a structure shaped like an inverted saucer with the capability of sufficient air storage volume, which is determined from the porosity of the porous media comprising the aquifer
2. A continuous impermeable overlying caprock with a low permeability that inhibits the stored pressurized air from displacing water contained within the caprock pores
3. Sufficient structure depth (at least 600–800 feet or 183–244 m) having the full hydraulic pressure to assure adequate capacity of the aquifer pore volume along with the required characteristics to ensure adequate airflow from the formation
4. Permeability of the storage zone, not only in the air reservoir but also in the aquifer surrounding the structure.

The air under pressure will displace the water in the structure to form the storage reservoir. High permeability is needed to give a reasonable time to develop the reservoir and maintain proper airflow during injection and withdrawal.

CAES was excluded in certain porous rock formations such as depleted gas wells, except in California, where this application has been examined in some detail, and there is at least one proposed plant (Hobson et al. 1977; CEC 2008). Use of CAES in hard rock was also excluded due to lack of data. Although the cost of excavating hard rock solely for use in CAES is typically considered cost prohibitive, CAES could be used in existing depleted hard rock mines, and at least one large (2,700-MW) CAES plant has been proposed used an existing hard rock mine (Bauer and Webb 2000).

Figure 12-11 provides the estimates of CAES availability (in gigawatts) for the locations (by ReEDS balancing area), the availability (in gigawatts), and assumed cost (in dollars per kilowatt) for each of the three CAES deployment options (with the cost including both the power components and cavern development, assuming about 15 hours of storage capacity). For the contiguous United States, the potential CAES resource was estimated to exceed 120 GW, with about 23 GW in domal salt, 37 GW in bedded salt, and 62 GW in porous rock. No technology-driven cost improvements for CAES are assumed in the model scenarios.

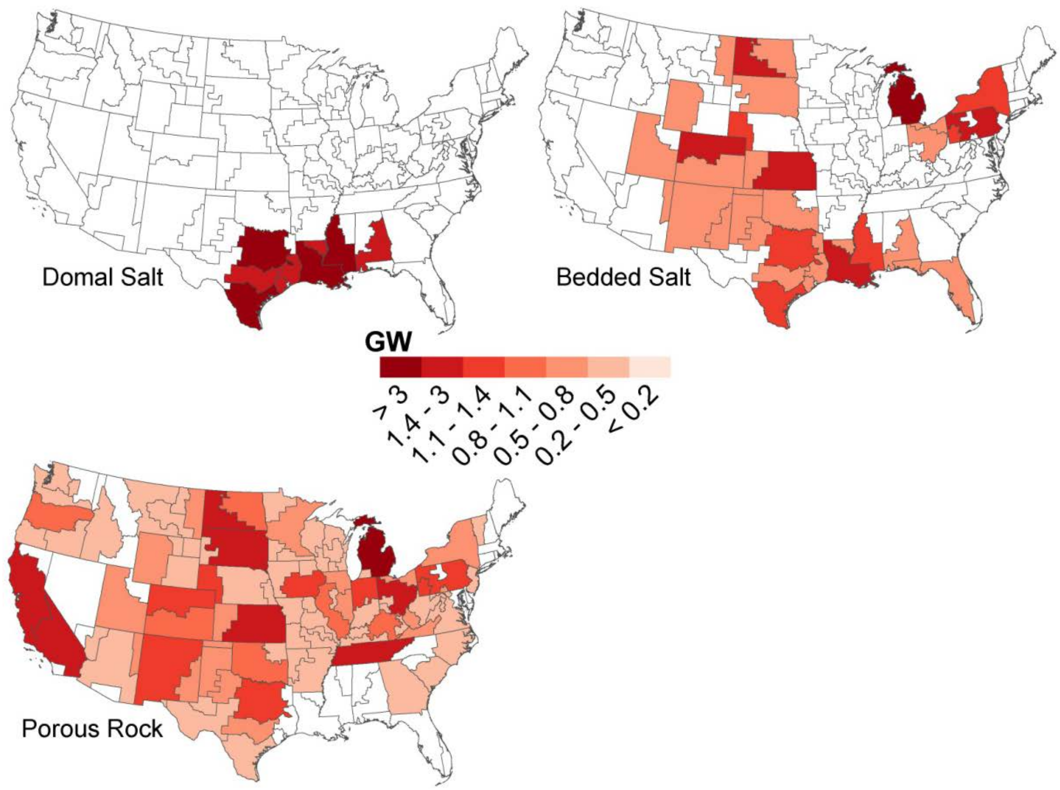

Figure 12-11. Assumed availability of compressed air energy storage in domal salt ($900/kW), bedded salt ($1,050/kW), and porous rock ($1,200/kW)

12.5 Output Characteristics and Grid Service Possibilities

Output characteristics and grid service possibilities are discussed in Section 12.3.

12.6 Deployment in RE Futures Scenarios

Deployment of new storage capacity is observed in all model scenarios described in Volume 1, and greater storage deployment is realized in scenarios with greater levels of renewables, and particularly variable renewable, penetration. For the (low-demand) core 80% RE scenarios described in Volume 1, 80–131 GW of new storage capacity was installed by 2050 in addition to the 20 GW of existing (PSH) storage capacity. Of the six core 80% RE scenarios, the constrained flexibility scenario projected the greatest level of storage deployment (152 GW of installed storage capacity by 2050). The constrained flexibility scenario was designed to capture greater institutional and technical barriers to managing variable generation, compared to the other 80% RE scenarios modeled. These barriers were implemented in ReEDS by halving the statistically calculated capacity values for wind and PV, increasing the reserve requirements for wind and PV forecast errors, reducing the flexibility of coal and biomass plants, and limiting the availability of demand response.[173] In the constrained flexibility scenario, new storage additions occur predominantly in the first two decades (2010–2030) of the study period, with an average annual installation rate of approximately 5 GW/yr and decade-averaged annual capital investments

[173] See Volume 1 for details on the design of the scenarios.

ranging from $4 billion/yr to $11 billion/yr between 2010 and 2030.[174] Figure 12-12 summarizes storage deployment in the constrained flexibility scenario, and Figure 12-13 shows the locations of storage deployment in the same scenario.

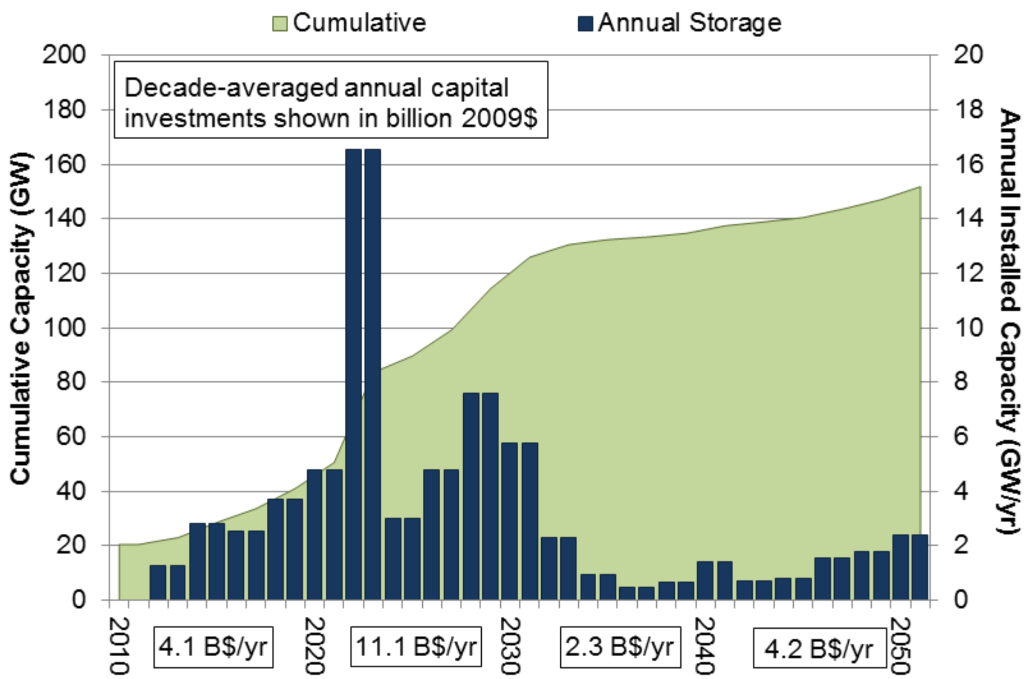

Figure 12-12. Deployment of energy storage technologies in the constrained flexibility scenario

[174] As a cost optimization model, ReEDS produces deployment results that can fluctuate greatly from year to year, whereas the actual deployment of technologies tends to vary more smoothly over time.

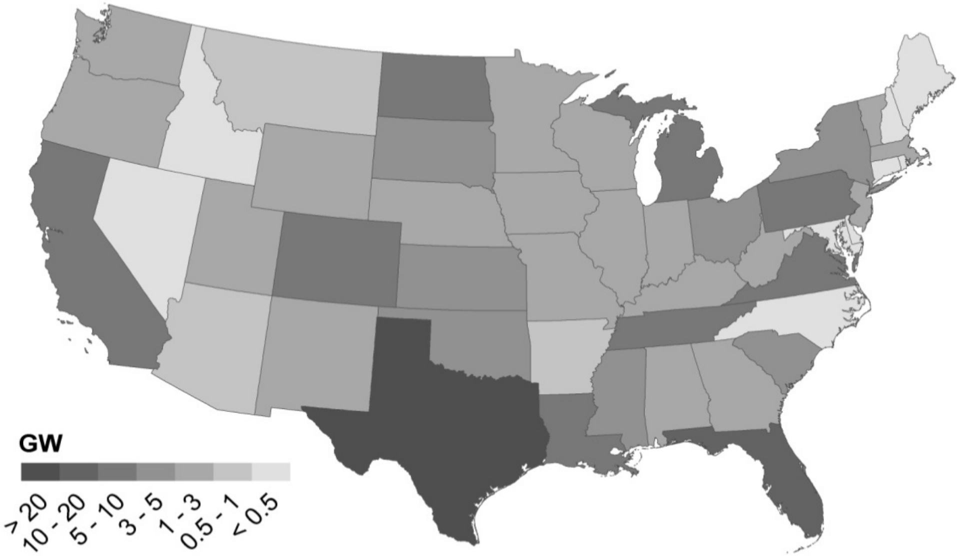

Figure 12-13. Regional deployment of storage in the contiguous United States in the constrained flexibility scenario

As discussed earlier, the modeled deployment indicates the general amount of storage that might be used to enable a high renewables scenario rather than to indicate a prescribed amount of each technology type. As a result of the modeling assumptions, most of the new storage is CAES; however, the tradeoff between CAES and PSH is largely due to the modeling and data limitations associated with the vast majority of potential PSH in much of the United States. In addition, the relative risk associated with CAES versus PSH was not considered. PSH is a proven technology, while CAES has yet to be deployed in either bedded salt or in porous rock formations, which represents a large fraction of assumed deployments. The limited deployment of batteries is due to their high cost and assumed minimal cost reduction but also to a lack of valuation of their benefits to the distribution system. This demonstrates an obvious discrepancy with relative historical and proposed deployment of these technologies, where PSH dominates. *The analysis of energy storage technologies for RE Futures demonstrates the need for more comprehensive estimates of the cost and resource availability for both CAES and PSH.*

Table 12-7 and Figure 12-14 show the variation in storage deployment between the low-demand core 80% RE scenarios and the high-demand 80% RE scenario. Between these scenarios, the 2050 installed storage capacity ranged from about 100 GW to 152 GW. A lower level of storage deployment is found under the 80% RE-ETI scenario, which included high levels of deployment of CSP with thermal storage and a corresponding lower deployment of variable generation technologies, thereby mitigating some of the need for the non-thermal storage technologies. Conversely, greater wind deployment in the 80% RE-NTI scenario and greater wind and PV deployment in the high-demand 80% RE scenario motivated high levels of storage deployment, although these two scenarios still realized slightly lower levels of deployment than the constrained flexibility scenario detailed above. Descriptions and results of the model scenarios are detailed in Volume 1.

Table 12-7. Deployment of Energy Storage Technologies in 2050 under 80% RE Scenarios[a,b]

Scenario	Capacity (GW)
Constrained Flexibility	152
80% RE-NTI	142
High-Demand 80% RE	136
Constrained Resources	131
Constrained Transmission	129
80% RE-ITI	122
80% RE-ETI	100

[a] See Volume 1 for a detailed description of each RE Futures scenario.
[b] Capacity totals represent the cumulative installed capacity for each scenario.

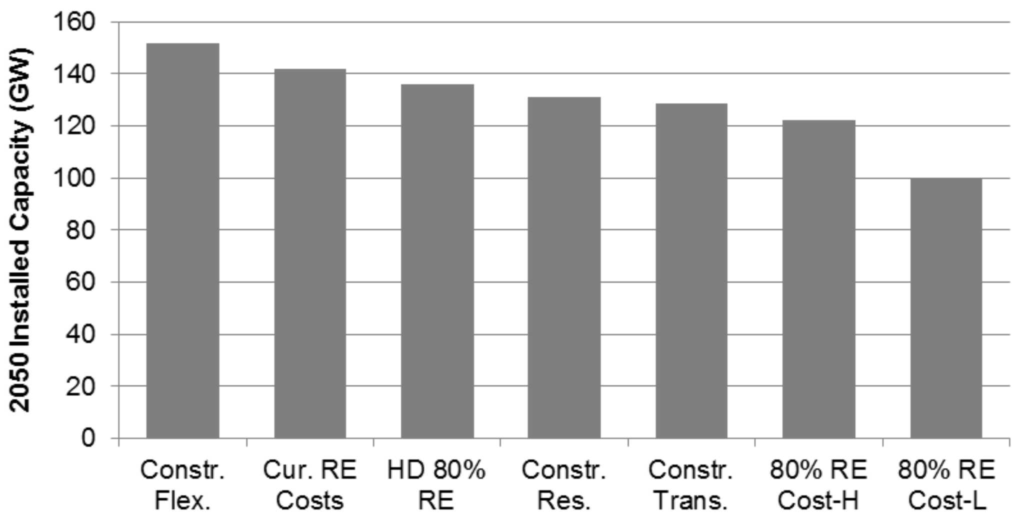

Figure 12-14. Deployment of energy storage technologies in 80% RE scenarios

12.7 Large-Scale Production and Deployment Issues

12.7.1 Environmental and Social Impacts

The impacts of energy storage are a function of two components. First is the localized impact due to development and direct use of the individual energy storage technologies. These vary significantly given the large differences in technology types. The second is associated with the upstream source of electricity, and the increased generation typically required due to inefficiencies in the storage process.

12.7.1.1 Land Use

Land use estimates for batteries are limited due to the lack of deployment at scale. For NaS, one estimate is approximately 211 m^2/MW with a 7.2-hour storage capacity (NGK n.d.), or approximately 300–350 m^2/MW for a 10- to 12-hour device more comparable to CAES or PSH. An estimate for a proposed (and subsequently cancelled) large (12 MW, 100–120 MWh) flow battery was approximately 850 m^2/MW (EPRI/DOE 2003) with additional land surrounding the facility (TVA 2001).

Land use impacts of CAES deployment are minimal because most of the plant is effectively underground. The land area estimates for one proposed CAES facility is approximately 140 m^2/MW (Norton Energy Storage 2000).

Pumped-storage hydropower can require a significant amount of land area for the upper and lower reservoir, depending on configuration. The total flooded area of three of the more recently constructed large PSH plants in the United States (the Bad Creek Hydroelectric Station in South Carolina, the Balsam Meadow Pumped Storage Project in California, and the Bath County Pumped Storage Station in Virginia) is in the range of 1,200 m^2/MW to 1,500 m^2/MW (ASCE 1993). Older PSH facilities with constructed upper and lower reservoirs have flooded areas that exceed 4,000 m^2/MW. New plants are more likely to have land use requirements towards the lower range, such as the proposed Eagle Mountain and Iowa Hill plants with flooded area requirements of approximately 1,100 m^2/MW (Tam 2008; Parfomak 2012). Additional discussion of land use associated with hydropower in general is provided in Chapter 8.

12.7.1.2 Water Use

For CAES, the dominant use of water is for formation of underground caverns in domal or bedded salt. Water use for solution mining is likely to be about 8 m^3 of water for each cubic meter excavated (Smith 2008) or about 4.8 million m^3 of fresh water withdrawals and brine management per 220-MW plant. Disposal of brine has been raised as a concern for some locations (Smith 2008). Additional cooling water is required during operation of the compressors, with one estimate of 2.5–3.0 million gallons per day for a 2700-MW facility (Ohio Power Siting Board 2001). Assuming a capacity factor of 25%, this corresponds to approximately 0.2 gallons/kWh.

Analysis and discussion of water impacts of PSH include Clugston (1980) and U.S. Bureau of Reclamation et al. (1993). Impacts on water quality and aquatic life have greatly delayed and even prevented operation of completed PSH facilities (Southeastern Power Administration 2009; U.S. GAO 1996). The actual water use and impacts of PSH depend partially on the source for the lower reservoir. Most existing U.S. PSH plants are “open-cycle” plants; that is, they use an existing water body, usually the lower reservoir, for one of their reservoirs. However “closed-cycle” plants—plants where both lower and upper reservoirs are constructed—will likely become more prevalent in the future because they minimize environmental effects as they do not interact with natural water bodies and they have little or no impact on aquatic life. Water sources for closed-cycle plants vary. Some proposed plants will use groundwater for the initial fill and make-up water required to replace seepage and evaporation. One estimate for make-up water for a 1,300-MW facility is 782 million gallons/yr (Tam 2008). Assuming a capacity factor of 25% (2,847 GWh/yr), this corresponds to a water consumption rate of approximately 0.3 gallons/kWh. At least one facility has proposed to use recycled wastewater, and it has been suggested that this could be a significant opportunity for other new PSH facilities (Yang and Jackson 2011).

12.7.1.3 Life Cycle Greenhouse Gas Emissions

Energy storage can add to net greenhouse gas (GHG) emissions in three ways. First, the losses associated with storage efficiencies increase the electricity needed to produce a unit of delivered energy via storage (energy storage losses can be partially offset by increased efficiency of thermal generators that is due to either operation that is closer to the “design point” or a reduced need for ancillary services [Denholm and Holloway 2005]). Second, energy storage technologies produce life cycle emissions that are due to construction and operations. These life cycle values for PSH, several battery types, and CAES (excluding natural gas use) are in the range of 5–40 grams equivalent carbon dioxide per kilowatt-hour (gCO_2e/kw) depending on operation, lifetime, and other factors (Denholm and Kulcinski 2004). This includes the methane emissions from vegetation decomposition by land flooded by new PSH reservoirs, which are relatively small, especially for sites in the United States (Gagnon and van de Vate 1997; Rosa and dos Santos 2000). Finally, CAES burns natural gas, emitting GHG emissions at a rate of about 215–240 gCO_2e/kWh of delivered energy, assuming a heat rate range of 4,000–4,400 Btu/kWh (plus GHG emissions associated with production and transport of natural gas.)

Given the uncertainty in storage technology mixes, and given limited data, the life cycle GHG emissions impacts due to energy storage manufacturing were not evaluated, resulting in a small underestimation of system-wide GHG emissions for the non-fuel storage component. However, the CAES fuel combustion emissions were counted. Thus, the degree of underestimation is likely very small because of both the limited deployment of storage and their relatively small emissions.

12.7.1.4 Other Waste and Emissions

In general, with the exception of CAES, energy storage does not require direct fuel or combustion processes, so it produces no direct air emissions. The use of natural gas in CAES produces the various impacts associated with gas exploration, production, transmission, and combustion. This produces emissions such as nitrogen oxides in a manner similar to conventional gas turbines, but at a correspondingly lower rate given the much lower heat rate. Nitrogen oxide emissions can be controlled using conventional emissions controls such as selective catalytic reduction, which has been proposed for use in the CAES plants under consideration (Norton Energy Storage 2000; CEC 2008.)

Batteries use a variety of materials, some of which are toxic. Lead and cadmium are examples, and collection and recycling programs are generally in place to avoid improper disposal (EPRI/DOE 2003). Additional programs would be required for new battery chemistries, depending on their level of deployment and materials used.

12.7.2 Manufacturing and Deployment Challenges

Both CAES and PSH are based on mature technologies that have been previously deployed in the United States at scale. For example, the equipment required for CAES is very similar to conventional gas turbines, and the historical installation of gas turbines has exceeded 10 GW/yr in some years (EIA n.d.). An additional discussion of issues related to PSH manufacturing is provided in Chapter 8. For batteries, the primary issues for large-scale deployment may be related to a combination of materials requirements and competition with automotive applications. Wadia et al. (2011) discusses this issue at length and finds essentially no material challenges for some technologies such as NaS, but potential constraints on others, such as Vanadium Redox or certain lithium-ion batteries using cobalt.

12.8 Barriers to High Penetration and Representative Responses

Although capital cost is a primary barrier to deployment of energy storage, many regulatory and market barriers prevent energy storage from competing equally with more conventional technologies that provide energy and capacity services.

Table 12-8 summarizes actions that could enable greater use of energy storage. Table 12-8 includes only a small subset of energy storage technologies. Other existing and emerging storage technologies could be deployed in substantial numbers given appropriate decreases in costs.

Table 12-8. Barriers to High Penetration of Electricity Storage Technologies and Representative Responses

R&D	Barrier	Representative Responses
Batteries	High capital cost, limited cycle life	Conduct fundamental science and engineering to improve power and energy density; research new electrolyte materials; standardize and integrate power conversion systems
CAES	Cost, efficiency, unproven availability of sites	Research and development into advanced CAES cycles, including cycles that reduce or eliminate use of natural gas; demonstrate CAES in aquifers, bedded salt, and depleted gas wells; conduct detailed national screening of suitable geologic formations
PSH	Availability of sites	Conduct detailed national screening of suitable formations
Market and Regulatory	**Barrier**	**Representative Responses**
All	Limited value proposition for energy storage	Provide comprehensive analysis of the system benefits of storage, including utility operations models that accurately represent the complete set of benefits of energy storage over multiple timescales
All	Unclear treatment of energy storage in regulatory framework	Establish a regulatory framework that provides fair and equitable cost-recovery mechanisms for new storage development congruent with its system benefits
Environmental and Siting	**Barrier**	**Representative Responses**
PSH	Land and water use	Conduct detailed screening of opportunities for closed-cycle plants, and siting on brown fields and other disturbed land

12.8.1 Research, Development, and Deployment

For batteries (and other electro-chemical storage technologies), most RD&D efforts are focused on reducing capital cost, increasing power and energy density, and increasing lifetimes. Several recent reports identify fundamental research and engineering needs for improving basic technologies, as well as developing manufacturing techniques to bring laboratory technologies to commercial products and to bring next-generation technologies to market (Hall and Bain 2008; APS 2007; DOE 2007).

The primary RD&D issues associated with both PSH and CAES are related to resource assessment. There is no known comprehensive assessment of the total availability of PSH or CAES geology to assess the resource potential, although efforts are underway by DOE and others to perform additional resource assessment for both technologies (Rogers et al. 2010). Additional near-term RD&D activities can aid in developing dedicated turbo-machinery equipment for CAES, providing incremental improvements in both cost and performance if deployed at large scale. Similarly, RD&D can provide incremental improvements to PSH pump-turbine equipment, and could examine opportunities to convert existing single speed units to variable speed operation (ORNL et al. 2010).

12.8.2 Market and Regulatory

The primary market and regulatory barrier to storage deployment in general is lack of appropriate valuation of storage benefits. Until recently, the value of ancillary services was largely unquantified. The creation of wholesale markets has placed value on those services and has increased participation of energy storage devices, but the level of participation varies by market.[175] In 2007, FERC issued Order 890 requiring wholesale markets to consider non-generation resources for grid services (Kaplan 2009). Since then, independent system operators and regional transmission operators have increased market access, including creating new tariffs for energy storage, and several storage projects have been proposed or built to take advantage of high-value ancillary service markets. However, market rules are still evolving in some locations (and of course, much of the United States has no access to restructured energy markets). A main benefit of energy storage is also its ability to provide multiple services, including load leveling (and associated benefits such as a reduction in cycling-induced maintenance) (Troy et al. 2010; Grimsrud et al. 2003) along with regulation and contingency reserves and firm capacity (Eyer and Corey 2010). However, quantifying these various value streams is difficult without sophisticated modeling and simulation methods. Because the economic analysis is difficult and benefits of storage are often uncertain, utilities tend to rely on more traditional generation assets, especially in regulated utilities where risk is minimized and new technologies are adopted relatively slowly. Changing and uncertain regulations and market structures also deter projects with long development times such as PSH, or uncertain technology challenges, such as CAES with site-specific geological screening requirements.

There are additional barriers to individual technologies. For PSH, the challenge of long permitting times could be reduced by applying an alternative licensing process to closed-cycle

[175] While ancillary services markets have been created in locations with restructured markets, large areas of the United States, including the entire West (excluding California) and most of the Southeast.

plants. These plants could be candidates for a streamlined FERC permitting process given their lack of interaction with any active stream, lake, or estuary.

12.8.3 Siting and Environmental Barriers

The primary siting challenge for new PSH and CAES is finding suitable geologic formations, discussed previously. PSH also faces potential opposition due to environmental impacts, which can be partially mitigated using closed-cycle plants. Both PSH and CAES plants are typically large, requiring new high-voltage transmission, which adds additional challenges, especially considering potentially remote locations. For batteries, the primary concern is the potential release of materials from liquid electrolyte flow-batteries. Proper containment and mitigation is required to minimize possible impacts (TVA 2001).

12.9 Conclusions

Energy storage is one of several potentially important enabling technologies supporting large-scale deployment of renewable energy, particularly variable renewables such as solar PV and wind. Energy storage is used in electric grids in the United States and worldwide. It is dominated by PSH. In addition to PSH, high-energy batteries and CAES can provide energy management services—shifting energy from periods of low demand to periods of high demand, which reduces curtailment and eases integration challenges associated with high levels of variable renewable generation—and were included in the RE Futures analysis. New storage capacity was deployed in all of the modeled scenarios and greater storage deployment is realized in scenarios with greater levels of renewables, and particularly variable renewable, penetration.

Capital cost is a primary barrier to deployment of energy storage. In addition, many regulatory and market barriers prevent energy storage from competing equally with more conventional technologies that provide energy and capacity services. A key issue for large-scale deployment of new storage capacity is finding suitable geologic formations for conventional PSH and CAES. PSH also faces potential opposition due to environmental impacts, which can be partially mitigated using closed-cycle plants. Both PSH and CAES plants are typically large, requiring new high-voltage transmission, which adds additional challenges, especially considering potentially remote locations. Batteries do not have the geologic constraints of CAES or PSH but large-scale deployment may face challenges related to a combination of materials requirements and competition with automotive applications.

More comprehensive estimates of the cost and resource availability for both CAES and PSH, advances in batteries to reduce capital cost, increase power and energy density, and increase lifetimes, and changes in market and regulations to quantify and value the ancillary services provided by energy storage are needed to support large-scale deployment of energy storage technologies in a high renewable electricity future.

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