Chapter 10

Power System Energy Storage Technologies

Energy storage plays a vital part in the modern global economy. At a national level oil and gas are regularly stored by both utilities and by governments, while at a smaller scale petrol stations store gasoline and all cars carry a storage tank to provide them with the ability to travel a significant distance between refuelling stops. Domestic storage of hot water is also usual in modern homes. Yet when it comes to electrical energy, storage on anything but a small scale, in batteries, is rare.

Part of the reason for this is that the storage of electricity, although it can be achieved in a number of ways, is difficult. In most storage technologies the electricity must be converted into some other form of energy before it can be stored. For example, in a battery, it is converted into chemical energy while in a pumped-storage hydropower plant the electrical energy is turned into the potential energy contained within an elevated mass of water. Energy conversion makes the storage process complex and the conversion itself is often inefficient. These and other factors help to make an energy storage system costly.

In spite of such obstacles, large-scale energy storage plants have been built in many countries. In the majority of cases, these installations are pumped-storage hydropower plants, often built to capture and store power from base-load nuclear power plants during off-peak periods. Many of these storage plants were built in the 1970s. More recently there has been renewed interest in technologies such as pumped storage for grid support, particularly in European countries that are installing large capacities of renewable capacity such as wind and solar power. However, the economics of energy storage often make construction difficult to justify in liberalised electricity market.

Although economics may not always favour their construction, energy storage plants offer significant benefits for the generation, distribution and use of electric power. At the utility level, for example, a large-energy storage facility can be used to store electricity generated during off-peak periods – typically overnight – and this energy can be delivered during peak periods of demand when the marginal cost of generating additional power can be several times the off-peak cost. Energy arbitrage of this type is potentially a

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lucrative source of revenue for storage plant operators and is how most pumped-storage plants operate.

At a smaller scale, energy storage plants can supply emergency backup in case of power plant failure as well as other grid support features, helping to maintain grid stability. They can also be used in factories or offices to take over in case of a power failure. Indeed, in a critical facility where an instantaneous response to loss of power is needed, a storage technology may be the only way to ensure complete reliability.

Energy storage also has an important role to play in the efficient use of electricity from renewable energy. Many renewable sources of energy such as solar, wind and tidal energy are intermittent and so are incapable of supply electrical power continuously. Combining some form of energy storage with a renewable energy source helps remove this uncertainty and increases the value of the electricity generated. It also allows all the renewable energy available to be used. Today the shedding of excess renewable power when demand does not exist for it, or when the grid cannot cope with it, is becoming common on some grid systems with high levels of renewable capacity.

Although there are many types of electrical energy storage system, pumped-storage hydropower plants account for virtually all grid-storage capacity available today with perhaps 150 GW of generating capacity in operation, based on estimates by the International Hydropower Association.[1] This was effectively the only large-scale energy storage technology available until the late 1970s. However in the past 30−40 years new interest has been stimulated and a range of other technologies have been developed. These vary in size so that some are suitable for transmission system level storage while others are more suited to the distribution grid or even for small microgrids. They include a range of battery storage systems, compressed air energy storage (CAES), large storage capacitors and flywheels, superconducting magnetic energy storage (SMES) and systems designed to generate hydrogen as an energy storage medium. The widespread adoption of electric vehicles which use battery energy storage could potentially offer a major new means of storing grid electricity too.

If deployed widely, these technologies could potentially transform the way the grid-based delivery of electrical energy operates by eliminating the need for expensive peak power plants while at the same time integrating the range of renewable generation technologies now available. This would, in turn, eliminate the vulnerability of electricity production to the vagaries of the global fossil fuel markets, creating more stable economic conditions everywhere. There is no consensus on how much storage capacity would be required to achieve this on a mature national grid but it could be equivalent to around 10%−15% of the available generating capacity.

1. *2018 Hydropower Status Report*, International Hydropower Association.

In spite of the apparent advantages offered by energy storage, widespread adoption remains slow. Cost appears to be the main obstacle although developments are slowly bringing costs down. At the same time the growth of distributed generation is offering new opportunities for small-scale energy storage facilities. This chapter will look at the range of technologies available and where they might fit into the electricity system.

TYPES OF ENERGY STORAGE

Electricity is an ephemeral form of energy which normally has to be used as soon as it has been generated. This is why the role of system operators and their electricity dispatching systems are important; they have to balance the demand for electricity with its supply. If one fails to match the other, problems occur: system voltages rise or fall and grid frequency may change, causing problems across the grid. It would seem obvious, given this situation, that some reservoir of saved electricity would be a major boon to grid operation. Yet storing electricity has proved difficult to master.

Storing electricity in its dynamic form, amps and volts, is almost impossible. The nearest one can get is an SMES ring which will store a circulating DC current indefinitely provided it is kept cold. A capacitor storage system stores electricity in the form of static electric charge. All other types of energy storage convert the electricity into another form of energy. This means that the energy must then be converted back into electricity when it is needed.

A rechargeable battery may appear to store electricity but in fact it stores the energy in chemical form. A pumped-storage hydropower plant stores potential energy; a flywheel stores kinetic energy, while CAES stores plant energy in the form of compressed air, another type of potential energy. Alternatively one might use electrolysis to turn electricity into hydrogen, yet another chemical transformation of the energy. This can then be burned in a thermal power plant or used in a fuel cell to turn the stored energy back into electricity.

The storage systems based on these processes are all viable ways of storing electricity, and many of them are commercially available. Each has different characteristics such as response time and storage efficiency which helps differentiate the technologies and define their applications.

Some of these systems can deliver power extremely rapidly. A capacitor can provide power in 5 ms, as can a superconducting energy storage system. Flywheels are very fast too, and batteries should respond in tens of milliseconds. A CAES plant probably takes 2−3 minutes to provide full power. Response times of pumped-storage hydropower plants can vary between around 10 seconds and 15 minutes. This technology is generally suitable for peak power delivery but less suited to fast response grid support.

The length of time the energy must be stored will also affect the technology choice. For very long-term storage of days or weeks, a mechanical storage system is best and pumped-storage hydropower is the most effective provided water loss is managed carefully. Batteries are also capable of holding their charge for extended periods. Energy loss in other systems will make them less practical for long-term storage. For daily cycling of energy, both pumped-storage and CAES are suitable while batteries can be used to store energy for periods of hours. Capacitors, flywheels and SMES are generally suited to short-term energy storage, although flywheels can be used for more extended energy storage too.

Another important consideration is the efficiency of the energy conversion process. An energy storage system utilises two complementary processes, one for storing the electricity and a second for retrieving it. Each will involve some loss. The round-trip efficiency is the percentage of the electricity sent for storage, which actually reappears as electricity again. Typical practical figures for different types of system are shown in Table 10.1.

Electronic storage systems such as capacitors can be very efficient, as can batteries. However, the efficiencies of both will fall with time due to energy leakage. Flow batteries, where the chemical reactants are separated, perform better in this respect and will maintain their round-trip efficiency better over time. Mechanical storage systems such as flywheels, CAES and pumped-storage hydropower are relatively less efficient. However, the latter two, in particular, can store their energy for long periods if necessary without significant loss.

All these factors must be taken into consideration when considering the most suitable energy storage technology for a given application. For large-scale utility energy storage, there are three possible technologies to choose between, pumped-storage hydropower, CAES and – at the low end of the capacity range – large batteries. Batteries can also be used for small- to

TABLE 10.1 Round-Trip Efficiency of Energy Storage Technologies

Energy Storage Technology	Round-Trip Storage Efficiency (%)
Capacitors	90
Superconducting magnetic energy storage	90
Flow batteries	90
CAES	65
Flywheels	80
Pumped-storage hydropower	75–80
Batteries	75–90

medium-sized distributed energy storage facilities,[2] along with flywheels and capacitor storage systems. Meanwhile fast-acting, small SMES units are being used to aid grid stability. Superconducting facilities have been considered in the past for large-scale energy storage as well, but they appear to be prodigiously expensive based on the technology available today.

GLOBAL ENERGY STORAGE CAPACITY

The installed base of energy storage across the globe has been collated by the US Department of Energy (US DOE). Figures from its energy storage database are shown in Table 10.2. Based on the figures in this table, the total number of storage projects across the globe in 2017 was 1630 and their aggregate installed capacity is 193,266 MW. The largest part of this, 183,387 MW (95%) is made up of pumped-storage hydropower plants. (Note, however, that the International Hydropower Association puts the global pumped-storage hydropower total at 150 GW.) Pumped-storage hydropower plants are both the largest and the most widely spread of all storage technologies. In terms of numbers of projects, the largest number, 986, belongs to electrochemical energy storage – batteries[3] – but the total installed capacity of these is only 3105 MW or an average size of 3 MW. The aggregate includes a few large and a large number of small battery storage facilities.

The other technology with a large number of projects is thermal storage with 207 projects and an aggregate installed capacity of 3692 MW. Although some of these thermal storage facilities are associated with solar thermal power plants (see Chapter 13), many are simply units that can store and then release heat energy for heating and hot water. Table 10.2 shows 70 electromechanical energy storage projects, primarily flywheel systems with a combined installed capacity of 2585 MW, 13 hydrogen storage facilities and 2 liquid air energy storage projects. The latter is a form of CAES.

Table 10.3 lists the major energy storage nations, ranked by the installed capacity in each country. Top of the list is China with 84 projects and an installed capacity of 32,104 MW followed by Japan with 90 projects (28,506 MW) and the United States with 494 projects (24,123 MW). In each of these countries the largest part of the capacity will be based on pumped-storage hydropower but the large number of projects in the United States suggests that a number of other technologies are gaining ground there too.

All the other countries on the list have less than 10,000 MW of installed capacity. Most of these are also nuclear nations that have built storage

2. Distributed storage facilities may be used by utilities to improve local grid stability or they may be used by consumers to make their own supplies more secure.
3. The table shows 985 electrochemical storage projects and one lithium-ion project.

TABLE 10.2 Global Energy Storage Capacity, Broken Down by Type

Storage Technology	Number of Projects	Installed Capacity (MW)
Electrochemical	985	3105
Pumped-storage hydropower	352	183,387
Thermal storage	207	3692
Electromechanical storage	70	2585
Hydrogen storage	13	18
Liquid air energy storage	2	5
Lithium-ion battery	1	24
Total	1630	193,266

Source: US Department of Energy.

TABLE 10.3 Top 15 Nations by Storage Capacity

Country	Number of Projects	Installed Capacity (MW)
China	94	32,104
Japan	90	28,506
United States	494	24,123
Spain	66	8,121
Germany	76	7,567
Italy	52	7,133
India	18	6,013
France	21	5,834
South Korea	62	4,991
Austria	19	4,680
Switzerland	23	4,530
United Kingdom	29	3,253
South Africa	9	3,212
Ukraine	3	3,173
Australia	39	2,893

Source: US Department of Energy.

capacity to support their nuclear plants. Spain is perhaps an exception. Pumped-storage capacity in Spain has been growing to support the country's wind and solar capacity.

PUMPED-STORAGE HYDROPOWER

Pumped-storage hydropower is both the simplest and the most widely used techniques for storing electrical energy today. It was first deployed in Switzerland around 1904[4] and there is probably around 150 GW of capacity in use, although estimates vary. These plants range in size from a few megawatts to more than 1000 MW, with the largest close to 3000 MW in capacity. Plants can be found in Australia and throughout Asia, across Europe and in Russia, but the largest aggregate capacities are in China, Japan and the United States. Many are used in conjunction with nuclear power plants so that the latter can operate at full power irrespective of demand. Some smaller plants are also used for peak shaving and load management duties independent of the availability of nuclear power.

The reservoir-based pumped-storage plant is an adaptation of the conventional hydropower plant to enable it to operate reversibly. In a conventional hydropower plant with a reservoir, water collects in the reservoir and is then released through the plant's turbines as power is required. This confers an element of energy storage but the water in the reservoir can only be used once.

In a pumped-storage plant there is a second reservoir below the turbine hall. Water that has been released from the first reservoir and used to generate electricity is collected again here and stored. The power station is also equipped with pumps – in most cases its power turbines can be operated in reverse as pumps – and during periods when excess power is available on the grid, these pumps are used to pump the water that has been collected in the reservoir below the turbine hall back into the higher reservoir above the turbine hall. The water is cycled between the two reservoirs to provide either power or energy storage as needed. A schematic of a pumped-storage hydropower plant is shown in Figure 10.1.

This type of plant is extremely robust. Round-trip efficiency is lower than for some other technologies but long-term energy losses are low allowing good long-term energy storage capability. Leakage and evaporation are the main sources of loss, and if these are managed well, water loss can be kept small. Today this is the only technology available for very large-scale energy storage.

4. The earliest recorded pumped-storage power plant was a 1.5 MW facility at Schaffhausen in Switzerland.

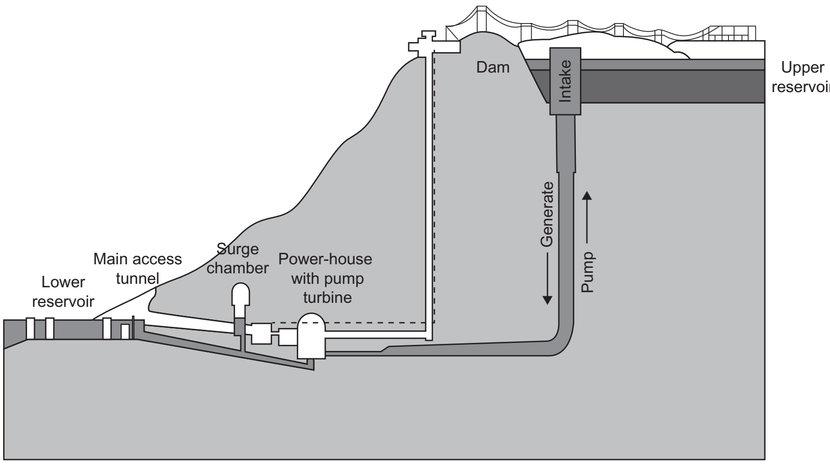

FIGURE 10.1 Pumped-storage hydropower plant. *US Tennessee Valley Authority.*

Pumped-Storage Technology

The basic layout of a pumped-storage hydropower plant involves two reservoirs, one above the other, and a turbine/pumping hall capable of both generating power from the stored water in the upper reservoir and pumping water from the lower reservoir back to the upper. For hydropower plants in general, the energy available from a given volume of water is greater, the greater the head of water. In the case of the pumped-storage plant, this head is the vertical distance between the upper reservoir and the turbines. The greater this distance, the more energy a given quantity of water can store; in other words, the larger the head, the smaller the volume of water needed for a given amount of energy. However, the pumped-storage head will be limited by the type of turbine that can be utilised.

Although the highest head available would in theory be best, very high heads require Pelton turbines to exploit them efficiently and these cannot be used as pumps. A very high head plant would therefore require separate pumps and turbines. This was the configuration as was used in the earliest pumped-storage facilities. Using separate pumps and turbines is more expensive than using a single pump/turbine unit. Most pumped-storage plants today use Francis or Deriaz turbines which can be used in both modes. This limits the head that can be exploited to achieve good efficiency to about 700 m. Modern multistage pump turbines may be capable of extending this to around 1200 m.

A pump turbine may not achieve the maximum efficiency possible when using independently optimised pumps and turbines but the best combined pump turbines are capable of reaching around 95% efficiency for generation and 90% for pumping, leading to a round-trip efficiency of 86%. Most plants operate in the 75%−80% range.

The Francis turbine is the type most commonly used as a pump turbine. Although highly efficient, it has fixed blades so the blade design is generally a compromise designed to optimise both generation and pumping efficiency. The Deriaz turbine is of similar design but with adjustable blades making it possible to optimise for generation and pumping independently. Deriaz turbines have been used for pumped-storage plants in several parts of the world but will generally be more costly than Francis turbines because of the additional complexity.

Variable Speed Operation

Although most pumped-storage hydropower plants have been built using pump turbines that operate at a fixed speed which is synchronised with the grid, there are significant advantages to be gained by having the ability to operate at variable speed. For pumping, variable speed operation allows the pump to function with surplus power at different demand levels and it can take power while the demand level is changing on the grid, allowing for much greater flexibility of operation. In generation mode, variable speed operation allows the unit to supply varying quantities of power. A fixed speed turbine can only supply its rated output at grid frequency.

Variable speed operation does require that the turbine generator be decoupled from the grid through a power electronic interface so that the electricity produced by the turbine at variable frequency can be injected into the grid at the synchronous frequency or the power from the grid can be adjusted when in pumping mode to allow variable pumping capacity. A variable speed pump generator will therefore be more costly than a fixed speed unit.

Pumped-Storage Sites

The single greatest limitation (aside from economics) faced by pumped-storage hydropower is the availability of suitable sites. A plant of this type requires two reservoirs at different heights. This can be difficult to engineer.

In rare cases, it is possible to find two existing lakes that can be utilised to create a pumped-storage facility. If natural lakes are exploited, it will be necessary to take into account the fact that the water level in both will vary more widely than it would naturally. The environmental impact of these changes must be assessed before such a plant is contemplated. More commonly a natural lake might form one reservoir while the second is man-made. The third option is for both reservoirs to be man-made. However, this can add significantly to the capital cost of such a plant.

A further, as yet rarely attempted, solution is to use the sea as the second or lower reservoir. This is the layout of the 30 MW Yanbaru seawater pumped-storage plant in Japan. One other idea that has never yet been exploited is to bury the lower reservoir underground in a suitable geological formation.

Plant capability depends on both the size of the reservoirs and the head, or vertical height between them. The volume of the reservoirs will determine the overall capacity of the plant to store and supply energy. The more water, the more energy it can contain. However, for a given storage capacity, the output will depend both on the size of the turbines and the head. A high head can deliver more power from a given flow of water than a small head.

Performance

Pumped-storage plants are capable of rapid response to sudden changes in demand. The Dinorwig plant in Wales can go from standby to synchronisation at full output of 1320 MW in 12 seconds, a ramp rate of 110 MW/s. Other, more modern pumped-storage plants have been specified to be capable of output ramping when in operation at up to 500 MW/min which compares favourably with gas turbine peaking plants and modern combined cycle power plants.

With adequate control of evaporation and leakage, the energy stored in a pumped-storage reservoir can be retained indefinitely. This is not a significant advantage when most plants cycle daily but it could prove so under circumstances where energy needs to be stored seasonally such as solar power for use in winter or wind power for use in less windy summer months.

The Cost of a Pumped-Storage Hydropower Plant

An energy storage plant such as a pumped-storage hydropower plant will depend for its revenue on being able to buy power at low cost and then sell it at a higher cost. The income will therefore vary depending on a wide range of conditions. From an economic point of view, the capital cost of building the plant will be the most important factor in determining its viability. This is likely to be relatively high because, like most hydropower plants, pumped storage is a capital-intensive technology.

At the top end, capital costs are likely to be as high or higher than for a traditional hydropower plant, which, as shown in Chapter 8, are generally in the range \$1000/kW to \$2000/kW. A 500 MW plant proposed for construction in California has an estimated cost of \$1.1 billion and a capacity of 500 MW, or around \$2200/kW. In contrast the Tianhuangping pumped-storage plant in Zhejiang province, China, cost \$1.1 billion for 1800 MW when it came online in 2001, around \$600/kW. Much of the difference can probably be accounted for by the lower labour costs in China.

Small pumped-storage plants are likely to be relatively more expensive than larger installations.

COMPRESSED AIR ENERGY STORAGE

CAES is a storage technology in which energy is stored in the form of air pressurised above atmospheric pressure. Compressed air has a long history as a means of both storing and distributing energy, and systems based on this energy distribution medium were installed during the late 19th century in cities as various as Paris (France), Birmingham (United Kingdom), Dresden (Germany) and Buenos Aries (Argentina) to supply power for industrial motors and for commercial use in a variety of applications including the textile and printing industries.

The use of compressed air storage as an adjunct to the power grid began with the construction of the Huntorf power plant which was built in Germany in 1978 but only operated commercially for 10 years. A second CAES plant was built by the Alabama Electric Cooperative in the United States and entered service in 1991. This second facility has continued to provide storage services ever since. Details of these two plants are shown in Table 10.4.

In spite of being championed by organisations such as the US Electric Power Research Institute, no further commercial project has ever been built although others have been proposed and work even started on two. Even so, CAES remains of interest because it is the only other very large-scale energy storage system after pumped-storage hydropower. Individual CAES plants are generally smaller than typical pumped-storage plants, but sites suitable for their construction are much more widespread than those for the hydro storage plants. They could, therefore, provide a more widely distributed large-scale energy storage network.

In addition to conventional CAES, there is another, similar technology that is attracting interest, liquid air energy storage. In this type of plant the air is liquefied instead of simply being compressed. The approach has some advantages in terms of space demands but requires cryogenic liquefaction

TABLE 10.4 Commercial CAES Plants

Plants	Generating Capacity	Commissioning Date
Huntorf, Germany	290	1987
McIntosh, Alabama, United States	110	1991

technology to function, making it technically more complex than the conventional approach.

The Compressed Air Energy Storage Principle

A CAES plant requires two principal components, a storage vessel in which compressed air can be stored without loss of pressure and a compressor/expander to charge the storage vessel and then extract the energy again. (The latter might in fact be a compressor and a separate expander.) In operation the plant is broadly analogous to the pumped-storage hydropower plant. Surplus electricity is used to compress air with the compressor and the higher pressure air is stored within the storage chamber. This stored energy can then be retrieved by allowing it to escape through the expander, an air turbine which is essentially a compressor operating in reverse. The expanding air drives the air turbine which turns a generator to provide electrical power.

The compression and expansion functions of the CAES plant can be performed by the two primary components of a standard gas turbine. As seen in Chapter 4 the gas turbine comprises three components: a compressor, a combustion chamber and a turbine. If the combustion chamber is removed and the two rotary components separated, then these can alternately use electricity to compress air for storage and extract energy from it again to regenerate the stored power.

In practice a slightly different arrangement is preferred which is closer still to the gas turbine. A rotary gas turbine compressor is used to compress air which is then stored in the storage chamber. When power is required, compressed air is extracted again and fed into a combustion chamber where it is mixed with fuel and ignited, generating a higher pressure, higher temperature thermodynamic fluid which is then used to drive the turbine stage of the plant.

Because a plant operated in this way requires natural gas or another fuel, it is not a straightforward energy storage system. However, the economics of this mode of operation appears to be most attractive because it can generate more electricity than was used to store the compressed air. Additional generation is between 25% and 60% depending upon the plant design. A further advantage Of all CAES plants is that the turbine stage of the plant does not have to drive the compressor as it would in a conventional gas turbine, so it can generate up to three times more power than it would when coupled to a compressor. Turbines for CAES plants are therefore relatively smaller than for a similar generating capacity gas turbine.

Compressed Air Storage Facilities

The most important part of a CAES plant is somewhere to store the compressed air. Small-scale CAES plants – with storage capacities of up to

100 MWh and outputs of up to 20 MW – can use above ground storage tanks built with steel pressure vessels but large, utility-scale plants need underground caverns in which to store the air. The natural gas industry has used underground storage caverns for years to store gas; these same caverns can provide ideal storage facilities for a CAES plant. However, the demand for such a cavern limits the development of CAES to places where such storage caverns are available.

Several different types of underground cavern can be exploited. The most expensive is a man-made rock cavern excavated in hard rock or created by expanding existing underground mine workings. Such a site must be located in an impervious rock formation if it is to retain the compressed air without loss, so the suitability of underground coal mines and limestone mines will depend on whether they are airtight.

Salt caverns are another type of storage site, one that has been commonly used for gas storage. These are created within naturally occurring underground salt domes by drilling into the dome and pumping in water to dissolve and remove the salt to create an enclosure. Salt deposits suitable for such caverns occur in many parts of the world.

It is another type of geological structure however, an underground porous rock formation, which offers the cheapest underground storage facility. Structures of this type suitable for gas storage are found where a layer of porous rock is covered by an impervious rock barrier. Examples can be found in water-bearing aquifers or in porous underground strata from which oil or gas have been extracted. Aquifers can be particularly attractive as storage media because the compressed air will displace water within the porous rock, setting up a constant pressure storage system. With rock and salt caverns, in contrast, the pressure of the air will vary as more is added or released.

All three types of underground storage structure require sound rock formations to prevent the air from escaping. They also need to be sufficiently deep and strong to withstand the pressures imposed on them. It is important, particularly in porous rock storage systems, that there are no minerals present that can deplete the oxygen in the air by reacting with it. Otherwise the ability of the air to react with the fuel during combustion will be affected, reducing the power available during the generation phase of the storage-generation cycle.

Underground rock structures capable of storing compressed air are often widely available. For example, a survey in the United States found accessible sites of different types across 80% of the country.

Turbine Technology and Compressed Air Energy Storage Cycles

A CAES plant generally exploits standard gas turbine compressor and turbine technology, but because the two units operate independently, they can be sized differently to match the requirements of the plant. The larger the compressor is compared to the turbine, the less time it requires to charge the cavern with a given amount of energy. The Hundorf plant that was built in Germany required 4 hours of compression to provide an hour of power generation, whereas the McIntosh plant in Alabama needs only 1.7 hours of compression for an hour of generation.

As a consequence of compression and generation being separated, a CAES plant turbine can operate well at part load as well as full load. More complex operation is also possible. The Alabama plant, for example, uses two turbine stages with the exhaust from the last turbine stage used to heat air from the cavern before it enters the first turbine stage. Fuel is not actually burnt in the compressed air until it enters a combustion chamber between the first and second chambers. A schematic of this more complex CAES plant configuration is shown in Figure 10.2.

Many of the refinements used to improve gas turbine performance outlined in Chapter 4 can be used in CAES plants too. For example, the compressor can be divided into two sections with air cooling between the stages to reduce its volume (intercooling), heat can be recovered from the turbine exhaust and used to heat the compressed air extracted from the storage chamber (recuperation) and reheating, where the turbine is divided into two stages with an additional combustion chamber between Stage 1 and Stage 2, can also be applied. Versions of these latter two are used in the McIntosh plant, as noted earlier.

Mechanical components are never 100% efficient, so there are consequential energy losses during compression and expansion in a CAES plant. There is also an additional source of energy loss. When air is compressed, it generates heat and this heat energy is lost in a conventional CAES plant. A proposed refinement to the conventional mode of operation involves capturing this heat and storing it for use to heat the pressured air as it exits the

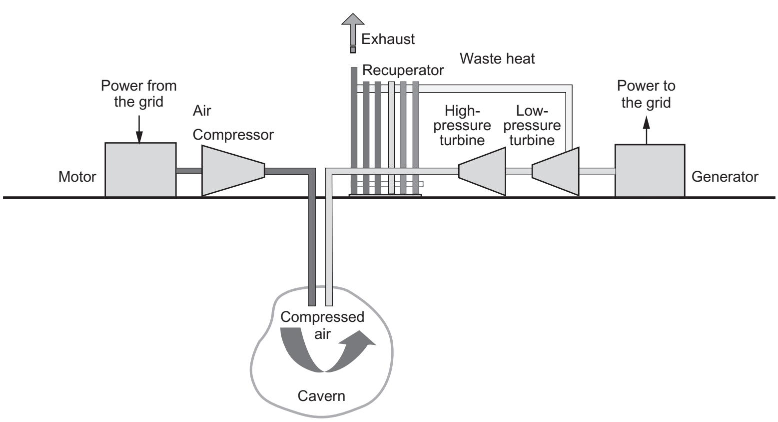

FIGURE 10.2 A CAES plant.

storage chamber, before entering the turbine. This adiabatic cycle could theoretically be used to design a CAES plant that has no need for additional fossil fuel and that can achieve a round-trip efficiency of 65%.

In principle a CAES plant could be of virtually any size, and one proposed project would have had a generating capacity of 2400 MW. However, in practice, most schemes are likely to be smaller than this, in the tens or hundreds of megawatts range. Start-up for the two plants that have operated was around 12 minutes but both could be brought into service in 5 minutes if necessary. Round-trip efficiency without the use of additional fuel will be low for conventional CAES plants such as the two that have operated but, as noted, refinements could improve this.

Liquid Air Energy Storage

Another technology that can be considered a form of CAES is liquid air energy storage. In this type of storage system the air is stored, not in a compressed gaseous state but in the liquefied state. This increases the energy storage density of the stored air by at least 10 times. In principle, for a plant of similar storage capacity, a liquid air energy storage system will be 10 times smaller than a conventional CAES system and 140 times smaller than a pumped-storage hydropower reservoir.

A liquid air energy storage system uses off-peak power to compress, cool and liquefy air. This air must then be stored in special cryogenic containers. Heat from compression may be captured and stored too if it is economic to do so. When power is required, liquefied air is released from the store and heated to regenerate the gaseous form. This provides a high-pressure stream of gas that can be used directly to drive an air turbine.

One of the potential attractions of this type of system is that it can use waste heat from various sources to heat the liquefied air. This has the potential to increase the overall efficiency significantly. Waste heat might be provided by an industrial process or it might be the waste heat from the exhaust of a combined cycle power plant.

The liquefaction of air is a commercial process that is used in a variety of industries and the technology is well known. However, it is expensive. The key to the economics of this technology is likely to be finding a more cost-effective means of liquefying air than the methods currently available. The first grid-connected pilot scale plant of this type began operating in Manchester, United Kingdom, in 2018. This facility has a generating capacity of 5 MW and a storage capacity of 15 MWh.

Costs

There is little experience with CAES, so any cost estimates must be considered tentative. However, it would appear to be an economically attractive option for energy storage. Proposals within the last 10 years or so for conventional CAES plants in the United States have had installed costs of $400/kW to $900/kW depending upon size and storage type. An adiabatic plant is likely to be much more expensive, with potential costs as high as $1700/kW.

LARGE-SCALE BATTERIES

Batteries are the most widely used means of storing electrical energy. Invented during the 19th century, they are now exploited in a whole range of portable applications. They are used to supply power to starter motors in road vehicles, to provide an electrical source for mobile phones and tablet computers and to deliver energy to tiny electronic devices such as hearing aids. More recently batteries have also been used to store energy in a range of mostly small renewable energy applications and in addition some large cells have been used for grid storage and stability uses.

All batteries are electrochemical devices that convert the energy that is released during a variety of chemical reactions into electrical energy. If the reaction was permitted to proceed conventionally by mixing the reactants, this energy would normally emerge from the reaction as heat. In an electrochemical cell (i.e., a battery), the reaction is controlled in such a way that most of this heat can be converted into electricity.

There are two distinct types of battery in common use, designated primary cells and secondary cells. A primary cell (or battery) can only be used once. After that, it cannot be recharged. A secondary cell is capable of being recharged, reversing the internal chemical reaction and regenerating the reactants that provided the power in the first place, so it can be used multiple times. It is these secondary cells that are of use in the power and utility industries.

Secondary cells can be further divided into two types, standard secondary cells and flow batteries. Standard secondary cells are the type found in portable computers or vehicles. They are completely self-contained and have no mechanical parts. Charging and discharging is carried out via the cell terminals and all of the reactants required are contained within the battery package. These standard secondary cells can be found in two varieties, shallow discharge cells such as those used for vehicle starter power which are never fully discharged, and deep discharge cells which can be completely exhausted and then recharged without damage.

A flow battery is also a secondary cell but it differs from the standard version because the actual cell within which the chemical reactants react and generate electricity does not carry the reactants themselves. Instead, these are stored in external reservoirs and pumped through the cell as required. This type of battery is more complex than a conventional secondary cell, but it has the advantage that battery capacity is limited only by reservoir size and this can easily be increased for a relatively little cost. However, flow batteries are much more complex than conventional secondary cells and this means they tend only to be economical in large sizes.

The Battery Principle

A battery is a device that can exploit a chemical reaction to produce electricity. The reactions upon which a cell is based will define the particular cell type. In all cases the reaction will occur spontaneously if the reactants are mixed, generating heat in the process. However, in the battery the reactants are separated and only allowed to react in a particular way.

The chemical reaction used in every battery can notionally be divided into two half reactions and the battery will contain two electrodes, called the anode and the cathode; each electrode is associated with one of these half reactions. The half reactions involve the creation of charged ions and the capture or release of electrons. Under normal circumstances where the reactants are intimately mixed, these processes occur simultaneously at the same location. However, in a battery, the two electrodes are separated by an electrolyte which will allow charged ions to pass from one electrode to the other but will not allow electrons to pass. These can only cross from one electrode to the second to complete the reaction through an external circuit. This is the electrical current that can be used to drive electrical and electronic equipment. It is this separation of processes by the use of a selective filter — in this case the electrolyte — that allows the cell to generate power.

As noted earlier, primary cells contain reactants that will only react once to produce power. After that the cell is spent. A secondary cell can be recharged by applying a reverse polarity to the cell, reversing the chemical cell reaction and regenerating the original cell reactants. It is this type of cell that is of use for energy storage.

There are a number of battery types that can be used for grid and utility applications. The most widely used secondary cell is the lead-acid battery, similar to the type commonly used in vehicles. A simple schematic of this type of cell, detailing the chemical reactants involved, is presented in Figure 10.3. Lead-acid batteries account for roughly half of all secondary cell sales, globally, and are widely available. Another type, the nickel—cadmium (Nicad) battery, is less common. Nicad batteries were used for portable computers until they were superseded by alternatives which were better suited to the duty cycle of such devices. They have also been used for automotive applications, particularly under low-temperature conditions when they behave more reliably than lead-acid cells. Other cell types developed specifically for portable electronic devices include nickel—metal hydride cells and lithium-ion cells. Both are potentially useful for utility storage. A high-temperature battery, the sodium sulphur battery, has also been popular for utility applications.

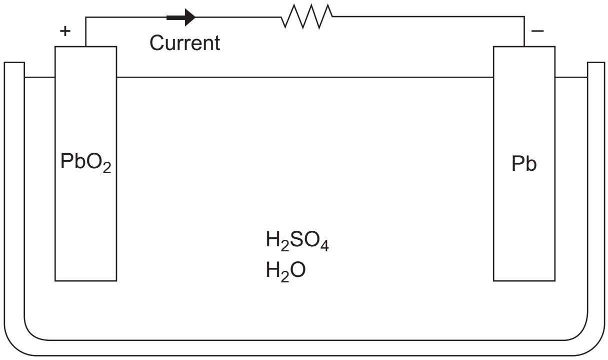

FIGURE 10.3 A schematic of a lead-acid battery.

In addition to these conventional secondary cells, a variety of flow cells or flow batteries have also been tested for large-scale energy storage applications. These including zinc bromide, vanadium redox and polysuphide−bromide flow cells. None has so far found widespread commercial application but new types are being developed. They are considered attractive because they have much longer lifetimes than conventional secondary batteries.

Traditional electrochemical storage systems boast a best case cycle conversion efficiency (electricity to cell storage and back into electricity) of 90% but a more typical figure would be 70%. Most batteries also suffer from leakage of power over time. Left for too long, the cell discharges itself. This means that battery systems can only be used for a relatively short-term storage. Flow cells do not suffer from this problem because the reactants are not stored together, and this helps reduce long-term energy losses.

An additional problem with traditional secondary batteries is their tendency to age. After a certain number of cycles, the cell stops holding its charge effectively, or the amount of charge it can hold declines. Much development work has been aimed at extending the lifetime of electrochemical cells but this remains a problem. Again flow cells, because of their design, can avoid this problem.

Against this, batteries are able to supply their output extremely quickly, in less than 5 ms for a conventional battery and less than 100 ms for a flow battery. Some are also capable of very high-power outputs and discharge rates.

Lead-Acid Batteries

Lead-acid batteries were among the first secondary cells to be developed and were used for load levelling in very early power distribution systems. The cell is based on a reaction between lead oxide and sulphuric acid.

Efficiencies of lead-acid batteries vary depending on factors such as the temperature and the duty cycle but are typically between 75% and 85% for DC–DC cycling. However, cells discharge themselves over time, so they cannot be used for very long-term power storage. If cycled carefully, cells for utility applications can have lifetimes of 15–30 years.

The cells have a water-based liquid electrolyte and operate at ambient temperature. Both high and low temperatures can reduce their performance. They are also relatively heavy and have a poor energy density although neither of these factors are a handicap for stationary applications. In addition, they are cheap and easily recycled.

Several very large-energy storage facilities based on lead-acid batteries have been built. These include an 8.5 MW unit constructed in West Berlin in 1986, while the city was still divided into East and West and a 20 MW unit built in Puerto Rico in 1994. Although the former operated successfully for several years, cell degradation led to the latter closing after only 5 years. Lead-acid cells have been very popular for renewable applications such as small wind or solar installations where they are used to store intermittently generated power to make it continuously available.

Nickel–Cadmium Batteries

The nickel–cadmium battery is one of the families of nickel batteries that include nickel–metal hydride, nickel–iron and nickel–zinc batteries. There is also a nickel hydrogen battery in which one cell reactant is gaseous hydrogen. All have a nickel electrode coated with a reactive and spongy nickel hydroxide, while the cell electrolyte is almost always potassium hydroxide. Cell reactions vary depending on the second component.

The only nickel-based cell that has been exploited for utility applications is the nickel–cadmium cell. Nickel–cadmium batteries have higher energy densities and are lighter than lead-acid batteries. They also operate better at low temperatures. However, they tend to be more expensive. This type of battery was used widely in portable computers and phones but has now been superseded by lithium-ion batteries.

Efficiencies of nickel–cadmium cells are typically around 70% although some have claimed up to 85%. Lifetime of the batteries tends to be rated at around 10–15 years although some have lasted longer. These cells discharge themselves more rapidly than lead-acid cells and can lose 5% of their charge in a month. There can also be a problem with disposal because cadmium is highly toxic.

The largest nickel–cadmium battery ever built is a 40 MW unit in Alaska which was completed in 2003. It occupies a building the size of a football field and comprises 13,760 individual cells.

Lithium Batteries

Lithium batteries including both lithium-hydride and lithium-ion batteries have become popular for consumer electronic devices because of their low weight, high-energy density and relatively long lifetime. Lithium is extremely reactive and can burst into flames if exposed to water. However modern lithium cells use lithium bound chemically so that it cannot react easily. As with nickel, there are a number of lithium cell variants but the most popular today is the lithium-ion cell. These are designed so that there is no free lithium present at any stage during the charging or discharging cycle.

The use of lithium batteries in grid and utility applications is beginning to grow with units being tested in a number of locations. An early large pilot battery storage installation rated at 2 MW was commissioned on the Orkney Islands, which are located off the coast of north-western Scotland, in 2013. This was topped in 2017 when the US utility San Diego Gas and Electric opened a 30 MW battery storage facility based on lithium-ion batteries with 120 MWh of storage capacity. A 20 MW facility is also being planned by the utility Southern California Edison. The future development of lithium batteries may benefit from interest by automotive manufacturers in their use in hybrid and electric vehicles.

Sodium Sulphur Batteries

The sodium sulphur battery is a high-temperature battery. It operates at 300°C and utilises a solid electrolyte, making it unique among the common secondary cells. One electrode is molten sodium and the other molten sulphur, and it is the reaction between these two that is the basis for the cell reaction. The cross section of a sodium sulphur battery is shown in Figure 10.4. Although the reactants, and particularly sodium, can behave explosively, modern cells are generally reliable. However, a fire was reported in 2012 at a sodium sulphur battery installation in Japan.

Early work on the sodium sulphur battery took place at the Ford Motor Co in the 1960s, but modern sodium sulphur technology was developed in Japan by the Tokyo Electric Power Co, in collaboration with NGK insulators, and it is these two companies that have commercialised the technology. Typical units have a rated power output of 50 kW and 400 kWh. Lifetime is claimed to be 15 years or 4500 cycles, and the efficiency is around 85%. Sodium sulphur batteries have one of the fastest response times, with a claimed start-up speed of 1 ms.

Flow Batteries

A flowing electrolyte battery, or a flow battery, is a cross between a conventional battery and a fuel cell. It has electrodes like a conventional battery where

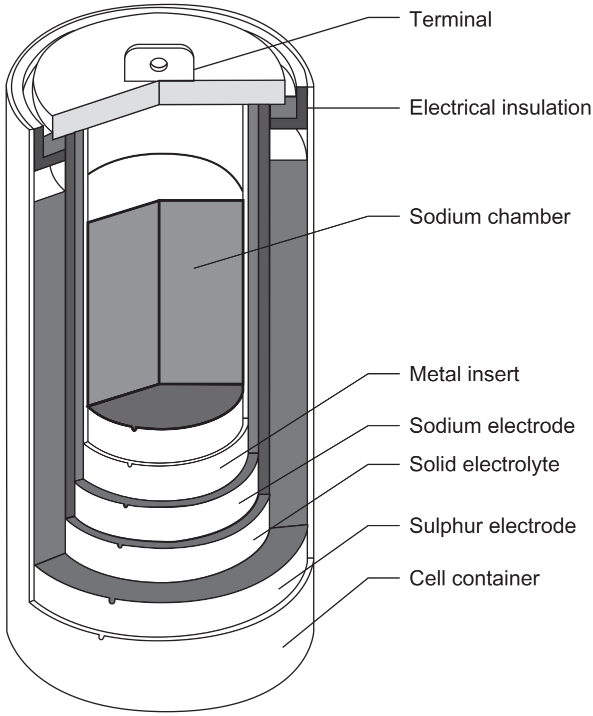

FIGURE 10.4 Sodium sulphur battery. *NASA*.

the electrochemical reaction responsible for electricity generation or storage takes place and an electrolyte. However, the chemical reactants responsible for the electrochemical reaction and the product of that reaction are stored in tanks separate from the cell and pumped to and from the electrodes as required much like a fuel cell. The processes occurring here are usually somewhat different to the simple electrochemical process described above but the principle is similar. A schematic of a typical flow battery is shown in Figure 10.5.

Several flow batteries have been tested including the zinc-bromide flow battery, the polysulphide—bromide battery and the vanadium redox battery. Several newer designs are also in the research stage. Response times for flow batteries are longer than for conventional secondary batteries but they should be able to supply full power within 100 ms. However, flow batteries have not been extensively tested commercially; therefore, their overall performance has yet to be established.

Costs

The costs of battery systems vary widely depending on type and size. Large batteries are generally cheaper than similar small installations. Battery costs

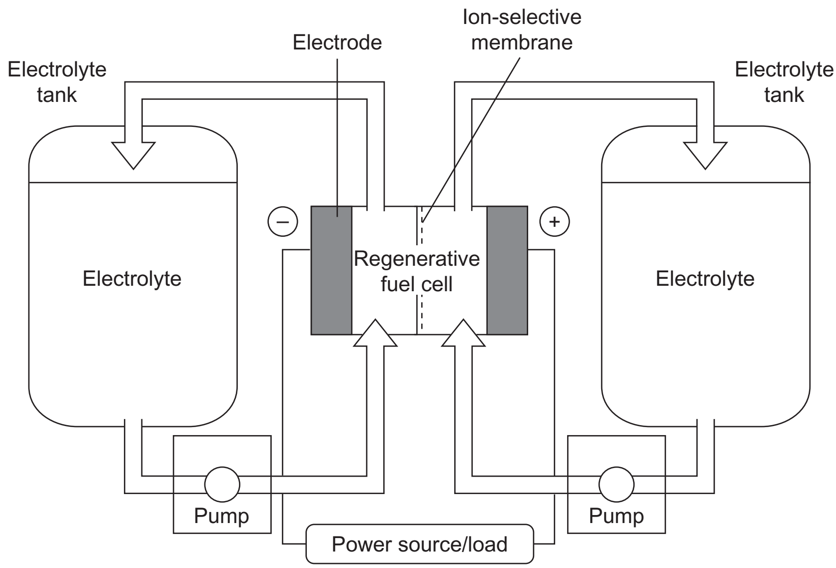

FIGURE 10.5 Diagram of a flow battery.

are normally based on the cost per kilowatt-hour rather than the cost per kilowatt. The cheapest of the conventional cells is the sodium sulphur with a cost in the range \$250/kWh–\$900/kWh. Lithium-ion batteries have costs of between \$400/kWh and \$1100/kWh. Lead-acid battery costs are in the range \$500/kWh–\$1200/kWh. Flow batteries are potentially cheaper with typical costs in the range \$400/kWh–\$1000/kWh depending upon the type.

SUPERCONDUCTING MAGNETIC ENERGY STORAGE

Superconductivity offers, in principle, the ideal way of storing electric power. The storage system comprises a coil of superconducting material which is kept extremely cold. Off-peak electricity is converted to DC and fed into the storage ring, and there it stays, ready to be retrieved as required. Provided the system is kept below a certain temperature, electricity stored in the ring will remain there indefinitely without loss. A schematic of a superconducting storage system is shown in Figure 10.6.

The key to the SMES device is a class of materials called superconductors. Superconductors undergo a fundamental change in their physical properties below a certain temperature called the transition temperature which is a characteristic of each material. When a material is cooled below its transition temperature, it becomes superconducting. In this state, it has zero electrical resistance. This means that it will conduct current with zero energy loss.

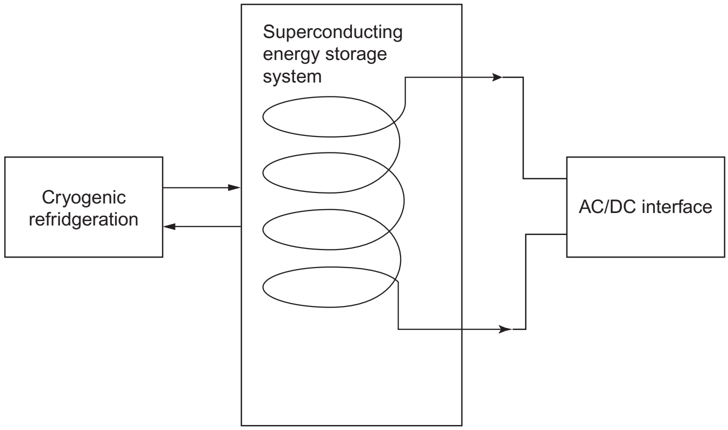

FIGURE 10.6 Schematic of a grid-connected SMES system.

Unfortunately, the best superconducting materials are metallic alloys that only undergo this transition at below 20°K (−253°C). Such low temperature must be maintained by cooling the superconducting coil with liquid hydrogen or liquid helium, in either case an expensive process. In recent years scientists have discovered a new range of ceramic materials that become superconducting at relatively high temperatures, temperatures accessible by cooling with liquid nitrogen. (Liquid nitrogen boils at 98K, −175°C.) Most of these materials have proved to be rather brittle ceramics which are difficult to work but techniques are being found to exploit them. This is helping make superconductivity more economically attractive for a range of utility applications including storage.

Superconductors store DC current without loss but energy losses occur during the conversion of grid AC to DC and then from DC back to AC. The round-trip efficiency is typically 90% for daily cycling but will be lower for long-term storage because of the energy required to maintain the coil at below its transition temperature. There are also small continuous losses within the coil at the point where power is fed in and out. Start-up time for an SMES system is around 5 ms.

When SMES devices were first proposed, they were conceived as massive energy storage rings of up to 1000 MW, similar in capacity to pumped-storage hydropower plants. No such storage ring has ever been built but smaller SMES devices are being used for grid support roles and this appears to be the main commercial market.

Current technology will allow small commercial SMES storage units with capacities of between 100 kW and 100 MW to be constructed; the largest built unit to date can deliver 10 MW. The storage capacity of these commercial devices is between 10 and 30 kWh, relatively low for utility storage but useful for very fast grid support functions.

One of the earliest SMES devices to be used commercially was commissioned by the US Bonneville Power Administration in the 1980s. This unit had a storage capacity of 30 MJ and a power rating of 10 MW. The device could release 10 MJ of energy in one-third of a second to damp power swings on the Pacific Intertie. Today a typical commercial unit has a storage capacity of 3 MJ (0.83 kWh) and can deliver 3 MW of power for 1 second.

Superconducting Magnetic Energy Storage Costs

Although a few commercial SMES devices are available, costs have been difficult to establish. In general the cost is relatively low per unit size (MW) but high in terms of storage capacity (MWh). For short-term grid stability duty, they appear to be competitive with other types of storage such as batteries, flywheels and capacitors.

FLYWHEELS

A flywheel is a simple mechanical energy storage device comprising a large wheel on an axle fitted with frictionless bearings. The flywheel stores kinetic energy as a result of its rotation. The faster it rotates, the more energy it stores. Provided there is a means to extract this energy again, the system can be used for a variety of applications.

Traditional flywheel-based systems have been in use as mechanical energy storage devices for thousands of years. Millstones, potters wheels and handlooms have all used them to both store energy and to smooth out the peaks in energy delivery by hand or foot. Simple flywheel energy storage devices are also fitted to all piston engines to maintain smooth engine motion. The engine flywheel is attached physically to the engine camshaft and as the pistons cause the camshaft to rotate they feed energy into the flywheel. For electricity storage applications, energy will normally be fed into the flywheel using a reversible motor generator.

The Flywheel Principle

A flywheel depends on a rotating mass to store energy which is then held in the kinetic energy of rotation of the rotor. The stored energy is proportional to the moment of inertia of the rotor about its axis (directly related to its mass) and its rotational speed.

Conventional flywheels such as those used for piston engines are fabricated from heavy metal discs made of iron or steel. However, these discs are only capable of rotating at low speeds. For power applications, new lighter composite materials have been developed, capable of rotating at 10,000−100,000 rpm without fracturing under the immense centrifugal force they experience. These are made from carbon fibre or glass fibre composite

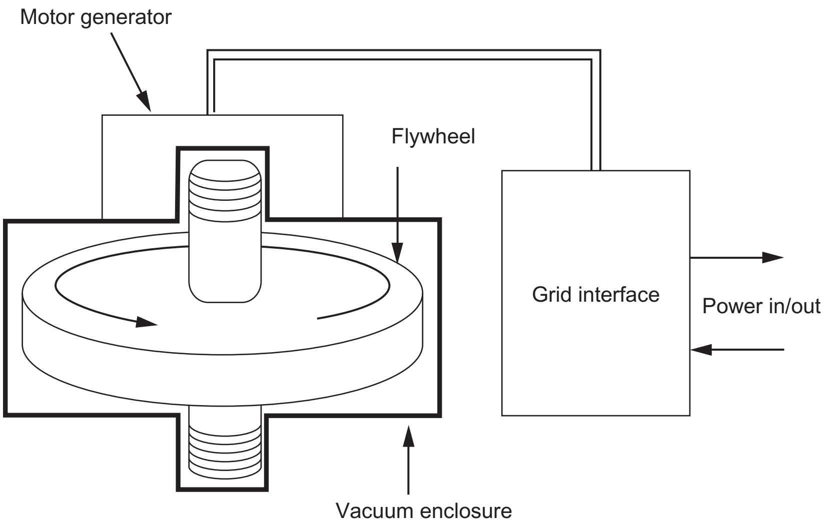

FIGURE 10.7 A Flywheel energy storage system.

materials which, although less dense than the metals they replace, can store more energy at the very high rotational speeds at which they operate. A schematic of a flywheel energy storage system is shown in Figure 10.7.

Friction losses can be significant at high rotational speeds and energy storage flywheels generally use magnetic bearings to minimise such losses. These are normally supplemented by conventional bearings in case the magnetic bearing fails. Friction losses from air drag can also be significant at the speeds at which modern flywheels rotate so the flywheel will be housed in a vacuum chamber, evacuated to reduce this source of loss as well. The whole device must be enclosed within an exceedingly strong container which will prevent the pieces of the flywheel scattering like shrapnel in the event of a catastrophic failure.

Energy is fed into a flywheel using a motor to rotate it up to its maximum speed. Energy is extracted from the rotor through a generator driven by the flywheel shaft. Extracting energy from the flywheel will lead to its rotational speed lowering. This makes direct grid synchronisation with the rotational frequency of the flywheel impossible so most flywheels use electronic AC−DC−AC converters to eliminate this problem and permit variable speed operation. Flywheels are generally maintenance-free.

Flywheel Performance Characteristics

For a flywheel to operate effectively as an electrical energy storage system, it must be kept rotating at its full operating speed. This requires continuous energy feed to compensate for friction losses. Round-trip efficiency estimates vary with some manufacturers claiming up to 90%. Other sources such as the US DOE suggest that 70%–80% is more typical.

The energy stored in a flywheel is a function of the mass of its rotor. The larger the rotor, the more it can hold. However, the power it can deliver will depend on the size of the generator used for energy extraction. Most flywheels are designed for backup power or grid support functions during which they are expected to deliver high power for a short period of perhaps a few seconds at most. Such units can have small rotors but relatively large power extraction systems. Other flywheels have been designed for long-term energy delivery. These will have rotors that are capable of storing a large amount of energy compared to the size of the energy extraction system.

Flywheels can usually respond extremely quickly. In grid backup systems they should be capable of reaching full power within half a cycle (25 ms at 50 Hz), and some are quoted with response times of 5 ms. Such units will probably be able to supply their full output for between 5 and 15 seconds.

Commercial flywheels are available with power ratings of between 2 kW and 2 MW and with storage capacities of between 1 and 100 kWh. One of the largest commercial systems is a unit with ten 100 kW flywheels used by the New York Transit System to support its electric traction power network. This system can supply 1 MW of power for 6 seconds. However, the largest flywheel is the one used in Japan for fusion research. This system can supply 340 MW for 30 seconds.

Costs

The commercial cost of a flywheel system is likely to be around $2000/kW although costs have been put as low as $500/kW. The cost per unit of stored energy is around $500/kWh–$1000/kWh for commercial flywheel systems depending on the size. This puts the cost broadly equivalent to that of a battery storage system. However, the application of a flywheel storage system is likely to be different from that of a battery.

CAPACITORS

Capacitors are electrical or electronic devices that store energy in the form of electrostatic charge. The simplest capacitor comprises two metal plates separated by a small air gap so that no DC current can pass between them. When a voltage is applied across it, the plates become statically charged and this charge can later be released by creating a short circuit between the plates.

Capacitors of various sorts are key components of electrical and electronic circuity, particularly when creating tuned circuits. While blocking DC current, they will allow an AC current to pass with an amplitude that is inversely proportional to the frequency. However, conventional capacitors are capable of storing only a limited quantity of electrical energy. Since the end of the 1970s a new type of capacitor has been available, called an electrochemical capacitor, and these can store much larger quantities of energy. The modern versions of these capacitors, developed for energy storage applications, have names like supercapacitors or ultracapacitors. They are based on electrochemical processes that are similar to those found in batteries.

Energy Storage Capacitor Principles

A simple electrostatic capacitor comprises two plates with an air gap between them. When a voltage is applied to the plates, charge builds up on them to neutralise the voltage by creating an equal and opposite static charge voltage across the plates. The charge will continue to build as the voltage is increased until it is high enough to cause air to breakdown and start conducting electricity.

The amount of charge the capacitor will hold can be increased by placing a dielectric material between the plates. This contains polar molecules that are usually randomly oriented but when they are subject to the electric field between the plates they orient in such a way as to reduce the electric field in the space. This allows more charge to build up on the plates for a similar field strength, increasing the capacitance of the device. An electrochemical capacitor is similar to this in that it has a dielectric material between the capacitor plates but in this case the dielectric is a liquid electrolyte such as sulphuric acid or potassium hydroxide which can support a much higher build-up of charge. The capacitor plates themselves are inert materials which will not react with these reagents. The supercapacitor principle is shown schematically in Figure 10.8.

When a charge is applied to the capacitor, it causes the usual charge build-up. However, in this case, the charge on each plate is neutralised by an

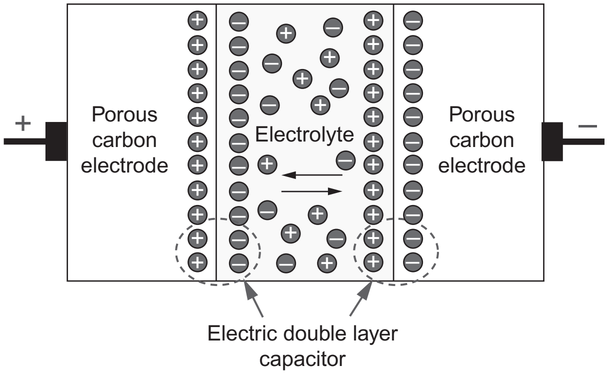

FIGURE 10.8 Schematic of a supercapacitor.

opposing layer of charged ions from the electrolyte. This creates a double layer of charge at each plate, effectively leading to two capacitive charged layers which massively increases the amount of charge the unit can hold.

The simplest electrochemical capacitors use a water-based electrolyte, and this restricts the voltage that each can support to around 0.9 V before electrolysis of the water begins. This limits the amount of charge the capacitor can hold but otherwise these capacitors have excellent characteristics. Basic capacitors of this type (known as symmetrical capacitors) have two identical electrodes made from carbon. By varying the construction of one electrode, it is possible to increase the amount of energy the device can hold. Devices of this type are called asymmetrical capacitors. A second type of electrochemical capacitor uses an organic electrolyte, and this allows it to support a voltage of up to 2.7 V. Both symmetrical and asymmetrical versions of these capacitors are also available. Because single capacitors of either type can only support a relatively low voltage (in grid terms), electrochemical capacitors are usually stacked in series to allow higher voltages to be exploited.

Performance Characteristics

Electrochemical capacitors can be cycled for tens of thousands of times without degradation, provided the voltage across them is kept below the maximum so that no internal reaction takes place. However, once they are charged they do lose charge slowly through leakage in the same way as a battery. The leakage levels in water-based electrochemical cells are similar to that of a lead-acid battery. Leakage levels are lower with organic-based electrolytes.

Leakage will reduce long-term storage. However, with fast cycling, round-trip efficiency can be 95% or higher. In addition, capacitors can normally discharge their energy very rapidly without damage so long as excessive internal heating is avoided. Energy density is moderate at between 1 and 5 Wh/kg for symmetrical capacitors and up to 20 Wh/kg for asymmetrical capacitors. In comparison a lead-acid battery has an energy density of up to 42 Wh/kg. Response time is fast at 5 ms.

Units can be designed with the capability to deliver power levels of between 1 kW and 5 MW, but actual energy storage capacity is generally relatively low at between 1 and 10 kWh. When power is withdrawn from a capacitor the voltage falls so sophisticated DC−AC conversion systems are needed to maintain a constant voltage output.

Applications

Electrochemical capacitors have been used both for energy storage and for braking energy recovery systems in automotive applications. For grid use, they are best suited to backup or fast reaction grid support, offering a similar performance to flywheels. Although capacitors are not yet widely deployed for grid support, they have been tested in a number of configurations. These include adding rapid response storage to small distributed generation grids or microgrids where they can provide fast reacting grid support when the output from intermittent renewable resources suddenly falls and before a backup engine-based system can take over. Capacitors are also being tested for high-voltage grid support services.

Costs

The cost of capacitor storage is likely to be similar to that for flywheels at around $2000/kW. Based on the cost per unit of energy storage, the price is again expected to be similar to that of flywheels with costs of around $500–1000/kWh. However, some manufacturers have claimed that they can produce devices for as little as $100/kWh. Such a low price is likely to depend on high volumes, perhaps for use in the automotive industry where they might replace batteries.

HYDROGEN ENERGY STORAGE

Hydrogen offers a potential energy storage medium because of its versatility. The gas can be produced by electrolysis of water, making it easy to integrate with electricity generation. Once made, the hydrogen can be burned in thermal power plants to generate electricity again or it can be used as the energy source for fuel cells. In both cases the only combustion product is water. Potentially it may also be used as an automotive replacement for petroleum or natural gas. Finally, hydrogen has a high-energy density making it an efficient means of storing energy.

For all these reasons hydrogen has been seen as a potential fossil fuel replacement in a future energy economy. For this to become feasible, several problems must be overcome including improving efficiency of its production and finding an economical means of storing it for automotive applications. In the meantime the limited use of hydrogen as an energy storage medium for intermittent renewable sources such as wind energy is being explored. A schematic of a hydrogen energy storage system designed to store power from wind and solar power plants is shown in Figure 10.9.

Hydrogen Energy Essentials

Hydrogen, as a fuel, can be generated by the electrolysis of water using an electrical voltage. This has been carried out industrially for many years with the main system being an alkaline electrolyser, exploited most successfully the Norwegian utility Norsk Hydro. Large-scale electrolysers have been built

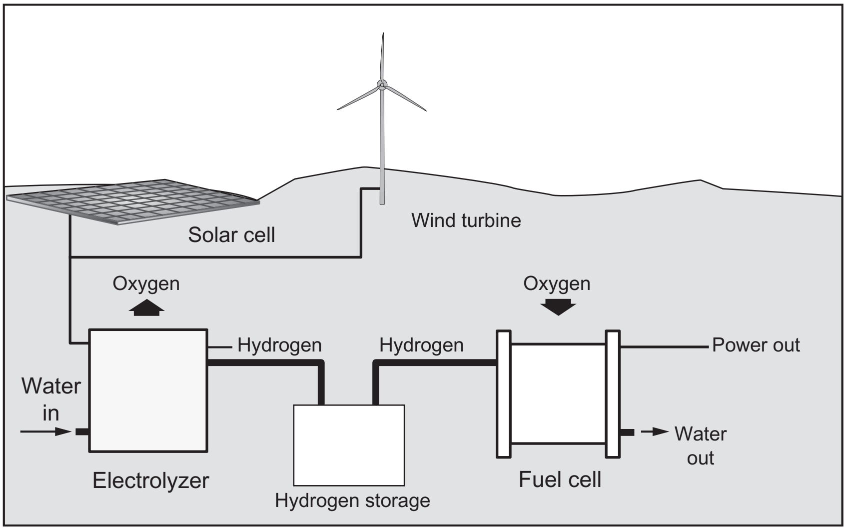

FIGURE 10.9 Schematic of a renewable energy, hydrogen energy storage system.

that are capable of handling inputs of 100 MW for hydrogen generation and the product is around 99.8% pure. Conversion efficiency is 90%. Alternatives to the alkaline electrolyser are proton exchange membrane electrolysers which are currently being developed and could potentially achieve 94% efficiency, but with the need for a platinum catalyst. High-temperature ceramic electrolysers are also under development.

Once produced, hydrogen must be stored. Although the gas has a high mass-energy density, it is very light and has a low volume-energy density so it must be compressed or stored in a concentrated state. For power generation applications, storage under pressure in steel or composite tanks is probably the favoured method. The gas can be liquefied but only by using cryogenic equipment, making the process costly. There have also been attempts to store hydrogen in the solid state within certain alloys that will absorb it in large quantities. This may eventually offer the best storage method for automotive applications although the weight of the storage system is currently a major problem.

Once manufactured and stored, hydrogen can be converted back into electricity in a number of ways. It can be burned like natural gas, although the combustion temperature is generally higher than for the former. However, most gas turbines, piston engines and gas-fired boilers can easily be adapted for its use. When burnt in this way, it produces only water as a by-product. Alternatively, and possibly most efficiently, hydrogen can provide the fuel for a fuel cell system. For a future energy economy based on hydrogen, this offers one of the most promising solutions with 60% efficiency achievable in a simple fuel cell and perhaps 70%−75% with a hybrid system.

Performance Characteristics

When used as an energy storage medium within an electricity system, hydrogen will generally be burned today in a conventional power plant which cannot be brought into service as rapidly as some of the fast-acting storage systems discussed earlier. It should therefore be considered as a system for energy arbitrage – storing off-peak or surplus renewable power which is then returned to the grid as demand rises or renewable output falls – rather than for grid support.

The main drawback today of hydrogen storage is the round-trip efficiency. With an electrolyser operating at 90% efficiency and a power plant converting it back into electricity with perhaps 60% efficiency, the best round-trip efficiency that can be expected is 54%, much lower than other storage systems discussed earlier. Such low efficiency may be tolerable in a renewable energy storage system such as a wind–hydrogen storage unit where the wind energy must otherwise be shed. It is unlikely to be considered sufficiently efficient for generation from off-peak grid power in most other circumstances if there is an alternative available.

Costs

Because hydrogen energy storage as an electrical energy storage medium has yet to be tested, there are no realistic costs available for practical systems. If it is to be of use, it would need to be able to compete with the high-storage capacity technologies such as pumped-storage hydropower, CAES of large battery storage.