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Electricity Storage

*Making Large-Scale Adoption of Wind and Solar Energies
a Reality*

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Electricity Storage

Making Large-Scale Adoption of Wind and Solar Energies a Reality

The growth case for using renewable energy remains very much intact—the effects of a global economic downturn notwithstanding—and the prospects for wind and solar photovoltaic (PV) power appear particularly strong. To realize that potential, however, these technologies will have to overcome a key hurdle: the challenge posed by their intermittent nature. Unlike other forms of renewable energy—such as hydropower and geothermal energy—the energy generated by wind and solar PV fluctuates. This fluctuation poses a sizable challenge to their integration into the power grid—and their widespread adoption as bona fide mainstream power sources.¹

While there are several potential answers to the challenges of intermittency, the most viable, we believe, is a credible form of electricity storage. Yet there is little on the immediate horizon to suggest that a storage solution is imminent. Unless and until that vital enabler exists and is practical, fluctuating renewables will struggle to become key players in the global push toward carbon dioxide-free energy sources.

In this paper, which is based on extensive research and more than 30 interviews that BCG conducted with industry experts in late 2009, we look at the current state of play in electricity storage. (Although we take a global perspective, we focus particularly closely on Europe, which will be the first region to experience large-scale storage challenges.) We examine why the need for storage will only grow; what the key technologies are, where they are developmentally, and what their prospects are for adoption; and what the potential alternatives to storage are, and why none is sufficient on its own. We also discuss implications for stakeholders. Among our key findings:

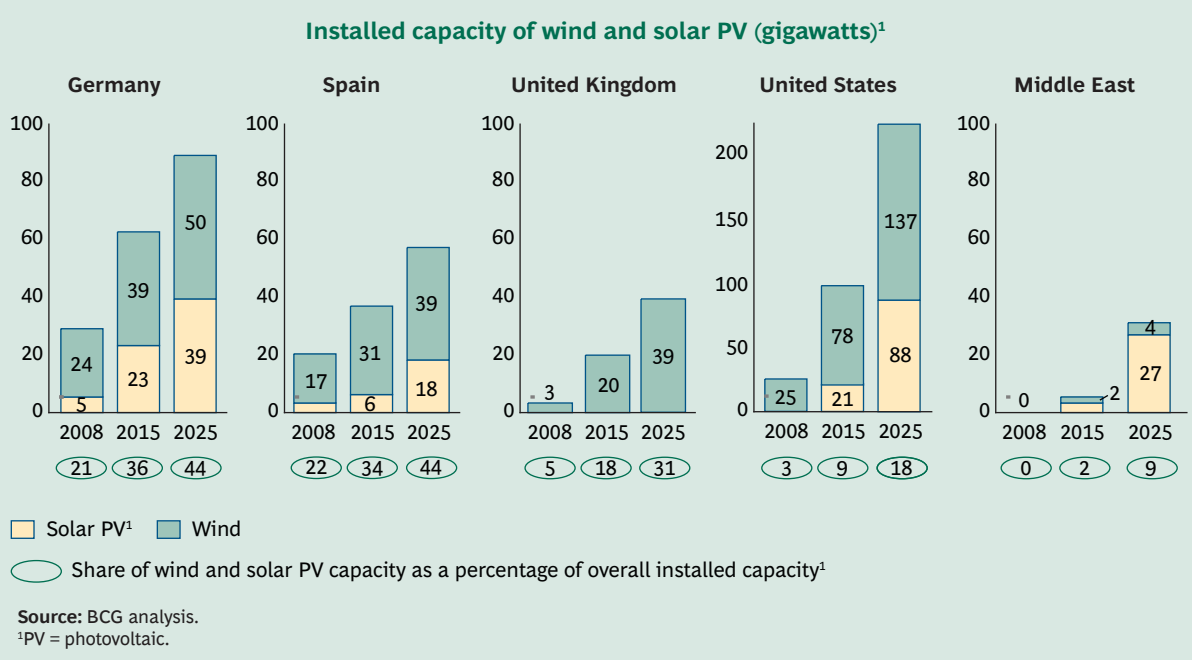
- ◇ Electricity storage will be essential for successful, critical-mass adoption of fluctuating renewables. Although alternative solutions such as interregional compensation, demand-side management, and conventional backup power exist and will continue to play important roles, the extent and degree of fluctuation resulting from increased deployment of fluctuating renewables will demand the use of storage technologies.
- ◇ Because the financial logic for investing aggressively to advance storage technologies is currently not compelling, incentives will be necessary to ensure that sufficient storage capacity is online in time to meet governments' green-energy targets.
- ◇ Players that actively participate in shaping the technological, political, and market frameworks that determine the future use of storage technologies stand to gain a clear competitive edge, since technologies will be chosen and established, policies will be negotiated and deployed, and R&D partnerships and customer relationships will be established and strengthened in the coming years.

The Growth of Wind and Solar PV Energies Means a Growing Need for Compensating Capacity

The need for compensating capacity will rise in lockstep with the growth in demand for fluctuating renewables. And the demand for that power, gauged by the growth of installed capacity, stands to rise strongly in several global regions through 2025, reflecting governments' intensifying efforts to move away from fossil-based fuels. (See Exhibit 1.)

1. We refer to wind and solar PV as “fluctuating renewables” throughout this paper. Furthermore, we use the term to refer to the electricity generated from fluctuating renewables. We also distinguish between solar PV and concentrated solar power (CSP), the other main solar technology. In many cases, CSP has an internal-storage capability to compensate for fluctuations. Thus, it already feeds a “flattened” power curve into the grid and does *not* typically require external grid storage. Hence, in this paper, we confine our discussion of solar energy to solar PV.

Exhibit 1. Growth in Demand for Wind and Solar PV Energies Will Likely Be Strong Across All Major Regions Through 2025



On balance, the greater the share of fluctuating renewables in a given energy-generation region, the greater the fluctuations produced. Hence, the greater the need for compensating capacity. (See the sidebar “The Transition to Greater Penetration of Fluctuating Renewables—and the Near-Term Impact on Energy Generation.”) But the degree of fluctuation will also be influenced by the mix of wind and solar PV energies within a particular system: fluctuations in one source can be partially offset by fluctuations in the other.

In Exhibit 2, we show demand projections for compensation capacity resulting from rising penetration of fluctuating renewables in Germany, Spain, and the United Kingdom for four reference years. As noted, Europe will be the first region to experience problems related to fluctuating renewables, so we have focused on Europe for quantification of the challenge. In principle, however, our findings will hold true for other regions as well.

Our estimates are based on what we consider realistic assumptions regarding compensation demands imposed by both predictable (that is, day-night and seasonal) and unpredictable (that is, driven by medium-term weather conditions and forecast errors) variability in fluctuating renewables. In 2025, as much as 28 gigawatts of compensating capacity will be required in Germany to provide up to 40 terawatt-hours of compensation energy. Spain and the United Kingdom will have similar requirements. By contrast, current storage capacities stand at about 7 gigawatts in Germany and 5 and 4 gigawatts in Spain and the United Kingdom, respectively. Almost all of this existing storage is in the form of pumped hydroelectric storage facilities.

Collectively, European countries will need about 100 gigawatts of compensating capacity. This corresponds to a total installed generation capacity in 2025 of approximately 1,000 gigawatts, roughly 350 gigawatts of which will come from renewable sources.² The facilities will need to be capable of providing roughly 150 terawatt-hours or more of compensation energy, corresponding to more than 5 percent of the annual demand for electricity.

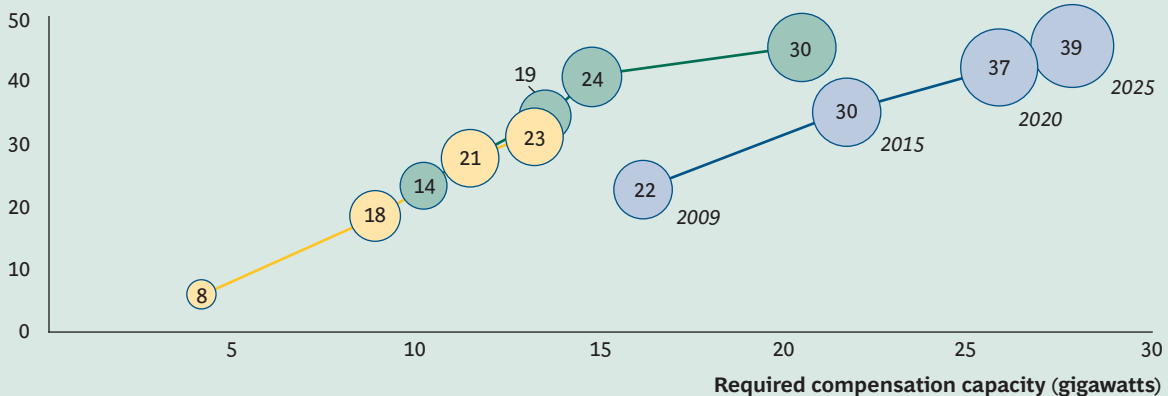
The United States, which has lower penetration of fluctuating renewables but a larger installed capacity in absolute terms, will need up to 170 gigawatts of compensating capacity by 2025, considerably more than

2. Eurostat.

Exhibit 2. The Need for Compensating Capacity Will Rise Sharply in Germany, Spain, and the United Kingdom Through 2025

Estimated need for compensation in actual terms

Installed capacity of fluctuating renewables as a percentage of total installed capacity



Legend: Germany (blue circle), Spain (teal circle), United Kingdom (yellow circle).
 terawatt-hours of energy required

Source: BCG analysis.

Note: A typical load curve from 2008 through 2009 was used to calculate required compensation capacity (output power). Potential changes in demand were not considered, assuming that—although absolute values may increase or decrease—the characteristic patterns of the load curve are likely to remain rather stable over time for the focus countries.

the roughly 25 gigawatts it has today. This corresponds to a forecast generation capacity of about 1,100 gigawatts in 2025, with renewable sources accounting for roughly 250 gigawatts.³ Given the current difficulty the United States has maintaining grid stability, the timely availability of adequate compensating capacity will be critical for a successful buildup of fluctuating renewables' capacity there.

Insufficient ability to compensate for fluctuations is not a far-into-the-future scenario. Already today, there are periods in which feed-in from renewables is higher than off-peak electricity demand in some regions, especially in countries where renewables represent a high share of overall generation capacity—for example, Denmark and Germany. In such periods, there is very high volatility in electricity prices. Furthermore, wholesale prices frequently turn negative, as happened several times in Germany in 2009, with record negative prices as low as –€500 per megawatt-hour despite a powerful grid infrastructure capable of shifting large amounts of energy across Europe. And this is only the beginning of the impact of increasing fluctuations from renewables on the power grid.

The upshot of the above: strongly rising demand for fluctuating renewables will necessitate a significant ramping-up of compensating capacity in the years ahead. Next, we explore the four broad approaches to providing that capacity.

Four Approaches to Compensation

There are four methods of compensating for variability in electricity generation from fluctuating renewables—interregional compensation (often referred to as grid extension), conventional backup capacity, demand-side management, and large-scale electricity storage. Each has its strengths and limitations.

Interregional Compensation (Grid Extension)

Interregional compensation, often referred to as grid extension (though, technically, grid extension is a means of achieving interregional compensation), involves linking electricity grids from different regions (each with its own generation and demand profile) and transferring power from one to the other to

3. U.S. Energy Information Administration.

The Transition to Greater Penetration of Fluctuating Renewables—and the Near-Term Impact on Energy Generation

The road to an energy landscape dominated by fluctuating renewables will not be without its challenges. The biggest challenge will be to compensate for the fluctuations that characterize electricity generation from these technologies. It should also be noted that as wind and solar photovoltaic technologies continue to evolve—wind being increasingly deployed offshore and centralized, solar PV being increasingly deployed on rooftops and distributed—they will pose very different challenges in terms of compensation, with significant implications for the underlying transmission and distribution grids.

Four types of fluctuations can be distinguished. (See the exhibit below.) Day-night fluctuations are specific to solar PV, while both wind and solar PV display distinct seasonal and annual patterns, depending on region. For instance, in Europe, there is more wind in winter and more sun in summer, so overall fluctuations are somewhat lower than elsewhere. Both types of fluctuations are cyclical and predictable, and they even coincide with load patterns to some extent. But fluctuations due to short- and medium-term changes in weather (stormy versus calm, sunny versus cloudy) are much more erratic and, hence, difficult to forecast. This is why the so-called forecast error continues to pose a challenge for generation dispatchers.

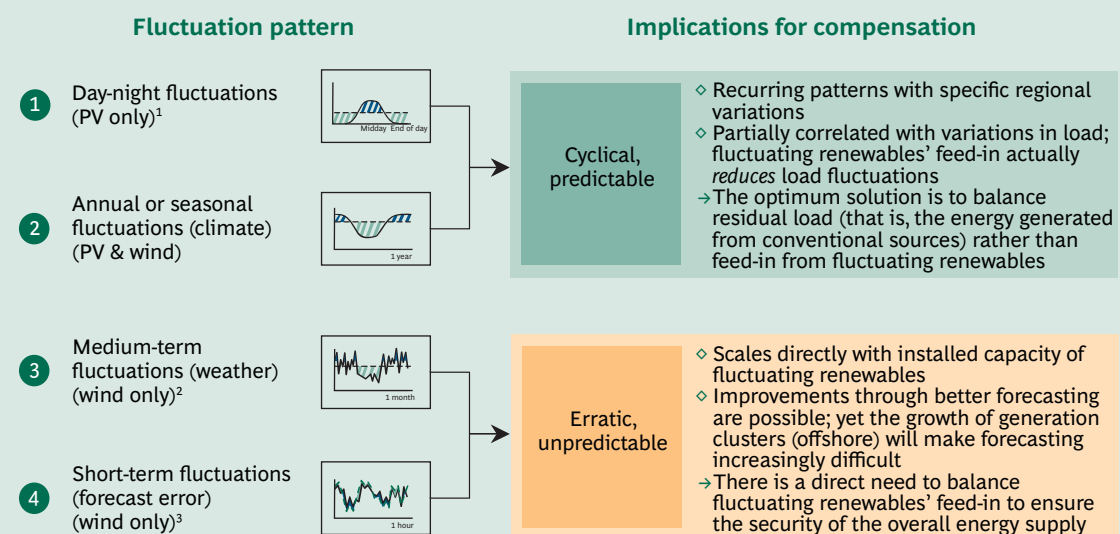
As a result of these fluctuations and the compensation challenges they pose, the growth of renewables will have severe impact on existing generation systems. In countries with constant or even declining demand for energy (for example, most industrialized nations), as capacity for fluctuating renewables grows, the same amount of energy will be generated by a significantly larger fleet of power plants.

Since power from renewable sources will receive feed-in priority, the utilization of conventional power plants will decrease.¹ Hence the residual capacity that can be dispatched across the remainder of the fleet will be low, especially in high-wind, low-load periods. It will always be necessary to operate a number of must-run conventional plants to ensure a supply of reserve capacity so that the remaining conventional plants can operate only very intermittently. But it is these must-run power plants that need to be able to provide flexibility to buffer variations in output from fluctuating renewables.

This will have a threefold negative effect on existing power-generation systems:

1. This is so except in currently rare extreme cases when grid stability is threatened and feed-in from renewable sources can be throttled.

Fluctuations from Wind and Solar PV Have Very Different Characteristics—with Different Implications for Compensation



Source: BCG analysis.

¹Not relevant for wind except for localized phenomena, which were not considered; PV = photovoltaic.

²When the study was conducted, no feed-in data for PV were available.

³Relates to 24-hour forecasts for wind energy. When the study was conducted, no forecast or feed-in data for PV were available.

The Transition to Greater Penetration of Fluctuating Renewables—and the Near-Term Impact on Energy Generation (continued)

- ◇ Reduced utilization rates will translate into a higher LCOE, or levelized cost of energy, because of the greater weight of fixed costs per generated megawatt-hour. This will become more acute as the share of fluctuating renewables continues to rise.
- ◇ To provide the flexibility required to balance the feed-in of fluctuating renewables, generation systems will have to shift from base-load plants, such as nuclear and lignite plants, that have low variable costs, to more flexible midload and peak-load plants, such as combined-cycle gas turbine (CCGT) and gas turbine (GT) plants, that have higher variable costs.²
- ◇ Adding “priority feed-in” capacity in the form of wind and solar PV will likely have a negative effect

on wholesale power prices and thus on generation margins. This will have a systemic effect, as the “cheaper” power plant will become the marginal one, setting the price for all others. Energy price volatility will also increase substantially.

While it is, therefore, possible that the generation landscape will evolve to a new optimum over time as the penetration of fluctuating renewables grows, during the transition period, excess costs will be incurred, and returns on currently invested capital will be diminished.

2. To some extent, modern hard-coal power plants can also be operated as rather flexible midload units; however, their efficiency rate is lower, and carbon dioxide emissions are higher than those of plants powered by CCGT and GT.

compensate for fluctuations: Grid A in Region X, for example, imports power from Grid B in Region Y when Grid A experiences periods of low wind (or sun) and high demand for power, and exports it when it experiences high wind and low demand, provided the grids’ profiles are complementary.⁴

Grid extension holds promise as a solution to the fluctuation challenge. In Europe, some experts even assume the future presence of a continental “copper plate.”⁵ However, grid extension also has the following significant limitations:

- ◇ It cannot mitigate all types of fluctuations. On a Europe-wide level, for example, it cannot compensate for day-night fluctuations.
- ◇ There are political barriers to implementation. Building new transmission lines entails an often-lengthy approval process and almost always meets heavy public resistance.
- ◇ Weather and climate conditions are relatively similar across large parts of Central Europe. This means that long high-voltage direct-current (HVDC) lines between two distant regions are required, offering only point-to-point links, which still require local tie-ins to the national grids. Alternating current (AC) grid infrastructure at the landing points of HVDC bridges will need to be upgraded as well. Similarly, large-scale grid projects, such as a North Sea supergrid, will require powerful links with the actual load centers inland.
- ◇ There are efficiency losses in transmission. Normal AC high-voltage transmission lines lose up to 15 percent for every 1,000 kilometers traveled; HVDC cables lose about 3 percent.
- ◇ The effectiveness of grid extension will decrease as deployment of fluctuating renewables rises across Europe—and the fluctuation problem becomes commonplace. This is, in our view, the strongest argument against interregional compensation. For Denmark, for example, a small country that already has a relatively high deployment of fluctuating renewables, interregional compensation currently works well. But today’s importers of the country’s excess energy may no longer be interested tomorrow, as they may be battling their own overcapacities.

4. Interregional, or cross-border, compensation is distinct from the challenge of strengthening and eliminating bottlenecks in national grids. But it should be emphasized that stronger national grids are critical to the task of integrating fluctuating renewables.

5. The so-called copper plate refers to the assumption of an unrestricted power network across Europe.

In sum, interregional grid extension will likely make an important contribution toward mitigating the variability in electricity generation induced by fluctuating renewables, and selective links between grids should be instrumental in solving local challenges. But grid extension is not a standalone solution for the long run.

Conventional Backup Power

Conventional backup power, especially when driven by combined-cycle gas turbine (CCGT) and pure-gas plants, is a mature, very flexible technology that could, at least theoretically, provide all the required compensating capacity. Conventional backup power also offers competitive economic parameters when renewables' penetration is still at low levels. Hence, in the coming years, we believe that much of the compensation capacity required to balance the variability in output due to fluctuating renewables will continue to be provided by flexible conventional power plants.

However, as is the case with grid extension, the following factors will limit the construction of new flexible conventional power plants (beyond the mere replacement of outgoing plants).

- ◇ Public and political resistance to dedicating new locations to conventional power plants will likely be strong at the local level. In addition, it will be difficult to argue, from an environmental perspective, that new construction of fossil-fuel-based plants is beneficial and logical, given that the ultimate goal is eventually to achieve CO₂-free electricity generation.
- ◇ Backup capacity (mainly gas-driven capacity) will extend countries' dependence on fossil fuel exporters.
- ◇ The economic risk associated with investing in the construction of new conventional power plants is increasing as a result of three factors: possible increases in CO₂ permit prices, uncertainty regarding fuel prices, and the risk of low utilization.⁶
- ◇ Conventional capacity can compensate for troughs—but not peaks—in fluctuating renewables' production. Hence, inefficient “throttling” of fluctuating renewables' output is still necessary, further reducing the utilization of generation assets (in this case, fluctuating renewables, which in some cases have been heavily subsidized) and driving up overall power-generation costs.

There is also a location-related challenge to consider. Renewable generation will be both centralized (in the cases of offshore wind and large ground-mounted solar PV installations) and decentralized (in the cases of small-scale onshore wind farms and rooftop and small-scale commercial solar PV applications). To minimize further strain on the grid infrastructure, the necessary conventional backup capacity will need to be located close to these respective sources. In particular, conventional backup generation will require a strong decentralized component in regions where small-scale wind and solar PV are present, necessitating sophisticated steering mechanisms.

In light of these considerations, we do not believe conventional backup capacity will be sufficient on its own or sustainable as we move toward a renewables-dominated electricity system in the long term. Still, we believe that conventional backup capacity will be indispensable for achieving the integration of renewable energy sources into the current power system in the coming years.

Demand-Side Management

Demand-side management (DSM) refers to the postponing or advancing of suitable demand elements among industrial and residential customers so as to minimize overall demand during peak periods. Prime candidates for DSM on the industrial side are such energy-intensive industries as aluminum and chemicals, which have the potential to become more flexible in managing their electrical loads, given the right incentives. And properly incentivized, many, if not most, households could be convinced to shift at least some of the operation of their electricity-intensive equipment (for example, air conditioners and heating systems) to off-peak periods.

6. *The Handelsblatt*, February 7, 2010, reported that in Germany alone, seven large projects for coal-fired power plants were canceled in 2009 and 2010, largely as a result of local protests and worries over the projects' uncertain economics due to unclear utilization prospects associated with fluctuating renewables.

But DSM has its limitations. Most loads can be deferred for a short period of time, but longer deferrals risk creating production disturbances. DSM also demands large investments, such as smart meters and customized-billing systems. In addition to being costly, these devices could raise issues of privacy that would need to be resolved. Furthermore, DSM requires behavioral adaptations by customers and sufficient pricing flexibility to actually drive changes in customer thinking. A savings of only 10 cents, for example, is unlikely to convince many customers to do their laundry at 3:00 a.m. rather than at a more convenient time.

Currently, DSM is being used mainly in the United States for peak shaving and reducing strain on grids. But DSM is no panacea. Indeed, two unrelated studies carried out in Germany and the United States found that DSM offers a demand reduction potential of only approximately 2 percent of peak load. All told, although DSM clearly has potential and should be explored, we expect its ultimate contribution to the smoothing of wind and solar PV fluctuations to be limited.

Large-Scale Electricity Storage

Large-scale electricity storage refers to harnessing excess power generated in times of abundant availability (or low demand or both) and releasing it later into the grid when power generation is low (or demand is high or both). Large-scale electricity storage offers structural advantages over both interregional compensation and compensation by backup capacity. Unlike interregional compensation, storage provides a self-sufficient solution for one specific region and hence is not affected by increases in penetration of fluctuating renewables across the board. And unlike compensation by backup capacity, storage can deal with troughs *and* peaks in fluctuating renewables' output. Additionally, because it can reduce fluctuations close to the respective generation sources, large-scale electricity storage translates into less strain on grids.

The approach is not perfect, however. All electricity-storage technologies are inefficient to a degree: part of the energy fed into the system cannot be discharged later on and is lost. With typical efficiency factors ranging between 45 percent (for hydrogen) and 80 percent (for batteries), efficiency is the key weakness of electricity storage technologies and, to a large extent, accounts for the currently unfavorable business case for them. As with conventional power plants, the business case for individual facilities is further affected by other factors, including the cost of charging electricity, capital expenditures, operating expenses, and number of cycles. The actual utilization of the storage facility is a complex function of many parameters, such as weather, load versus demand, and grid constraints.

Large-scale electricity storage has other question marks. Technologically, it is still relatively immature for large applications other than pumped hydroelectric storage; its implementation entails additional costs on top of generation costs, including capital and operating expenditures and costs related to the loss of electricity; and, to date, it has had limited operational testing at large scale. Yet despite these concerns, we consider large-scale electricity storage a key means of addressing the challenge of compensation—one that will likely have to provide a significant share of the compensating capacity necessary in future power systems.

Storage Technologies as Compensation Capacity: Characterization, Applicability, and Economic Viability

Many different energy-storage technologies exist, but most are in the pilot phase of development. There are five main types of storage and key technologies within those categories:

- ◇ *Mechanical* storage, including pumped hydroelectric storage, compressed air energy storage (CAES), and flywheel energy storage
- ◇ *Thermal* storage, including hot-water storage, molten-salt storage, and phase-change material storage
- ◇ *Electrical* storage, including supercapacitors and superconducting magnets
- ◇ *Electrochemical* storage, including flow and static batteries
- ◇ *Chemical*, or hydrogen, storage

Among these, the technologies that look most promising today for large-scale deployment are CAES, hydrogen storage, batteries, and pumped hydroelectric storage. All of these technologies are capable of storing significant amounts of energy, which is essential for balancing fluctuating renewables. Some of the other technologies, such as flywheels and supercapacitors, offer good performance in providing high amounts of capacity for short periods of time, but they deliver only very limited amounts of energy and have very high rates of self-discharge.⁷ Currently, however, there are relatively few examples of these technologies in large-scale use. The most common are pumped hydroelectric facilities, of which there are approximately 300. There are only two CAES facilities in operation—one in Huntorf, Germany, and one in Alabama in the United States—and there are a few pilot installations of large-scale batteries (mainly sodium sulfur [NaS] high-temperature batteries) operating in the United States and Japan.

The four technologies in focus have different profiles in terms of developmental maturity, cost, and hurdles to implementation. These are summarized in Exhibit 3. We touch on some of the technologies’ most noteworthy characteristics below.

Compressed Air Energy Storage

CAES, or the compression of air to be used later as an energy source, is an existing technology that has proved its operational performance over many years in the German and U.S. installations mentioned above. The working principle is simple: excess electricity is used to compress air into an underground cavern (or, for small installations, a surface tank). The pressurized air is subsequently released and used to drive the compressor of a natural-gas turbine, thereby creating electricity. In its current state of development, CAES is relatively inefficient, with efficiency levels of only 45 to 55 percent—mainly the result of not retaining the heat obtained during compression. Also, if, when expanded, the compressed air were used to drive an air turbine, the turbine would basically freeze, because expanding air is cooling down. Since the

7. In the case of flywheels, for example, the rate of self-discharge is 100 percent per day.

Exhibit 3. A-CAES, Hydrogen Storage, Batteries, and Pumped Hydroelectric Storage Are the Most Relevant Large-Scale Technologies

	Technological maturity	Key application focus	Site limitations	Public concerns
A-CAES¹	Partially mature	Mainly for large-scale centralized applications	Most developed countries have the necessary potential storage caverns; Japan and Spain have very few potential sites, however	Little concern expected
Hydrogen storage	Has yet to be demonstrated on a large scale	Generally, very flexible in terms of capacity; particularly suitable for decentralized applications	No specific geological requirements	Potential for safety concerns; however, reference projects are running safely
Stationary batteries	NaS is relatively mature; redox flow remains to be demonstrated on a large scale ²	Generally, very flexible; particularly suitable for decentralized applications	No specific geological requirements	Few environmental concerns expected except for those related to the disposal of chemicals
Pumped hydroelectric storage	Mature	Very well suited for centralized applications; not yet implemented on a small scale	Europe, including Norway, has a limited number of potential sites left	Potential for environmental concerns, given the profound impact on landscapes

key disadvantage
 key advantage

Source: BCG analysis.
¹A-CAES = adiabatic compressed air energy storage.
²NaS = sodium sulfur.

decompressing air is used merely to support a conventional gas-power plant, CAES in its current setup is not a self-sustaining method of energy storage.

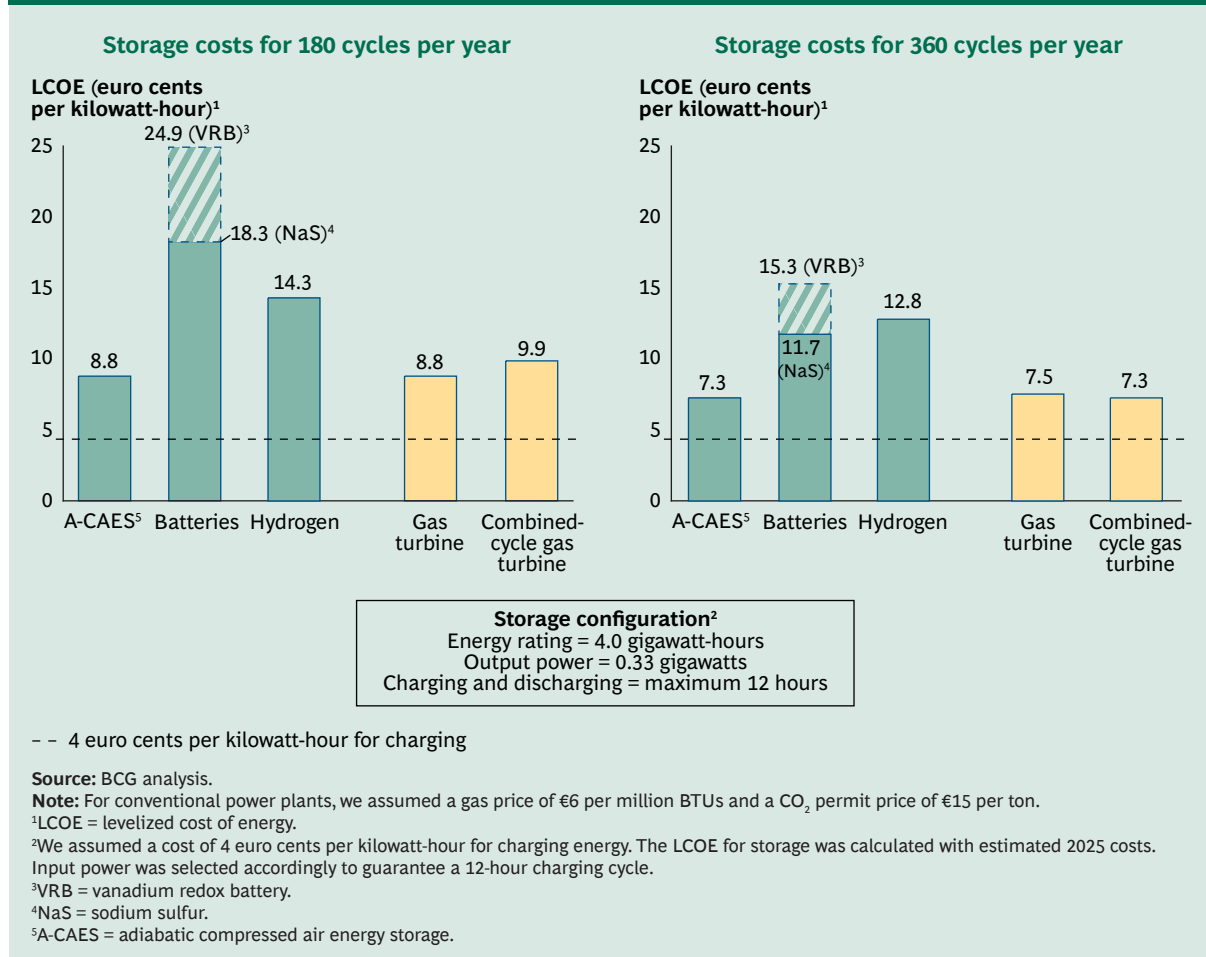
On the horizon, however, is so-called adiabatic compressed air energy storage (A-CAES), which we focus on in this paper. The main difference between A-CAES and conventional CAES is that A-CAES captures compression heat and stores it in a thermal-storage unit. This heat, which is released upon discharging electricity, reheats the decompressing air. The heated air, in turn, drives an air turbine, which creates electricity. Hence, this technology is a self-sufficient storage solution. It remains in development, with its first pilot installations expected after 2013.

A-CAES is expected to be significantly more efficient than current CAES and should ultimately have a very attractive cost profile compared with other forms of storage. (See Exhibit 4.) Indeed, our calculations indicate that A-CAES could be competitive on a cost basis with conventional forms of generation by 2025, provided its development continues as planned.⁸

A-CAES will have to deal with a hurdle that faces all compressed-air storage technologies: there must be a sufficient number of suitable caverns or other geological formations for storage. This will pose little problem in certain locations, such as Northern Germany and large parts of the United States, but it could be more problematic in other regions, including Spain and Japan, where suitable sites are rare.

8. We assumed a rate of 4 euro cents per kilowatt-hour for the electricity used to charge the storage facility. But operators of storage facilities may achieve additional savings through lower grid fees resulting from more balanced grid utilization with lower power.

Exhibit 4. By 2025, A-CAES Could Be Competitive with Conventional Generation



Hydrogen Storage

Hydrogen storage refers to using electricity to produce hydrogen with alkaline or proton exchange membrane electrolysis; storing the hydrogen, pressurized in an underground cavern (similar to compressed-air storage) or in a surface tank; and using the hydrogen for the generation of thermal electricity. Relative to A-CAES, hydrogen storage has somewhat higher investment costs and lower efficiency. Simultaneously, it has significantly higher energy density and, hence, significantly higher energy capacity. This, combined with its low efficiency, makes hydrogen storage most appropriate for the compensation of long-term (for example, seasonal) fluctuations.

Indeed, only hydrogen storage is capable of storing the huge amounts of electricity required for balancing seasonal fluctuations. And in a seasonal operating mode with only one or two cycles a year, the disadvantages posed by hydrogen storage's low efficiency are less of an issue. In fact, in the very same cavern, approximately 65 times more energy can be stored with hydrogen than with A-CAES. Because of this high energy efficiency, hydrogen storage may well emerge as the only storage option that can enable the balancing of seasonal fluctuations, which is a prerequisite for a 100 percent renewables-based electricity system. Implementing seasonal storage implies that storage infrastructure is set up to run only one or two cycles a year, which is likely to result in high storage costs per unit of energy.

Storage concepts that rely on hydrogen do not necessarily require costly infrastructure, as hydrogen is produced, stored, and consumed at the same site—or, alternatively, directly used for purposes other than power generation. A challenge facing hydrogen storage, however, is whether it can operate efficiently at sufficiently large scale. Although the maturity of the technology—especially that portion required to produce hydrogen from electricity—has been demonstrated on smaller installations of up to two megawatts of power intake, it remains to be seen whether it can be scaled up to reach greater capacities.

Another challenge facing hydrogen storage is concern for public safety. Although the actual safety hazard posed by the technology, especially in the case of cavern storage, is relatively low, the industry may need to engage in educational efforts to overcome the public's reservations.

Stationary Batteries

Stationary batteries, such as NaS batteries and vanadium redox batteries (VRBs), have the potential to become attractive choices for storage, especially in midsize applications, where cavern and turbine size limit other storage technologies. Stationary batteries are rechargeable. They are also the most efficient and flexible of the storage alternatives and are thus particularly cost competitive when the number of cycles is high—that is, when used to compensate for day-night fluctuations. Battery storage also has relatively few site requirements, and there will likely be limited resistance to battery storage from the public.

It is noteworthy that electrolyte tanks and fuel cells are separate components of VRBs and all other flow batteries. This means that the energy size and power rating can be scaled independently, increasing the flexibility of these batteries.

Stationary batteries are currently the focus of much attention—especially in Japan, a leader in the development of battery technologies. Stationary batteries are also garnering attention in the United States in the context of so-called community storage schemes, which are midsize decentralized storage facilities aimed at managing fluctuations from renewables and at reducing strain on the distribution grids.

The main hurdles for batteries are high investment costs, though these are expected to decrease over the next decade, driven by scale benefits and technology innovations. We estimate that for both NaS batteries and VRBs, cost reductions of 30 percent or more in the next ten years are possible, leading to investment costs of well below €2,000 per kilowatt for an entire system. As most current battery installations come with average energy sizes for six to eight hours of operation per cycle (1 megawatt of capacity translates into 6 to 8 megawatt-hours of stored energy), the investment cost per kilowatt-hour would be around €300.

The much-discussed idea of virtually bundling electric-car batteries (utilizing so-called vehicle-to-grid technology) to create storage is appealing but will not be realistic until the electric car increases its market share significantly. We do not expect that to happen before 2025. First, the absolute number and size of

individual batteries will limit storage capacity. Second, the revenue potential for owners who make their batteries available to central dispatching will likely be too low to overcome owners' reluctance to shortening their battery's lifespan or having a partially discharged battery at an inopportune time. Third, the lithium ion batteries used in electric cars (and consumer electronics) have comparatively high storage costs, as they are optimized for power rather than energy. This premium is acceptable for mobile applications, but a distributed stationary application for this technology will not likely be cost efficient.

Pumped Hydroelectric Storage

Pumped hydroelectric storage is an established, mature technology. Given its mode of operation (in periods of low demand, low-cost electricity is used to pump water to a reservoir at a higher elevation; this water is subsequently released through turbines in peak-load periods to generate hydroelectric power), it requires very specific locations: a suitable location must have sufficient water and a significant difference in altitude between its high and low points. Such geographic constraints—combined with political resistance (the environmental impact of the construction of a pumped hydroelectric storage site is significant)—pose clear limits to the additional growth potential of the technology.

Yet some experts regard selected pumped hydroelectric plants, connected by long-distance transmission lines, as potential buffers for fluctuating renewables. A prominent pointer toward such developments is the NorNed cable, which transports up to 700 megawatts between hydroelectric plants in Norway and the Netherlands. There may be a few more new pumped hydroelectric projects in continental Europe—notably in Austria, Norway, Spain, and Switzerland—within the next 10 to 15 years.⁹ But local and political resistance associated with the environmental impact of these plants will remain a large barrier.¹⁰

Given the strengths and weaknesses of these different technologies and their different applications, we believe that a combination will ultimately be used to provide the necessary compensation capacity. None of the technologies listed is capable of solving the challenge alone.

New Business Opportunities Will Emerge—but So Will Challenges

Growing demand for storage will present a range of business opportunities for energy companies, utilities, and related players. But it will also require gaining clarity on some key issues. We answer the fundamental questions below.

Who Are the Likely Operators of Storage Facilities?

The value chain for energy storage facilities encompasses four distinct roles: *component suppliers*, which will design, produce, and market components for storage facilities; *solution providers*, which will design, produce, and market components and also design and integrate systems and storage facilities; *storage facility operators*, which will operate facilities and buy and sell electricity; and *service operators*, which will offer maintenance and operational assistance to storage facilities. The provision of components, solutions, and service is similar to existing businesses in related applications (such as gas storage, power plants, water technology, and industrial facilities), but the actual operation of energy storage facilities presents a new set of challenges to potential operators and investors.

By necessity, the operators of energy storage facilities will most likely come from the energy sector, as only these players have applicable experience that can be leveraged.¹¹ Thus utilities, municipalities, independent power producers (IPPs), and grid operators would all be immediate candidates. The European Union's unbundling directive, though, prevents grid operators from operating storage facilities, because it

9. Iberdrola is currently constructing an extension of its La Muela pumped hydroelectric plant (La Muela II will have 850 megawatts of capacity and is expected to be completed in 2012) and plans an additional 900-megawatt facility at Alto Tâmega in Portugal, scheduled for completion in 2018.

10. The proposed North Sea supergrid appears to be an exception: It would use hydropower from Norway as a complementary energy source for offshore wind parks. In the current planning, however, this relates mainly to the country's existing hydropower stations, which can modulate their generation output but do not have pumps. Thus, we do not consider them storage facilities vis-à-vis those discussed in this paper; rather, we view them as a means of intermodal compensation.

11. It is possible that households could eventually adopt their own storage solutions. From a cost perspective, this would be the most expensive solution. We do not focus on this possibility in this paper.

classifies grid operators in the “generation” category. Hence the field seems to be left to utilities, municipalities, and IPPs.

Our research suggests that large established utilities may be reluctant to take on the role of storage operator, given their traditional focus on conventional investment projects, which compete for internal funding. Smaller utilities, however, especially municipal ones, could turn out to be more flexible and open to exploring this new line of business if they believed it offered them an opportunity to strengthen their footprint in the local market. Whether it will afford them that opportunity will greatly depend on their specific regional or local setting.

IPPs also have incentive to look seriously into energy storage opportunities: as the share of fluctuating renewables in overall generation continues to rise, regulators are expected to increase IPPs’ responsibility to better structure their power feed-in relative to peak and off-peak times. Given their small size, however, many IPPs may struggle to bear the required investment alone. Hence, they may need to form alliances to have the capacity to implement large storage projects, and single IPPs may provide storage for smaller, decentralized projects (such as small communities) if required.

It is also possible that other players will enter the storage market once it has become established. For operators of underground natural-gas storage, for example, moving to A-CAES would not be a huge leap. New entrants could come from other quarters as well. Suppliers of PV equipment, in fact, are already offering small-scale battery storage solutions to improve the reliability of their products.

What Are the Economic Incentives for Operators?

The key lever for the economically successful operation of an energy storage facility is the spread between the cost the facility incurs for charging energy and the price the facility can obtain for discharged energy. This price spread has to cover not only capital expenses and operations and maintenance costs but also make up for efficiency losses incurred during the storage process. Our calculations indicate that, for a while, that spread will not be sufficiently large on a continuous basis for operators. It is also extremely complex for operators to reliably chart their business cases, as the actual utilization of a storage facility at any point in time depends on the complex interaction of various parameters, such as weather, load, and grid capacities. While additional revenues from the provision of reserve energy and other grid services may help the financial viability of the storage business model at some point, the economics of storage will remain unattractive, or at least not fully transparent, for some time.

We should mention that providing grid stability and transmission and distribution deferral is currently a viable business case for storage operators, especially in the United States.¹² But this is a transitory business case that will not require large volumes of storage, and we do not analyze it further here.

Given the currently weak business case for storage technologies compared with other approaches to compensation, it is unlikely that investments in storage facilities will be made in the next few years. But storage is, as we have concluded, a vital component of the push toward fluctuating renewables. Unless the integration of fluctuating renewables into the grid is provided for, the growth of power generation from intermittent sources—wind and sun—will reach a ceiling. Many governments have committed to ambitious targets with regard to renewable energy, so they will need to provide suitable forms of incentives and subsidies in order to assure market readiness for storage infrastructure and to get key pilot projects off the ground. These could be investment-linked incentives (for example, loan guarantees and investment tax credits, such as those widely used in the United States) or power-price-linked incentives (for example, guaranteed feed-in tariffs or price premiums paid per unit of energy stored in proportion to subsidies given to renewable energy, such as those common in many European countries).

In addition to these “pull” incentives, “push” incentives could be employed. Today, feed-in tariffs for renewable generation are time independent. By adding a peak-related component, owners of renewable

12. Transmission and distribution (T&D) deferral refers to the use of storage infrastructure to defer the replacement or upgrading of existing T&D equipment that is no longer capable of handling peaks in the grid: by using storage for peak shaving, existing installations can be used for a longer period of time. The business case for the storage investment is driven by the cost of capital required for the T&D upgrade and by the number of years the upgrade can be deferred.

generation facilities might be pushed to structure their feed-in to optimize their returns, increasing their need for storage. Alternatively, regulators could require new installations of wind or solar PV to provide a certain amount of storage to structure their output.

What Are the Key Success Factors for Operators?

To succeed, storage operators will need to make the right decisions about strategic positioning and technology. Regarding strategic positioning, operators should aim to optimize the following:

- ◇ *Degree of utilization.* Storage projects should be designed to be available for frequent charging and discharging. This will require a suitable location, sufficient input and output capacity, and a high-performance grid connection.
- ◇ *Revenue streams.* The operating model should facilitate revenue creation not only from the structuring of fluctuating renewables' generation but from other sources as well. For example, some part of overall capacity could be set aside to provide reserve capacity as a source of revenue.
- ◇ *Use of subsidies.* Storage facilities should be designed to leverage existing (and forthcoming, if known) subsidies. This will necessitate a close monitoring of regulatory developments.

Optimization of technology will require focusing on these considerations:

- ◇ *Size and capacity.* Operators will need to strike a balance between size of investment and potential revenue streams. A larger incremental investment could, for example, enable the parallel provision of reserve capacity.
- ◇ *Charging and discharging capacity.* To enable high turnover and the ability to compensate for day-night fluctuations, input and output capacity must be sufficiently dimensioned to ensure the possibility of charging and discharging within approximately ten hours.
- ◇ *Response time and flexibility.* The provision of reserve energy, for example, requires a response time of less than 15 minutes. The technology must enable this.
- ◇ *Charging-energy prices vis-à-vis efficiency losses.* Technologies that have low efficiency, for example hydrogen, are better suited for settings that command very low prices for charging energy than for settings in which substantial prices have to be paid for charging energy—as long as self-discharge, or the spontaneous loss of energy, is low (which is the case for hydrogen).

We are witnessing a paradigm change. Historically, electricity generation has been designed to follow demand. Now, we are moving toward a world in which virtually continuous demand is expected to be met, to a large extent, by energy sources—wind and sun—that are not “on,” or able to generate, much of the time. This challenge makes electricity storage critical—and the next frontier in energy infrastructure.

While the business case for investing in storage is currently weak, that situation will necessarily change. Today's fluctuations in generation are compensated for relatively easily and cheaply by flexible conventional power plants, but there are limits to how much capacity these plants will be able to provide. Simultaneously, the march toward a fossil-fuel-free energy landscape continues: ambitious targets for the share of electricity to be provided by renewables have been formulated and confirmed. Wind and solar PV are the most competitive and widely available renewable sources and will certainly account for the lion's share of renewable energy produced—and they require storage to be viable.

To realize fruit from their investments (through subsidies) in building a renewable generation base, governments will necessarily turn their attention to integration. And compensating for the fluctuations induced by wind and solar power generation, a big piece of the integration challenge, will require massive

investments. A tremendously large market will develop around fluctuation management technologies, and large-scale electricity storage will account for a good part of those investments. Indeed, we expect a strongly growing market around electricity storage, with annual revenues well above €10 billion by 2020. Already, the beginnings of that market are evident: the first projects are being tendered, research activities are picking up, and venture capital is viewing electricity storage as a key investment topic in clean technology.¹³ All participants in the industry value chain would therefore be wise to take the initiative and start positioning themselves for the inevitable. The race for the best technologies, the most advantageous sites, gaining operational experiences, and shaping standards and policies is open, and the commercial payoff for getting into that race early stands to be significant.

Governments that are committed to fluctuating renewables need to be similarly proactive. Given its current economics, storage needs a push to get it off the ground, and governments are uniquely positioned to provide that push. As was the case with renewable electricity generation itself some years ago, the right and timely incentives will spur private investment. That investment, in turn, will ensure that adequate storage capacity exists to allow the realization of gains from those earlier heavy investments in renewable capacity—and that the vision of a truly sustainable electricity supply can become a reality.

13. Thomson Reuters survey of 41 clean-technology venture-capital investors, presented at the World Economic Forum in Davos, Switzerland, January 2010.

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