Grid-Scale Electricity Storage

Implications for Renewable Energy

An Energy Technology Distillate from the Andlinger Center for Energy and the Environment at Princeton University

Contributors

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Biographical sketches of the contributors and their disclosures are available at http://acee.princeton.edu/distillates.

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Scope: This article provides a brief overview of grid-scale electricity storage and its roles in the growth of intermittent renewable energy. This overview and its associated articles constitute an "energy technology distillate," a synopsis of challenge and opportunity at a specific frontier area of the energy system. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 1: Overview

Electricity is provided to most of the world's users through complex grids that connect large sources of electric power to millions of users through transmission and distribution power lines. Although demand for electricity from the grid varies throughout the day, many of the sources providing energy to the grid are controllable, allowing generation to be seamlessly matched to user demand. However, increasingly during the past 10 years, power produced from renewable sources, predominantly wind and solar, has begun to enter the grid, and the result has been greater intermittency and unpredictability.

Over the same period, new developments in electricity storage technology have brought forward the possibility that the very problems renewables introduce, storage may solve. Electricity storage devices differ fundamentally from traditional power plants. Storage systems are capable of both absorbing electricity *from* the grid and providing electricity *to* the grid. By contrast, power plants can only generate electricity. The promise of storage and the promise of renewables are intertwined.

This "energy technology distillate" is a collection of brief articles that introduce aspects of the interplay between intermittency and storage. Each article has the goal of providing the non-expert reader with the language and key concepts needed to ask informed questions – in this case, about energy storage in general and, particularly, about how energy storage might be integrated into the grid in ways that enhance the penetration of renewables. Each article is neither a detailed technical treatise nor a brief on behalf of any specific technological, political, or regulatory policy. The overall goal of the distillate is to provide a starting point where the reader can learn basic vocabulary, concepts, and principles.

Intermittent renewables

Renewable energy is, in effect, energy from the sun. It can be harvested either directly or indirectly. Direct collection occurs when sunlight produces electricity via special materials that sunlight can activate or when it heats water or another fluid. Indirect collection includes collection after the sun's heat evaporates water, the water falls as rain, and the rainwater is gathered by a river basin (hydropower). Other examples of indirect collection of solar energy produce electricity by harnessing the power in winds, waves, and currents. Biology provides still another version of indirect collection, after sunlight has been used by a leaf to create grass or a tree (biomass). Hydropower produces the most renewable electricity today; it is well matched to the assignment of providing electricity whenever it is wanted: it is "dispatchable." By contrast, solar and wind energy – the two sources that are growing most rapidly – are *intermittent*; that is, they are not available all the time, creating electricity only when the sun is shining or the wind is blowing above a certain speed.

Intermittent renewable energy has grown quickly over the past decade. Between 2001 and 2011, global wind capacity grew tenfold and solar electricity capacity grew forty-fold. In 2011, between them, these two intermittent sources produced 2.4 percent of total global electricity. In some areas, power generation from renewable sources has far exceeded this percentage; for example, in 2011 wind accounted for 28 percent of Denmark's total power production. However, even at significantly smaller wind penetration levels, such as in Germany and Texas (in both cases, 8 percent of total power production), the integration of wind and solar energy into the electricity grid is proving to be difficult.

These difficulties arise not only because wind and solar energy are intermittent but also because they are unpredictable. The grid is a dynamic system that must balance generation (supply) and load (demand) at all times to maintain reliability and stability. When a customer turns on a light, electricity must be available to meet this demand. The grid balances load with demand by turning "load-following" power plants on or off throughout the day and raising or lowering their output. Unpredictable variations in the output of renewables resemble unpredictable variations in user demand, both over the short term (minute to minute) and longer term (hour to hour or day to day). The unpredictability of renewables is gradually diminishing through advanced computational techniques that improve the forecasting of power generation from wind and solar facilities. Nonetheless the growing presence on the grid of unpredictable sources of power is already beginning to create larger challenges to grid management than have been presented by uncertain demand.

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Electricity storage

One approach to addressing intermittency and unpredictability on the grid is to have resources online that are able to vary their output, or standing by and able to be brought online when needed, commonly called, respectively, spinning and non-spinning reserves. Today, these functions are provided largely by hydroelectric and natural gas-fired power plants varying their output. An alternative strategy is to use electricity storage systems, absorbing electricity when it is abundant and releasing it back to the grid when it is desired.

Storage systems in various guises are capable of reducing and controlling the output variability across time periods as short as milliseconds and as long as days. The shortest periods are associated with controlling the voltage and frequency of grid electricity within a tight range (regulation). Fluctuations in voltage and frequency can be created in many ways, including by wind variability and cloud cover. Storage for a few minutes can remove bottlenecks from transmission and distribution lines. Storage that can reliably prevent the overloading of these lines may enable the deferral of expensive upgrades. Multi-hour storage systems allow nighttime wind to provide energy in the daytime, when it is more valuable. At small scale, they can enable a household to shift load away from times when electricity is particularly expensive. At all time scales, storage can provide emergency services.

To focus the discussion about storage in this distillate, batteries are highlighted. Batteries are indeed a prominent option, and the battery research frontier is particularly dynamic. However, several other storage technologies with grid applications are appearing at this time. One of these, flywheel storage, shares many features with battery storage. Others, including chemical storage, compressed-air energy storage, storage as high-temperature heat, and storage in water reservoirs (“pumped storage”) have much less in common.

How important grid-scale electricity storage becomes, and how quickly it arrives, will depend upon the availability of cost-competitive technologies. Market competitiveness, in turn, requires lower storage costs and supportive policies. It also is strongly affected by the cost of natural gas, which today provides much of the grid’s fine-tuning and load-following capability. In the U.S., policies that promote storage in its various grid-supportive roles are being introduced both by the federal government and by some states, notably California. These policies follow on the heels of federal and state policies to promote renewable energy and demonstrate many of the same difficulties of coherent implementation.

Subsequent articles

This distillate currently consists of this Overview (Article 1) and six supplementary articles with restricted focus. The articles are self-standing and can be read independently. The hierarchical structure is presented in Figure 1.1.

Article 1 is this Overview.

Article 2 introduces the concepts and vocabulary of energy storage. It may be useful for the reader to consult Article 2 when reading the other articles.

Article 3 introduces a simplified methodology for estimating costs and uses it to explore a three-way competition where intermittent wind supplemented by multi-hour storage competes with a) natural gas on its own and b) intermittent wind supplemented by natural gas but without storage.

Article 4 reviews the frontier of battery technology. Current approaches to improving the performance and cost of three battery systems are contrasted so as to highlight the most pressing challenges.

Article 5 adopts a systems perspective to introduce the challenge of improving the reliability of an electricity grid. Intermittency and unpredictability are contrasted, both of which become substantially more difficult to manage as the presence of intermittent renewables grows.

Article 6 examines the competition between fossil fuel-based and storage-based solutions to grid problems from the perspective of climate change mitigation and the low-carbon economy.

Article 7 explains how, in the U.S., new state and federal policies are being put in place to encourage investments in grid reliability and electricity storage. The complexities inherent in there being, in effect, two parallel electric utility industries, differing in how federal and state authority interact, are introduced.

The distillate process is open-ended. There may be additional articles and periodic revisions.

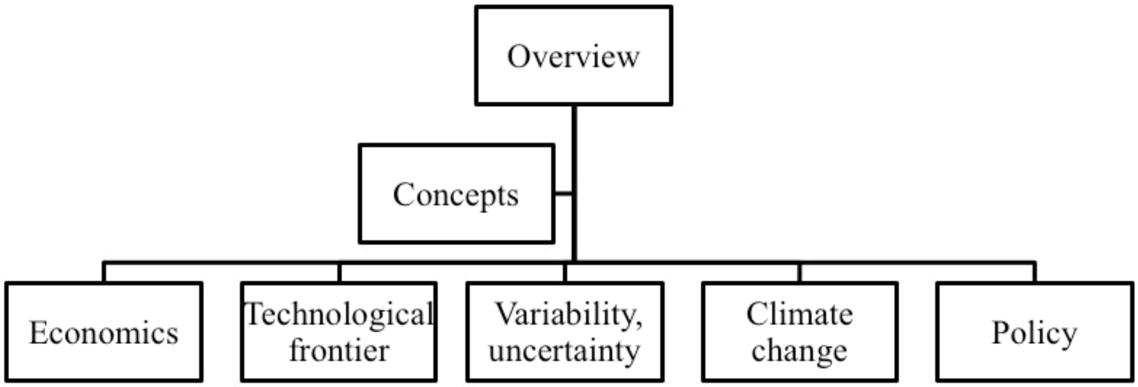

Figure 1.1 Hierarchical relationships among the seven articles in this distillate.

Scope: This article provides an introduction to some of the key concepts and vocabulary associated with electricity storage. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 2: Key Concepts in Electricity Storage

Storage is a widespread phenomenon. Every garage and closet is a storage site. The inventory of a business consists of stored items. In the energy domain, oil in large cylindrical tanks at the edge of a city is stored energy. So is the wood in the trunk of a tree, the water in a reservoir behind a dam, and the heat in a tank containing molten salt made very hot by concentrated sunlight. Here, we are confining attention to the storage of electricity. To qualify, energy must enter and exit the storage system as electricity.

We are also confining attention here to storage related to electric power, which is one of the three major frontiers for electricity storage today, alongside storage for vehicles and for consumer electronics. A crucial difference is that both weight and volume matter far less for electric power applications. Many storage concepts that have potential for power systems can be quickly ruled out for the other two domains.

The feature of electricity storage systems that distinguishes them from electricity generators is their ability not only to produce electricity, but also to take it in. Batteries are the electricity storage systems that many people think of first. There are many other systems, however, and the goal here is to provide the generic vocabulary applicable to all forms of electricity storage. Toward that end, we introduce, in two pairs, four widely used storage metrics that determine the suitability of energy storage systems for grid applications: power & capacity, and round-trip efficiency & cycle life. We then relate this vocabulary to costs.

Power and capacity

The *power* of a storage system, *P*, is the rate at which energy flows through it, in or out. It is usually measured in watts (*W*). The *energy storage capacity* of a storage system, *E*, is the maximum amount of energy that it can store and release. It is often measured in watt-hours (Wh). A bathtub, for example, is a storage system for water. Its "power" would be the maximum rate at which the spigot and drain can let water flow in and out. Its "capacity" would be the amount of water the tub can hold.

Together, the power and the capacity determine how long it will take to fill (charge) or empty (discharge) the energy storage system. Specifically, dividing the capacity by the power tells us the *duration*, *d*, of filling or emptying: $d = E/P$. Thus, a system with an energy storage capacity of 1,000 Wh and a power of 100 W will empty or fill in 10 hours, while a storage system with the same capacity but a power of 10,000 W will empty or fill in six minutes. Thus, to determine the time to empty or fill a storage system, both the capacity and power must be specified. The time to empty or fill provides a guide as to how a storage system will be used. An energy storage system based on transferring water back and forth between two large reservoirs at different altitudes ("pumped storage") will typically take many hours to complete the transfer in either direction. Pumped storage is suitable for situations where power is desired many hours after it can be produced, such as occurs when wind is strong at night but demand is strong during the day. Batteries chargeable and dischargeable over many hours are included in systems that provide 24-hour electricity for a remote home with a rooftop solar collector and no connection to any electric grid.

Another important parameter for storage systems is how quickly the power can "ramp" up or down – how responsive the storage system is. Battery and flywheel storage systems can change the rate at which they can absorb or deliver energy so rapidly (changing the power level in or out by as much as a few percent per second) that they are competing with gas-turbine generating systems that can also vary their power output, but not as quickly.

The distinction between the two units just introduced that are amounts of time – the time required for full discharge and the time required to ramp up and down – have exact analogs when distance substitutes for electric charge: How far a car can travel, starting with a full gas tank, before the tank is empty is the discharge time. If the car can go from zero to 60 miles per hour in six seconds, six seconds is a measure of the ramp time.

Scientific notation allows a compact way to discuss larger amounts of power: thousands of watts (kilowatts, kW), millions of watts (megawatts, MW), and billions of watts (gigawatts, GW). Similarly, to discuss storage capacity: thousands of watt-hours (kilowatt-hours, kWh), millions of watt-hours (megawatt-hours, MWh), and billions of watt-hours (gigawatt-hours, GWh). For vehicle applications, it is useful to know that one horsepower = 746 watts and that car engines typically deliver upwards of 100 horsepower. Thus, a battery for driving an electric car will deliver at least tens of kilowatts of power, while its range will be determined by its storage capacity in kilowatt-hours. "Grid-scale storage" requires, roughly, storage capacity greater than one MWh.

For vehicle and consumer electronics applications, the most common metrics modify the power and capacity units introduced here by dividing then by either mass or volume, thereby conveying the implications for situations where portability is critical. One finds units like watts per kilogram (W/kg) and kilowatt hours per cubic meter (kWh/m^3). We will not be using these units here.

Round-trip efficiency and cycle life

An *ideal* cycle for an electricity storage system is a sequence where some amount of electricity is used to add energy to the storage system and then exactly the same amount of electricity is produced when energy is extracted from the storage system while it returns to a state that is exactly the same as the initial state.

In all real cycles, this cannot happen: not all of the electricity stored can be retrieved, and the initial state is somewhat modified. During charging, electricity taken from the grid is converted into another form of energy, e.g. lifting water, compressing air, spinning a flywheel, separating electrical charges, making/breaking chemical bonds. During discharging, whichever the process, it must be reversed. In all cases these conversion processes have irreversibilities such as resistances in circuits, friction in flywheel bearings, and friction in pipes carrying water between an upper and a lower reservoir. The result is that heat is produced and less electricity can be extracted from a storage system than was put into it, when the system returns to its initial state. The *round-trip efficiency* is the energy delivered, divided by the energy received.

The rate of filling impacts the round-trip efficiency – usually less capacity can be accessed when a storage system is filled very quickly compared to very slowly. Therefore, power and *useful* capacity are not independent. The round-trip efficiency will also be less after a storage device is filled and emptied many times, compared to its value when the storage device is new. The *cycle life* is the number of cycles of filling and emptying before the performance falls below some predetermined level.

Not surprisingly, the round-trip efficiency and the cycle life strongly affect the value of a storage device and are the object of much research. In principle, storage elements can be replaced several times during the period of operation of a storage system, but this constrains system design and is usually undesirable. If a storage system needs to swap its storage elements for new ones every five years, for example, and it is competing with a generator that can run for 20 years, the cost of four storage elements needs to be factored into the cost comparison. Replacement costs can represent a significant portion of total lifetime system costs.

The fractional "state of charge" (SOC) of a storage device (a term most commonly used for batteries but applicable to all storage systems) is the energy stored at that moment divided by the maximum energy that can be stored. One refers to a deep discharge cycle when a storage system is emptied and filled almost completely; for example, the SOC might go back and forth between 0.9 and 0.1. A discharge cycle might be called shallow if the SOC varies between 0.6 and 0.4. The cycle life of a storage system will generally be longer – sometimes *much* longer – when a storage system undergoes only shallow cycles rather than deep discharges, because deep discharge, like fast discharge, adds its own irreversibilities that are detrimental to the storage device.

When a storage system can perform adequately for many cycles it is called "reversible," and if it is a battery it is called "rechargeable."

Storage system cost

The total cost of an electricity storage system reflects both capital costs and operating costs. For most storage systems the operating cost is a small fraction of the total storage cost, and the focus is on capital costs. The total capital cost, in turn, is often separated into two components: costs associated with moving stored energy in and out (power costs, in $/kW) and costs associated with the size of the storage system (energy costs, in $/kWh). The fractions of the total capital cost assignable to power-related and the energy-related costs vary with the storage technology.

The ability to drive down total costs through research and development (R&D) and commercial deployment depends on how novel the storage system is. For mature technologies such as pumped storage, there may be little opportunity for significant cost reductions, because the required equipment is already in wide commercial use. For newer technologies, costs are likely to fall as a result of the "learning by doing" that accompanies extensive commercial deployment.

The cost of a storage system is traded against the revenue it generates from providing various services. It is useful to distinguish between services that provide benefits immediately and only after some time passes. Storage can provide immediate benefits by absorbing energy when demand falls and thereby enabling operating generators not to curtail their power, which can be costly. Storage can provide delayed benefits by decoupling electricity production from electricity delivery, thereby enabling the shifting of energy delivery from an earlier time to a later time. Both benefits can also be provided by power generators, so storage faces similar competition in both cases. Immediate benefits provided by storage systems can also be provided by a generator already running on the grid that is able to reduce its output quickly. Delayed benefits of storage can also be provided by running a generator at the later time.

Chemical storage presents a special case, because the stored energy can be directed toward another market. Suppose electricity is stored as hydrogen via the electrolysis of water. At a later time, the hydrogen can be combined with oxygen (e.g., in a fuel cell) to produce electricity (perhaps with a round-trip efficiency of two-thirds). However, the hydrogen can also be sold for use in the production of chemicals. In this case, the storage function is undermined. The sale of hydrogen becomes an off-ramp of electricity storage.

Scope: This article introduces, via an idealized example, the three-way economic competition among intermittent power, back-up power, and multi-hour energy storage. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 3: The Economics of Multi-hour Electricity Storage

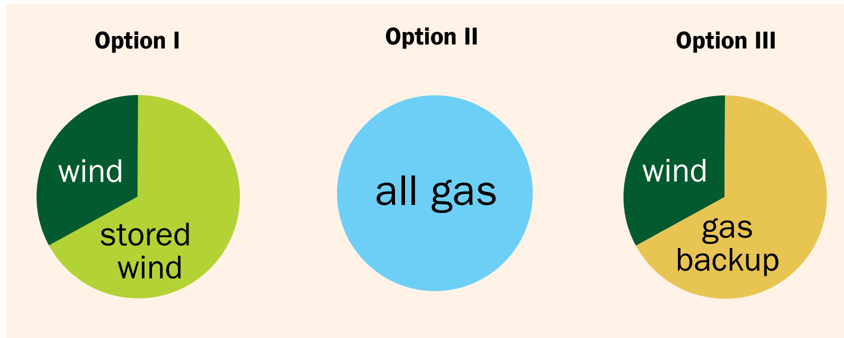

Figure 3.1 Three options for providing one unit of constant power over a full day. Wind is assumed to be available only for the first eight hours. In Option I, three units of wind are collected and two are stored to provide power during the other 16 hours. In Option II, natural gas provides power at a constant rate throughout the day. In Option III, wind provides power during the first eight hours and gas provides the "backup" power during the other 16 hours.

The intermittency of wind and solar energy creates a fundamental complication: it is not always available when it is needed. To be sure, some "needs" can be moved, instead of moving the energy, so that clothes are washed during windy hours. But setting that aside, the choices for meeting demand are to produce power in some complementary way when the renewable source is deficient (to produce 'backup power") or to collect extra renewable energy at the time of abundance, store the extra energy, and deliver it when it is needed. The economic competition between backup power and storage for grid-scale electricity is explored here.

We introduce the concepts that capture this competition by means of a single idealized example: a competition among three systems that provide a constant supply of electricity (base load). Option I (wind+storage) couples storage to an intermittent electricity supply, which we call wind for specificity. We deal with the intermittency of wind by assuming an idealized intermittent wind which produces electricity reliably and at a constant rate for eight hours in a row each day (a time period we call "night") and produces nothing during the other 16 hours. (With these assumptions, we subordinate all issues of unpredictability.) To provide baseload energy in Option I, three units of wind energy are captured at night, one of which delivers power to the grid at night while the other two units charge a storage system (which we will call a "battery") during the night, and the storage system delivers these two units to the grid over the 16 daylight hours. (For simplicity, we ignore the inefficiencies of charging and discharging the storage system, i.e., we assume perfect round-trip efficiency.)

Option II ("all gas") and Option III ("wind+gas") use natural gas. In Option II, natural gas power is produced throughout the 24 hours of the day at a constant rate; there are no intermittent renewables at all. In Option III, the same constant wind as in Option I produces power for the eight hours when wind is available, but it does not produce extra electricity for storage; instead, natural gas produces "backup power" for the other 16 hours. Accordingly, in Option III, only one unit of wind energy is installed, as compared with three units for Option I. The three options are shown schematically in Figure 3.1.

We are interested in comparing costs, and we wish to introduce only a minimal set of concepts and variables to do so. We introduce just four variables: the capital cost of wind power, the capital cost of the battery, the capital cost of natural gas power, and the recurrent operating cost for natural gas fuel. The capital cost is, essentially, the cost of construction. Omitting all operating costs other than fuel is a defensible first approximation for these capital-intensive systems. Writing for readers who do not all learn in the same way, we first present a numerical example and then redo the work using algebra.

Capital costs

We quote capital costs in dollars per kilowatt of capacity ($/kW). We assume the capital cost for the production of electricity from wind is $2,000/kW (DOE, 2013). Our system for the production of electricity from natural gas is a "combined-cycle" (a gas turbine coupled to a steam turbine) power plant, whose capital cost is $1,000/kW ($933 in Brattle, 2011). For purposes of calculations, we choose $2,600/kW as the cost of a 16-hour storage system. We will discuss this cost further in a later section.

From these assumptions we can work out the capital costs for all three of our options for baseload power, where in each case one kilowatt is delivered to the consumer at a steady rate throughout the year. The capital cost of Option I is $8,600, since when the wind is blowing three kW of power must be collected in order to deliver one kW throughout the day ($6,000) and a storage system is also needed ($2,600). The capital cost of Option II, which requires only the collocated gas and steam turbines for a combined cycle, is ($1,000). The capital cost of Option III is $3,000, since now there is no storage and wind can be collected at the rate of use ($2,000), but the capital equipment for a combined cycle is also needed ($1,000). Table 3.1 lists these costs.

Oversimplifying, we assume that these one-time capital costs are financed by investors who then receive constant payments over a specific number of years. The annual cost of the borrowed capital depends on the cost of borrowing money and the assumed lifetime; the cost of borrowing, in turn, depends on project risk, and the cost is higher when a technology is immature. We assume here that the annualized cost of capital is 15 percent of the total capital cost, a reasonable generic assumption (EPRI, 1993) in the absence of subsidies. The three annualized costs are, therefore, $1,290/kW-year, $150/kW-year, and $450/kW-year, for Options I, II, and III, respectively.

Fuel cost

The corresponding cost for producing one kilowatt of baseload power for a year via natural gas alone (Option II) and via natural gas and wind together (Option III) must include the cost of the natural gas fuel. The natural gas required to produce one kW-year of electricity depends on the efficiency of conversion of the thermal energy in natural gas to electricity in the combined-cycle system. We assume 50 percent gas-to-electricity conversion efficiency (NPCC, 2005), so the natural gas must provide two kW-year of thermal energy to produce one kW-year of electricity.

In the U.S. the usual unit for discussing quantities of natural gas is "millions of Btu." We will abbreviate this unit as "mmBtu," with "mm" meaning "thousands of thousands," i.e., millions. (The metric system's abbreviation of million is upper case M.) The mmBtu and the kW-year are two energy units that are exactly proportional:

30 mmBtu = one kW-year.

The required two kW-year of thermal energy required above to produce one kW-year of electricity is therefore, in the conventional energy units used for natural gas, approximately 60 mmBtu of natural gas.

Using the symbol, f, to represent the price of natural gas fuel in its conventional units ($/mmBtu), the annualized cost of fuel to produce power for Option II is (60*f)/kW-year, since gas is burned every hour of the day. By contrast, the annualized cost of fuel for Option III is (40*f)/kW-year, since gas is burned only two-thirds of the time. Note that * here is the symbol for multiplication. These costs, too, are in Table 3.1.

The price of natural gas varies by location, season, and amount of processing at the time of the transaction. A widely used natural gas price is the price at the Henry Hub, a transfer station in Louisiana where gas enters the natural gas grid for wide distribution. The average spot-market price in December 2013 was $4.24/mmBtu. Over the previous 10 years the monthly average Henry Hub price exceeded $10/mmBtu in two four-month periods: September through December 2005 and April through July 2008. The same price fell below $2.50/mmBtu in another four-month period: March through June 2012. (These are prices in current dollars, i.e., not corrected for inflation.) The price of natural gas in the major industrialized countries is higher than in the U.S.

Today's prices for natural gas do not include any cost for its CO_2 emissions, because broad-ranging carbon markets are still not established. For purposes of computation and analysis, we can work out an "effective" price for natural gas that includes a price for the CO_2 emissions. Each million Btu of natural gas produces about one-twentieth of a ton of CO_2 when it is burned. Thus, imposing a price of $100/t$CO_2$ on natural gas emissions raises the price of one million Btu of natural gas by $5. Thus, when a CO_2 price of $100/t$CO_2$ is added to a gas cost of $8/mmBtu in the absence of a CO_2 price, the result is an effective natural gas price of $13/mmBtu.

Total cost

The total annualized cost for all options is the sum of capital cost and operating cost (here, simplified to be the fuel cost). The sum is shown in Table 3.1. We see that for Option II, whose total cost is ($150 + 60*$f$), at a price of $2.50/mmBtu (i.e.,

	Capital investment ($/kW)	Annual capital cost ($/kW-year)	Annual fuel cost ($/kW-year)	Total annual cost ($/kW-year)
Option I (wind+storage)	8,600	1,290	0	1,290
Option II (all gas)	1,000	150	60*ƒ	150 + 60*ƒ
Option III (wind+gas)	3,000	450	40*ƒ	450 + 40*ƒ

Table 3.1: Costs to deliver constant power for the three idealized options shown in Figure 3.1. The parameter, ƒ, is the price of natural gas in $/mmBtu.

ƒ = 2.50), natural gas accounts for half of the total cost. As noted above, this price is well below the current price of gas even in the United States, where it is lower than in most other industrialized countries. Thus, we learn that the cost of the all-gas option is dominated by the fuel cost.

The competition between Options I (wind+storage) and Option II (all gas)

Figure 3.2 shows the two cost lines for Options I and II as the cost of natural gas varies. Where the two cost lines cross, the two options are equally expensive; this occurs at a gas price of $19/mmBtu.

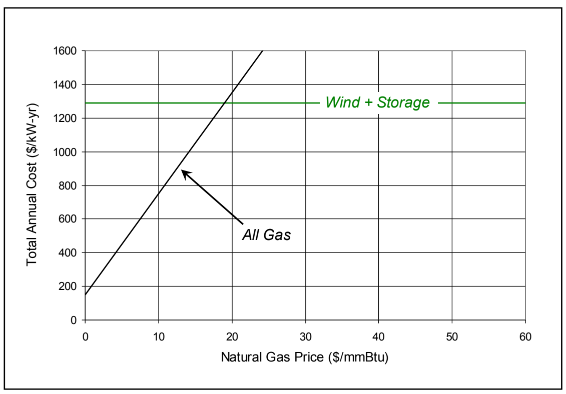

Figure 3.2. In an idealized example with specific capital costs for wind, gas and storage, there is a two-way competition to provide constant power: intermittent wind with storage vs. natural gas on its own. Natural gas wins until the gas price exceeds $19/mmBtu.

The wind+storage option is more expensive than the all-gas option for all gas prices below that value.

A gas price of $19/mmBtu is very high, more than four times the Dec 2013 reference gas price discussed above. Does this mean that the combination of wind and battery storage has no hope of competing with natural gas for baseload power? Might some combination of a climbing gas price and a falling capital cost for wind change the message that our simple calculation seems to be conveying? On an energy basis, a gas price of $19/mmBtu is equivalent to a crude oil price of $110/barrel (since a barrel of crude oil, by convention, has an energy content of 5.8 mmBtu); but in recent years the price of oil and the price of natural gas have been uncoupled. Climate policy would need to be very strict to play a large role here: to raise the price of natural gas from $4/mmBtu to $19/mmBtu by taxing CO_2 emissions, the tax would need to be about $300 per ton of CO_2, far higher than is usually considered plausible for the next few decades. Driving the comparison from the other direction, suppose the capital cost of wind power was to fall to $500/kW, four times less than we assumed above. The reader can work out that, for the same $2,600/kW cost of storage that was assumed above, the breakeven natural gas price comes out to be $7.75/mmBtu, which is a credible future price. Indeed, although wind+storage cannot beat natural gas today in the competition described here, one ought to be cautious about predicting the outcome in the future.

The three-way competition including Option III (wind with natural gas backup)

Where does Option III fit into this story? Option III (wind+gas) provides baseload power using wind supplemented by natural gas backup, with no storage. One can anticipate how Option III will compete with Options I and II, as the gas price ranges from low to high. When the gas price is very low, burning gas instead of buying extra capital equipment wins the day; Option II should be the cheapest of the three options. Indeed, inspecting Table 3.1, it is certainly the cheapest option for the limiting case when fuel is free, i.e., when ƒ = 0. When the gas price is very high, the less the use of gas, the better, and since Option I uses no gas, it should be the least expensive option. We are led to ask: Is there an intermediate zone of gas prices (a price window) within which Option III is the least expensive?

Figure 3.3 shows that there is such a window for the costs we have assumed here. The cost lines for Options I and II are identical to those shown in Figure 3.2, and a third cost line is added for Option III. Thus, we have a complete representation of Table 3.1. The cost line for Option III crosses the other two lines, and Option III is the least expensive option starting when the cost of natural gas is $15/mmBtu and ending at $21/mmBtu. The upper price, $21/mmBtu, where Option I (the only one with storage) first wins this three-way competition, is $2/mmBtu higher than $19/mmBtu, the gas price at which it first wins the two-way competition in which Option III is not a participant.

To understand how the features of Figure 3.3 depend on specific cost assumptions, an analysis using algebra is recommended. It is presented in the next section. One can learn, for example, that as the capital cost of the storage system falls

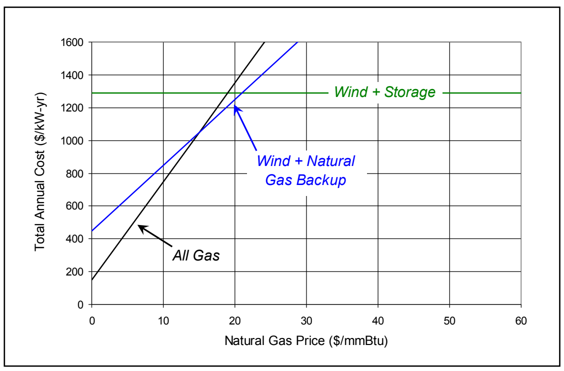

Figure 3.3 **In the same example as in Figure 3.2, there is a three-way competition to provide constant power: intermittent wind with storage *vs.* natural gas on its own *vs.* intermittent wind with natural gas backup. Wind wiith gas backup has the lowest cost at an intermediate gas price ranging from $15/mmBtu to $21/mmBtu.**

relative to the capital cost of natural gas combined-cycle power, the window discussed above gets smaller. Indeed, in the unlikely case that this price gap is closed entirely, the window disappears – all three cost lines in Figure 3.3 cross at the same point.

Algebra

For some readers, but certainly not all readers, presenting these arguments using algebra simplifies the discussion and adds insight. Let W, S, and G be the annualized capital costs for wind turbine power, battery storage, and natural gas power, respectively, all expressed in the same units, $/kW-year.

To simplify the algebra, let F be the fuel cost, *divided by the efficiency of conversion of fuel to electricity*, and define F also to have the same physical units, $/kW-year, as W, B, and G. Recall that the variable, ƒ, was defined above as the price of natural gas in dollars per mmBtu and that the two energy units, 30 mmBtu and one kW-year, are equal. The relationship between F and ƒ, therefore, is:

$$F = 30*f\ /(\text{efficiency}), \text{ in units of \$/kW-year.}$$

(In the numerical example above, ƒ was one-half.)

Let K be the total cost of any of the options. The costs of the three options are:

$$\text{For Option I:} \quad K = 3*W + S;$$

$$\text{For Option II:} \quad K = G + F;$$

$$\text{For Option III:} \quad K = G + (2/3)*F + W.$$

To identify the points of intersection in Figure 3.2 and Figure 3.3, we define

$$D = S – G.$$

The two coordinates of the point of intersection in Figure 3.2 (with equal values of K) are:

$$F = 3*W + D, \quad K = 3*W + S.$$
(Option I vs. Option II)

The coordinates of the two additional points of intersection in Figure 3.3 (with equal values of K) are:

$$F = 3*W + (3/2)*D, \quad K = 3*W + S.$$
(Option I vs. Option III)

$$F = 3*W, \quad K = 3*W + G.$$
(Option II vs. Option III).

It is clear from these expressions that a critical cost comparison is S vs. G. When S > G (i.e. D > 0), Option III is the least expensive option for some intermediate range of F, but when S < G (i.e. D < 0), there is no such range. As seen in Figure 3.3, our specific example above is in the former category, with S = $390/kW-year and G = $150/kW-year (15 percent of $2,600 and of $1,000, respectively). If S = G (i.e., D = 0), the three lines drawn in Figure 3.3 cross at a single point, whose coordinates are:

$$F = 3*W, \quad K = 3*W + G.$$

Figure 3.4 displays the three-way competition graphically by showing which option is least expensive when the fuel cost and the cost of storage are allowed to vary, but the annualized capital costs of the wind turbine (W) and the gas turbine (G) are fixed (at $300/kW-year and $150/kW, respectively). Option III (wind+gas) wins the competition in a wedge-shaped intermediate zone. The reader can verify that at the common point from which all three boundary lines diverge (f = \$15/mmBtu, S = \$150/kW-year), all three options have the same total cost, \$1,050/kW-year.

The vertical line in Figure 3.4 results from equating Option II and Option III, which is equivalent to equating the cost of eight hours/day of extra fuel (20*f) to the annualized capital cost of building a wind system (W); therefore, for W = \$300/kW-year, assumed in Figure 3.4, f = \$15/mmBtu. Neither Option II nor Option III involves a storage system, and therefore this value of f doesn't depend on the storage price, S. The result is that Options II and III have equal costs along the vertical line in Figure 3.4 where f = \$15/mmBtu.

Checking our earlier numerical example against Figure 3.4, we confirm that for the case where the annualized capital cost of storage (S) is \$390/kW-year, Option III (wind with natural gas backup) is the least expensive option in a region bounded by f = \$15/mmBtu and f = \$21/mmBtu.

Estimating the cost of storage

In our numerical examples thus far and in Figures 3.2 and 3.3, we have assumed that the capital cost of the storage system in Option I is \$2,600/kW, resulting in an annualized storage cost, S, of \$390/kW-year when the capital charge rate is 15 percent. How might the \$2,600/kW estimate for the capital cost be constructed from the bottom up?

As before, we assume that the operating cost is negligible, when compared with the capital cost. The capital cost can be expressed as the sum of two terms: 1) a *power-related* capital cost, reflecting the cost of equipment needed for electricity to enter and exit the storage system, and 2) a *storage-related* capital cost, reflecting the system's capacity (the amount of energy that the system can store). Although some components of a storage system contribute to both functions, there are conventions for some storage systems which assign each element to just one [EPRI (2003) and EPRI (2013)]. As a general rule, the storage-related cost dominates the power-related cost in the total cost of multi-hour storage systems.

First, let's estimate the capital cost for the power-related component of the storage system in Option I. This component includes the inverter (which changes power from AC to DC and back), power electronics, pumps, fans, transformers, and connections with the utility. In Option I electricity flows in for eight hours and flows out for 16 hours. When the capital cost of the power component of any storage system is quoted in units of \$/kW, the "kilowatts" refers to the larger of the two power flows, in this case, the flow *in*, because the equipment generally must be sized to handle those flows. Thus, to receive two-kW of power and deliver one kW, as in Option I, a two kW storage system is required.

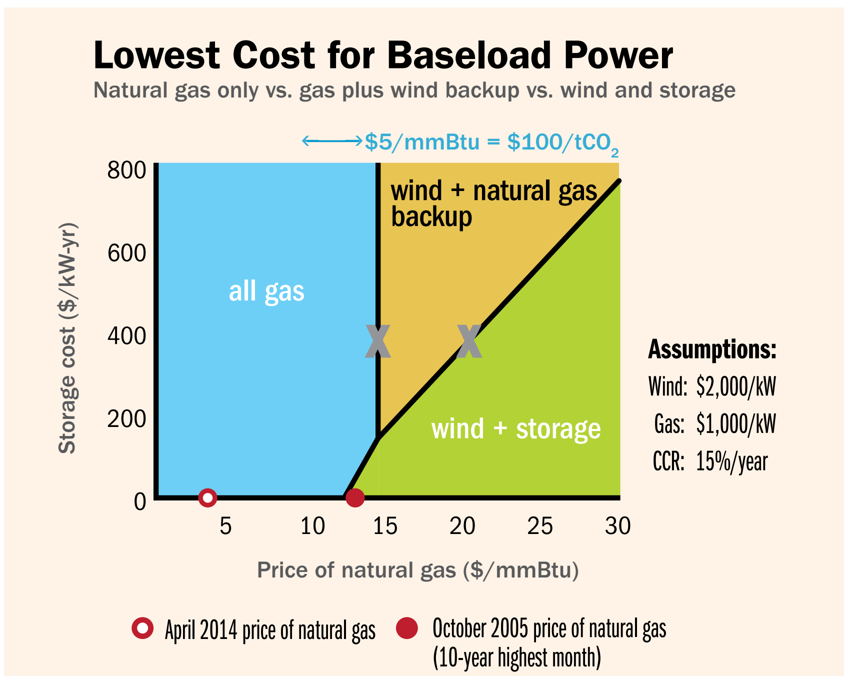

Figure 3.4 The same three-way competition as in Figure 3.3, but the storage cost is now a variable. Domains of lowest cost are differentiated by color. The storage cost assumed in Figures 3.2 and 3.3 is \$390/kW-year; for this cost, the cross-over points, marked with an X, occur at the same gas prices as in Figure 3.3. The Henry Hub price is a frequently used reference price. As seen by the double arrow at the top of the Figure, the price of natural gas increases by about \$5/mmBtu when a carbon price of \$100/tCO2 is imposed. "CCR" (the capital charge rate), is the multiplicative factor that relates the total capital cost to the annualized capital cost; its assumed value, here 15 percent/year, is a key input to the analysis.

For battery systems, a typical value for the power-related capital cost is $500/kW [$481 in EPRI (2013) for a generic storage system that absorbs and delivers ten megawatts of electric power]. For our system, which absorbs at twice the rate at which it delivers, the cost per kW *delivered* is $1,000/kW because electricity is acquired twice as fast as it is delivered. Indeed, whenever we tabulate values in $/kW for all the components, as in Table 3.1, $\$/kW_{delivered}$ is understood. Thus, the power component of our storage system contributes $1,000/kW to its capital cost. Since in our numerical example the capital costs for wind and gas are assumed to be $2,000/kW and $1,000/kW, respectively, this component of the capital cost of storage is one-half of the corresponding capital cost for our wind system and, by chance, exactly equal to the corresponding capital cost of our gas generation system.

As for the battery's *storage-related* capital cost, these include all costs that depend on the amount of energy stored by the system. For battery storage, this would include the cost of the electrochemical cells, while for hydropower pumped storage it would include the cost of the reservoir. A goal for current battery R&D programs is for the storage-related capital cost to fall to $100/kWh, where "kWh" here refers to the energy storage capacity of the system, *not* to a unit of energy output. For the 16-hour storage system of Option I, an assumed storage-related capital cost of $100/kWh implies an up-front capital cost of $1,600/kW. Our estimate for the total cost of the battery storage system for Option I, therefore, is $2,600/kW.

In summary, we have built up our $2,600/kW estimate for the capital cost of the storage system in Option I from two assumptions: a) a cost of $500/kW for flow-related components, where kilowatts are measured at the point where wind energy flows *into* the storage system; and b) a cost of $100/kWh for storage capacity, which is a current "aspirational" goal of battery research and development.

Simplifying assumptions

Throughout, we are making numerous simplifying assumptions, notably the following four. First, we have abstracted the problem of matching intermittency to demand by a squared-off wind supply and flat ("baseload") demand, when, of course, variants include situations where the initial match-up is pretty good (where full sunlight drives up solar collection and air conditioning load) and others where the match is poor (where winds blow hard mostly at night). Second, we assume ballpark capital costs without discussing exactly what they include; comparing capital costs of completely different systems is difficult, because there are often unstated assumptions about exactly what costs are included in their definitions. Third, we assume the round-trip efficiency of the storage system is 100 percent, when it is more likely to be about 80 percent, thereby making the storage option appear cheaper than it will actually be. Fourth, we neglect all running fixed and variable operating costs aside from fuel costs.

The ambitious reader can turn to more elaborate but conceptually similar economic analyses of storage and intermittent renewables in competition with natural gas (Greenblatt et al. 2007). The concepts developed here can also be used to evaluate storage in other grid-scale applications, such as alternating-current frequency regulation and electricity-price arbitrage.

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Scope: This article provides insights into the trade-offs among performance parameters affecting battery cost that are now driving the research frontier of battery storage. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 4: The Technological Frontier of Electrochemical Energy Storage

The designer of a battery for grid-scale storage aspires to achieve fast discharge, a long cycle life, high efficiency, and low-cost capacity. It is not inconceivable that a storage system can be fully discharged in seconds, can cycle reliably thousands of times, can achieve nearly 100 percent round-trip efficiency, and can meet a target for the installed cost of storage capacity like $100/kWh. However, today, no single technology meets all of these goals, and few meet even one of these goals. In order to gain an appreciation of the research frontier for battery storage, we explore here the characteristics of three popular battery chemistries: lead-acid chemistry, lithium-ion chemistry, and sodium-sulfur chemistry. These by no means span all possibilities, but when considered as a group they provide insight into the balancing of objectives that one must consider at the frontier of electrochemical energy storage.

The discussion below focuses on the differences between cells based on these chemistries, but it is important to keep in mind what these cells and many others have in common. Foremost, all of these electrochemical cells promote a reversible reaction between a reduced and an oxidized species, while generating or absorbing energy depending on the direction of the reaction. All cells generate heat in both charge and discharge mode, due to electric-resistance-based losses (Ohmic losses) during operation, and therefore cells based on these chemistries must be designed with heat management in mind. All cells must also contend with unwanted ("parasitic") side reactions, due to both innate chemistry and interactions with their environment. The parasitic reactions, if left unchecked, can further reduce roundtrip efficiency, and if these side reactions are irreversible they will limit the ultimate cycle life and shelf life of the cell.

Lead-acid chemistry is the basis of the oldest and most ubiquitous battery storage system. Conventional car batteries are typical lead-acid batteries. The lead-acid battery consists of a lead anode, a lead oxide cathode, and an aqueous electrolyte (typically, sulfuric acid). Other water-stable cells include the alkaline batteries (zinc nickel, nickel cadmium, and others), aqueous flow cells (vanadium redox, hydrogen bromide, zinc bromide, and others), and the more recent sodium ion systems. The nomenclature is confusing in this respect: the well-known "dry" alkaline cell is an aqueous cell, with massive water content compared to the non-aqueous cells discussed below. It is called a dry cell because the caustic electrolyte is present in gel form and will not "leak" when punctured. Aqueous systems are the easiest to manufacture and scale up.

However, water brings problems. The lead-acid system, like other aqueous systems, must contend with damaging water-based parasitic side reactions that restrict their operating cell potential (voltage), notably the electrolysis of water, which produces hydrogen gas. The generation of hydrogen promotes self-discharge, which limits long-term stability, shelf life, and round-trip efficiency. The generation of hydrogen also presents a risk of fire. Electrolysis occurs at the relatively low voltage of 1.23 volts, and therefore, in theory, to prevent hydrogen production 1.23 volts should be the maximum allowed cell potential. In fact, for some systems, due to the sluggish kinetics of water-splitting, active and passive gas management systems can mitigate or eliminate the unwanted electrolysis side reaction until a voltage as high as 2.2 volts is reached. The deleterious effects of electrolysis are the main constraint on aqueous storage systems.

Maximum power, self-discharge, and shelf life vary with temperature, and the battery's range of operating temperatures is determined by the boiling point and freezing point of the water-based electrolyte. The range of operating temperatures is wider than that of pure water, because the electrolytes tend to be concentrated salt solutions.

Lithium-ion chemistry represents the pinnacle for batteries of energy density (deliverable energy divided by mass) and power density (deliverable power divided by mass), and as a result batteries based upon this chemistry dominate the portable electronics market. These cells operate reversibly at a cell potential as high as three to four volts, which requires that the concentrations of both oxygen and water be restricted to less than one part per million. The need to exclude water requires non-aqueous electrolytes today. Typically, the electrolyte is a volatile organic compound, but solid-state electrolytes and ionic liquids with reduced flammability are under investigation. The exclusion of oxygen and water increases the manufacturing and materials cost of lithium-ion batteries compared to aqueous cells. Lithium chemistry is inherently less safe than aqueous chemistries because of the higher voltage and (at least at present) the flammability of the volatile electrolyte.

Due to the reactivity of lithium, parasitic reactions within lithium-ion cells are almost always irreversible: there is no effective way to "reform" a lithium-ion cell (retrieve its original properties) in-situ. As a result, for high cycle-life applications there must be almost no undesired side reactions (side reactions should occur less than 0.01 percent as often as the desired reaction). Since side reactions are enhanced at higher temperatures, reaching this target requires clever cooling systems. Heat can dissipate passively in small systems, but larger systems require active thermal management, which adds cost. The optimum design that keeps the cooling costs of a large lithium-ion system within bounds as the system gets larger generally results in a system that also has a lower energy density.

Sodium-sulfur chemistry represents a stationary storage system with demonstrated cycle life and calendar life that meets typical grid-scale needs (greater than 5,000 cycles over a 20-year period). Sodium sulfur (NaS) batteries operate at temperatures between 250ºC and 300ºC. The structure of NaS batteries is inverted compared to the previous cells: the anode and cathode in NaS cells are liquids, and the electrolyte is a solid ionic conductor. The high operating temperature of this cell excludes it from standalone and standby operation, but it also speeds up charging and discharging. The liquid electrode enables these cells to cycle much more quickly, and many more times, relative to the aqueous and lithium-ion cells.

The elements within a NaS cell are abundant (Na, S, Al, O, C), and the heat generation of this system can stabilize operation rather than create parasitic losses. However, the enhanced reactivity of both sodium and sulfur at high temperatures requires precise assembly and power management, which is the cell's dominating cost, much larger than the raw cost of the materials. To date, the cost of this system has not decreased as its scale has become larger. NaS batteries have the longest demonstrated use-life of any large terrestrial electrochemical systems (some systems have operated in outer space for even longer), but several recent NaS fires at large grid-connected installations – immune to all known fire suppression methods – have halted further installation of NaS batteries.

Comparisons

Lead-acid cells are at present the lowest cost and safest of the three. The voltage is restricted by the side reactions of the aqueous electrolyte, especially by the electrolysis side reaction that produces hazardous hydrogen gas (and oxygen gas) from water. The engineering challenge for the lead-acid cell is to extend its life without increasing its cost, for example by finding better ways to reduce the chemical and physical degradation of its electrodes. Even though lead is a toxic metal, the design of a modern battery makes it relatively easy to prevent any environmental exposure. In fact, environmental exposure is almost always the result of gross negligence with respect to end of life removal rather than the result of operational failure.

Lithium-ion cells are the most energy dense of the three systems. The properties of the lithium electrolyte at present limit the per-cycle efficiency and the cycle life of the cell. Manufacturing costs related to materials purity limit widespread implementation at present. The engineering challenge for lithium-ion cells is to maintain per-cycle current efficiency while decreasing manufacturing costs, materials costs, and flammability.

Liquid sodium cells have the longest operating history of the three technologies in grid applications. The abundance and low cost of the active materials is appealing, but the manufacturing and operational tolerances are inherently expensive, due to the reactivity of the materials and temperature of operation. The engineering challenge for sodium-sulfur cells is to decrease cost while increasing safety of operation. Liquid sodium cells should not be confused with sodium-ion cells, which are a new class of aqueous battery.

The storage frontier

The three chemical systems just discussed are being improved both incrementally and disruptively, but how much these systems will be improved remains to be seen. In parallel, novel battery systems are beginning to be explored that represent larger changes in structure. Bear in mind that to date, there are only promising beaker-scale experiments on these novel systems, and there is ample reason for caution in extrapolating to grid-scale applications.

To comprehend the current frontier of electrochemical energy storage, it is helpful to appreciate that this frontier actually embraces two diametrically opposed design principles. One strategy accepts significant change as the result of materials transport. The system is designed so that the substantial changes to the chemically reacting surfaces can be reversed by a carefully engineered supporting structure, so that the battery can be cycled a very large number of times. Traditional chemicals are being pursued in this newer geometry; for example, plate metals such as lithium, zinc, and aluminum are being utilized as anodes in this approach. With this strategy, the objective is to utilize every bond in the electrode for energy, so that the resulting system can be compact and light weight. In such systems the structure of the electrodes undergoes a reversible transformation (a "phase change," analogous to the evaporation and condensation that take a liquid to a gas and back to a liquid). Such phase changes erase all memory of the electrode's mechanical history and allow a new cycle to start from scratch. The compromise here is that the core electrochemically active system requires substantial supplementary systems to maintain stability, such as pumps and heat exchangers, which add complexity and cost.

A cousin to this first approach, in the sense that it also seeks to maximize the use of the chemical bonds in the structure, is the flow battery (equivalently, flow cell). In a flow battery, the electrochemically active constituents are stored outside the battery and are pumped through it, thereby enabling high capacity.

The second design principle is to minimize the changes induced in the battery when the electrochemically active material is transported from one location in the battery to another. This approach creates "open-framework" systems, where the electrodes contain "atomic tunnels" that allow ions to enter and leave with little to no resultant strain on the electrode structure, resulting in a theoretically unlimited cycle life. The resultant design is a compromise that trades very long cycle life against additional volume (there is much open space that could otherwise be dedicated to energy storage bonds) and weight (in these open framework structure there can be 16 to 24 structural bonds for every single energetic bond).

Among existing batteries, in principle the lead-acid battery can undergo deep discharge cycles, following the first approach, but in practice this battery would last for only a few cycles. Instead, by "underutilizing" the lead-acid system, the lead-acid battery lasts much longer, providing thousands of "shallow" cycles. As for the lithium-ion battery, its chemistry is designed to exploit the second approach, but the first approach is engaged as well, because most lithium-ion variants would suffer from irreversible structural changes if their full capacity were used, and therefore they too must be "underutilized" and restricted to shallow discharge. There are notable exceptions among lithium-ion chemistries that avoid the compromises that force shallow cycles, such as batteries with a lithium-iron-phosphate ($LiFePO_4$) cathode. But for these cases, another compromise must be dealt with: batteries with these exceptional chemistries can store less electric charge per kilogram than their non-exceptional cousins, such as batteries with a lithium-cobalt-oxide ($LiCoO_2$) cathode.

What all of these "next generation" approaches have in common is a systematic use of the non-active components in supporting roles. Most modern batteries have a large amount of inactive mass that *could* provide energy but would do so at the cost of cycle life. These new approaches, if successful, will enable much more effective use of the whole structure over thousands of cycles.

A hierarchy of demands for storage

In estimating how quickly batteries will penetrate new markets for grid-scale storage, it is helpful to consider three categories of markets: markets where the needs are dire, moderate, and emergent. In all three categories, costs can be expected to fall as commercialization proceeds.

Dire needs for storage are associated with unpredictable, rare events, such as hurricanes, which create power failures at various scales that lead to damage ranging from severe to catastrophic. These are events where, if people had been able to predict the event, they would have gladly paid for storage at prices far above those at which storage can now be bought. When storage is sufficiently reliable in this domain, the result is "uninterruptible power supply," and it is bought by customers ranging from data centers to nuclear power plants. In spite of the rarity and unpredictability of catastrophic events, the market for this kind of storage is certain to increase, given the increased focus on hardening critical loads and enhancing the resiliency of the distribution grid in response to severe weather events. Not only is the cost of storage likely to fall, but the cost of nasty events is likely to increase.

Moderate needs for storage are, essentially, the needs for ancillary services on the grid. These include improvements in frequency and voltage regulation, congestion reduction, and the management of transmission overload. Events triggering these needs are already frequent, and many are not predictable. An increased presence of wind and solar on the grid brings with it greater unpredictability and thus greater demand for solutions that storage may provide in this middle category. Renewables tighten the knot, and storage loosens it.

Emergent needs for storage accompany a world that, contending with climate change, seeks non-carbon electricity and confronts the intermittency of wind and solar energy. This is a world that will prefer to supplement intermittent renewables with multi-hour storage rather than with traditional natural gas power plants. This class of needs is largely motivated by the arrival of renewable energy.

Dire needs can justify the purchase of high-cost storage when there is reason to believe that the nasty events will occur. The promise is safety for people and vulnerable equipment. Whether moderate needs will be met depends critically on the cost and performance of storage options; demand exists in the marketplace now. The promise is a better performing grid. Emergent needs require storage to be sufficiently low-cost to compete with traditional power generation. The promise is a lower-carbon economy.

An optimistic view would hold that cost reductions will propagate from one market to the next. But are such fundamentally different markets actually related like links in a chain, like stepping stones across a stream? In particular, can the progress that energy storage is making in supplying fast-response ancillary services be translated into the technological advancement required to enable electricity grids that are dominated by intermittent renewables? This is far from certain.

Scope: This article emphasizes the limitations on grid performance created by unpredictable resources. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 5: Storage for grid reliability under variability and uncertainty

The purpose of storage is to manage the mismatch between supply and demand. Systems today exhibit demand that varies predictably with time of day and temperature. When a generation system can be adjusted to meet these variations, we say that it is *dispatchable*. Generation from natural gas (and, to a lesser extent, from coal and hydroelectric sources) is dispatchable, while generation from wind and solar is not.

The transition to higher penetrations of wind and solar energy introduces the need to work with generation that cannot be controlled. However, it is particularly important to distinguish between *predictable variability* and *uncertainty*.

Predictable variability includes hour-of-day patterns, forecastable weather patterns, planned generator outages, and human-driven events such as the behavior at half time of those watching the Superbowl on TV.

Uncertainty comes in several forms, including unexpected weather events that differ from the forecast, rare or infrequent events such as equipment failures or storm-related outages, spikes in real-time electricity prices, and erratic behavior by consumers. Quantitatively, unexpectedly high or low outdoor temperatures can produce variations in electricity consumption of around five percent relative to the demand that the utility had planned for the day before. Grid operators have learned to deal with these uncertainties, which are today the dominant effect of normal weather on the supply-demand balance. But where wind and solar energy contribute as much as 20 percent of total electricity supply, another effect will become more important than the effect of poorly predicted temperature, namely an unexpectedly windy or calm day, or an unexpectedly sunny or cloudy day. The contribution of wind energy, in particular, can drop all the way to zero in a broad geographical region on days when a full contribution had been expected, forcing the grid operator to replace the wind with other forms of generation.

A very common error in studies of renewable generation is the mistake of assuming you can predict the future. These studies recall the famous line from Will Rogers: *Don't gamble; take all your savings and buy some good stock and hold it till it goes up, then sell it. If it don't go up, don't buy it.* While we recognize that we can't buy stocks that are guaranteed to go up, this is a surprisingly common error in energy systems modeling.

Variability versus uncertainty

Figure 5.1 illustrates the difference between predictable variation and uncertainty. It shows five days of energy collection from a large solar array at Princeton University. Output on Thursday and Friday (very sunny) and on Monday and Tuesday (very cloudy) is easy to predict. Much more difficult are mixed cloudy days like Wednesday, where patches of clouds dramatically reduce energy generation for short periods of time. Such variations represent a challenge to the stable and reliable operation of the electricity grid.

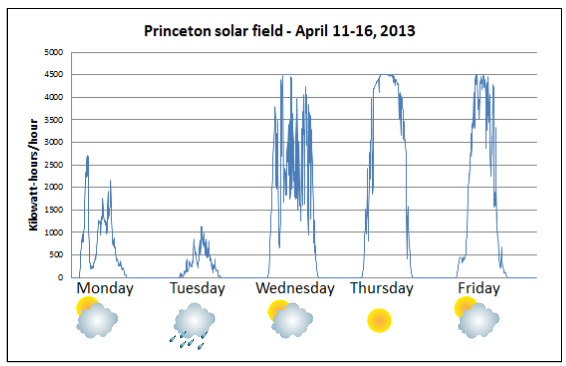

Figure 5.1 Energy from the Princeton solar field.

Figure 5.2 shows the electricity generated during one week of July, 2013, by all the wind farms on the PJM grid at that time, The Figure shows both the forecasted wind (in black) and the actual wind (in pink). Neither the strongest nor the weakest winds were forecasted accurately. If the forecast were to come true exactly, we could use virtually all of the wind, despite the variability. Day-ahead forecast errors limit our ability to use less-expensive energy from steam, but even hour-ahead errors are significant, forcing us to schedule reserve capacity that can respond quickly to variations.

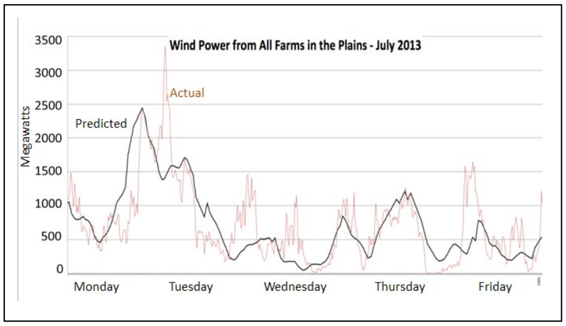

Figure 5.2 shows the total electricity generated in one week of July 2013 by all the wind farms that were on the PJM grid at that time – actual (pink) and forecasted (black).

Working with predictable variability

If we could remove all forms of uncertainty, powerful optimization algorithms (used by most grid operators) could match almost any load pattern with a large number of dispatchable generators (nuclear, steam, gas turbines), even in the presence of variable wind and solar energy sources. The problem is not unlike creating a wall from a pile of stones of many sizes (Figure 5.3).

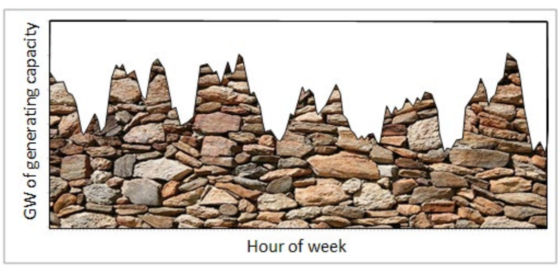

Figure 5.3 If we can perfectly forecast loads, we can plan a set of generators to meet demand just like building a wall from a set of stones.

However, the capacity to manage uncertainty in today's grids is limited by the realities of advance notification requirements, which range from instantaneous to a year or more. The examples below have a very wide range of time horizons:

> An alternating current (AC) power grid will react instantaneously to small, unexpected deviations (several percent) much as an air-filled tire will absorb small variations in a road surface. An AC grid will stretch to cover voltage deviations of a few percent, which can amount to several gigawatts on PJM Interconnection, a regional transmission organization serving the mid-Atlantic states out to Chicago.
>
> Automatic generator controllers (AGC) will tune different types of generators (including steam turbines) up or down based on signals that arrive every two to four seconds.
>
> Economic dispatch procedures will adjust generators up or down once every five to 15 minutes (without turning anything on or off).
>
> PJM's intermediate scheduling process will turn gas turbines on and off. It is run every 30 minutes with a horizon of approximately 45 minutes.
>
> Customers that have signed up to adjust their loads on demand typically require two to four hours of notice. Some demand response systems are much faster, but these are less popular.
>
> In anticipation of a peak load that the grid cannot meet (say, at 3 p.m. on a summer day), the grid operator needs to plan eight to 16 hours ahead to assure that storage or other resources are located where they can be used to meet this peak.
>
> Operation of steam generators is typically planned 12 to 36 hours into the future.
>
> Scheduled maintenance of a nuclear power plant is planned at least a year in advance.
>
> New generation capacity is planned with a two- to 10-year horizon.

Both the variation in notification times and the range of lags between when a decision is made and when it goes into effect create complex interactions that play a major role in the ability of a grid operator to deal with uncertainty. One value of storage is that it does not require advance notification, but the marginal value of storage has to be compared against the ability of the system to handle variability without storage.

Managing a portfolio

It is essential to recognize that electricity generation and storage must be managed as a portfolio. The value of each type of storage has to be measured in terms of how it interacts with all the other types of generation. This is particularly important on a larger grid, which emphasizes the value of a network. Microgrids, where a building or campus operates independently, limit the ability to coordinate different types of generation. A residence trying to run entirely off a solar array requires a very large storage device to accommodate the lack of sun at night and during cloudy days. These variations are easier to manage when the residence is part of a larger grid.

Access to the grid, with its ability to tap an array of generators, usually reduces total system costs, and moderate penetration of distributed generation can be handled using existing mechanisms for managing variability, including storage. However, high penetration of distributed generation introduces formidable challenges related to impact on power quality, the ability of grid operators to meet loads, and the economic viability of the traditional electric utility.

But they can do it, so why can't we?

It is common to hear people talk about how a particular country (such as Denmark or Spain), or a particular state (such as Iowa or South Dakota) is generating a high percentage of its energy from wind. Wind (and solar) are variable ("intermittent") resources and inevitably require backup generation to handle periods when the intermittent resource is not available. Denmark, which is roughly the size of northern New Jersey, draws power from Norway and Sweden, with their large hydroelectric resources whose output can be varied. Maine and South Dakota are small regions in a larger grid that can easily export excess wind to the rest of the grid, and import energy when the renewable resource is not available. New England has access to energy from Hydro-Québec, which manages generous hydroelectric resources. PJM's limited access to hydroelectric power will complicate its ability to manage high penetrations of wind and solar power.

Scope: This article explores some of the challenges facing renewable energy and energy storage if significant CO_2 emissions reductions are to be achieved. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 6: Multi-hour Storage and Climate Change

The rising concentration of carbon dioxide (CO_2) in the atmosphere contributes to climate change. This concentration has been climbing recently at about one-half percent per year, and most of the increase is due to a global energy system that continues to be dominated by fossil fuels. Because coal and natural gas power plants are concentrated sources of emissions, and because they now produce roughly 40 percent of the carbon dioxide emissions from the world's energy system, existing and future coal and gas plants are the first target of emissions reduction strategies.

To what extent could the CO_2 emissions from coal and natural power plants be eliminated by wind and solar energy, for some specific region or grid? A substantial literature makes the case that an electricity system powered by 80 percent and even 100 percent renewables is potentially achievable. However, formidable challenges would need to be overcome for such an outcome to emerge.

Clearly, the whole job could not be done just by wind and solar, both of which are not only intermittent, but partially unpredictable. The fraction of the load over a year that could be supplied by an individual facility is, typically, one-third or less. A considerably larger fraction can be provided by wind and solar when the grid incorporates multiple facilities located hundreds of miles from each other, each with its own time variation, linked by grid transmission lines. Multiple sources of renewable energy that are geographically diverse will experience distinct weather conditions, and, moreover, in many regions, wind is night-peaking. But even when there is considerable linkage of different intermittent renewable energy sources, it is likely that there will still be considerable mismatches between supply and demand. A deeper understanding of the limits to managing intermittency via multiple sources will be available once correlations among sites become better known.

After taking into account transmission opportunities, the rest of the job could be done by some combination of four options.

A. The grid could include renewable energy sources that can run all the time and that are predictable ("dispatchable"). Examples are hydropower, biopower, and (in some locations) geothermal energy produced from heat deep underground.

B. Demand for power could be shifted to align with the intermittency; for example, a clothes dryer can be set to run only on windy days. Such load shifting is a key element of the emergent "smart grid."

C. There are strategies based on building so much capacity that demand can be met even when winds are moderate. It then becomes necessary to "spill" wind energy when winds are strong, rather than to collect and sell it.

D. Additional wind and solar facilities could be built, and the extra electricity produced could be stored in still other facilities that would hold the extra power for delivery when it is needed, typically many hours later. The high cost of multi-hour storage is one of the most serious detriments to an all-renewable power system.

Second best, from the standpoint of CO_2 emissions, would be a system where energy from natural gas fills in the troughs where renewable energy supply falls below grid demand and also compensates for any unpredictability. Natural gas systems have the needed flexibility to accomplish both of these assignments. They can provide power for many hours at a stretch and are also capable of modulating their output and relatively easily turning on and off. In this sense natural gas is the default partner for intermittent renewables.

How low-carbon is this hybrid system? Imagine a regional grid where over the course of a year electricity is produced half by carbon-free renewables and half by natural gas. That system would produce one-fourth as much carbon as a system producing the same amount of electricity entirely from coal – since natural gas power on its own emits half as much CO_2 as coal power, and the use renewable energy, in some guises, entails negligible CO_2 emissions. For many, "one-fourth of coal," it must be noted, is too high.

A variant of such a hybrid system would reduce the total CO_2 emissions from the system by adding CO_2 capture at the natural gas power plant and storing the captured the CO_2 deep underground ("geological sequestration"). This modification is called carbon capture and storage (CCS); adding CCS to a natural gas plant could reduce its CO_2 emissions by as much as 90 percent. But the result is probably a mismatch: the modified natural gas plant would be less nimble and better suited for running at constant output. From the perspective of project economics, coupling intermittent renewable power and load-following natural gas power becomes less attractive when CCS is added, because the plant becomes more "capital intensive," meaning that the fraction of the plant's total costs assignable to building it (fixed costs) is large, relative to running it (operating costs). The more a system is capital-intensive, the more it is advantageous to operate the plant nearly all the time so as to spread the fixed costs over as many hours of sales as possible, which militates against including CCS in a load-following plant. A second handicap of a load-following system with CCS arises from its greater operational complexity; a CCS plant is less suited to frequent up and down ramping of its power output, as compared with the same plant without CCS. Accordingly, and unfortunately from the perspective of reducing CO_2 emissions, natural gas power accompanied by CCS is a less credible partner for intermittent renewables than natural gas power on its own, without CCS.

Scope: This article describes how policies and regulations affect the deployment of innovative technology by electric utilities in states with regulated and deregulated electricity markets. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 7: Supporting innovative electricity storage with federal and state policy

Introduction: Utilities and innovation

In order for energy storage to become an important component of the U.S. electricity grid, costs need to fall or rules need to change, or both. In the cases of solar and wind energy, costs have fallen with large-scale commercial deployment as the technology has progressed along a "learning curve." Commercial deployment, in turn, has been facilitated by public policies implemented at both the federal and state levels that have stimulated innovation. In the case of storage, one cannot yet know if the story will be similar.

The extra costs associated with the initial deployment of renewable energy have included the costs of research and development (R&D), the costs of pilot projects, and the costs prior to full commercialization when the first full-scale facilities incur costs that exceed the market price. These costs have been paid partly by taxpayers and partly by ratepayers (electric utility customers): governments have collected and allocated tax revenue, and utilities have collected and allocated revenue from sales of electricity, subject in the U.S. to federal and state regulations. Similar costs are arising for energy storage, again paid by ratepayers and taxpayers.

This article describes how new federal and state regulatory initiatives, rules, and policies governing the electric utility industry have affected the commercial deployment of renewable energy and could affect energy storage. It does not discuss R&D or direct government involvement in late-stage deployment (such as direct government procurement). We first review the current regulatory landscape in the U.S. at the state level, where utilities operate under two distinct kinds of regulatory regimes, with consequences for how innovation can be promoted and supported. We then explore how grid-scale renewable energy is supported via federal and state policies, to see the two parallel regulatory systems in action. We conclude with implications for the deployment of storage.

In the U.S., two parallel electric utility industries

The U.S. electric utility industry today is a "tale of two industries." In some states, a regulated industry operates under a legacy system overseen by state public utility commissions. In the other states, a "new" deregulated industry operates largely under a framework established by the federal government, with an overlay of modest state regulation that bears mostly on the distribution of electric power to customers.

This parallel industrial structure emerged only over the past 20 years, largely as the result of major federal initiatives. For most of the period since the creation of the U.S. electric power industry by Edison, Insull, and others in the late 19th century, the industry consisted of several kinds of Load Serving Entities (LSEs): Investor Owned Utilities (IOUs), federally organized entities (e.g., the Tennessee Valley Authority), utilities serving single municipalities, and Rural Electric Cooperatives. These LSEs were granted monopoly franchises by state and federal government agencies, which allowed them to operate in identified regions (service territories). Their activities were regulated by state public utility commissions (PUCs) as well as federal agencies such as the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission.

For the most part, irrespective of ownership, these utilities were vertically integrated. Vertical integration refers to the inclusion, in one entity, of power generation, high-voltage electric transmission, and lower-voltage power distribution to customers. The larger utilities had sufficient resources to invest in R&D and to support the deployment of advanced technology. Utilities determined the combinations of generation and transmission assets required to achieve grid reliability at least cost, and the PUCs allowed them to deploy the necessary capital in any of the segments. System reliability – the assurance that a light will come on when a customer flips a switch – became the foundational value proposition of public utilities. Today, system reliability is supplemented by new objectives, such as cybersecurity, but it retains its prominence.

The first steps toward change in the electric utility industry were taken in 1978 with the passage of the Public Utility Regulatory Policy Act (PURPA), which, for the first time, allowed non-utilities to generate power at wholesale. Restructuring of the industry began in earnest with the 1992 Energy Policy Act, which created full-scale competition in wholesale power generation, governed by federal authority. The objective of enhancing competition was to reduce electric prices, and an influential model was the deregulation of telecommunications (the dismemberment of Ma Bell). The new power-generation markets were opened so that both utility and non-utility generators could sell their power into large transmission grids. These grids are managed by Regional Transmission Organizations (RTOs) and overseen by FERC.

States were free to decline to participate in RTOs and to stay in the old system with regulated vertically integrated utilities supervised by the state's PUC. States that decided to deregulate their utility industry began the process by unbundling their power generation system from transmission and distribution, so that power was generated on a competitive basis, transmitted at high voltage over the interstate transmission system by FERC-regulated entities, and then distributed to customers via state-regulated distribution utilities. In such a market each segment of the industry acts independently. It seeks new investment opportunities and the maximization of its returns on these investments without regard for other industry segments.

Today, roughly half of the states participate in RTOs, and there is little further momentum toward deregulation. The deregulated states form a swath from New England and New York to the Mid-Atlantic States (New Jersey, Delaware, Maryland, Pennsylvania, and Ohio) and also include Texas and California, while the southeast extending into Florida as well as several states in the Midwest continue to have regulated, vertically integrated utilities. As seen in Figure 7.1, the U.S. has three single-state RTOs (also called ISOs) – New York, Texas, and California – and four multi-state RTOs.

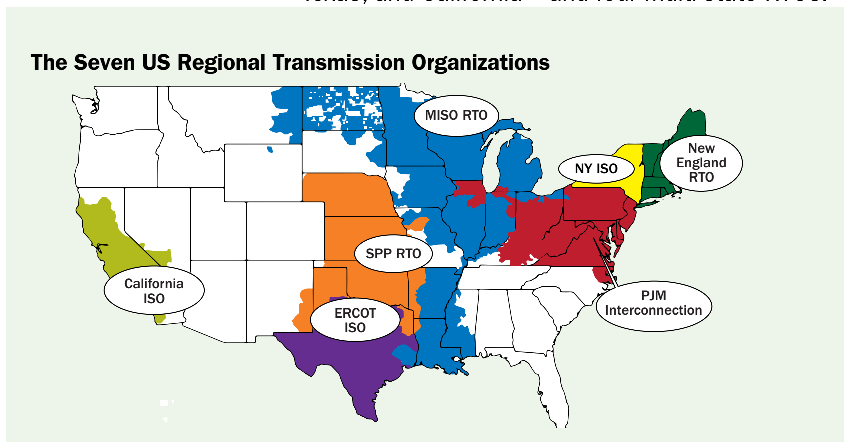

Figure 7.1 Colored regions of this map show states that have undergone partial deregulation of electric utilities, opening the generation of electricity to competition and assigning transmission to regional organizations.
Source: http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp

Not surprisingly, investment in technology innovation in areas like electricity storage is encouraged differently in states where utilities are regulated by PUCs and states that participate in RTOs. In a fully regulated state, the traditional vertically integrated utility is responsible for all aspects of the electricity value chain and plans its investments under integrated resource planning processes overseen by state regulators. The PUC decides which of a utility's expenditures can be recovered from its customers. If a PUC judges that an innovative technology has long-term value for the state's customers, it can allow the costs of investments in R&D, demonstration, and deployment to be recovered across the value chain that includes generation, transmission, and distribution.

In states that are part of the new, partially deregulated system, power generators and owners of interstate transmission and distribution utilities can coordinate in only limited areas and in effect make investments independently. FERC, which sets the rules in these states, fosters innovation and investment by opening access to the grid and creating new performance-based markets for grid services such as energy storage. However, in this case there is no guarantee that these new markets will be sufficiently remunerative to lead to the intended investments in innovative technologies.

For the purposes of understanding current innovation processes, what matters is that the two-industry structure will remain for some substantial period of time. The reality today is that the northeast of the U.S., Texas, parts of the Midwest, and California have effectively abolished vertically integrated utilities and have created, instead, independently organized generation, transmission, and distribution segments.

The jury is still out regarding whether utility deregulation has actually achieved lower costs. Meanwhile, a new wave of regulatory reform is being discussed that would foster distributed generation and related technologies, including those required for the "smart" grid. Whatever new structure emerges will have its own consequences for the commercialization of the innovations required to manage the transitions that lie ahead in this century.

Policies for the promotion of grid-scale renewable energy

An increasingly important factor in determining the trajectory for innovation in the electric utility industry is the ascendency of renewable energy. Understanding the dynamics of the interactions between electric utility policies and renewable energy investments can shed light on the future for investments in storage. We start with the passage of the 2005 Energy Policy Act (EPAct) and the 2007 Energy Independence and Security Act (EISA). Both acts received the support of members of the Congress wishing to address climate change and wishing to encourage alternative energy sources. This legislation came in the aftermath of a dramatic increase in natural gas prices in 2005 and the collapse of both Enron and the merchant natural gas power industry. The 2005 EPAct and 2007 EISA provided for federal tax credits in the form of investment tax credits (ITCs) for solar energy and production tax credits (PTCs) for wind and all other types of renewables. Both ITCs and PTCs are available to the owners of renewable energy projects irrespective of whether such projects supply power to regulated utilities or LSEs operating in competitive power markets.

Although ITCs and PTCs have played critical roles in the commercialization of renewable energy, both have shortcomings. When a solar facility is placed into commercial service it receives an ITC that is based on the facility's capacity to produce power. After an initial period during which the ITC can be "recaptured" if the solar facility does not operate, there are no requirements that the project run for any particular period or achieve any specified level of performance.

As for the PTC, although its value to a wind project depends on actual generation for a substantial number of years, its value does not depend on the time of day when the power is produced or its value to the grid. As a result, with the PTC taken into account, wind can sometimes supply power to the grid less expensively than any other sources, even "baseload" sources designed to operate at constant output (coal and nuclear plants). In situations where wind power is abundant and demand is low (e.g., in the middle of the night), low-cost wind is creating a novel problem: the least-cost mix of power sources that meets the demand is achieved only if the grid operator accepts less baseload power than the system was designed for. Providers of baseload power then incur substantial costs for not operating at constant output.

In parallel with ITCs and PTCs at the federal level, many states have developed their own policies to encourage renewable energy. These have taken the form of Renewable Portfolio Standards, which require all utilities operating in a state to provide a minimum fraction of their power from "certified" renewable energy facilities and by specific dates. These facilities are eligible to receive state Renewable Energy Credits that can be monetized in-state and, in some cases, in broader regional markets. Exactly which kinds of facilities are certified varies from state to state, but most renewable energy technologies are certified.

Renewable Energy Credits, like Production Tax Credits, are linked to actual generation but are not valued by time of day or other metrics. Neither recognizes the value of grid impacts arising from intermittency, the high cost of power at peak times, or other costs arising from the details of the displacement of conventional generation. The market inefficiencies created by these federal and state policies to promote renewables could be addressed by introducing market-based incentives, with the result, for example, of making it more attractive to store wind produced at low-value times (a windy night), for sale into the grid at high-value times (a calm day). Another area of constructive change would bring about coordination between federal tax policy, RTO rules, and state renewable energy programs. Policies to promote storage, which we consider next, evidently interact with current and prospective policies to promote renewables.

Implications for storage

The deployment of solar and wind energy has grown rapidly, thanks in part to broad-based political support from major corporations, environmental advocacy groups, and governments. By contrast, energy storage has not yet been able to garner the support necessary to propel sustained growth and thus remains at an earlier stage in the commercialization process. The limited advocacy for new policy constructs to support the introduction of energy storage into U.S. electric grids has come largely from private companies seeking to develop and deploy energy storage technologies commercially as a new business and from renewable energy advocates who see storage as key to accelerated deployment. Nonetheless, significant initiatives have emerged recently at the federal level and in California to promote energy storage and other unconventional grid-management technologies.

To understand policy options, consider the requirement of providing reliability on the grid. Under both unregulated markets and traditional markets featuring state regulation, the National Electric Reliability Corporation (NERC), operating under FERC oversight and through its regional coordinating councils, determines minimum grid reliability standards as well as other metrics that address grid safety and security. In both kinds of markets today, electric utilities are able to support grid reliability using a portfolio of conventional generation and transmission technologies. Only rarely have utilities used energy storage to satisfy NERC's regulatory requirements. But as new energy storage options emerge, both regulatory systems are challenged to respond, and they are likely to respond differently and in different timeframes.

In a regulated state the initiative for introducing energy storage lies with its PUC. The PUC determines the portfolio of generation assets that the utilities under its jurisdiction must hold, including the assets the utility is required to hold in reserve. The utility then invests in the appropriate resources and operates its portfolio of generating units to maintain this level of reserve. The PUC allows each utility to recover from its customers all capital and operating costs associated with reserve power. The utilities, in turn, have no need to separate the cost of providing operating reserve from the cost of generating energy. The PUC regularly evaluates the integrated resource plans formulated by its utilities to ensure that system reliability is being achieved at the lowest cost. The PUC, for instance, can decide to mandate storage investments, on the grounds that early deployment of storage will buy down its cost, to the long-term benefit to its customers.

The situation is more complicated in states where there is an RTO. NERC's reliability rules are then implemented not by a single entity such as a vertically integrated utility but, potentially, by transmission owners, LSEs, and even individual generators. The challenge is to assure that reliability standards are implemented in a way that is consistent with established governance and market design. An LSE seeking to meet its reserve requirements will commit to energy storage only if it is the least-cost way of doing so. Absent special circumstances, the LSE cannot recover from its customers any extra costs of meeting its reliability requirements resulting from using a storage option rather than a conventional resource such as a natural gas turbine.

New FERC regulations

Cost-competitiveness within an RTO depends on the rules that FERC sets. In the past several years, notably in its Order 755 (October 2011) and Order 784 (July 2013), FERC has focused on insuring that all innovative technologies capable of providing reliability-related services to the grid compete on a level playing field, when it comes to market compensation for the services they provide. For example, FERC recognizes that many storage systems can add or remove load from the grid more quickly and with greater accuracy than conventional generators. The result is better "ancillary services," such as tighter control of the frequency of alternating current (AC) so that it stays very close to 60 cycles per second. FERC now requires its RTOs to send out two different signals to accomplish frequency regulation, one requiring a faster response and one requiring a slower response, and to pay more for the faster response. (Previously there had been only one signal.) Only a few generators on the grid can respond to the faster signal, but many storage systems have the potential to do so. In these ways FERC is improving the competitiveness of fast-response storage for ancillary services. PJM (the largest of the RTOs) is implementing the new FERC orders particularly rapidly.

New California state regulations

The California ISO (as this RTO is called, see Figure 7.1) is proceeding in a unique fashion today, because it is being driven not only by FERC orders but also by state regulations governing the California Public Utility Commission (CPUC).

California has long been committed to including a significant share of renewable energy in its electricity generation mix (33 percent of total power generation by 2020). Toward this end, the state of California has been developing its own regulations to accommodate intermittent generating resources while maintaining grid reliability. Specifically, California now has state legislation, AB2514, enacted in 2011, which directs the CPUC to promulgate rules that support the commercial deployment of energy storage across the entire electricity value chain.

To implement AB2514, in October 2013, after a three-year deliberative process featuring stakeholder engagement, the CPUC announced the first mandatory energy-storage procurement targets in the nation. The targets apply to California's three major investor-owned utilities: Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric. Collectively, they are required to procure 1,325 MWs of energy storage capacity by 2020, with an installation deadline of the end of 2024.

To drive industry toward advanced technologies, there are CPUC rules limiting the use of conventional energy storage technologies, such as pumped storage of hydropower, to meet the targets. Additional CPUC rules seek to foster a storage industry that is independent of the state's utilities: utilities are not allowed to own a majority of the storage resources, and utility-owned storage is preferentially treated when it has not been developed by the utilities themselves but rather has been developed by others and sold to the utility on a turnkey basis under a purchase agreement. Overall, the CPUC is seeking to create significant new market demand and new supply for a broad range of advanced energy storage technologies.

The CPUC recognizes the issue of storage cost by requiring energy storage targets and procurements to be "viable and cost-effective," based upon a predetermined methodology developed for each utility. To provide flexibility, the CPUC allows a utility to meet its targets by a wide range of combinations of transmission projects and distribution projects. Thus, substantial investment in innovative multi-hour storage is not assured. To the extent that the primary reason for policies supportive of storage is to facilitate a large role for renewable energy, if only modest investments in multi-hour storage are forthcoming, one can imagine that procurement rules would be revisited. As it is, targets can be revised on an ongoing basis, and a utility is allowed to defer up to 80 percent of its targeted procurement to the next solicitation period.

The integration of FERC rules and CPUC rules to assure coherence and self-consistency is currently a work in progress.