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

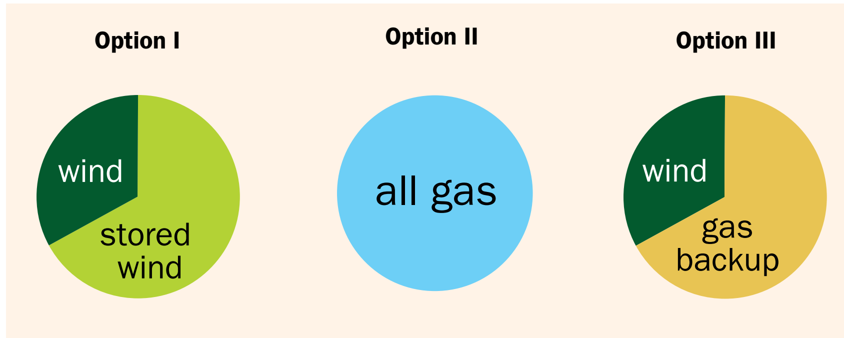

Figure 3.1 Three options for providing one unit of constant power over a full day. Wind is assumed to be available only for the first eight hours. In Option I, three units of wind are collected and two are stored to provide power during the other 16 hours. In Option II, natural gas provides power at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

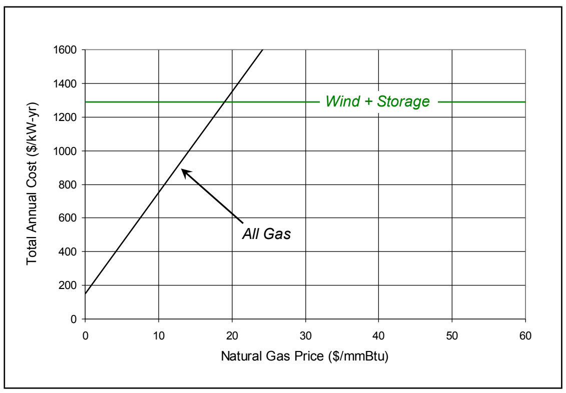

Figure 3.2. In an idealized example with specific capital costs for wind, gas and storage, there is a two-way competition to provide constant power: intermittent wind with storage vs. natural gas on its own. Natural gas wins until the gas price exceeds $19/mmBtu.

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

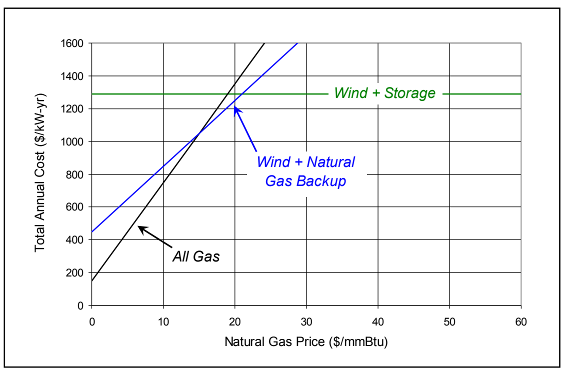

Figure 3.3 **In the same example as in Figure 3.2, there is a three-way competition to provide constant power: intermittent wind with storage *vs.* natural gas on its own *vs.* intermittent wind with natural gas backup. Wind wiith gas backup has the lowest cost at an intermediate gas price ranging from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

For Option I: K = 3*W + S;

For Option II: K = G + F;

For Option III: 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, 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, K = 3*W + S.
(Option I vs. Option III)

F = 3*W, 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, 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.

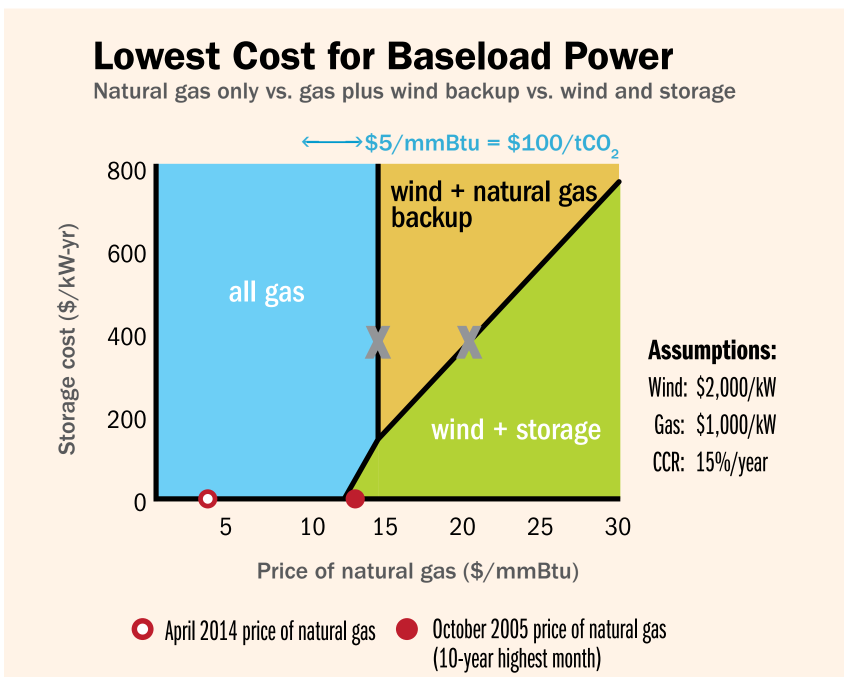

Figure 3.4 The same three-way competition as in Figure 3.3, but the storage cost is now a variable. Domains of lowest cost are differentiated by color. The storage cost assumed in Figures 3.2 and 3.3 is \$390/kW-year; for this cost, the cross-over points, marked with an X, occur at the same gas prices 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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