# The Value of Compressed Air Energy Storage with Wind in Transmission-Constrained Electric Power Systems

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**Abstract**

In this work we examine the potential advantages of co-locating wind and energy storage in order to increase transmission utilization and decrease transmission costs. Co-location of wind and storage decreases transmission requirements, but also decreases the economic value of energy storage compared to locating energy storage at the load. This represents a tradeoff which we examine to estimate the transmission costs required to justify moving storage from load-sited to wind-sited in three different locations in the United States. We examined compressed air energy storage (CAES) in three "wind by wire" scenarios with a variety of transmission and CAES sizes relative to a given amount of wind. In the sites and years evaluated, the optimal amount of transmission ranges from 60 to 100% of the wind farm rating, with the optimal amount of CAES equal to 0 to 35% of the wind farm rating, depending heavily on wind resource, value of electricity in the local market, and the cost of natural gas.

*Keywords:* Wind, energy storage, transmission

## 1. Introduction

A number of studies suggest combining energy storage with wind farms to increase the utilization of transmission assets, beginning with Cavallo (1995) with addition analysis by DeCarolis and Keith (2006); Denholm et al. (2005); Greenblatt et al. (2007); Lower Colorado River Authority (2003); Succar et al. (2006). Much of the high-quality wind resources in the United States are not near major load centers, and have limited ability to integrate into the existing transmission network. Long-distance "wind by wire" power plants have been proposed to tap some of the nation's best wind resources, and deliver that energy to major load centers. This proposed increase in wind development will require new, expensive, and potentially difficult to site transmission lines. If carrying only wind, these lines will be lightly loaded (at the capacity factor of the wind plant). Alternatively, if energy storage is co-located with the wind generation, the transmission line capacity factor can be greatly increased and less transmission will be needed to deliver wind energy to market.

In addition to increasing the overall capacity factor of the transmission system, energy storage can provide additional benefits to wind and to the grid as a whole. Storage can be used to shape wind output, provide firm capacity, provide energy arbitrage for existing generation assets, and provide high-value ancillary services (EPRI-DOE, 2003). The potential benefits of wind shaping have been previously evaluated in Texas by Desai

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(2005); Son (2005). Yet storage can potentially be placed anywhere on the grid, and will receive maximum benefits where it can take advantage of the system as a whole, unconstrained by the need to respond only to variation in wind output. It is unclear whether the transmission-related benefits of combining wind and storage outweigh the constraints imposed when storage and wind both share the same transmission line.

In this work, we examine the relative costs and benefits of combined wind and compressed air energy storage (CAES) power plants, compared to energy storage on the grid as a whole. We estimate the annual revenue from independent wind and energy storage plants, and then compare the individual benefits to those from a combined co-located wind/storage system to determine the transmission costs required to support moving storage devices from the load site to the wind site.

Using a model that optimally dispatches an energy storage device whether located at a load center or when co-located with wind, we evaluate the transmission benefits in three locations: the Midwestern United States (selling energy into PJM's market hub in the Chicago area), Texas, and the Western United States (selling into the California Independent System Operator (CAISO) market). It should be noted that this study is not intended to be a complete evaluation of the role of energy storage, or energy storage valuation. The primary focus of this analysis is evaluating the "break-even" cost of transmission where moving the storage device from load to wind is justified, while also considering the alternative of downsizing transmission. In addition to a base scenario, several sensitivities are considered, including storage capacity and the impact of capacity and ancillary services. We also discuss how our results may change under increasing penetration of wind energy.

The results of this work may aid in the formulation of appropriate policies that capture the transmission value of storage. Significant transmission expansion will be needed if wind is to provide a large fraction of the nation's electricity supply (United States Department of Energy, 2008). Historically, storage has been treated as a generation asset and the ability of storage to capture both transmission and energy benefits in the existing regulatory framework is uncertain.[1] Given the difficulty in siting new transmission, it is important to ensure that all mechanisms to maximize transmission utilization are considered, including storage. This could help increase the viability of wind energy as a major supplier of carbon-free energy, provided that the economic benefits of storage as an alternative to transmission are large enough to warrant this application.

## 2. Framework: Wind-Sited vs. Load Sited Energy Storage

The overall question we attempt to evaluate in this work is the potential change in storage value associated with co-locating storage with wind. We begin by considering the independent value of wind and storage in the grid, illustrated in Figure 1. In this scenario, wind sells its energy via a long-distance transmission line into a market. The value of wind energy varies as a function of time (set by the energy market as a whole), and wind has no ability to "dispatch" its energy according to this time-varying value, although wind may be curtailed when the price of electricity is less than the variable price of wind generation. The wind power plant also must also potentially pay for a new dedicated transmission line loaded at the capacity factor of the wind farm.

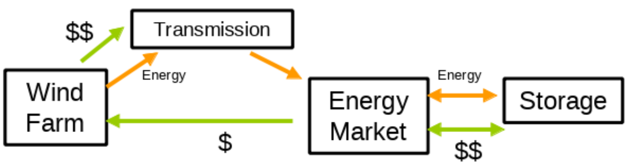


Figure 1: Independent wind and storage scenario.

In addition to the wind power plant, this scenario includes an energy storage plant, which is taking advantage of the time-varying price of electricity by purchasing low-cost off-peak energy, and reselling this

[1] http://www.oe.energy.gov/DocumentsandMedia/final-energy-storage_12-16-08.pdf

energy when the prices are higher. It should be noted that in this scenario, the storage plant and wind energy plant are not physically or operationally related. The storage plant buys and sells energy from the grid as a whole, not from the wind plant or any other single generator. In fact, a storage plant buying from any single entity would be a non-optimal use of this resource. The storage plant may also provide high-value ancillary services such as spinning reserves and frequency regulation. In this scenario, the revenue streams and profitability of the wind plant and storage plant are largely unrelated, with the possible exception of high penetration of either wind, storage, or both. High penetration of wind may increase the spread of off-peak and on-peak prices, increasing the profitability of the storage plant. Similarly, large-scale storage may increase the off-peak price of electricity, increasing wind profitability.

An alternative to this scenario is illustrated in Figure 2. In this case, the storage plant is co-located with the wind. There are advantages and disadvantages to this scenario. The main advantage is the ability to downsize the transmission line, and increase the transmission line loading. In essence, storage provides an alternative to transmission for wind to deliver its product to market. Disadvantages to this scenario involve the transmission-related constraints on storage plant operation. The storage plant is forced to take wind under the constraints of wind production and transmission, and not when it would normally buy and sell electricity based on price. As a result of sharing the transmission line, (and due to increased distance-based transmission losses), the storage plant will not be as profitable as unconstrained and sited closer to load.

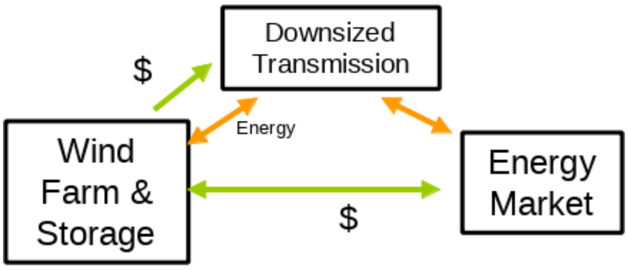


Figure 2: Co-located wind/storage scenario.

The primary question becomes one of whether the reduced transmission costs exceed the penalties associated with sub-optimal use of the energy storage plant, or whether or not energy storage truly is an economic alternative to transmission for bringing wind energy to the market.

## 3. Value of Wind and Storage Systems

We begin by analyzing wind and storage systems when operated completely independently, as in Figure 1. The combined value of these individual components can then be compared to the co-located wind/storage system.

### *3.1. Wind Value in Energy Markets Considering Transmission Constraints*

The lack of geographical coincidence between much of the wind resource and major load centers in the United States will require new transmission lines to support significant new wind development (United States Department of Energy, 2008).

To evaluate the issue of energy storage plant siting, we developed three wind/transmission scenarios, illustrated in Figure 3. The cases chosen were not intended to be optimal, only representative of many possible scenarios. In each case, we selected a set of wind locations with sufficient resources to provide several GW of capacity, enough to potentially justify building a dedicated line. We used hourly simulated wind plant output generated for the Western Wind and Solar Integration Study and the Eastern Wind and Transmission Study (Potter et al., 2008),[2] and corresponding hourly wholesale electricity prices to estimate

[2] http://wind.nrel.gov/public/EWITS/

the value of the wind selling into an energy market. Addition details about this data are provided in Appendix B. We used the day-ahead market in the Midwest (PJM Market) scenario, and the balancing energy markets for the CAISO and ERCOT scenarios.

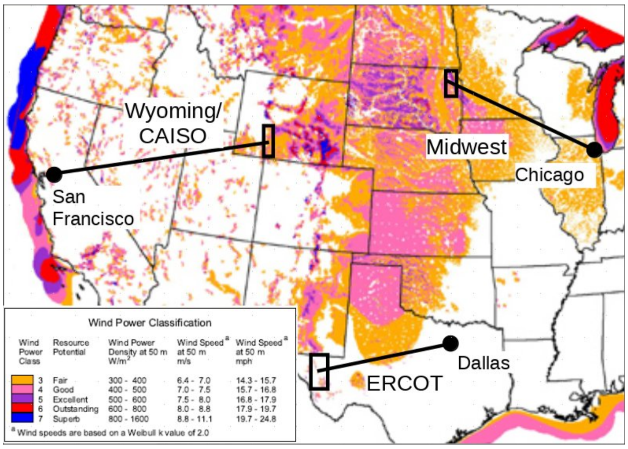


Figure 3: Wind scenarios (https://www.windpoweringamerica.gov/pdfs/wind_maps/us_windmap.pdf).

Table 1 provides a summary of the wind plant characteristics. In addition to the wind plant, we assumed a dedicated high-voltage direct-current (HVDC) transmission line is constructed. The actual length of the line is the linear distance from the wind plant to the load multiplied by 1.12, based on the characteristics of the Intermountain Power Project HVDC line from southwest Utah to southern California (Wu et al., 1988). Losses were also based on this line. The annual revenue in each case was determined by multiplying the delivered wind farm output during each hour by the wholesale energy price in the relevant market during the same hour, plus the federal production tax credit (PTC) valued at \$19/MWh for all hours in the analyzed year. During hours of negative prices, the output of the wind farm was curtailed.[3] It should be noted that the values in this table assume the wind farm is a "price-taker" and not sufficiently large to itself effect the price of electricity. The implications of larger deployment of wind are discussed in more detail later in this work.

The results in Table 1 assume that the transmission line is sized at the maximum actual output of the wind farm; however sizing the transmission line to the maximum output of the wind power plant may not be optimal given the characteristics of the wind output and the cost of transmission.

Figure 4 provides the generation duration curves for each of the three wind plant scenarios derived from the data described in Appendix B, which have been normalized to the fraction of capacity rating. These curves indicate that the plants operate near full capacity for a relatively short period of time. In addition, the aggregated peak output for the year analyzed was always less than the nameplate rating.

Figure 5 provides the annual lost revenue as a function of transmission downsizing. The loss of CAISO revenue is substantially less than from the other two regions due to the sharper generation curve and lower energy prices in the CAISO market.

Figure 5 can be used to evaluate the optimized transmission capacity as a function of cost. If the wind developer must pay for transmission, the annual lost revenues associated with transmission "downsizing" may be less than the annual cost associated with additional transmission capacity. Annual cost may be translated into total cost by the simplified relationship:

$$\text{Annual Cost} = \text{Total Capital Cost} \times \text{Capital Charge Rate},$$

[3] Negative prices occur when demand drops to the point where "must-run" generators may have to be shut off, creating potentially unstable operation, or require expensive plant shut downs. Plant operators are willing to sell energy at a loss to avoid this scenario. See Denholm and Margolis (2007) for additional discussion. In this case curtailment actually occurs when the price of electricity drops below the negative value of the PTC (after transmission losses). This essentially represents the variable cost of wind generation.

Table 1: Wind/transmission scenarios evaluated.

| Scenario Name | ERCOT | Midwest | Wyoming/CAISO |
|---|---|---|---|
| Wind Plant Location | West Texas | MN/ND | South-Central Wyoming |
| Wind/Price Year | 2006 | 2005 | 2006 |
| Market/Pricing Location | ERCOT North | PJM Com-Ed | CAISO NP15 |
| Wind Plant Capacity Factor (%) | 35.1 | 40.6 | 34.5 |
| Wind Plant Peak Output (% of Rating) | 98.9 | 93.2 | 98.8 |
| Wind Plant to Market Linear Distance (km) | 700 | 870 | 1232 |
| Transmission Line Length (km) | 784 | 974 | 1380 |
| Transmission Loss Rate (%) | 4.2 | 4.7 | 6.0 |
| Average Value of Delivered Energy (not including PTC) ($/MWh) | 50.1 | 46.0 | 41.9 |
| Annual Value ($/kW wind capacity) | 206 | 223 | 177 |

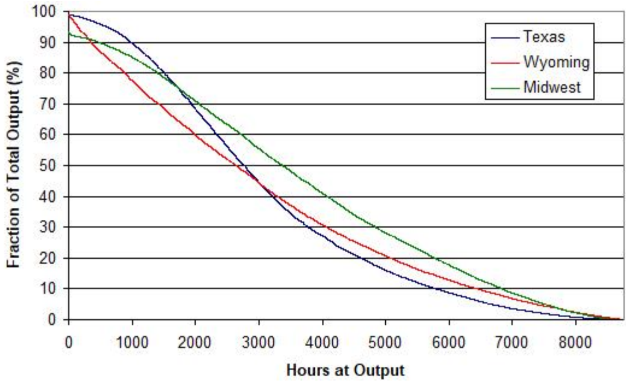


Figure 4: Wind generation duration curves.

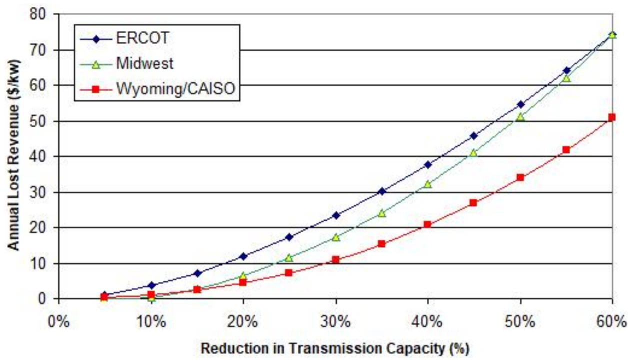


Figure 5: Lost revenues due to reduced transmission capacity and resulting wind curtailment.

where the capital charge rate (CCR) captures all the various financing parameters, and we assume an 11% CCR (Greenblatt et al., 2007). Figure 6 provides the optimal transmission size (as a fraction of the wind farm size) as a function of transmission costs ($/MW-km), using the length of each line as provided in Table 1.

The Wyoming-CAISO scenario has lower revenue losses from downsizing transmission (when compared to the other scenarios), so it incurs a lower penalty associated with wind curtailment; as such, it is optimal

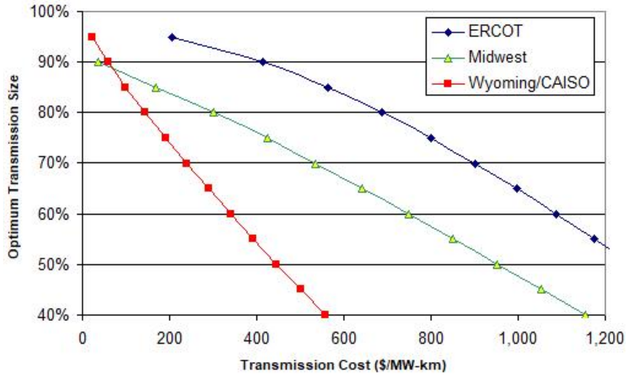


Figure 6: Optimum transmission size as a function of transmission cost in a wind-only scenario.

to build less transmission.

Establishing the wind-only scenarios in this section provides a basis for comparing a wind-sited CAES scenario. The optimal solution for increasing transmission-line loading should consider a combination of both downsized transmission and co-location of energy storage.

*3.2. Grid Storage*

Before evaluating the benefits of storage co-located with wind, we consider the "base case" value of an energy storage plant located in the grid as a whole. Grid storage is used in the electric power grid for energy services (such as load leveling), peak capacity, and ancillary services (such as spinning reserve and frequency regulation). Because nearly all of the energy storage (on a capacity basis) in use is pumped-hydro storage (PHS) (Denholm and Kulcinski, 2004), location of energy storage historically has been driven by geologic requirements. If location is flexible, the "best" location for energy storage is dictated by price—wherever the value of ancillary services, energy arbitrage or other opportunities are highest.

To establish a "base" value of energy storage, we simulated the dispatch of an energy storage device into the energy market at each of the three study locations.

Many previous assessments of energy storage technologies applied to wind have concluded that compressed air energy storage (CAES) is a likely storage technology due to several factors including: limited availability of PHS sites in the middle of the United States, likely availability of CAES caverns, and lower cost compared to non-PHS technologies (such as batteries).

CAES systems are based on conventional gas turbine technology and use the elastic potential energy of compressed air (Succar and Williams, 2008). Energy is stored by compressing air in an airtight underground storage cavern. To extract the stored energy, compressed air is drawn from the storage vessel, heated, and then expanded through a high-pressure turbine that captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, with the exhaust expanded through a low-pressure gas turbine. The turbines are connected to an electric generator. As a result of its use of natural gas, CAES is considered a hybrid generation/storage system.

Our base assumption for the performance of CAES is an energy ratio (kWh in per kWh out) of 0.72, a heat rate of 4431 kJ/kWh,[4] and a variable operation and maintenance (O&M) cost of $3/MWh of generation. Our base CAES size is 20 hours of discharge at rated power capacity.

For a direct comparison between load-sited and wind-sited storage, we considered a mode of storage operation that would be somewhat similar in both cases, whereby the storage plant arbitrages electricity prices by buying low-cost off-peak energy and selling it during periods with higher prices. This energy

[4]There have been no CAES plants built since 1992 and the actual performance of a modern CAES plant is unknown. This performance is based on the range of estimates from sources including Denholm and Kulcinski (2004); Greenblatt et al. (2007); Succar and Williams (2008).

Table 2: Arbitrage performance of a 20-hour CAES device in evaluated scenarios.

| Scenario Name | Texas | Midwest | Wyoming/CAISO |
|---|---|---|---|
| Market/Pricing Location | ERCOT North | PJM Com-Ed | CAISO NP15 |
| Avg. Purchase Price ($/MWh) | 26.8 | 24.3 | 16.0 |
| Avg. Sales Price ($/MWh) | 81.4 | 79.8 | 73.2 |
| Avg. NG Cost ($/GJ) | 6.1 | 8.3 | 6.2 |
| Discharge Capacity Factor | 30.4 | 25.2 | 25.8 |
| Net Revenue ($ per kW) | 86.2 | 49.3 | 70.7 |
| Year-1 ROI @ $750/kW of CAES Capacity | 11.4 | 6.6 | 9.4 |

arbitrage is formulated as a mixed-integer program (the integer variables track whether the expansion turbine is on- or off-line in each hour), the details of which are given in Appendix A. Following Sioshansi et al. (2009) we assume the storage operator has perfect foresight of electricity prices over a two-week period, which allows the storage operator to exploit the predictable pattern that electricity prices follow.[5] Our base case ignores potentially high-value opportunities such as ancillary services, which we discuss later in this work.

Table 2 provides the results for storage plant arbitrage value in the three locations evaluated. Hourly electricity prices for the one year evaluated are identical to those used to evaluate wind value discussed previously. The natural gas price during each hour is derived from monthly average prices of gas delivered to electricity utilities as reported by the U.S. Energy Information Administration. As with the wind-only scenario, we assume a price-taking device. Additional discussion of reduction of arbitrage value resulting from large scale deployment of energy storage is provided by Sioshansi et al. (2009).

Although we do not attempt to determine the optimal storage value (which would require co-optimization with ancillary services and other potential values), we do provide a basic financial performance metric for the arbitrage-only scenario. The overall profitability or financial performance would be determined by the future prices of electricity and natural gas. Instead of making predictions about these future prices, we provide the "Year-1 Return on Investment" (ROI) as a financial performance metric, which is simply the annual net revenue divided by the capital cost. The net revenue is equal to:

$$\text{Sales Revenue} - \text{Electricity Purchases} - \text{Natural Gas} - \text{O\&M}.$$

The Year-1 ROI for the three projects can be compared to a typical capital charge rate (10-12%) for generation assets. Assuming a value of $750/kW,[6] CAES appears to come close to meeting a minimum revenue requirement in the ERCOT system for the year evaluated on arbitrage revenues alone. The profitability of the PJM/Com-Ed case is limited by the high cost of natural gas in Illinois, and along with the CAISO scenario would require additional revenues to be justified economically.

*3.3. Combined Wind/Storage Power Plants*

The value of "independent" wind and storage plants can be compared to the value of moving the CAES plant to the wind site, with energy storage providing an alternative to downsizing alone. The primary question is whether the decreased transmission costs can provide enough incentive for a CAES plant to move from a load-sited location to co-location with the wind plant.

This analysis was done by co-optimizing operation of the wind farm and storage plant, assuming the two are being operated in concert to maximize net profits. The storage plant continues to arbitrage price

[5]Although the assumption of perfect foresight of electricity prices may seem unrealistic, Sioshansi et al. (2009) found that using very simple dispatch techniques that use only historical data and no price forecasting can capture up to 90% of the potential arbitrage value with perfect foresight of prices.

[6]This cost is roughly midway between $650/kW cited by Succar and Williams (2008) and $890/kW cited by Greenblatt (2005).

differences off- and on-peak, but its operations are constrained by the capacity of the transmission, utilization of transmission capacity by the wind farm, and transmission losses. The wind plant continues to sell to the grid, constrained by transmission. When the wind plant output exceeds the transmission capacity, it provides a costless (because it would otherwise be curtailed) source of energy to the storage plant. Again, the model was formulated as a mixed-integer program, the details of which are given in Appendix A.

Moving the CAES plant from load site to the wind site and downsizing transmission has several impacts on the net revenues of the combined wind/CAES system, compared to independent wind and CAES plants. As quantified earlier, downsizing alone results in wind curtailment and lost revenue. Replacing some or all of this transmission capacity will reduce, but not eliminate, curtailment because the CAES storage cavern occasionally will be filled and unable to take all of the wind when the output exceeds the downsized transmission line. Moving the CAES plant from independent to "wind-coupled" operation results in several losses in revenue due to transmission constraints. Most obviously, all grid sales and non-wind grid purchases are subject to the additional transmission losses associated with remote siting. More significantly is the lost opportunities for the CAES plant to buy and sell electricity optimally—the plant has reduced sales opportunities due to sharing the transmission line with the wind farm. It should be noted that assigning costs and benefits to the various components is a matter of accounting. Ultimately, the net revenue of the combined system compared to the base configuration (independent wind and CAES plants) determines the value of shifting CAES from the load to the wind site; however, breaking out the components provides useful insight into the change in profitability associated with moving CAES from the load to the wind site.

Figures 7 and 8 compare the operation of the load-sited CAES with the wind-sited device in ERCOT. Figure 8 provides an optimized CAES charge/discharge pattern during a three-day period for a 200 MW, 20-hour device located at the load, independent of wind operation or transmission constraints. Among the noticeable patterns in Figure 7 is the greater amount of discharging compared to charging, resulting from the hybrid nature of CAES (requiring only 0.72 hours of charging for each hour of discharge).

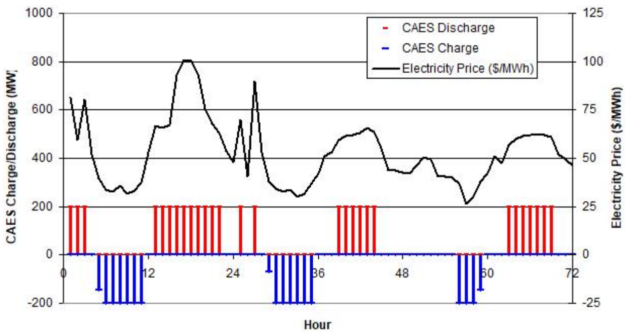


Figure 7: Operation of an independent CAES device maximizing arbitrage revenue.

Figure 8 provides the operation for a co-located wind/CAES plant, with a 1000 MW wind plant, the same 200 MW, 20-hour CAES plant as before, and an 800 MW transmission line, during the same four-day period shown in Figure 7. The differences between Figures 7 and 8 partially qualify the potential losses in revenue associated with the combined wind/CAES system.

Several events in Figure 8 reduce the revenue of the CAES device relative to the load-sited storage case. In day one, operation of the CAES device is quite similar between the two cases, so CAES revenue losses are driven largely by the relatively small transmission losses. In days two and three, however, there is some coincidence between periods of high prices and high wind output. There are two higher-price periods in the middle of these two days; and in the load-sited case, the CAES discharges at maximum capacity during these periods at high profitability. In the wind-sited case, during both price spikes, the wind output is high, and the CAES plant cannot take complete advantage of the arbitrage opportunity.

In the independent case, with load-sited storage, the wind farm's gross annual revenue (assuming a 1000 MW wind farm and 1000 MW transmission line) is $210.0 million, while the CAES plant's net revenue is $17.2 million, for a total of $227.2 million. In the co-located case, with a downsized 800 MW line, the

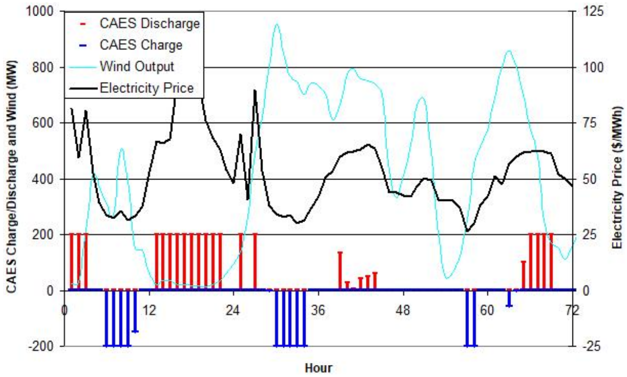


Figure 8: Operation of a wind-co-located CAES device maximizing wind and arbitrage revenue.

combined revenue is \$216.0 million. This means that the loss of profit by co-locating the CAES plant and downsizing the transmission line is \$11.2 million in this year, which represents the annualized "break-even" cost of the extra 200 MW of transmission capacity, above which it makes sense to move CAES from the load to the wind site. Assuming an 11% capital charge rate, this corresponds to a capital cost of \$97.6 million for 780 km of additional transmission capacity, or a break-even cost of \$650/MW-km.

The lost revenue associated with a combination of transmission downsizing and CAES co-location was calculated for cases where the transmission line was sized from 60% to 100% of the wind farm size in 10% increments, and the CAES plant was sized from 0% to 40% of the wind farm size. This included cases in which the combined transmission and CAES size is less than the wind farm rating.

Figure 9 provides an example of the reduced revenue cases calculated for the ERCOT scenario. It is similar to Figure 6 but lost revenue is shown as a function of both transmission capacity (individual lines representing different transmission capacity) and CAES size, both rated as a fraction of the wind farm. The fact that the lost revenue resulting from transmission downsizing can be reduced by adding CAES indicates that use of CAES co-located with wind may be warranted given sufficiently high transmission costs.

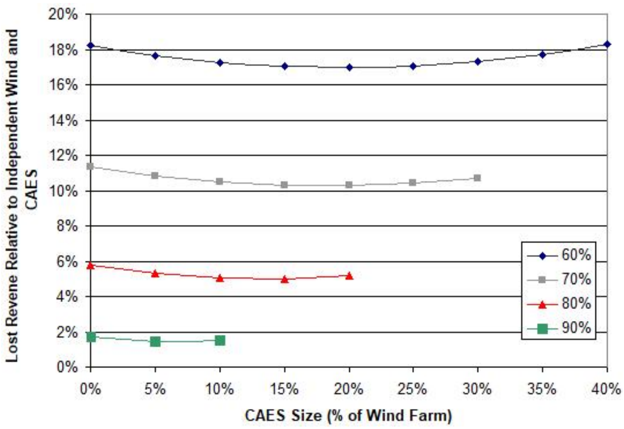


Figure 9: Lost revenue associated with downsizing transmission and moving CAES from load site to wind site in ERCOT.

Lost revenue was calculated at each location with previously stated combinations of transmission and CAES sizes. The results were used to create a surface space of possible solutions that can be compared to the "break-even" cost for transmission where the savings exceed the reduction in value associated with co-locating wind and CAES. For each transmission cost, the optimal combination of transmission and CAES was then identified.

Figure 10 shows the optimal transmission and CAES size as a function of transmission cost in \$/MW-km for ERCOT. When the transmission cost is less than about $350/MW-km, the optimal transmission capacity is close to 100%—the revenue losses associated with downsized transmission are greater than the benefits of decreased transmission costs. When the transmission cost exceeds about $350/MW-km, this cost is greater than the lost revenue of downsizing the transmission line by 5%. Referring back to Figure 9, the optimal size of the CAES plant at a 90% transmission line size is 5% of rated capacity. This is represented by the minimum point on the 90% transmission curve. Beyond $850/MW-km, the optimum transmission size is 80% of rated capacity, and the optimum point on the 80% transmission size curve is a CAES rating of 15%. As illustrated in Figure 10, the actual optimization curve for the CAES size is fairly shallow, meaning that the difference in economic performance for a somewhat greater or smaller amount of co-located CAES is relatively small.

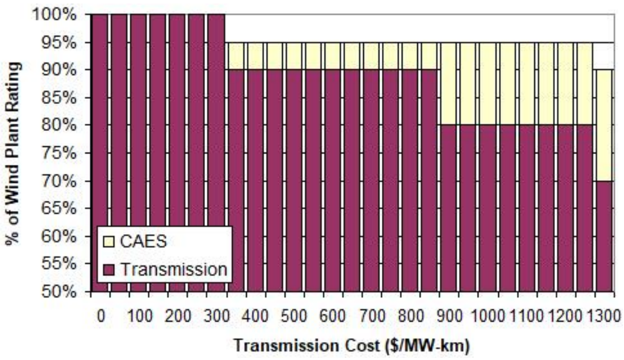


Figure 10: Optimal mix of transmission size and CAES co-location in ERCOT.

Figures 9 and 12 provide the lost revenue curves and resulting transmission & CAES optimization curves for the Midwest scenario. The largest difference in this case is the much lower transmission cost at which downsizing transmission is economic, as discussed in Section 3.1. In addition, the optimal CAES size in the Midwest is larger. This is largely due to the low arbitrage revenues in the storage only case—reducing the penalty associated with moving storage from load-site to wind-site.

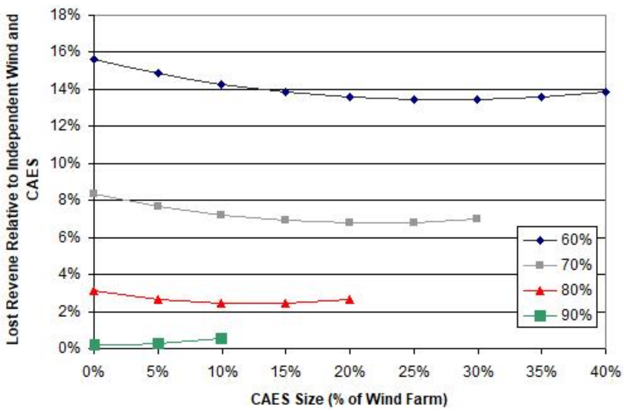


Figure 11: Lost revenue associated with downsizing transmission and moving CAES from load site to wind site in Midwest.

The results for CAISO, in Figures 13 and 14 are substantially different, with very little CAES being optimal.

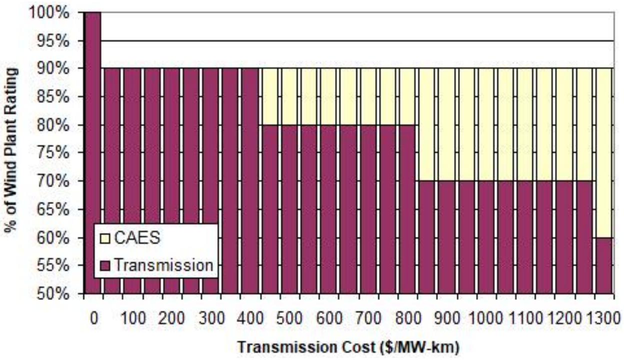


Figure 12: Optimal mix of transmission size and CAES co-location in Midwest.

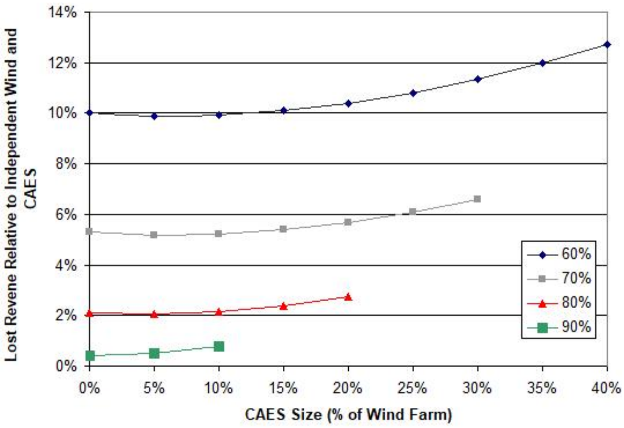


Figure 13: Lost revenue associated with downsizing transmission and moving CAES from load site to wind site in Wyoming/CAISO.

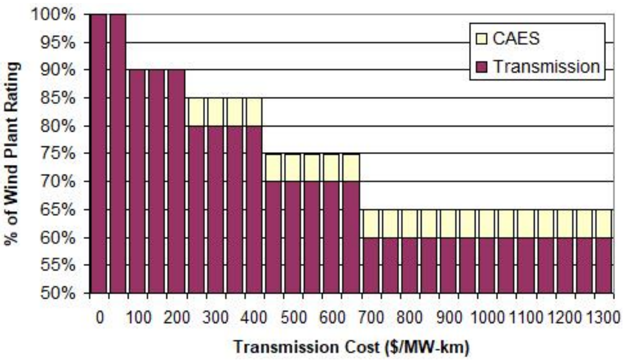


Figure 14: Optimal mix of transmission size and CAES co-location in Wyoming/CAISO.

*3.4. Comparison to Actual Transmission Costs*

To place our results cost in context, we collected transmission development cost data for a variety of projects.[7] The values are provided in Figure 15, and consider both AC lines and HVDC lines rated at 500 MW or greater. Each line cost was adjusted to 2008$, and includes data from 1995 to 2008. The results

[7]National Renewable Energy Laboratory, Historical Transmission Cost Data.

do not reflect changes in commodity costs or costs associated with long delays and other siting difficulties. It is difficult to draw any specific conclusions from this data, but it is clear that there are a large number of data points representing transmission costs that are greater than the cost required to warrant moving at least some CAES capacity from load center to wind site. (The minimum costs justifying moving some CAES capacity are \$350, \$450, and \$250 per MW-km for ERCOT, PJM, and CAISO, respectively). A more detailed analysis of transmission costs and projections of new transmission development for wind is provided by Mills et al. (2012).

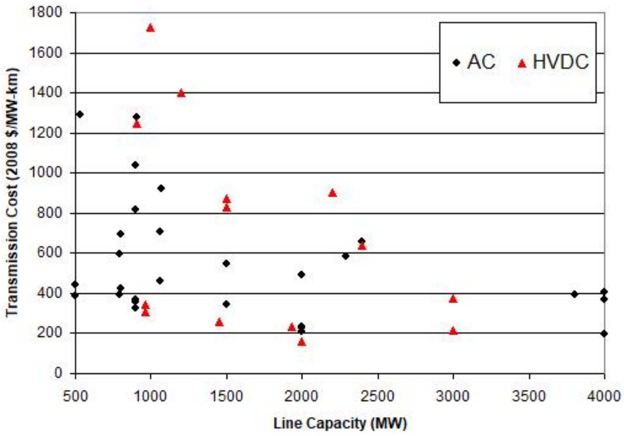


Figure 15: Historical transmission cost data.

## 4. Sensitivities

The results provided in Section 3 represent a base scenario with several simplifying assumptions. The actual "break-even" cost of transmission that would justify moving CAES from load to wind site would be higher or lower depending on additional factors discussed in this section, including storage size, additional storage value, and the configuration of the CAES device.

### *4.1. Storage Energy Capacity*

One of the significant decreases in revenue associated with downsizing transmission is wind curtailment. As noted earlier, a device with 20 hours of storage will occasionally fill completely during the windy seasons. Longer storage times may be possible for CAES, if large formations are available in aquifers, depleted gas wells, and other natural formations. These long storage times may decrease the break-even cost of transmission when compared to load-sited storage. We repeated the scenarios with devices of up to 200 hours of capacity for one scenario in each location—a 70% transmission rating and 20% CAES rating. Figure 16 illustrates how the transmission breakeven cost drops as a function of storage size. This scenario is not the optimal sizing for each location, but provided as an illustration of the potential benefits of larger storage capacity. It is important to note that for this analysis, extremely long foresight of prices and wind resource is necessary—in this case the optimization period was extended to a month (with an additional two-week lookahead period) to ensure long carryover periods are possible.

It should be noted that the justification for moving additional CAES from the load site to the wind site is based on the relative increase in storage value for the wind-sited device relative to the load-sited device. A load-sited device has exhausted most of the arbitrage value at 20 hours of capacity; moving from 20 to 40 hours of discharge capacity increases the arbitrage value by about 3% and from 20 to 200 hours by less than 7%, even with the improbably long foresight of prices used here. The relationship between storage capacity and value is discussed in more detail in Sioshansi et al. (2009). Alternately, the larger device located at the wind site can continue to add value by decreasing curtailment. This relative increase in value for

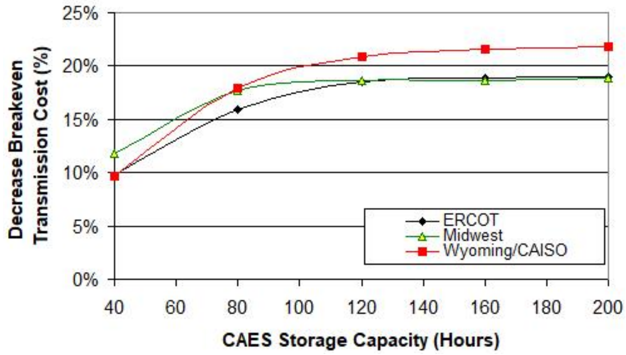


Figure 16: Decrease in transmission breakeven cost relative to a 20 hour device for a 70% transmission & 20% CAES scenario.

the larger wind-sited device allows the decrease in break-even costs, assuming large storage formations are available.

*4.2. Additional Storage Values*

One of the most obvious shortcomings in the base storage evaluation is the lack of complete valuation of the storage device. Our base analysis ignored the potentially significant revenue associated with capacity payments, ancillary services, and other opportunities. The 6.6% one-year ROI for the PJM case, for example, certainly would not justify building a device to take advantage of arbitrage alone. However, this lack of appropriate valuation would not justify moving the storage device from the load center to the wind center. In all cases, the transmission constraints of wind-sited storage will reduce the value of capacity and ancillary services relative to a load-sited device due to both the increased transmission losses and the reduced capacity available resulting from wind occupying the lines during many hours. The lack of consideration of alternative value streams means the break-even values presented in Section 3 represent essentially a "best-case" scenario for moving storage from load to wind, and the real break-even costs will increase when full storage valuation is considered.

A complete valuation of an energy storage device is beyond the scope of this work, but we can provide a simple example of how the ancillary service value of a CAES device will be higher when sited at the load, and will tend to increase the break-even price of transmission.[8] Evaluation of the value of multiple services (energy and capacity) requires optimization of a CAES device to ensure the device meets operational constraints. For example, a CAES device providing spinning reserve requires optimization of the expander considering part load operation. However, an obvious use of the device with virtually no trade-offs between energy and capacity services is offering spinning reserve whenever the device is charging. In the ERCOT example, the load-sited device with 20 hours of storage charges for a total of 1970 hours during the year. Using market data for the ERCOT zone (Responsive Reserve Service) for 2006, a 400 MW device bid into this market (at zero cost, so it is always taken, and assuming this bid does not suppress the price of spinning reserve) would have received an additional $5.1 million of revenue, increasing the annual value of the device by nearly 15%. When co-located with wind, the CAES device is unable to offer this amount of reserve while charging, because the wind will often completely fill the line, and the CAES device cannot offer additional energy supply by reducing its charging rate. In the scenario where the 400 MW device is co-located with wind, the number of hours where the device is charging and spare transmission capacity is available is reduced from 1970 to 983 hours, and the corresponding potential spinning reserve value is reduced by more than 50%. This increases the break-even transmission price required to justify co-locating wind and CAES, and we would expect this difference to increase if a complete storage valuation were performed, including bidding into high-value ancillary service markets and/or capacity markets (not considering any impact of downsizing the transmission line on wind capacity value). The same issues apply for any wind "firming"

[8]See Walawalkar et al. (2007) for additional discussion of the value of ancillary services as well as energy arbitrage.

or minimizing imbalance penalties—a wind-sited storage device will always be at a disadvantage relative to a load-sited device when providing these services. There are several caveats to this result, primarily related to the depth of markets for ancillary services. The total market for ancillary services is limited, and previous analysis has found rapid decline in the value of ancillary service markets with the introduction of energy storage devices (Sioshansi and Denholm, 2010). Despite these limitations, complete valuation of the potential revenues for a storage device will clearly decrease the incentive for co-locating wind and storage.

One of the important factors in evaluating the total value of a CAES device (and a potential advantage of CAES over certain other energy storage devices) is its potentially independent charging and discharging capacity. Although the existing U.S. facility shares a common turbo-machinery train, resulting in equal input and output capacity, these components can be sized independently, and at least one proposed CAES facility would use separate expander and compressor components.[9] These components could be optimized to provide different energy and capacity services at the load site. This benefit has also been applied to evaluation of wind/storage systems by Greenblatt et al. (2007) who evaluated a baseload wind configuration designed to minimize cost, and found an optimal ratio of expander to compressor size equal to 0.82:1. Our base case assumes a ratio of 1:1 which may be non-optimal when optimizing for maximum profit in either the load-sited case, or wind sited case. One of the difficulties in examining sensitivity of different CAES components is the limited ability to perform a direct comparison—a CAES configuration optimized for ancillary services and energy arbitrage when sited at the load may be different that a configuration optimized for transmission downsizing when sited at a wind farm. Despite this, it is useful to provide an indication of how net revenue may vary as a function of expander/compressor ratio considering the cost of increased capacity. Figure 17 illustrates the change in system net revenue in ERCOT for a scenario where the transmission system is set to 70% capacity and the compressor is set to 30% capacity. The expander is varied from 10% capacity to 70% capacity, (equivalent to a expander to compressor ratio range of 0.33:1 to 2.33:1). We examined the change in total system revenue including the change in expander costs, assuming an annualized expander cost of \$20.4/kW (Greenblatt et al., 2007).

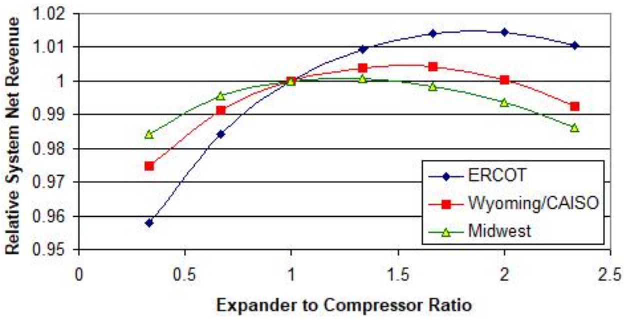


Figure 17: Change in net revenue as a function of expander size in ERCOT a 70% transmission & 30% compressor.

Figure 17 illustrates that a better comparison between load-sited and wind-sited CAES would use a different configuration than the 1:1 ratio used in the base case, although the overall benefit of changing this ratio is relatively small. Overall, the ability of a CAES plant to provide multiple services complicates a direct comparison between load-sited and wind-sited CAES. The results in Section 3 illustrate substantial differences in the regional value of CAES, restricting the ability to determine a generalized value for transmission replacement even without considering the substantial variation in capacity and ancillary services which may be obtained. In addition, the potential ability to vary the size of both the storage cavern and storage components means that at each location an optimal configuration will need to be determined based on the combination of transmission, energy, and ancillary services to be provided.

[9] *cf.* Ohio Power Siting Board Case Number 99-1626-EL-BGN.

## 5. Discussion and Conclusions

We have performed a purely economic analysis in an attempt to determine the transmission-related value of moving a load-sited storage device to the wind site. While there is also a large range in historical transmission price data, there appears to be significant number of cases of transmission costs that warrant co-locating wind with storage. However, co-location of wind and storage will be less attractive if a load-sited storage device is able to take advantage of high-value ancillary or capacity services. Further analysis will be required to evaluate the benefit of using CAES devices to provide ancillary services, especially because providing these services with CAES is not as simple as from batteries or other pure storage devices. Overall, however, the optimal sizing of co-located CAES relative to the wind in most cases evaluated is less than 25% of the rated wind farm capacity.

There are a number of additional caveats that must be addressed when considering the results of this analysis. The most obvious is the fact that we calculate transmission costs using a linear relationship with length and capacity. In reality, transmission is extremely lumpy in nature, and much of the cost is associated with right-of-way acquisition and development. Despite this limitation, the results presented here can be used to understand the tradeoffs when considering line upgrades or multiline development into wind-rich resources.

Another complicating factor is related to the ability to site both transmission lines and energy storage facilities. There are significant uncertainties in costs, ability, and time requirements to site and develop new transmission lines. CAES offers an option for adding wind to existing lines, and can be developed on a shorter time scale than new lines. An additional factor is the ability to site CAES plants. Our analysis placed the CAES plant at or very close to the load center; it may be easier to site a CAES plant in a remote location. A final advantage of remote-sited CAES may be benefits of fuel supply. In our analysis, the price of natural gas was assumed to be equivalent in both locations to isolate the main issue of the value of co-location (we did not want to derive results that were based on arbitrage of natural gas prices between regions, as opposed to the transmission value of CAES relocation). In reality, there almost certainly will be price variation between CAES plants at two locations, and remotely sited CAES may experience fewer constraints on actual supply, and take advantage of alternatives to natural gas, such as coal or biomass-derived syngas (Denholm, 2006). If the economics of CAES are "close" in some scenarios, this mix of additional advantages of remote or wind-sited CAES may motivate this application.

Finally, additional work will be needed to examine the impact of large-scale wind deployment, and changes in storage value that occur when the load and corresponding market prices change under large-scale penetration of wind. We would hypothesize that co-located wind/CAES would become more attractive as the penetration of wind increases. Fundamentally, the problem with co-located wind/CAES is that wind production and energy costs are largely decoupled at the current levels of wind penetration. As the amount of wind on the system increases, it will begin to drive electricity prices, resulting in lower energy prices during periods of high wind, and higher prices during periods of lower wind. An optimally dispatched CAES system will begin to more closely respond to wind patterns, so the operation of wind-sited and load-sited CAES will begin to converge. This would likely reduce (but not eliminate) the "penalty" of non-optimized CAES dispatch associated with wind-sited CAES, and increase the attractiveness of CAES as an alternative to additional transmission development.

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## Appendix A. Mathematical Formulation

We describe the models used in our analysis of a standalone and co-located CAES device. Both models were formulated using GAMS 21.7 and were solved CPLEX 9.0. GAMS is a mathematical programming language, which allows mathematical programs to be formulated in a relatively simplified and user-understandable manner. CPLEX is a software package, which solves continuous and integer linear programs.

### *Appendix A.1. Standalone Storage Model*

We first define the following notation.

*Appendix A.1.1. Problem Parameters*

$T$ number of hours in planning horizon
$\kappa$ power capacity of CAES device
$h$ hours of storage in CAES device
$\eta$ roundtrip efficiency of CAES device
$G$ natural gas used (mmBTU/MWh) in CAES expander
$c^C$ compression cost ($/MWh) of CAES
$c^E$ expansion cost ($/MWh) of CAES
$\lambda$ minimum load (MW) of CAES expander
$p_t$ price ($/MWh) of electricity in hour $t$
$c_t^G$ cost ($/mmBTU) of natural gas in hour $t$

*Appendix A.1.2. Decision Variables*

$l_t$ storage level of CAES device (MWh) at end of hour $t$
$s_t$ energy put into CAES (MWh) in hour $t$
$d_t$ energy taken out of CAES (MWh) in hour $t$
$u_t$ binary variable indicating whether CAES expander is on- or off-line in hour $t$
$\sigma_t$ energy sold in hour $t$
$\pi_t$ energy purchased in hour $t$

*Appendix A.1.3. Model Formulation*

The problem is formulated as maximizing net profits from arbitrage:

$$\max_{l,s,d,u,\sigma,\pi} \sum_t \left( p_t(\sigma_t - \pi_t) - c^C s_t - (G \cdot c_t^G + c^E)\frac{d_t}{\eta} \right),$$

subject to the following constraints:

- storage level definition ($\forall\ t = 1, \dots, T$):

$$l_t = l_{t-1} + s_t - d_t,$$

- energy balance ($\forall\ t = 1, \dots, T$):

$$\sigma_t - \pi_t + s_t - \frac{d_t}{\eta} = 0,$$

- CAES expander capacity ($\forall\ t = 1, \dots, T$):

$$\lambda u_t \leq \frac{d_t}{\eta} \leq \kappa u_t,$$

- CAES compressor capacity ($\forall\ t = 1, \dots, T$):

$$0 \leq s_t \leq \kappa,$$

- CAES storage capacity ($\forall\ t = 1, \dots, T$):

$$o \leq l_t \leq h\kappa,$$

- binary constraint ($\forall\ t = 1, \dots, T$):

$$u_t \in \{0, 1\},$$

- non-negativity ($\forall\ t = 1, \dots, T$):

$$\sigma_t, \pi_t \geq 0.$$

*Appendix A.2. Co-located Storage Model*

When the storage device is co-located with the wind farm, and its operation is co-optimized with wind generation, we add the following notation to the model.

*Appendix A.2.1. Problem Parameters*

$\tau$ capacity of transmission link
$\rho$ transmission losses
$X$ wind production tax credit
$\overline{w}_t$ wind generation available in hour $t$

*Appendix A.2.2. Decision Variables*

$w_t$ wind generation used in hour $t$

*Appendix A.2.3. Model Formulation*

The problem is then formulated as maximizing profits from arbitrage and wind production:

$$\max_{l,s,d,u,\sigma,\pi,w} \sum_t \left( (1-\rho)p_t\sigma_t - (1+\rho)p_t\pi_t + Xw_t - c^C s_t - (G \cdot c_t^G + c^E)\frac{d_t}{\eta} \right),$$

subject to the following constraints:

- storage level definition ($\forall\ t = 1, \ldots, T$):

$$l_t = l_{t-1} + s_t - d_t,$$

- energy balance ($\forall\ t = 1, \ldots, T$):

$$\sigma_t - \pi_t + s_t - \frac{d_t}{\eta} = w_t,$$

- wind availability ($\forall\ t = 1, \ldots, T$):

$$0 \leq w_t \leq \overline{w}_t,$$

- CAES expander capacity ($\forall\ t = 1, \ldots, T$):

$$\lambda u_t \leq \frac{d_t}{\eta} \leq \kappa u_t,$$

- CAES compressor capacity ($\forall\ t = 1, \ldots, T$):

$$0 \leq s_t \leq \kappa,$$

- CAES storage capacity ($\forall\ t = 1, \ldots, T$):

$$o \leq l_t \leq h\kappa,$$

- transmission capacity ($\forall\ t = 1, \ldots, T$):

$$-\tau \leq \sigma_t - \pi_t \leq \tau,$$

- binary constraint ($\forall\ t = 1, \ldots, T$):

$$u_t \in \{0, 1\},$$

- non-negativity ($\forall\ t = 1, \ldots, T$):

$$\sigma_t, \pi_t \geq 0.$$

## Appendix B. Wind Resource Data

Data for the Wyoming/CAISO Scenario and the ERCOT Scenario were derived from the Western Wind and Solar Integration Study (Potter et al., 2008). Full hourly resource data may be obtained from http://mercator.nrel.gov/wwsi/. Each data point represents 30 MW of capacity, and may be obtained by the Site ID number provided in the table.

| | Wyoming | | | | | ERCOT (West Texas) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | W | Cap. | Wind | | | W | Cap. | Wind |
| SiteID | Lat. | Long. | Factor | Speed | SiteID | Lat. | Long. | Factor | Speed |
| 14146 | 41.11 | 110.38 | 33 | 8.2 | 125 | 31.71 | 104.69 | 37.8 | 8.88 |
| 14212 | 41.13 | 110.49 | 33.5 | 8.19 | 139 | 31.74 | 104.69 | 37.7 | 8.88 |
| 14214 | 41.13 | 110.46 | 33.3 | 8.15 | 154 | 31.78 | 104.73 | 37.6 | 8.83 |
| 14274 | 41.14 | 110.49 | 33.5 | 8.17 | 127 | 31.71 | 104.66 | 37.6 | 8.86 |
| 14277 | 41.14 | 110.34 | 33.4 | 8.13 | 51 | 31.51 | 104.56 | 37.5 | 8.77 |
| 14276 | 41.14 | 110.46 | 33.2 | 8.12 | 111 | 31.68 | 104.66 | 37.5 | 8.83 |
| 14328 | 41.16 | 110.46 | 33.2 | 8.09 | 102 | 31.64 | 104.63 | 37.3 | 8.81 |
| 20449 | 42.34 | 108.68 | 38.1 | 8.64 | 65 | 31.54 | 104.59 | 37.2 | 8.71 |
| 20451 | 42.34 | 108.64 | 37.8 | 8.61 | 118 | 31.69 | 104.66 | 37.2 | 8.8 |
| 20287 | 42.31 | 108.71 | 37.8 | 8.52 | 113 | 31.68 | 104.63 | 37.2 | 8.8 |
| 20450 | 42.34 | 108.66 | 37.7 | 8.59 | 116 | 31.69 | 104.69 | 37.2 | 8.77 |
| 20286 | 42.31 | 108.73 | 37.4 | 8.47 | 156 | 31.78 | 104.69 | 37.2 | 8.84 |
| 20364 | 42.33 | 108.71 | 37.3 | 8.47 | 133 | 31.73 | 104.69 | 37.1 | 8.77 |
| 13691 | 41.01 | 108.93 | 37 | 8.72 | 67 | 31.54 | 104.56 | 37.1 | 8.74 |
| 13692 | 41.01 | 108.89 | 37 | 8.69 | 141 | 31.74 | 104.66 | 37.1 | 8.79 |
| 20289 | 42.31 | 108.68 | 37 | 8.41 | 135 | 31.73 | 104.66 | 37 | 8.78 |
| 20216 | 42.29 | 108.71 | 36.9 | 8.36 | 126 | 31.71 | 104.68 | 37 | 8.76 |
| 20365 | 42.33 | 108.69 | 36.8 | 8.41 | 175 | 31.81 | 104.73 | 36.9 | 8.74 |
| 13909 | 41.06 | 108.93 | 36.8 | 8.78 | 45 | 31.49 | 104.56 | 36.9 | 8.65 |
| 13694 | 41.01 | 108.86 | 36.7 | 8.68 | 98 | 31.63 | 104.63 | 36.9 | 8.73 |
| 21206 | 42.46 | 108.51 | 36.7 | 8.6 | 106 | 31.66 | 104.63 | 36.8 | 8.74 |
| 20368 | 42.33 | 108.64 | 36.7 | 8.41 | 112 | 31.68 | 104.64 | 36.8 | 8.73 |
| 20367 | 42.33 | 108.66 | 36.7 | 8.42 | 60 | 31.53 | 104.56 | 36.8 | 8.67 |
| 13910 | 41.06 | 108.91 | 36.6 | 8.79 | 140 | 31.74 | 104.68 | 36.8 | 8.74 |
| 20290 | 42.31 | 108.66 | 36.6 | 8.36 | 79 | 31.58 | 104.59 | 36.7 | 8.72 |
| 20217 | 42.29 | 108.69 | 36.5 | 8.31 | 104 | 31.64 | 104.59 | 36.7 | 8.74 |
| 13693 | 41.01 | 108.88 | 36.3 | 8.61 | 146 | 31.76 | 104.69 | 36.6 | 8.73 |
| 21334 | 42.48 | 108.53 | 36.2 | 8.59 | 155 | 31.78 | 104.71 | 36.6 | 8.72 |
| 21580 | 42.51 | 108.53 | 36.2 | 8.66 | 138 | 31.74 | 104.71 | 36.6 | 8.67 |
| 13911 | 41.06 | 108.89 | 36.2 | 8.7 | 73 | 31.56 | 104.59 | 36.6 | 8.66 |
| 21578 | 42.51 | 108.56 | 36.2 | 8.63 | 164 | 31.79 | 104.73 | 36.6 | 8.67 |
| 21579 | 42.51 | 108.54 | 36.1 | 8.64 | 114 | 31.68 | 104.61 | 36.6 | 8.69 |
| 21333 | 42.48 | 108.54 | 36.1 | 8.57 | 94 | 31.61 | 104.59 | 36.6 | 8.72 |
| 21577 | 42.51 | 108.58 | 36 | 8.59 | 103 | 31.64 | 104.61 | 36.5 | 8.71 |
| 21581 | 42.51 | 108.51 | 36 | 8.62 | 75 | 31.56 | 104.56 | 36.5 | 8.69 |
| 21576 | 42.51 | 108.59 | 35.9 | 8.56 | 66 | 31.54 | 104.58 | 36.5 | 8.62 |
| 21454 | 42.49 | 108.53 | 35.7 | 8.55 | 117 | 31.69 | 104.68 | 36.5 | 8.67 |
| 13912 | 41.06 | 108.88 | 35.7 | 8.6 | 120 | 31.69 | 104.63 | 36.5 | 8.7 |
| 21453 | 42.49 | 108.54 | 35.6 | 8.53 | 100 | 31.63 | 104.59 | 36.4 | 8.71 |
| 14148 | 41.11 | 108.98 | 35.6 | 8.61 | 128 | 31.71 | 104.64 | 36.4 | 8.67 |
| 21452 | 42.49 | 108.56 | 35.6 | 8.5 | 53 | 31.51 | 104.53 | 36.4 | 8.62 |
| 21455 | 42.49 | 108.51 | 35.5 | 8.51 | 85 | 31.59 | 104.59 | 36.4 | 8.68 |
| 21575 | 42.51 | 108.61 | 35.5 | 8.5 | 115 | 31.68 | 104.59 | 36.3 | 8.65 |
| 21571 | 42.51 | 108.78 | 35.4 | 8.58 | 52 | 31.51 | 104.54 | 36.3 | 8.6 |
| 21574 | 42.51 | 108.63 | 35.4 | 8.49 | 134 | 31.73 | 104.68 | 36.3 | 8.66 |
| 21573 | 42.51 | 108.74 | 35.3 | 8.56 | 129 | 31.71 | 104.63 | 36.3 | 8.65 |
| 21572 | 42.51 | 108.76 | 35.3 | 8.56 | 157 | 31.78 | 104.68 | 36.3 | 8.69 |
| 13695 | 41.01 | 108.84 | 35.2 | 8.45 | 173 | 31.81 | 104.76 | 36.3 | 8.56 |
| 13978 | 41.08 | 108.98 | 35.1 | 8.53 | 119 | 31.69 | 104.64 | 36.3 | 8.65 |

| | | | | |
|---|---|---|---|---|
| 13763 | 41.03 | 108.86 | 35 | 8.44 |
| 13696 | 41.01 | 108.83 | 35 | 8.4 |
| 21797 | 42.54 | 108.53 | 35 | 8.56 |
| 21795 | 42.54 | 108.56 | 35 | 8.56 |
| 21796 | 42.54 | 108.54 | 35 | 8.56 |
| 21798 | 42.54 | 108.51 | 34.9 | 8.55 |
| 21794 | 42.54 | 108.58 | 34.9 | 8.54 |
| 21793 | 42.54 | 108.59 | 34.9 | 8.52 |
| 13977 | 41.08 | 108.99 | 34.9 | 8.53 |
| 14740 | 41.33 | 108.63 | 34.8 | 8.39 |
| 14789 | 41.34 | 108.61 | 34.7 | 8.39 |
| 13837 | 41.04 | 108.86 | 34.7 | 8.4 |
| 21792 | 42.54 | 108.61 | 34.7 | 8.43 |
| 21692 | 42.53 | 108.64 | 34.5 | 8.36 |
| 20448 | 42.34 | 108.69 | 34.5 | 8.59 |
| 14680 | 41.31 | 108.63 | 34.5 | 8.36 |
| 13762 | 41.03 | 108.89 | 34.5 | 8.36 |
| 21699 | 42.53 | 108.53 | 34.4 | 8.4 |
| 21697 | 42.53 | 108.56 | 34.4 | 8.38 |
| 21693 | 42.53 | 108.63 | 34.4 | 8.33 |
| 21791 | 42.54 | 108.64 | 34.4 | 8.35 |
| 21695 | 42.53 | 108.59 | 34.4 | 8.33 |
| 21696 | 42.53 | 108.58 | 34.4 | 8.35 |
| 21698 | 42.53 | 108.54 | 34.3 | 8.38 |
| 21700 | 42.53 | 108.51 | 34.3 | 8.37 |
| 13907 | 41.06 | 108.99 | 34.2 | 8.43 |
| 21694 | 42.53 | 108.61 | 34.2 | 8.3 |
| 20452 | 42.34 | 108.63 | 34.1 | 8.52 |
| 14056 | 41.09 | 108.98 | 34.1 | 8.4 |
| 14741 | 41.33 | 108.61 | 33.8 | 8.26 |
| 13908 | 41.06 | 108.98 | 33.7 | 8.31 |
| 13764 | 41.03 | 108.83 | 33.7 | 8.21 |
| 20366 | 42.33 | 108.68 | 33.4 | 8.43 |
| 20288 | 42.31 | 108.69 | 33.2 | 8.42 |
| 21883 | 42.56 | 108.51 | 33.1 | 8.22 |
| 108 | 31.66 | 104.59 | 36.3 | 8.65 |
| 68 | 31.54 | 104.54 | 36.2 | 8.62 |
| 158 | 31.78 | 104.66 | 36.2 | 8.67 |
| 81 | 31.58 | 104.56 | 36.2 | 8.67 |
| 124 | 31.71 | 104.73 | 36.2 | 8.56 |
| 142 | 31.74 | 104.64 | 36.2 | 8.63 |
| 166 | 31.79 | 104.69 | 36.1 | 8.67 |
| 46 | 31.49 | 104.53 | 36.1 | 8.56 |
| 99 | 31.63 | 104.61 | 36.1 | 8.65 |
| 107 | 31.66 | 104.61 | 36.1 | 8.63 |
| 183 | 31.83 | 104.73 | 36.1 | 8.6 |
| 69 | 31.54 | 104.53 | 36.1 | 8.59 |
| 177 | 31.81 | 104.69 | 36.1 | 8.66 |
| 87 | 31.59 | 104.56 | 36.1 | 8.64 |
| 148 | 31.76 | 104.66 | 36 | 8.63 |
| 80 | 31.58 | 104.58 | 36 | 8.63 |
| 62 | 31.53 | 104.53 | 36 | 8.56 |
| 95 | 31.61 | 104.58 | 36 | 8.63 |
| 96 | 31.61 | 104.56 | 36 | 8.61 |
| 105 | 31.64 | 104.58 | 36 | 8.61 |
| 132 | 31.73 | 104.73 | 35.9 | 8.52 |
| 136 | 31.73 | 104.64 | 35.9 | 8.6 |
| 137 | 31.73 | 104.63 | 35.9 | 8.6 |
| 40 | 31.46 | 104.56 | 35.9 | 8.49 |
| 174 | 31.81 | 104.74 | 35.9 | 8.52 |
| 176 | 31.81 | 104.71 | 35.9 | 8.61 |
| 194 | 31.84 | 104.73 | 35.9 | 8.55 |
| 145 | 31.76 | 104.71 | 35.8 | 8.56 |
| 76 | 31.56 | 104.54 | 35.8 | 8.58 |
| 74 | 31.56 | 104.58 | 35.8 | 8.57 |
| 121 | 31.69 | 104.61 | 35.8 | 8.57 |
| 61 | 31.53 | 104.54 | 35.8 | 8.52 |
| 77 | 31.56 | 104.53 | 35.8 | 8.56 |
| 101 | 31.63 | 104.58 | 35.8 | 8.59 |
| 86 | 31.59 | 104.58 | 35.8 | 8.6 |
| 147 | 31.76 | 104.68 | 35.7 | 8.58 |
| 192 | 31.84 | 104.76 | 35.7 | 8.47 |
| 159 | 31.78 | 104.64 | 35.7 | 8.55 |
| 122 | 31.69 | 104.59 | 35.6 | 8.53 |
| 82 | 31.58 | 104.54 | 35.6 | 8.55 |
| 130 | 31.71 | 104.61 | 35.5 | 8.52 |
| 168 | 31.79 | 104.66 | 35.5 | 8.55 |
| 83 | 31.58 | 104.53 | 35.5 | 8.52 |
| 178 | 31.81 | 104.68 | 35.5 | 8.56 |
| 165 | 31.79 | 104.71 | 35.5 | 8.54 |
| 54 | 31.51 | 104.51 | 35.5 | 8.46 |
| 167 | 31.79 | 104.68 | 35.5 | 8.55 |
| 185 | 31.83 | 104.69 | 35.4 | 8.54 |
| 143 | 31.74 | 104.63 | 35.4 | 8.51 |
| 88 | 31.59 | 104.54 | 35.4 | 8.52 |
| 179 | 31.81 | 104.66 | 35.4 | 8.51 |
| 70 | 31.54 | 104.51 | 35.3 | 8.45 |

| | | | | |
|---|---|---|---|---|
| 149 | 31.76 | 104.64 | 35.3 | 8.49 |
| 89 | 31.59 | 104.53 | 35.3 | 8.47 |
| 14 | 31.29 | 104.46 | 35.2 | 8.27 |
| 184 | 31.83 | 104.71 | 35.1 | 8.48 |
| 182 | 31.83 | 104.74 | 35.1 | 8.39 |
| 78 | 31.56 | 104.51 | 35.1 | 8.42 |
| 169 | 31.79 | 104.64 | 35.1 | 8.45 |
| 186 | 31.83 | 104.68 | 35 | 8.45 |
| 17 | 31.31 | 104.49 | 35 | 8.26 |
| 195 | 31.84 | 104.71 | 35 | 8.43 |
| 196 | 31.84 | 104.69 | 35 | 8.43 |
| 131 | 31.73 | 104.74 | 34.9 | 8.37 |
| 180 | 31.81 | 104.64 | 34.9 | 8.41 |
| 193 | 31.84 | 104.74 | 34.9 | 8.36 |
| 187 | 31.83 | 104.66 | 34.8 | 8.4 |
| 160 | 31.78 | 104.63 | 34.8 | 8.37 |
| 150 | 31.76 | 104.63 | 34.8 | 8.39 |
| 110 | 31.68 | 104.73 | 34.6 | 8.35 |
| 201 | 31.86 | 104.76 | 34.6 | 8.33 |
| 197 | 31.84 | 104.68 | 34.6 | 8.35 |
| 203 | 31.86 | 104.73 | 34.6 | 8.35 |
| 208 | 31.88 | 104.76 | 34.3 | 8.37 |
| 198 | 31.84 | 104.66 | 34.3 | 8.28 |
| 188 | 31.83 | 104.64 | 34.2 | 8.29 |
| 18 | 31.31 | 104.48 | 33.9 | 8.14 |
| 191 | 31.84 | 104.78 | 33.9 | 8.2 |
| 15 | 31.29 | 104.44 | 33.8 | 8.11 |
| 205 | 31.86 | 104.69 | 33.7 | 8.22 |
| 204 | 31.86 | 104.71 | 33.7 | 8.22 |
| 202 | 31.86 | 104.74 | 33.7 | 8.19 |
| 199 | 31.84 | 104.64 | 33.6 | 8.17 |
| 16 | 31.31 | 104.51 | 33.6 | 8.11 |
| 210 | 31.88 | 104.73 | 33.6 | 8.25 |

Data for the Midwest/PJM Scenario and the were derived from the Eastern Wind and Transmission Study.[10] Additional information and full hourly resource data may be obtained from http://wind.nrel.gov/public/EWITS/. Unlike the western data, this data has much larger capacity at each data point. Data may be obtained by the Site ID number provided in the table.

Midwest (South Dakota)

| SiteID | Lat. | W Long. | Cap. Factor | Wind Speed | Capacity |
|---|---|---|---|---|---|
| 114 | 43.88 | 97.16 | 42.6 | 8.51 | 382 |
| 220 | 44.17 | 97.44 | 41.9 | 8.43 | 739 |
| 231 | 44.63 | 97.71 | 41.9 | 8.47 | 503 |
| 264 | 44.12 | 97.31 | 41.7 | 8.4 | 644 |
| 267 | 44.66 | 97.44 | 41.7 | 8.41 | 302 |
| 271 | 44.5 | 97.45 | 41.7 | 8.42 | 467 |
| 335 | 44.61 | 97.51 | 41.4 | 8.38 | 580 |
| 411 | 44.42 | 97.61 | 41.1 | 8.34 | 426 |
| 427 | 44.39 | 97.11 | 41 | 8.31 | 763 |
| 435 | 44.29 | 97.41 | 41 | 8.31 | 447 |

[10] http://www.windpoweringamerica.gov/pdfs/wind_maps/us_windmap.pdf