# Economics of Compressed Air Energy Storage to Integrate Wind Power: A Case Study in ERCOT

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**Abstract**

Compressed air energy storage (CAES) could be paired with a wind farm to provide firm, dispatchable baseload power, or serve as a peaking plant and capture upswings in electricity prices. We present a firm-level engineering-economic analysis of a wind/CAES system with a wind farm in central Texas, load in either Dallas or Houston, and a CAES plant whose location is profit-optimized. With 2008 hourly prices and load in Houston, the economically optimal CAES expander capacity is unrealistically large - 24 GW - and dispatches for only a few hours per week when prices are highest; a price cap and capacity payment likewise results in a large (15 GW) profit-maximizing CAES expander. Under all other scenarios considered the CAES plant is unprofitable. Using 2008 data, a baseload wind/CAES system is less profitable than a natural gas combined cycle (NGCC) plant at carbon prices less than \$56/t$CO_2$ (\$15/MMBTU gas) to \$230/t$CO_2$ (\$5/MMBTU gas). Entering regulation markets raises profit only slightly. Social benefits of CAES paired with wind include avoided construction of new generation capacity, improved air quality during peak times, and increased economic surplus, but may not outweigh the private cost of the CAES system nor justify a subsidy.

## 1. Introduction

Renewable energy currently comprises 9% of the United States' net electric power generation (Energy Information Administration, 2009a). Twenty-nine states' enactment of Renewable Portfolio Standards (RPS) (Database of State Incentives for Renewables and Energy Efficiency, 2009) and the Federal RPS under consideration in Congress suggest that the nationwide share of renewables in the electricity sector could double by 2020 (Waxman and Markey, 2009).

With high penetration of renewables, variability of power output increases the need for fast-ramping backup generation and increases the need for reliable forecasting. Pairing a variable renewable generator with large-scale electricity storage could provide firm, dispatchable power and alleviate the costs and stability threats of integrating renewable energy into power grids. Although it has been argued elsewhere (e.g., DOE, 2008) that dedicated storage is not a cost-effective means of integrating renewables, the cost savings from constructing a small transmission line with a high capacity factor instead of a large transmission line with a low capacity factor could in some cases be sufficient to justify building a dedicated CAES plant.

Utility-scale electricity storage has not been widely implemented: batteries remain prohibitively expensive and pumped hydroelectric storage is feasible only in locations with suitable hydrology. An emerging large-scale storage technology is compressed air energy storage (CAES), in which energy is stored in a pressure gradient between ambient air and an underground cavern. Two CAES plants are in operation: one in Huntorf, Germany and the other in McIntosh, Alabama, USA. FirstEnergy, the Iowa Association of Municipal Utilities, and PG&E are building new CAES systems, the last with the help of federal funding (Haug, 2006; 2009; LaMonica, 2009). The New York State Energy Research and Development Authority

(NYSERDA) has commissioned an engineering study for a possible CAES plant in New York (Hull, 2008), and Ridge Energy Storage has proposed a CAES system in Matagorda, Texas (Ridge Energy Storage, 2005).

Denholm and Sioshansi (2009) compare the costs of (1) a co-located wind farm/CAES plant with an efficiently-used low-capacity transmission line to load and (2) a CAES plant located near load that uses inexpensive off-peak power for arbitrage, with a higher-capacity, less efficiently-used transmission line from the wind farm. Avoided transmission costs for co-located CAES and wind in ERCOT outweigh the higher arbitrage revenue of load-sited CAES at transmission costs higher than $450 per MW-km. Although actual transmission cost data vary greatly, many transmission projects cost more than $450/MW-km and would warrant wind-CAES co-location (Denholm and Sioshansi, 2009).

Greenblatt et al. (2007) model CAES and conventional gas generators as competing technologies to enable baseload wind power. The wind/CAES system had the highest levelized cost per kWh at an effective fuel price (the sum of natural gas price and greenhouse emissions price) of less than $9.GJ ($8.5/MMBTU). The wind/CAES system had a lower short-run marginal cost, rendering it competitive in economic dispatch and at greenhouse emissions prices above $35/tC$_{equiv}$ ($9.5/tCO$_2$) the wind/CAES system outcompetes coal for lowest dispatch cost (Greenblatt et al., 2007).

DeCarolis and Keith (2006) optimize the use of simple and combined cycle gas turbines, storage, and widely-distributed wind sites to enable large-scale integration of distant wind resources. Diversifying wind sites produces benefits that outweigh the ensuing transmission costs, and smoothing due to wind site diversity renders CAES economically uncompetitive at carbon prices below \$1000/tC (\$270/t$CO_2$). For a single wind site, CAES is cost effective at \$500/tC (\$135/t$CO_2$).

Each of the above studies uses simulated wind power data or a power curve applied to measured wind speed data. Denholm and Sioshansi (2009) use hourly electricity price data from Independent System Operators (ISOs), while the other two studies examine the cost-effectiveness of storage for wind integration and make no assumptions about electricity price. We examine the economic and technical feasibility of a wind/CAES system in Texas, using wind power data from a large wind farm in the central part of the state, hourly electricity prices from the Electric Reliability Council of Texas (ERCOT), and monthly gas prices to Texas electric utilities. The model is further constrained by the underlying geology suitable for a CAES cavern. CAES size, transmission capacity, and dispatch strategy are optimized for profit. This research differs from previous work in that it examines CAES as a means of wind power integration in a specific location and incorporates a multiparameter optimization of the wind-CAES system, transmission, and dispatch strategy.

Section 2 describes the mechanics of CAES and the two CAES plants currently in operation. Section 3 describes the wind/CAES system modeled in the current study, and Section 4 explains how the underlying geology and concerns about transmission congestion influence the siting of CAES. Section 5 provides the sources of the data used in the study and describes the function of ERCOT balancing energy and regulation markets. Section 6 provides the cost models used for the CAES system and transmission lines. Section 7 describes the heuristic dispatch strategies and profit optimization models for the wind/CAES system in the energy and regulation markets, Section 8 presents results, and Section 9 provides discussion and policy implications.

## 2. CAES mechanics and extant plants

Figure 1 is a schematic diagram of a CAES plant, which is analogous to a natural gas generator in which the compression and expansion stages are separated by a storage stage. In a conventional gas plant, 55-70% of the electricity produced is used to compress air in preparation for combustion and expansion (Gyuk and Eckroad, 2003). In a CAES plant, air is compressed with electricity from a wind farm or off-peak electricity from the grid, so the heat rate is about 4300 BTU/kWh compared with 6700 BTU/kWh for a high-efficiency natural gas combined cycle turbine (Klara and Wimer, 2007). All designs demonstrated to date combust natural gas, but conceptual adiabatic designs reheat the expanding air with the stored heat of compression and do not use gas.

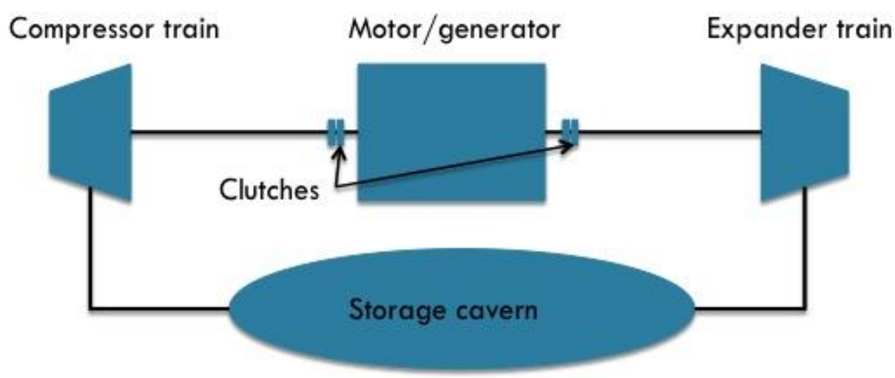


**Figure 1. Schematic diagram of a CAES plant. In the compression stage, CAES uses electricity to compress air into a pressure-sealed vessel or underground cavern, storing energy in a pressure gradient. The air is cooled between each compressor to increase its density and aid compression. To generate electricity, the air is mixed with natural gas and expanded through combustion turbines.**

Two CAES plants are currently operational: one in Huntorf, Germany, and one in McIntosh, Alabama, USA. The Huntorf plant was completed in 1978 and is used for peak shaving, to supplement the ramp rate of coal plants, and more recently to mitigate wind power variability. The McIntosh plant was completed in 1991 and is used for storing off-peak baseload power, generating during peak times, and providing spinning reserve (see Appendices 1 and 2) (Gardner and Haynes, 2007).

In a new, less costly, and more efficient design proposed by the Electric Power Research Institute (EPRI), only the low-pressure turbine is combustion-based; the high-pressure turbine is similar to a steam turbine. This difference partially accounts for the lower heat rate of the EPRI design (3800 BTU/kWh) (Schainker, 2008). This study uses technical parameters of the EPRI design.

A CAES plant could reduce wind power curtailment by storing wind energy in excess of transmission capacity, thereby deferring transmission upgrades and allowing system operators to avoid curtailment payments to wind farm owners. CAES systems have fast ramp rates that match fluctuations in wind power output. A CAES plant with one or more 135 MW generators starts up in 7-10 minutes and once online ramps at about 4.5 MW per second (or 10% every 3 seconds) (McGowin and Steeley, 2004). In the compression phase, a CAES plant starts up in 10-12 minutes and ramps at 20% per minute, which is fast enough to smooth wind power on the hourly timescales modeled in the current study. The fast ramp rate of a CAES expander compared with that of a natural gas turbine (7% per minute (Western Governors' Association, 2002)) is possible because the compression stage of the CAES cycle is already complete when the CAES ramps.

A wind/CAES system could act as a baseload generator in place of coal and nuclear plants, or could be dispatched as a peak-shaving or shoulder-load plant. The operating flexibility of CAES also enables a wind/CAES system to provide ancillary services such as frequency regulation, spinning reserve, capacity, voltage support, and black-start capability (Gyuk, 2004). Previous research has shown that pumped hydroelectric storage can decrease the total cost of ancillary services by 80% and generate significant revenue in a simulated market in Tennessee Valley Authority (TVA) (Perekhodtsev, 2004); a quick-ramping, large-capacity CAES system could provide similar benefit. Here we examine the profitability of CAES in up- and down-regulation markets as well as the balancing energy market.

## 3. Wind/CAES system model

*Physical Design*

The wind/CAES system is modeled as a 1300 MW wind farm (the combined nameplate capacity of Sweetwater and Horse Hollow wind farms, 16 km apart in central Texas), a wind-CAES transmission line, a CAES plant, and a CAES-load transmission line. Pattanariyankool and Lave (2010) observe that the economically efficient transmission capacity from a wind farm is often well below the nameplate capacity of the wind farm. Parameters in the economic optimization include the lengths ($L_W$ and $L_C$) and capacities ($T_W$ and $T_C$) of both transmission lines as well as the CAES expander capacity ($E_E$), compressor capacity ($E_C$), and storage cavern size ($E_S$) (Figure 2). The cost and optimal location of the CAES plant are also contingent on the underlying geology, as discussed below. Relevant variables for the wind/CAES system operation and profit models are shown in Table 1.

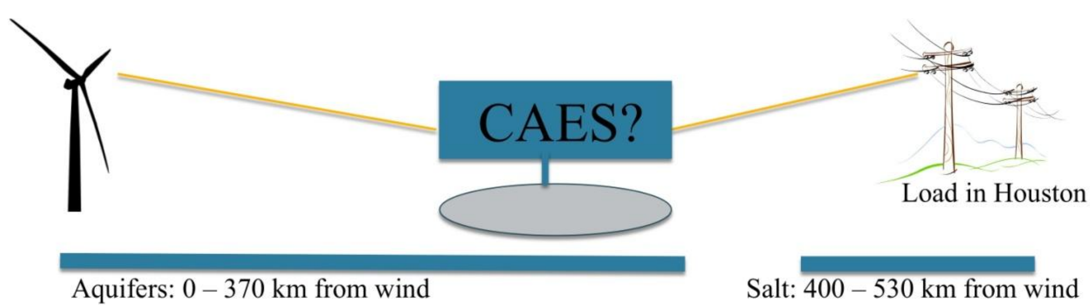

**Figure 2. Sketch of the wind/CAES system with load in Houston. With load in Dallas, aquifers underlie the entire 320 km distance between wind and load.**

**Table 1. Parameters and decision variables for the wind/CAES dispatch and profit optimization models. Subscript *i* denotes a variable that changes hourly. Costs are adjusted to 2009$ with the Chemical Engineering Plant Cost Index (Lozowski, 2009).**

| Parameter | Symbol | Base Value | Unit | Reference |
|---|---|---|---|---|
| Marginal cost of generating wind power | $MC_W$ | $0.00 | $/MWh | |
| Wind energy output | $w_i$ | | MWh | ERCOT, 2009b |
| Hourly zonal electricity price | $p_i$ | | $/MWh | ERCOT, 2009a |
| Hourly up-regulation price | $u_i$ | | $/MW | |
| Hourly down-regulation price | $d_i$ | | $/MW | |
| Cost of gas | $g_i$ | | $/MMBTU | EIA, 2009b |
| Energy ratio of CAES system | *ER* | .7 | kWh in/kWh out | Schainker, 2008 |
| Heat rate of CAES system | *HR* | 3800 | BTU/kWh | Schainker, 2008 |
| Heat rate of CAES as a gas turbine | *HRgas* | 10000 | | |
| Blended cost of capital | *dr* | .10 | | |
| 30-year annualization factor | *A* | $dr/(1-(1+dr)^{30})$ | | |
| Baseline cost of CAES system | $C_{CAES}$ | 1700/2000 | $/kW | Schainker, 2008 |
| Marginal cost of CAES expander | $C_E$ | 560 | $/kW | Greenblatt et al., 2007 |
| Marginal cost of CAES compressor | $C_C$ | 520 | $/kW | Greenblatt et al., 2007 |
| Marginal cost of storage cavern capacity | $C_S$ | 1.5 | $/kWh | Schainker, 2008 |
| Energy CAES system can store, hour *i* | $x_i$ | | MWh | |
| Energy CAES system can generate, hour *i* | $y_i$ | | MWh | |
| Energy state of cavern, hour *i* | $s_i$ | | MWh | |
| Energy discharged from storage, hour *i* | $r_i$ | | MWh | |
| Total energy sold, hour *i* | $e_i$ | | MWh | |

| Decision variable | Symbol | Unit |
|---|---|---|
| Zonal electricity price below which wind energy is stored | $p_s$ | $/MWh |
| Zonal electricity price above which CAES is discharged | $p_d$ | $/MWh |
| Length of wind-CAES transmission line | $L_W$ | km |
| Length of CAES-load transmission line | $L_C$ | km |
| Capacity of wind-CAES transmission line | $T_W$ | MW |
| Capacity of CAES-load transmission line | $T_C$ | MW |
| CAES expander power | $E_E$ | MW |
| CAES compressor power | $E_C$ | MW |
| CAES storage capacity (expander hours) | $E_S$ | MWh |

**4. Siting the CAES Plant**

We assume fixed locations of the wind farm in central Texas and load either 530 km away in Houston or 320 km away in Dallas. The location of a CAES plant, subject to the geological constraints discussed below, can be optimized for profit with respect to the lengths and capacities of the transmission lines.

CAES is feasible in three broad types of geology: solution-mined salt caverns, aquifers of sufficient porosity and permeability, and mined hard rock caverns (Succar and Williams, 2008). Due to the disproportionately high cost of developing hard rock caverns, we do not consider them here.

The two operational CAES plants in Alabama and Germany both use solution-mined salt caverns for air storage. These structures are advantageous for CAES due to the low permeability of salt, which enables an effective pressure seal, and the speed and low cost of cavern development. The caverns are formed by dissolving underground halite (NaCl) in water and removing the brine solution. The CAES plant injects and removes air through a single well connecting the salt cavern and turbomachinery. Salt that can house a CAES cavern occurs in two general forms: bedded and domal. Domal salt is purer and thicker than bedded salt and therefore superior for CAES caverns, but specific sites in bedded salt can be suitable for CAES as well (Hovorka, 2009).

Underground storage for CAES is also feasible in an aquifer-bearing sedimentary rock of sufficient permeability and porosity that lies beneath an anticline of impermeable caprock to stop the buoyant rise of air and impede fingering (Succar and Williams, 2008). A bubble in the aquifer, developed by pumping air down multiple wells, serves as the air storage cavern. The

Iowa Stored Energy Project (ISEP), a wind/CAES system under construction in Dallas Center, IA, will use an aquifer for underground storage (Haug, 2006).

Domal salt is located in the East Texas Basin, South Texas Basin, and Gulf Coast Basin surrounding Houston, as well as the Delaware and Midland Basins of West Texas. Bedded salt underlies much of the eastern part of the state, from the Gulf Coast to 160 – 240 km inland (Hovorka, 2009). Aquifers possibly suitable for a CAES cavern underlie the western and central parts of the state, including Dallas (Succar and Williams, 2008). Aquifer CAES is dependent on highly localized aquifer parameters such as porosity, permeability, and caprock composition and geometry, so generalizing on the geographic extent of suitable aquifers is impossible. Appendix 3 contains further information on CAES geology in Texas.

Siting the CAES near wind enables a high-capacity wind-CAES transmission line that minimizes wind power curtailment due to transmission constraints as well as a lower-capacity CAES-load line that the system fills efficiently. Wind-sited CAES, however, compromises the ability of the CAES system to buy and sell electricity optimally from the grid because the lower-capacity CAES-load line is often congested with wind power (Denholm and Sioshansi, 2009). Siting the CAES near load enables larger CAES-load transmission capacity, thereby increasing the potential for arbitrage. Load-sited CAES can also store and supply slightly more power to the grid because transmission losses are incurred before the CAES. Sullivan et al. (2008) found that "the capacity, transmission loss, and congestion penalties evidently outweighed the cost savings of downsizing transmission lines," making load-sited CAES economically superior.

**5. Data and Energy Markets**

Hourly zonal electricity prices are from the ERCOT Balancing Energy Services (BES) market for 2007, 2008, and 2009 (Electric Reliability Council of Texas (ERCOT), 2009a).

Although most energy in ERCOT is traded bilaterally, 5-10% is traded on the BES market that ERCOT administers for the purpose of balancing generation and load. BES prices are thus proxies for locational marginal prices (LMPs) of electricity (Denholm and Sioshansi, 2009). ERCOT is currently divided into four pricing zones: West, North, South, and Houston. Sweetwater and Horse Hollow wind farms are located in ERCOT West, which experiences frequent negative prices due to wind power congestion that a large CAES system would help relieve. We use ERCOT Houston prices if the CAES plant is sited in Houston and ERCOT North prices if the CAES is in Dallas. ERCOT plans to switch its primary energy market to nodal pricing within the next few years, allowing prices to better reflect local market conditions (ERCOT, 2008).

In addition to the BES market, ERCOT administers hourly markets for up-regulation and down-regulation. A generator bids capacity into a regulation market 24 hours in advance and can edit the bid until an hour in advance. The generator is paid the product of its accepted capacity bid and the market-clearing price of the regulation market, plus the BES price for the additional energy generated or curtailed. Hourly prices for up-regulation and down-regulation in ERCOT in 2008 and 2009 were obtained from a commercial data provider.

Fifteen-minute wind energy output data from Sweetwater and Horse Hollow wind farms for 2008 and 2009 were obtained from ERCOT's website and summed to produce hourly data (ERCOT, 2009b). To approximate 2007 power output from the two wind farms, system-wide ERCOT wind power data was scaled to the appropriate nameplate capacity (in 2008, power output from Sweetwater and Horse Hollow was highly correlated with aggregate ERCOT wind output ($R^2$ = 0.96)). The data were affected by wind curtailment, which occurred on 45-50% of the days from January to August 2008 at an average amount of 140-150 MW. Since the installed wind capacity in ERCOT at that time was 7100 MW, curtailment of Sweetwater/Horse Hollow would have averaged, at most, approximately 2% of capacity. Curtailment would decrease the calculated profit of both the wind/CAES system and the standalone wind farm, and generally tend to increase the profitability of the former (since the extra energy could be sold when prices are high and not only when the wind farm produced it). Our analysis does not account for this effect, which we believe to be small.

Monthly natural gas prices for the electric power industry in Texas in 2007 - 2009 are from the United States Energy Information Administration (2009b).

**6. Wind/CAES System Cost Models**

*CAES plant*

Equation 1 shows the estimated total capital cost of a large CAES system in a salt cavern. The cost model begins with the EPRI estimate for a 346 MW expansion/145 MW compression/10 storage-hour CAES plant ($C_{\mathrm{CAES}}$), plus incremental costs per MW of expander capacity ($C_E$), compressor capacity ($C_C$), and storage cavern capacity ($C_S$) (Greenblatt et al., 2007; Schainker, 2008). The model is then adjusted upward by a factor of 2.3 to conform to recent industry estimates (Gonzales, 2010; Leidich, 2010). The cost of a CAES plant larger than 1 GW is adjusted from $1700/kW for a 2 GW plant, after estimates for the anticipated Norton plant. The cost of a smaller CAES plant is adjusted from $2000/kW for a 500 MW plant. Costs are inflation-adjusted to 2008 USD with the Chemical Engineering Plant Cost Index (CEPCI) (Lozowski, 2009). The cost of CAES with aquifer storage is modeled as 30% higher, which reflects the difference in average capital cost per kW generation capacity between CAES plants in the two geologies according to data on a possible CAES system in New York (Swensen, 1994), EPRI reports, and data from extant and upcoming plants (Haug, 2004; The Hydrodynamics Group, 2009; Marchese, 2009) (see Appendix 4).

$$\text{Cost of CAES} = C_{\text{CAES}} \cdot 2000 + C_E \cdot (E_E - 2000) + C_C \cdot (E_C - 1500) + C_S \cdot (1000 \cdot E_E \cdot E_S - 2 \cdot 10^7) \quad (1)$$

*Transmission*

Equation 2 models the capital cost of transmission as a function of lengths ($L_W$ and $L_C$) and capacities ($T_W$ and $T_C$).

$$\text{Cost of transmission} = 14266 \cdot (L_W \cdot T_W^{0.527} + L_C \cdot T_C^{0.527}) \quad (2)$$

Figure 3 shows a plot of the transmission cost model in dollars per GWm as a function of MW capacity. The model was derived by fitting an exponential curve to transmission costs from planning studies and reflects an economy of scale in which the cost per GWm decreases as power capacity increases (Hirst and Kirby, 2001). Although transmission costs vary widely and are highly dependent on terrain, land use patterns, and other site-specific factors, this function provides a cost estimate that is consistent with past projects (see Appendix 5).

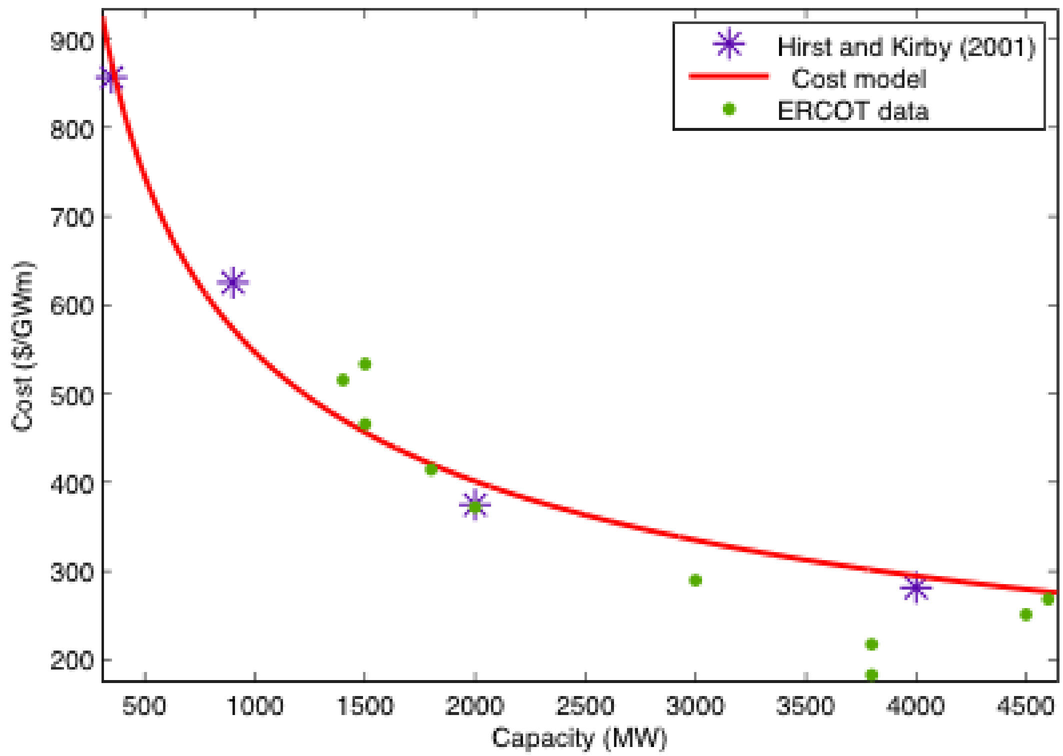


**Figure 3. Transmission cost model used in profit optimization. Data are from Hirst and Kirby (2001) and an ERCOT transmission planning study that assessed the costs of wind integration (ERCOT, 2006). The model fits the ERCOT data with $R^2$ = 0.72.**

The wind farm is assumed to already exist so its cost is not modeled.

## 7. Wind/CAES heuristic dispatch strategies and hourly profit models

*Balancing Energy Services (BES) Market*

In the hourly BES market, the wind/CAES system is operated to maximize profit based on $p_i$, price of electricity at hour $i$ for the ERCOT zone in which the CAES system is located. If $p_i$ is less than the marginal cost of generating wind power ($MC_W$, taken as 0), the model stores wind energy up to capacity and curtails the excess. If $p_i$ is greater than $MC_W$ but less than the storage threshold price $p_s$, the system stores wind energy to capacity and sells the excess. If $p_i$ is greater than $p_s$ but less than the dispatch threshold price $p_d$, the system sells wind power and leaves the CAES system idle. If $p_i$ is greater than $p_d$, energy is generated from the CAES plant.

The prices $p_s$ and $p_d$ are decision variables in the profit optimization, while $MC_W$ is an economic property of the wind farm. Since the amount of wind power produced by the wind/CAES system is equal to that produced by the standalone wind farm, the production tax credit for wind power and the sale of renewable energy credits does not affect the difference in profitability between the two and was not included in the analysis. Appendix 6 contains further description of the model. Equation 3 shows the total amount of energy delivered by the wind/CAES system in the hourly energy market in hour *i*.

$$e_i = \begin{cases} 0 & \text{if } p_i < MC_W \\ \min(T_W, T_C, w_i - x_i) \text{ if } w_i > x_i, \text{ else } 0 & \text{if } MC_W < p_i < p_s \\ \min(T_W, T_C, w_i) & \text{if } p_s < p_i < p_d \\ \min(T_W + y_i, T_C, w_i + y_i) & \text{if } p_d < p_i \end{cases} \tag{3}$$

Yearly profit, including annualized capital costs, is shown in Equation 4. Revenue is calculated as the product of electricity sold and the current zonal price, summed over all hours of the year. Operating cost is the cost of gas used by the CAES system. Costs of the CAES system and transmission lines are modeled according to Equations 2 and 3 and are annualized with a 10% discount rate and 30-year project lifetime.

$$\Pi = \Sigma(p_i \cdot e_i - g_i \cdot r_i \cdot HR) - A \cdot (\text{CAES cost} + \text{transmission cost}) \tag{4}$$

Profit is maximized for three electricity price scenarios: hourly BES prices, the prices capped at \$300/MWh with a \$100/MWd capacity payment, and a constant contract price equal to the mean hourly BES price. The price-cap scenario simulates the case in which a price cap plus capacity payment, instead of price spikes, signals the need for investment in new capacity, and is meant to generalize our results beyond the current ERCOT case. Since ERCOT currently has no capacity market, the value of \$100/MWd is based on the PJM capacity market clearing prices of \$40.80 to \$237.33/MWd for 2007-2009 (mean: \$159.68/MWd), and the observation that prices in the PJM capacity market for these years overrepresented the need for additional capacity and did not provide a cost-effective means of promoting system reliability (Wilson, 2008).

For the contract price scenario, the price-threshold dispatch strategy is infeasible so profit is maximized with the constraint that the capacity factor of the CAES-load transmission line be 80%, which is approximately representative of a baseload generator. The constraint on transmission capacity factor is not meant to simulate an actual contract; it is imposed only to determine the size and cost of a CAES plant for a wind/CAES system acting as a baseload generator. For all scenarios, we compare results using data from 2007 to 2009.

A simulated annealing algorithm was used to optimize yearly profit (Equation 4) with decision variables of $p_s$ and $p_d$ (determined monthly), $T_C$, $T_W$, $E_C$, $E_E$, and $E_S$ (see Appendix 7) (Goffe et al., 1994).

*Regulation and Balancing Energy Markets*

A separate model allows the wind/CAES system to bid into the up-regulation and down-regulation markets in addition to the BES market. During the morning ramp, the average down-regulation price is greater than the average up-regulation price; during the evening ramp down, the opposite is true. We define a bidding strategy based on four progressively greater daily time thresholds, $h_1$ through $h_4$, as described in Table 2.

**Table 2. Rules for wind/CAES dispatch in ancillary service markets. Parameter *h* denotes the hour of the day, while $h_i$, *i=1,4,* denote thresholds that are decision variables in the optimization. All of the parameters *h* have integer values from 1 to 24. *HR*gas denotes the heat rate of CAES when run as a natural gas generator.**

| *Condition* | *Market into which system bids* | *Hourly marginal profit* |
|---|---|---|
| $h_1 < h < h_2$ | Down-regulation. | $d_i \cdot \min(E_C,T_C) + p_i \cdot 0.2 \cdot \min(E_C,T_C)$ |
| $h_3 < h < h_4$ | Up-regulation. | $u_i \cdot E_C + 0.2 \cdot E_C \cdot p_i - d_i \cdot HR + \max(E_E\text{-}(w_i+y_i),0) \cdot HR\text{gas}) \cdot g_i /1000$ |
| $h < h_1$, $h_2 < h < h_3$, or $h > h_4$ | BES. | $e_i \cdot p_i - d_i \cdot g_i \cdot HR/1000$ |

When bidding into the BES market, the system uses the same strategy as in the BES-only scenario above with $p_s$ equal to the 33rd percentile price and $p_d$ equal to the 67th percentile price. Since up-regulation and down-regulation procurements in ERCOT are on the order of 1 GW, we fix the CAES expander and compressor capacities at 450 MW to adhere to the price-taker assumption. We assume that the system bids 450 MW into the up-regulation or down-regulation markets and is deployed 90 MW (consistent with average regulation deployment as a fraction of procurement in ERCOT (ERCOT, 2010)). When up-regulation is deployed, any wind energy generated up to 90 MWh is transmitted to load, and the CAES plant provides the remainder. If the CAES cavern is depleted, the CAES acts as a natural gas-fired generator with a higher heat rate. When down-regulation is deployed, the CAES cavern stores 90 MWh. If the cavern is full, the compressor is run and exhausted to the ambient air. The 49 decision variables correspond to the four time thresholds optimized monthly and the capacity of the wind-CAES transmission line.

**8. Results**

*Balancing Energy Market – Zonal prices*

Using 2008 zonal prices with load in Houston, the profit optimization results in a CAES with an unrealistically large 24 GW expander that dispatches infrequently (Figure 4). The optimal price thresholds for the dispatch strategy, $p_s$ and $p_d$, were such that the wind/CAES system stored wind energy 91% of the time, sold only wind energy 6% of the time, and discharged the CAES 3% of the time. This system would earn $900 million in the BES market, and a standalone wind farm with a single wind-load transmission line would earn $245 million. Lower expander capacities result in less energy sold during price spikes and therefore lower profit despite the additional cost of expander power. Due to the nature of the objective function, the heuristic optimization algorithm may have failed to find a larger CAES system that could generate even more profit; however, 24 GW is an unrealistically large plant and the profit-generating price spikes are of unpredictable magnitude and frequency, such that a larger CAES system that generates more profit under this strategy is not a valuable result. The economically optimal location for the CAES plant is close to load in Houston, enabling a shorter and less costly high-capacity transmission line from CAES to load. Air storage is in a solution-mined salt cavern, the less expensive of the two geologies considered.

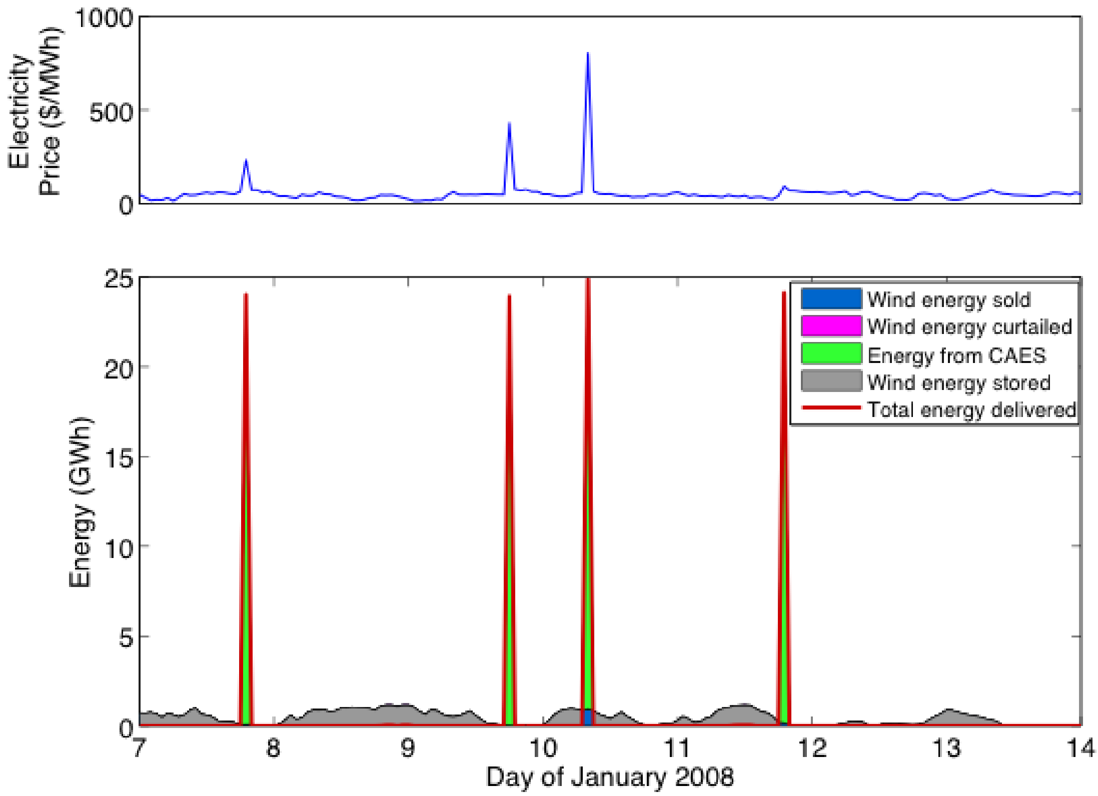


**Figure 4. Wind/CAES system operation for January 7-14, 2008 with load in Houston.**

For all other zonal price scenarios (load in Houston for 2007 and 2009, and load in Dallas for 2007-2009), no CAES system could capture annual revenue that compensates for its annualized capital cost, so the optimal size of all CAES components is 0. The higher cost of building CAES in an aquifer near Dallas or the wind site instead of in a salt cavern near Houston contributes to the unprofitability of CAES with load in Dallas. These results suggest that the profitability of CAES given 2008 data is due to anomalous price spikes.

A profit-maximizing energy trader would not use constant storage and discharge threshold prices as an operations strategy: a high BES price in the morning, for example, could cause the trader to anticipate an even higher afternoon peak and wait to discharge the storage, and the same price at night could motivate the trader to discharge the storage immediately in anticipation of falling prices and increased wind power output to refill the storage. The current dispatch algorithm would likely generate less profit than a strategy applied by an energy trader.

*Balancing Energy Market – Price cap of $300/MWh plus capacity payment of $100/MWd*

For 2008 prices with load in Houston, the optimal CAES expander size is 17 GW and the system generates $300 million in profit, compared with $245 million for a standalone wind farm. For 2007 and 2009 prices, the optimal CAES expander size is 6 GW and 3 GW respectively, and generates negative profit. With load in Dallas, the optimal CAES size for all years is zero. Once again, the higher cost of building CAES in an aquifer rendered the Dallas CAES system unprofitable.

*Balancing Energy Market – Contract Price*

With a contract price and a set capacity factor of 80% for the CAES-load transmission line, no wind/CAES system generated more profit than a standalone wind farm. The highest profit generated for a system with load in Houston was $110 million (with a 300 MW CAES expander and 480 MW CAES-load transmission line), compared with $245 million for the standalone wind farm. The highest profit for a system with load in Dallas was $70 million in 2008 (for a 260 MW expander and 460 MW CAES-load line), compared with $210 million for the standalone wind farm. The optimization algorithm convergence characteristics for some scenarios indicate that there are a number of combinations of the decision variables that have approximately the same profit. This gives these results an uncertainty of approximately 10%; even accounting for this uncertainty, in all cases the lower capital costs of the smaller CAES-load transmission line do not compensate for the cost of the CAES system, and using CAES to smooth power from the wind farm is not profitable.

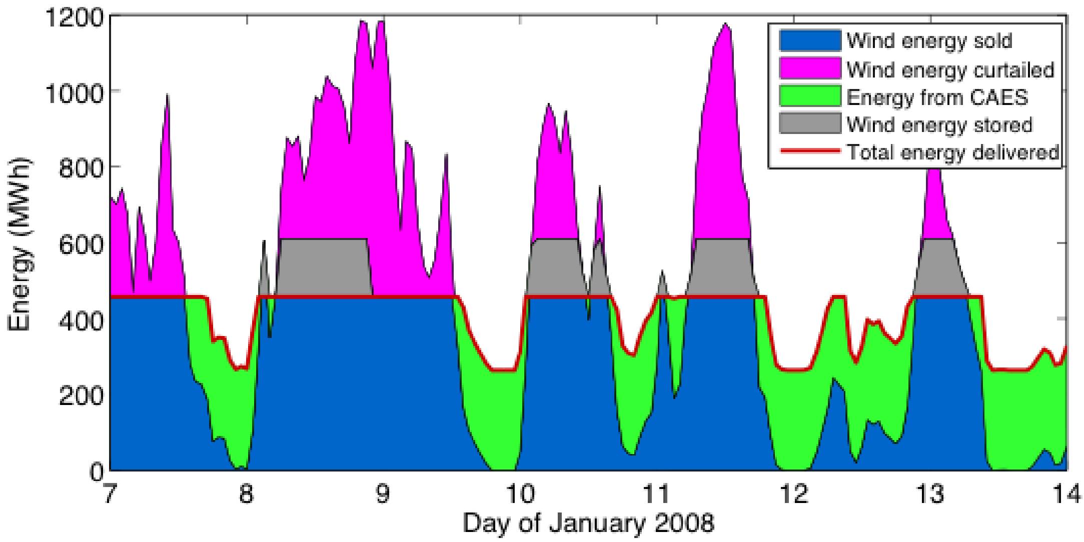


**Figure 5. Wind-CAES system operation under a $63/MWh contract price with load in Dallas. This scenario represents the wind/CAES system acting as a baseload generator, with a 1300 MW wind farm and 260 MW (expansion) CAES plant filling a 460 MW transmission line with 80% capacity factor.**

*Analysis of the Price-Taker Assumption for the Zonal Price Scenario*

The profit-maximizing CAES expander in the zonal price scenario would shift the ERCOT generation supply curve outward and reduce prices during times of high demand. To account for this effect, we examined supply curves for Wednesdays in each season of 2008, which we take to be representative of average days. In the region of the supply curve between first percentile load and $99^{th}$ percentile load, the maximum price decrease caused by an additional 24 MW generator with low marginal cost is less than $30/MWh. The optimization for the zonal price scenario was re-run with prices decreased by $30/MWh when the CAES expander comes online and calculated annual profit decreased to $700 million, still well above that of a standalone wind farm ($245 million).

Daily supply curves, including those for days with price spikes on the order of $1000/MWh, tend to have maximum bids of less than $200/MWh. This implies that the price spikes are due to factors not directly represented by the bid stacks and ERCOT's economic dispatch algorithm. Possible alternative explanations include strategic bidding by electric power producers and outages of generators and transmission, which may remain largely unaffected by the presence of an additional large generator.

*BES and Regulation Markets*

For 2008 data with load in Houston, a wind/CAES system would maximize profit by bidding into the down-regulation market for 4-7 hours in the early morning in July through November and 0-3 hours the rest of the year. The system would only bid into the up-regulation market for 1-3 hours in the early evening in October through December, and from 9 am until midnight in September. This strategy results in an annual profit of $100 million, in contrast to an annual profit of $80 million if the system bids into the BES market alone under the given strategy. With load in Dallas, bidding patterns are similar and entry into regulation markets allows an identically-sized system to earn $50 million, while bidding into the BES market alone generates a profit of $20 million. Using 2009 wind and price data, participating in the regulation markets results in a loss of $40 million (load in Houston) or $70 million (load in Dallas), in contrast to a loss of $50 million (Houston) or $90 million (Dallas) if the system bids into the BES market alone under the given heuristic. In all cases, profit in the regulation and BES markets falls far short of that of a standalone wind farm.

*Carbon Price for an Economically Competitive Wind/CAES System*

We assessed the carbon price at which the profit-maximizing wind/CAES systems under the contract price scenarios would be economically competitive with a natural gas combined cycle (NGCC) generator producing the same amount of energy per year with a capital cost of $900/kW and heat rate of 6800 BTU/kWh. At a natural gas price of $5/MMBTU, the wind/CAES system with 2008 data and load in Dallas (Houston) would be cost-competitive with NGCC at a carbon price of \$230/t$CO_2$ (\$200/t$CO_2$); at a gas price of $15/MMBTU, the wind/CAES system would be cost-competitive at \$56/t$CO_2$ (\$28/t$CO_2$). The lower cost of building air storage in a salt cavern renders the Houston system more competitive. For the smaller profit-maximizing CAES systems of 2007 and 2009, the carbon prices to break even with NGCC are much higher—\$180-\$410/t$CO_2$ at \$15/MMBTU gas, and \$360-\$580/t$CO_2$ at \$5/MMBTU gas (Appendix 8). The 2008 results are similar to those of DeCarolis and Keith (2006), who used a different method and found that CAES paired with a single wind farm was cost-competitive at carbon prices above \$140/t$CO_2$ (2004\$). Since the NGCC could be sited closer to load than the wind farm, accounting for transmission costs would raise the carbon price at which a wind/CAES system is cost competitive.

**9. Discussion and Policy Implication**

Given 2007 - 2009 wind power output, electricity prices, and gas prices, a profit-maximizing owner of a 1300 MW wind farm in central Texas providing power to Dallas or Houston would not build a CAES system. The only profitable wind/CAES system under the zonal price scenario generates its revenue during large price spikes, which cannot be forecasted or expected to occur regularly, and thus provide uncertain revenue with limited power to attract investment (Wilson, 2008). Although such a system could have profitably captured the price spikes of 2008, a risk-averse firm might set future electricity price expectations closer to 2007 or 2009 levels, and thus decide not to build. Modifying the ERCOT supply curve to account for the presence of an additional large generator does not change this result.

With a $300/MWh price cap and a $100/MWd capacity payment, a wind/CAES system would be profitable given 2008 data and load in Houston. This result does not account for the additional fuel cost if the system were deployed when the cavern was depleted and the CAES plant was forced to run as a natural gas turbine. Since ERCOT does not currently have a capacity market (and since the system under this scenario is unprofitable given 2007 or 2009 data, or load in Dallas), this result does not support investment in CAES.

Under the third pricing scenario, selling at a constant price equivalent to the mean BES price, a wind/CAES system is unprofitable. The cost savings of the smaller CAES-load transmission line with an 80% capacity factor does not compensate for the capital cost of CAES. Allowing the wind/CAES system to bid into regulation markets raises its profit, though not enough to justify pairing CAES with a wind farm. There are currently no rigorous predictions of whether increased wind power penetration would raise ancillary service prices enough to change this result.

While a wind/CAES system in ERCOT would not be economically viable at the firm level, pairing CAES with wind has social benefits that could outweigh private costs. Sioshansi et al. (2009) calculated the net social benefit of large-scale energy storage for arbitrage in PJM (the sum of the changes in consumer and producer surplus due to increased off-peak prices and decreased on-peak prices) as $4.6 million for a 1 GW/16 hour storage device, with negligible marginal benefit for more storage hours. This calculation was based on data from 2002, when PJM had an average load about 50% greater than ERCOT's 2008 average load (Biewald et al., 2004). Although more detailed analysis would be necessary to assess the change in economic surplus due to the wind/CAES systems of contract price scenarios, for example, their smaller size and operation in a smaller market both suggest that the benefit would be less than that calculated by Sioshansi et al. (2009). The increase in economic surplus is thus unlikely to compensate for the private deficit and thus does not warrant a subsidy.

A wind/CAES system displacing a natural gas plant would also have human health benefits resulting from improved air quality. Gilmore et al. (2010) analyzed the air-quality effects of a 2000 MWh battery in New York City that charges for 5 hours off-peak and discharges for 4 hours on-peak. When the battery was charged with wind power and used to displace a simple-cycle gas turbine, the resulting social benefit due to reductions in particulate matter ($PM_{2.5}$) and $CO_2$ (assuming \$20/t$CO_2$) was \$0.06/kWh. The large population density of New York City compared with Dallas or Houston, the different generation mixes in ERCOT and NYISO, and different atmospheric circulation patterns prohibit a direct extension of these results to ERCOT. A detailed study of the air quality benefits of storage in ERCOT is warranted to assess whether these benefits are large enough to justify a subsidy.

Pairing a CAES plant with a wind farm, either to produce smooth, dispatchable power or to store wind power and capture large upswings in hourly electricity prices, is not economically viable in ERCOT at the firm level. Further, our results suggest that current CAES technology is not a competitive method of wind power integration in ERCOT under plausible near-future carbon prices and does not produce social benefit that outweighs private costs, unless air quality benefits are shown to be substantial.

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**Appendix 1: CAES mechanics**

The compression stage of CAES begins with the intake of air at ambient pressure and temperature. A motor, drawing electricity from the grid, wind farm, or other source, runs a series of progressively higher-pressure compressors and intercoolers to bring the air to its storage pressure and temperature. By cooling the air after each compression stage, the intercoolers reduce the power necessary for compression and the aftercooler reduces the required storage volume for a given mass of air (Gyuk and Eckroad, 2003).

The compressed air is stored in an underground cavern. Above-ground CAES designs have also been explored but are only cost-effective for systems storing less than approximately 100 MWh (Gyuk and Eckroad, 2003). Since this study examines CAES paired with large-scale wind, above-ground air storage is not considered further. Underground air storage is feasible in solution-mined salt caverns, aquifer-bearing porous rock, or mined hard-rock caverns. CAES geology is discussed further in Section 4.

When air is released from the cavern, the pressure must be throttled down to inlet pressure of the first expansion turbine. The expansion phase of the McIntosh-type CAES cycle consists of a high-pressure then a low-pressure combustion turbine. Before entering the high-pressure turbine, the air is heated in a recuperator, a heat exchanger that captures the exhaust heat from the low-pressure turbine. The turbines drive the generator, producing electricity that is sent to the grid and thus completes the CAES cycle.

Between the high- and low-pressure turbines, air is chilled to 60°F and 1 atmosphere, allowing the system to operate with consistent efficiency even in hot weather (Gyuk and Eckroad, 2003).

*Ramp rates*

Aspects of CAES that make it well-suited for leveling wind power output are high ramp rate and quick startup time (Schainker, 2007). In its compression phase, a CAES plant starts up in 10-12 minutes and ramps at 20% per minute. In its generation phase, CAES starts up in 7-10 minutes and ramps at 200% per minute. These parameters allow a CAES system to store or supplement wind power output such that the wind/CAES system delivers highly consistent power.

*Adiabatic CAES*

Although not yet demonstrated, the concept of adiabatic CAES would eliminate the use of fossil fuel in CAES. Rather than dissipating the heat of compression, as in the current CAES designs, adiabatic CAES would store the heat and subsequently use it to re-heat the air before the expansion stage. The efficiency of the system would be approximately 0.8 (kWh generated per kWh stored). EPRI has estimated the capital cost of an adiabatic CAES plant at $1000/kW (EPRI estimates $600 - $750/kW for the second-generation CAES design modeled in this paper). Although adiabatic CAES is likely not cost-effective at current natural gas prices and under current greenhouse gas regulations, that could reverse under higher gas prices and stricter limits on greenhouse emissions. Industry experts affirm that the technology required to build a viable adiabatic CAES demonstration plant are within reach (Bullough et al., 2004).

## Appendix 2: Extant and planned CAES plants

Two CAES plants are currently operational: one in Huntorf, Germany and one in McIntosh, Alabama. At least three others, in Iowa, Ohio, and Texas, are in planning or construction stages.

Huntorf: The oldest operating CAES plant, in Huntorf, Germany, was completed in 1978. It is used primarily for peak shaving, as a supplement to hydroelectric storage facilities, and as a means to supplement the ramp rate of coal plants. The system was originally designed to provide black-start services to nuclear plants and as a source of inexpensive peak power. The original two hours of storage were sufficient for these purposes, but the plant has since been modified for four storage hours (Gyuk and Eckroad, 2003). Aside from its original functions, it now helps mitigate power fluctuations from wind plants in North Germany (Succar and Williams, 2008).

McIntosh: The Alabama Electric Cooperative owns the McIntosh CAES plant, and completed it in 1991 after 30 months of construction (Gyuk and Eckroad, 2003). After initial problems with the underground storage were addressed, the McIntosh plant reached 91.2% and 92.1% starting reliability and 96.8% and 99.5% running reliability over 10 years for the generation and compression cycles respectively (Succar and Williams, 2008).

Iowa Stored Energy Park (ISEP): ISEP, slated to come online in 2011, will consist of a 268 MW CAES plant paired with 75 – 100 MW wind transported from as far as 320 km away (Succar and Williams, 2008). The underground storage will be developed in a saline aquifer in an anticline at a depth of approximately 900 m. The site was the third studied thoroughly after an initial screening of 20 possibilities.

Norton, OH: The Norton CAES plant will be a 2700 MW facility with air storage in an inactive limestone mine 670 m underground. The Hydrodynamics Group, LLC (2009) and Sandia National Laboratories conducted tests to ensure that the limestone formation would hold its pressure seal and structural integrity at CAES operating pressures. Although the project has encountered siting problems, construction of the plant is now slated to move forward (Succar and Williams, 2008).

*Wind-CAES ancillary services*

In addition to ancillary services described in the paper, a wind-CAES system could provide reactive power support, either in an ancillary services market or to compensate for fluctuations in wind power output. ERCOT, however, requires local reactive power support from all generators with capacities greater than 20 MVA, so this service is not traded on the ancillary services market (ERCOT, 2009c). Furthermore, wind turbines with power electronic converter interfaces have a certain amount of built-in static VAR compensation, perhaps rendering VAR support from the CAES system unnecessary (Key, 2004).

As discussed previously, the two extant CAES plants primarily serve functions of peak shaving, arbitrage, black start, and supporting the ramp rate of coal plants. Future CAES plants, such as ISEP, will firm and shape wind power to reduce the need for spinning reserve to fill in gaps in wind power generation. The flexibility of CAES operation gives it a broad range of options over which to find the most profitable mode of operation.

**Appendix 3: CAES Geology in Texas**

CAES is feasible in three broad types of geology: solution-mined salt caverns, aquifers of sufficient porosity and permeability, and mined hard rock caverns. Due to the disproportionately high cost of developing hard rock caverns, they are not considered in this study. Succar and Williams (2008) estimate ranges of each type of CAES geology in the United States. While this map provides a broad indication of possible locations for CAES development, it is not definitive because siting a CAES plant depends largely on local geological characteristics and preexisting land use patterns.

*CAES in Solution-Mined Salt Caverns*

The two currently operational CAES plants, in McIntosh, Alabama and Huntorf, Germany, both use solution-mined salt caverns for air storage. These structures are advantageous for CAES due to the low permeability of salt, which enables an effective pressure seal, and the speed and low cost of cavern development. The caverns are formed by dissolution of underground halite (NaCl) in water and subsequent removal of the brine solution. The CAES plant injects and removes air through a single well connecting the salt cavern and turbomachinery.

A layer of water, left over from the solution mining process, remains on the bottom of the cavern and suspends particulates. Particulate matter does not reach the turboexpander inlet to cause corrosion or other problems (Davis, 2009).

While the cost of the salt cavern is relatively independent of the cavern's depth, the operating pressure range of the salt cavern depends on depth: 0.3 psi/ft (6.41 kPa/m) is an approximate lower bound, and 0.7 – 0.85 psi/ft (15.0 – 18.2 kPa/m) is an approximate upper bound (Swensen, 1994). The lower bound ensures that the cavern pressure does not deviate excessively from the surrounding lithostatic pressure and cause inward stress to the cavern walls. The upper bound must be less than the pressure that would cause upward force on the casing pipe to exceed the downward force of soil friction on the pipe. The pressure range of the salt cavern constrains the inlet pressure of the high-pressure expansion turbine, which cannot exceed the lower bound on cavern pressure less losses accrued between the cavern and HP expander.

*Occurrence of salt formations amenable to CAES*

Salt that can house a CAES cavern occurs in two general forms: bedded and domal. Domal salt is more pure and massive than bedded salt and therefore superior for CAES cavern development, but specific sites in areas of bedded salt can be amenable to CAES as well. Domal salt occurs primarily in the Gulf Coast and East Texas Basin (Hovorka, 2009). Salt domes are formed when denser lithologies overlie salt beds and the salt begins to buoyantly rise to form diapirs, domes, and other intrusive structures in the overlying rock. The upper regions of salt domes often have concentrations of impurities that form a cap rock that protects the rest of the dome from dissolution in near-surface meteoric water. The salt caverns of both extant CAES plants, in McIntosh and Huntorf, were solution-mined in domal salt.

Bedded salt is originally deposited in restricted marine basins that undergo cyclic flooding and evaporation to form repetitive evaporite sequences containing halite interbedded with limestone, dolomite, anhydrite, polyhalite ($K_2Ca_2Mg(SO_4)_4 \bullet 2(H_2O)$), and mudstone. The Bureau of Economic Geology at University of Texas at Austin performed a detailed characterization of bedded salt in the Midland Basin (Hovorka, 2009). Results of the study indicate that the Salado Formation, the dominant halite-bearing unit of the Midland Basin, contains thick and laterally-homogenous bedded salt that thins toward the east. The study provided a map of salt in Texas that provides a good indication of general areas that are likely to harbor the right conditions for a solution-mined CAES cavern (but cannot be interpreted as indicative of sites where CAES is feasible without further study.)

*CAES in Saline Aquifers*

Underground storage for a CAES plant is also feasible in an aquifer-bearing sedimentary rock. The rock must be sufficiently permeable and porous to allow water displacement and air cycling, and lie beneath an anticline of impermeable caprock to stop the buoyant rise of air and impede fingering (Succar and Williams, 2008). A bubble in the aquifer, developed by pumping air down multiple wells, serves as the air storage cavern. The ratio of the total amount of air in the bubble to the amount that cycles over the course of CAES operation is typically between 5 and 30 (Swensen, 1994). This large amount of cushion serves to keep the bubble at a relatively constant size (Succar and Williams, 2008) and isolate the air/water interface from the wells that serve as conduits to the aboveground turbomachinery. The use of multiple wells instead of a single one ensures that the pressure gradient surrounding each well during CAES operation does not exceed the fracture pressure of the host rock. The Iowa Stored Energy Project (ISEP), a wind/CAES system under construction in Dallas Center, IA, will use an aquifer for underground storage.

The native pressure in the reservoir is approximately equal to the hydrostatic pressure of the aquifer. The operating pressure range of the reservoir is relatively narrow; the total mass of air in the storage bubble is typically 5 – 30 times the cycling air mass, such that the removal of the cycling air causes a relatively small drop in reservoir pressure. Since water has approximately 50 times the viscosity of air and flow rate is inversely proportional to viscosity, water in the aquifer does not significantly encroach on the bubble over the time-scale of plant operation. The storage reservoir is thus not pressure-compensated, and its function can be modeled as a salt cavern to good approximation (Succar and Williams, 2008).

The total turboexpander volume flow rate during power generation divided by the number of wells is given by $Q$ in Equation A1 (Swensen, 1994).

$$Q = K \cdot (P_w^2 - P_c^2)^n \tag{A1}$$

$Q$ = flow rate

$P_w$ = flowing wellhead pressure

$P_c$ = static wellhead pressure

$K,n$ = constants dependent on reservoir properties and well size

Increasing the number of wells increases $P_w$ but leaves $P_c$ relatively fixed. This raises the turboexpander flow rate ($Q$ times the number of wells) and therefore the turboexpander inlet pressure. A high turboexpander inlet pressure reduces the specific air consumption (kg/kWh) of the generation phase, which lowers the heat rate and energy ratio and reduces the operating cost. The cost of drilling more wells, however, can offset the reduced operating cost. The number of wells and turboexpander inlet pressure can be optimized to produce the lowest cost per kWh of electricity generation. The optimal number of wells and turbine inlet pressure depend on aquifer parameters such as permeability, porosity, thickness, and depth, which constrain the bulk flow of air through the turbomachinery.

*Occurrence of saline aquifers amenable to CAES*

An early study on the use of aquifers for CAES was based on the success in storing natural gas in porous formations, and on the assumption that the techniques of storing air and natural gas are identical. The resulting map of possible aquifer CAES sites covered most of the central United States (Allen, 1985).

In 1994, Energy Storage and Power Consultants (ESPC) screened non-potable aquifers and depleted gas reservoirs in New York as potential sites for CAES (Swensen, 1994). To evaluate aquifers, ESPC first eliminated all geological groups, formations, and members solely associated with potable aquifers. The remaining sites were assessed for adequate thickness and porosity, and areas with land use incompatible with a CAES facility were eliminated. ESPC's search generated three possible sites for air storage in an aquifer, each with depths of 460 – 910 m and permeability of 100 mD. The report concluded with an enumeration of the process to further assess the aquifer sites for CAES cavern development and the associated costs, which included further searching of public and private records for relevant data, conducting seismic tests, developing a test well, modeling the reservoir to evaluate compatibility with CAES, securing permits, and testing air cycling facilities for the selected reservoir. The process was estimated to take two years and cost $2,975,000 (1993$). Although the results of this study cannot be directly applied to CAES in Texas, they are illustrative of the processes and costs involved in characterizing and choosing an aquifer CAES site.

Following EPRI (1982), Succar and Williams (2008) assembled a table of suitable aquifer characteristics for CAES. It bears noting that the New York ESPC study chose a 3000-foot deep aquifer as a possible CAES site and that the Iowa Stored Energy Project will use an aquifer 880 m deep, both of which fall into the "unusable" depth range of this table (above 760 m). In addition, all three sites in the New York study have permeabilities of 100 mD, on the border between "unusable" and "marginal" in the table. These discrepancies underscore the importance of individual site testing and the difficulty of generalizing parameters for aquifer CAES sites.

Although specific sites for aquifer CAES in Texas have not been extensively examined, the Texas Bureau of Economic Geology (BEG) has evaluated aquifers for use in carbon capture and sequestration (CCS) at depths of 800-3000 m based on the criteria of injectivity and trapping (Hovorka, 1999). Injectivity is a measure of the formation's ability to receive fluid and is determined by depth, permeability, formation thickness, net sand thickness, percent shale (injectivity declines above 50% shale), and sand-body continuity (a measure of the possible size of the storage). Trapping is a measure of the formation's ability to hold the injected fluid in place, and is determined by the thickness and continuity of the top seal, hydrocarbon production from the interval, fluid residence time, flow direction, solubility of the injected fluid in the fluid it displaces, rock/water reaction, and porosity.

CAES requires adequate injectivity and caprock for trapping, but also deliverability of air from the formation to the wells. Unlike CAES aquifers, CCS sites do not require an anticline: flat caprock structures are superior for CCS because they enable faster migration and dissolution of $CO_2$. The high viscosity of $CO_2$ under storage conditions and the low permeability in deep aquifers indicate that $CO_2$ flow behavior will be different than air in CAES (Succar and Williams 2008). In addition, ideal CCS aquifers are at least 800 m deep to keep $CO_2$ in its supercritical state. Depth requirements for aquifer CAES storage are less stringent, though the depth of the formation influences the operating pressure range of the air storage and thus the turboexpander inlet pressure. Although CAES is technically feasible at depths as shallow as 140 m (Succar and Williams, 2008), aquifers at these depths often contain potable water and are hence illegal to disturb (Swensen, 1994).

Studies of aquifers for CCS storage are poor wholesale proxies for CAES siting studies. Nevertheless, CCS studies provide data and analyses that yield limited insight into the siting of

CAES facilities. The BEG compiled a database on possible CCS aquifers nationwide, including the Paluxy, Woodbine, Frio, Jasper, and Granite Wash formations of Texas that can be found in its online database (Texas Bureau of Economic Geology, 2009).

*Depleted Natural Gas Fields*

Energy Storage and Power consultants screened depleted gas fields in New York for possible conversion to CAES caverns. ESPC chose to evaluate only those between 460 and 1520 m deep and with uncomplicated reservoir and caprock geology, and exclude fields with measurable oil production, more than 20 producing wells, or sensitive surface land use. The sites were further restricted by agreement with host utilities and the New York State Energy Research and Development Authority (NYSERDA). With these constraints, no depleted natural gas fields were found suitable for CAES cavern development (Swensen, 1994).

**Appendix 4: CAES plant cost**

The total cost of a CAES plant consists of its capital and operating costs. The capital cost includes the plant's turbomachinery (high and low pressure expanders, compressor, and recuperator), underground storage facility, and the balance-of-plant (including site preparation, building construction, and electrical and controls).

If the underlying geology is suited to a solution-mined salt cavern, storage cavern capital costs include the cost of drilling the wells, the leaching plant, cavern development and dewatering, the brine pipe (to transport the solution away from the site), and water. Development costs associated with aquifer CAES include the cost of drilling multiple wells, the gathering system, the water separator facility, and the electricity used to run an air compressor to initially create the air-storage bubble in the aquifer (Swensen, 1994).

CAES cost data from planning studies and extant plants was regressed against expander capacity (Figures A1 and A2) (Swensen, 1994; Haug, 2004; Schainker, 2008; Hydrodynamics Group, 2009). The capital cost of a CAES plant with salt-cavern storage is close to linear with expander capacity ($R^2$ = 0.94). The capital cost of a CAES plant with aquifer storage is more variable, due to the high site-specificity of the underground storage cost ($R^2$ = 0.78). The data were plotted with a 95% prediction interval, which defines the range in which 95% of future observations are expected to fall.

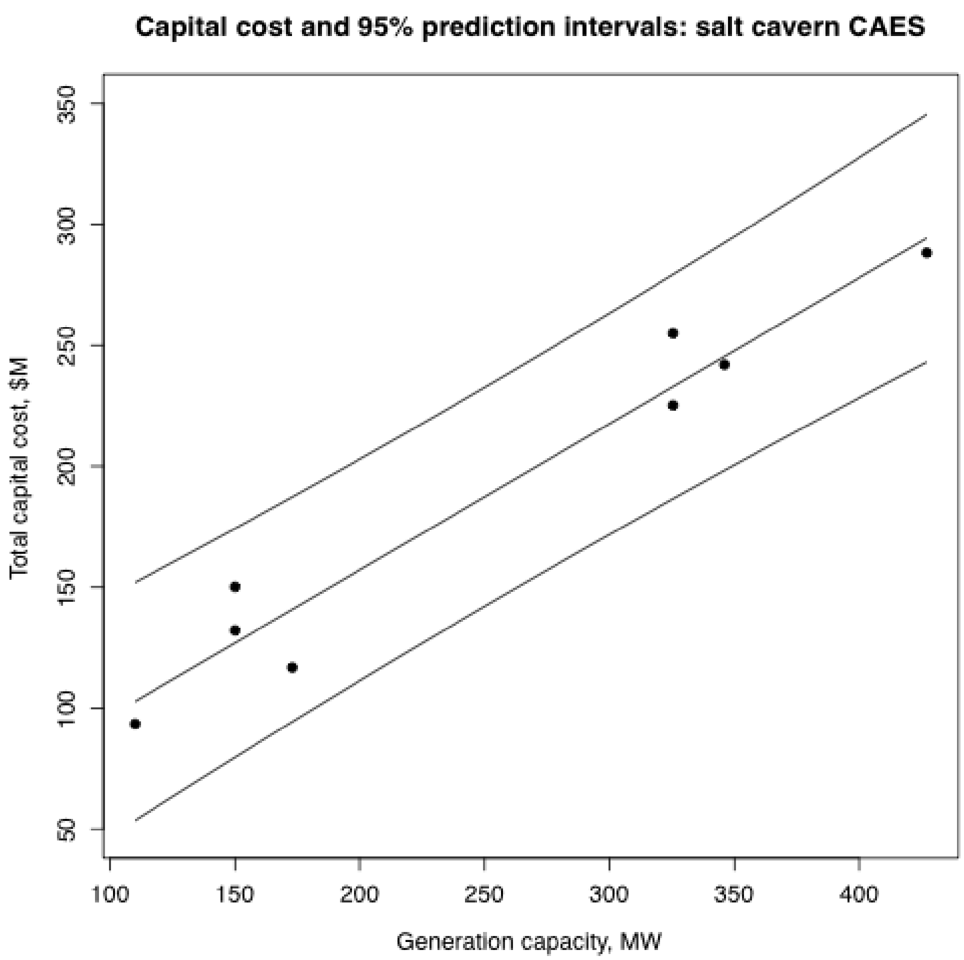


**Figure A1. Capital cost and 95% prediction intervals for development of a CAES plant with salt-cavern storage.**

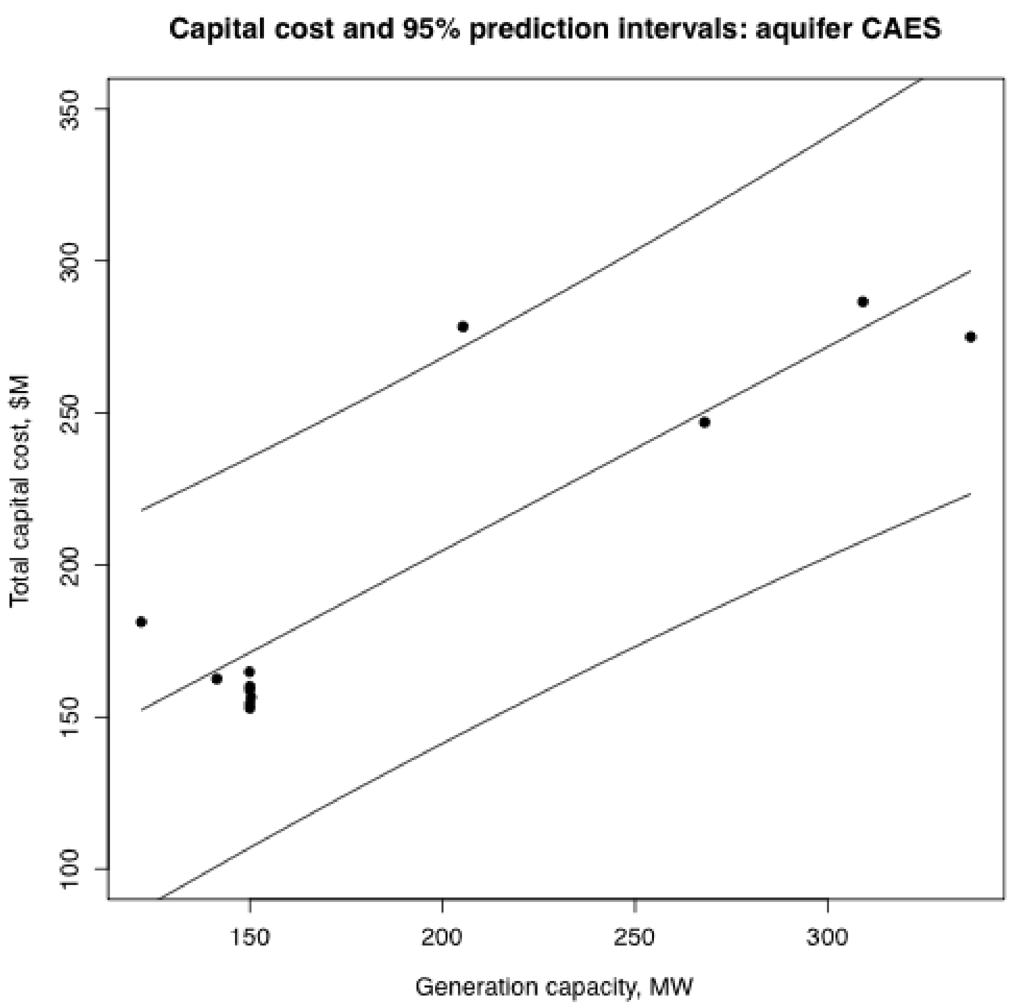


**Figure A2. Capital cost and 95% prediction intervals for development of a CAES plant with aquifer storage.**

The marginal cost per kWh of energy storage in an aquifer is $0.10-$0.20, which reflects the cost of electricity required to expand the bubble such that the generation phase produces an additional kWh. The marginal cost to expand a solution-mined salt cavern to produce an additional kWh is $1-$2 (Schainker, 2008).

**Appendix 5: Transmission capital cost**

Transmission capital cost was first modeled as a linear regression of cost per GWm on MW capacity. This line had a negative slope and thus produced a parabolic function for total cost, in which extremely high-capacity transmission lines had costs that were near zero or negative. The optimization thus resulted in profits that were artificially high.

The transmission cost model (in $/GWm) used in this research as a function of length in km ($L$) and capacity in MW ($T$) is reproduced in Equation A2.

$$Cost_T = 14266 \cdot L \cdot T^{0.527} \tag{A2}$$

The model is of the same form as the transmission cost model in Pattanariyankool and Lave (2010) but generates lower cost predictions. Pattanariyankool and Lave (2010) derived their cost model from a regression of inflation-adjusted, log-transformed data from transmission projects across the United States.

The model used in the current study was derived from a consultant report on transmission planning that contained the cost estimates presented in Table A1. The declining capital cost per GWm as a function of MW represents an economy of scale due to decreasing corridor widths per MW and to fixed costs of transmission line construction.

**Table A1. Physical and cost parameters of transmission lines from Hirst and Kirby (2001).**

| Voltage (kV) | Capacity (MW) | Capital cost ($/GWm) | Corridor width (m) |
|---|---|---|---|
| 230 | 350 | 856 | 30 |
| 345 | 900 | 625 | 38 |
| 500 | 2000 | 375 | 53 |
| 765 | 4000 | 281 | 61 |

Predictions generated by the model in Equation A2 were tested against data from an ERCOT study on transmission costs associated with wind integration. Table A2 presents data from the ERCOT study on the costs and lengths of transmission lines needed to transport a given nameplate capacity of central Texas wind power to load. The model fit the ERCOT data with $R^2 = 0.72$. The mean ratio of predicted to actual cost was 1.04 with a standard deviation of 0.22.

**Table A2. Length, capacity, and total cost of transmission from ERCOT study, and predicted total cost based on Equation A2.**

| MW | Cost ($millions) | Predicted cost ($millions) | Length (km) |
|---|---|---|---|
| 1400 | 381 | 344 | 528 |
| 1500 | 190 | 184 | 272 |
| 1500 | 320 | 270 | 400 |
| 1800 | 258 | 257 | 346 |
| 2000 | 376 | 397 | 506 |
| 3000 | 320 | 358 | 368 |
| 3800 | 960 | 1,516 | 1380 |
| 3800 | 860 | 1,144 | 1040 |
| 4500 | 1,130 | 1,202 | 1000 |
| 4600 | 1,520 | 1,498 | 1232 |
| 500 | 12 | 13 | 32 |

As a counterpoint to the model in which transmission cost is directly proportional to length, Mills et al. (2009) analyzed 40 transmission planning studies and found that cost per kW of transmission capacity is independent of length. Mills et al. (2009) note that the absence of observed length-dependency in the transmission data could be due to inconsistencies among the methodologies of the transmission studies analyzed; the fact that transmission costs are compared in unadjusted nominal dollars for different years could also have obscured other trends in the data. Mills et al. (2009) also note that projects involving greater transmission lengths tend to integrate more wind capacity; this trend reduces the apparent cost per kW of transmission projects involving large cumulative lengths of transmission lines. Mills et al. (2009) examine cost estimates for projects in all areas of the United States, which have large variation in siting difficulties. For a quantitative framework with which to analyze transmission siting difficulty, see Vajjhala and Fischbeck (2007).

**Appendix 6: Wind-CAES dispatch model**

If $p_i < MC_W$, the CAES system stores an amount of wind energy equal to the minimum of $w_i$ (wind energy generated), $E_C$ (compressor power), $T_W$ (wind-CAES transmission capacity), and the amount of energy the CAES cavern is capable of storing ($E_E * E_S * ER - s_i$). Any wind energy produced in excess of this amount is curtailed.

If $MC_W < p_i < p_s$, the system stores as much wind power as possible and sells the excess. The model first calculates $x_i$, the amount of energy that the CAES system can store in hour $i$, as the minimum of $T_W$ and the amount of extra energy the cavern can store in its current state ($E_E * E_S * ER - s_i$). If $w_i < x_i$, the system stores the entire output of the wind farm. If $w_i > x_i$, the system stores $x_i$ and sells the remainder of the wind energy that does not exceed the transmission capacities of either line, and curtails any additional wind power.

If $p_s < p_i < p_d$, the system sells as much wind energy as possible directly into the grid. If the wind energy output does not exceed either transmission capacity, $w_i$ is transmitted to load. If wind energy output exceeds $T_W$, wind generation is curtailed to the minimum of $T_W$ and $T_C + x_i$ and the amount of energy sold is equal to the lower transmission capacity. If wind energy output exceeds $T_C$ but not $T_W$, the CAES-load line is filled and the excess wind energy up to $x_i$ is stored.

If $p_i > p_d$, the system supplements the wind energy output by discharging the CAES until the CAES-load transmission line is full or the storage cavern is emptied. The model first calculates $y_i$, the energy that the CAES system can produce in hour $i$, as the minimum of the expander capacity over the time interval ($E_E$), and the total amount of energy that the storage cavern can supply in its current state ($s_i/ER$). If wind energy output does not exceed the capacity of either transmission line, the system sells all of the wind energy and supplements it by discharging the storage up to $y_i$ or the capacity of the CAES-load transmission line. If the wind-CAES transmission line is the smaller of the two and wind energy output exceeds the capacity of this line, the model fills the wind-CAES line, curtails the rest of the wind power, and sells the transmitted wind power supplemented with $y_i$ up to the capacity of the CAES-load line. If the CAES-load line is the smaller of the two and wind energy output exceeds the capacity of this line, the system transmits wind energy up to the CAES-load line capacity, stores wind energy up to $x_i$, and curtails the rest.

## Appendix 7. Optimization algorithm

A simulated annealing algorithm after Goffe et al. (1994) was used to optimize the profit function. The temperature at each iteration was 85% of the temperature of the last, and the initial temperature was 1000. Gradient-descent algorithms were impractical because the optimization function has zero local gradient with respect to the storage and discharge threshold prices $p_s$ and $p_d$: if, for example, the zonal price data contains values of \$76.52 and \$76.58 but nothing in between, all $p_s$ or $p_d$ values between those two prices will generate the same profit (all other parameters being equal) and there is a plateau in the profit function.

## Appendix 8. Extended Carbon Price Results

**Table A3. Profit-maximizing CAES expander sizes under the contract price scenario, fractions of wind/CAES system energy output from the CAES plant, and carbon prices to reach cost-parity with a NGCC plant at \$5/MMBTU and \$15/MMBTU gas, for both load centers and all years considered.**

| | CAES expander (MW) | Fraction of energy from CAES | Carbon price (\$/t$CO_2$), \$5/MMBTU gas | Carbon price (t$CO_2$), \$15/MMBTU gas |
|---|---|---|---|---|
| Dallas 2007 | 300 | 0.16 | 380 | 210 |
| Dallas 2008 | 460 | 0.16 | 230 | 56 |
| Dallas 2009 | 200 | 0.12 | 580 | 410 |
| Houston 2007 | 300 | 0.17 | 360 | 180 |
| Houston 2008 | 480 | 0.17 | 200 | 28 |
| Houston 2009 | 200 | 0.13 | 540 | 370 |