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WIND ENERGY AND COMPRESSED AIR ENERGY STORAGE POTENTIAL FOR NEW YORK CITY

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ABSTRACT

The energy potential from wind is significant in many locations in the U.S., including in some areas of New York State. The intermittent availability of wind – specifically, higher wind potential at night and in the winter in New York – would require extensive storage to make use of that energy during times of peak electricity demand – during the day and in the summer. Although the total energy available from wind may be sufficient and available at a low cost, the cost of implementing traditional storage techniques (e.g. batteries) would be expensive and require large amounts of space to address the offset supply and demand profiles. As such, base electricity loads are likely to continue to be served by a combination of less expensive energy conversion technologies, particularly given the current low cost of wholesale natural gas for gas-fueled power plants. Compressed air energy storage (CAES) has been evaluated – and implemented or proposed at a small number of facilities – as a potential energy storage technology that could be used to reduce the amount natural gas required to operate compressors at natural gas-fueled power plants serving base electricity demands. The result of this strategy is, effectively, an increase in thermal efficiency of the power plant.

This paper presents an evaluation of wind energy available at a site in New York State, its potential to meet the electricity demand in New York City, the expected capital and recurring costs of the overall system, and a comparison to electricity provided by natural gas, a likely alternative large-scale fuel source. Annual wind data for the site and annual New York City electricity usage were analyzed. Available wind energy was first assumed to serve any electricity demand above the New York City base load. Additional available wind energy operates compressors, storing compressed air in underground caverns. The cavern sizes required and associated capital costs was calculated. The expected reduction in natural gas requirements were calculated for gas-fuelled power plants designed to accept compressed air from the caverns, with additional electricity demand met by gas turbine power plants. The recurrent cost reductions associated with reduced natural gas volumes were calculated based on a range of natural gas prices to evaluate the feasibility of the system described above under different market conditions. The potential usage of CAES systems for peak electricity demands was also evaluated.

INTRODUCTION

Electricity generated from wind is a renewable, but intermittent energy resource. In New York, specifically, winds are higher at night and in the winter in New York, but peak electricity demands are during the day and in the summer. Although the total energy available from wind may be sufficient and available at a low cost, the cost of implementing traditional storage techniques (e.g. batteries) would be expensive and require large amounts of space to address the offset supply and demand profiles. As such, base electricity loads are likely to continue to be served by a combination of less expensive energy conversion technologies, particularly given the current low cost of wholesale natural gas for gas-fueled power plants.

To improve the cost-effectiveness of intermittent renewable energy resources, several energy storage techniques are being considered [1]. Compressed air energy storage (CAES) has been evaluated as a potential energy storage technology and has been projected to be a low-cost utility-scale storage approach [2]. In a wind-CAES system, electricity generated by wind turbines compresses air and stores it in an underground cavern. When power is needed, the compressed air expands as the working fluid in a modified gas turbine cycle. This reduces the amount of natural gas required to produce electricity compared to gas-fueled power plants and provides a usage for electricity from wind that may otherwise be “dumped”. Despite the potential advantages, only three CAES facilities have been operational worldwide [3], including a 110 MW facility in McIntosh, AL. Another CAES facility is under consideration in Ohio [3] and a proposed facility in Iowa [2] was recently abandoned due to geological concerns

There are many performance and design considerations for a CAES system, charged by wind power, and coupled to a natural gas power plant, including the following [4]: Proximity to wind resources; CAES reservoir type (e.g. salt domes and beds, hard rock caverns, and porous rock formations); geology at the location(s) of desired CAES reservoir(s); available storage volumes and required cavern size; constant versus variable cabin and turbine inlet pressures; fuel consumed per electricity unit output (Fuel Rate); and charging electricity ratio (CER) the ratio of plant electricity output to compressor input.

While the items above can vary widely depending on the site, plant design and CAES system parameters, previous studies have established cost assumptions for wind [3,5-6], CAES [1-3] and other natural gas electricity generation systems [3,7-11]. Assumptions used in the analysis described in this paper are summarized under the “Analysis: Assumptions” section, below.

Previous studies have primarily focused on analyses of generic systems [3,12] or locations benefiting from high winds in the central plains of the US [13]. This paper summarizes the analysis of a potential wind farm site in Upstate New York serving a densely populated, large urban energy user (New York City).

Because of its large capital costs, CAES has primarily been evaluated for base electricity demand. This paper includes discussion of incorporating CAES serving peak demands into the model presented.

ANALYSIS

A model was developed for the electricity produced from wind resources in New York State and utilized to meet electricity demand in New York City by both direct usage to meet peak electricity demands (i.e. electricity usage exceeding the base electricity demand) and CAES coupled with natural gas-fueled expanders to meet base electricity demands.

Wind Speeds and Power Output

Wind speed data for an actual site in upstate New York [14], recorded at 10 minute intervals in 2006, was used as the basis for hourly winds available and hourly power generation from wind resources in the model. This data is available at 80 m and 100 m heights to allow flexibility for typical wind turbine hub heights. Based on the hub height of the wind turbine used in the model, the wind speed at 100 m was averaged at each hour.

The performance profile of a commercially available 3.0 MW (rated capacity) wind turbine was assumed for all wind turbines in the model. Figure 1, below, shows the power coefficient (Cp) for this wind turbine as a function of wind speed for the wind speed range in which the wind turbine power output varies. Cp is the proportion of the theoretical maximum power available in the air passing through the plane of the turbine blades that is converted to electric power. At wind speeds below 2 m/s and above the 28 m/s cut out velocity, the power output is zero. The power output at wind speeds between 13 m/s and 28 m/s is the peak power output.

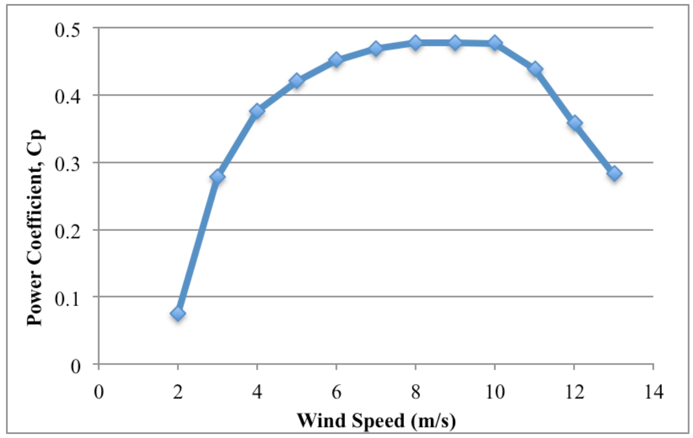

Figure 1 – Power Coefficient of 3.0 MW Wind Turbine

A sixth-order polynomial fit of the Cp data shown in Figure 1 was used to calculate the power output of each wind turbine at each hour.

Electricity Usage

Hourly electricity demand for New York City in 2006, as published by the New York Independent System Operator (NYISO), was used in the analysis [15]. This data represents the total electric load for New York and ranges from a minimum of 3.86 GW to a maximum of 11.35 GW. The base electricity demand for New York was assumed to be the minimum hourly demand and electricity usage above this was considered to represent the peak demands.

Model

A model of the electricity delivery system shown in schematic in Figure 2 and described in this section was analyzed using Matlab. The hourly wind speed data and hourly electricity demand data for New York City, described above, were used for all analyses.

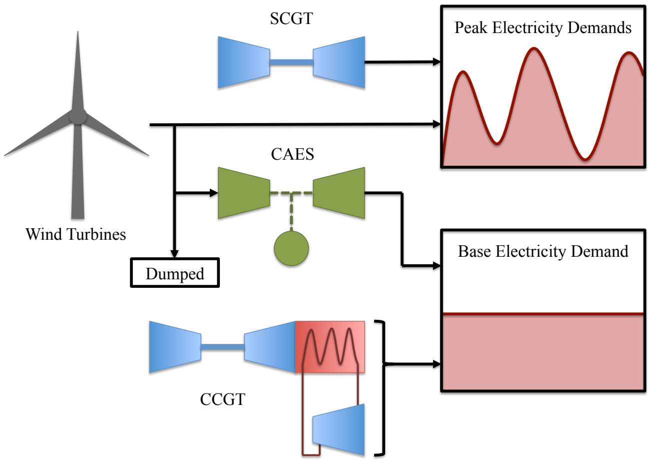

Figure 2 – Schematic Diagram of Wind-CAES-Gas Model

At each hour of the year (8760 hours total), the total power output of wind turbines was calculated for a range of turbines from 0 to 5,000 in increments of 1,000. If the wind turbine power output was less than the electricity demand above base load at that hour, any available wind power went to electricity demand, with the difference in peak demands provided by simple cycle gas turbine (SCGT) plants. If the wind turbine power output was greater than the electricity demand above base load for that hour, the wind turbine power met the electricity demand, and the remaining wind turbine power was considered available to operate the CAES compressor to store compressed air for base load application. If the CAES storage reservoir reached capacity, the remainder of the wind power was "dumped". For all hours, the base electricity load was provided by a combination of natural gas-fueled CAES expanders and combined cycle gas turbine (CCGT) plants. The CAES storage and conversion capacities were optimized for each wind turbine configuration. The CCGT capacity for each wind turbine configuration represents the balance of the base electricity demand.

At each hour, the amount of natural gas burned in the CCGTs, SCGTs and CAES expanders was calculated based on the respective heat rates and power outputs of each system. The amount of compressed air stored in the CAES reservoir was decreased by the amount required to operate the CAES expander.

For each wind turbine configurations, the total capital costs were calculated for each element of the system. To annuitize the costs for overall system comparisons, the total capital cost for each system was multiplied by a cost recovery factor (CRF). For each configuration, operations and maintenance costs for each element of the system and total gas usage costs were calculated. All recurring costs and annuitized capital costs were added for each system to determine a total annual cost for each wind turbine configuration.

Assumptions

Previous studies have established cost assumptions for CAES and other natural gas electricity generation systems. Consistent with previous studies of long-term, large-scale wind implementation, projected installed costs were used. Table 1, below, summarizes the parameter values assumed for the analysis described in this paper, as well as the source(s) of the values.

Table 1 - Cost and Performance Parameters

Parameter	Value	Ref.
Wind Turbine Park Capital	$700/kW	[3,5]
Wind Turbine Park Fixed O&M	$15/kW-yr	[6]
Wind Turbine Park Variable O&M	0.3 ¢/kWh	[6]
CAES Storage Capital Cost	$1/kWh	[1]
CAES Compressor Capital Cost	$170/kW	[1]
CAES Expander Capital Cost	$185/kW	[1]
Balance of CAES Plant Cost	63%	[1]
CAES Fixed O&M	$15/kW-yr	[1]
CAES Variable O&M	0.3 ¢/kWh	[1]
CAES CER	1.5	[1]
CAES Heat Rate	4220 kJ/kWh	[1]
SCGT Plant Capital	$240/kW	[3,7]
SCGT Fixed O&M	$10.8/kW-yr	[8]
SCGT Variable O&M	0.13 ¢/kWh	[8]
SCGT Maximum Derating	20%	[9]
SCGT Heat Rate	9400 kJ/kWh	[3]
CCGT Plant Capital	$580/kW	[3,8]
CCGT Fixed O&M	$10.8/kW-yr	[9]
CCGT Variable O&M	0.13 ¢/kWh	[9]
CCGT Maximum Derating	14.7%	[10]
CCGT Heat Rate	6700 kJ/kWh	[3,11]
Natural Gas CO_2 Emissions	65.91 tCO_2/GJ	[3]
Cost Recovery Factor (CRF)	0.11	[3]

The price of natural gas has fluctuated in the past 15 years with a steady decline over the last 3-4 years. Figure 3, below, shows annual average natural gas prices for electric power generation [16], as well as 3-year running average[1].

[1] The 2011 natural gas price was averaged through September 2011, the time period for which the data was available.

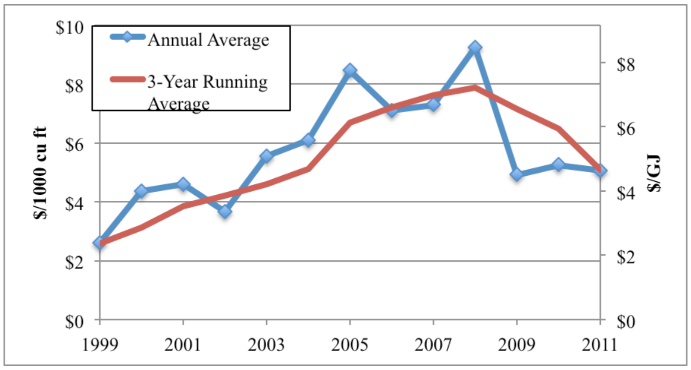

Figure 3 – Natural Gas Prices for Electricity Generation

A natural gas price of $4.66/GJ was used for the analysis described in this paper. This represents the 3-year running average price for 2009-2011. For some analyses, the maximum natural gas price ($9.26/GJ) was used for comparative purposes and only where stated explicitly.

RESULTS AND DISCUSSION

Table 2 includes the results of system sizing and cost calculations for each of six wind turbine configurations with CAES, SCGTs and CCGTs. Several trends can be observed in the data. The effects of the wind turbines on the peak electricity demands are indicated by the SCGT capacity and the percentage of demand met by SCGTs and directly by wind. While increases in installed wind capacity have a significant impact on increasing peak electricity demands met by wind and decreasing electricity demands met by SCGT. However, the introduction of wind allows only very little SCGT capacity to be taken offline, so the effects on the capital costs is a significant increase. For example, with 9,000 MW wind capacity installed, SCGT electricity generation accounts for 20% less electricity demand, but the total SCGT capacity decreases by only 1.8%.

Table 2 – Results of Model Simulations

Installed Wind Capacity	0	3000	6000	9000	*11142*	12000	15000	MW
CAES Expander Capacity	0	399	1542	2524	*3864*	3864	3864	MW
CCGT Capacity	4529	4061	2721	1570	*0*	0	0	MW
SCGT Capacity	9354	9253	9217	9182	*9157*	9147	9111	MW
Percent Total Electricity Demand Met by:								
Direct by Wind	0	12.8	17.3	19.9	*21.2*	21.6	22.8	% Total
CAES	0	6.6	25.4	41.6	*63.7*	63.7	63.7	% Total
CCGT	63.7	57.2	38.3	22.1	*0.0*	0.0	0.0	% Total
SCGT	36.3	23.5	18.9	16.3	*15.1*	14.6	13.4	% Total
Total Annual Costs	2.66	2.80	3.15	3.47	*3.79*	3.83	4.04	10^9 USD
Annual Capital + O&M Costs	0.75	1.24	1.81	2.29	*2.77*	2.82	3.06	10^9 USD
Annual Gas Costs (@$4.66/GJ)	1.90	1.56	1.34	1.18	*1.02*	1.01	0.98	10^9 USD

The effect of the wind turbines, coupled with CAES, on electricity generation to meet base load demand is more significant. Both the required CCGT capacity and the percentage of electricity demand met be CCGT decrease with increased wind turbine capacity. With 3,714 wind turbines installed (11,142 MW capacity), no CCGT is required to meet base load demand. (This configuration is shown in italics in Table 2.)

Although the annual recurring costs from natural gas requirements decrease significantly with increasing wind capacity, it is not enough to offset increasing capital costs. Although the use of CAES significantly increases the amount of wind power output that can be utilized by the overall network (see Figure 4), the nature of the wind availability and electricity demand (i.e. high winds in the winter, low winds in the summer and high electricity demand in the summer) requires large compressed air storage capacities. For example, for the case when the wind-CAES system is just large enough to meet all base load demand, the system requires 2380 GWh storage capacity (7.0×10^8 m^3 volume). This is significantly smaller than the salt cavern capacity in New York State [15]; however, it is 48 times larger than the a storage cavern similar to that at the McIntosh CAES plant scaled for the system capacity calculated in this analysis. This is also reflected in Table 4, which indicates that, even with CAES included, the optimum cost solution involves "dumping" some wind-generated electricity and CAES system capacity less than the largest capacity possible for the maximum wind power output.

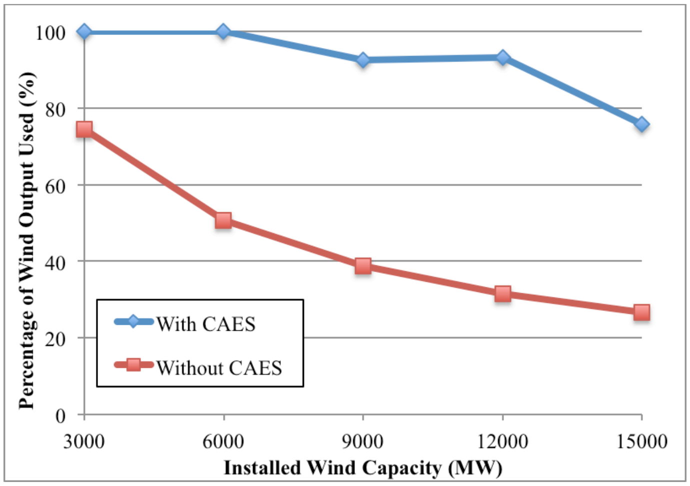

Figure 4 – Percentage Wind Output Used vs. Installed Capacity

Of particular interest in evaluating alternative energy resources is comparing costs to traditional carbon-emitting resources (i.e. natural gas for this analysis). As annual costs are very sensitive to fuel prices, which are difficult to project, these comparisons can be difficult for long-term evaluations. Further, it is unclear whether the USA or New York State will institute some carbon pricing program or market. As such, an effective "break-even" natural gas price was calculated for each wind turbine configuration modeled (see Figure 5).

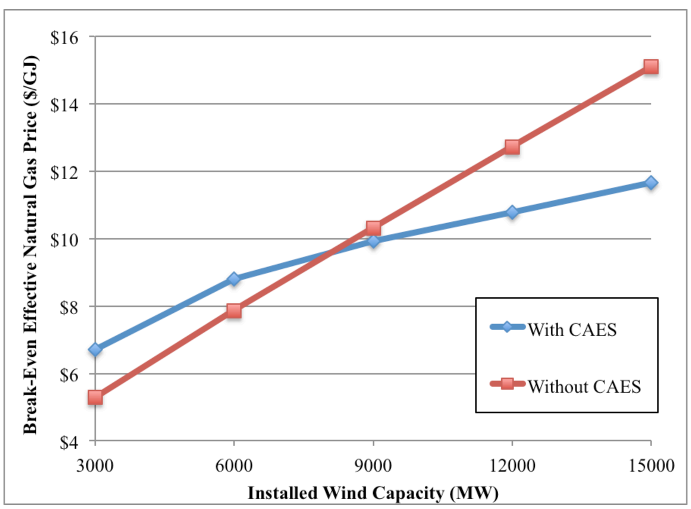

Figure 5 – Break-Even Effective Natural Gas Price vs. Installed Wind Capacity

Figure 5 indicates that as the installed wind capacity increases, CAES becomes more cost effective than the case of wind without CAES. However, the break-even natural gas price for none of the modeled systems is less than the price used in the previously discussed calculations. Figure 6, below, shows the break-even carbon emissions price (in USD per ton CO_2) versus installed wind capacity (with CAES) for two natural gas prices: $4.66/GJ (the most recent 3-year running average) and $9.26/GJ (the maximum annual average price during the past 10 years).

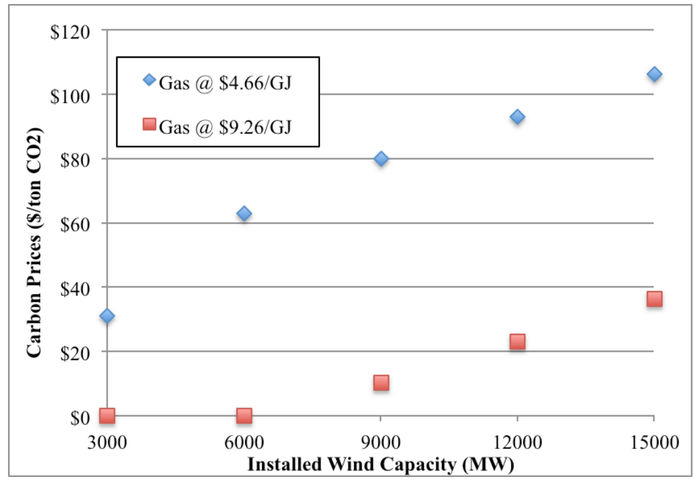

Figure 6 – Break-Even Carbon Price vs. Installed Wind Capacity at Two Natural Gas Prices

The analysis indicates that, at high natural gas prices, grid-integrated win with CAES is cost-effective without a carbon price at the lower end of the capacities analyzed and may remain competitive at carbon prices that may be reasonable in a carbon market. This is unlikely to be the case if natural gas prices remain low, as the break-even carbon prices are very high in that case.

Because of the large capital costs associated with CAES, it has primarily been considered as an alternative for base electric load capacity. In this analysis, the use of CAES for peak electric demands was also evaluated for the case of 15,000 MW installed wind capacity (see Table 3).

Table 3 - CAES for Peak Load Applications 15,000 MW Installed Wind Capacity

CAES Application	Base Electric Only	Base + Peak	Units
CAES Expander Capacity	3864	11153	MW
CCGT Capacity	0	0	MW
SCGT Capacity	9111	0	MW
Percent Demand Met by:			
Direct by Wind	22.8	22.8	% Total
CAES	63.7	77.2	% Total
CCGT	0.0	0.0	% Total
SCGT	13.4	0.0	% Total
Total Annual Costs	4.04	4.98	109 USD
Annual Capital + O&M Costs	3.06	4.17	109 USD
Annual Gas Costs ($4.66/GJ)	0.98	0.81	109 USD
Break-Even Effective Gas Price	$11.66	$14.55	$/GJ
Break-Even Carbon Price (Gas Price: $4.66/GJ)	$106.15	$549.80	$/ton CO2
Break-Even Carbon Price (Gas Price: $9.26/GJ)	$36.35	$80.24	$/ton CO2

The results of this analysis, as shown in Table 3, indicate that using CAES to meet peak electricity demand is less cost effective than "dumping" the excess electricity generated from wind. After addressing the full base load with CAES and 63%

of the peak loads using electricity directly from the wind, the energy savings associated with switching the remaining SCGT capacity to CAES is small compared to the significant increase in capital costs associated with the CAES equipment and storage.

CONCLUSIONS

Significant fossil fuel reduction and associated GHG emission reductions can be achieved by utilizing renewable resources, such as wind. However, wind availability is intermittent and not necessarily easy to predict. As such, without an inexpensive energy storage mechanism, fossil fuel-burning power plants typically cannot be taken off line after introducing wind-generated electricity to the grid.

Integrating electricity generated from wind turbines with CAES after serving peak electricity demands further decreases natural gas usage and GHG emissions. Further, CAES systems can replace traditional fossil fuel-burning power plants. Emissions are not eliminated at CAES facilities, but they are reduced without sacrificing system reliability as would be the case with shutting down power plants after bringing wind power on line, but without employing storage.

Despite the advantages of wind-CAES systems, they are not cost-effective to serve New York City's base electricity demand at today's natural gas prices. However, for larger deployments of wind power, it may be more cost-effective than wind-generated electricity without CAES storage and electricity generation. The discrepancy between peak wind availability (winter nights) and the highest electricity demand (summer days) requires large storage volumes that would add significantly to the system's capital costs. The overall effect of this issue becomes less significant at larger installed wind capacities.

At high natural gas prices, the lower-wind-capacity systems evaluated are cost-effective for CAES systems serving New York City. Larger-wind-capacity systems with CAES may be cost-effective if a price for GHG emissions is included and natural gas prices increase to previous levels. Under any expected scenario, cost-effective deployment of CAES is likely to be limited to systems in which wind-generated electricity directly serves peak demands and CAES serves base loads.

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