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An alternate wind power integration mechanism: Coal plants with flexible amine-based CCS

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ABSTRACT

This paper explores a solution to problems associated with two promising technologies for decarbonizing the electricity generation system: high costs of energy penalty of carbon capture and storage, and the intermittency and non-dispatchability of wind power. It looks at the optimal design and operating strategy of a hybrid system consisting of a coal plant retrofitted with a post-combustion amine-based Carbon Capture & Storage (CCS) system equipped with the option to perform partial CO_2 capture, and a co-located wind farm. A linear optimization model determines the optimal component sizes for the hybrid system and capture rates while meeting constraints on annual average emission targets of CO_2, and variability of the combined power output. Economic benefits result from capturing less CO_2 during high electricity price time periods and capturing more CO_2 during times of relatively low electricity prices or times when integrating wind power output would exceed the transmission capacity of the connector lines. The hybrid system has Levelized Cost of Electricity (LCOE) and Cost of Carbon Capture (CoC) comparable to those of a new Natural Gas Combined Cycle Power Plant (NGCC), and provides a mechanism for muting the variability of wind power in the same way an energy storage system would.

1. Introduction

Wind power and Carbon Capture & Storage (CCS) are two of the most promising technologies to reduce CO_2 emissions from the electricity generation industry. The vital role of CCS for achieving significant reductions in CO_2 emissions is highlighted in multiple publications examining pathways for de-carbonization of the electricity sector. For example [1], estimates that CCS retrofits in 90% of the fossil-fired power plants, together with an addition of solar photo-voltaic power representing 10% of the energy mix, would result in a reduction of up to 80% of annual CO_2 emissions in Saudi Arabia by 2025. Similar studies in China [2], and the US [3] emphasize the need to facilitate the use of CCS technologies to reach their respective CO_2 emission reduction goals. Of the different kinds of CCS technology available, post-combustion amine based CCS is the best developed and most likely to be used for retrofitting an existing coal plant [4,5]. However, the use of steam from the plant's heat cycle during regeneration of sorbent results in significant loss of net plant efficiency [4] and a reduction of 20–40% in net power output [6] [7]. The loss of revenue due to the energy penalty from operation of CCS could be reduced by performing partial capture of CO_2 during times of high electricity prices [8] [9]. Integrating a CCS retrofitted coal plant with an on-site wind farm would take advantage of the remaining transmission capacity in the connector lines that results from the reduction in coal plant power output, and would allow using wind power (whenever available) to compensate for the energy penalty associated with CCS. Stand-alone wind farms are a source of intermittent supply of electricity which affects the reliability and reserve requirements of the power system. By providing flexibility to balance the wind power availability, the CCS system provides a form of 'storage' for wind power.

This system could be of significant interest in the U.S. where reducing CO_2 emissions from coal fired plants is an important policy goal [10–13]. Although it is expected that the combined impact of more stringent air emissions regulations for coal-fired power plants and low natural gas prices will force the retirement of inefficient coal plants, roughly 37% of total electric power in the US is expected to be generated from coal-plants during the next 20 years [14]. Also, given availability and comparatively low costs of wind power, it is expected that a number of states may choose to meet Renewable Portfolio Standard (RPS) goals by developing both

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local and distant wind resources depending on power transmission capacity and siting constraints [15–17].

Previous literature indicates the positive effects that enabling flexible operation of CCS equipment would have in facilitating wind power integration. Our work studying a hybrid system with flexible operation of the CCS unit through amine storage technology [18], indicates that for electricity prices justifying investments in amine storage, the hybrid system enables considerable quantities of wind power integration (within the range of 18–32% of the system nameplate capacity) and a significant increase in profits and decrease in LCOE and CoC, relative to a CCS retrofitted coal plant operating continuously [18]. Similarly, an investigation of the operating regimes of CCS power plants in future generation portfolios with significant wind power generation in Great Britain demonstrates the importance of optimally scheduling the on/off operation of CCS units for increased profits and wind power integration [19]. In [20] it is demonstrated that flexible operation of CCS yields higher profits than operation of CCS strictly with or without carbon capture (i.e. continuous flexible operation rather than 0/1 mode of operation). A recent technical analysis of flexible post-combustion CCS operation with solvent storage using Aspen software [21] concludes that flexible operations do not affect the unit's ability to maintain a 90% CO_2 capture rate at varying power output levels, and the ramp rate of a flexible CCS power plant could be enhanced by delaying solvent regeneration. Current literature [22–28] demonstrates that in addition to reducing the costs associated to the CCS′ energy penalty, enabling flexible capture also increases the range of operation of the power plants (by reducing the minimum power output required to keep the plant online), and hence, flexible CCS may be optimally dispatched to meet peak power demand, provide ancillary services, obtain higher profits, and offset the intermittent nature of renewable sources of power such as wind and solar.

Venting or partial capture CCS operation of retrofitted plants is always at least as profitable as continuous-operation of CCS. Retrofitted plants are better candidates for flexible capture than new coal plants because no additional investment is necessary to enable bypassing the CCS system in a retrofitted coal plant, while new coal plants with CCS require an additional larger capacity low pressure turbine to facilitate use of additional steam, when bypassing the capture unit. For a retrofitted plant [8], reported a reduction in cost of capture of 1–8 cents/ton of CO_2 captured for 1 h of bypass of the CCS unit every week, and up to 58 cents/ton of captured CO_2 for 24 h of bypass every week. Case study results [8] indicate a threshold price differential of 33–54 $/MWh for the retrofitted coal plant to make a profit by using a CCS system bypass [26]. demonstrates that optimizing the capture rates leads to higher profits for the flexible CCS System by up to 10% for a CCS unit with the option to perform bypass compared to the inflexible CCS unit, and a 9–29% increase in profits for a CCS system with both bypass and storage for carbon prices beyond 50$/ton [27]. presents an analysis of a hybrid system consisting of a coal gasification plant with a CCS unit operating at a constant capture rate, a syngas storage facility, and a wind farm, which achieves a $2.5/MWh reduction in levelized costs compared to an advanced coal-wind non-hybrid system (i.e. operating independently). The higher LCOE for the non-hybrid system is due to higher wind-power integration costs, higher resource adequacy costs, and increased costs of building transmission lines [29]. studied a wind-coal hybrid system for CCS equipped with amine storage and estimated a relative increase in profits of about 20% for optimized operation of the hybrid system when compared to heuristic based operation, under the assumption of perfect foresight. Another hybrid system including coal gasification hydrogen production with CCS, underground storage of hydrogen, and independent gas turbine power generation to buffer the variability of wind was analyzed in Ref. [30]. Results show that cost of capture is reduced by 40% relative to inflexible CCS in coal-fired plant.

In contrast to [27] and [29], this paper has three primary aims: (a) to identify the optimum component sizes as well as the optimal operation schedule (variable capture rates) of the hybrid system, (b) to quantify the reduction in cost of capture of CO_2 for the hybrid system compared to a continuous operation CCS unit, and (c) to analyze the effects of capital costs, restrictions on power output variations of generating units, CO_2 emissions constraints, wind power variability, and electricity prices variability on the optimum size and economic benefit of the hybrid system. In addition, rather than assuming arbitrary values of potential CO_2 tax levels we estimate the Cost of CO_2 Capture (CoC) and Levelized Cost of Electricity (LCOE) for the corresponding hybrid system. These metrics are used as a basis for comparison of different configurations and as a way to assess the economic value of the hybrid system relative to other CO_2 emission reduction strategies (such as replacing existing coal plants with natural-gas fired power plants).

2. Materials and methods

A linear optimization model finds the optimum installed capacity of the new wind farm and the optimum schedule of partial capture operation of CCS in order to maximize profits over a given planning horizon. Please refer to SI for a full list of variable definitions.

2.1. Data

We analyze a hybrid system consisting of an existing sub-critical coal plant with specifications similar to the Powerton Plant in Illinois (eGrid [31]) with a CCS retrofit, and an optimally sized co-located wind farm. Data for CCS energy penalty, capital costs and O&M costs of the coal plant were estimated by representing a similar plant in IECM [7], and by assuming a CCS system with a maximum capture rate of 90%. Capital costs and Annual Operating Expenses (AOE) of wind farms were obtained from Ref. [32]. Wind power data was simulated with SynTiSe (see SI Section I): an application that uses Markov Chain Monte Carlo models [33] to obtain long-term synthetic time series of wind power output. Input data for SynTiSe came from the EWITS database [34]. The expected lifespan of the hybrid system is assumed to be 20 years, the same as that of an onshore wind farm [32]. Coal costs were obtained from Ref. [35] (See SI Section II for details). Information about coal plant ramp-rate and minimum generation requirements was obtained from Ref. [36]. Data on electricity prices comes from historical time series of hourly Locational Marginal Prices (LMP) from multiple hubs in PJM [37].

2.2. Assumptions

The optimization model determines the optimal CO_2 capture rate for every 10 min time periods in the planning horizon. This time resolution is necessary to adequately represent the advantages of the hybrid system smoothing out the potential high variability of wind power output during short time durations, and to obtain the corresponding optimum wind farm size. To ensure tractability of the optimization problem, we set the planning horizon as one year and applied the necessary adjustment to capital and fixed costs for cost of capture and LCOE calculations. Since the historic electricity price data from PJM [37] is given as an hourly time series, we assume the same LMP values correspond to the prices in the six 10-min sub periods within an hour. The use of varying LMP values corresponding to each 10 min time period in an hour could lead to greater opportunities of price arbitrage depending upon the extent of 10-min variability (measured in term of standard deviation, price differentials etc.) compared to hourly variability. We assume operators can choose to set the percentage of CO_2 capture from the flue gas anywhere between 20% and 90% (see SI Section III). It is assumed that no additional transmission lines are installed to connect the wind farm to the grid and that instead the system uses the spare transmission capacity of the existing transmission lines that results from the power output reduction from CCS operation.

2.3. Formulation of linear optimization model

Operating the CCS system at partial capture or partial load involves bypassing part of the flue gas so that only a fraction of the total flue gas generated enters the CCS absorber. As a result, a less lean amine solution is required to capture CO_2, which allows for lower sorbent regeneration. Thus there is a reduction in the overall energy penalty of the CCS unit [38] [9].

The decision variables for the optimization model are:

$O_{w,t}$ – the average dispatched wind power (MW) in every time period t
$O_{c,t}$ – the average power generated by the coal plant (MW) in every time period including heat energy (in equivalent MW) being used for regeneration of CO_2-rich amine
O_W^{max} – the installed capacity of the onsite wind farm (MW)
x_t – the fraction of CO_2 capture relative to maximum capture by system design at time period t

(i.e. $x_t = 1$ means that at time period t, the system is capturing at its maximum capacity).

The CCS energy penalty is reduced in proportion to the fraction of CO_2 remaining in the flue gas being released to the atmosphere [9] [38].

The parameters used as input to the model are:

LMP_t – the average Locational Marginal Price at time period t ($/MWh)
$C_{fuel,t}$ – fuel (i.e. coal) cost ($/MWh) at time period t
CC_{wind} – Overnight Capital Cost of the onsite wind farm per MW of installed capacity ($/MW)
AOE_{wind} – Annual Fixed Operating Expenses of the wind farm ($/MW/yr) years – number of years in the planning horizon
T – Total number of time periods in the planning horizon
VOM_{CCS} – Variable O&M Cost of CCS per unit capture of CO_2 per unit time period ($)
E_0 – energy penalty associated with CCS operation at 90% CO_2 capture level for one time period (MW)
$O\&M_{coal}^{variable}$ – Variable O&M cost of coal plant apart from fuel costs ($/MWh)

The objective of this linear optimization model is to maximize the profits (Ω) of the hybrid system over the planning horizon T:

$$\max_{x_t, O_{c,t}, O_{w,t}, O_W^{max}} \Omega \tag{1}$$

Where the profit Ω is calculated by taking the sum of the revenue from electricity dispatched from the wind and coal unit in the hybrid system and the Production Tax Credit (PTC) earned by the wind farm and subtracting the fuel costs and the fixed and variable capital and O&M costs of the coal plant and the wind farm,

$$\Omega = \sum_{t=1}^{T} \left[\left\{ O_{w,t} + O_{c,t} - x_t * E_0 \right\} LMP_t - O_{c,t} * \left(C_{fuel} + O\&M_{coal}^{variable} \right) + PTC * O_{w,t} - VOM_{CCS} * x_t \right] - CC_{wind} * O_W^{max} - AOE * O_W^{max} * years \tag{2}$$

This optimization is subject to constraints that reflect physical limitations on the operation of the coal plant, the wind farm site, and the CCS system, as well as policy and power system operating requirements described in Section 2.2 (See SI Section IV for list of constraints).

Operation and maintenance costs of the coal plant are incurred irrespective of whether or not partial capture is performed. Hence they are not included in the objective function. The capital costs of the CCS system, SO_2, NO_x, and particulate matter control devices are also excluded from the objective function. This is because irrespective of the optimum percentage of CO_2 capture at any time period (allowed to vary between 90% and 20%), a CCS system capable of capturing 90% of CO_2 from flue gases requires proportionately sized SO_2 and NO_x control devices to be installed in order to adhere to CSAPR [39], MATS [40] and CAIR [41] requirements.

The performance of the hybrid system is measured in terms of two commonly used measures of performance for new generation resources aimed at reducing CO_2 emissions [38–40]: Cost of CO_2 Capture (CoC) and the Levelized Cost of Electricity (LCOE). These metrics are calculated in a similar fashion to [42–45] and are given by Equations (3) And (4):

$$\text{Cost of } CO_2 \text{ Capture } (\$/\text{ton}) = \frac{LCOE_{\text{Hybrid System}} - LCOE_{\text{Coal Plant without CCS Retrofit}}}{CO_2Emissions_{\text{Coal Plant without CCS Retrofit}} - CO_2Emissions_{\text{Hybrid System}}} \tag{3}$$

The Levelized Cost of Electricity ($/MWh) is calculated as the ratio of 1) the annualized fixed and variable capital and O&M costs and the loss of revenue due to CCS operation and 2) the net annual power dispatched by the hybrid system. This is expressed as:

$$LCOE = \frac{CC_{wind} * O_W^{max} + AOE * O_W^{max} * years + CC_{CCS} + FOM_{CCS} + \sum_{t=1}^{T} VOM_{CCS} * x_t + LoR_{CCS} + O\&M_{Coal}}{\sum_{t=1}^{T} \left[O_{c,t} + O_{w,t} - x_t * \overline{E} \right]} \tag{4}$$

Where,

CC_{CCS}	=Capital Cost of CCS unit (\$)*
LCOE	=Levelized Cost of Electricity (\$/MWh)
FOM_{CCS}	=Fixed O&M Cost of the CCS unit (\$)
$O\&M_{Coal}$	=O&M Cost of the coal plant including fuel costs (\$)
CO_2 Emission Rate	=CO_2 emission rate of the coal plant if it were not retrofitted with CCS (tons/MWh)
LoR_{CCS}	=Loss of revenue due to reduced electricity sales that result from a reduction in power output equal to the energy penalty associated with CCS operation (\$)

*Since building the hybrid system involves retrofitting an existing plant with CCS the capital costs of the original plant are not part of the Levelized Cost.

3. Results

3.1. Base case analysis

Table 1 compares the LCOE, CoC, and annual revenue of seven configurations that meet an average CO_2 annual emission cap of 1000 lb/MWh under different scenarios that vary in their restrictions on maximum variability of net power output and maximum allowed size of wind farm. Table 2 repeats the analysis assuming an average CO_2 annual emission cap of 300 lb/MWh.

In Table 1, under a BAU scenario that requires a constant power output and forbids the installation of a wind farm, there are two viable configurations. One configuration (BAU I) consists of a retrofitted coal plant with a CCS system capable of removing 49% of CO_2 emissions. Operating continuously at full capacity this plant would reach an annual CO_2 emissions rate of 1000 lb/MWh with associated CoC and LCOE of 61.9 \$/ton and 89.3 \$/MWh (see SI Section V for details). A second possible configuration (BAU II) would consist of a retrofitted plant able to achieve 90% capture but operating continuously at a partial capacity to achieve the 1000 lb/MWh target. In this case the CoC and LCOE would be 69.8 \$/ton and 95 \$/MWh due to higher capital costs of the CCS retrofit. The specific effects that different assumptions on requirements (scenarios 1–6) have on profitability of the hybrid system are discussed below.

3.1.1. Economic benefits of flexible operation vs continuous operation

A comparison of scenario 1 with the BAU II scenario, and scenario 7 with scenario 8 indicate lower CoCs, lower LCOEs and higher profits (indicated by higher values of Ω) from flexible operation of CCS (as opposed to continuous operation CCS). The difference in costs quantifies the benefit from electricity price arbitrage.

3.1.2. Effects of constraint on power output variation on LCOE and CoC

The LCOE of the wind farm alone is about 72 \$/MWh (not considering the interconnection costs and integration costs), while the variable costs (including fuel expenses) of the coal plant retrofitted with flexible operation CCS is about 83.6 \$/MWh for a maximum capture rate of 90% when maintaining an annual CO_2 emission cap of 1000 lb/MWh.

This implies that lower costs are incurred by the hybrid system if it harvests as much wind power as possible within physical constraints of the system, provided the intermittent nature of the wind power is accounted for.

The intermittency of wind power can be remedied with two methods: by ramping up and down the coal plant power output within physical limits, or by allowing the net hybrid system output to vary. Allowing the net output of the hybrid system to vary instead of forcing it to act as a base-load plant reduces LCOE and CoC because it facilitates price arbitrage through partial capture, while providing greater flexibility of operation for the co-located wind farm.

A comparison of scenario 2 with scenario 1 in Table 1 demonstrates the relative decrease in revenue and subsequent increase in CoC and LCOE when the net power output of the hybrid system is constrained to vary within 10% of its nameplate capacity. This contrasts with scenario 1, in which there are no restrictions on the variability of power output and price arbitrage opportunities can be exploited. Scenarios 3, 4, 5 and 6 are used to demonstrate the effect of gradual decrease in allowed variability of net output of the hybrid system. From Table 1, a decrease in allowed variability leads to reduced optimum size of the wind farm, a reduction in Ω, and consequently, an increase in CoC and LCOE.

3.1.3. Effect of CO_2 emissions limit on LCOE and cost of capture

The economic benefits of price arbitrage are reduced with a tighter emissions limit because a decrease in flexibility of CO_2 capture rates implies fewer opportunities to generate more electricity and capture less CO_2 during periods of high electricity prices. Due to price arbitrage opportunities, when the emissions limit is set at 1,000 lbs/MWh, the LCOE and cost of capture of the variable capture system (scenario 1) are 10.6 \$/ton and 7.6 \$/MWh lower than the CoC and LCOE of the continuous operating system (BAU), respectively. But when the emissions cap is lowered to 300 lbs/MWh, the CoC and LCOE obtained with price arbitrage (scenario 8) is only 4.4 \$/ton and 4.6 \$/MWh lower than the continuous operation system (scenario 7). Note that while the LCOEs are lower and Ωs are higher in Table 1, the CoC is actually lower in Table 2 in comparison to analogous scenarios in Table 1 (as a result of increased variable costs of the CCS system to meet a tighter cap). This is because the relative increase in variable costs of CCS is lower than the relative increase in CO_2 captured (i.e. the increase in the numerator of the CoC metric is much lower than the increase in the denominator) for a tighter emission cap of 300 lb/MWh when compared to an emission cap of 1000 lb/MWh.

3.1.4. Effect of CO_2 emissions limit and constraints on net output variation on optimal wind farm size

Provided the net power output of the hybrid system is allowed to vary, a tighter emission cap results in a larger optimum size wind farm, since it is cheaper to reduce the net CO_2 emission of the hybrid system by replacing the coal plant power output with variable wind power within the physical constraints of the system. This is demonstrated by scenarios 3 and 10, where scenario 10 has a larger optimal size of wind farm due to a tighter constraint on emissions. However, in cases which the power output of the hybrid system is forced to remain constant at all times, the installed size of the wind farm may decrease rather than increase. This is because the average capture rate must be higher for a tighter emission cap. Since the net power output of the hybrid system must be held constant, the coal plant cannot rely as much on the intermittent source of wind power to compensate for reduced power output. So, instead of running the CCS unit at high capture rates during periods of low electricity prices and at low capture rates during times of high prices, the plant must maintain a more constant capture rate that oscillates around the average capture rate it would have had to maintain if it did not have partial capture capabilities. This almost constant capture rate of the CCS plant does not allow integrating time-variable wind power output, and makes a smaller wind farm optimal (See effects of PTC in SI Section VI).

Table 1
Performance of the hybrid system considering 10 min wind power variations for an emission cap of 1000 lb/MWh.

Scenario	Assumptions: Maximum annual average CO_2 emissions allowed (lbs/MWh)	Assumptions: Allowed variability of power output. (In MW/hr and as % of nameplate capacity of the hybrid system)	Assumptions: Maximum size of wind farm (MW) allowed	Results: Name plate capacity of hybrid system (MW) = coal plant name plate capacity + optimum size of wind farm	Results: Optimum size of wind farm (in MW and as percentage of nameplate capacity of hybrid system)	Results: Cost of CO_2 capture ($/ton) for the overall hybrid system	Results: Average CO_2 emission (lbs/MWh)	Results: Levelized cost of electricity ($/MWh) not accounting for capital cost of coal plant	Results: The value of Ω^* ($/yr)	Results: The value of Ω ($/yr)
BAU I#		No variability allowed, CCS must operate at a constant rate				61.9	1000	89.3	108,064,155	218,114,155
BAU II##			0	1786.5	No Wind Farm installed for these scenarios	69.8	1000	95.0	36,814,155	218,114,155
1		No upper limit				59.2	1000	87.4	81,273,019	262,573,019
2	1000	178.5 MW/h or 10% (approx.) of nameplate capacity				62.7	1000	89.9	76,119,418	257,419,418
3		No upper limit		2262.1	475.6 MW or 21% of nameplate capacity	59.8	950	89.3	81,567,213	262,867,213
4		500 MW/h or 26% of nameplate capacity	No upper limit	1904.26	117.76 MW or 6% of nameplate capacity	56.1	1000	85.2	80,591,903	261,891,903
5		178.5 MW/h or 9% of nameplate capacity		1895.58	109.08 MW or 6% of nameplate capacity	60.5	1000	88.3	76,254,768	257,554,768
6		0 MW/h		1876.4	89.9 MW or 5% of nameplate capacity	62.8	1000	90.0	36,857,719	218,157,719

[#]BAU I: CCS unit capable of capturing 49% of total CO_2 emissions. CCS must operate continuously to acheive a CO_2 emission rate of 1000 lb/MWh.
[##]BAU II:CCS unit capable of capturing 90% of CO_2 emissions. If CCS operated continuously CO_2 emissions would be ~200 lb/MWh.
$\Omega^* = \Omega -$ Annualized Fixed O&M Cost of CCS - Annualized Capital Cost of CCS.

Table 2
Performance of the hybrid system considering 10 min wind power variations for an emission cap of 300 lb/MWh.

Scenario	Assumption			Results						
	Maximum annual average CO_2 emissions (lbs/MWh)	Allowed variability of power output. (In MW/hr and as % of nameplate capacity of the hybrid system)	Maximum size of wind farm (MW)	Name plate capacity of hybrid system (MW) = coal plant nameplate capacity + optimum size of wind farm	Optimum size of wind farm (in MW and as percentage of nameplate capacity of hybrid system)	Cost of CO_2 capture ($/ton) for the overall hybrid system	Average CO_2 emission (lbs/MWh)	Levelized cost of electricity ($/MWh) not accounting for capital cost of coal plant	The value of Ω^* ($/yr)	The value of Ω^* ($/yr)
7 (BAU, 300 lb/MWh CO_2 Emission Cap)		CCS operates at a constant capture rate so variability is 0 by definition			No Wind Farm installed for these scenarios	58.8	300	107.6	−40319490.04	140,980,510
8		No Cap	0	1786.5		54.4	300	103.0	−20228958.86	161,071,041
9	300	178.5 MW/h or 10% (approx.) of nameplate capacity				58.1	300	106.9	−23666632.25	157,633,368
10		No upper limit	No upper limit	2306.15	519.65 MW or 23% of nameplate capacity	53.6	279	102.7	−19472977.15	161,827,023
11		500 MW/h or 25% of nameplate capacity		1998.09	211.59 MW or 11% of nameplate capacity	54.9	294	103.6	−20266324.15	161,033,676
12		178.5 MW/h or 9% of nameplate capacity		1893.68	107.18 MW or 6% of nameplate capacity	57.8	299	106.6	−23527067.12	157,772,933
13		0 MW/h		1808.15	21.65 or 1% of nameplate capacity	52.1	299	100.6	−40316219.69	140,983,780

$\boldsymbol{\Omega}^* = \boldsymbol{\Omega}$ - Annual Fixed O&M Cost of CCS - Annulaized Capital Cost of CCS.

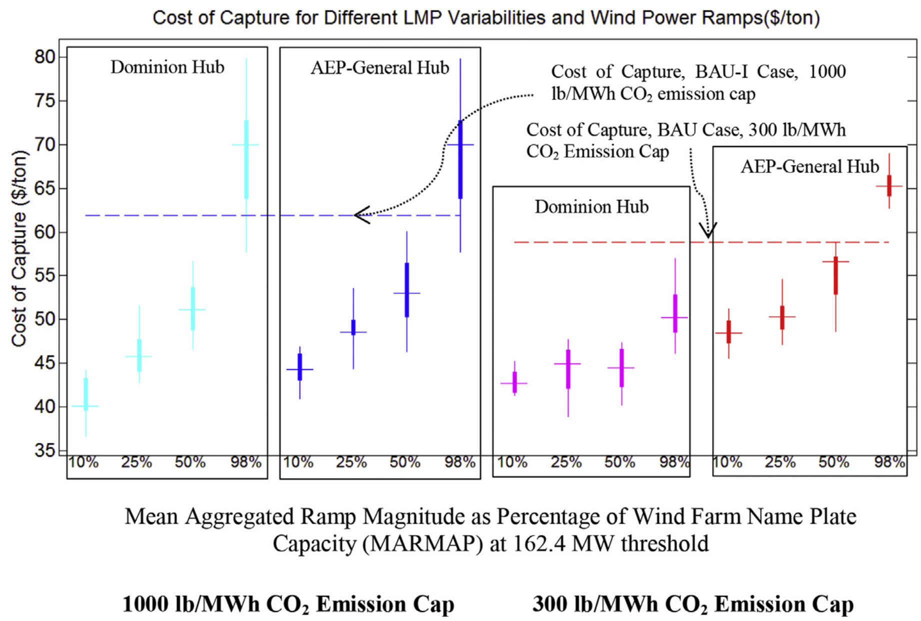

Fig. 1. Cost of CO_2 capture for different levels of wind variability for two electricity price time series with high variability (Dominion Hub) and low variability (AEP-General Hub). Panels on the left and right show results when CO_2 emissions limits are 1000 lbs/MWh and 300 lb/MWh.

3.2. *Quantifying the effects of variability in hourly prices and wind power output on the profitability of the hybrid system: an analysis of the hybrid system's performance in the PJM interconnect*

Higher time variability of electricity prices improves the profitability of the hybrid system by increasing the revenues from price arbitrage. We characterize price variability using an *Average Price Differential (APD)* metric (see SI Section VII). Calculations of *APD* for all PJM hubs using the hourly LMP time series [37] in year 2013 point to Dominion Hub and AEP-General Hub as the hubs that offer highest and lowest opportunities for price arbitrage.

Similarly, the profitability of the hybrid system and its value as an enabler of wind integration is dependent on the wind power variability. We characterize wind power variability with a *Mean Aggregated Ramp Magnitude As Percentage of Name Plate Capacity* (*MARMAP*) metric: the average of the magnitude of all *ramping events* (defined as those instances when changes in wind power output during a 10 min period exceed 162.4 MW, see SI Section IX) expressed as a percentage of the nameplate capacity of the wind farm. We estimated *MARMAP* for all the EWITS [27] wind-sites within the PJM region. For each PJM hub and potential wind *MARMAP* levels, we simulated 15 instances of wind power output

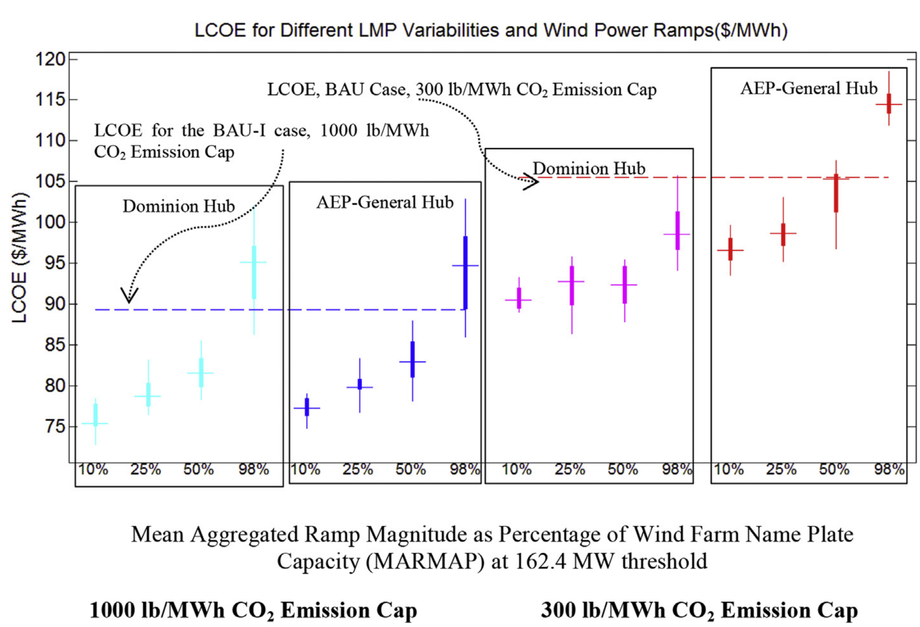

Fig. 2. LCOE for different levels of wind variability for two electricity price time series with high variability (Dominion Hub) and low variability (AEP-General Hub). Panels on the left and right show results when CO_2 emissions limits are 1000 lbs/MWh and 300 lbs/MWh.

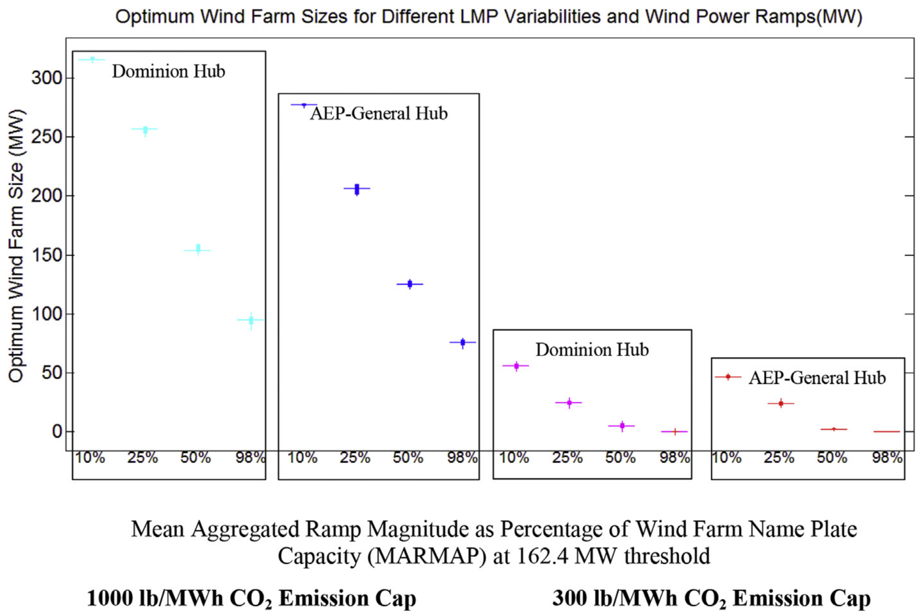

Fig. 3. Optimum Wind Farm Size for different levels of wind variability for two electricity price time series with high variability (Dominion Hub) and low variability (AEP-General Hub). Panels on the left and right show results when CO_2 emissions limits are 1000 lbs/MWh and 300 lb/MWh.

throughout the planning horizon, and found the optimal configuration and operation of the hybrid system using the model described in Section 2. The 15 instances of wind power simulations corresponding to the same MARMAP value are considered for each scenario (i.e. under varying conditions on annual average CO_2 limit, and APD values) to calculate the corresponding 15 observations of CoC, LCOE, percent of wind power integrated and net annual average CO_2 emissions. The box-plots in Figs. 1–4 present the summary statistics of the 15 simulations for each scenario. The small horizontal bar along each box in the box plots indicate the median value of the metric being plotted. The thin vertical lines represent the range of values obtained for that metric when using the 15 power output simulations corresponding to a given *MARMAP* level, while the thick lines represent the 25th and 75th percentiles. Please refer to SI Section I for further details. Since current sample size is small (to maintain computational tractability) a confidence interval analysis was not attempted.

These experiments show the effect of different levels of *MARMAP* and electricity price time series on the CoC, LCOE, Optimum Wind Farm Size, and Annual Average CO_2 emissions for two different CO_2 emission limits. Figs. 1 and 2 report the range of values of CoC and LCOEs of the hybrid system for the Dominion and AEP hubs at different levels of *MARMAP* for wind power. In 2013, the *APD* values were 7.049 \$/hr and 10.06 \$/hr for the AEP-General and Dominion hubs respectively. Figs. 1 and 2 show that higher values of *APD* result in lower costs of capture and LCOE (since higher

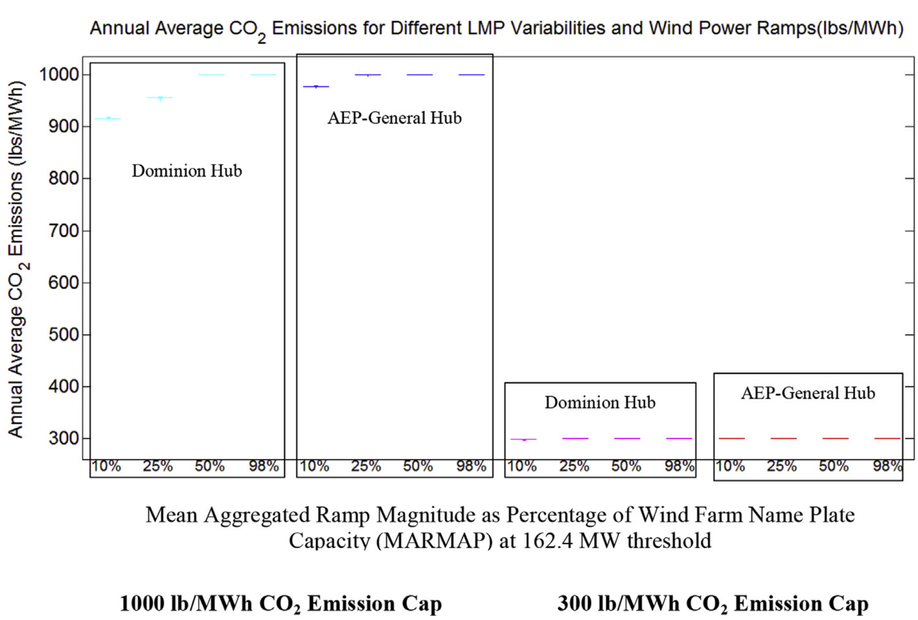

Fig. 4. Annual Average CO_2 emissions for different levels of wind variability for two electricity price time series with high variability (Dominion Hub) and low variability (AEP-General Hub). Panels on the left and right show results when CO_2 emissions limits are 1000 lbs/MWh and 300 lb/MWh.

variability leads to greater profits from price arbitrage). In contrast, greater variability of wind resources (i.e. higher *MARMAP*) leads to higher CoC and LCOE. Figs. 1–3 indicate that high variations of LMP time series coupled with low wind power variability lead to lower costs of capture and LCOE, and that higher optimum sizes of wind farms result in more time periods when wind power (with lower O&M costs) can replace coal-based electricity due to better price arbitrage opportunities and more reliable wind power resources.

The combination of high LMP price differentials and low wind variability, however, is not a requirement for hybrid system profitability. From Fig. 1, a hybrid system in a node with low price differentials (equal or higher than those observed in AEP in 2013) would likely have a reduced cost of CO_2 capture (relative to the BAU plant) if integrating a wind resource with relatively low variability (25% or less).

From Fig. 2, a hybrid system in any hub, would likely result in a reduced LCOE provided the wind resource variability did not exceed 50%.

An analysis of the EWITS dataset [34] indicates that 90% of all the wind-sites in EWITS have *MARMAP* (at a 162.4 MW threshold) less than or equal to 50%, and 88% of sites have a *MARMAP* less than or equal to 25%.

Fig. 3 indicates that the effects of CO_2 emission cap and *MARMAP* on optimum wind farm size is much more prominent than the effect of variations of the LMP time series. This is to be expected since lower limits on annual average CO_2 emissions lead to decreased flexibility of the hybrid system. A high degree of variability of wind power indicated by high values of *MARMAP* leads to fewer time periods when wind power may be used to compensate for CCS energy penalty, and hence leads to lower optimum sizes of wind farms. For the most part, the annual average CO_2 emissions are equal to the allowed limit, although slightly lower emissions are observed for 1000 lb/MWh CO_2 emission limits at *MARMAP* values of 10% and 25% in Fig. 4.

3.3. Effect of variable costs and CO_2 tax regimes

An increase in capital costs, fixed O&M costs, or variable O&M of the wind farm leads to proportionately lower revenues, higher estimates of LCOEs and higher CoC. Similarly, increased coal prices result in higher LCOEs and CoC. If coal plant O&M costs and coal prices are lower than the levelized cost of electricity of the wind farm, then the optimum size of wind farm is zero. As long as the levelized cost of electricity of the wind farm is less than the coal plant O&M costs and fuel costs, it is profitable to have a co-located wind farm even if other constraints (such as lack of land availability, public opposition etc.) force the utility owners to set up a wind farm that is smaller than the optimum size indicated by the linear optimization model. When relaxing the constraints that pose limits on the CO_2 emissions rates of the power plant, we find that the CO_2 tax values necessary to achieve the desired reduced emission rates of 1000 lb/MWh and 300 lb/MWh are equal to the estimated CoC for the given set of inputs, as was expected.

4. Discussion

Results indicate lower CoC and LCOE of the hybrid system relative to a baseline continuous operation system that achieves the same emissions and operational constraints. At least three other benefits that have not been included in the above calculations: (a) avoided costs of procuring additional transmission capacity for wind power, (b) avoided costs associated with integration of variable electric power sources to the grid, and (c) increased ramp-capability of the hybrid system.

Although joint optimization of electric power dispatched from the wind farm and the retrofitted coal plant could occur if the plants are not collocated, this would miss an additional advantage of the hybrid system that results from avoiding the need to install additional transmission capacity. Stand-alone wind farms require additional transmission lines to inject power to the existing grid. Recent publications indicate that levelized transmission costs in the range of 3.2–14.3 \$/MWh for onshore wind farms with a capacity factor of 34% [4346]. The Eastern Wind Integration and Transmission Study [46] estimates a transmission cost of 17.5–23.4 Billion USD (in 2024 USD) to achieve a wind penetration level of 20% along the US Eastern Interconnect. Scenario 6 in Table 1 demonstrates that building the coal-wind hybrid system could enable 6% of sub-critical coal-based capacity to be replaced by wind power in sites with strong wind resources without incurring additional transmission costs.

On the other hand, the hybrid system effectively integrates “baseload wind” and hence avoids an increase in system's costs associated with the wind power variability. Incorporating stand-alone intermittent resources in the power grid (such as wind and solar power) requires capital investments and O&M costs for additional spinning reserves, cycling costs and additional fuel cost of generating units (mainly natural gas plants) with rapid ramp up/down capabilities. These costs are estimated to be 3.10–5.13 \$/MWh for up to 30% of penetration of wind power in the Eastern Interconnect [46], and 0.47–1.28 \$/MWh (13%–24%) for up to 33% of wind and solar penetration in the Western Interconnect [47]. Also, this system provides a hedge against any potential charges to wind-producers for deviations of power output from the forecast [48].

Finally, a hybrid system that includes a CCS capable of 90% capture has the potential to ramp-up and down its power output at a faster rate than is possible in a continuous operation CCS plant capable of 49% capture. This is of great value –and soon to be priced-in systems with high penetration of renewables like MISO [49].

5. Conclusion

This hybrid system is a viable method of transitioning to a power system with lower carbon emissions. It provides a hedge against uncertainty on natural gas prices and carbon emissions constraints, and facilitates the integration of renewables. The right panel of Fig. 2 indicates LCOEs in the range of 86.4–107.7 \$/MWh for annual average CO_2 limits of 300 lb/MWh (roughly corresponding to about 85% annual average CO_2 capture rates) for wind farms with average *MARMAP* values less than or equal to 50% of maximum potential of the wind site (a characteristic common to roughly 90% of the wind sites in the US east coast [30]). This range is comparable to LCOE values of NGCC plants [50] with 90% capture rates of 85.9–111.7 \$/MWh for NG prices in the range of 6–11 \$/MMBtu, and lower than the LCOE of IGCC plants with 90% capture rates estimated at 111.8 \$/MWh [50].

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Appendix A. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.renene.2015.07.025.

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