Supporting Information

I. Simulation of Wind Power Time Series

As mentioned in section 3.2 of the paper, wind power simulations were used to analyze the performance of the hybrid system for different levels of wind power variability and electricity price differentials. These wind power simulations were obtained by using software called SynTiSe, based on Markov Chain Monte Carlo method[1] developed by the Modeling Tools for Energy Systems Analysis (MOTESA) research group[2], a part of the Bass Connections initiative at Duke University. This technique generates simulated time series that have characteristics, such as the pdf, the acf, the capacity factor and ramping characteristics that are very similar to those of the original time series.

Figures S1-S3 demonstrates the performance of the simulation tool for a 5th order Markov Chain with 10 states used to simulate year-long data for input wind power time series of EWITS[3] on-shore wind-site #4431.

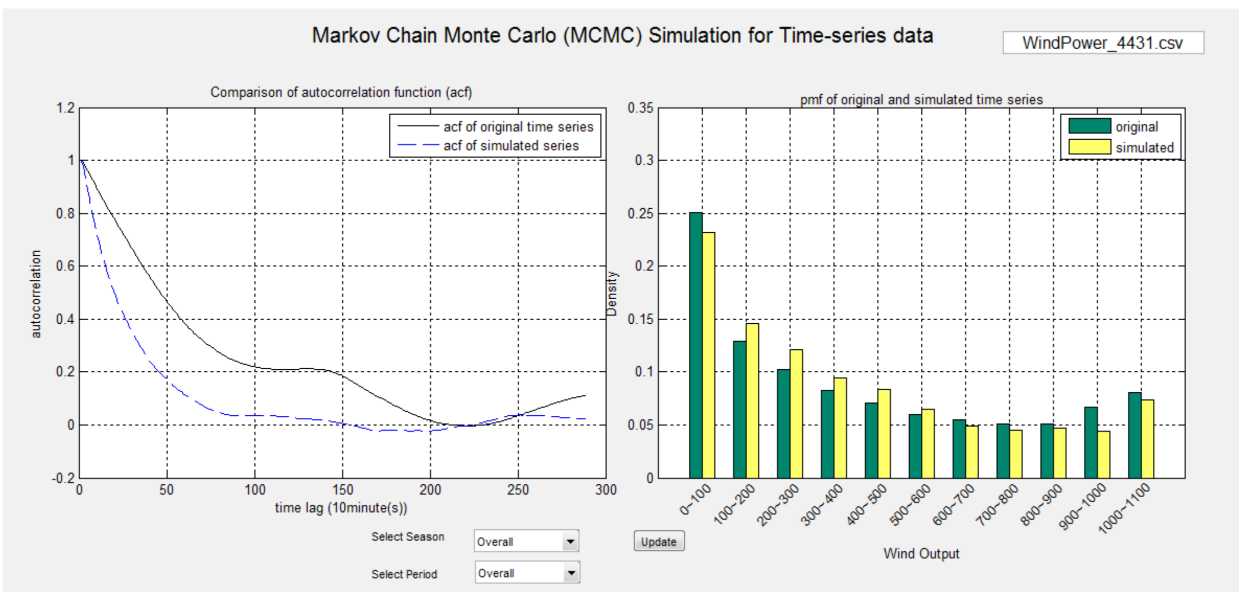


Fig S1: Comparison of the pdf and acf of the simulated and original time wind power time series for a 5th order Markov Chain with 10 states. Original wind power time series corresponds to data from meso-scale model of EWITS[3] windsite #4431

Average Annual Capacity factors

		Morning			Afternoon			Evening			Night		
		Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
Winter	Org	0.4303	0	0.9900	0.4225	0	0.9952	0.3525	0	0.9959	0.4774	0	0.9978
	Sim	0.3855	0.0019	0.9794	0.3676	0.0049	0.9781	0.3306	0.0058	0.9819	0.3516	0.0021	0.9871
Spring	Org	0.4299	0	0.9924	0.3568	0	0.9987	0.3803	0	0.9998	0.4643	0	1
	Sim	0.4142	0.0051	0.9836	0.3978	0.0077	0.9840	0.3742	0.0055	0.9764	0.3829	0.0029	0.9912
Summer	Org	0.2769	0	0.9951	0.1614	0	0.9884	0.2262	0	0.9676	0.3537	0	0.9952
	Sim	0.3462	0	0.9732	0.2972	0	0.9755	0.2858	0	0.9896	0.3760	0	0.9906
Fall	Org	0.4002	0	0.9611	0.2913	0	0.9865	0.3187	0	0.9845	0.4313	0	0.9775
	Sim	0.2733	0.0083	0.9645	0.2501	0.0077	0.8490	0.2748	0.0080	0.9372	0.3120	0.0025	0.9712

Fig S2: Comparison of capacity factors of the simulated and original time wind power time series for a 5^{th} order Markov Chain with 10 states. Original wind power time series corresponds to data from meso-scale model of EWITS[3] windsite #4431

Ramping Events Statistics

	Single Period Ramp-Up Events	Single Period Ramp-Down Events
No. of Events in Original Series	606	579
No. of Events in Simulated Series	642	678
Mean Ramp in Original Series	243.6655	-240.7867
Mean Ramp in Simulated Series	229.3340	-232.8676
Median Ramp in Original Series	217.2000	-215.3000
Median Ramp in Simulated Series	217.6362	-222.2889

Fig S3: Comparison of Ramping Event Statistics of the simulated and original time wind power time series for a 5^{th} order Markov Chain with 10 states. Original wind power time series corresponds to data from meso-scale model of EWITS[3] windsite #4431. Refer to section 9 for definition of ramp events

II. Accessing data for cost of coal

Coal prices are taken from the 2012 Annual Energy Outlook[4] (Table on Total Energy Supply, Disposition & Price Summary, and subject filter Coal Supply & Prices, Section: Coal Prices (delivered)) for the years 2013 to 2033, from this website: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=7-AEO2012&table=1-AEO2012&region=0-0&cases=ref2012-d020112c

III. Assumption of operational range in CO_2 capture rate

We assume operators can choose to set the percentage of CO_2 capture from the flue gas anywhere between 20% and 90%.

As per current estimates [5,6], state-of-the-art post-combustion amine based systems can capture up to 90% of CO_2 in the flue gas. Percentage of capture is not allowed to go below 20% of the maximum capture rate to prevent degradation of system components and to avoid large start-up times to resume operation after a complete shutdown [7,8].

IV. Constraints for Linear Model of the Hybrid System

Definitions for additional parameters:

Em^{cap} (lb/MWh) : Cap on CO_2 emissions from the coal plant

$CO_2^{Emissions\,w.o\,CCS}$ (lb/MWh): The CO_2 emission rate from the coal plant when it does not have any CO_2 emission control mechanism

H_T (hours): : The number of hours in each time period

$Output_{variations}^{hybrid}$ (MW/hr) : The maximum limit on the hybrid units power output fluctuation from one hour to another

$O_{c,t}^{dispatched}$ (MWh) : The amount of power dispatched by the coal plant at time period t ($O_{c,t}^{dispatched} = O_{c,t} - X_t * E_0 ¿$

$O_{w,t}^{available}$ (MWh) : The available wind power forecast for each time period

$O_C^{nameplate}$ (MW) : The nameplate capacity of the existing PC plant before the CCS retrofit

O_c^{min} (MW) : The minimum stable power generation level for PC plant

$rr_{coal\ plant}$ (MW/hr) : The ramp rate capability of the PC plant assuming its power output never falls below the minimum stable power generation level.

Constraints:

i. At any instant of time the amount of CO_2 captured cannot exceed the maximum % capture set at design (i.e. $\chi_t \le 1$). The capture rate of the CCS unit must be maintained within a given range due to reasons mentioned in Part III [7,8]:

$$0.2 \le \chi_t \le 1$$

ii. A maximum annual CO_2 emissions level (Em^{cap} lbs/MWh) cannot be exceeded:

$$CO_2^{Emissions\ w/o\ CCS} * \sum_{t=1}^{T} \left(1 - \chi_t * capture\ rate\right) \le Em^{cap}$$

iii. The average hourly wind power in every time period dispatched by the hybrid system at all instants of time, should be less than or equal than the installed capacity of the wind farm.

$$\left(\frac{O_{w,t}}{H_T}\right) - O_w^{max} \le 0, \forall t \in \left(1, \dots, T\right)$$

iv. The maximum limit on the hybrid unit's power output fluctuation must be maintained.

$$-Output_t^{hybrid}{}_{fluctuations} \le \left(\frac{O_{c,t}^{dispatched} + O_{w,t}}{H_T}\right) - \left(\frac{O_{c,t-1}^{dispatched} + O_{w,t-1}}{H_T}\right) \le Output_t^{hybrid}{}_{fluctuations}$$

$$, \forall t \in \left(2, \dots, T\right)$$

v. The wind power dispatched should be less than or equal to the available wind power forecast for each time period

$$O_{w,t} \le O_{w,t}^{available}, \forall t \in \left(1, \dots, T\right)$$

vi. No additional transmission capacity should be required.

$$\frac{\left(O_{c,t}^{dispatched}+O_{w,t}\right)}{H_T} \le O_C^{nameplate}, \forall t \in \{1,\dots,T\}$$

vii. The power generated by the coal unit at any time period should be at least as high as the minimum stable power generation level for the coal plant.

$$-\left(\frac{O_{c,t}}{H_T}\right) \le -O_c^{min}, \forall t \in \{2,\dots,T\}$$

viii. The coal plant power output variations between consecutive hours should be within the ramp rate capabilities of the coal plant:

$$-rr_{coalplant} \le O_{c,t} - O_{c,t-1} \le rr_{coalplant}, \forall t \in \{2,\dots,T\}$$

ix. Non-negativity constraints for all decision variables

V. Computing Cost Of Capture (CoC) and LCOE for CCS retrofit designed to achieve only the necessary capture rate to maintain an average annual CO_2 emission rate of 1000 lb/MWh

Since no industrial-scale CCS units for power plants are operational at this point, the effect of economies of scale on cost of CCS retrofits is unclear. The following steps were therefore used to compute CoC and LCOE for a coal plant with retrofitted with a smaller-sized continuous operation CCS unit that is designed to achieve the necessary capture rate to maintain an average annual CO_2 emission rate of 1000 lb/MWh:

- The 1786.5 MW coal plant model built in IECM[9] has an emission rate of 1944.35 lb/MWh without CCS. With a 90% capture rate, the CCS unit captures about 1750 lbs/MWh. Since we want a continuous operation CCS unit that captures 944.35 lb/MWh (so that net emission is at 1000 lbs/MWh) , it is then sufficient to look at the capital and fixed O&M costs of CCS for a similar coal plant of size 1786*(944.35/1750)=963.7 MW in IECM[9]

- Note that the variable O&M costs of CCS, the O&M cost of the coal plant (including fuel), and the loss of revenue remains identical to the BAU case, since these values were already scaled to capture such that net emissions is limited to 1000 lb/MWh even though the max capture rate is 90%

- By replacing the fixed O&M and Capital Cost of CCS with values obtained from IECM model with a 963.7 MW coal plant and keeping all other cost components identical to the BAU case in equation 4 of this paper, a LCOE of about 89.3 $/MWh and a CoC of 61.9 $/ton is obtained

Note that similar calculations could have been performed for a continuous operation CCS unit designed to achieve the necessary capture rate to maintain an average annual CO_2 emission rate of 300 lb/MWh. However, since this emission limit requires a capture rate very close to 90% capture rate, the corresponding LCOE and CoC values have not been reported.

VI. Effect of PTC

A comparison of the BAU II scenario with scenario 6 demonstrates that even when no PTC is available for the wind farm and the hybrid system is not allowed to vary its power output at all, it is beneficial to have a hybrid system with a wind farm that accounts for 5% of the total nameplate capacity, rather than retrofitting the existing coal plant with a continuous operation CCS system. In this case, the hybrid system leads to roughly 7 $/ton and 5 $/MWh decreases in CO_2 capture cost and LCOE respectively when compared to the BAU scenario. For a tighter emission constraint of 300 lb/MWh (please see scenarios 7 and 13 in table 2) the percentage decrease in CoC and LCOE is lower, and it is optimal to have a wind farm that accounts for only about 1% of the total nameplate capacity. If a PTC is available for the co-located wind farm, this increases the revenue from the sale of wind power and leads to higher optimum wind farm sizes, lower CO_2 emissions, lower LCOEs and lower costs of capture.

VII. Quantifying variability of electricity prices: defining *Average Price Differential (APD)*

The time variability of electricity prices plays a major role in the profitability of the hybrid system, because as the difference among consecutive times increases, the chances of performing better price arbitrage increase accordingly. To characterize price variability and explore its effects, we define two metrics:

The *Electricity Price Differential* at time t (PD_t), and the *Average of Price Differential during a Trend-Block* ($PD_{t_0,d_{t_0}}^{Rolling\,Avg}$).

The *Electricity Price Differential at time t* (PD_t) is the absolute difference between the electricity price (LMP) at the consecutive time periods *t* and *t-1*:

Electricity Price Differentials: $PD_t = ¿LMP_t - LMP_{t-1} \vee ¿$ (1)

For the second metric, we first define a *Trend-Block* as a time-series of consecutive non-zero PD_t s with the same direction of change (i.e. continuously increasing or continuously decreasing values exceeding the threshold difference). By definition, t_0 is the first time instant in the *Trend-Block* and d_{t0} is the duration of the trend-block. Hence, the *Average of Price Differential during a Trend-Block* (P $D^{Rolling\,Avg}_{t_0,d_{t_0}}$) is the average of price differentials PD_t over the times t_0 to t_0+d_{t0} when there is a price-increasing or price-decreasing trend:

$$PD^{Rolling\,Avg}_{t_0,d_{t_0}} = \frac{\sum_{i=t0}^{t0+d_{t_0}} PD_i}{d_{t_0}} \tag{2}$$

We now define the following metric to compute the *Average Price Differential (APD) or the Mean Value of* $PD^{Rolling\,Avg}_{t_0,d_{t_0}}$ *corresponding to all Trend-Blocks* within the planning horizon:

$$PD^{Rolling\,Avg}_{Mean} = \frac{\sum_{i \in I} PD^{Rolling\,Avg}_{t_i,d_{t_i}}}{¿} \quad ¿I \vee ¿ \tag{3}$$

Where I is the index set of the starting times of all trend-blocks within the planning horizon and |I| is the cardinality of the set I.

VIII. Price Differentials in all the PJM Hubs[9]

Price differential metrics of all the 12 hubs in the PJM interconnect for hourly LMP data for year 2013 (Jan 1st – December 31st) are computed as described in the paper. Results are summarized as follows:

Table S1: Summarizing electricity price variability in the PJM hubs

Hub Name	**Mean Annual** $PD^{Rolling\,Avg}$ **($/MWh)**	**Mean Annual PD_t**	$\frac{\sum_{i=1}^{8760} d_i}{8760}$ urationagr year 2013¿ jionfor PD>0	**Standard Deviation (LMP_t)**
'AEP GEN HUB'	7.049	4.795	0.198	14.44
'OHIO HUB'	7.277	5.070	0.201	15.25
'AEP-DAYTON HUB'	7.644	5.196	0.200	15.76
'CHICAGO GEN HUB'	7.684	5.514	0.212	15.37
'N ILLINOIS HUB'	7.875	5.680	0.213	15.92
'CHICAGO HUB'	8.210	6.002	0.213	16.88

'WEST INT HUB'	8.393	6.045	0.199	31.52
'ATSI GEN HUB'	8.501	6.481	0.198	73.35
'WESTERN HUB'	9.200	6.512	0.201	20.90
'EASTERN HUB'	9.439	7.010	0.203	23.27
'NEW JERSEY HUB'	9.553	7.031	0.203	23.55
'DOMINION HUB'	10.060	7.159	0.207	22.63

IX. Defining *Mean Aggregated Ramp Magnitude as Percentage of Name Plate Capacity (MARMAP)* in Wind Power Output

To characterize wind power variability we look at the amount and size of *ramping events*, which are defined as those instances when changes in wind power output (WP) exceed a threshold (H). During a particular time period there may be one or multiple ramp events. The following metrics are used to identify ramping events in wind power data similar to the metrics defined in current literature [10][11]:

a) Single Period Ramp Events:

$$P \vee ¿_{t-1} \geq H \quad ¿ WP_t - W ¿ \quad ¿ \quad ¿ \quad Ramp_t(H) = Single\ Period\ Ramp\ Magnitude = I_¿ \qquad (4)$$

$$Ramp \quad I_{(¿>0)} \quad +¿(H) = No.\ of\ upward\ single\ period\ ramp\ events\ during\ T\ time\ periods = \sum_{t=1}^{T} ¿ \quad N_{Ramp_t} \qquad (5)$$

$$Ramp \quad I_{(¿<0)} \quad -¿(H) = No.\ of\ downward\ single\ period\ ramp\ events\ during\ T\ time\ periods = \sum_{t=1}^{T} ¿ \quad N_{Ramp_t} \qquad (6)$$

(Where WP_t is the wind power generated at time t, and I is an indicator function of the form

$$I_{(X>x)} = 1\ if\ X > x \wedge 0\ otherwise.¿$$

b) Aggregated ramp events:

Consecutive ramping events with the same upward or downward trend are treated as a single ramping event. An algorithm similar to [9] has been developed to identify the start and stop times (t_o and $t_o + d_{to}$) of each of the aggregated ramping events and the corresponding duration (i.e. d_{to}). The algorithm also reports the number of occurrences, mean average value, and the mean of all aggregated ramps expressed as a percentage of the Name Plate Capacity of the wind farm.

The threshold value (H) for defining ramping events relevant for the analysis of the hybrid system under consideration has been chosen as:

Threshold Value for hybrid system H = Ramp Capability of Coal Plant in 10 minutes + CCS Energy Penalty = 162.4 MW (7)

The magnitude of an aggregated ramp event is:

Aggregated Ramp Magnitude: $Ramp^{aggregated}_{t_0,d_{t_0}} = ¿WP_{t_0} - WP_{t_0+d_{t_0}} \vee ¿$ (8)

Where t_o is the start time of the aggregated ramp event and d_{to} is the end time of the aggregated ramp event.

The average of the magnitude of the *individual ramp* events that constitute a given *aggregated ramp* event is:

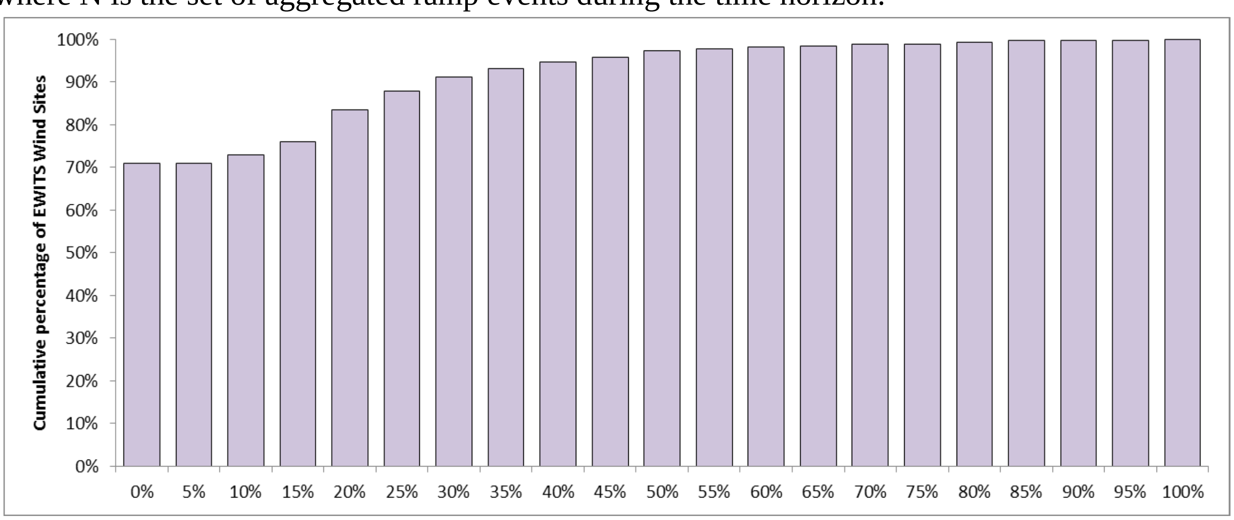
Average Ramp Magnitude within an Aggregated Ramp: $Ramp^{Avg}_{t_0,d_{t_0}} = \frac{\sum_{i=t_0}^{t_0+d_{t_0}} Ramp_i}{d_{t_0}}$ (9)

Taking the mean of the *Average Ramp Magnitude within an Aggregated Ramp* of all *aggregated ramps* observed during a time horizon results in a metric of the ramp characteristics of the wind farm which we label as:

Mean Aggregated Ramp Magnitude as Percentage of Name Plate Capacity (MARMAP):

$$Nameplate\,Capacity * ¿N \vee ¿ * 100$$
$$Percentage\,Ramp^{Avg}_{Mean} = \frac{\sum_{i\in N} Ramp^{Avg}_{t_i,d_i}}{¿}$$ (10)

where N is the set of aggregated ramp events during the time horizon.



MARMAP

Figure S4: Cumulative Percentage of EWITS Wind sites[3] corresponding to a given value of MARMAP for a 162.4MW threshold to identify ramp events

We estimated the MARMAP (162.4) for each of the 1326 on-shore wind sites included in the EWITS data-base[3]. For all the sites analyzes the average of the magnitude of aggregated ramping events $Ramp_{t0,d_{t0}}^{Rolling\,Avg}$ varied between 0% and 98% of the potential installed wind power capacity. A site with a MARMAP (162.5) of 0% is a site for which there was never a time period where wind power output would be 162.4 MW higher or lower than the power output in the immediately previous time period. Figure S4 shows the cumulative distribution of $PercentageRamp_{Mean}^{Rolling\,Avg}$ of all on-shore wind-sites in EWITS[3]. As shown in Figure S4, there are about 70% of sites with MAMAP (162.4) of 0%. For those sites for which MARMAP (162.4) is higher than 0%, the mean and median MARMAP (162.4) are 28% and 22% respectively).

X. Identifying existing U.S. power plants that could be retrofitted with CCS and therefore could be candidates for implementation on the hybrid system.

Figure S5 was generated using Matlab and information from the eGrid database[12]. It indicates the locations of all existing coal plants suitable for CCS retrofit (the criteria for selection was that the coal plant should have a rated nameplate capacity of 350 MW or greater and be less than or equal to 35 years of age – the same set of conditions used by the International Energy Agency to identify coal plants suitable for CCS retrofit[13]). The size of the dot indicates the relative size (nameplate capacity) of the power plant. A study of the eGrid database[12] further indicates that in the US, 20% of the total annual generation is supplied by these coal plants and that they account for roughly 35% of the total CO_2 emissions from the US electricity sector. Here we have a sizeable percentage of coal-plants in the US that could be retrofitted with CCS resulting in significant reduction in CO_2 emissions from the electricity sector.

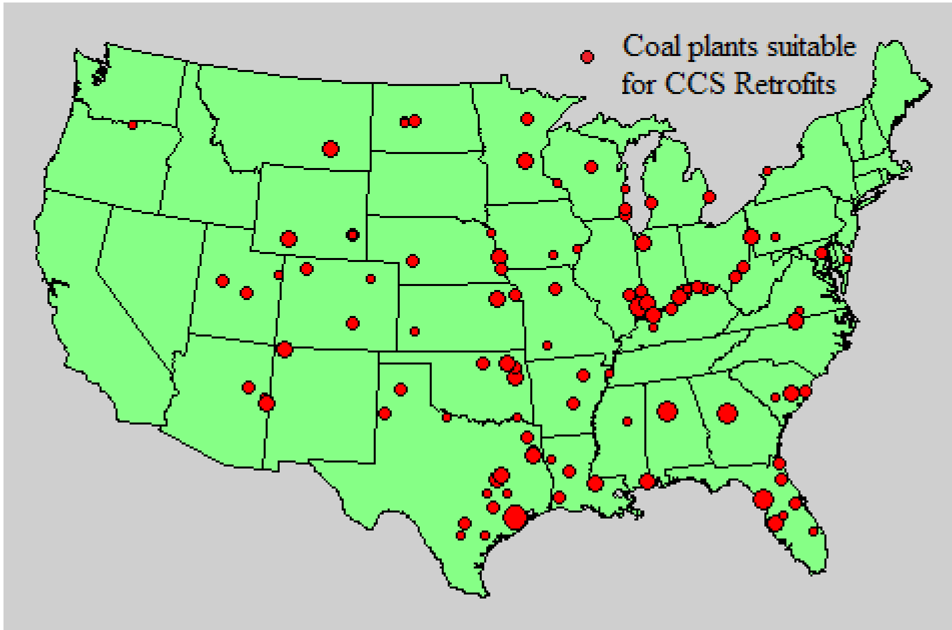


Fig S5. Location of existing coal plants in the US suitable for CCS retrofits

The hybrid system provides an added advantage by providing flexibility to reduce or increase the power that flows from the wind farm and coal plant to the grid via optimization of operation of the two types of power plants. The CCS system operation provides a form of 'storage' for wind power by optimizing the operation of the units within physical constraints of the system. Such a hybrid system would also reduce the variability of the wind power output, therefore substantially mitigating the need for adjustments in the overall flexibility of the power system where it operates.

In this study, an analysis of the performance of the hybrid system has been conducted in the PJM Interconnect where roughly 16% of the annual generation comes from coal plants suitable for CCS retrofit (results obtained from analysis of eGrid database[12] and FERC[14] website). Electricity generation from these plants currently contributes about 24% of the total CO_2 emissions from the generating units in the PJM Interconnect. The NREL database[15] for utility scale 80-meters wind power potential, indicates that 11% of the annual generation from the PJM Interconnect could be supplied by wind power resources in the region. The estimated wind power potential in the region is about 363 GW with capacity factors ranging between 30 and 36 percent[11]. As of now, only about 2% of this wind power potential has been harnessed in the PJM region (results obtained from analysis of the NREL[15], EWITS[3], eGrid[12] and FERC[14] databases). In addition, a visual inspection of the maps in Figure 2 indicate that the PJM Interconnect is in a region where CO_2 is likely to surpass any legislative and physical barriers. From the maps it can be seen that with the exception of a small portion of PJM in the state of North Carolina, most of the PJM Interconnect is in states where CCS legislation (such as policies for financial incentives to encourage CCS) already exists or where NETL has developed CO_2 demonstration projects.

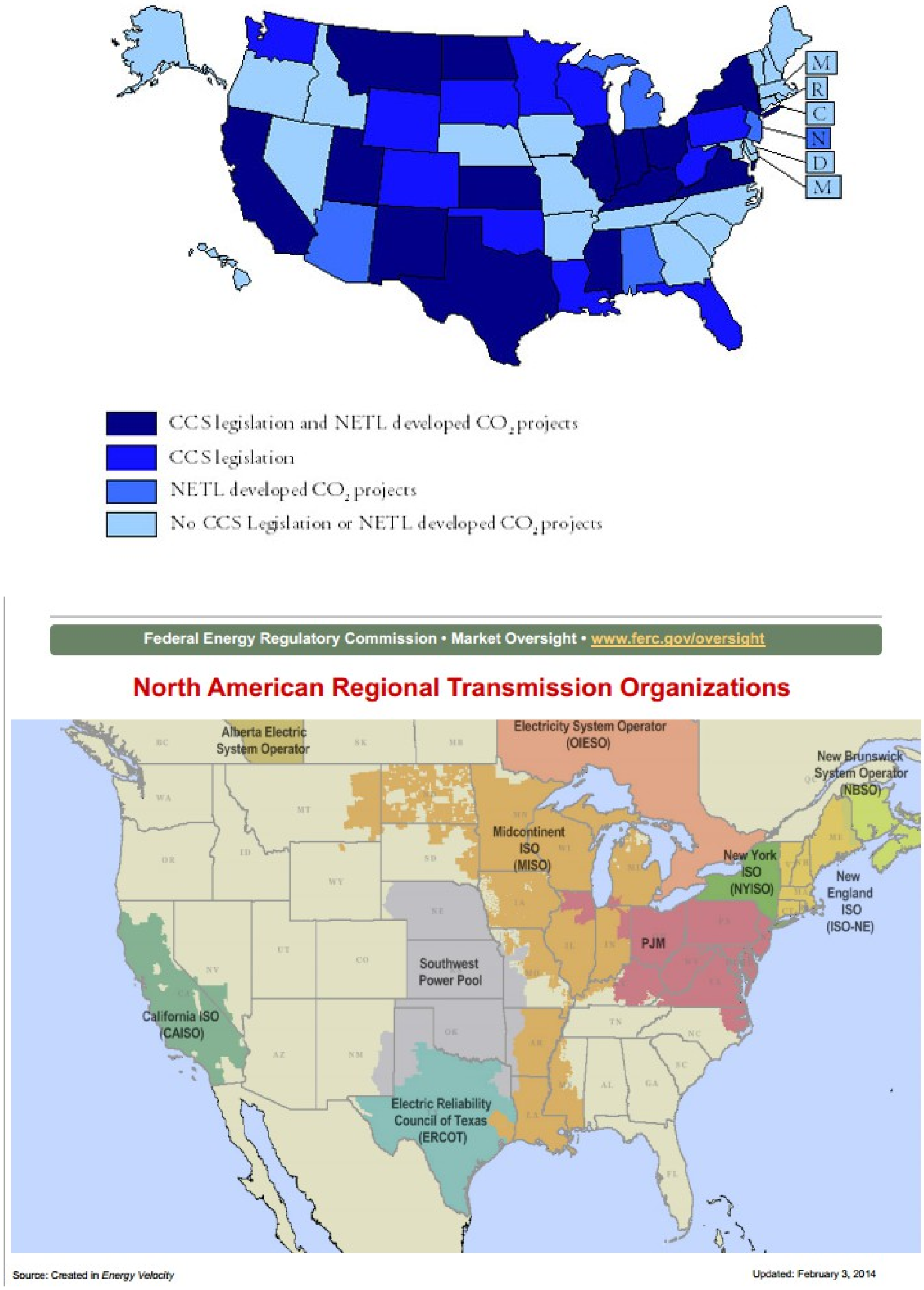


Figure S6. CCS Legislation[16] and NETL developed CO_2 projects[16] by North American RTO regions[17]

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