The Social Costs and Benefits of Wind Energy: A Case Study of the PJM Interconnection

Roger Lueken[1,], Jared Moore[1], and Jay Apt[1,2]

[1] Department of Engineering and Public Policy, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213, USA

[2] Tepper School of Business, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213, USA

ABSTRACT

Large deployments of wind create social costs and benefits that are not captured by traditional levelized cost of electricity (LCOE) analyses. Social costs are due to the inherent variability and unpredictability of wind power; social benefits are due to reductions in greenhouse gas and criteria pollutant emissions from fossil fuel plants. We investigated the social costs and benefits of wind in the PJM Interconnection for two scenarios: a 2012 scenario with 1.5% of energy from wind, and a high wind scenario with 20% of energy from wind. We found that social costs are uncertain but significant when compared to wind's LCOE. Social costs range from $4/MWh - $74/MWh in the low wind scenario, with an expected value of $36/MWh; in the high wind scenario costs range from $9/MWh - $94/MWh with an expected value of $51/MWh. Pollution reduction benefits exceed social costs with very high probability; the median expected net benefit is $74/MWh for both the low and high wind scenarios. EPA regulations may reduce the pollution reduction benefits of additional wind in the future. If cross-state air pollution regulations result in binding emission caps at anticipated permit prices, policies that incentivize additional wind will not reduce criteria pollutant emissions.

INTRODUCTION

In the United States, a variety of government incentives have resulted in nationwide deployments of more than 60 GW of wind capacity since 2002 *(1)*. Wind benefits society by reducing emissions of pollutants from the electric power sector. However, wind introduces system-level costs into the management of the electricity grid that arise from the need to manage wind's inherent variability. Although forecasting tools are in use, no forecast is perfect, and the un-forecast fluctuations of renewable energy can cause the grid to be operated sub-optimally and require additional reserves. Large deployments of wind create social costs and benefits that accrue to entities other than the wind plant investor. These social costs and benefits are not captured by traditional levelized cost of electricity (LCOE) nor by calculations of project revenue.

Social costs and benefits (SCBs) are highly uncertain and are affected by factors such as the quality of wind resource, the composition of the existing generators, and the capacity of wind installed. However, an evaluation of wind's SCBs is useful in determining if additional deployments of wind are beneficial to society. Table 1 divides wind's SCBs into six categories and provides definitions for each. These categories are consistent with existing terminology used in the academic literature and by industry.

Table 1. Definitions of Wind's Socialized Cost and Benefit Categories

Cost and benefit categories	**Definition**
Operational costs	The cost of ensuring stable grid operations, distributed across different markets (unit commitment, load following, regulation, and reserves)
Transmission costs	The cost of connecting electricity produced by distant and variable renewables to load
Curtailment costs	The cost of intentionally reducing the power produced by wind turbines due to transmission congestions, oversupply of electricity, or to ensure grid stability
Capacity costs	Cost of providing grid reliability (capacity) similar to dispatchable generators
Greenhouse gas reduction benefits	The societal benefit of reducing CO_2 and other greenhouse gas pollutants by displacing fossil-fueled generation with wind
Criteria pollutant reduction benefits	The societal benefit of reducing criteria pollutant emissions (NO_x, SO_2, particulate matter) that harm human health and the environment, by displacing fossil-fueled generation with wind

The unpriced social costs of wind, sometimes called integration costs, are due to wind's variability and partial unpredictability, which create difficulties for system operators managing the grid. These costs occur at timescales that range from seconds to decades in the future, and are generally socialized among all market participants, although some jurisdictions allocate costs to wind plant operators. Several analyses estimate the social costs for different electrical systems *(2 – 8)*. These studies vary in terms of completeness and complexity.

The primary social benefit of wind is due to its low emissions of greenhouse gases (GHGs) and criteria pollutants (CPs) relative to fossil-fueled generators. CP reductions are valued by estimating how wind power reduces harm to human health and the environment *(9 - 11)*. Estimates of the benefits of CP reductions due to wind range from $3/MWh - $82/MWh in the U.S. depending on the location and thus what type of generators are displaced by wind *(12)*. The social cost of carbon (SCC) is difficult to quantify *(13)*, so we used the most recent estimate developed by the U.S. Government *(14)*.

Few studies have attempted to comprehensively measure wind's social costs and benefits. The OECD analyzes the comprehensive costs of wind for several developed countries *(15)*. However, that work is limited by a focus on country-level and not sub-national costs. The study also excludes the benefits of wind.

We estimated the social costs and benefits of wind in the PJM Interconnection. We levelized the SCBs so they can be directly compared to traditional LCOE estimates. We analyzed two scenarios: a low wind scenario representative of PJM as it was in 2012 with 1.5% of energy from wind, and a high wind scenario with 20% of energy from wind. These two scenarios can be viewed as lower and upper bounds of wind's SCBs in PJM.

Because recognizing the uncertain character of both the benefits and the costs is important for policy, we presented the results as probability density functions.

METHODS

Costs and benefits vary regionally based on grid topology and wind resources. Estimates are highly dependent on assumptions of the makeup of the electricity grid, generator technologies, and fuel costs. Most importantly, estimates vary due to differences in methods among studies.

We treated wind's SCBs probabilistically with Monte Carlo simulation *(16)*. For each SCB category, we developed a triangular probability distribution. We then used Monte Carlo simulation to calculate the probability density function of the net SCB.

Studies modeling the social costs of wind typically involve both statistical models of wind generation and unit commitment and economic dispatch (UCED) models to simulate grid operations. We used both the results of existing UCED analyses, as well as our own reduced-form, open source UCED of the PJM Interconnection's day-ahead market, using 2010 data modified to represent 2012 (as described below). Our UCED, the PHORUM model, was used to estimate operational costs, criteria pollution reduction benefits, and greenhouse gas reduction benefits *(17)*. PHORUM uses mixed integer linear optimization to find the least-cost combination of generators to meet load at each hour of the year. The high wind scenario, with 20% of energy from wind, used data from the Eastern Wind Integration and Transmission Study (EWITS) to characterize likely locations for new wind plants in PJM states *(6)*.

We separately analyzed the value of six categories of costs and benefits: operational costs, transmission costs, curtailment costs, capacity costs, GHG reduction benefits, and criteria pollutant reduction benefits. For each category we estimated a lower bound, upper bound, and expected value for triangular distributions in the low wind and high wind scenarios. These analyses are described in detail below.

Operational costs

Operational costs are the costs of maintaining grid stability by continuously balancing total generation with total load, given the variability and unpredictability of renewable energy. Operational costs occur from the next 48 hours to real-time *(18)*. The net effect of these costs is increased prices in several markets run by the independent system operator (ISO), including the unit commitment/day-ahead market, load following/real-time market, regulation market, and reserve markets. Compensating for wind variability requires ramping other generators in the system, which in turn can cause generators to operate suboptimally and increase the frequency of generator cycling. The variability of wind also leads to forecasting errors that increase reserve requirements and, when realized, may force system operators to use fast-ramping but inefficient generation instead of more cost-effective generators. Day-ahead wind forecast errors are typically 8% - 14% (RMS error) *(19)*.

Calculating increases in operational costs requires both a statistical model of wind generation and a model of the electricity grid. Wind models use either measured or simulated wind speed data. Grid simulations vary in complexity from simple unit commitment models to more sophisticated models that capture forecast uncertainty and electrical dynamics of the grid. To isolate the costs of wind variability and unpredictability, it is common to use the 'flat-block' approach, in which a scenario with wind is compared not to a scenario without wind, but to a scenario in which the wind generation is constant and perfectly known *(20)*.

Figure 1 shows operational cost estimates of several published studies and our modeling with PHORUM. The studies vary in the costs they include (Table 2). Lueken et al. *(8)* used historical price data instead of simulation techniques to estimate operational costs; the high resulting costs suggests simulation methods may be biased to under-predict operational costs or that the observed California price data may be unrepresentative of areas used in simulations.

The low wind scenario operational costs range from \$0 - \$4.3/MWh, with an expected value of \$1.2/MWh, and high wind scenario costs range from \$1.9 - \$9.7/MWh, with an expected value of \$4.0. For both scenarios, bounds were derived from existing literature and most likely values from PHORUM simulations.

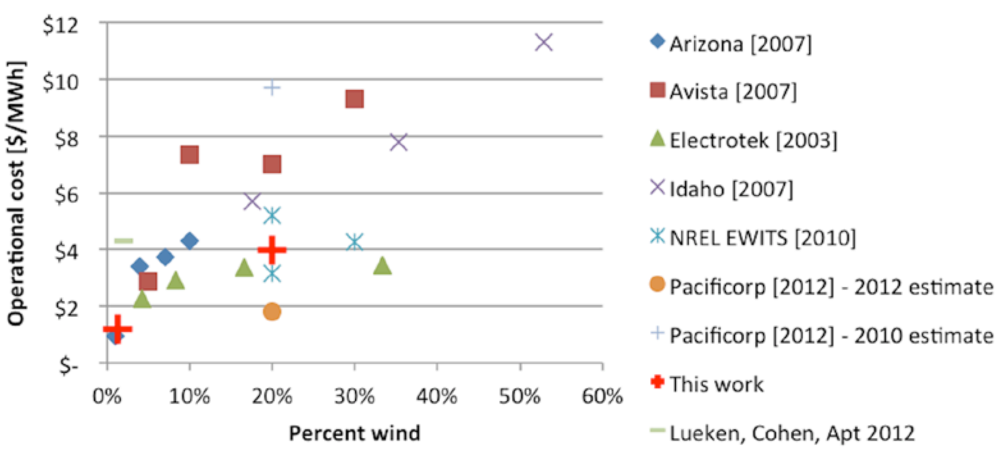

Figure 1. Estimates of operational integration costs from previous literature and this work (2010 dollars).

Table 2. Cost Categories Included (Dark Squares) In Each Wind Integration Study

	Unit commitment	Load following	Forecast error	Reserves	Regulation
Arizona (2007)	■	■	■	■	
Avista (2007)	■	■		■	
Electrotek (2003)		■	■	■	■
Idaho (2007)	■	■	■	■	■
NREL EWITS (2009)	■	■			
Pacificorp (2012)	■	■	■	■	■
This work	■				
Lueken, Cohen, Apt 2012					■

Transmission Costs

The cost of connecting electricity produced by distant and variable renewables to load is an appreciable cost for wind energy. Typically, transmission costs are omitted from estimates of wind LCOE because they are very site specific *(21)*. Since transmission costs will either be socialized among ratepayers or paid by developers, we included them as a category of SCBs. Studies of wind transmission costs can be bottom-up, in which costs are estimated for connecting individual wind plants, or top-down, in which a significant expansion of the transmission grid is designed to integrate very high wind penetrations.

A bottom-up cost study by the Lawrence Berkeley National Laboratory (LBNL) study reviewed a sample of 40 transmission planning studies to assess the range of costs allocated to wind for transmission *(22)*. LBNL found that the cost of transmission has a median cost of $300/kW of wind capacity. We converted these numbers to a levelized cost ($/MWh of wind) assuming a 28% capacity factor for PJM wind projects *(1)* and a fixed charged factor of 15% as assumed by the LBNL authors. A histogram of the costs is shown below in Figure 2.

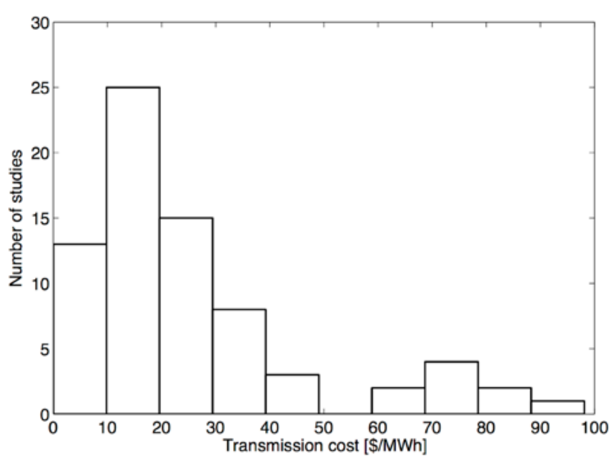

Figure 2. Histogram of transmission line costs from LBNL *(22)*, assuming a wind capacity factor of 28% and fixed charge factor of 15%.

Transmission costs varied from $0/MWh to $98/MWh with a median of $18/MWh. Cost estimates at the high end are due to projects with transmission oversized for future plant development. Ignoring these projects, we assumed transmission costs range from $0/MWh - $48/MWh with a median of $16/MWh. The study also examined the case in which costs were not allocated to fossil plants on the same transmission line. This made a small difference increasing the cost allocated to wind by $30/kW ($2/MWh). However, it should be noted that new transmission may have other co-benefits such as easing transmission congestion or increasing grid reliability by connecting dispatchable generators. New transmission can also increase system congestion *(23)*. We did not include these co-benefits or costs in this analysis, but note that they may be appreciable *(6, 24)*.

In order to realize 20% penetration of renewable energy, a significant "top-down" expansion of the transmission grid may be necessary *(6)*. Table 3 shows capital cost estimates from studies of very large transmission expansions in order to incorporate high wind penetrations. Based on these studies, we assumed bounds of $4 - $35/MWh of wind for the high wind scenario, with a most likely value of $15/MWh.

Table 3. Capital Costs from Various Large Transmission Studies and Calculated Levelized Cost, assuming 28% Wind Capacity Factor and 15% Fixed Charge Factor

Cost per kW of Wind [$/kW]	Levelized Cost Per MWh of Wind [$/MWh]	Study
150 - 300	9 – 18	LBNL from AEP *(22)*
207	13	NREL *(6)*
316	19	LBNL from NEMS *(22)*
67-367	4 - 22	Holttinen *(25)*
350-570	21 - 35	ERCOT *(26)*
-	9	Dobesova et al. *(27)*

Curtailment costs

Curtailment costs occur when wind plants intentionally reduce power output due to grid or market conditions. Curtailment costs are generally socialized via make-whole payments to wind generators for the energy they were forced to curtail, although market rules vary by region *(28)*. Wind curtailment has been reported for only six months in PJM, and has been insignificant *(1)*. However, regions with significant wind have experienced appreciable curtailment; annual wind curtailment in ERCOT was 17% in 2009 *(1)* before declining to 3.7% in 2012 after new transmission lines and nodal pricing eased transmission congestion *(29)*.

To estimate curtailment rates in the low wind scenario, we used data from the Midcontinent Independent System Operator (MISO), which has similar generator characteristics to PJM. Curtailment in MISO has varied from 2.0% to 4.2% from 2009 to 2012; these are the bounds we used for our distribution. We used as the median value the midpoint of 3.1% *(1)*. For the high wind scenario, we used simulated curtailment estimates from the EWITS study, as historic curtailment data do not exist for wind penetrations of 20% in the United States. EWITS estimated curtailments would range from 3.6% to 10% assuming a large expansion of the transmission grid necessary to support 20% wind *(6)*; these are the bounds we used for the high wind scenario. Our median value is the midpoint, 6.8%.

We quantified the societal costs of curtailment as the make-whole revenues paid to wind producers for energy they curtail. As a first order approximation, we assumed these revenues equal the levelized power purchase agreement (PPA) price ($/MWh), multiplied by the percentage of power curtailed. Average levelized PPA price in 2012 was ~$50/MWh in the PJM region *(1)*. With our assumed curtailment, this translated to curtailment costs in the low wind scenario of $1/MWh - $2.1/MWh (median value $1.6/MWh) and curtailment costs for the high wind scenario of $1.8/MWh - $5.0/MWh (median value $3.4/MWh).

Capacity costs

The North American Electric Reliability Corporation (NERC) requires system operators to ensure that sufficient capacity exists in their system to reliably meet system load. In 2007, PJM created the Reliability Pricing Model to ensure that adequate capacity is available to meet peak demand. Reliability can be met through a variety of technologies such as generation capacity, demand side management, energy efficiency, and imports. PJM has a need for approximately 170 GW of capacity; ~15 GW will be met in 2015 through demand side management *(30)*.

A generator's net expected contribution to reliability in terms of capacity is defined as the equivalent load carrying capability (ELCC) *(20)*. An ELCC of 90% means that a generator can be expected to provide 90% of its nameplate capacity during peak hours. The ELCC provided by onshore wind in the United States is much lower than that of conventional generators. At low penetrations of wind, the ELCC of wind could be roughly approximated by the capacity factor (28% in PJM) *(31)*. In PJM, wind receives a capacity credit of only 13%, because wind output does not coincide well with peak demand periods *(30)*. Typically, as penetration of onshore wind or solar increases, the value of ELCC diminishes *(22, 31)*.

In order for wind plants to provide the same capacity as dispatchable power plants, some form of capacity must be added to offer the same ELCC. For the low penetration scenario, we assumed that the cost of capacity is the marginal cost of capacity from PJM's Reliability Pricing Model (RPM). Capacity prices have varied from $16 to $174/MW-day with a median value of $106/MW-day since the RPM began in 2007 *(30)*. This provided our range and expected value for capacity costs in the low wind scenario.

To find the range for the high penetration scenario, we broadened our range. For the lower bound, we assumed that PJM has excess capacity resulting in no capacity costs. For the upper bound, we relied on PJM estimates of the cost of new entry (CONE) of new simple cycle power plants. The CONE is used to construct the demand curve for capacity for the RPM. PJM estimates the CONE of new simple cycle power plants to be approximately $380/MW-day *(31)*.

For the expected value of capacity cost in a high penetration scenario, we assumed that the marginal capacity cost is \$200/MW-day. This figure is based on two estimates. The first estimate is the amount of "missing-money" needed for adequate capacity in ERCOT's energy only market as calculated by Spees et al. (\$190/MW-day) *(32)*. The second estimate is the avoidable cost rate of sub-critical coal-fired power plants in PJM (\$210/MW-day) *(33)*. We assumed that if low-cost gas and high penetrations of wind undercut energy profit revenues of coal-fired power plants in PJM, capacity costs would be set by the avoidable cost rate of coal-fired power plants. For both the low and high wind scenarios, we converted capacity costs from \$/MW-day to \$/MWh wind assuming a 28% wind capacity factor and an ELCC of 13% for wind in PJM (see Table 4).

Pollution reduction benefits

A primary benefit of wind energy is pollution reduction. Because wind has very low short-run marginal costs, it is dispatched before more expensive generators. If wind displaces fossil-fueled generators, it reduces net grid emissions. Emission reductions are typically stated as pounds of emissions avoided per MWh of electricity produced by wind. We monetized the benefit of pollution reductions with the estimated social cost of each pollutant.

We modeled pollution reduction benefits in the low wind and high wind scenarios as triangular distributions. We used PHORUM to simulate how adding wind to PJM in 2012 would have changed each plant's annual power generation and emissions. CO_2 emission reductions are valued with a social cost of carbon (SCC) of \$13 - \$136/ton, with a mode of \$45/ton (2010 dollars) as valued by the US Government *(14)*. We valued criteria pollutant reductions (NO_x, SO_2, 2.5 micrometer particulate matter ($PM_{2.5}$)) with the APEEP model, a reduced form, integrated assessment model that links emissions of criteria pollutants to human health and environmental damages for all U.S. counties *(34)*. We assigned location-specific damage rates to each plant. Because APEEP does not provide uncertainty estimates for the correlated damages between plants in different locations, we used a point estimate of damages for each plant rather than a triangular distribution. In the high wind scenario, it can be argued that APEEP's baseline emissions are affected enough so that the human health effects are no longer accurate. In the case of SO_2, there is clear evidence that $PM_{2.5}$ formation is linear, no threshold with reduced SO_2 emissions *(35)*. Large cohort studies have found $PM_{2.5}$ concentration-response functions and mortality are linear with no threshold *(36, 37)*. Thus, for our high wind case at 20% wind the APEEP model predictions are justified.

Since 2010, the year for which our base data are available, emissions of CO_2 and criteria pollutants have dropped significantly in PJM due to lower natural gas prices, the Clean Air Interstate Rule (CAIR) *(10)*, and the Mercury and Air Toxics Standard (MATS) *(38)*. 2012 emissions of SO_2 were 42% lower than 2010 levels in PJM states, and NO_X and CO_2 emissions have both dropped 15% *(39)*. To compensate for these reductions, we reduced the simulated 2010 emissions and associated damages from each plant by 42% for SO_2, 15% for NO_X, and 15% for CO_2. This adjustment ignores any changes to the dispatch order that may have occurred since 2010. We have applied this adjustment in the results that follow.

RESULTS & DISCUSSION

Table 4 summarizes the parameters used in our Monte Carlo analysis of social costs and benefits in PJM. Social costs are significant when compared to private costs – the average PPA price in 2012 was ~$50/MWh in the PJM region *(1)*. However, social costs are much smaller than both GHG emission reduction benefits and criteria pollutant emission reduction benefits (Figure 3). Emission reduction benefits are higher in PJM than other ISOs due to the combination of PJM's reliance on high emitting fossil-fueled generators and high population, resulting in increased pollution exposure compared to other ISOs.

Table 4. Social cost and benefit parameters used in Monte Carlo simulation

Cost and benefit categories	**Low wind scenario ($/MWh)**			**High wind scenario ($/MWh)**		
	Lower bound	Median	Upper bound	Lower bound	Median	Upper bound
Operational costs	$0	$1	$4	$2	$4	$10
Transmission costs	$0	$16	$48	$4	$15	$35
Curtailment costs	$1	$2	$2	$2	$3	$5
Capacity costs	$2	$14	$23	$0	$26	$49
Greenhouse gas reduction benefits	$10	$35	$110	$10	$36	$110
Criteria pollutant reduction benefits*	$64	$64	$64	$77	$77	$77
* Point estimates were used for low wind and high wind scenarios.						

Monte Carlo simulation results are shown in Figure 3. Total social benefits are highly uncertain, but with very high probability exceed total social costs for both the low wind and high wind scenarios. Total costs in the high wind scenario likely exceed those in the low wind scenario, and are more uncertain. Total benefits are higher in the high wind scenario than the low wind scenario, as wind offsets a greater proportion of coal generation.

We next calculated the net social benefit of wind power, or total social benefit minus total social cost (Figure 4). The net benefit is positive for both scenarios; the median expected net benefit is $74/MWh for both the low wind scenario and high wind scenario.

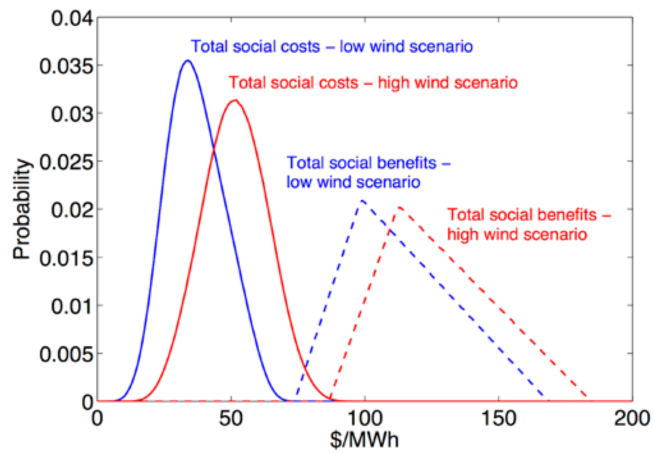

Figure 3. Distribution of total social costs and benefits. Social costs and benefits are larger in the high wind scenario than the low wind scenario. Total social benefits are highly uncertain but have a very high probability of being significantly greater than costs.

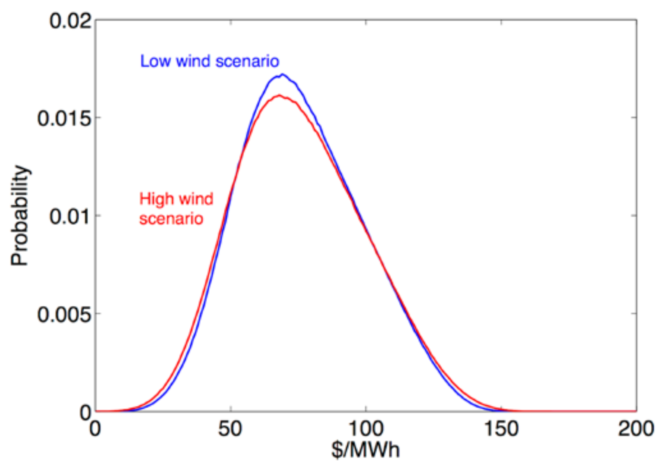

Figure 4. Net social benefit (total social benefit minus total social cost). Expected net benefits are $74/MWh in each scenario; net benefits are more uncertain in the high wind scenario.

Net social benefits under a future, cleaner grid

Over the next decade, several rules by the U.S. Environmental Protection Agency are expected force many of PJM's coal generators to either retire or retrofit with improved emission control technologies. Rules include the Clean Air Interstate Rule (CAIR), which limits emissions of NO_x and SO_2 *(10)*; the Mercury and Air Toxics Standard (MATS), which limits emissions of mercury and primary particulate matter *(38)*; and President Obama's stated intention to place CO_2 restrictions on existing power plants *(40)*. EPA has proposed the Cross-State Air Pollution Rule (CSPAR) to replace CAIR *(41)*. Although CSPAR was voided by the D.C. Circuit Court of Appeals *(42)* and as of this writing the case is pending before the U.S. Supreme Court, CAIR remains in effect. PJM anticipates as much as 20 GW of coal capacity is at risk of retirement by

CAIR/CSAPR and MATS, or 25% of total coal capacity. An additional 29 GW of capacity may need at least two retrofits to comply with the rules *(43)*.

Two future scenarios are possible under the EPA regulations. The first scenario is that the emission caps established by CAIR bind. In this case, total emissions of NO_x and SO_2 will be fixed at the emissions cap and new additions of wind will not result in a net reduction in emissions. Rather, the displaced NO_X and SO_2 emissions will be valued at the market emission permit price, anticipated by the EPA to be $1,300/ton for SO_2 and $2,100/ton for NO_X in 2015 (2010 dollars) *(10)*. These anticipated permit prices are much lower than the health damages caused by emissions from PJM plants. According to the APEEP model, expected damages are as high as $71,000/ton for SO_2 and $13,000/ton for NO_x for PJM plants, depending on plant location. If CAIR emission caps bind, the effect of additional wind would be downward pressure on permit prices and minimal reductions in criteria pollutant emissions. If valued at anticipated permit prices, criteria pollution reduction benefits would be $7/MWh for the low wind scenario and $8/MWh in the high wind scenario, resulting in net social benefits of $9/MWh and -$4/MWh, respectively. This suggests that for the socially optimal amount of wind to be deployed under a cap system, the permit price would need to be closer to the estimated health damages.

The second scenario is that emission caps do not bind due to significant wind deployment, low natural gas prices, or tightened regulations under MATS *(44)*. In this scenario, new additions of wind would reduce criteria pollutant emissions and should be valued by the human health benefits they induce. These benefits will be lower than those in Table 4 if criteria pollutant emission rates from coal and oil plants continue to drop as mandated by MATS. How much emission benefits fall will depend on the specifics of which plants retrofit or retire.

Market implications

The addition of wind to electric power systems creates social costs and benefits that are not priced in today's markets. These social costs and benefits (SCBs) are highly uncertain and vary between markets. In PJM, our median estimate of total social costs is $36/MWh in a low wind scenario and $51/MWh in a high wind scenario with 20% of energy from wind. The social benefits wind creates by reducing GHG and criteria pollutant emissions are expected to exceed total social costs. The median expected net societal benefit of wind in PJM is $74/MWh for both the low wind and high wind scenarios. If CAIR results in binding emission caps at anticipated permit prices, additional wind will not reduce criteria pollutant emissions and net social benefits will be close to zero. If these caps bind at the low anticipated permit prices, state renewable portfolio standards should be revisited. If caps do not bind, additional wind will reduce criteria pollutant emissions and human health damages, resulting in positive net social benefits, albeit lower than our calculated net benefit of $74/MWh. Policymakers and market operators should establish rules that correctly price the social costs and benefits of wind, and therefore encourage the socially optimal amount of wind to be deployed.

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