The challenge of integrating offshore wind power in the U.S. electric grid. Part II: Simulation of electricity market operations.

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Highlights:

1. Smart-ISO, a simulator of the PJM planning process, is developed, tested, and evaluated.
2. Injecting large amounts of offshore wind power (36 GW) in the current electricity grid is feasible with current planning process and current wind forecast errors simply via additional reserves;
3. With perfect wind forecasts, at least twice as much offshore wind power can be integrated with less than half of the reserves than with the current wind forecast errors.

Word count: 6975.

Abstract

The purpose of this two-part study is to analyze large penetrations of offshore wind power into the grid of a large Regional Transmission Organization (RTO), using the case of the grid operated by PJM Interconnection in the northeastern U.S. Part I of the study introduces the wind forecast error model and Part II, this paper, describes Smart-ISO, our simulator of PJM's planning process for generator scheduling, including day-ahead and intermediate-term commitments to energy generators and real-time economic dispatch. Using a carefully calibrated model of the PJM grid and realistic models of offshore wind (described in Part I), we show that, except in summer, an unconstrained transmission grid can meet the load at five build-out levels spanning 7 to 70 GW of capacity, with the addition of at most 1 to 8 GW of reserves.

In the summer, the combination of high load and variable winds is challenging. We find that the simulated grid can handle up through build-out level 3 (36 GW of offshore wind capacity), with 8 GW of reserves and without any generation shortage. For comparison, when Smart-ISO is run with perfect forecasts, all five build-out levels, up to 70 GW of wind, can be integrated in all seasons with at most 3 GW of reserves. This reinforces the importance of accurate wind forecasts. At build-out level 3, energy from wind would satisfy between 11 and 20% of the demand for electricity and settlement prices could

be reduced by up to 24%, though in the summer peak they could actually increase by up to 6%. CO_2 emissions are reduced by 19-40%, SO_2 emissions by 21-43%, and NOx emissions by 13-37%.

This study finds that integrating up to 36 GW of offshore wind is feasible in PJM with today's transmission grid, generation fleet, and today's planning policies with the addition of 8 GW of reserves. Above that, PJM would require additional investments in fast-ramping gas turbines, storage for smoothing fast-ramping events, and/or other strategies such as demand response.

1 Introduction

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity serving 13 states and the District of Columbia, covering from the mid-Atlantic region out to Chicago (PJM Interconnection 2014). Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity transmission grid to ensure reliability for more than 61 million people. Figure 1 shows the geographical area covered by PJM and the high-voltage backbone (345 kV and higher) of its transmission grid.

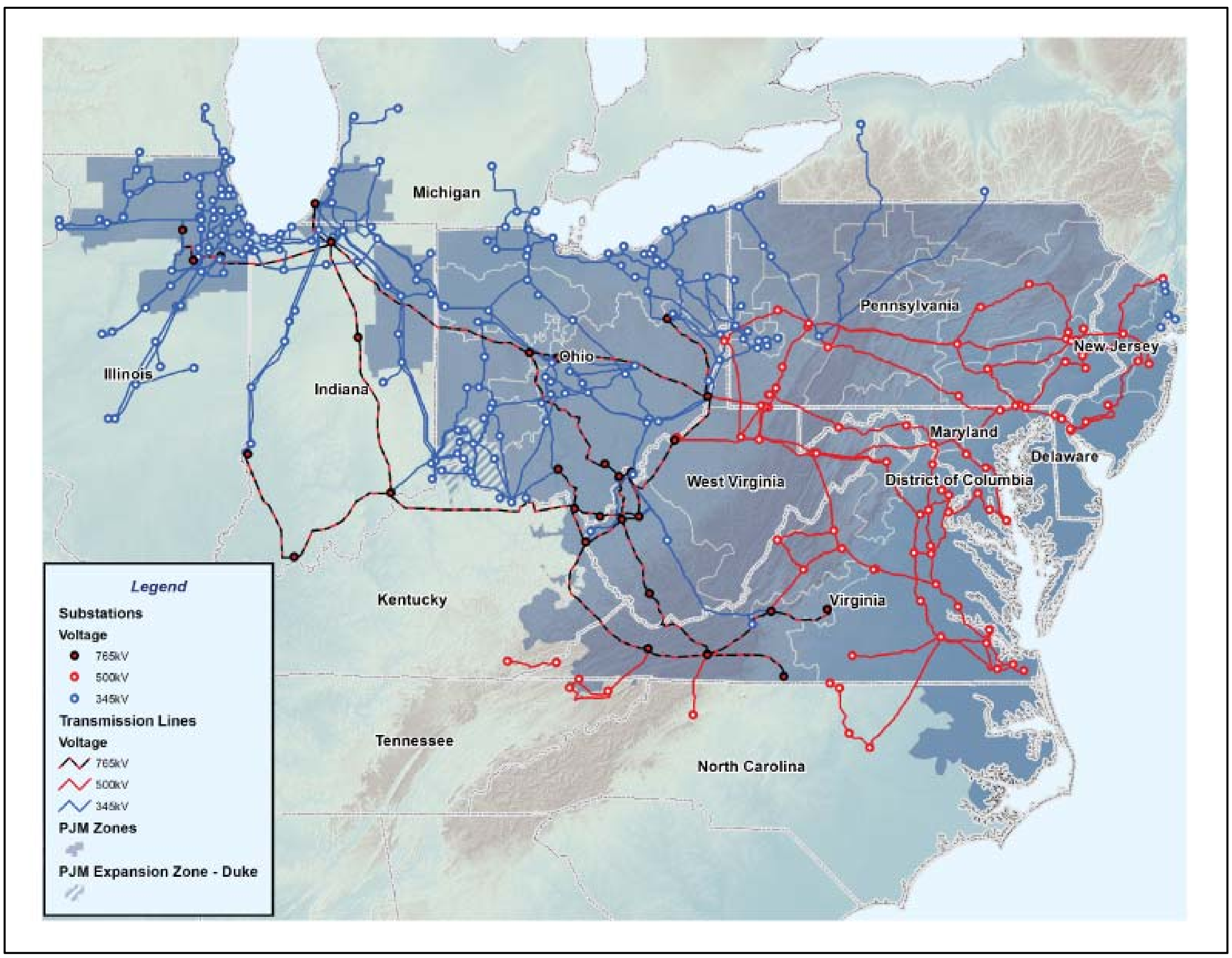

Figure 1: PJM high-voltage backbone.

At the end of 2013, the total installed capacity within the PJM market was about 183 Gigawatts (GW) and the peak load during the year was over 157 GW (Monitoring Analytics 2014). The yearly generation in PJM by percentage of each fuel source between 2010 and 2013 is shown in Table I (Monitoring Analytics 2011, 2012, 2013, 2014).

Table I: PJM actual generation by fuel source (%) between 2010 and 2013

Fuel Source	2010	2011	2012	2013
Coal	49.3	47.1	42.1	44.3
Nuclear	34.6	34.5	34.6	34.8
Gas	11.7	14.0	18.8	16.3
Hydroelectric	2.0	1.9	1.6	1.8
Wind	1.2	1.4	1.6	1.9
Other	1.2	1.1	1.3	0.9

The basic functions of PJM comprise grid operations (supply/demand balance and transmission monitoring), market operations (managing open markets for energy, capacity and ancillary services) and regional planning (15-year look-ahead) (PJM Interconnection 2014). Our interest in this paper is to analyze the ability of the energy market and the transmission grid within the PJM area to integrate non-dispatchable generation in quantities much larger than the current levels. As indicated in Table I, in 2013 wind power corresponded to less than 2% of the total generation. The Mid-Atlantic offshore wind power production proposed and modeled in Part I of this paper (Archer et al. 2015) would bring that fraction to as much as 28% at certain times of the year, thus raising the question of how to manage the generation schedule and the transmission grid capacity under such a scenario.

In order to answer this question, we introduce SMART-ISO, a simulator of the market operations of PJM, including the transmission grid. Developed at PENSA Lab at Princeton University, SMART-ISO is a detailed model of the PJM planning process designed specifically to model the variability and uncertainty from high penetrations of renewables. It captures the timing of information and decisions, stepping forward in 5-minute increments to capture the effect of ramping constraints during rapid changes in wind energy. Considerable care was invested to capture the accuracy of wind forecasts using information from PJM's forecasts of their own wind farms, as detailed in Part I of this two-part article.

2 The SMART-ISO model

SMART-ISO is a simulator of the market operations of PJM that aims to strike a balance between detailed representation of the system and computational performance. It comprises three optimization models embedded within a simulation model that captures the nested decision-making process:

1. Day-ahead unit commitment (DA-UC) model.
2. Intermediate-term unit commitment (IT-UC) model.
3. Real-time economic dispatch.

Accurate modeling of the nesting of these three models is a central (and powerful) tool used by ISOs to adapt to uncertainty. In SMART-ISO all three optimization models include a DC approximation of the power flow. In addition, an AC power flow model is run after both the intermediate-term UC and the real-time economic dispatch models in order to verify the electrical stability of the grid.

The simulator takes as inputs:

1. The list of generators available for scheduling in the PJM area (including all relevant operational and economic parameters).
2. The transmission grid (buses and lines), including relevant transmission parameters.
3. Historical (and/or simulated) time series of loads (both active and reactive) at the bus level over the simulation horizon.
4. Rolling time series forecasts of non-dispatchable generation (e.g. wind) over the same horizon.
5. Historical (and/or simulated) time series of non-dispatchable generation.

The forecasted time series are used in the scheduling models (day-ahead and intermediate-term UC's), whereas the historical or simulated time series are used in the economic dispatch model.

The list of generators available in the simulator included 830 units, which comprised 97.8% of the installed capacity in 2010. These generators were partitioned into four categories: (1) *must-run*, which include all nuclear-fueled generators and those (predominantly coal-fueled) with notification plus warm-up times above 32 hours; (2) *slow*, which include all generators with notification plus warm-up times between 2 and 32 hours; (3) *fast*, which include those with notification plus warm-up times below 2 hours; and (4) *other*, which include hydro, pumped storage, and wind. The generators in the categories *must-run* and *other* are assumed to be always on. Therefore only the *slow* and *fast* generators are scheduled in the unit commitment models.

PJM's transmission grid comprised over 9,000 buses and 11,500 branches in 2010. Though feasible, running the unit commitment and economic dispatch models with a full-size integrated grid has significant computational costs. To strike a balance between grid representation and computational complexity, we created multiple aggregate versions of the grid, including only the buses at or above a given voltage. SMART-ISO can run the different models at different levels of aggregation, but we recommend running the unit commitment models at higher aggregation level(s) than the economic dispatch model. Table II displays the levels of grid aggregation available in SMART-ISO, with their respective dimensions in terms of the total number of buses and branches. In the runs performed in this study, we used the 315-kV grid for unit commitment (both day-ahead and intermediate-term) and the 220-kV grid for economic dispatch.

Table II: Grid aggregation levels available in SMART-ISO. Column "0" includes all buses and all branches.

Minimum Voltage (kV)	0	69	72	118	220	315	500
# of Buses	9,154	5,881	4,829	3,950	1,360	354	131
# of Branches	11,840	7,750	6,260	5,210	1,715	454	159

Special care was taken within SMART-ISO to closely match PJM's *lead times* between *when a decision is made* (e.g. when a unit commitment model runs) and *when it is implemented*. Not surprisingly, lead times highlight the importance of the quality of the forecasts, especially for the intermediate-term unit commitment model where even hour-ahead projections can be quite poor. As this article will show, forecasting errors proved to be the major factor limiting the absorption of high penetrations of offshore wind.

Typically we run SMART-ISO for a simulation horizon of 8 days, where the first day is discarded to avoid any initialization bias. Each of the three optimization models is run sequentially over the entire simulation horizon, with their different planning horizons and time scales nested and synchronized. The simulation is repeated for as many sample paths of the random realizations as desired. In the next subsections we briefly describe some details of each one of the optimization models and the power flow models, as well as the main policy to deal with uncertainty in unit commitment.

2.1 Day-ahead unit commitment model

The day-ahead UC model in SMART-ISO runs once every 24 hours, at noon, similarly to how it actually runs in PJM. Its planning horizon spans 40 hours in hourly time steps, starting from noon on a given day until 4am on the second day following. Historical loads and long-term (day-ahead) forecasts of non-dispatchable generation are used in this model. The planning horizon is functionally sub-divided into four blocks of time, as depicted in Figure 2.

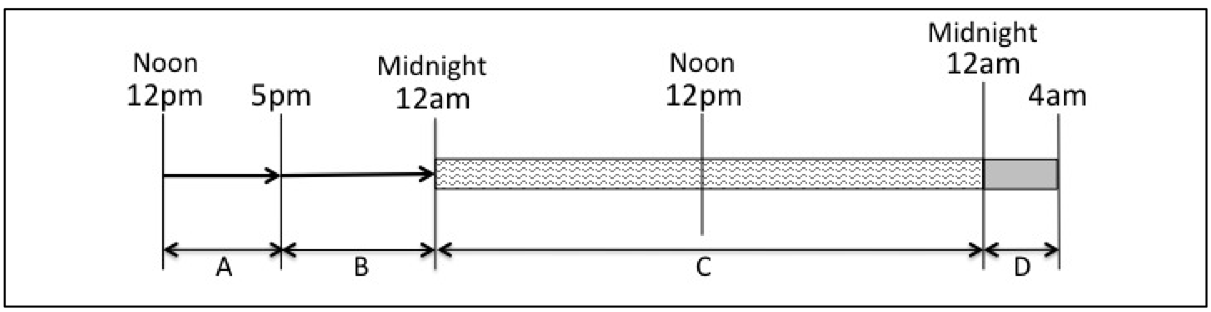

Figure 2: Planning horizon of day-ahead UC model.

Blocks A and B correspond to the initial period of time when no generators are turned on or off because those decisions would have been made in previous unit commitments, either the day-ahead or the intermediate-term. During those blocks of time the UC model acts just as an economic dispatch model; that is, it varies the amount of energy produced by each (turned-on) dispatchable generator, in order to follow the forecasted load and adjust for the non-dispatchable generation (also forecasted). However, in block B generators may be notified that they will have to go on or off starting from the beginning of block C. In blocks C and D any *slow* or *fast* generator can be scheduled or unscheduled, but only the notification and on/off decisions involving *slow* generators during periods B and C will be made effective (that is, *locked in*), whereas decisions involving *fast* generators are finalized in the intermediate-term model, described next. Block D is added to the time horizon to minimize end-of-horizon effects on the decisions made at the end of block C.

2.2 Intermediate-term unit commitment model

The intermediate-term UC model in SMART-ISO runs twice every hour, at 15 minutes after and before the hour. There are no on/off decisions made for *slow* generators in this model (they were all made in the appropriate day-ahead model); only *fast* generators will be turned on or off. Short-term forecasts of non-dispatchable generation (usually done through persistence) are used in this model. Its planning horizon comprises 2 hours and 15 minutes, in time steps of 15 minutes, and is illustrated in Figure 3.

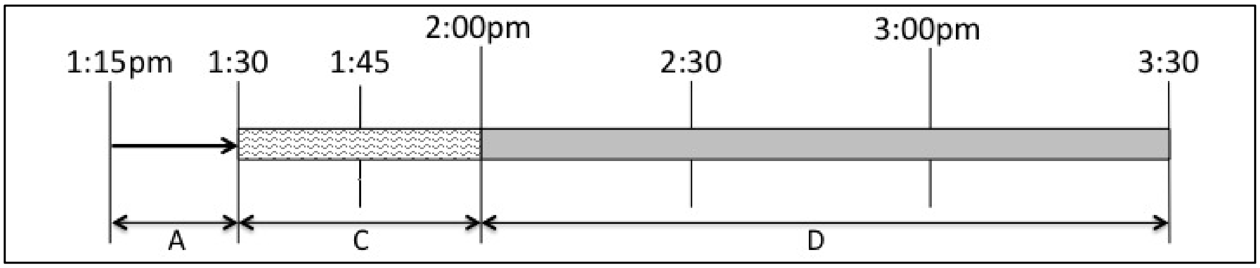

Figure 3: Planning horizon of the intermediate-term UC model.

During block A no generators can be turned on or off; they only follow the load and adjust to non-dispatchable generation (given by short-term forecasts). *Fast* generators can be scheduled or unscheduled in blocks C and D, though only the decisions made in block C will be locked in. Our implementation of the intermediate-term scheduling process represents an approximation of PJM's own process (called *IT-SCED*), which involves running the process in 15-minute cycles, with updates every 5 minutes in case the data change. There is a variable lead-time (30 to 40 minutes) between when PJM runs IT-SCED and the time of first potential dispatch of a generator (block A). After careful review with PJM, we decided that our approximation reasonably matched their lead times, striking a balance between model accuracy and computational complexity. The calibration results reported in a later section further confirmed our assessment.

2.3 Real-time economic dispatch model

The real-time economic dispatch model in SMART-ISO runs every 5 minutes, over a planning horizon of 15 minutes, with time steps of 5 minutes, as illustrated in Figure 4. PJM also runs the economic dispatch every 5 minutes, but over a planning horizon of 5 minutes (only one time step).

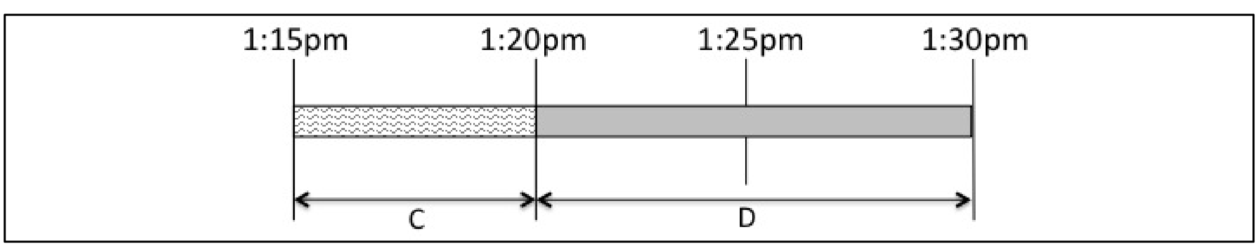

Figure 4: Planning horizon of the real-time economic dispatch model.

No generators are turned on or off in this model. Instead, generators are only modulated to follow the actual (or simulated) load and adjust to non-dispatchable generation (also actual or simulated). The generation amounts simulated in block C are kept, whereas the ones simulated in block D are discarded, as block D was added to the planning horizon of this model again to mitigate end-of-horizon biases in the calculations in block C.

2.4 Power flow models

To incorporate transmission grid constraints into SMART-ISO, we opted for implementing unit commitment and economic dispatch models that include power flow modeling as well. We used the DC approximation to solve the power flow embedded in the linear optimization problems. This is a widely used approximation for the power flow in transmission grids, since it does not require iterations (as the AC power flow does) and the optimization problem remains linear and consequently less complex (Stott et al. 2009, Hedman et al. 2011, Overbye et al. 2004). The DC approximation power flow model considers only active power and assumes that the nominal voltages remain constant.

However, to verify the voltage stability of the grid, and possibly correct for it, we also implemented an AC power flow model that runs once after every intermediate-term UC and once after every economic dispatch model in the simulation. If the AC power flow solution after an intermediate-term UC model shows significant voltage deviations from the nominal values (where “significant” is defined in terms of observed historical patterns), a single feedback loop will make temporary adjustments to local bus loads, and the intermediate-term UC model will be solved again, aiming to change the allocation of power generation so as to lessen the voltage deviations.

We found that the DC approximation can be too rigid, indicating that we might not meet power requirements (while holding voltages constant), while the AC model can flex voltages to meet loads, frequently by increasing currents. Higher currents can be tolerated for short periods of time. The greater flexibility of the AC power flow proved to be important in our studies of non-dispatchable sources, which required that we adapt to short but sudden drops in wind.

For this reason, the AC power flow model is solved again after each economic dispatch model run, in order to assess the overall stability and feasibility of the operation of the grid. When load is greater than generation within PJM, we refer to that as “generation shortfall.” An RTO will handle this problem with demand management, calling interruptible customers to close down, or transfers from neighboring RTOs. If there is a threat to the stability of the larger system, they would shed load by unannounced cutoffs, an emergency procedure. Without stating how PJM would respond, we simply call such cases “generation shortfall.” If the AC power flow solution does not converge or significant voltage deviations are detected, we flag the operation of the grid as “AC unstable” during that 5-minute time period. If, however, there is generation shortfall in the solution of the DC-based economic dispatch (usually an infeasible situation), but the AC power flow solution converges and is voltage-stable, then we dismiss the DC generation shortfall (that is, we declare a “no-generation shortfall” – or feasible – situation). We will allow up to 10 consecutive minutes of dismissed DC generation shortfall. If the situation persists for 15 minutes or longer, then we revert the dismissal and flag the generation shortfall, regardless of the AC power flow stability.

2.5 Reserves

RTOs such as PJM use a variety of strategies to manage the uncertainties that arise in any energy system, including the hedging of decisions with the sequence of day-ahead, intermediate-term, and real-time planning, combined with the use of reserves that make it possible for PJM to respond to changing forecasts and real-time conditions that deviate from forecast. Our interest in testing much higher penetrations of wind required that we exploited these strategies, but our experiments focused primarily on increasing the availability of synchronized reserves that could be ramped (up or down) within 10 minutes.

Our base model represented PJM's default policy of providing enough spinning reserve to cover unexpected power imbalance equivalent to its largest generator, that is, 1300 MW. We then introduced additional reserve in the form of *fast* generators that could ramp up or down. Up-ramping was used to cover unexpected drops in wind, while down-ramping was used to take advantage of sudden surges in wind. These ramping reserves were expressed and tuned as single parameters, for each season, reflecting the differences in both the average and maximum loads, but also the types of weather encountered in each season.

Not surprisingly, reserves represent a powerful strategy for handling uncertainty, widely used by RTOs. An important finding of our research was that this simple industry practice could be extended to handle dramatically higher penetrations of wind than now exist, as we show below.

The challenge of planning market operations under uncertainty has attracted considerable attention from the algorithmic community, with special attention being given to a solution of the "stochastic unit commitment problem" (Takriti et al. 1996, Ryan et al. 2013). This is a particular algorithmic strategy developed by the stochastic programming community (Birge and Louveaux 2011), which replaces a deterministic forecast (used by all RTOs) with a set of scenarios that approximate what might happen. In this paper, we demonstrate that standard reserve policies used by RTOs are very effective at handling the uncertainty from even very high levels of renewables.

3 Calibration of SMART-ISO

The first task was to calibrate SMART-ISO against a base case with no offshore wind power. We chose 2010 as the base year because it was the latest year for which a complete data set of the PJM network and actual operations was available when we started the project. We chose to simulate four weeks during the year, one in each season. April and October were chosen as representative of the shoulder (lowest demand) months in spring and fall. January was chosen as representative of the winter demand, and July was picked as representative of the peak summer demand.

To focus on uncertainty in wind forecasts, we eliminated other sources of uncertainty from the simulation by (1) using actual (historical) time series of demand (loads) rather than long-term or short-term forecasts, (2) ignoring onshore wind and solar production, (3) ignoring potential generator and transmission failures, and (4) ignoring variations due to neighboring RTOs. Therefore, the only uncertainty present in this study comes from the forecasted offshore wind power. Similarly, we modeled the same level of synchronized reserve used by PJM, which was 1300 MW (the size of their largest generator). While this reserve would cover the loss of any one generator, we used it to respond to uncertainty in wind forecasts as well. We also found that modest reserves were needed to deal with what might be called "model noise" – variations in the solution arising from model truncation and from solving large integer programs. In this section we present results on the calibration of SMART-ISO, whereas in the next we discuss the results from the integration study.

We validated SMART-ISO by comparing two sets of statistics from the model to history: the hourly generation type mix and the hourly locational marginal price (LMP) averaged over the entire grid. These statistics were created for each of the four seasonal weeks. Figure 5 displays the plots of the historical hourly generation type mix for each one of the four weeks (left column), placed side-by-side with the corresponding simulated mixes (right column). We grouped the generation types in four major categories: nuclear, steam, combined-cycle/gas-turbines, and hydroelectric/pumped-storage.

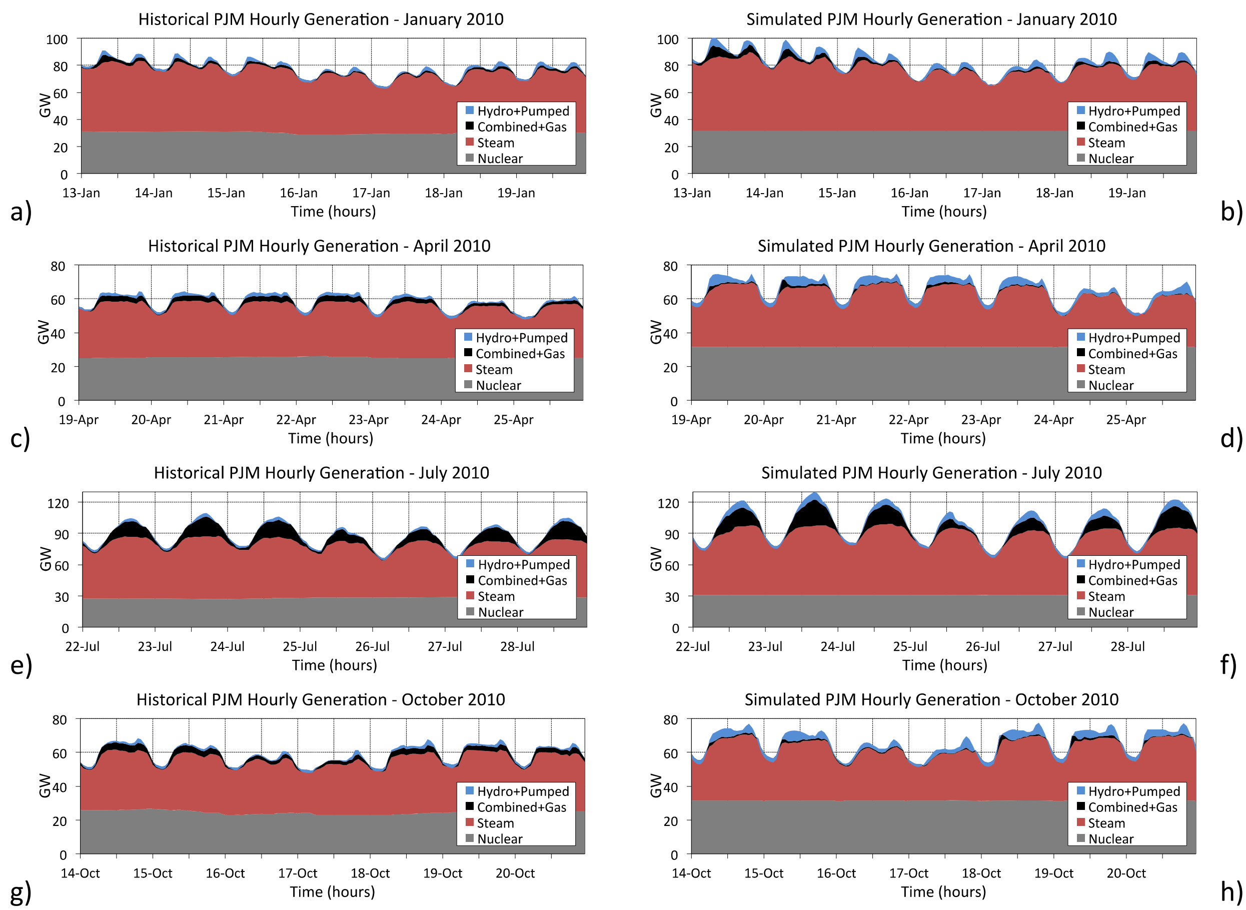

Figure 5 Comparison of historical versus simulated PJM hourly generation mixes in 2010. The scale of the values shown in the vertical axis (generated power) varies from month to month.

We note that while we had access to detailed actual generation and load data at the bus level, we were not able to map all buses to actual generators. As a result, our accounting of the total historical generation is below the total load by about 10% (this explains the higher level of generation displayed in the simulation plots). However, we can still compare the patterns of the hourly generation mix within each month, which show a good match between historical and simulated results. It is noteworthy also that the proportion of simulated generation from combined-cycle and gas turbines in the low-demand months (April and October) is lower than the actual historical values, possibly due to the fact that SMART-ISO does not take into consideration long-term contracts that may exist between some *fast* generation suppliers and PJM, but schedules all *fast* generation on an hourly basis and as needed (note this issue is *not* present in the higher-demand months of January and July). While this introduced a modest error, it was important for us to avoid capturing long-term contracts, because we cannot assume the same contracts would be in place as we model high penetrations of wind energy.

More significant, however, are the results shown in Figure 6, where we compare the locational marginal prices (LMPs – in $/MWhr) produced by the simulator with those observed in the actual operation of PJM. Please note that the LMPs produced by SMART-ISO include the energy and the transmission grid congestion costs, but not the costs due to transmission line losses or to occasional contingencies (a failure of a generator or of a transmission line, or off-grid outages). This would explain why historical prices might be spikier than simulated ones. In general, however, there is a remarkable agreement in the patterns between the network-averaged LMPs produced by the simulation and those observed in history for the four time periods in question (Figure 6).

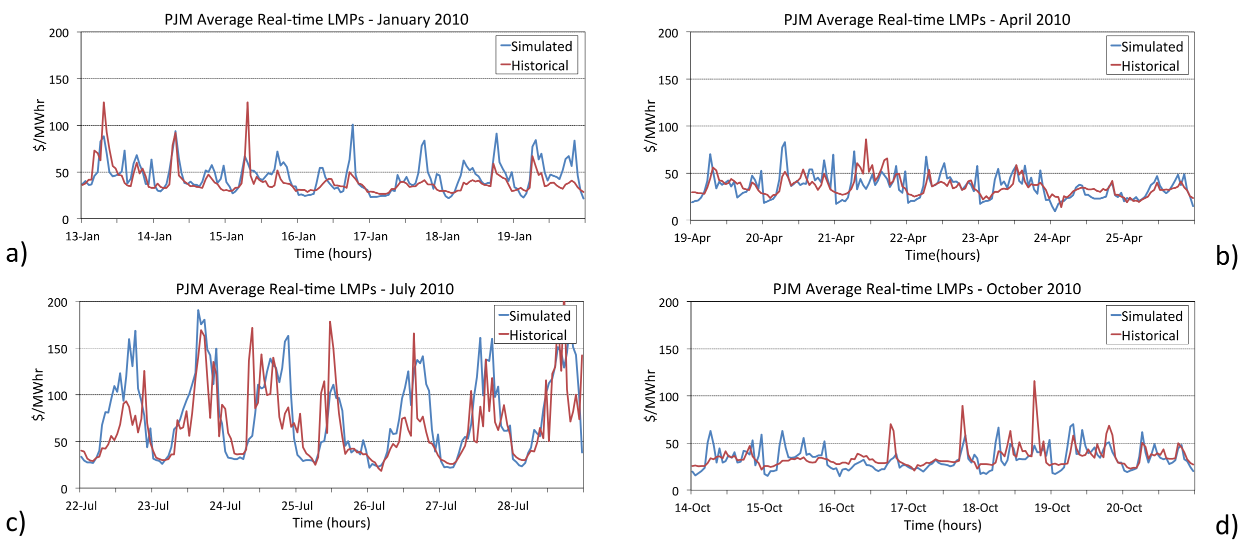

Figure 6 Comparison of historical versus simulated PJM average real-time LMPs.

On the basis of these results, we conclude that SMART-ISO closely matches the behavior of PJM, since accurate modeling of LMPs requires that all the components of the system capture real-world behavior. We note that we achieved these results without using any tunable parameters.

4 Mid-Atlantic Offshore Wind Integration (MAOWIT) Study

There are four core questions concerning the integration of large amounts of non-dispatchable energy (in this case, offshore wind) into a generation and transmission market:

1. Will the existing generation capacity be able to handle the discrepancy between the forecasts used in the commitment phase and the actual energy observed in real-time?

2. Will the *planning process* be able to handle the much higher level of variability and uncertainty (even if there is enough generation capacity)?
3. What reserve levels will be required to handle the uncertainty introduced with high penetrations of wind?
4. Will the transmission grid be able to handle the additional load?

In this study, offshore wind power, in five increasing levels of build-out, is assumed to be injected into the eastern side of the PJM grid through six points of interconnection on the coast, stretching from Central New Jersey to Virginia. Therefore, it is almost certain that the transmission grid along the Mid-Atlantic coast will hit capacity when significant amounts of energy from offshore wind are injected.

To separate the issue of grid capacity from the planning and supply of energy from a fleet of generators, we divided our study into two parts: 1) analysis with a hypothetical grid, referred to as the unconstrained grid, that has the same physical lines as the current PJM system, but thermal capacities, thus electric power carrying capacities, high enough to handle any penetration level (this is not the same as ignoring the grid, which we did not do); and 2) analysis with a grid constrained by current thermal capacities. We report on the results of these two parts in the remainder of this section.

4.1 Unconstrained grid, no ramp-up or -down reserves added

We ran the SMART-ISO simulator over one-week horizons in each of the four seasonal months, first without any offshore wind (the “current” situation, also called build-out level 0) and then with each one of the five build-out levels of offshore wind. For each level of build-out and each month, we picked three different weeks, each exhibiting different meteorological conditions. For example, different weeks might exhibit various storm systems that introduce a variety of ramping events produced by the WRF meteorological simulator. We then used our model of forecast errors to generate seven sample paths of offshore wind for each week, thus totaling 21 sample paths for each month, or 84 sample paths overall (Archer et al. 2015). The results presented henceforth were compiled from simulations using these sample paths.

Table III shows the results of adding increasingly higher levels of offshore wind into the unconstrained PJM grid. The percentage of offshore wind participation in the total generation at build-out level 1 ranged from 2.2% in the peak load month of July to 4.3% in the winter month of January, whereas at build-out level 5 (the highest) it ranged from 16.7% to 30%. The percentage of wind used, with respect to what was actually available, was as high as 94.8% at build-out level 1 in January, and as low as 56.4% at build-out level 5 in October.

The most noteworthy results in Table III, though, are the estimates of the likelihood of generation shortfall at some time during the simulated week, due to unexpected differences between the forecasted and actual wind power generation. At build-out level 1, in January and July, for instance, when the loads are higher, the probabilities that the system may operate *without* any generation shortfall during the week are much smaller than in the shoulder months of April and October. From build-out level 2 and up, in any season, it is practically certain that the PJM system as currently operated (including current reserves) will face generation shortfall at least once a week.

There are different ways in which the PJM market operation can be modified to try to cope with the uncertainty in the wind power forecasts. We tested one of them (the one that is actually already used by the ISOs to deal with uncertainties in the power generation): the addition of ramp-up and ramp-down reserves from dispatchable (*fast*) generation. The levels of these additional reserves had to be estimated for each build-out level and season of the year. In addition to these runs, we also performed experiments assuming the idealized situation of having access to *perfect forecasts*, that is, day-ahead and intermediate-term wind forecasts that are equal to the actual observed values. These experiments allowed us to get a sense of the value of better forecasting. We refer to the latter experiments as the *perfect forecast* cases, whereas the runs with the original forecasts are referred to as the *imperfect forecast* cases.

Table III: Performance metrics of the simulated, unconstrained PJM grid, with imperfect forecasts and no additional reserves, after adding increasingly higher levels of offshore wind power.

Build-out Level	Installed Capacity (GW)	Month-Year	Generation from Offshore Wind (%)	Used Wind (%)	Likelihood There Will Be Generation Shortfall at Some Time During the Week (%)	Average Peak Generation Shortfall (GW), When There Is Any Shortfall
1	7.3	Jan-10	4.3	94.8	38.1	0.6
		Apr-10	4.0	78.3	9.5	0.3
		Jul-10	2.2	92.1	81.0	2.3
		Oct-10	4.0	78.2	9.5	0.6
2	25.3	Jan-10	14.5	93.4	100.0	3.1
		Apr-10	15.1	87.7	100.0	3.8
		Jul-10	7.1	86.9	100.0	6.4
		Oct-10	15.8	90.0	100.0	2.3
3	35.8	Jan-10	20.8	93.4	100.0	5.2
		Apr-10	20.4	83.9	100.0	4.3
		Jul-10	10.3	85.6	100.0	7.7
		Oct-10	20.8	83.9	100.0	3.2
4	48.9	Jan-10	25.6	84.2	100.0	5.4
		Apr-10	24.2	74.0	100.0	4.4
		Jul-10	14.1	80.5	100.0	9.8
		Oct-10	24.1	72.1	100.0	3.9
5	69.7	Jan-10	30.0	68.7	100.0	7.4
		Apr-10	29.9	62.9	100.0	5.4
		Jul-10	16.7	68.1	100.0	12.5
		Oct-10	27.5	56.4	100.0	3.1

4.2 Unconstrained grid, with ramp-up and -down reserves added

Figure 7 shows the levels of 10-minute ramp-up and down reserves (synchronized) that were added to the system in order to guarantee that it would operate without generation shortfall. These levels were estimated (or “tuned”) through a series of simulation runs where we varied the amount of required reserves until we found the approximate minimum amount, for each month and each build-out level, such that no generation shortfall was observed in any of the 21 simulation sample paths. These reserves are in addition to the usual PJM synchronized reserve (or spinning reserve), which is currently set at 1.3 GW (the size of the largest generator operating in the system). Each plot in Figure 7 depicts the additional reserve level (in GW) required in that month, for each one of the five offshore wind build-out levels, indicated by their respective installed capacities (in GW). Note that build-out level “0” corresponds to the case with no offshore wind power, and thus the zero level of additional reserves required.

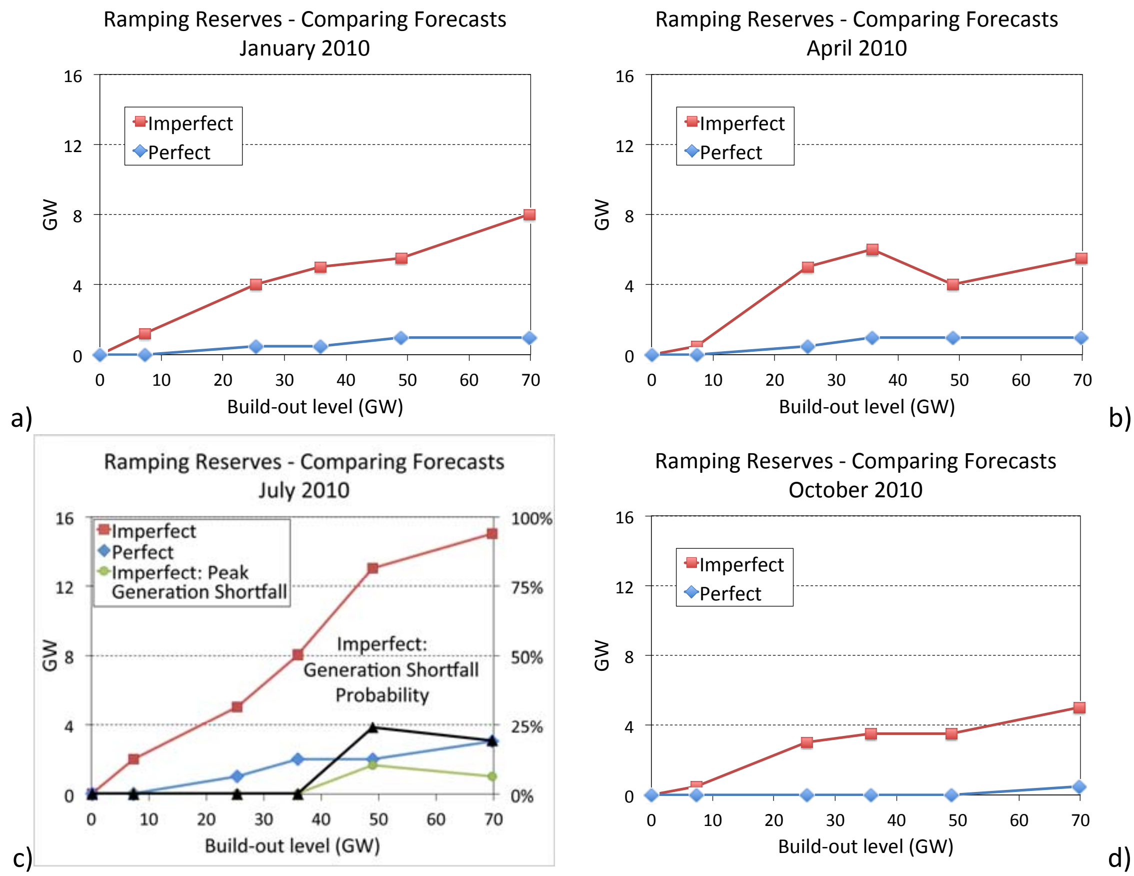

Figure 7 Ramping reserves needed for a range of build-outs, comparing the cases of imperfect and perfect wind forecasts. For the July case (c), the right axis is the reference for generation shortfall probability.

Table IV shows all performance metrics of the simulated, unconstrained grid, with additional ramp-up and down reserves, for the imperfect forecast case. With the exception of the peak summer load period, it is possible to mitigate the uncertainty in the imperfect wind forecasts, for all build-out levels, with the addition of synchronized reserves provided by *fast* generators. As expected, the higher the build-out level, the larger the required reserves. For July, they amounted to over 15 GW (>20% of wind generation *capacity*).

For the summer peak month, we were not able to find a level of ramp-up and down reserves that could completely eliminate generation shortfall for build-out levels 4 and 5, *given the available fleet of gas turbines*. Our conjecture is that the combination of a load increase in the mid-day peak hours with an unexpected, steep wind power decrease at the same time creates a situation where the existing *fast* generators might simply not have enough capacity or be fast enough to avoid generation shortfall. This is illustrated in Figure 8, where the simulated wind power unexpectedly drops by about 25 GW within 40 minutes (bottom plot), at a time when the load is still increasing (between 1 and 2pm). This creates a generation shortfall for about 35 minutes, with a peak power shortage of about 2.5 GW (top plot), *after* the additional reserves of 13 GW have already been exhausted.

Table IV: Performance metrics of the simulated, unconstrained PJM grid with imperfect forecasts after adding increasingly higher levels of offshore wind power and specific ramp-up and ramp-down reserves.

Build -out Level	Installed Capacity (GW)	Month-Year	Ramping Reserves (GW)	Generation from Offshore Wind (%)	Used Wind (%)	Likelihood There Will Be Generation Shortfall at Some Time During the Week (%)	Average Peak Generation Shortfall (GW), When There Is Any Shortfall
1	7.3	Jan-10	1.2	4.3	95.0	0.0	0
		Apr-10	0.5	3.9	77.2	0.0	0
		Jul-10	2	2.3	92.5	0.0	0
		Oct-10	0.5	4.0	77.2	0.0	0
2	25.3	Jan-10	4	14.0	90.1	0.0	0
		Apr-10	5	13.5	78.6	0.0	0
		Jul-10	5	7.4	86.0	0.0	0
		Oct-10	3	15.1	85.6	0.0	0
3	35.8	Jan-10	5	20.0	90.3	0.0	0
		Apr-10	6	16.1	67.3	0.0	0
		Jul-10	8	10.8	86.2	0.0	0
		Oct-10	3.5	18.4	73.9	0.0	0
4	48.9	Jan-10	5.5	24.6	81.4	0.0	0
		Apr-10	4	21.0	62.5	0.0	0
		Jul-10	13	14.7	82.1	23.8	1.6
		Oct-10	3.5	20.5	61.2	0.0	0
5	69.7	Jan-10	8	27.8	63.8	0.0	0
		Apr-10	5.5	23.4	49.0	0.0	0
		Jul-10	15	17.4	69.6	19.1	1.0
		Oct-10	5	21.2	43.3	0.0	0

Figure 7c shows on the right-hand vertical axis the increasing probability that there will be a generation shortfall in one week of operation in the peak summer month. The same plot also shows the average peak generation shortfall, when there is any shortfall. For build-out level 3 in July we observed no generation shortfall. Therefore we can say that the maximum build-out level of offshore wind that the current PJM market can take – without any generation shortfall – and with additional synchronized ramping reserves of up to 8 GW, is 3, which corresponds to an installed capacity of 35.8 GW.

On the other hand, if we had access to perfect wind forecasts in the unit commitment planning, we would be able to handle all build-out levels of wind, including in the summer, with just nominal amounts of additional synchronized reserves, as shown in the plots of Figure 7. In the real world there will obviously never exist perfect wind forecasts. However, these results suggest that a *future* combination of forecast improvements *with* additional synchronized reserves (and corresponding investments in the grid) could potentially allow the PJM system to operate without generation shortfall, for levels of installed offshore capacity of up to about 70 GW (which would provide for about 30% of the demand for electricity in the winter, for example). These results highlight the importance of considering uncertainty when managing energy from wind.

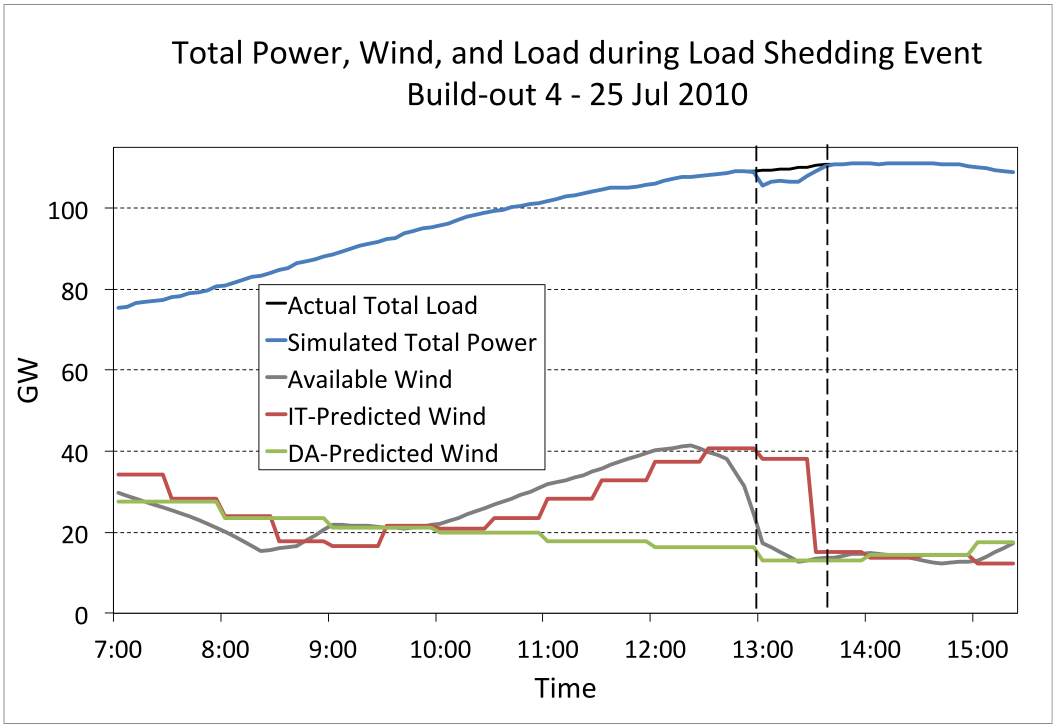

Figure 8: Total simulated power, actual load, and wind during a 35-minute generation shortfall event caused by an unexpected, sharp decrease in actual wind that was not predicted by either the day-ahead forecast (DA-Predicted) or the short-term forecast (IT-Predicted).

Figure 9 shows plots with the generation mix on the left-hand vertical axis and used wind as a percentage of available wind on the right-hand vertical axis. In the generation mix we display the percentage of energy produced by steam generators, combined-cycle/gas-turbines and offshore wind farms only, since these are the forms of generation that are mostly affected by the introduction of offshore wind. The plots on the left column depict the results for the case of imperfect forecasts, whereas the ones on the right column depict the ones for perfect forecasts.

The main difference between the imperfect and perfect forecast cases is the usage of combined-cycle/gas-turbines. In the imperfect case, this usage progressively increases with the wind build-out level, as *fast* (gas) generators are employed more as the additional reserve needed to guarantee the generation shortfall-free operation of the system. In the case of perfect forecasts, though, the usage of combined-cycle/gas generation remains essentially flat with the wind build-out, since *slow* (steam) generation can be used to balance the variability of wind.

We also note that wind utilization tends to decrease at higher penetration levels. As wind increases, we need a larger number of dispatchable generators running at their minimum operational levels, in order to guarantee that the system will be free of generation shortfalls when the wind power varies. As a result, we end up using less of the available wind. Also, for the same level of wind *and* for the shoulder months (that is, the times of the year when the difference between lowest and highest demand within a day is smaller), perfect wind forecasts tend to produce higher wind usage than imperfect forecasts.

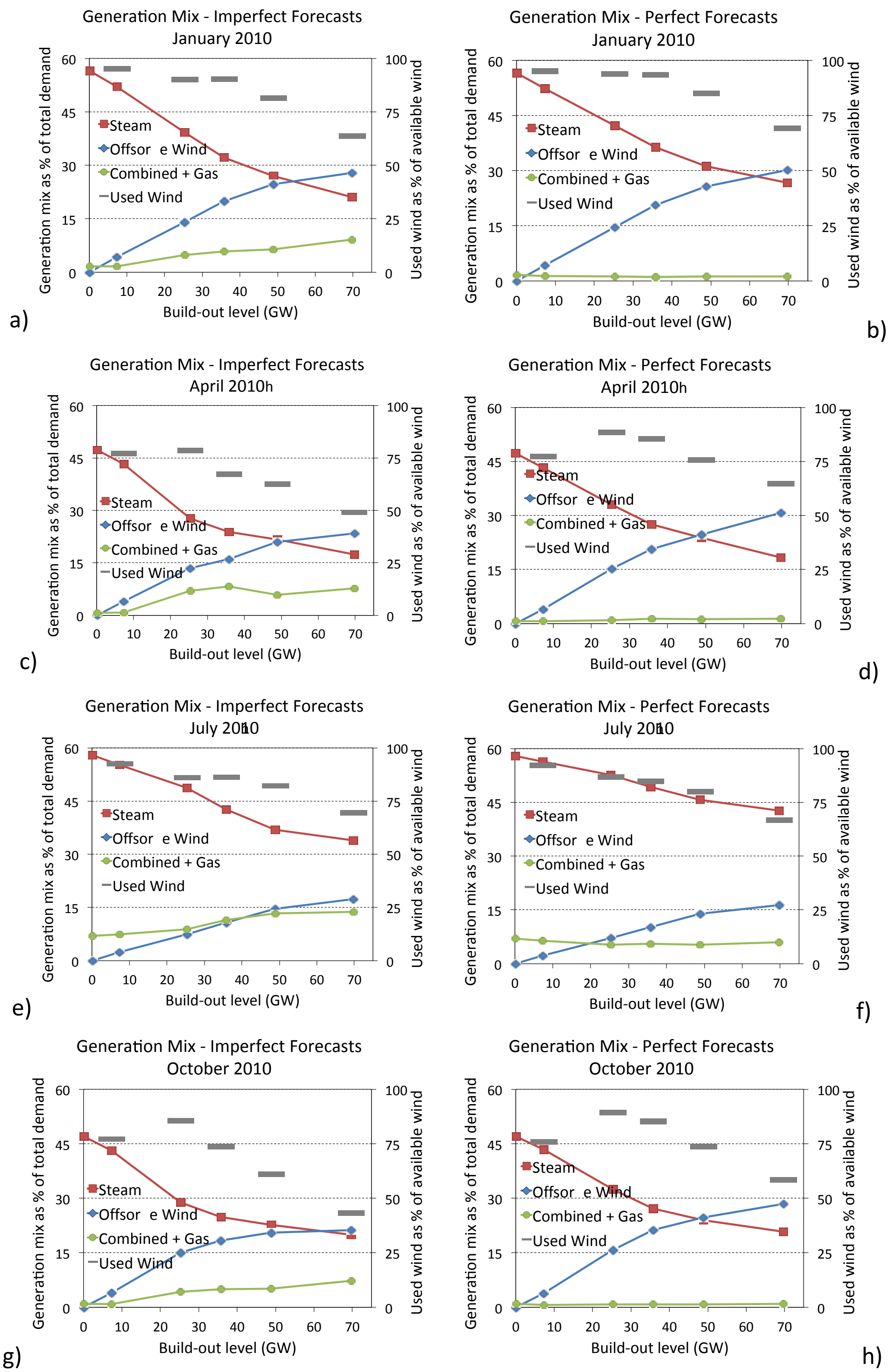

Figure 9 Generation mix and percentage of wind used for the cases of imperfect (left column) and perfect (right column) wind forecasts. The right axis is the reference for Used Wind.

4.3 Impact on settlement prices and emissions

At least two additional questions arise from the trends observed in the generation mix as the levels of wind power in the system increase: (1) what is the overall impact on the network average settlement price (based on LMPs), and (2) what is the impact on the emission of air pollutants?

Figure 10 shows that the settlement price paid to generators by PJM (averaged over all generators) decreases as the level of offshore wind power in the system increases. Note also that the prices for build-out levels 4 and 5 in the summer season (July) have been affected by the penalties imposed for the observed generation shortfall. Both in the unit commitment and in the economic dispatch models, we use large penalties to curb demand shortage, rather than hard constraints. Consequently, when the solution of those optimization problems does involve generation shortfall, the marginal value of additional available generation – the LMPs – will be artificially inflated by the active penalties.

It is important to recognize that the reduction in the LMP is not necessarily proportional to total consumer or wholesale electricity savings — for example, it does not include capital cost of either existing generation or new wind generation, which would be reflected in the capacity market. To understand consumer savings, we would need to understand the relative effects of the cost savings shown in Figure 10 against the cost of energy from new wind generation and transmission. To understand the costs or savings to society, we would need to understand those factors as well as the social costs and savings of externalities such as health damages due to pollution reductions, like those itemized below. These total economic calculations are beyond the scope of the present study.

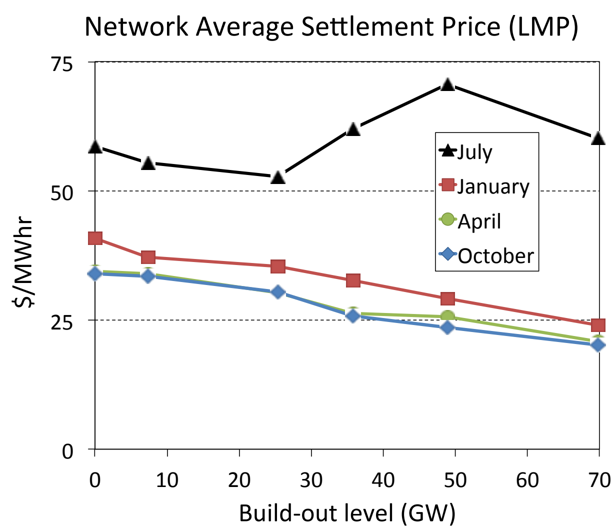

Figure 10 Network average settlement price for the cases of imperfect wind forecasts and added ramp-up and -down reserves by month.

Figure 11 shows the reduction in emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrogen oxides (NO_x), three of the main air pollutants released in the burning of fossil fuels for the generation of electricity. As expected, the higher the levels of wind power in the system, the greater the reduction in the emission of these three pollutants. Furthermore, perfect forecasts yield higher reductions in emissions than imperfect forecasts.

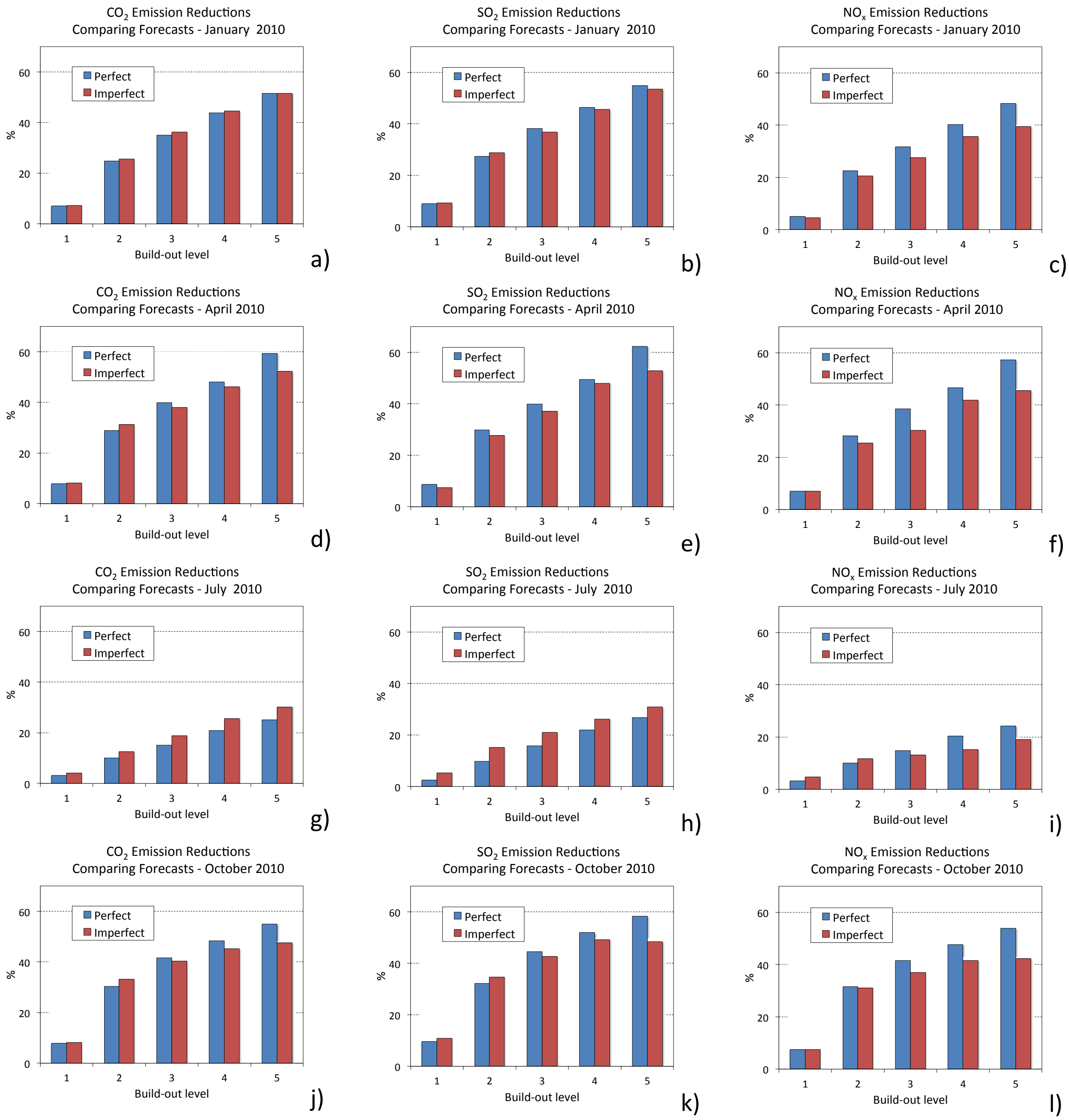

Figure 11 Emission reductions of air pollutants (CO_2, SO_2, and NO_x) for the cases of imperfect and perfect wind forecasts.

Table V summarizes the estimates in the reduction of settlement prices and emissions resulting from the introduction of the several build-out levels of offshore wind power, obtained with imperfect wind forecasts.

Table V: Summary of reductions in settlement prices and emissions for the case of imperfect wind forecasts

Build-out Level	Installed Capacity (GW)	Month-Year	Generation from Offshore Wind (%)	Network Average Settlement Price Reduction (%)	CO_2 Emission Reduction (%)	SO_2 Emission Reduction (%)	NO_x Emission Reduction (%)
1	7.3	Jan-10	4	9	7	9	5
		Apr-10	4	2	8	7	7
		Jul-10	2	5	4	5	5
		Oct-10	4	1	8	11	8
2	25.3	Jan-10	14	13	26	29	21
		Apr-10	14	12	31	28	25
		Jul-10	8	10	13	15	12
		Oct-10	15	10	33	35	31
3	35.8	Jan-10	20	20	36	37	28
		Apr-10	16	24	38	37	30
		Jul-10	11	-6	19	21	13
		Oct-10	18	24	40	43	37
4	48.9	Jan-10	25	28	45	46	36
		Apr-10	21	26	46	48	42
		Jul-10	15	-20	26	26	15
		Oct-10	21	31	45	49	42
5	69.7	Jan-10	28	41	52	54	40
		Apr-10	23	39	52	53	46
		Jul-10	18	-3	30	31	19
		Oct-10	21	41	48	49	42

We note that the average settlement prices for the month of July, for build-out levels 3 and above actually increased, rather than decrease. This is probably due, at least partially, to the significantly higher levels of usage of the more expensive *fast* generation as reserves. The addition of generation shortfall penalties in build-out levels 4 and 5 may also have contributed to further inflate the settlement prices.

Wind build-out level 3, corresponding to an installed offshore capacity of 35.8 GW, is the highest capacity at which we estimate the current PJM market can operate without any generation shortfall, *with* additional ramping reserves *and* an unconstrained transmission grid. For this level, depending on the season of the year, we obtained the following estimates:

- Energy from wind would satisfy between 11 and 20% of the demand for electricity;
- Settlement prices could be reduced by up to 24% (though in the peak summer season they may actually increase by up to 6%);
- CO_2 emissions are reduced between 19 and 40%;
- SO_2 emissions are reduced between 21 and 43%;
- NO_x emissions are reduced between 13 and 37%.

4.4 Constrained grid, no ramp-up or -down reserves added

We were also interested in evaluating the capacity of the PJM system to integrate the various build-out levels of offshore wind power with the transmission grid constrained by its current thermal capacities.

Two particular scenarios of connection between the offshore wind farms and the six onshore points of interconnection (POI) were tested:

- HVDC scenario - We envisioned the existence of a high-voltage DC (HVDC) backbone line under the sea, along the continental shelf of the Mid-Atlantic coast. The farms would be connected to this line, which in turn would be connected to the six POIs. Because new multi-terminal HVDC technologies are fully switchable, this scenario implies that each and every wind farm would be connected to each and every POI, and energy would thus be injected in the POI where needed.
- AC radial scenario - We envisioned each farm being connected by an AC radial line to one POI only, the nearest one geographically.

The HVDC backbone line, the AC radial lines and the POIs themselves were assumed to have thermal capacities sufficiently large that they did not constrain transmission.

Table VI shows statistics for the runs with the constrained grid and the HVDC backbone connection. They can be directly compared to those displayed in Table III for the unconstrained case. For build-out level 1, the amounts of wind power used in the constrained grid case, as a percentage of the total amount available in each season, are comparable to those in the unconstrained case; and so are the percentages of demand that are satisfied by electricity generated from offshore wind. This means that the injection of these relatively modest amounts of offshore wind power (between 2.4 and 4.0% of total demand, depending on the season) do not exceed the transmission grid capacities. We note that the generation shortfall observed at this level could be easily taken care of by the addition of some synchronized ramp-up and down reserves; the average peak generation shortfall, when there is any shortfall, depicted in Table VI, offers good initial estimates of what these reserves should be.

As we move to build-out levels 2 and beyond, offshore wind power becomes severely curtailed by the current grid capacity constraints, as indicated by the percentage of used wind, which drops to between 37.8 and 60.7%, as opposed to the 86.9 to 93.4% range observed in the unconstrained case. This issue can only be resolved by an upgrade in the onshore transmission lines, particularly in the coastal areas. Therefore, installing offshore wind capacity of 25.3 GW (level 2) or more, without upgrading the PJM transmission grid, would not allow integration or efficient use of these large offshore wind build-out levels.

Note also that, particularly for build-out levels 2 and 3, the likelihood that there will be generation shortfall is smaller than what was observed for the unconstrained grid case (Table III). This is due to the fact that less offshore wind power is being used in the constrained case, as a result of the wind power curtailment induced by the grid capacity constraints.

Finally, Figure 12 shows plots with the percentage of used wind obtained using the HVDC backbone and the AC radial connections to link the offshore wind farms with the onshore PJM grid. AC radial connections will cause significantly more spilling of offshore wind power (about 20% more for build-out level 1) than an HVDC backbone connection.

Table VI: Same as in Table III but for the constrained PJM grid with an HVDC backbone connection.

Build-out Level	Installed Capacity (GW)	Month-Year	Generation from Offshore Wind (%)	Used Wind (%)	Likelihood There Will Be Generation Shortfall at Some Time During the Week (%)	Average Peak Generation Shortfall (GW), When There Is Any Shortfall
1	7.3	Jan-10	4.1	91.3	47.6	0.7
		Apr-10	4.0	79.1	9.5	0.4
		Jul-10	2.4	97.1	52.4	2.2
		Oct-10	4.2	81.2	0.0	0
2	25.3	Jan-10	6.8	43.7	47.6	1.0
		Apr-10	7.4	43.2	28.6	1.3
		Jul-10	5.0	60.7	100.0	3.3
		Oct-10	6.7	37.8	33.3	0.6
3	35.8	Jan-10	7.2	32.5	57.1	0.8
		Apr-10	8.0	32.6	38.1	1.0
		Jul-10	5.7	46.9	100.0	3.9
		Oct-10	7.2	28.7	52.4	0.9

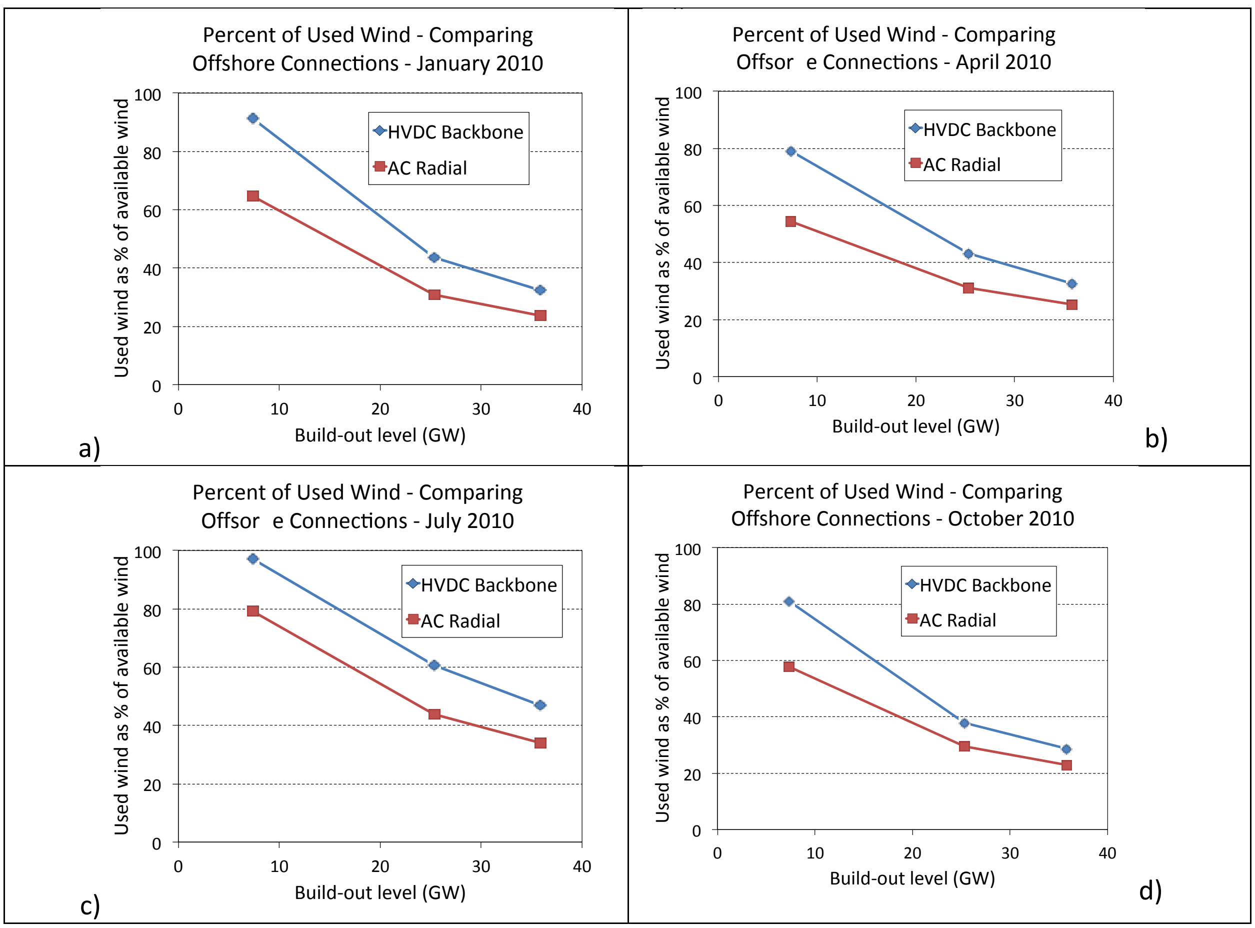

Figure 12 Percentages of used wind with HVDC-backbone versus AC-radial offshore connections.

5 Conclusions

In this paper we showed that increasing amounts of offshore wind generation from the Mid-Atlantic section of the U.S. can be integrated into the PJM market, up to a certain level, provided that additional synchronized reserves be secured and that the transmission lines be upgraded (or in our model, that the grid be unconstrained). Furthermore, we also showed that improvements in the quality of the wind power forecasts used for both day-ahead and intermediate-term unit commitment planning have the potential to enable the integration of larger amounts of offshore wind power, with less amounts of required additional reserves.

Constrained by the current capacities of the onshore transmission grid, in the PJM market, we found that:

1. Up to about 7.3 GW of installed offshore wind capacity (build-out level 1) could be integrated, with required additional synchronized ramp-up and down reserves between 1 and 2 GW in the peak summer period.
2. Wind power curtailment would range from 3 to 21%, depending on the season of the year.
3. Using AC radial connections to link the offshore farms to the onshore grid, instead of an HVDC backbone connection, would cause an additional wind power curtailment on the order of 20%.

Assuming that the onshore transmission grid were appropriately upgraded by increasing the capacities of some lines, in the PJM market, we found that:

1. Up to about 35.8 GW of installed offshore wind capacity (build-out level 3) could be integrated, with required additional reserves of about 8 GW in the peak summer period (between 3 and 6 GW in the other periods). These reserves range from 10 to over 20 percent of the installed wind generation capacity at build-out level 3.
2. In this scenario, offshore wind power would satisfy about 11% of the loads in the summer and an average of 18% in the other seasons of the year.
3. Wind curtailment would range from 10 to 33%, depending on the period of the year.

In the idealized case of having access to *perfect* wind power forecasts (that is, forecasts exactly equal to the observed wind power), the system would be able to handle up to 69.7 GW of installed offshore wind capacity (satisfying 16% of demand in the summer, and an average of 30% in the other seasons).

Finally, even with the addition of significant amounts of synchronized ramp-up and down reserves, we showed that integrating increasing amounts of offshore wind power will, in most cases, progressively lower the network-averaged settlement price of operating the PJM market, as well as consistently decrease the emissions of the three most important air pollutants associated with the burning of fossil fuels. More specifically, in the aforementioned case of integrating offshore wind power at build-out level 3, with additional reserves of up to 8 GW and an unconstrained onshore transmission grid:

- Settlement prices could be reduced by up to 24%;
- CO_2 emissions, between 19 and 40%;
- SO_2 emissions, between 21 and 43%; and

- NO_x emissions, between 13 and 37%.

We believe that SMART-ISO represents, as of this writing, an accurate reproduction of PJM's dispatch planning process, with careful attention given to the modeling of the variability and uncertainty of wind. Of course, any model, or set of simulations, requires assumptions and approximations. The most significant assumption, in our view, is that we have focused on using existing planning and forecasting processes, as well as both existing generation technology and the current fleet of generators. We feel that we are now well-positioned to undertake studies that capture the effects of changes to this planning process and of improved forecasting, in addition to investments in existing and new technologies.

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