

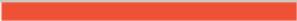
Managing Price Risk for Merchant Renewable Investments:

Role of Market Interactions and Dynamics on Effective Hedging Strategies

PREPARED BY

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All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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I. Introduction

Significant amounts of renewable resources are being developed in ISO/RTO markets beyond renewable portfolio standards (“RPS”) targets. While some of the investments in these resources are supported by power purchase agreements (“PPAs”) with utilities and large commercial and industrial (C&I) customers, an increasing share of renewables, especially wind resources, are being developed on a merchant basis without long-term contracts. Merchant wind projects face substantial market risk due to price fluctuations, which could impact developers’ ability to fulfill debt obligations and the level of investment returns. Price risk may also affect willingness, size, or timing of market entry. Customized, bilateral hedging arrangements (also called “synthetic PPA”) are gaining popularity to provide the level of revenue certainty needed for project financing. However, these arrangements can be offered at prices with heavy discounts compared to forward prices, which can be detrimental to the value captured by developers.

Using standardized financial contracts (e.g., electric or gas forwards) as a hedging instrument could be a more cost-effective way to manage market risk and achieve the level of revenue certainty needed. However, there are many complex nuances (such as correlation between wind output and spot prices, uncertainties in short- and long-run market heat rates, basis risk between the locations of forward price settlement and wind plant, and unstable statistical relationships between wind output and market conditions over time) that could ultimately affect whether or not standard contracts could be used as viable hedges, and if so, more importantly, what the dynamic strategies for their size and composition should be.

In this paper, we present a case study demonstrating how standard contracts could be used and how the design of optimal hedging terms is affected by volumetric and locational risk. Our focus is on hedging the expected value of wind output for a standalone asset. That is, we do not consider the potential effects of wind as an offset to existing risks in a portfolio of conventional power generation and fuel contract assets. However, the concepts we discuss here would also be important when managing a portfolio of assets. We conduct this demonstration using wind generation and market data in the Electric Reliability Council of Texas (ERCOT) to illustrate key concepts, though our findings would apply to most other markets, albeit with changes in the numerical parameters.

We start with the view that it is somewhat difficult to hedge merchant revenues of wind generators even with electric forward contracts, because the uncertainty in the total amount and timing of wind output creates a forecasting problem with some degree of irreducible volume risk. First, we evaluate how well electric forwards can or cannot hedge a wind facility over a 1–2 year period. Here, we demonstrate how the volume-weighted value of expected wind output at expected spot prices, less an adjustment for a likely negative correlation between variation in wind output and corresponding locational marginal prices (“LMPs”), can be used to determine the necessary hedge ratios to secure the expected spot market wind revenues. We also show that wind volume and timing uncertainty means that this hedge would intrinsically be imperfect. That is, some wind volume will be settled at spot prices because the realized volume will not equal hedged volumes, but while more risky than a fixed price PPA for all the wind output, this partial hedge may be preferable if the PPA would be at a discount.

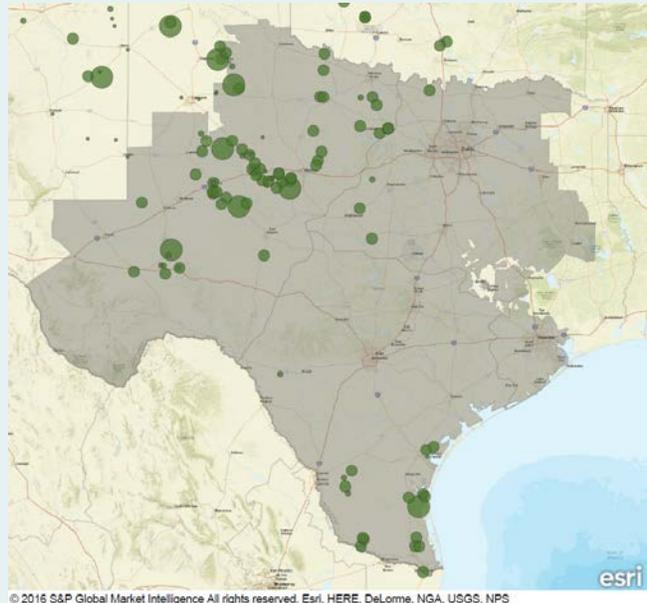
Next, we provide an assessment of whether natural gas swap contracts could serve as an effective hedge for spot revenues of wind resources over longer horizons, and if so, how the hedging strategies might be developed and updated. Relying on a gas contract instead of an electric forward involves using the spot electric revenues from the wind output to buy spot gas that is swapped for a fixed gas contract price. This conversion adds another type of risk to the wind hedging process because: (1) the spot market heat rates that effectively determine the electric prices and merchant revenues for the wind plant would generally not match the underlying forward market heat rates that set the initial gas-electric conversion ratios, and (2) the long-run market heat rates cannot be observed at all in the forward markets due to limited trading so they will have to be forecasted. Hence, they too must be estimated, but that is a tractable and familiar exercise that can be conducted with historical market data or with a structural model of projected prices. Overall, we show that gas-based hedging, with dynamic adjustments over time, can be effective as a wind value hedge.

For background, the box below provides a brief overview of the ERCOT market and wind development in the region.

Snapshot of ERCOT Market and Wind Development

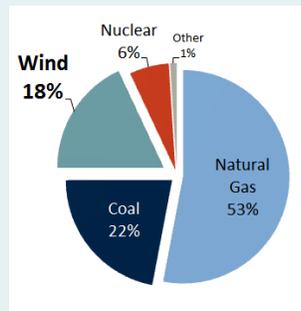
- About 90% of Texas load
- 24 million customers
- Energy used in 2015: 347 million MWh
- Peak demand: 69,877 MW (Aug. 10, 2015)
- More than 46,500 circuit miles of high-voltage transmission and 550 generating units
- More than 77,000 MW of available summer capacity
- Wind power accounts for approximately:
 - 18% of installed capacity
 - 12% of annual energy (as of 2015)
- ISO since 1996
- Nodal pricing implemented in 2010
- “Energy-only” market design (there is no separate capacity market)
- LMP contains energy and congestion components
- \$9,000/MWh price cap

Existing Wind Plants in ERCOT

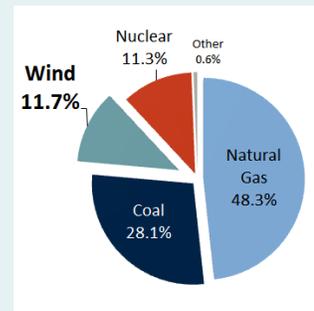


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2015 Installed Capacity



2015 Annual Energy



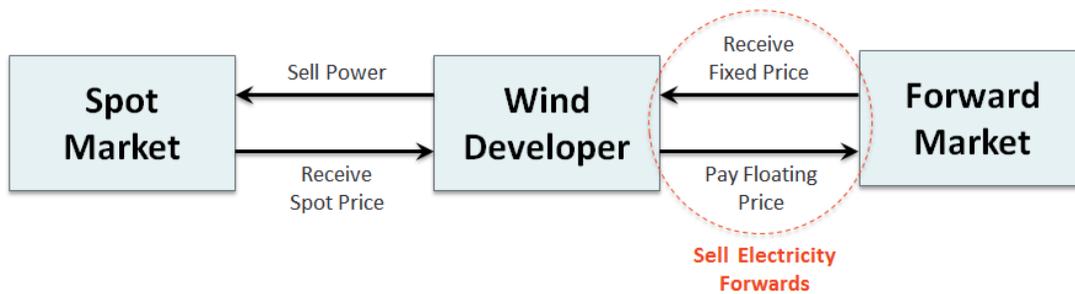
Sources: ERCOT 2015 State of the Grid Report and SNL Financials

II. Using Electricity Forwards as a Hedging Instrument

A. BASIC HEDGE STRUCTURE

The basic electric hedge for a wind plant would involve selling forward contracts to receive a fixed price in exchange with a “floating” price set based on average spot prices at the settlement point. The deviations in spot revenues would be offset to some degree by the changes in floating contract payments, which allows for a less volatile net revenue stream for the merchant wind assets.

Figure 1: Selling Forwards to Hedge Merchant Revenues



Of course, the purpose of selling forwards is to lock in expected prices rather than face full spot exposure, but for wind resources, the uncertainty in the total amount and timing of wind output creates a certain amount of irreducible volume risk. If that variance has properties correlated with other market outcomes, then that volume risk should be taken into account when hedge ratios are determined. Selling too little forward relative to likely wind volumes leaves a long position exposed to spot prices, while selling too much forward creates a short position exposed to spot prices. An effective hedge aiming to reduce variance in net revenues can be constructed by estimating the hourly output pattern for a MW of wind in a given month and valuing that at the expected volume-weighted spot prices of electricity in those hours. That expected revenue per MW-month would then be divided by the fixed cost per MWh of a standard forward contract and adjusted for the correlation between wind output and LMPs to find the required number of contracts needed for the hedge.

For example, suppose that in March a wind plant is expected to have a 50% capacity factor in off-peak hours, and that its output is expected to be randomly and uniformly distributed across all those off-peak hours. Then, this output would have the same expected price as the off-peak forward price (assume at \$25/MWh), but since it will have 0.5 MW of average output per MW of installed wind capacity, you need half as many hedge contract MWs as you have wind MWs. If

the wind output is not uniformly distributed, but is more likely to be concentrated in hours with the lowest spot prices (say, averaging \$10/MWh), then you can expect only \$5/MWh over all off-peak hours, so you need 0.25 hedge MWs per wind MW. Similar calculations would be done for on- and off-peak hours in each month, likely with different hedge ratios because of the differences in relationship between the expected wind output and spot prices.

Electric hedges are intrinsically imperfect, with residual risks arising from:

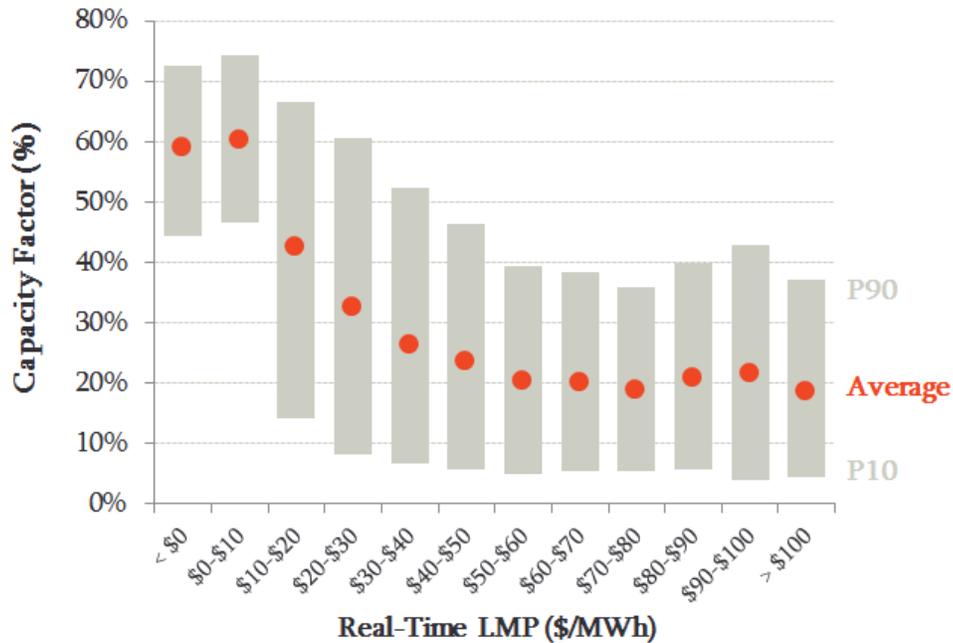
- The uncertainty in wind output quantity per month;
- The hourly pattern of when that wind output quantity will be realized within the month;
- The hourly pattern of spot prices; and
- Any congestion risk between the location of the electric forward price settlement and the bus that wind plant is physically connected to.

These factors combine into a net uncertainty surrounding the realized wind revenues vs. the hedge payoff. The realized spot prices in the realized hours of wind output will not match the floating amount needed to be swapped for fixed contract payments, and therefore, there will be a net gain or loss. If the variances in wind output are negatively correlated with the price of spot power (i.e., less wind leading to higher prices, and vice versa) then net gains and losses do not balance out, resulting in an expected loss from the error terms. Overall, the expected spot revenues would be lower and the hedge ratios (and value of the wind plant) would also be somewhat lower.

B. EFFECTS OF WIND-PRICE CORRELATION

On average over a 5-year period during 2011–2016, the wind generators in ERCOT ran at a capacity factor of approximately 60% in hours when hub prices were negative or between zero and \$10/MWh, but only 20% when prices reached at \$50/MWh or higher. Thus, there is a negative correlation. Figure 2 below demonstrates this negative correlation in the form of a stylized scatter-plot of the wind output and spot prices. The nature of the wind-price correlation would be influenced by the aggregate wind output, and therefore, it could vary significantly from one region to another depending on the total amount of wind resources available in the system relative to load at the time. In regions with higher wind penetration (e.g., ERCOT, SPP), spot prices are likely to be strongly correlated with wind output. On the other hand, in regions with more modest levels of wind development (e.g., ISO-NE, PJM), the relationship between wind output and prices would be less evident.

Figure 2: Relationship between ERCOT Regional Wind Capacity Factors and Real-Time LMPs
 (Based on Historical Hourly Data from January '11 through November '16)

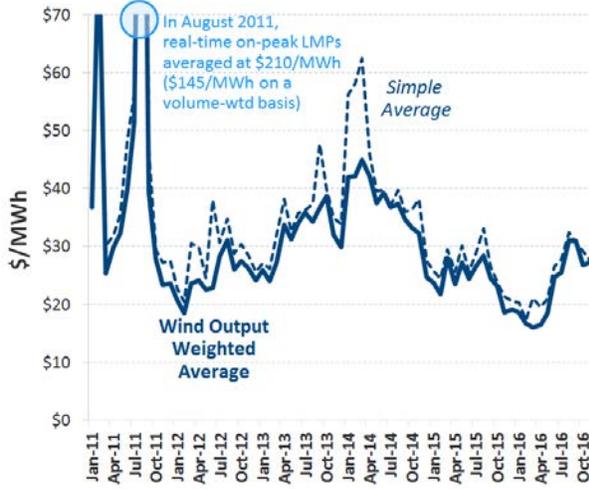


Source: Calculated based on data compiled by ABB, Inc., Energy Velocity Suite (2016).

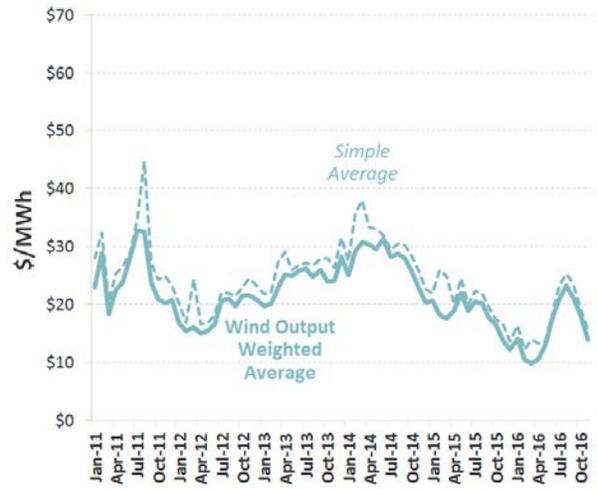
Depending on wind-price correlation, the expected revenues collected by a wind plant could be much lower than the expected spot price multiplied by expected wind volume. As shown in Figures 3 and 4, the wind-output, volume-weighted monthly average LMPs for wind generators in ERCOT have been persistently below the simple average LMPs over the past 5 years, with the difference as large as 30–40% in some months. This means that if the hedge quantities were set to match expected wind output, then the spot market revenues would often fall short compared to the floating contract payments. Setting the hedge quantities based on expected revenues while recognizing the effects of negative wind-price correlation is essential to reduce the revenue shortage described above and the associated exposure to spot prices.

Figure 3: ERCOT Monthly Average Real-Time LMPs

(a) On-Peak



(b) Off-Peak

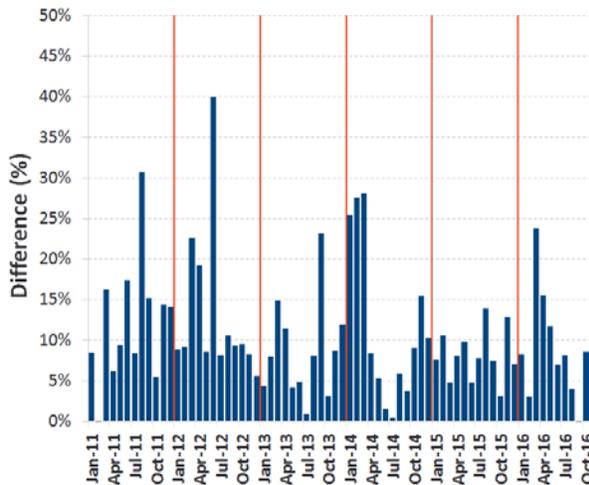


	2011	2012	2013	2014	2015	2016 Jan-Nov
Simple	\$56.2	\$28.8	\$35.1	\$43.1	\$26.2	\$24.9
Wind-Wtd	\$43.7	\$24.3	\$31.7	\$38.0	\$23.8	\$22.4
Diff.	\$12.6	\$4.5	\$3.4	\$5.2	\$2.5	\$2.5
	22%	16%	10%	12%	9%	10%

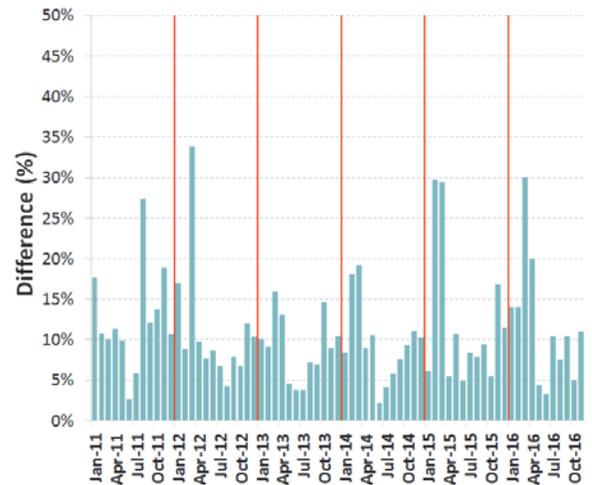
	2011	2012	2013	2014	2015	2016 Jan-Nov
Simple	\$28.3	\$20.8	\$26.8	\$30.6	\$20.7	\$17.7
Wind-Wtd	\$24.6	\$18.3	\$24.2	\$27.6	\$18.0	\$15.4
Diff.	\$3.7	\$2.5	\$2.5	\$3.0	\$2.7	\$2.3
	13%	12%	10%	10%	13%	13%

Figure 4: Discount of Wind Output Weighted Prices Relative to Simple Average Prices

(a) On-Peak



(b) Off-Peak



Source: Calculated based on data compiled by ABB, Inc., Energy Velocity Suite (2016).

While it is clear that there is a net “discount” for wind output from simple average prices, the overall magnitude of this discount varies significantly from one month to another, with possibly some seasonality. Some of this variation is random, but some is probably recurring and predictable, due to seasonal norms for peak wind vs. peak market prices, which ought to be taken into account as a part of the hedging decisions.

C. EFFECTS OF SCARCITY PRICING

Electric prices can be substantially higher during scarcity conditions compared to other periods. For example, in ERCOT the real-time LMPs may increase up to \$9,000/MWh in order to attract new generation investments under an “energy-only” market design without a capacity market. In other ISO/RTO markets, the price caps are typically lower, but spot prices are allowed to reach at least \$1,000/MWh under the current rules. While timing, frequency, and magnitude of price spikes are uncertain and can vary widely from year to year, electric forward prices typically include a “premium” to account for the effects of price spikes during occasional scarcity events.¹ For example, on-peak futures at ERCOT North Hub for August 2017 traded at approximately \$65/MWh as of November 2016, while the marginal cost of generators to set prices in non-scarcity hours was only \$25/MWh. This suggests a market expectation that scarcity events in August 2017 will increase average on-peak prices by \$40/MWh, corresponding to having 15 hours at \$1,000/MWh or fewer hours at even higher prices.

If a wind plant sells forwards to hedge prices in August 2017, it would collect a fixed payment of \$65/MWh in exchange with a floating contract payment to be determined based on average of realized spot prices. Of course, depending on market conditions, the floating payments can be wildly different than the fix payments collected; however, what matters more is how floating payments compare against spot revenues. If the wind plant were to run above expected levels during high-priced hours, its spot revenues would more than offset floating payments. However, price spikes often occur due to a combination of extremely high demand and limited supply, during which wind resources tend to run less (e.g., very hot, still days). So it is far more likely that the spot revenues of the wind plant would remain below the floating payments (on a \$/MWh basis). For the example above, suppose that the wind plant is estimated to run at 40%

¹ The term “premium” here is not used as a risk compensation. Rather it is an upward adjustment of the expected value for somewhat rare events, but since these events do not usually occur, the adjustment can appear to be a risk premium on prices.

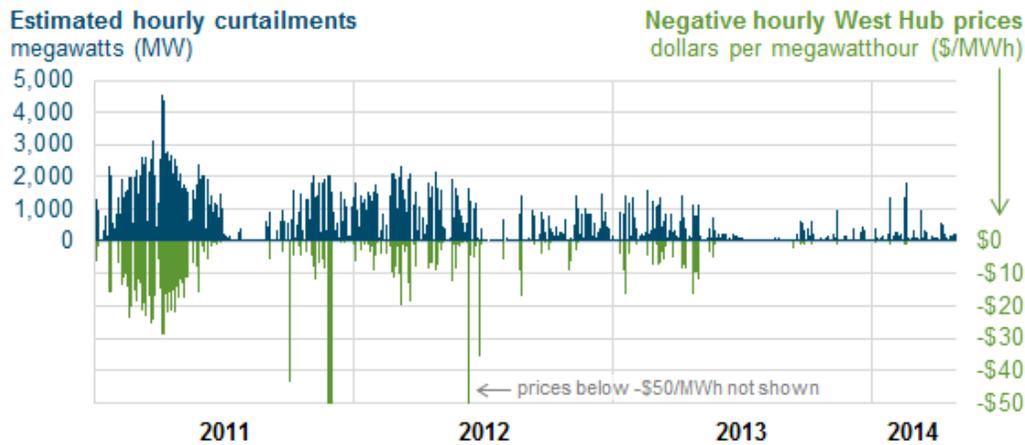
capacity factor on average, but only 10% during scarcity hours in August 2017. If so, it would collect only $\frac{1}{4}$ of the scarcity premium (or \$10/MWh) on average, resulting in expected spot revenues of \$35/MWh calculated as the average of \$25/MWh in non-scarcity hours *plus* an additional \$10/MWh for scarcity premium. In this case, the effective hedging strategy would be to sell forwards in the amount of $\$35 \div \$65 = 53.8\%$ of the expected average monthly wind generation, which translates to approximately 0.215 hedge MWs per wind MW.

D. RISK PARAMETER ESTIMATION CHALLENGES

As mentioned earlier, the wind-price correlation is largely driven by the aggregate wind output in the system. A specific wind plant may have a very different output pattern compared to the aggregate wind, which means that certain risk characteristics identified based on regional wind data may not directly apply to an individual site. For effective hedging, it is therefore important to understand the correlation of wind output at specific facilities with the aggregate output, which creates a complex data development problem in itself because wind data is typically reported at an aggregate (region-wide) level for a growing fleet and does not allow detailed analysis of a performance or risks of a given fixed facility.

In addition, market conditions continuously change over time, which may affect the identified relationships going forward. For example, Figure 5 below illustrates how negative LMPs and wind curtailments in western Texas have declined over time due to considerable expansion of the transmission system (the CREZ lines in Texas) and changes in market design (such as 5-minute dispatch, more centralized scheduling, and integrated wind forecasting). As a result, it is often challenging to find a long period of history that is likely to exemplify patterns going forward.

Figure 5: ERCOT Wind Curtailments and Negative West Hub Real-Time Electricity Prices
(January 2011 – April 2014)



Source: EIA (2014).

Overall, the estimation challenges due to year-to-year variations of market conditions and forward expectations make it particularly difficult to find a static hedging strategy that can be used on auto pilot. Thus, an effective hedging process needs to incorporate unexpected changes in the market and adjust the identified risk parameters dynamically.

III. Using Natural Gas Swaps for Partial but Longer-Term Hedging

A. HEDGE CONCEPT AND DESIGN ELEMENTS

Electric forwards are typically traded for only 1–2 years out, or at least beyond that horizon they tend to be fairly illiquid, so they do not readily support much long-term hedging (and they may not be reliable risk-adjusted predictors of likely spot outcomes). On the other hand, gas contracts are often available and liquid for longer delivery periods (especially at Henry Hub) and so they can serve as a potential hedging instrument to provide increased revenue certainty over a longer future period. The main concept for using them is the same, except that instead of swapping the real-time spot value of the wind output for an electric forward, the electric spot market revenues of the wind asset are used to buy spot gas scaled by the expected market heat rate (HR) to settle against a fixed gas forward purchase. The on-peak vs. off-peak distinction in the hedging contract is lost, since gas is not differentiated by time of delivery, so total monthly wind revenues must be used to scale the number of gas contracts needed.

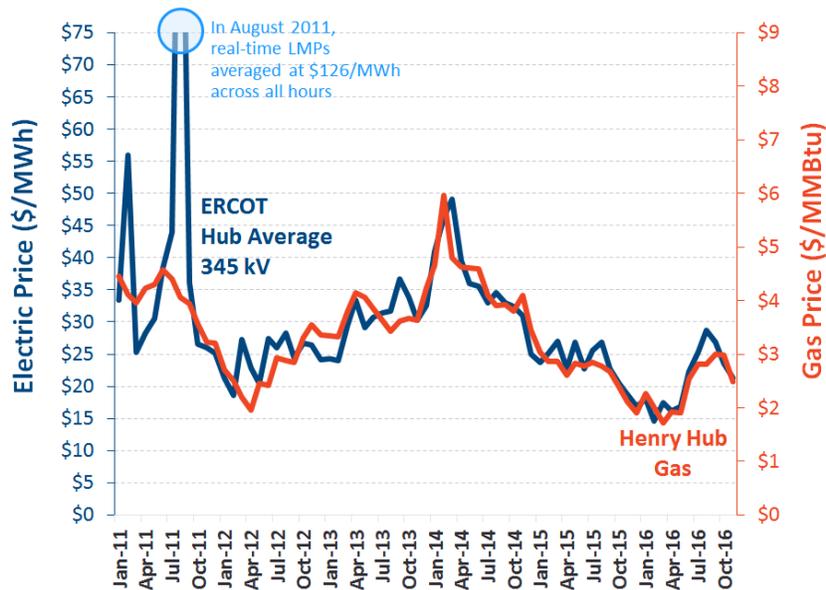
The risk factors listed for electric hedging also apply here, but there are several additional hedge design elements and uncertainties to consider:

- The expected correlation of gas and electric forward prices over time, and whether that relationship is sufficiently strong that gas forwards can be a good proxy for an electric forward contract;
- The stability of the expected market HR (the long-run market HR cannot be observed at all in the forward markets due to limited trading of the electric contract so they will have to be forecasted, recognizing how future wind entry itself will tend to create a downward pressure); and
- Gas basis risk between the settlement location of the gas contract and the delivered gas for the plants setting prices at the wind production node.

B. GAS-ELECTRIC PRICE CO-DEPENDENCE AND OPTIMAL HEDGING

In most of the U.S. markets, spot gas and electric prices have become strongly correlated due to increasing share of gas-fired generators as the price-setting technology. For example, in ERCOT, as shown in Figure 6, average real-time LMPs and spot Henry Hub gas prices have often moved together over the past 5 years except during extreme weather conditions in 2011, which led to significantly high LMPs that are disconnected from gas prices. While electric prices in most regions are also highly correlated with gas prices, the strength and timing of this relationship varies depending on regions' electric supply mix, market characteristics, and gas price hub. For instance, in ISO-NE, even though gas-fired plants set prices in most hours, spot electric prices often do not increase as much as gas prices in winter due to dual-fuel generators that can use oil instead of gas when gas prices spike unexpectedly.

Figure 6: ERCOT Historical Gas and Real-Time Electricity Prices

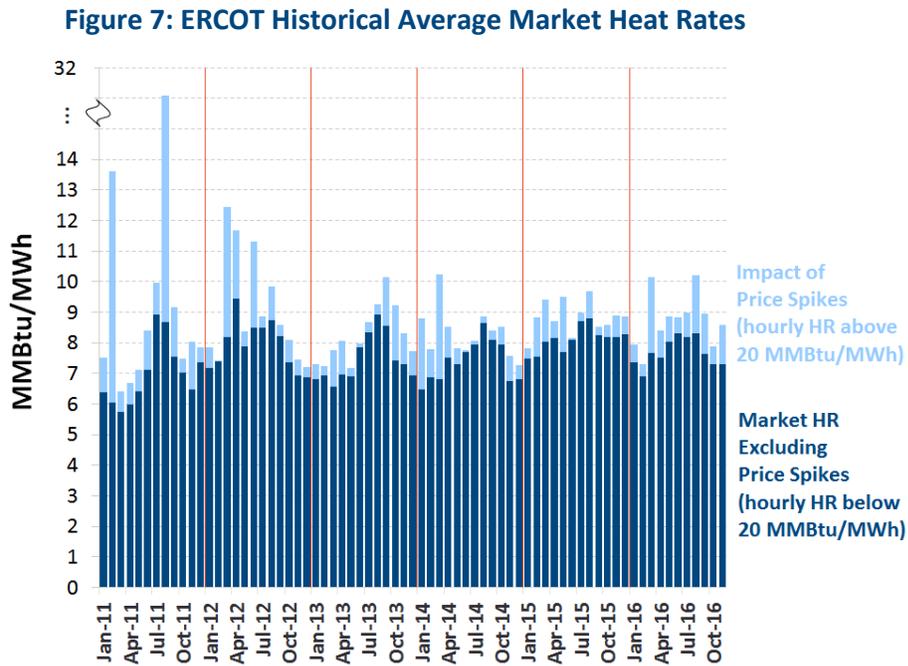


Sources: Calculated based on data compiled by ABB, Inc., Energy Velocity Suite and SNL Financials (2016).

Gas-electric price relationships can be captured by analyzing the “implied” market HRs (ratio of electric to gas prices). In ERCOT, monthly average market HRs have fluctuated considerably within a range of 6–32 MMBtu/MWh during 2011–2016. As shown in Figure 7, the changes in market HR were largely driven by price spikes when there is scarcity in the system. When such price spikes are excluded, the average market HR across the remaining hours follows a relatively steady and seasonal pattern within the historical 5-year period, ranging from around 7 MMBtu/MWh in the winter up to 8–9 MMBtu/MWh in the summer.

If market HRs were known and fixed in future periods, then it would be simple to substitute gas contracts for electric forwards to achieve equivalent hedging with either one. Take the example described on page 9, in which the wind plant expects to have a 40% capacity factor and \$35/MWh spot revenues during on-peak hours in August 2017 (below the \$65/MWh forward price due to negative wind-price correlation). In this case, the effective hedging strategy would require 0.215 hedge MWs per wind MW. The gas forwards for August 2017 traded at approximately \$3/MMBtu as of November 2016, which implies expected on-peak HR to be 21.7 MMBtu/MWh including expected effects of scarcity prices. If market HRs were to be fixed at that level, then the equivalent hedging strategy using gas swaps would be $0.215 \times 21.7 = 4.67$ hedge MMBtus per wind MW. Under this strategy, the expected spot revenues would match fixed charges associated with the gas swap contracts.

For example, a 100 MW wind plant would expect $40\% \times 100 \text{ MW} \times 368 \text{ hours} = 14,600 \text{ MWh}$ of total generation during on-peak hours in August 2017, and at $\$35/\text{MWh}$, it would expect to collect $\$510,000$ of spot revenues over that period. On the other hand, it would sell $467 \text{ MMBtu} \times 368 \text{ hours} = 170,500 \text{ MMBtus}$ of gas swap contracts, and at $\$3/\text{MMBtu}$, pay $\$510,000$ for the fixed contract charges.



Sources: Calculated based on data compiled by ABB, Inc., Energy Velocity Suite and SNL Financials (2016).

As illustrated in Figure 7 above, market HRs are variable over short and long timeframes, creating conversion risk for using gas swaps as a surrogate. The expected market HRs can be observed directly over the timeframe when both electric and gas forward contracts are traded. However, electric forwards are often traded for only near-term (up to a few years out) while gas forwards extend farther into the future. Neither one is visible over 20 years, so market HRs and their associated risk characteristics are needed to be forecasted. A fundamental model of power market marginal costs or market clearing prices would typically forecast only the portion of the market HRs that are not linked to price spikes (shown as dark blue in Figure 7), which would understate the likely value of market HRs and result in selling fewer gas contracts than needed. Thus, it is important to capture the effects of price spikes on market HRs either by explicitly

modeling scarcity events in a probabilistic framework, or by analyzing the past statistical relationship among price spikes, system characteristics, and market drivers.²

The forecasted market HRs will have some estimation error, whether simply extrapolated or fundamentally modeled, and they will likely change over time depending on prevailing conditions. If/when they change, there will be a corresponding increase or decrease in the quantity of gas contracts needed to replicate an electric hedge. Specifically, if the expected market HR rises, then the same quantity of wind output becomes more valuable and more gas contracts are needed to hedge it. In contrast, if the expected market HR declines, then fewer contracts are needed. As summarized in Figure 8, the market HRs could change systemically for many reasons over a long horizon. For instance, increasing penetration of renewables or newer, more efficient gas-fired generation plants could lower market HRs, while coal plant retirements, load growth, or carbon pricing could raise them. Though these shifts can be forecasted structurally with some useful accuracy, it is quite difficult to anticipate precisely when or to what extent any of these events will occur, suggesting that a long-dated hedge struck with a fixed HR will not track the market value of the wind output. Consequently, a series of hedges or HR-indexed hedges (if available) might be more effective.

Figure 8: Examples of Market Drivers That Could Systematically Change Market Heat Rates

Market Driver	Likely Impact
Increased penetration of renewables	(-) Lower HR
Addition of new efficient gas generation	(-) Lower HR
Coal plants retirements	(+) Higher HR
Load growth	(+) Higher HR
CO ₂ price	(+) Higher HR

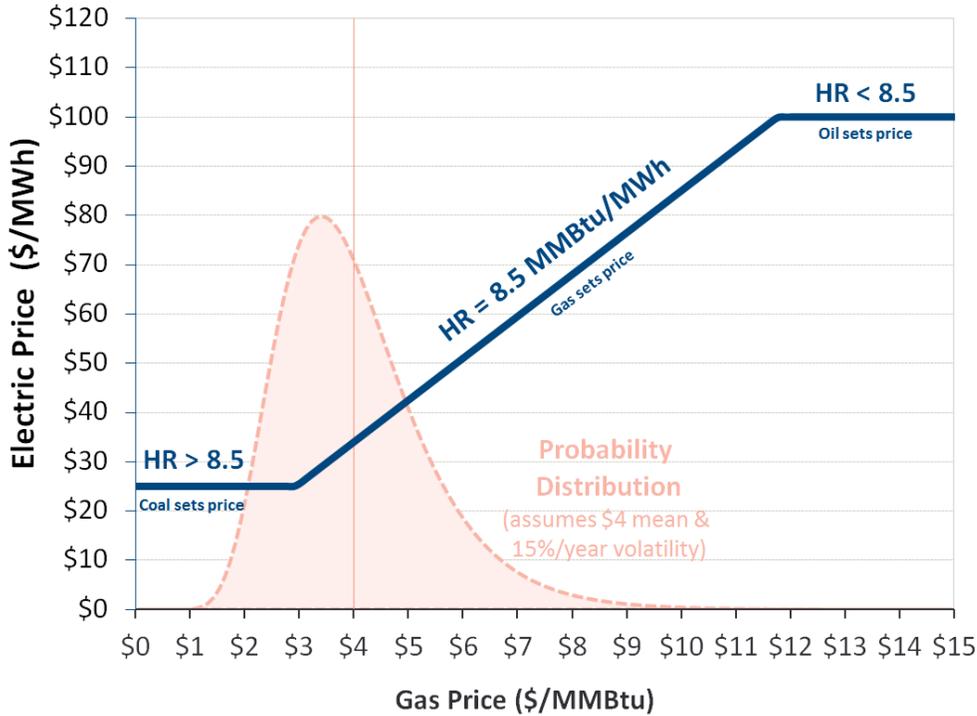
² For example, see the Brattle study below for a detailed description of the probabilistic modeling framework used for evaluating market conditions and resource adequacy in ERCOT to determine the economically optimal reserve margin in the region.

Newell, Spees, Pfeifenberger, Karkatsouli, Wintermantel, and Carden, “Estimating the Economically Optimal Reserve Margin in ERCOT,” report prepared for The Public Utility Commission of Texas, The Brattle Group, January 31, 2014.

The hedging decisions should also consider that the errors in forecasting HR may be correlated with unexpected changes in gas prices. For example, in coal-heavy regions, very low gas prices (as experienced in 2012) can push gas plants to be infra-marginal while it would make coal plants to set prices more often. This would result in market HR to be higher because the electric prices do not decrease as much as gas prices do. On the other hand, in regions with considerable amounts of oil-fired generation capability, unexpected gas price spikes can lower market HR because electricity prices would not rise as much as gas prices under extreme conditions (e.g., during the Polar Vortex in 2014). Such examples illustrate that gas prices and market HRs could be negatively correlated at certain price levels, which may affect the optimal hedging strategy for wind plants.

Suppose average electric prices in 5 years would be set by: (1) gas plants with a HR of 8.5 MMBtu/MWh when the gas prices are within the range of \$3–\$12 per MMBtu; (2) coal plants expected to run at \$25/MWh when gas prices drop below \$3/MMBtu; or (3) oil plants expected to run at \$100/MWh when gas prices exceed \$12/MMBtu. This relationship is illustrated in Figure 9 below. Also, suppose gas forwards for the same period trade at \$4/MMBtu and gas price volatility is estimated to be 15% per year based on options and other market data. Assuming a lognormal shape, the resulting probability distribution is shown as the pink area on the same chart. In this stylized example, even though the market HRs are stable at 8.5 MMBtu/MWh in most scenarios, the expected market HR would be 9 MMBtu/MWh which is higher due to the breakdown of gas-electric price relationship at lower gas prices. Thus, the hedge ratio should be calculated based on a market HR of 9 MMBtu/MWh, instead of 8.5 MMBtu/MWh, which would require selling more gas swaps. Alternatively, if gas prices were centered around a higher level instead (e.g., \$10/MMBtu), then the expected market HR would be fall below 8.5 MMBtu and fewer gas swap contracts would be needed for hedging.

Figure 9: Illustration of a Negative Relationship between Gas Prices and Market Heat Rates

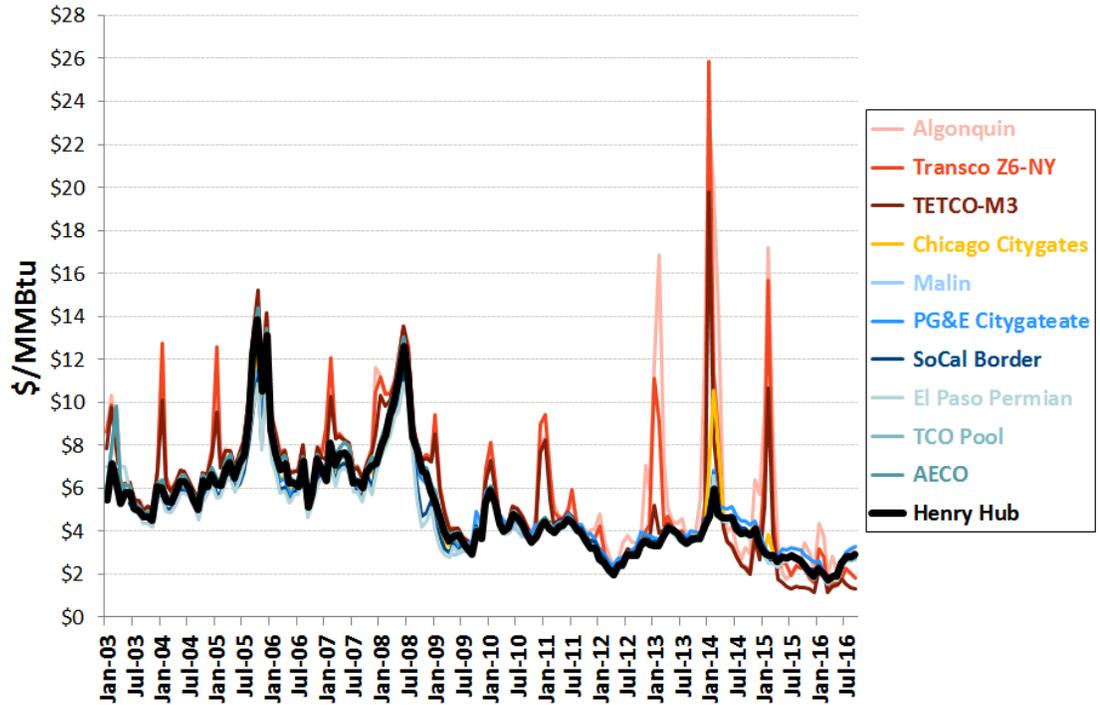


C. EFFECTS OF GAS BASIS RISK

The price differential between gas contract hub and marginal gas resources setting electric prices at the wind production node may create an additional “basis” risk that needs to be considered as a part of the hedging strategy. If this is material, then the gas hedges need to also cover delivery risk, for at least the expected quantity of equivalent gas, but that need will be uncertain over time.

As shown in Figure 10 below, while the gas basis in the Texas area has not been very volatile in recent years, other parts of the country have seen substantial short-term basis risk – sometimes much larger than the price variability at Henry Hub. With LNG exports likely to increase, as well as the increased reliance and access to new gas resources in many parts of the country, basis risk could be significant over the long-term.

Figure 10: Historical Monthly Average Gas Prices at Selected Hubs



Sources: Calculated based on data compiled by SNL Financials (2016).

If available, selling basis swaps could hedge gas basis price risk faced by wind plants by providing net payments (either positive or negative) to largely offset the effects of unexpected changes of locational gas prices on electric revenues. However, gas basis swaps are often traded for only a few years or less. In areas with significant basis risk (e.g., the Northeast), this could limit the viability of gas contracts' to offer longer-term hedging compared to electric forwards.

Without basis swaps, delivery risk could be partially mitigated by adjusting the total amount of Henry Hub gas contracts sold. For example, if Henry Hub forwards trade at \$4/MMBtu in a given month and gas basis differentials are expected to be \$1/MMBtu over the same period, then selling 25% more of Henry Hub contracts (relative to the amount that would have been needed without basis risk) would lower the overall risk exposure assuming that Henry Hub prices are somewhat positively correlated with gas basis differentials.³

³ Note that this strategy would be equivalent to estimating the market HRs in reference to Henry Hub gas prices instead of delivered gas prices.

D. EFFECTS OF CO₂ PRICES

Increasingly ambitious climate and environmental policy goals and consumer preferences are transforming the electric power industry. While there are significant uncertainties about when or what kinds of policies may eventually be introduced, it is very plausible that in many regions, some kind of environmental or climate protection policy will affect the value of wind plants over their useful lives. For instance, several states in the Northeast have already have established carbon dioxide (CO₂) pricing under their Regional Greenhouse Gas Initiative (RGGI), and California's Assembly Bill (AB) 32 cap-and-trade program is spreading in participation to parts of Canada. The interaction of CO₂ constraints with power prices, though regionally distinct in marginal sensitivity, is fairly well understood, so it is useful to think about what a carbon constraint might do to a wind hedging practice when/where implemented.

First, we note that short- and long-run effects of CO₂ prices on markets could be very different. Initially, CO₂ prices would likely be positively correlated with gas prices especially in coal-heavy regions, because higher gas prices would increase CO₂ prices needed for coal-to-gas switching. However, over a longer horizon, this relationship could change and perhaps even reverse, since higher gas prices would raise electricity prices and accelerate future renewables entry, which would then reduce CO₂ prices to meet emission goals. Note also that neighboring regions' CO₂ policies can affect the value of a wind asset, even if the region where the wind generator is located has no such policy in place.

The relationship between gas and CO₂ prices could alter appropriate hedge ratios for wind plants using gas contracts. If positively correlated (due to short-run gas-coal substitution effects, as well as gas being on the margin in many market areas) then it is more likely that the unexpected changes in future electric prices would move together with the gas price forecasting errors. Accordingly, more gas contracts would be needed for hedging if CO₂ constraints were expected to be imposed or tightened. On the other hand, a negative gas-CO₂ price correlation (driven by long-run dynamics) would have the opposite effect resulting in fewer gas contracts needed. Forward markets can provide some information on immediate effects of CO₂ prices, but only when both electric and gas forwards are traded. Therefore, cognizant of planning and hedging horizon, the risk parameters needed to characterize future CO₂ price risk and capture gas-CO₂ price interactions will have to be forecasted using a structural, fundamental-based market model to simulate a wide range of scenarios.

IV. Conclusion

Increasing amounts of renewables, especially wind, are being developed, often in excess of states' RPS targets and increasingly without PPAs. Such merchant projects are exposed to significant market risk as they need to absorb price fluctuations and anticipate how their own production outputs may or may not vary favorably in relation to market tightness. This risk can create a barrier for initial financing and can impact the economic feasibility of the projects. In response, customized, bilateral hedging arrangements are gaining popularity, but they could be offered at prices with heavy discounts that reduce the value of the projects from the developer's perspective.

In this paper, we investigated whether, and if so, how, standardized financial contracts (e.g., electric or gas forwards) could be used as effective hedging instruments for renewables (wind in the examples studied) and what the dynamic strategies for their size and composition should be. As summarized in Figure 11, there are several nuances that can be factored into wind hedging strategies, ranging from very rudimentary approaches to ones that require complex models to analyze trends in market dynamics and their effects on wind revenues. A basic hedge would involve selling electric forwards at expected wind output levels (**Stage 1**); however, this could create a revenue shortage if wind output is negatively correlated with market prices, because realized spot revenues would often be lower compared to the floating contract payments needed. Setting the hedge quantities based on expected revenues with a negative adjustment for wind-price correlation (**Stage 2**) can reduce revenue shortage and the associated exposure to spot prices. Price spikes during scarcity events could result in forward prices to include a "premium" to account for expected impact of such events. In this case, the value of this forward price premium and the portion of it that will be captured by the wind plant in the spot market needs to be estimated (**Stage 3**), which would likely lower the appropriate hedge ratios because wind resources tend to run less during price spikes.

Electric forwards are typically traded for only 1–2 years out, so they do not readily support long-term hedging. On the other hand, gas contracts are often available and liquid for longer delivery periods (especially at Henry Hub) and they can serve as a potential hedging instrument to provide increased revenue certainty over a longer future horizon. The main concepts for using them are the same, except that instead of swapping the real-time spot value of the wind output for an electric forward, the electric spot market revenues of the wind asset are used to buy

spot gas scaled by the forecasted market heat rate to settle against a fixed gas forward purchase (**Stage 4**). (There is also a loss of peak/off peak distinction in the available hedges.)

The hedging decisions should consider that the errors in forecasting HR may be correlated with unexpected changes in gas prices. For example, in coal-heavy regions, market HRs could go up under very low gas prices because electricity prices would not decrease as much as gas prices do (when gas plants are pushed to be infra-marginal and coal plants set prices). On the other hand, in regions with considerable amounts of oil-fired generation capability, unexpected gas price spikes can lower market HRs because electricity prices would not rise as much as gas prices do (due to gas-oil switching). Characterizing the relationship between gas prices and market HRs requires a structural analysis and a probabilistic framework, in which a fundamental-based model is used to simulate future market conditions under several gas price scenarios (**Stage 5**).

The price difference between the gas contract hub and marginal gas resources setting electric prices at the wind production node may create an additional “basis” risk that needs to be considered as a part of the hedging strategy. Selling basis swaps could hedge gas basis risk, but those basis contracts are often traded for only a few years or less. Without basis swaps, the amount of Henry Hub gas contracts sold needs to be adjusted to match the expected spot revenues related to basis differentials (**Stage 6**). Of course, there are several key market drivers (such as increased penetration of renewables, addition of new efficient gas generation, coal plant retirements, load growth, and CO₂ price) that could drastically change the direction of the gas-electric price relationship and estimated market HRs. Though the effects of these market drivers can be forecasted structurally with some useful accuracy, it is quite difficult to anticipate precisely when or to what extent any of the market events will occur, suggesting that a long-dated, static hedging strategy with a fixed HR will not track the market value of the wind output. Consequently, a series of hedges or HR-indexed hedges (if available) that are adjusted over time might be more effective. Monitoring the continuous shifts in the marketplace and dynamically adjusting the hedge ratios would be necessary (**Stage 7**).

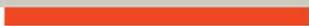
Figure 11: Summary of Wind Hedging Considerations

Stage	Factors Considered/ Hedge	Analytical Implications	Likely Risk Position Adjustment
1	Electric forward	Hedge expected on-peak/off-peak wind output	
2	Electric forward w/ wind-price correlation	Incorporate net discount in volume-weighted prices relative to simple average prices	↓ Hedge less than #1
3	Electric forward w/ wind-price correlation + scarcity prices	Estimate market price premium due to scarcity events and adjust average spot revenues based on expected wind output during scarcity hours	↓ Hedge less than #2
4	Gas swap	Forecast market heat rates (HRs) to determine gas-electric conversion ratios	↔ Equivalent to #3
5	Gas swap w/ gas-HR correlation	Characterize relationship between gas prices and market HRs and adjust gas-electric conversion ratios based on probability-weighted market HRs	↓ Hedge less than #4
6	Gas swap w/ gas-HR correlation + basis risk	Forecast basis differential for marginal resources setting electricity prices at wind production node and adjust the quantity of Henry Hub contracts to match expected spot revenues related to +/- basis differential	↑ Hedge more than #5
7	Gas swap w/ gas-HR correlation + basis risk + evolving HRs	Monitor key market drivers and dynamically adjust hedge ratios to account for changes in expected market HRs	↑↓ Hedge more/less depending on market HRs

While the examples we present in this paper used wind generation and market data in ERCOT to illustrate key concepts, our findings apply in concept to most other markets. Of course, the significance of the factors discussed in this paper can vary from one region to another. (E.g., wind-price correlation could be limited in regions with low wind penetration; scarcity pricing could be less important in regions with capacity markets, since energy prices typically do not increase as much as in ERCOT’s energy-only market; basis risk could be less relevant in regions other than the Northeast.) Thus, the hedging approach would need to be tailored to address a subset of factors that are most relevant to the specific region where wind generator is located. Also, in this paper we focused on hedging the expected value of output for a standalone wind

asset, but the concepts we discuss here would also be important when managing a portfolio of assets. Only the net risk would be important, but as more wind assets are added to a portfolio, the marginal hedging needed to keep portfolio risk at a constant level would be similar to the standalone determinants we describe herein.

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