



# Using Wind Power to Hedge Volatile Electricity Prices for Commercial and Industrial Customers in New York

Final Report - Complete

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# Executive Summary

## Introduction

The introduction of competitive wholesale electricity markets is leading to greater price volatility. Reliance on a single fuel source – natural gas – to meet the vast majority of incremental supply needs on a nationwide basis has the potential to exacerbate this situation.

Wind power generation is increasing in New York, in large part due to aggressive incentive programs developed by the New York State Energy Research and Development Authority (NYSERDA). Wind power projects, however, are capital-intensive and have generally required long-term contracts with credit-worthy power purchasers to attract financing. Questions remain over whether new wind projects in New York will be able to find viable demand for their output.

A key advantage of wind power is that it is free of fuel costs, and it has often been sold through fixed-price power sales contracts to utilities and ESCOs. While this “hedge” value can clearly be provided at the wholesale level, open questions remain over whether and how a wind generator or an ESCO might take advantage of this benefit and sell a renewable electricity product to end-use customers as a long-term hedge with terms and quantities sufficient to support financing. Could a generator or an ESCO design such a green power product? How, and at what cost? Would such products be attractive to end-use customers, and would the marketing of a wind-hedge product significantly increase customer demand for wind power?

This scoping paper addresses these questions from the perspective of commercial and industrial (C&I) customers in New York, wind generators seeking to access markets and financing, and ESCOs or other organizations selling wind power to end-use customers. Our purpose is to assess whether the potential value of wind power as a price hedge for large electricity end-users in New York is substantial enough to warrant more detailed investigation.

As highlighted below, this study concludes that wind-generated electricity can provide important hedging benefits to New York’s wholesale electricity markets, but that providing this benefit to individual C&I customers is more challenging. The barriers to using wind as a retail wind hedge can be significant, and suggest that retail wind hedge tools may be most attractive to a limited segment of the C&I market. Nonetheless, our analysis suggests that wind can provide a good, if not perfect, hedge for many C&I customers. While opportunities for retail wind power hedges may not be pervasive, there are certainly niche applications and certain customer types that merit further attention.

This executive summary is intended to provide a concise yet reasonably detailed review of the full report, and is organized as follows. We begin by describing the basics of electricity price volatility, the determinants of that volatility, the disconnect between wholesale price volatility and retail rates, and the interests of C&I customers and wind generators in seeking price stability. We review conventional hedging strategies used at the wholesale and retail levels to provide price stability, and their relative advantages and disadvantages. The advantages of using wind to hedge wholesale and retail electricity price risks are then described, and we identify two transaction structures that might be used to deliver the hedge value of wind power to C&I customers. We also highlight industry experience in using wind power as a hedge in green power product offerings. We then turn to a discussion of six key barriers to the use of wind-generated



electricity as a hedge against retail price volatility. We also summarize our quantitative analysis of two of these key barriers, and present results on the overall effectiveness of a wind hedge product. Because this study is intended as a scoping exercise, not a comprehensive literature review or analysis of the issues at hand, we conclude by identifying possible next steps for NYSERDA and future areas of study.

## The Basics of Price Volatility

The report begins in Section 2 with an introduction to electricity price volatility, the determinants of that volatility, how wholesale price volatility is reflected in retail electric rates, and the interests of C&I customers and wind generators in seeking price stability.

***Price Volatility in Wholesale Electricity Markets.*** Particularly in emerging competitive wholesale electricity markets such as New York, electricity prices have proven to be especially volatile, subject to rapid and severe price fluctuations on hourly to annual timeframes. The risk of rising prices based on shifts in underlying fundamentals, such as natural gas prices or capacity shortages, can be especially severe, as demonstrated by the California electricity crisis in 2000 and 2001. Such market events can lead to degraded electrical reliability, and to financial distress for electric utilities, competitive energy providers, and end-use customers.

***The Determinants of Wholesale Volatility and Rising Prices.*** Price volatility in wholesale electricity markets is caused by the complex interaction of a number of key factors. These factors are exacerbated by the lack of cost-effective physical storage and the need for real-time delivery of power. The supply-demand balance is perhaps the most critical determinant of wholesale price volatility. Tighter supply leads to higher price and greater potential for price volatility. This balance is dictated by demand fluctuations, installed generation capacity, and plant availability. The incremental operating cost of the marginal generating unit called upon at any point in time will dictate prices in times of sufficient supply, with the plant's fuel costs being a primary driver. Volatility can be exacerbated, however, particularly when available supply gets tight, by transmission congestion, lack of demand response, or the exercise of market power. Finally, environmental compliance costs can influence long-term price trends.

***How Wholesale Prices and Volatility Translates to Retail Rates.*** The degree to which wholesale price volatility is reflected in the electricity prices faced by retail customers is a fundamental factor influencing a customer's need for or interest in price hedging. In monopoly markets characterized by vertically integrated utilities, a traditional goal of utility regulation has been to stabilize retail electricity prices. In restructured markets such as New York, however, retail customers have increasingly been exposed to greater price volatility.

In New York, C&I customers can choose supply from an incumbent utility under regulated rate structures or from an ESCO.

- **ESCO Service:** Under ESCO service, volatility depends on the pricing structure the customer selects. Options typically include wholesale spot market pass-through and fully- (e.g. fixed-price) or partially hedged products. Few customers, however, have switched away from the utility option and take ESCO service.
- **Utility Service:** The exposure of retail customers taking utility service to wholesale price volatility varies by utility service territory, in part because New York's utilities have divested



their generating capacity to varying degrees and in part because each utility has a different wholesale procurement strategy. For instance, we find that in the Niagara Mohawk service area, rates are set on an hourly basis, thus exposing default service customers to the full volatility and uncertainty of the wholesale electricity market. In contrast, Con Edison sets generation rates for six months at a time, based on significant short-term hedging, without making the details of its hedging strategy widely available.

Without volatility in retail electric prices, retail electricity consumers have little reason to consider price hedges. As a result, the market opportunity for wind-hedge products (or any retail electric hedge products) is largely limited to the utility service territories in New York where consumers are exposed to significant price volatility, unless customers move to ESCO service with prices based on a wholesale spot market pass-through.

***C&I Customers' Interest in Hedging Exposure to Rate Changes.*** The goal of hedging electricity prices is to reduce a market participant's exposure to price volatility or changes in price trends. Hedges do not reduce prices on average, and typically there are costs associated with putting hedges in place. Where commercial, industrial and institutional customers do face electricity price volatility, a subset of those customers may value a retail price hedge. For instance, price hedging might help end-use customers protect their annual energy budget, stabilize their competitive position in a regional and global market place, and insulate their economic performance from energy price risk. Surveys indicate that many large electricity consumers state a willingness to pay a premium for stable electricity rates. Experience, meanwhile, suggests that in markets where customers have been recently exposed to such volatility, their interest in hedging may become heightened.

***Wind Generators' Interest in Long-Term Fixed-Price Contracts.*** For generators, the value of price hedging is to remove some or all of the uncertainty in the revenue stream on which project lenders and investors rely. Given wind's capital-intensity, substantially fixed cost structure, higher overall costs, and intermittence, the relative importance of locked-in minimum cash flows is magnified. As a result, lenders generally require wind projects to have long-term agreements to sell electricity and/or generation attributes at fixed-prices with credit-worthy parties.

In New York, however, credit-worthy buyers in the wholesale market appear to be scarce. Utilities, seen as credit-worthy by the financial community, are generally not making long-term purchases. Competitive ESCOs rarely have the capitalization to enter financially long-term contracts. Wholesale intermediaries, meanwhile, rarely enter into long-term, uncovered positions in additional generation without evidence of a strong market and/or short-term sales commitments already in place. With few credit-worthy *wholesale* alternatives, a wind generator could look directly to credit-worthy customers in the *retail* C&I market to provide sufficient cash flow to attract financing through the sale of wind-hedge products..

## **Conventional Hedging Strategies**

Since wind power must compete against conventional means of hedging electricity prices, the value and cost of conventional hedging instruments, as well as their availability to C&I end-users, provides a benchmark for wind as a hedge. Section 3 addresses these issues in depth, starting with a discussion of wholesale hedging strategies, and then turning to retail hedging strategies and the possible cost of those strategies.



**Wholesale Electricity Market Hedging Strategies.** There are a number of tools available to hedge prices in wholesale electric markets. These include physical hedges, such as ownership of generating assets, forward purchases of energy or other electric commodities (capacity, ancillary services), or options to buy or sell electricity in the future at a specified price. Financial hedging tools are also available, including exchange-traded futures contracts, as well as other derivatives such as financial call and put options and contracts for differences (CFDs). These tools are generally available in large standardized blocks that are ill-suited to all but the largest end-use customers.

**Retail Rate Hedging Strategies.** C&I customers can use conventional hedging tools to reduce retail rate volatility in three ways:

- *Remain on floating priced utility generation service or switch to spot-price pass-through ESCO service, and separately hedge price with a financial tool such as a CFD.* Remaining on utility service avoids the credit risk associated with entering a long-term hedge with an ESCO, and avoids the need to enter into new electricity contracts. If utility prices do not closely track wholesale spot prices, however, the combination with a financial hedge may not produce the desired results. Whether on utility or ESCO service, the tools available for financial hedging may be traded in sizes larger and/or terms shorter than desired by the customer. Directly entering into financial hedges also requires a significant level of commercial sophistication that may only be available to larger C&I customers.
- *Purchase electricity from an ESCO under a fixed-price contract or a floating price arrangement with caps or collars.* This is the simplest way, and for some customers, perhaps the only conventional way to hedge price risk. ESCOs are well suited to provide standard pricing structures, and can also provide the advantages of one-stop shopping, transparent pricing, access to an ESCO's market knowledge, and availability at desired scale. Potential disadvantages include credit risk associated with the ESCO, and the need to address this risk in contract negotiations, as well as the short duration of most ESCO hedge offerings.
- *Install on-site generation or curtail load.* Under this final approach, the degree of price protection is limited to the times in which it is economic to curtail load or run the generator, so that in many cases such a hedge can be valuable but imperfect.

**Cost of Conventional Hedging Approaches.** While all forms of hedging bear costs (either direct, opportunity, or both), quantifying the total cost of implementing a conventional electricity hedge is tricky business. Accordingly, we are only able to provide a general discussion of these issues, and some indicative numbers on hedging costs.

Some components of electricity price risk can be hedged directly and independently. For example, natural gas price risk can be hedged through derivatives or fixed-price physical supply contracts. Bolinger et al. (2002) estimate the cost of hedging fuel price risk (i.e., the natural gas component of electricity price risk) at the *wholesale* level to be on the order of 0.5¢/kWh. Similarly, if generation supply sources are located in a different LBMP pricing zone than the load, or if financial hedges are indexed to prices in a different zone, then the potential for transmission congestion becomes an additional electricity price risk. Transmission congestion contracts can be purchased at auction or in a secondary market as a hedge on inter-zone transmission.



Other determinants of wholesale price volatility, such as those caused by a supply-demand imbalance, cannot readily be hedged independently (of fuel price or other risks). One must either hedge all price risks (i.e., including fuel price risk) collectively through physical electricity forwards or financial hedges, or alternatively, hedge many non-fuel risks collectively through a “tolling agreement.” Lack of demand response, and market power, largely fall within the same category. Finally, the costs of complying with *future* environmental regulations cannot be easily hedged through conventional means, both because the exact nature of the risk cannot be known in advance, and because most generation sources have limited means to mitigate their impacts.

One additional component of hedging costs common to all hedges, whether physical or financial, is transaction costs. Generally speaking, using financial markets to hedge for longer than a few years can potentially result in significant transaction costs and the more illiquid and inefficient the market, the higher the transaction costs will be. Electricity markets are thinly traded beyond a few years. An advantage of using wind power as a hedge, therefore, is that it reduces (if not eliminates) the need to incur wide bid/offer spreads and large transaction costs on conventional futures or forward hedge products (though, of course, the wind product itself may have its own transaction costs).

## **Providing a Retail Wind Hedge – The Basics**

Section 4 builds upon the background on volatility and conventional hedging instruments by evaluating the merits of using wind power as a retail rate hedge, highlighting two distinct structures to a wind-hedge product, and summarizing industry experience with wind-hedge products to date.

***The Price Stability Benefits of Wind Power at Wholesale and Retail.*** The fact that wind power can hedge *wholesale* electricity rates is relatively well established. The characteristics of wind that provide these price hedge benefits include the lack of fuel costs, limited exposure to future environmental compliance costs, modularity and short lead-time. These characteristics ensure that wind generation can provide value in moderating electricity price levels and volatility relative to physical contracts backed by natural gas combined cycle capacity, for example.

Though the ability to pass on the *wholesale* price stability benefits of wind power to specific C&I customers at *retail* is the subject of much additional discussion in this report, it is first important to establish the fact that there are certain advantages to wind-hedge products for C&I customers. First, because wind projects require long-term contracts for financing, wind generators can offer longer-term hedges than are typically available through conventional means. Even where long-term conventional hedges are available, these markets are often thinly traded, so high transactions costs create a higher benchmark against which a wind power hedge would be measured. In addition, as a physical hedge backed by a sizable fixed asset with low operating costs and few long-term risks, a wind hedge may be less susceptible to credit risk concerns than some of the conventional hedge strategies. Finally, the hedge value may provide added value to a C&I customer considering a green power purchase.

From the wind generator’s perspective, meanwhile, selling a wind hedge may satisfy the lender’s requirements for a long-term, stable revenue stream. In addition, the hedge value provides the potential for an incremental revenue stream. Three products - commodity energy supply,



renewable energy attributes, and a financial hedge - could conceivably be sold, either independently or collectively.

**Wind Hedge Transaction Structures.** We find that the hedge-value of wind power can be delivered to end-use customers through two classes of transaction structures: bundled renewable electricity service, or financial contracts-for-differences.

- **Bundled renewable electricity service** entails the supply of a standard electricity product by an ESCO. The ESCO would presumably purchase wind energy at a fixed price, and then offer its customers a wind-based retail electricity product at a fixed or stable price.
- **Financial contracts-for-differences** would represent a purely financial product that may be able to provide similar stability to a bundled electric supply product. Under this arrangement, the customer would continue to receive electricity supply from the default service provider or from a traditional ESCO. The price of this supply would not be fixed, but would instead be indexed to the local LBMP. A separate financial contracts-for-difference (CFD) would be signed with a wind power generator or intermediary. As with a conventional CFD, a wind-based CFD is a financial fixed-for-floating swap transaction between a wind generator (or intermediary) and an end-user. The variable payment equals the difference between the chosen spot market index and a negotiated “strike price.” When the strike price exceeds the index, the hedger pays the wind plant the difference, and when the index price exceeds the strike price, the wind plant pays the hedger the difference.<sup>1</sup> Such a CFD is a perfect hedge for the wind generator if the generator sells energy into the same spot market to which the CFD is indexed. If wind production is low (high) at times when the index price exceeds (falls below) the fixed hedge price, however, this CFD will provide a poor hedge for the customer. On the other hand, the customer will profit under this CFD if the reverse is true. While a perfect *full* hedge for the customer is not possible, wind may provide an acceptable and attractive hedge if the prices faced by the generator and the customer are positively correlated, and production and consumptions patterns are reasonably well aligned. A primary focus of this paper is identifying the effectiveness of wind as a hedge given these imperfections.

**Industry Experience with Using Wind as a Hedge.** Most green power products sold in regulated and restructured markets in the United States do not offer truly fixed prices for generation service. Nonetheless, there is some experience in the U.S. in supplying the hedge value of wind to retail customers, especially hedges based on bundled renewable electricity service. In regulated markets, offering a fixed-price wind hedge is straightforward, and has been implemented successfully, as demonstrated by the experiences of Austin Energy, Eugene Water and Electric Board, and Xcel Energy. The competitive market experiences of Green Mountain Energy and Community Energy demonstrate offerings that have some of the characteristics of a wind hedge – fixed price and/or long-term. However, unlike monopoly markets, in restructured markets there is as yet no experience with successful delivery of a long-term wind-based hedge that benefits both wind generators and end-users. In Appendix A we summarize examples of

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<sup>1</sup> The CFD can take the form of a commodity hedge, where the strike price is set based on commodity market expectations and “green” attributes are sold elsewhere, or a green hedge, in which the strike price is set at a premium payment that assures the generator its full revenue needs. For further discussion and graphical examples, see Section 4.3 of the full report.



this industry experience from both regulated and restructured markets, demonstrating how the hedge-value of wind power can be delivered to retail customers, as well as the challenges of offering such products. We also discuss an example of C&I customers seeking renewable energy hedge products.

## Challenges Facing Wind Hedge Products

We identify and describe in Section 5 six general challenges to developing and selling wind hedge products: lack of retail rate volatility, wind intermittence, locational basis differences, market resistance to long-term hedges, market resistance to customer switching, and credit risk. The first three of these challenges make wind power an imperfect retail hedge (the latter two of these are evaluated further in Section 6). For financial CFD wind hedge products, the risk manifests itself in the selection of an underlying price index that is either imperfect for the customer, or imperfect for the generator. For bundled renewable electricity service, the risk will generally be absorbed by the ESCO, which may be required to purchase spot electricity during periods of low wind generation and high customer load. The latter three challenges are more general difficulties in selling a wind hedge product.

- **Lack of retail rate volatility.** As noted earlier, retail electricity rates offered by New York's electric utilities may not match wholesale locational spot prices. As a result, customers may not face substantial enough price volatility to motivate them to hedge, or alternatively, the retail price volatility facing customer may be sufficiently different from wholesale volatility as to undermine the ability of an end-use customer to implement financial CFD hedges.
- **Wind intermittence.** Wind generation will not be perfectly coincident with any individual end-user's demand, making it an imperfect hedge. This mismatch between load and generation profiles can be manifested over the short, medium, and long term. In any given hour, either the seller or buyer of the hedge may face both price and quantity risk. Price risk reflects the unknown level and volatility of wholesale electricity prices encountered when covering any shortfall or unloading any excess wind generation. Quantity risk reflects the fact that electricity consumption will often be higher when prices rise (e.g., due to cooling loads); if wind generation is low during these periods, either the customer or the supplier will be particularly exposed to price volatility. In addition, because wind generation itself cannot be accurately predicted well in advance of delivery, the degree of non-coincidence is not perfectly predictable, making it unlikely that the wind hedge can be improved through conventional means in any given hour. Over a longer time frame, wind generation in New York might fluctuate by 10% or more from one year to the next simply due to variations in the annual wind resource. This adds the additional complication that the correct volume of a wind hedge can only be approximated.
- **Locational basis differential between wind generators and customers.** Due to transmission constraints and locational pricing, the wind generator and the customer may face different spot market prices. The differences in market prices faced by the generator and the customer may fluctuate over time, in a manner that is not perfectly correlated in direction or magnitude, introducing transmission basis risk. This may be a major issue in New York, where much of the wind development activity is in upstate zones that typically experience low wholesale prices relative to the more populated New York City area where many target



customers may be located. To mitigate this locational basis risk, the wind generator or the customer could purchase transmission congestion contracts. Such contracts are not available for terms matching a long-term wind hedge, however, and due to the intermittence of wind generation, purchasing transmission congestion contracts cannot perfectly hedge transmission congestion costs.

- **Market resistance to entering into long-term hedges.** To date, retail customers have expressed limited interest in long-term hedges (e.g., 10-20 years). Market research suggests that many customers dislike being locked into a contract more than they value the price guarantee that the contract provides. This resistance may be *the* critical barrier to offering a long-term wind-hedge product. The fact that few C&I customers have revealed an interest in hedging over the long-term could partially relate to the considerable uncertainty surrounding newly competitive retail markets. Moreover, some governmental customers are simply not allowed to enter into long-term electricity contracts, while many C&I customers may also have corporate policies that largely stymie such long-term contracting. Wind-based hedge products, however, may be able to combat customer concerns because they may be backed by a highly visible and tangible physical asset (i.e., the wind farm), engendering a sense of stability, permanence, and comfort among potential customers. In addition, financial wind hedge products do not require customers to switch electricity providers, allowing them the option of selecting a low-cost ESCO in conjunction with a separate wind hedge.
- **Market resistance to customer switching.** A wind-hedge based on bundled electricity service requires the customer to switch to an ESCO, unless the hedge product is offered by the incumbent utility. Many states do not yet offer retail customer choice, while those that do (including New York) often find that the act of switching suppliers is a barrier in and of itself. A financial wind hedge product, on the other hand, can avoid this barrier by allowing customers to maintain their current electric service provider.
- **Credit risk.** Credit risk is pervasive throughout the electric industry today. From a buyer's perspective, the credit risk (real and perceived) of the hedge seller is critical, particularly in long-term hedge deals in competitive markets. Exchange-traded futures and options (i.e., "traditional" hedging instruments) pose very little credit risk to the buyer. A wind hedge will take the form of an over-the-counter bilateral transaction, on the other hand, and may be offered by an ESCO or the wind generator directly. The specific credit risk to which a customer is exposed depends on whether the product is financial or physical. The sanctity of long-term wind-hedge products based on bundled electricity service will depend on the continued viability of the ESCO, while long-term financial CFD hedges will generally be more dependent on the continued viability of the generator. Because the generator owns the physical asset behind the product (i.e., the wind plant) and the retailer does not, financial wind hedge products may face lower perceived credit risk than bundled electricity products.

## **Analysis of a Retail Wind Hedge in New York**

The combination of wind intermittence and locational basis differences between wind generators and end-use customers (discussed above) ensures that wind does not offer a natural "perfect" hedge for C&I customers. One could attempt to estimate the cost of "perfecting," or at least "improving," the hedge that wind power can provide in order to make it comparable to



conventional wholesale hedge benchmarks. While such an assessment may be feasible,<sup>2</sup> it is beyond the scope of this report. There may also be sharply diminishing returns to perfecting a wind hedge: much of the cost of hedging is likely to be associated with improving the hedge from “pretty good” to a truly fixed price per kWh that will apply under all load conditions.

In Section 6 we prefer to look at the problem through a different lens: a wind-based hedge at retail may not need to be *perfect* in order to be *effective* for customers. Accordingly, here we focus primarily on evaluating the overall effectiveness of wind at hedging volatility and rising prices in the New York market, using scenario analysis. Though our analysis assumes a financial CFD wind-hedge structure, the basic findings are also relevant to bundled electricity service options. We do not address several additional questions necessary to fully characterize a wind hedge, however, including the cost of the wind hedge, the value of the hedge to retail customers, and the relative cost-effectiveness of a wind hedge compared to alternative hedging options.

This section begins by assessing the sensitivity of retail prices in upstate New York to the determinants of price risk in that region. We then use scenario analysis to assess the effectiveness of a wind power hedge to a large, high load factor customer located in the same LBMP zone as the generator. We then consider in sequence the effect of inter-annual variation in wind production, the effectiveness of hedging different (less idealized) load shapes, and the effectiveness of a wind hedge for customers located across congested transmission interfaces from the wind generator.

***Sensitivity of Upstate New York Market Prices to Electric Price Risk Determinants.*** We begin Section 6 by considering the electricity price risks faced by large New York end-use customers within the same locational pricing region as a wind plant. Since the majority of current wind development in New York is in the upstate area, largely in a locational pricing region referred to for our purposes as *NY-West*, we first concentrate on the determinants of electricity price risk in NY-West. Later we discuss the use of wind as a hedge for customers in the higher-price New York City region, which requires consideration of transmission bottlenecks and locational basis differences in market prices.

Our analysis finds that wholesale electricity prices in the NY-West region are sensitive to fuel price risk, as well as changes in the overall supply-demand balance, lack of demand response, and the bidding behavior of generation owners. For these risks, which may act to increase or decrease market prices, hedging brings greater certainty. In addition, due to substantial reliance on coal and other fossil-fuel generation, market prices in this territory are exposed to the one-way risk of increased environmental compliance costs.

***Hedging an Annual Electricity Bill – Same Zone Analysis.*** We first assume that the wind generator and the customer are both located in NY-West. We consider a typical three-shift industrial customer (85% load factor) purchasing electricity under an ESCO wholesale spot market pass-through pricing structure, who separately contracts with a wind generator for a

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<sup>2</sup> Some of the mechanisms that could be used to perfect a wind hedge include: purchasing wind risk insurance products to shift the financial consequences of inter- or intra-annual variance in production to third parties; combining wind hedge purchases with conventional hedges or energy call options during seasons in which wind production is low; installing on-site peaking generation to protect the customer against high energy price spikes; or entering swaps with wholesale intermediaries to effectively convert variable and intermittent production streams into fixed blocks of energy.



financial CFD hedge indexed to the local energy LBMP. We use one year of actual output from an operating wind farm located in NY-West, and hold that production constant from year to year in both total energy output and hourly profile.

We test the effectiveness of using wind as a hedge in this environment by looking backward and observing how hedging approaches would have worked under historical LBMP prices. Our historical LBMP data set, covering May 2000 through December 2002, provides a significant degree of insight, as the movement in NY-West market prices during that period covers a representative range of experience.

Using the data and assumptions described above, superimposed on historical LBMP prices in NY-West, we compared the variability of the customer’s electric bill under an unhedged ESCO wholesale spot market pass-through pricing structure with four simple hedging approaches:

(a) *100% wind hedge*: A wind CFD whose expected annual volume (in MWh) matches the customer’s anticipated annual load. Note that this results in wind production substantially exceeding the customer’s winter loads, while constituting a partial hedge position in summer months.

(b) *50% wind hedge*: A wind CFD whose expected annual volume equals 50% of the customer’s anticipated annual load. In this case, the wind production volume during winter months approximates the customer’s winter load while leaving the customer less hedged in the summer.

(c) *Wind hedge plus conventional block forwards*: A wind CFD sized to match the customer’s winter usage, combined with a conventional summer seasonal forward block purchase. The total combined quantity of the hedge is sized to match 100% of the customer’s total expected annual load, with the wind hedge comprising 77.3% of the volume, and the conventional hedge the remainder.

(d) *Conventional block forwards*: A conventional annual forward block purchase, sized at a constant hourly scale to match the customer’s annual average load (e.g. sized to match 100% of the customer’s total expected annual load). This represents the benchmark, a conventional financial approach that may be used by a number of customers today.

In each case, the strike price was set at the average historical LBMP, so as to reveal the hedge effect without introducing any absolute, directional bias.

Our backward-looking analysis reveals that if sized effectively or combined with other strategies, wind hedges may be able to produce results, on an expected value basis, approaching those that

could be provided by a conventional hedge purchase of similar duration.<sup>3</sup> Figure ES-1 compares the annual bill under spot, and spot + 100% wind scenarios, as a percentage of each scenario’s average annual bill, for four staggered 12-

**TableES-1: Relative Stability of Annual Bill**

	All Spot	Spot + 100% Wind
12 months ending 6/01	114%	96%
12 months ending 12/01	104%	102%
12 months ending 6/02	88%	102%
12 months ending 12/02	94%	100%

<sup>3</sup> Note that even for this very high load-factor end-use customer, a conventional block forward approach is a very good, but still not perfect, hedge.



month periods within our historical period, while Table ES-2 compares the standard deviations of monthly bills and average price over the historical period. While there is significant month-to-month variation, all three wind hedge alternatives appear quite effective at stabilizing monthly and annual electricity prices for a baseload C&I customer in NY-West. Hedge strategies using

**TableES-2: Comparison of Standard Deviations between Spot and Hedged Electric Supply for High Load Factor Customer**

	All Spot	Spot + 100% Wind	Spot + 50% Wind	Spot + Wind & Summer Forwards	Spot + Conventional Forwards
Standard Deviation of Monthly Average Bill (as % of avg.)	19.9%	7.9%	10.2%	3.9%	2.9%
Standard Deviation of Monthly Average Price (as % of avg.)	19.2%	9.0%	9.8%	3.3%	1.8%

wind would have dramatically reduced the degree of variation of bills over time and in aggregate, despite volatile spot market prices and intermittent wind production. Since a primary motivation for some C&I customers to hedge may be fixed energy budgets, this annual stabilization appears to be an important result.

***The Effect of Annual Wind Production Variability on Hedge Value.*** In the previous section we concluded that a wind CFD between a large end-user with a nearly flat load profile and a wind generator in the same zone, at least within NY-West, can significantly dampen the volatility in a customer’s annual electricity bill. The analysis leading to this conclusion ignored one important variable, however: fluctuations in production – both total and among months – from year to year. Quantifying the specific impact of such annual variations in wind generation profiles is beyond the scope of this paper. Nonetheless, we believe that the historic period assessed in the previous section contains periods with intra-annual variation well surpassing the expected inter-annual standard deviation of 8-12%. Furthermore, derivative products are being developed for the wind power industry to insure against inter-annual wind resource risk.

***Hedging Different Retail Load Shapes.*** We have so far considered only the usefulness of a wind hedge for a very high load-factor customer. While it would be straightforward to repeat the analysis with a variety of load shapes, such analysis is not necessary to draw meaningful qualitative conclusions.

As a proxy for the value of wind hedges in both a portfolio context and for a customer with *average* load shape, however, we re-ran the analysis described earlier for a customer with a load profile mirroring the aggregate NYISO profile. As shown in Table ES-3, based on our backward-looking process using actual market prices, the various wind hedge approaches identified earlier reduce the volatility experienced by such a customer substantially, but less effectively (roughly two-thirds as effectively) than in the case of the high-load factor customer considered earlier. The weakened effectiveness of the wind hedge product in this case is due to the fact that the NYISO aggregate load is more heavily weighed towards summer peak (which are generally low wind months) than the hypothetical baseload customer used earlier.



The determining factors of the degree to which a specific C&I customer will derive maximum effectiveness from a wind hedge will be usage during periods of high volatility, and coincidence of load with wind production. For example, the winter-oriented wind production in NY-West

**TableES-3: Comparison of Standard Deviations between Spot and Hedged Electric Supply  
For Customer with Average NYISO Load Shape**

	All Spot	Spot + 100% Wind	Spot + 50% Wind	Spot + Wind & Summer Forwards
<b>Standard Deviation of Monthly Average Bill (as % of avg.)</b>	24.7%	14.3%	17.2%	10.7%
<b>Standard Deviation of Monthly Average Price (as % of avg)</b>	18.6%	9.8%	10.0%	3.9%

suggests that facilities with particularly winter-oriented end-uses without corresponding summer load may be particularly well suited for a wind hedge in NY-West. Examples include electric heat customers, ski areas, educational facilities that do not have much summer load, or perhaps even streetlight loads. The converse is also true: customers with summer-peak intensive usage, particularly high air-conditioning loads, may not find a wind-only hedge to be as effective, although if combined with other hedge options, a wind hedge may still have value.

***Hedging an Annual Electricity Bill with the Generator and Customer Located in Different Zones.*** The highest and most volatile electricity costs in New York State are in New York City and Long Island, areas subject to significant transmission constraints and with minimal opportunities for on-shore wind power development. One would expect New York City and its suburbs to also host the highest concentration of customers potentially interested in buying wind as “green power”. The final step of our analysis considered the value of a wind hedge when the wind generator is in a different zone than the end-use customer. In particular, we consider the effectiveness of a hedge from a wind plant in NY-West from the perspective of a customer in New York City (NYC).

In New York’s wholesale market structure, when the location of the generator and the customer are in different zones, between which there is frequent transmission congestion, a basis difference is introduced between the generator and customer, as described earlier. Transmission congestion risk is introduced. While there are tools available to hedge this transmission risk – called transmission congestion contracts (TCCs) – this risk cannot be hedged perfectly due to a combination of wind intermittence, rigid dimensions (size and shape) of TCCs, and the different shapes of wind generation and customer load. Nonetheless, a wind hedge may still be effective enough to provide value to a customer.

We tested this hypothesis by performing the same analysis described earlier (but only for a 100% wind hedge), except that the customer’s commodity electricity price is tied to the NYC LBMP, while the wind CFD remains indexed to the NY-West LBMP. This approach provides a perfect hedge for the generator, but perhaps a weaker hedge for the customer than if the customer were located in NY-West. The results of this analysis, looking at the same May 2000 through



December 2002 historical period of actual LBMP prices in NYC and NY-West used earlier, suggest that the 100% NY-West Wind Hedge would provide reasonable hedge value to a NYC customer, in addition to being a perfect hedge for the generator. As shown in Table ES-4, the 100% NY-West Wind Hedge leads to a 40% reduction in the volatility of monthly average electricity

**TableES-4: Comparison of Standard Deviations between Spot and Hedged Electric Supply for a Customer in New York City Hedging with a NY-West Wind Project**

	All Spot	NYC Spot + 100% NY-West Wind
<b>Standard Deviation of Monthly Average Bill (as % of avg.)</b>	20.9%	12.7%
<b>Standard Deviation of Monthly Average Price (as % of avg)</b>	20.2%	12.3%

prices and bills, relative to an unhedged commodity electricity purchase. The explanation for this phenomenon is that the two LBMPs are directionally correlated in most hours, if not tightly correlated in magnitude, so that some hedging effect is seen.

Alternatively, the wind CFD could be indexed to the NYC LBMP (instead of NY-West), exposing the wind generator to an imperfect hedge but presumably improving the hedge value for the customer. In this case, the wind generator could either accept the less-than-perfect hedge, or try to hedge the transmission congestion risk by scheduling power into the NYC zone through a bilateral transaction, and then purchasing TCCs. Our preliminary analysis shows that, in the first case (where the generator accepts the imperfect hedge), the customer does garner additional hedge value, but that depending on the strike price chosen and the movement of prices, there could be a net gain or loss to the generator, the customer, or both. A more comprehensive analysis of this situation, as well as the degree to which the transmission basis difference could be hedged with adequate cost-effectiveness to justify the second approach, is beyond the scope of this paper, but is ripe for further study.

## Conclusions and Next Steps

Based on this study, we conclude that wind-generated electricity can provide important hedging benefits to New York’s wholesale electricity markets, but that providing this benefit to individual C&I customers is challenging. The structure of retail rates can insulate customers from the full impact of wholesale price volatility. Retail customers who do experience price volatility may be in different locations from the wind generator or have usage profiles that are not well matched to wind production profiles. Finally, customers in general may be averse to switching retail suppliers or otherwise entering into long-term hedges for many reasons, including concerns over counter-party credit quality. These barriers to using wind as a retail wind hedge can be significant, and suggest that retail wind hedge tools may be most attractive to a limited segment of the C&I market.

Despite these barriers, our analysis suggests that wind can provide a good, if not perfect, hedge for many C&I customers. Alternative means of hedging are also imperfect, and face many of the same barriers facing wind hedges, yet they clearly have value to some customers. Furthermore, the availability of conventional hedging instruments over longer terms appears to be limited. Thus, while opportunities for wind power hedging against retail electricity price volatility may



not be pervasive, there are certainly applications and certain customer types that merit further attention. Further investigation of these opportunities is warranted.

Yet it is difficult to conclude that wind's hedge value alone – i.e., apart from its environmental benefits – is enough to make it a superior resource choice. In other words, though difficult to quantify, the hedge value of wind power is unlikely to sufficiently cover the full direct cost premium for wind power in New York with today's technology. This observation, however, does not mean that wind does not provide significant value as a hedging tool in certain circumstances – value that can factor into the sales pitch of wind sellers if the wind product is structured as a hedge. Furthermore, wind power has other “green” attributes that are valued by customers, as well as by policymakers and retail electricity suppliers. Since (in principle) the products and services created by wind generators can be unbundled and sold independently, wind's hedge value perhaps need not support wind's full cost premium above commodity market value; wind's green attributes can also provide premium support although a lower premium may be required if the hedge value can be captured independently.

Given the potential for wind hedge product development, there are several avenues that merit further consideration by NYSERDA.

- **Support development of a base of experience with retail wind power hedges.** Some consideration should be given to: (1) supporting a demonstration project, in which expertise is provided to facilitate the development of a retail wind hedge transaction, or (2) undertaking a more comprehensive project by subsidizing a retail ESCO or a wind generator that develops and tries to sell such a product.
- **Remove remaining unhedged risks from wind hedge transactions.** Alternatively, by helping to perfect wind hedges, current barriers to parties entering into wind hedge transactions could be removed. This could be accomplished by (1) funding or insuring hedge transactions against the transmission basis differences between LBMP zones (or perhaps even against the mismatch between generation and load, which includes basis but also includes load/generation mismatch), and/or (2) enticing one or more firms to offer wind insurance products in New York by sharing some of the risk.
- **Fund additional areas of study.** NYSERDA might also consider funding research to further flesh out the viability of using wind as a retail price hedge for C&I customers in New York. Specific areas of further study that we believe worthy of attention include: (1) conducting a survey of C&I customers' interest in hedging electricity price risk, particularly with a wind-based product, and (2) more thoroughly assessing the effectiveness of a wind hedge when the customer is in a different LBMP zone than the generator. Studies that deserve lower priority attention include: (1) testing the preliminary conclusions reached using historical data in this report with hypothetical future market price and production data, (2) testing the effectiveness of a wind hedge for other retail load shapes, and (3) more thoroughly assessing the effect of annual wind production variability on hedge value and effectiveness. Finally, an important area of study that is related to our topic, but that is outside the scope of our effort, is an assessment of the effectiveness of wind as a hedge against gas price escalation more generally.



# 1 Introduction

The introduction of competitive wholesale markets is leading to greater electricity price volatility as the electricity services industry moves from regulated, embedded cost-based rates towards market prices driven by marginal cost and scarcity. Reliance on a single fuel source – natural gas – to meet the vast majority of incremental supply needs on a nationwide basis and in New York has the potential to exacerbate this situation. Over time, this increased volatility at wholesale is likely to result in end-use customers facing greater hourly, daily, monthly, and yearly retail price fluctuations. Customers themselves will become responsible for obtaining protection against undesired short- and long-term price swings; the level of that protection will depend on each customer's risk tolerance.

Wind power generation is increasing in New York, in large part due to aggressive incentive programs developed by the New York State Energy Research and Development Authority (NYSERDA). Wind power projects, however, are capital-intensive and have generally required long-term contracts with credit-worthy power purchasers to attract financing. Questions remain over whether these new and potential wind projects in New York will be able to find viable and profitable demand for their output. Thus far, "green power" markets in New York have been slow to develop, though NYSEDA has recently initiated an effort to further encourage the market.<sup>4</sup> Related, few utilities or credit-worthy energy service companies (ESCOs) in New York's restructured markets have shown the combination of interest in and capability of entering into long-term contracts for these wind power projects.

A key advantage of wind power is that wind-generated electricity is free of fuel costs, and it has often been sold through fixed-price power sales contracts to utilities and ESCOs, providing a hedge against rising and volatile wholesale electricity prices as part of a supply portfolio. While this value can clearly be provided at the wholesale level, open questions remain over whether and how a wind generator or an ESCO might take advantage of this benefit and sell a renewable electricity product to large credit-worthy end-use customers as a long-term hedge with terms and quantities sufficient to support financing. Could a generator or an ESCO design such a green power product? How, and at what cost? Would such products be attractive to end-use customers, and would the marketing of a wind-hedge product significantly increase customer demand for wind power?

This scoping paper addresses these questions from the perspective of (a) commercial and industrial (C&I) customers in New York, (b) wind generators seeking to access markets and financing, and (c) ESCOs or other organizations selling wind power to C&I customers in New York. We focus on C&I customers because these customers often look for "added value" in their green power purchases, and a hedged product might be particularly important in driving wind power demand among this customer segment. In addition, some C&I customers not otherwise interested in green power might have interest in a hedged offering. Though our emphasis is on C&I customers, the majority of our findings are relevant to residential customers as well.

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<sup>4</sup> It deserves note that the entire competitive retail electricity market in New York, and other states, has been slow to develop. In New York, as of October 2002, 5.3% of eligible customers – representing 21% of eligible load – had switched suppliers. Customer switching has been more prevalent among non-residential customers (6.5% of customers had switched, representing 29.6% of non-residential load) than residential customers (5.1% of customers had switched, representing 6% of residential load). [http://www.dps.state.ny.us/Electric\\_RA\\_Migration.htm](http://www.dps.state.ny.us/Electric_RA_Migration.htm).



Building on previous research, our purpose is to assess whether the potential value of wind power as a price hedge for large electricity end-users in New York is substantial enough to warrant more detailed investigation.

This study concludes that wind-generated electricity can provide important hedging benefits to New York's wholesale electricity markets, but that concentrating this benefit to individual ESCO customers is more challenging for a number of reasons. The structure of retail rates can insulate customers from the full impact of wholesale price volatility. Retail customers who do experience price volatility may be in different locations from the wind generator or have usage profiles not well matched to wind production profiles. Finally, customers in general may be averse to switching retail suppliers or otherwise entering into long-term hedges for many reasons, including concerns over counterparty credit quality. These barriers to using wind as a retail wind hedge can be significant, and suggest that retail wind hedge tools may be most attractive to a limited segment of the C&I market.

Despite these barriers, our analysis suggests that wind can provide a good, if not perfect, hedge to many customer types. Alternative means of hedging are also imperfect, and face many of the same barriers facing wind hedges, yet they clearly have value to some customers. Furthermore, the availability of conventional hedging instruments over longer terms appears to be limited. Thus, while opportunities for wind power hedging against retail electricity price volatility may not be pervasive, there are certainly niche applications and certain customer types that merit further attention. Specific customer types for whom the consequences of upward movements in energy costs are particularly onerous may be particularly good targets for a wind hedge product, particularly if they have significant wintertime usage (as upstate New York wind generation appears to have a bias towards winter production). This value can be imparted to those customers interested in the "green power" value proposition; but the market is larger than that, as wind's hedge value can also be stripped unbundled and sold to customers who value the hedge, in effect lowering the revenue required from green power customers necessary to meet the revenue targets of wind generators.

The paper is organized as follows:

**Section 2** describes the basics of electricity price volatility, the determinants of that volatility, and the disconnect between wholesale price volatility and retail rates. The section goes on to document the reasons that a C&I customer might value price stability and the reasons that a wind generator will generally seek long-term, fixed price contracts for its output.

**Section 3** highlights conventional hedging strategies used at the wholesale and retail level to provide price stability, and the relative advantages and disadvantages of these strategies. It then attempts to evaluate the costs of hedging the determinants of price risk individually and collectively.

**Section 4** summarizes the advantages of using wind to hedge wholesale and retail electricity price risks, and the pros and cons of different transaction structures for delivering this value to end-use customers. It highlights industry experience in using wind power as a hedge in green power product offerings.

**Section 5** identifies six barriers to the use of wind-generated electricity as a hedge against retail price volatility.



**Section 6** evaluates the use of wind-generated electricity as a hedge against price volatility at retail in New York. The section begins by assessing the sensitivity of retail prices in upstate New York to the determinants of price risk in that region, particularly natural gas prices. We then use scenario analysis to assess the effectiveness of a wind power hedge to a large, low-load factor customer located in the same LBMP zone as the generator. We then consider in sequence the effect of inter-annual variation in wind production, the effectiveness of hedging different (less idealized) load shapes, and the effectiveness of a wind hedge for customers located across congested transmission interfaces from the wind generator.

**Section 7** summarizes the study's conclusions. It provides a summary of the barriers and opportunities to using wind power as a hedge against retail rate fluctuations. This study is intended as a scoping exercise, not a comprehensive literature review or analysis of the issues at hand. Accordingly, the conclusion identifies future areas of study and possible roles for NYSERDA.



## 2 The Basics of Price Volatility

This section provides a basic overview of electricity price volatility. Section 2.1 highlights the volatility that appears inherent in wholesale electricity markets, including New York, while Section 2.2 identifies the causes of this volatility. Section 2.3 then turns to the important disconnect between wholesale price volatility and retail electricity rates in New York. Section 2.4 documents the reasons that a C&I customer might value price stability. Finally, Section 2.5 discusses the reasons that wind generators seek long-term fixed revenue streams.

### 2.1 Price Volatility in Wholesale Electricity Markets

Experience in the US and across the Globe has shown that emerging wholesale electricity markets are subject to large price fluctuations on an hourly, daily, monthly, seasonal, and yearly

Figure 1

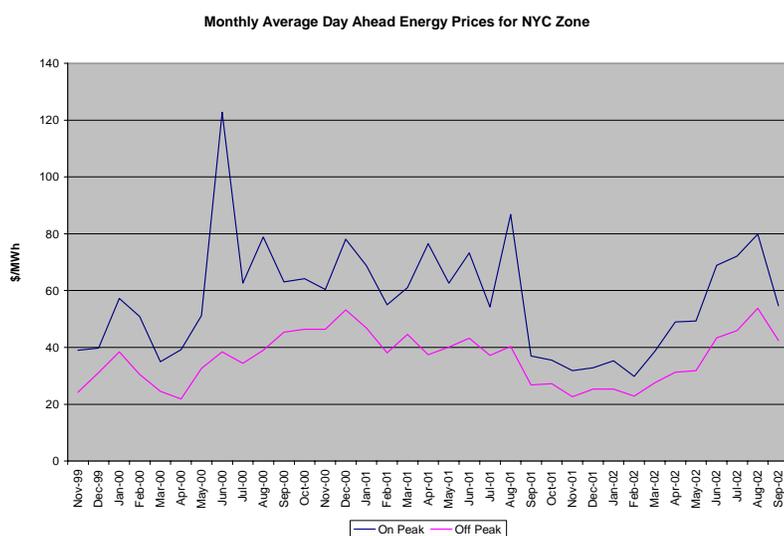
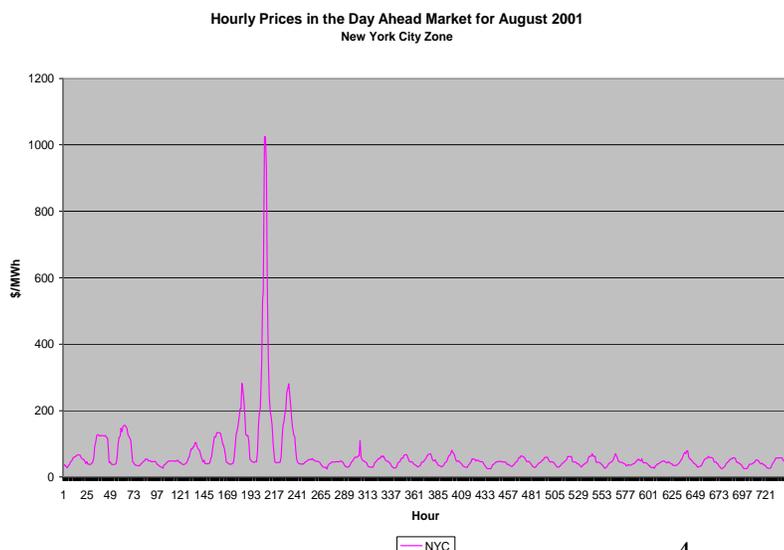


Figure 2



basis. The ramifications of this volatility can be very serious as illustrated by experience in the Western U.S. during 2000 and 2001. In California alone, wholesale electricity procurement costs to serve load in the California ISO control area increased from \$7.4 billion in 1999 to \$28 billion in 2000. Power prices soared, electricity reliability suffered, and a financial catastrophe for the state and for its utilities ensued.

But one need not look west to witness wholesale electricity price spikes. Prices in New York have also experienced rapid price swings in recent years. These fluctuations can be seen on a monthly basis (Figure 1) and on an hourly basis (Figure 2). Rapid and severe price fluctuations appear endemic to all competitive wholesale electricity markets, as similar graphs could be constructed for other power markets in the U.S. and worldwide. In fact, short-term price volatility in wholesale electricity markets generally exceeds that of other energy and commodity markets (Hakes 1998).



## 2.2 The Determinants of Wholesale Volatility and Rising Prices

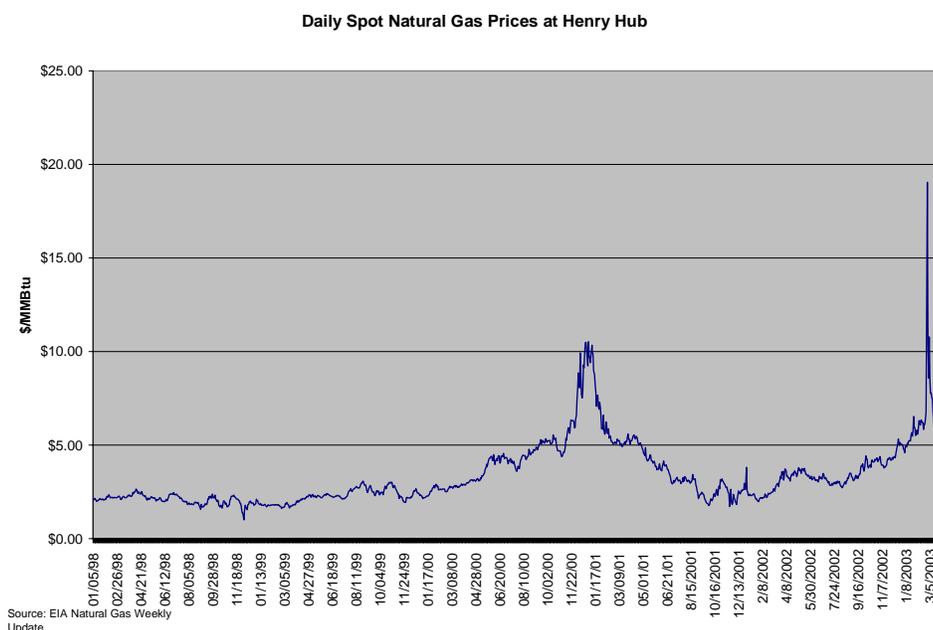
The drivers of wholesale price volatility fall into two broad categories: factors that affect the cost of generation at particular generating plants (e.g. fuel prices, heat rates, emission allowance prices), and factors that affect the supply/demand balance in the market as a whole (e.g. demand changes, generation additions or attrition, generation outages, market power, and transmission congestion). These causes of price volatility are exacerbated by a unique quality of electricity markets: the lack of cost-effective large-scale physical storage and the need for real-time delivery of power. To be more specific, the price volatility in wholesale electricity markets is caused by the complex interaction of the following key factors:

- **Demand Fluctuations** – Demand for electricity fluctuates on an hourly, daily, monthly, and yearly basis. In general, as demands approach the limits of available supply, prices increase. In addition, while demand fluctuations can often be predicted, those predictions are not always accurate. Changes in the weather alone can dramatically alter system demand. Unexpected escalations in demand can crimp generation supply and further increase electricity prices. This was one factor that has been cited as a reason for the volatility seen in the first two years of NYISO’s operation (State Energy Plan 2002).
- **Generation Capacity and Availability** – The supply-demand balance is perhaps the most critical determinant of wholesale price volatility. The tighter the supply situation, the higher the price and greater the potential for price volatility. In addition, the “blocky” nature of generation capacity additions impacts the supply-demand balance and increases volatility. On one hand, new additions to capacity can take years to come on line, so available capacity is rigid in the short-term and delays adding new capacity can exacerbate price volatility. On the other, large supply additions, once in place, can depress market-clearing prices until demand catches up. Moreover, even if adequate capacity exists to meet load in theory, in practice generators may not be available when called upon due to scheduled or forced outages, transmission constraints or other factors.
- **Generation Supply Curve and Incremental Cost** – New York’s power system, like most others, is comprised of generators with a wide range of capital costs and incremental costs of operation. The mix of these generators has developed over the years through utility and Public Service Commission efforts to “optimize” the generation mix against the expected hourly demand profile. The baseload generators in the mix are typically characterized by high capital costs and low incremental operating costs (i.e. nuclear, coal-fired, and many hydro power plants). These units are most economic when operated at high capacity factors or as available basis. At the other end of the cost spectrum are “peaking” units that typically have low capital costs and high incremental operating costs. These units are intended for operation during several hundred system peak hours each year. The incremental operating costs of these classes of generators can range from less than \$0.01/kWh for some baseload units to \$0.25/kWh or more for some peaking units. Even when system-wide capacity is roughly “in-balance” with system load on an annual basis, short-term demand excursions can produce price volatility of an order of magnitude or more as high-cost peaking units set the market price. During periods when system-wide capacity is short on an annual basis, these high-price units set market prices more frequently causing annual average prices to shift upwards. Conversely, when excess low-cost baseload capacity is available, average prices will tend to shift down.



- **Transmission Congestion** –Transmission congestion may exacerbate price volatility by not allowing available, low-cost generation in one location to reach load in another location. This is especially true in New York, where severe transmission limitations constrain the movement of electricity even within the State’s own boundaries, for instance between the capacity-long upstate region and capacity-short New York City and Long Island.
- **Lack of Demand Response** – When short-term demand approaches available capacity, market clearing prices increase sharply because the incremental operating costs of peaking generators increase. In markets for commodities other than electricity, increasing prices cause consumers to limit their demand thus limiting price increases, not so in the electricity markets. However, in a bid-based market like that operated by the NYISO, market clearing prices can rise well beyond incremental generation costs in the face of inflexible demand. Though time-of-use and real time rate structures, as well as demand response measures are becoming increasingly popular, fluctuations in wholesale electricity costs are often not immediately nor proportionately experienced by a majority of consumers. As a result, load response to such increased costs is very limited and supply prices may increase unmoderated. Under these conditions, the market does not equilibrate and price volatility can increase dramatically (Hirst 2002, Caves et al. 2000, Boisvert et al. 2002).
- **Fuel Costs** – Fossil-fuel costs often dominate the overall level, trend and volatility of pricing in wholesale electricity markets. In recent years, natural gas plants have become the “marginal” generating units for an increasing numbers of hours per year. In fact, the amount of New York’s electricity supply that has come from natural gas has increased to twenty-five percent. As a result, natural gas supply price volatility translates directly to increased electricity price volatility when gas plants are on the margin. Natural gas prices are quite volatile themselves (Figure 3), influenced by both national supply-demand conditions and local pipeline constraints. With an ever-increasing demand for natural gas in the U.S., many

Figure 3



believe that prices are likely to become increasingly high and volatile (e.g., Ferguson 2002, Bernstein et al. 2002). Gas prices increased dramatically in the winters of 2000-2001 and 2002-2003, leading in each case to a substantial increase in wholesale electricity prices. With plans announced for large amounts of new gas-fired generation



in the state and with gas use expected to rise accordingly,<sup>5</sup> price volatility will likely grow in importance in the state's electricity sector and exert an increasing effect on wholesale market prices (State Energy Plan 2002). For example, a recent simulation by La Capra Associates indicates that in 2003, natural gas-fired resources (including imports) will define market prices over 40 percent of the time in western New York, and over 70 percent of the time in the capital area.

- **Market Power** – Market manipulation by generators can increase electricity rates and enhance volatility. This is especially true when the supply-demand balance is tight (in an entire region, state, or even load pocket), or when wholesale market rules are flawed. This has been an ongoing concern of New York's ISO and electricity regulators.
- **Environmental Compliance Costs** – Environmental regulations often change, forcing fossil plants in particular to incur unexpected costs and raising electricity rates. At some point over the next 10 years, for example, additional requirements to reduce emissions of NO<sub>x</sub>, SO<sub>2</sub>, CO<sub>2</sub> and mercury are possible, even likely. Such changes would induce an upward shift in the overall cost trend for electricity in general and generation from fossil-fuel plants, but not zero emission plants like wind.

## 2.3 How Wholesale Prices and Volatility Translate to Retail Rates

Unlike most commodity markets, electricity markets are heavily regulated at the wholesale and retail levels. Historically, a traditional goal of state utility regulation has been to stabilize retail electricity prices, even though the underlying cost of generation is volatile (Bonbright 1961). The provision of such stability through regulatory regimes mutes the hedge value of wind power to C&I customers.

In monopoly markets characterized by vertically integrated utilities, retail rates have historically been set on an *embedded* or average cost basis: rates reflect the actual costs and performance of the power plants and contracts in a utility's portfolio. The customer is partially insulated from wholesale market volatility in this regime as a result of several factors. First, integrated electric utilities typically hold a diverse set of power plants and contracts in their supply portfolios (many of which are long-term agreements), reducing short- and long-term variability in their underlying costs. Second, retail rates cover actual fixed operating and capital costs plus fuel costs, only the latter of which is volatile. Third, even where some short-term variability in underlying costs exists, this variability is often passed on to customers on an average, long-term basis, and not through hourly, daily, or even monthly changes in retail rates. In such markets, electric price volatility is a function of the embedded mix. For instance, if natural gas makes up 20 percent of the mix and contributes 20% of the total cost, a doubling of natural gas fuel costs would only result in rates increasing by 4% or less because (a) the rest of the portfolio's costs do not change, and (b) some of the cost of the natural gas plants recovered in rates is fixed (i.e., fuel represents only a portion of the cost).

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<sup>5</sup> The State Energy Plan (2002) forecasts that 40% of electricity generation in New York will be fuelled by natural gas in 2020, up from 26% in 2002.



In restructured electricity markets such as New York, however, some utilities have divested their generation and now purchase supply on the market largely through a combination of spot market and fairly short-term purchases. In addition, since the prices for “capacity” in New York markets are low to non-existent, generators must recover a greater proportion of their total capital and operating costs through the price of energy. As a result, the supply costs for utilities and energy service companies (ESCO) in New York are more closely linked to the volatile wholesale spot market. Movement in the cost of the marginal fuel (often natural gas) can have a much greater influence on retail price volatility under this structure than it would for a supplier purchasing power from a portfolio of supplies.

In New York’s market, C&I customers have the option of choosing supply from an incumbent utility under regulated rate structures<sup>6</sup> or from an ESCO. For a customer taking service from a competitive ESCO volatility depends on the pricing structure the customer selects from options including spot market pass-through, fixed price (fully hedged product), and other variations. The range of typical product offerings from ESCOs is described in Section 3.2. For customers taking a spot-market pass-through from an ESCO (as described more fully in Section 3.2), retail rate volatility would resemble the wholesale volatility shown Figures 1 and 2.

In New York, however, few customers have switched away from the utility option and those that have switched, retain the right to return. For example, as of October 2002, the Department of Public Service reports that 6.5% of non-residential customers, representing 29.6% of eligible non-residential load, have switched to a competitive ESCO. So for this study of the role of wind as a hedge in New York state, it is important to understand how the utility rates work and how volatility is passed on to retail customers under this service option.

In New York, the exposure of the utilities’ retail customers to wholesale price volatility varies by utility territory, in part because New York utilities have divested their owned generating capacity to varying degrees. At one extreme, Con Edison and Niagara Mohawk have divested most or all of their generating plants and must rely on wholesale market purchases to meet most of the needs of their generation service customers. Retail generation service rates for these utilities therefore fundamentally reflect the cost of the utilities’ wholesale market purchases, and can be volatile on at least a monthly basis (though not necessarily on an hourly or daily basis). At the other extreme, Rochester Gas & Electric and the New York Power Authority obtain most or all of their power needs from owned generating plants and long-term power purchase contracts. These utilities rely much less on market purchases, and their retail generation service prices are less volatile.

Rather than comprehensively comparing the details of generation service pricing for all the New York utilities, the following discussion will focus in more detail on two utility service territories: Niagara Mohawk (in whose territory much of the New York wind energy potential exists) and Con Edison (where the greatest load concentration and therefore largest potential market for wind power exists).

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<sup>6</sup> While there is good reason to provide stable rates to end-use customers, a growing number of electricity industry analysts are now calling for a closer connection between wholesale and retail rates to tame market price spikes. End-use customers would then have the option and perhaps the motivation (but not the obligation) to seek out hedged electricity offerings and to pay any necessary price premiums to obtain them.



Con Edison serves about 3.1 million electricity customers in New York City and Westchester County. The key features of the Con Edison generation service rates are as follows:

- Con Edison must purchase substantial volumes of wholesale power (including energy, capacity, and ancillary services). The generation service price generally reflects Con Edison's actual cost of purchased power at wholesale, without any markup.<sup>7</sup>
- Fixed generation rates ("Market Supply Charges") are set every six months, and vary significantly by month, based on Con Edison's estimated cost of supply. Generation rates therefore depend on the wholesale price drivers (e.g., fuel prices, supply/demand changes) discussed in Section 2.2, as well as on Con Edison's purchasing strategy (e.g., how much of its needs are purchased on a forward basis, rather than in the spot market).
- To the extent that actual costs turn out differently than forecast, the difference is reflected the following month in the Market Supply Charge Adjustment factor.
- Generation rates for commercial and industrial customers include energy and demand charges, so that each customer's price of generation depends somewhat on its monthly load factor.
- Con Edison's stranded generation costs were set based on the actual sales prices that it received for generating plants that it sold. Changes that customers experience in the generation price are not offset by changes in the stranded cost charge.

Figure 4 illustrates Con Edison's monthly generation price, including both the Market Supply Charge and the Market Supply Charge Adjustment, since 2000. The illustration reflects a hypothetical industrial customer, with a constant monthly load factor of 85 percent. Clearly, retail generation prices have shown substantial volatility during the past three years. In particular:

- Generation prices during this period showed very strong variance from month to month, from a low of under 5¢/kWh to a high of over 14¢/kWh. During this period the monthly generation price often changed by more than 50 percent from the year before.
- The highest generation prices tend to be in summer when electricity demand in New York and neighboring regions is at its maximum. Winter prices also varied strongly. For example, the average generation price in the winter of 2000-01 (when natural gas prices reached historic highs) was over 9¢/kWh, almost two thirds higher than the subsequent winter.
- Annual average generation prices also varied significantly during this period. For example, the average price for the 12 months ending October 2001 was about 37 percent higher than the average for the following 12 months.
- Prices changed significantly between 6-month rate periods, so that current generation rates were not good predictors of future rates.

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<sup>7</sup> Certain costs such as transaction fees, option premiums, professional fees associated with hedging instruments are included in the generation rate. All gains and losses are passed through to the customer. The MSC is reconciled to actual procurement costs on a monthly basis.



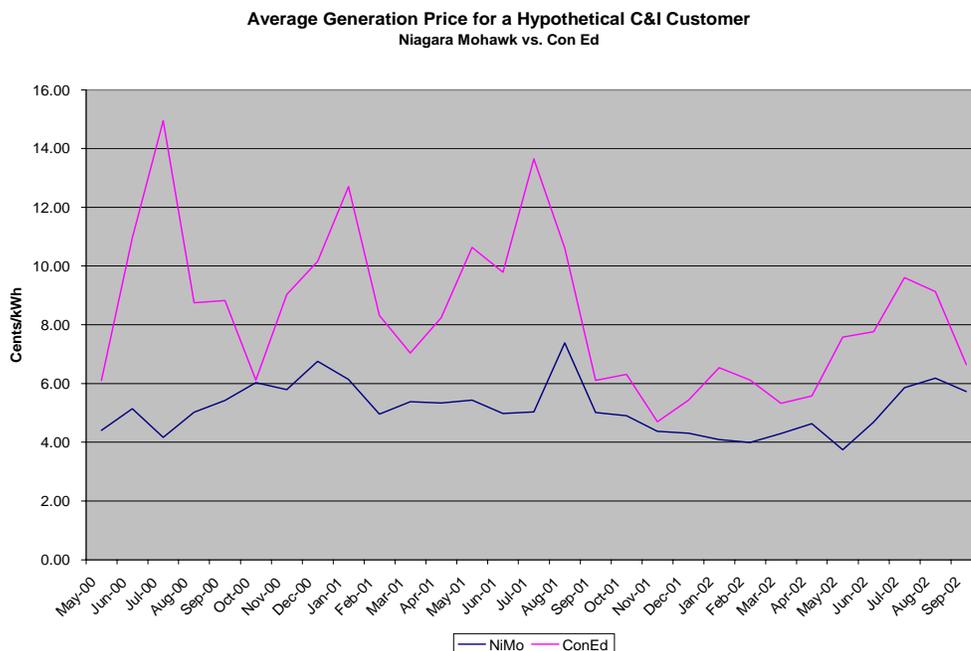
Niagara Mohawk serves 1.5 million electricity customers in a large service territory covering western and central New York State. The key features of Niagara Mohawk’s retail generation rate are as follows:

- Niagara Mohawk also purchases substantial volumes of wholesale power. The retail price Niagara Mohawk charges for generation service (called Electricity Supply Cost) is a direct pass through of wholesale spot market prices. Niagara Mohawk does not presently purchase its needs on a forward basis.
- Based on actual market prices of energy, ICAP, and ancillary services, Niagara Mohawk calculates an hourly price for generation service. This hourly price is multiplied by the hourly load for each customer to calculate the monthly bill. For customers without time-of-use meters, an aggregate class load shape is used along with the customer’s total monthly usage to calculate the generation charges.

Figure 4 also shows the historical monthly generation price for the same hypothetical customer located in Niagara Mohawk’s service territory. The exact location is NiMo’s “frontier” zone which is in western New York. The graph shows that there is also variation in the monthly generation price, though not to the degree of Con Ed.

In summary, Con Edison’s generation rates are set for only six months at a time, and they are subject to adjustment, while Niagara Mohawk’s rates are set on an hourly basis using actual prices. Past experience has shown that the generation rates can vary substantially on a monthly and annual basis, and we are not aware of any structural changes that would dampen the volatility of Con Edison’s or Niagara Mohawk’s generation price in the future. Given this rate structure, it probably makes sense for risk-averse customers to seek ways to make their electricity costs more predictable. Specific potential hedging strategies are discussed in Section 3.

**Figure 4**



Significantly, while Con Ed indicates that it employs significant short-term hedging, it does not make the details of its hedging strategy widely available. Customers therefore do not know the extent of coverage or the term for which the utility is hedged. This uncertainty makes it difficult for a customer to structure an effective hedge that could be used while the customer remains on



utility generation service. This indicates that for customers in the Con Ed service area to develop a highly effective hedge, whether using wind power or more traditional tools, they will have to switch to a competitive ESCO with more transparent pricing.

In contrast, customers of Niagara Mohawk are fully exposed to the spot market and face the full uncertainty that comes with spot market prices. To the extent that Niagara Mohawk continues to price its generation service using a spot market approach, customers in that territory will be able to develop an effective financial hedge (based on wind or other hedging tools) without leaving utility generation service.

The value of a wind-based hedge product, especially a financial one, will tend to be highest in utility service territories where the default generation service rate is volatile. Wind can potentially be used as a financial hedging product in utility territories where generation service is priced in a transparent way.

## 2.4 C&I Customers' Interest in Hedging Exposure to Rate Changes

If faced with volatile retail electricity prices through either utility default or ESCO service, some subset of C&I customers may choose to hedge their exposure to price swings. Whether a particular C&I customer chooses to hedge its exposure depends on the extent of the exposure and the risk tolerance of the customer. Experience in newly restructured electricity markets suggests that many customers may seek hedging strategies that ensure some stability in rates rather than receive a pass through of volatile spot-market prices (Kee 2001, Maudlin 1997). The motivations of C&I customers in seeking price protection may include:

- **Competitive Position.** Firms that compete in global markets face product output prices that are set based on aggregate demand and supply conditions globally, and not on local input prices. Rising input prices, such as electricity, will put such firms at a competitive disadvantage to their global peers that do not face localized price increases (Maudlin 1997).
- **Fixed Energy Budgets.** Many energy or facilities managers face energy budgets that are largely fixed from year to year. This is especially true in the government/institutional sector. Fixed energy budgets provide a clear incentive to hedge volatile electricity prices (Maudlin 1997).
- **Risk Aversion.** Even when energy budgets are not fixed per se, managers may in some cases choose stable electricity rates due to risk aversion. Some businesses may do this to stabilize their internal cash flow and therefore facilitate internal management decisions (Costello and Cita 2001). Other managers may seek stable electricity rates to simply “not look bad” to upper management. Risk aversion may be especially prevalent when electricity rates co-vary positively with stock market returns, such that high electricity rates are more prevalent during economic downturns (Awerbuch 2000).

Customer surveys show that many large electricity consumers state a willingness to pay a premium for stable electricity rates. While the predicted willingness to pay magnitudes revealed in such studies tend to overstate what is observed in practice, the nature of the sentiments expressed in such surveys as well as the relative preferences among hypothetical product choices are instructive.



- A 1998 study by National Economics Research Associates, for example, shows that commercial customers “exhibit a notable willingness to pay for contracts that limit their exposure to market price volatility” (Cox and Forcier 1998). In particular, the study’s results show that commercial customers appear willing to pay a premium of 0.9¢/kWh in exchange for a 1¢/kWh reduction in the *maximum* price they will likely face. This result suggests that commercial customers seem to equate price volatility with significant price risks.
- Another study of customer preferences for fixed versus variable rates indicates that (on average) small/medium C&I customers are willing to pay 0.8¢/kWh, 1.4¢/kWh, and 3.91¢/kWh more to obtain fixed-price rather than seasonal, time-of-use, or hourly real-time rates, respectively (Goett et al. 2000). Furthermore, fewer than 14%, 12%, and 4% of customers that responded to the survey prefer a seasonal, time-of-use, or hourly rate respectively over a fixed rate when the average price is the same.<sup>8</sup>

While some of the price points revealed in these surveys may raise eyebrows as being unrealistic (e.g., 3.91¢/kWh preference for fixed over real-time rates!), the prices are less important than the sentiment they express: many C&I customers strongly prefer fixed-price electricity rates over rates that vary. Yet, it is apparent that when retail access and associated policies were being determined in many states from 1995 to 1999, customers did not perceive the potential for price volatility nearly as clearly as they now do since experiencing the turmoil in electricity and natural gas markets since 2000. We would therefore postulate that, at least in markets where customers have been recently exposed to such volatility, their interest in hedging likely becomes heightened. This hypothesis would seem to be supported by the surge of post-crisis self-generation installations of both renewable and fossil generation in California and other states.

## 2.5 Wind Generators’ Interest in Long-Term Fixed-Price Contracts

Wind power generators must generally be able to attract both debt and equity financing if they are to be built. Typically, debt is needed to leverage sufficient returns to equity investors. Lenders also impose restrictive covenants on borrowers because, unlike equity participants, lenders do not generally share in a project’s “upside.” As a result, the requirements of lenders largely drive the needs of generators in competitive markets.

Before committing to a project loan, lenders must be provided with risk-commensurate returns as well as assurance of sufficient cash flows to cover both debt service and operation and maintenance costs under worst-case scenarios. Confidence in production estimates, as well as low risk exposure to generator availability, default, drop in market value, or changes in regulations, are also critical. Given wind’s capital-intensity, substantially fixed cost structure, higher overall costs, and intermittence, the relative importance of locked-in minimum cash flows is magnified. Lenders generally require a power purchase agreement (PPA) with a credit-worthy

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<sup>8</sup> A survey of *residential* customers conducted by the Colorado Office of Consumer Council found that a 12-month, fixed-price natural gas contract would be attractive to some customers. If such a contract was priced at a 10% premium, 11.4% of respondents would “definitely” sign up, while 28.6% would probably sign up. At a 15% and 20% premium, the percentage of “definites” drops to 7.5% and 2.5%, respectively (Colorado Office of Consumer Counsel 2001). For additional survey research results along these lines, see Faruqi and Mauldin (2002).



party for roughly 80% of the debt term to be willing to invest in a wind project at commercially attractive rates (Harper 2002).

A well-capitalized generator can use balance sheet financing to free itself of the direct requirements imposed by lenders, and proceed to commit capital without a long-term power purchase contracts with credit-worthy buyers. In practice, however, this type of merchant plant activity is extremely rare for commercial-scale renewables<sup>9</sup>, even more so with Wall Street's recent punishment of those who carry too heavy a corporate debt burden.

More likely, regardless of the financial structure used, a generator will seek sufficient revenues in *wholesale* markets under one of the following scenarios:

1. Enter into a long-term bilateral power sale agreement for bundled energy and attributes at a fixed price; or
2. In a market in which attributes may be bought and sold independently of energy, e.g. in New York with a conversion transaction or in many other markets that support renewable energy certificates (RECs):
  - a. sell electric commodities<sup>10</sup> under long-term bilateral contracts and enter a long-term bilateral contract to sell attributes, both at fixed price;
  - b. sell electric commodities into the spot market and enter into a long-term bilateral contracts for attributes on a "contract-for-difference" basis (effectively a financial hedge);
  - c. sell electric commodities into the spot market and attributes under a long-term bilateral contract at fixed price; or
  - d. sell electric commodities under long-term bilateral contracts and sell attributes into a spot or short-term bilateral attribute market.

Options 2c and 2d require that the long-term contracts (for attributes or energy/capacity, respectively) provide sufficient revenues to cover the risk of low spot prices (for energy/capacity or attributes, respectively) and still meet debt service coverage requirements. Scenario 2c might be feasible if the prevailing attributes market allowed high prices that reflect a significant risk premium. With competitive markets for energy/capacity, a generator would be unable to increase the energy/capacity price in scenario 2d above prevailing commodity prices, so this case is only realistic once wind power becomes nearly competitive head-to-head with fossil generation or if long-term predictions for the price of renewable energy attributes are high and reasonably firm.

In any of the above cases, the buyer under the long-term bilateral contract would need to be seen by lenders as credit-worthy to attract financing. In New York's market, however, such buyers in the wholesale market appear to be scarce:

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<sup>9</sup> The few renewable merchant plants are generally anomalies and are not easily replicable. Examples include: subsidized projects (e.g. the Fenner wind project, or landfill methane projects that have qualified for now-expired tax credits and/or had gas collections systems paid for as a result of other mandates); corporate experiments (e.g. the Madison wind plant built by PG&E); and projects necessary to secure a first-mover advantage (the Garrett wind project purchased by Green Mountain Energy in Pennsylvania).

<sup>10</sup> Specifically, electricity and, if applicable, capacity and any ancillary services.



- Utilities, seen as credit-worthy by the financial community, are generally not making long-term purchases. As described earlier, many of these utilities have divested their generation and have taken the role of supplier of last resort under regulated rates that are required to be market-based, a situation sometime not thought to be compatible with long-term contracting.
- The competitive ESCOs are most often thinly capitalized. Even if they are affiliates of New York utilities or otherwise backed by well-capitalized entities, because of the transient nature of their customer commitments and the inherently low margins associated with energy retailing, corporate parents are reticent to back significant long-term commitments.
- Wholesale intermediaries (generation companies or wholesale traders) that generally do not serve load are another alternative. Such intermediaries may consider taking a long-term position in wind power if they believe strongly in a future market and have short-term commitments lined up. However, such intermediaries have limited interest in taking long-term, uncovered positions in additional generation until evidence of a stronger market or some degree of shorter-term sell commitments are in place. The only examples of taking uncovered power purchase positions in the Eastern U.S. to date include long-term commitments in New York by Ontario Power Generation to the Western New York wind plant as well as commitments by Exelon Power Team to several PJM wind plants. In two other cases wholesale intermediaries have taken uncovered ownership positions in wind plants: PG&E National Energy Group for the Madison wind plant and CHI Energy for the Fenner wind plant. All three of the New York wind projects mentioned here had secured financial grants to defray their risk, and two of them represented corporate experiments entered into at times when markets for wind power appeared to be developing more rapidly, and before such merchant risk-taking was strongly discouraged by the financial community. This sector has suffered in the recent post-Enron industry turmoil, with dropouts, failures, mergers and shedding of generation or long-term commitments to shore up balance sheets resulting in very few potential buyers.

With few credit-worthy wholesale alternatives, a wind generator could look directly to credit-worthy customers in the *retail* C&I market to provide sufficient cash flow to attract financing – the subject of this paper.



## 3 Conventional Hedging Strategies

One approach to managing the risks of volatile wholesale power markets is to use financial instruments such as options and futures contracts. Another approach is to own physical assets that have low risks. In this section we discuss conventional hedging strategies. Section 3.1 discusses wholesale market hedging approaches, while Section 3.2 addresses retail hedging strategies. A discussion of the costs of different retail hedging approaches follows in Section 3.3. This discussion of conventional hedging strategies is highly relevant to this paper because understanding the prospects for delivering the hedge benefit to wind power customers requires that one understand the competition: conventional hedging strategies.

### 3.1 Wholesale Electricity Market Hedging Strategies

Wholesale electricity market participants can access a range of potential hedging tools, each of which has its advantages and limitations. The following is an overview of key physical and financial tools that wholesale market participants may be able to use to hedge their electricity costs and revenues.

At the outset, it is important to note that the electricity market is presently at a relatively immature stage with respect to hedging tools. It is therefore possible that as the electricity market matures, the breadth and availability of hedging tools will increase substantially over time. The pace of this maturation is uncertain, however. During the past year a number of major energy trading companies have suffered major financial setbacks, including credit rating downgrades, large stock price declines, and liquidity shortfalls. Some energy trading companies have gone bankrupt (e.g., Enron) or cut back the scale of their electricity trading businesses (e.g., Aquila), and there has been a substantial drop in wholesale electricity trading. At the same time, the rules and scope of regional transmission organizations, as well as some basic rules of wholesale electricity trade, are being debated at the national level. FERC Standard Market Design proceedings pose the prospect for additional market changes. In summary, wholesale electricity markets are still developing, and their maturation will take a number of years. The discussion below provides an overview of the primary hedging tools available today, but it is reasonable to expect that the available tools will evolve (and likely broaden) over the long term.

#### 3.1.1 Physical Hedging Tools

The following is a brief overview of physical tools that may be used to hedge an electricity supply or purchase obligation:

- **Large-scale generation assets.** The vast majority of generating capacity in the Northeast and the U.S. is large-scale central stations. These may be owned by electric utilities or (particularly in New York and New England) generation companies that specialize in the development and/or operation of generating plants. Generation asset ownership can mitigate volatile electricity prices because it offers the advantage of a known source of power with known output and characteristics, including fuel source and cost profile. The owner of a dispatchable generating unit may choose to operate the unit only when it is economic to do so (i.e., when its variable costs of production are less than the market price of energy for a



particular period), thereby achieving benefits similar to an energy call option (see below). This type of flexibility is needed to provide load-following service to retail customers, and to provide some ancillary services. In addition, large generation assets often provide additional real (as opposed to financial) options that are not available from financial hedging tools. In particular, the owner may be able to modify a plant's operation in one or more ways (e.g., expand capacity, switch fuels, retirement) in response to changes in market conditions. Because large-scale generation sources require extensive capital and organizational capabilities, they are not easily accessible to retail end users or small retail generation suppliers.

- **Small-scale generation assets.** Some smaller-scale generation assets are owned by the same group of large generation companies that own large-scale assets, but others are owned by a wider range of non-utility generating companies. In general, small-scale generation assets offer the same benefits as large-scale assets, although the value of the additional real options may not be as great.
- **Forward purchase of energy, or a forward contract.** A forward energy trade<sup>11</sup> is a binding agreement made directly between a buyer and seller for the delivery of a specific volume of energy at a specific location during a specific period in the future. Many forward energy trades are made on a fixed-price basis. To limit the cost of price discovery and contract development, forward energy trades are often made for standard delivery points (e.g., PJM Western Hub) and delivery hours (e.g., weekday hours 7 through 22, excluding NERC holidays). In other cases, unit-contingent or unit-entitlement type contracts are developed that may be priced on a fixed- or fuel-index-based. Finally, some publicly-owned utilities purchase forward energy on an all-requirements basis. The success of forward trades, regardless of the type, depends on the ability of the particular seller to deliver and the particular buyer to pay, making credit approval and performance/default issues important parts of the contracting process. A buyer relying on a forward energy purchase to hedge its electricity costs should ideally make sure that it is purchasing from a financially-strong seller, and monitor the seller's financial strength over time. In the Northeast, standard forward energy trades (not including unit-contingent or all-requirements contracts) are typically made in standard blocks of 25 to 50 MW, with a price premium required for smaller trades that would match the needs of smaller retail customers.
- **Physical call and put options.** Physical call (put) options represent a contract in which the buyer and seller exchange the right, but not the obligation, to purchase (sell) a specific volume of energy at a specific location during a specific future period, at a specific strike price. Options offer the buyer significant flexibility in hedging market price risk, without having to commit to a forward purchase. The price of an option ("premium") must, however, be paid whether or not the option is actually exercised. For some physical call options, the premium is simply the capacity charge paid by a buyer to a specific generating plant to reserve the right to dispatch that plant as needed and allowed under the contract.
- **Load curtailment.** An ESCO or a utility provider that has the ability to call on its customers to curtail their load (either through self-generation or specific load curtailment) may also

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<sup>11</sup> Energy represents the largest component of electricity supply costs and associated price risk. Forward trades may, in some markets, also be available for capacity and other generation services.



avoid some price volatility by shedding load and therefore market purchases when the market price of power is particularly high. This load response can have to effect of moderating price spikes for all market participants.

### **3.1.2 Financial Hedging Tools**

The following is a brief overview of the financial tools that may be available for use in hedging an electricity purchase or supply obligation.

- **Futures contracts.** Futures contracts are exchange-traded contracts for the delivery of a specific volume of energy at a specific location during a specific period in the future. In this sense, their hedging role is similar to forward contracts. Futures contracts are bought and sold directly with an exchange where participants maintain adequate levels of creditworthiness and financial strength. This feature of these exchanges greatly reduces the risk of counterparty non-performance. For several years NYMEX offered electricity futures contracts for several active trading locations across the U.S., with a 2 MW contract size that would be very useful for large retail customers. The electricity futures contracts failed to attract large market volumes, however, and during 2002 NYMEX suspended trading.<sup>12</sup> At present, there are no active futures that New York retail customers could use to effectively hedge their electricity purchases.
- **Financial call and put options.** Financial call and put options are similar in nature to physical options, but are often based upon the option to buy or sell a futures contract at a specified strike price. Standardized call and put options of this type can be purchased in electricity markets, therefore reducing transaction costs. At this time, however, the liquidity of put options and call options is fairly limited. Price discovery can be difficult, and options may not be available in sizes that are useful for the hedging of retail loads. For financial call options, the premium is a function of the relationships between option strike price, spot price, and forward price, the volatility value, and carrying costs of the option.
- **Contracts for differences.** A contract for difference (“CFD”) represents a contract in which two parties conduct a swap of fixed and variable cash flows (sometimes referred to as a fixed-for-floating swap). A CFD does not involve the sale of electricity, only a financial exchange between the two parties. A pertinent form of CFD for this “wind-as-a-hedge” analysis would be one in which a fixed reference price (e.g., 5 cents/kWh) is established, and a generator and ESCO pay each other the difference between the reference price and an independent variable underlying index (e.g., the hourly ISO spot market price at the generator’s location). Using this approach (which is detailed from an end-use customer perspective in Section 4), it is possible to structure a transaction in which payments between the generator and the ESCO vary strongly, but the generator’s total revenue and ESCO’s total price for energy are fixed.

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<sup>12</sup> NYMEX recently announced its intention to establish a PJM futures contract in 2003.



## 3.2 Retail Rate Hedging Strategies

Broadly, C&I customers can hedge retail rate volatility using one of three approaches alone or in some combination: (1) remain on utility generation service or switch to variable-price ESCO service, and separately utilize financial tools to hedge price risk; (2) hedge directly through a retail electricity supplier; or (3) install on-site generation or curtail load. The following discussion summarizes the strengths and weaknesses of these approaches.

### 3.2.1 Utility or ESCO Generation Service with Separate Financial Hedges

In this approach, the customer continues to purchase retail generation service from its local utility, or alternatively purchases electricity from an ESCO that offers variable priced service. It is reasonable to expect that the price of utility generation service will continue to be regulated over the long term, although (as shown in Section 2) the price could be quite volatile on at least a monthly basis. At its most simple, the variability in the price of ESCO service could be an hourly pass through of ISO spot market prices similar to utility service in the Niagara Mohawk service area. The needs of the customer (i.e. hourly and monthly load shapes) will influence this variability from customer to customer. Whether a utility or ESCO provides electricity services, the customer would attempt to hedge the uncertain utility or ESCO generation price stream *separately* using financial tools.

A potential advantage of remaining on utility electricity service and separately hedging with a financial transaction would be reduced credit risk, relative to entering into a long-term hedged supply agreement with an ESCO. Unlike switching to an ESCO, remaining with utility generation service also avoids the need to develop new contracts for electricity supply. The only commercial development required would be associated with the financial tool(s) that are used to hedge the utility price. Without these hedging tools, this option is not a viable method of hedging customer risk exposure. Finally, the utility may (depending on the specific details of regulatory arrangements that have been developed) supply its generation service at cost, with no markup for profit margin, an important extra factor in the cost of generation from an ESCO.

A critical disadvantage of hedging while on utility generation service is that, in New York, the prices from different utilities reflect different combinations of spot market purchases and forward purchases, and may also include longer term power purchase agreements. Therefore prices from some utilities may be quite variable, while for others it may already be hedged to a substantial degree. Purchasing a separate financial hedge would only be valuable to a customer that faces a volatile price stream in utility generation service. Even in these cases, because the utility relies on a variety of power purchasing tools, the utility price and inherent volatility cannot be effectively characterized and therefore cannot be perfectly hedged. Discussions with a retail supplier confirms that while financial contracts for differences are available at wholesale in New York, retailers are not frequently entering into such contracts in the Con Edison service territory, due to the non-transparency of Con Edison's hedging activities.

In the Con Edison service area and others with similar pricing, hedging is a more viable option for a customer receiving service from an ESCO with pricing that is variable and transparent. As detailed later, ESCOs are willing to offer electricity products whose price volatility is well characterized, such as a simple pass through of the hourly wholesale spot market price. A separate financial hedge products (such as CFDs) could therefore be more easily designed



around such ESCO service, though some of the potential disadvantages of switching to ESCO service are discussed earlier.

Whether a utility or ESCO provides generation service, it deserves note that some of the prevalent hedging tools in the wholesale electricity market are traded in sizes (e.g., 25 MW, 50 MW) much larger than the needs of all but the largest retail customers. They also are most often traded for terms (e.g., a few months to two years) that may be significantly shorter than a risk-averse retail customer would seek. As a result, smaller retail hedging transactions - particularly ones with unique characteristics or long terms - would be “custom jobs” that suffer from a combination of poor liquidity and high prices. (On the other hand, utility hedging programs, such as the renewable energy programs cited in Section 4, are different because they tap scale economies from multiple customers, they use the utility’s procurement expertise, and they may not require the same degree of customer financial commitment as a bilateral hedge).

These collective disadvantages indicate to us that it would be very difficult to tap any of the conventional financial hedge mechanisms if a customer were to remain on service from most of the utilities in New York state. If a customer were to switch to variable price ESCO service, on the other hand, it may be possible to execute separate conventional financial hedges at reasonable cost. Implementation of this approach would require a significant level of commercial sophistication, but it is reasonable to assume that sizable C&I customers could obtain it from a combination of in-house personnel and consultants.

### ***3.2.2 Competitive Generation Service***

At present, the simplest way (and perhaps the only way for some customers) to obtain a fixed price for generation service is to switch to a competitive ESCO that provides a fixed price directly. Retail suppliers can use the wholesale tools above to offer customers a number of hedged pricing structures. Conversations with competitive electricity suppliers indicate that the following retail price structures are the most popular:

- **Fixed price per kWh.** In this structure, the customer pays a fixed price per kWh for all energy consumed. The ESCO assumes all volume and market price risk, though the contract may feature a price adjustment if the customer’s annual electricity use falls outside a prescribed bandwidth (e.g., +/- 20 percent) based on past or projected usage parameters. This price structure is the easiest for the customer to solicit, evaluate, and budget for. It is typically, however, the most costly option at any given time because it reflects the costs of hedging and a risk premium for any components of the supply that cannot be effectively hedged.
- **Fixed discount.** In this structure, the ESCO offers a fixed discount from the utility’s floating generation price. In our experience the discount is typically only a small fraction of the utility price, and may only be available for accounts that have some unique advantage (e.g., favorable load shape or geographic location) relative to the utility’s system average. This price structure is also easy for the customer to solicit and evaluate, but it does not provide budget certainty for the customer and it requires an incremental level of effort to verify the supplier’s billing calculations.
- **Wholesale pass-through.** In this structure, the price to the customer is designed to reflect the ESCO’s actual cost of procuring the power (including energy, capacity, and ancillary



services) at wholesale, plus a fixed markup to cover the supplier's overhead costs and profit margin. The ESCO may, at the customer's direction, use one or more of the wholesale hedging tools discussed above to hedge the delivered cost of supply, with the cost of the hedge(s) included as part of the supply cost. For example, forward energy purchases can be used to hedge much of the market price risk for customers with relatively flat loads. Similarly, call options and put options can be used to create "cap" or "collar" pricing structures, in which the customer pays the spot price of electricity within certain limits. In summary, the wholesale pass-through approach offers the potential for the lowest total cost of power, and it allows the customer to select the tradeoff between expected cost and risk. This approach requires a substantial degree of customer sophistication with respect to energy costs and hedging decisions, and it requires the customer to monitor their electricity bills and the risk hedging strategy of the ESCO on an ongoing basis. As such, the wholesale pass-through approach is ideal for large, sophisticated retail customers.

A primary advantage of hedging directly through an ESCO is that it provides a transparent pricing approach, against which effective hedging strategies (including wind-based ones) can be developed and measured. Other advantages include access to the ESCO's market knowledge and trading capabilities and to its full range of wholesale risk management tools (including ones that are typically traded on a large scale).<sup>13</sup> As a result, ESCOs are well suited to provide some standard pricing structures, or to develop unique solutions to meet the needs of particular customers.

Potential disadvantages include credit risk associated with the ESCO, and the need to address this risk in contract negotiations. Given recent events resulting in the financial failure or market withdrawal of many in the retailing segment, and less aggressive risk-taking by those who remain, there are few retailers with the capitalization to offer long-term hedges. Also, the duration of hedges offered by ESCOs are limited by the available wholesale tools, including forward trades that show only limited liquidity for terms longer than a few years. Accordingly, a customer looking for a cost-effective long-term hedge may not find one through an ESCO. Finally, ESCOs will require some amount of markup (at least a few tenths of a cent per kWh) to cover their overhead and profit margin; some or all of this cost may be avoided by remaining on utility service.

### ***3.2.3 On-Site Generation and Load Curtailment***

A final option for hedging price exposure at the disposal of large end-use customers is on-site generation and load curtailment. Take on-site diesel generators: while it is typically not economic to operate such units regularly, they are accessible to retail end-users and can provide significant hedging benefits if they are able to operate reliably during occasional (and typically brief) but extreme "spikes" in wholesale market prices. (Such generating units might also provide value to end users considering using wind as a hedge, because they can cap the

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<sup>13</sup> Note that for a fixed price supply, the price typically does not depend significantly on the past hedging steps (including owned generation) that the supplier has in place. Suppliers almost universally develop their prices from large scale forward price quotations that reflect the current market conditions, as they reflect the opportunity cost of the transactions. [let's discuss this – it appears to be a major distinction between private sector and public utilities]



customer's exposure to market price spikes during periods when intermittent wind generation is low.)

Similarly, a customer that is able to curtail its load during high price periods can, at a minimum, offset the high cost of electricity purchases at that time. By participating in a demand response program, the customer may even be remunerated at a level higher than the price of wholesale power.

For both on-site generation and load curtailment, however, the degree of price protection is limited to the times in which it is economic to curtail load or run the generator. For example, if fuel and electricity prices are tightly correlated, use of on-site natural gas generators may do little to protect the customer from high prices because the cost of using the on-site generator will, to some degree, mimic the price of the overall electricity market. Therefore, such options provide a valuable but imperfect hedge (the exception here is the use of on-site generation to meet a majority of customer load from a generating unit that is immune to price spikes, e.g., photovoltaics with storage).

### **3.3 Costs of Conventional Hedging Approaches**

All forms of hedging bear costs (either direct, opportunity, or both). Quantifying the total cost of implementing a conventional electricity hedge, however, is tricky business, in part because doing so requires gauging market expectations for future prices at the time the hedge is initiated. In other words, in order to know how much *extra* it costs to lock in prices over a certain period, one must first know, as a baseline, what the market expects spot prices to be over that same period. Data on market expectations, however, is often proprietary, and is somewhat subjective. In this section, therefore, rather than attempting to reach a conclusive and comprehensive estimate of the costs of arranging conventional electricity hedges, we instead discuss the most relevant issues surrounding hedging costs.

As noted earlier in Section 2.2, fuel price risk, supply-demand imbalances, transmission congestion, environmental compliance costs, lack of demand response, and even the exercise of market power can all contribute to electricity price volatility. Below, Section 3.3.1 considers the availability of hedging instruments for each of these determinants, and where possible, the costs of arranging hedges. Section 3.3.2 discusses how transaction costs contribute to the total cost of establishing any type of hedge.

#### **3.3.1 Risk Determinants and Hedging Costs**

In this section, we revisit the determinants of wholesale price volatility listed in Section 2.2 (categorized somewhat differently) and add one source of retail price volatility (ancillary services), noting in each case the availability of conventional hedging instruments and, where possible, the costs of procuring them.

##### **Fuel Price Risk**

Natural gas fuel price risk can be hedged through derivatives or fixed-price physical supply contracts. Bolinger et al. (2002) estimate the cost of hedging fuel price risk (i.e., the natural gas



component of electricity price risk) at the *wholesale* level to be on the order of 0.5¢/kWh. The authors derive this estimate in large part by comparing the price of 10-year natural gas swaps (i.e., a fixed gas price over 10 years) to a range of publicly available 10-year natural gas price forecasts (i.e., the market's expectations of future gas prices). With the swaps priced above market expectations of future spot prices, Bolinger et al. conclude that the difference (~0.50¢/kWh, for a gas plant of typical efficiency) represents the cost of locking in a known gas price over 10 years at the wholesale level (i.e., the cost of hedging gas price risk). Unfortunately, with electricity markets not as well developed or as liquid as natural gas markets, it is difficult if not impossible to find the data necessary to conduct a comparable analysis on the price of wholesale electricity.

There are several potential explanations behind the empirical results of Bolinger et al. (2002). The first, as set forth by the authors, is that the observed premium represents an implicit *risk premium* that gas buyers are willing to pay in order to lock in gas prices over the long term. In other words, consumers are willing to pay a price that is higher than their expectations of future spot prices in order to guarantee price stability. The authors look to the Capital Asset Pricing Model (CAPM) for theoretical support for this explanation – a review of their analysis is beyond the scope of this paper. A second potential explanation involves the transaction costs of hedging, which are discussed below in Section 3.3.2.

### **The Supply-Demand Balance**

Electricity price volatility is also caused by imbalances in supply and demand, which operate independent of fuel prices. For example, new generation coming on-line may push electricity prices down as reserve margins increase from current levels, while load growth, plant retirements or major outages of large generators can tighten reserve margins and drive up electricity prices independent of fuel trends. In addition, the fuel substitution effect will tend to dampen the response of electric prices to movements in the price of natural gas: the more expensive natural gas is relative to other fuels, the more that other fuels will be substituted for natural gas, and thus all else being equal, electric prices are unlikely to double if gas prices double.

The risk of price volatility caused by a supply-demand imbalance cannot readily be hedged independently (of fuel price or other risks). One must either hedge all price risks (i.e., including fuel price risk) collectively through physical electricity forwards or financial hedges, or alternatively, hedge many non-fuel risks collectively through a “tolling agreement”. In a tolling arrangement, a buyer delivers its own fuel to a fossil-fuel-fired generator, and buys electricity from the generator for a fee, or toll. The next cost the buyer is its own cost of fuel, and a fixed additional markup which effectively locks in non-fuel costs.

### **Lack of Demand Response, and Market Power**

In periods of tight supply, the inability of demand to respond to supply scarcity can cause spot market prices to escalate to incredible heights, limited only by regulatory price caps. The possible exercise of market power by owners of generation resources that are on the margin during particular hours can exacerbate such effects, or have a similar effect at unpredictable times. These issues are particularly acute for those serving retail loads, due to the high coincidence between high-priced hours and hours of peak demand. As with supply-demand imbalances, however, these risks can largely be mitigated only collectively, through physical or financial hedges in the electricity market (with some exceptions, e.g., though demand response programs and real time pricing).



## **Transmission Congestion**

New York's market is structured using locational marginal prices for different load zones. These prices differ at many times of the year due to transmission congestion between zones. The difference between zonal prices represents the transmission congestion cost attributed and charged to bilateral transactions between zones. If generation supply sources are located in a different load zone than the load, or if financial hedges are indexed to prices in a different zone, then the potential for congestion becomes an additional electricity price risk.

Transmission congestion contracts (TCCs) can be purchased at auction or in a secondary market, in fixed contract sizes, as a hedge on inter-zone transmission. For a price, TCCs give their owner the right to collect transmission rents from those using a constrained path. In effect, a TCC is a fixed-for-floating swap on congestion prices. A buyer using a TCC to hedge an energy transaction for a flat block of electricity of standard contract magnitude between two zones could perfectly hedge the transaction against congestion cost risk. For example, in the auction held in March 2003, one year TCC's from the West Zone to New York City Zone traded at a price of almost \$76,000 per MW. For a flat block of power this translates into about \$9/MWh.

## **Environmental Compliance Costs**

While the costs of complying with current environmental regulations can be hedged by purchasing pollution permits or credits in the forward market, the costs of complying with any future environmental regulations, such as a carbon tax, cannot be easily hedged through conventional means; this is largely because the exact nature of the future regulation cannot be known in advance. In the face of such uncertainty, wind power and other environmentally preferable forms of power may provide one of the only available means of risk mitigation.

## **Ancillary Services**

In addition to the components of wholesale price volatility discussed above, the cost of supplying *retail* load also requires the provision of a variety of ancillary services, such as operating reserves, and (in some markets, including New York's) installed capacity. Installed capacity requirements can be hedged through forward contracts. However, with uncertainty as to how long such markets may exist into the future, and how the markets may be designed, there is little or no liquidity for long-term forward ancillary service contracts years. Other ancillary services may also be hedged with physical or financial tools, although it is difficult (if not impossible) to hedge perfectly in timing or quantity. In the case of Green Mountain Energy's fixed-price product in Southern California, discussed in Section 0, the wholesaler agreed to shoulder these risks.

### ***3.3.2 Transaction Costs of Hedging***

The previous section discussed the availability of hedging instruments for various components of electricity price risk and, where data was available, the costs of procuring them. One additional component of hedging costs common to all hedges, whether physical or financial, is transaction costs.

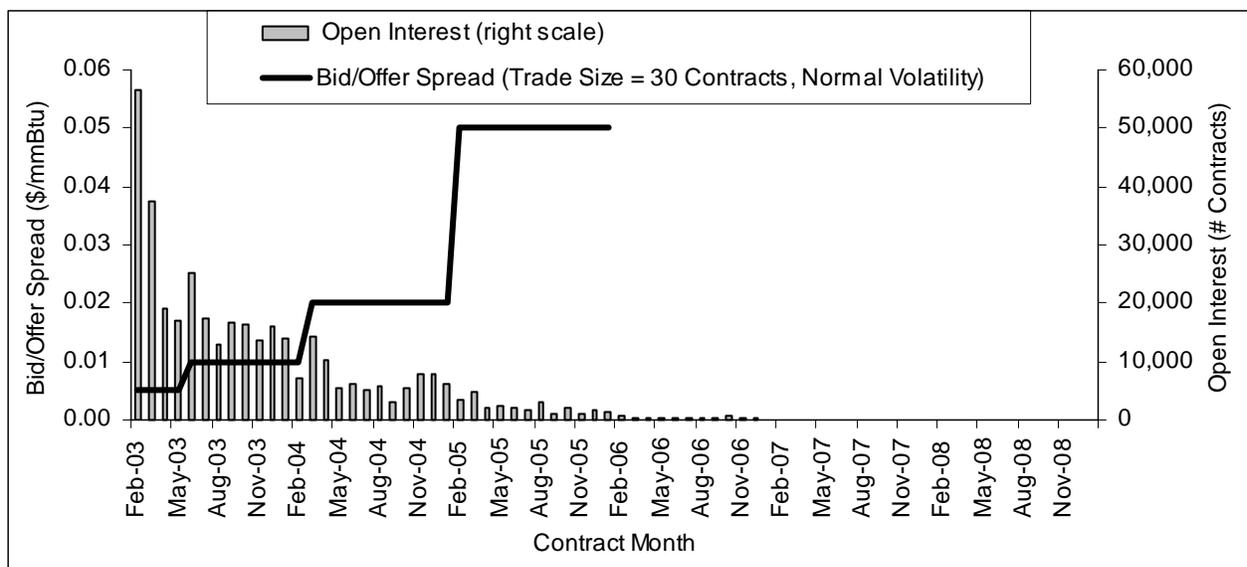
Simply put, there is an inescapable cost to virtually all transactions. In financial markets, transaction costs are manifested in the bid/offer spread: the spread between the price at which one is willing to buy (bid) and sell (offer) a product. To execute a deal with minimal price risk



(i.e., the risk that the market price rises (falls) while you are trying to buy (sell)), one must typically “cross” the bid offer spread (i.e., pay the offering price (if buying) or accept the bid price (if selling)). Since the “true” market price lies somewhere in between the bid and the offer, crossing the bid/offer spread to execute a deal results in transaction costs being incurred (i.e., paying more, or receiving less, than the “true” market price). For analytical purposes, the size of the transaction cost of dealing in a market are typically considered to be half the size of the bid/offer spread in that market (under the assumption that the “true” market price lies half way in between the bid and the offer).

In liquid markets, transaction costs (i.e., bid/offer spreads) are typically very small, and of little concern. In less-liquid markets, however, bid/offer spreads can be wide, and can have a more significant impact on the cost of transactions. To illustrate this point, we turn to the natural gas markets (again, because similar data from the electricity markets is hard to come by). Consider the bid/offer spreads in the NYMEX futures market, depicted in Figure 5. Under normal market conditions for a normal trade size, bid/offer spreads in the first four futures contracts (i.e., representing delivery in each of the next four months) are immaterial. Moving beyond these first few very liquid contracts, however, the bid/offer spread doubles for the next nine contracts (as

**Figure 5: Bid/Offer Spread and Open Interest for NYMEX Natural Gas Futures**



liquidity – proxied here by “open interest”<sup>14</sup> – declines), then doubles again for the subsequent eleven contracts, before more than doubling for the next twelve contracts (representing a total of 36 months or 3 years). Though even out 36 months the transaction costs are small in absolute magnitude, beyond these first 36 months (NYMEX gas futures are listed out 72 months), NYMEX gas futures are *very* thinly traded (open interest essentially drops to zero), making it difficult to even complete a trade.

<sup>14</sup> “Open interest” represents the number of open or outstanding contracts to the exchange (i.e., contracts that have not been closed out either through an offsetting position or via delivery).



Though pertaining to the natural gas rather than electricity market, this example illustrates a simple point: using financial markets to hedge for longer than a few years can potentially result in significant transaction costs and the more illiquid and inefficient the market, the higher the transaction costs will be. This may be particularly true in the thinly traded electricity markets.

For example, one broker of energy and installed capacity (ICAP) transactions in New England, New York, and PJM notes that utilities in the Northeast do not procure new electricity supplies out beyond a few years, and only a limited number of retail customers express interest in long-term deals (Natsource 2003). As a result, there is not an active market in the long end of the forward curve, and any trades that do occur are usually “structured” or custom deals, whereby an interested buyer posts a bid for the desired product and term, and waits to see who responds. With a limited number of potential sellers over this time frame, there is typically not much competition to win the deal, resulting in higher transactions costs than would be incurred over shorter contract terms. This dynamic will continue unless (or until) more buyers begin to seek long-term electricity contracts, which will no doubt draw more potential sellers into the market.

An advantage of using wind power as a hedge, therefore, is that it reduces (if not eliminates) the need to incur wide bid/offer spreads and large transaction costs on conventional futures or forward hedge products (though, of course, the wind product itself may have its own transaction costs). The magnitude of the avoided transaction costs could be considered at least a partial proxy for the value of wind as a hedge, with the rest of the value coming from any implicit risk premium that might be present, as discussed above in Section 3.3.1.



## 4 Providing a Retail Wind Hedge – The Basics

Advocates of renewable energy have long argued that wind power can mitigate price risks within a resource portfolio. This section begins to evaluate the merits of using wind power to hedge retail electricity rate risk. Section 4.1 identifies the characteristics of wind power that allow it to provide a hedge against *wholesale* electricity price volatility. Section 4.2 discusses some of the possible advantages of using wind-generated electricity to hedge the *retail* electricity rates of customers that specifically purchase renewable energy. Section 4.3 describes two transaction structures for delivering these benefits to retail customers: (1) bundled renewable electricity service, and (2) financial delivery using contracts-for-differences, with or without tradable renewable certificates. Finally, Section 4.4 highlights industry experience with both of these transaction structures.

### 4.1 The Price Stability Benefits of Wind Power at Wholesale

Wind-generated electricity can be used to hedge some of the risks of traditional generation sources, and may therefore offer a substitute for conventional hedging strategies. The attributes of wind power that provide these hedge benefits include:

- **No Fuel Costs** – Wind-generated electricity relies on a naturally replenishing energy flow and therefore requires no ongoing fuel expenditures. Major expenditures for wind generation include the initial capital outlays to build the plant, stable ongoing debt service costs in the event of project finance, and low and reasonably predictable ongoing operations and maintenance costs. This allows wind-generated electricity to be sold at relatively fixed prices (e.g., flat nominal price for many years, or moderate inflationary escalation) for the life of the plant, thus providing a direct hedge benefit to the buyer.<sup>15</sup>
- **Limited Environmental Compliance Cost Exposure** – Once built, wind generation delivers electricity that is free of air pollutant emissions. Though wind power does leave an impact on the environment (avian, visual, land, and noise issues are frequently mentioned), unlike fossil generation sources wind power plants are not likely to be exposed to increasingly stringent and costly environmental measures once built. Some power sales contracts associated with or backed by fossil fired generating plants contain adjustment clauses based on potential costs of compliance with future environmental regulation. Contracts backed by wind generation require no such “regulatory outs.”
- **Modularity, Lead Time, and Investment Reversibility** – Wind farms can be built modularly and with reasonable speed in many circumstances. Faced with uncertain supply-demand conditions and market price expectations, wholesale market participants value these traits.

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<sup>15</sup> Note that by offsetting natural gas generation and therefore reducing natural gas demand, wind-generated electricity can put downward pressure on short- and long-term natural gas prices. This appears to be a socialized benefit which would lower cost or risk for all customers in a region, but the benefit is difficult to quantify and it would only provide minimal savings to any particular customer. As a result, this will probably not be a benefit that individual customers factor into their purchasing decisions.



- **Independence of Fuel Supply Risks** – In addition to being free of fuel costs, wind generation will, on the margin, offset natural gas demand in the state. Given growing absolute demands for gas, and the prospect for natural gas pipeline constraints and interruption risks, wind power may also improve the reliability of the natural gas system in the state, and thereby improve electricity reliability. Of course, because this benefit flows to virtually the entire state, no single end-use customer that purchases wind power will uniquely benefit from this characteristic.
- **Small Turbine and Project Sizes** – By virtue of the small size of individual wind power projects and turbines, and the independence of their operation, failures of wind generators are unlikely to add to the need for contingency reserves. Of course, this benefit is widely considered to be offset by the system costs of intermittent output of wind generation.

These characteristics ensure that wind generation can provide value in moderating electricity price levels and volatility relative to physical contracts backed by natural gas combined cycle capacity, for example.<sup>16</sup> While quantification of this value is still in an incipient stage, several analysts have sought to estimate these benefits using a variety of analytic techniques: discounted cash-flow analysis, options valuation, decision analysis, and market comparison (e.g., see Hoff 1997, Bolinger et al. 2002, Awerbuch 2000, Awerbuch 1994, Brower 1997, Kahn and Stoft 1993, Venetsanos 2002, etc.). While the results of these studies are not reviewed here, it is important to emphasize that they focus on the risk-hedging benefits of renewable energy largely from the perspective of a wholesale market participant or an integrated electric utility.

## 4.2 The Advantages of Using Wind to Hedge Retail Rate Risk

The characteristics discussed in Section 4.1 make wind power an appropriate tool for hedging volatile and potentially increasing *wholesale* electricity rates. Generally, these benefits then flow to all retail customers through less frequent electricity rate adjustments. But how can these wholesale hedging strategies be used to hedge the *retail* electricity rate risk of individual retail customers? Specifically, how can a wind generator or an ESCO offer this value to its energy customers?

These fundamental questions have not been addressed in the literature to date, and are discussed in later sections of this paper. To frame that later discussion, three possible advantages of using wind to hedge retail rate risk deserve mention. These advantages may provide wind power hedge retailers a comparative advantage over those that offer the conventional hedging strategies discussed in Section 3.

- **Long-Term Hedge** – As noted in earlier, wind power projects often require long-term (> 10 year) power purchase contracts to ensure reasonable financing terms. Wind-generated electricity can therefore offer a longer-term hedge than many of the conventional hedging strategies, which often focus on short-term markets. Even where long-term conventional hedges are available, these markets are often thinly traded, so transactions costs would be

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<sup>16</sup> We do acknowledge that the characteristics of wind power, including intermittence, impose other costs and risks to the electricity system that are not addressed in this paper.



expected to increase (as discussed in Section 3.3.2), creating a higher benchmark against which a wind power hedge would be measured.

- **Physical Hedge** – Wind power offers a physical hedge, backed by a sizable, fixed asset: the wind project itself. This may make hedging strategies with wind less susceptible to credit risk concerns and nonperformance than some of the conventional strategies.
- **Leveraging a Green Premium** – By bundling the hedge value of wind power with a green power product offering, a wind power hedge may provide additional value to a green power purchaser. With wind power products that offer benefits beyond the traditional environmental sales pitch, customer demand for wind power may increase.

From the wind generator’s perspective, the value of using wind as a hedge comes from two sources. First, the wind generator that is hedged is able to meet lender requirements for a stable revenue stream. Second, wind generators may be able to increase their revenues by selling a hedged product. Without the hedge, the wind generator is able to sell two products: commodity energy supply and renewable energy attributes. With the hedge, three products could conceivably be sold: commodity energy supply, renewable energy attributes, and a financial hedge. The details of wind-based financial and physical hedge offerings are described below.

### 4.3 Wind Hedge Transaction Structures

The hedge-value of wind power can be delivered to end-use customers through two classes of transaction structures:

- bundled renewable electricity service, or
- financial contracts-for-differences.

**Bundled renewable electricity service** entails the supply of a standard electricity product by an ESCO. In New York, where physical electricity bilateral transactions may not be unbundled, the ESCO would, presumably, purchase wind power at a fixed price either bilaterally or through a conversion transaction.<sup>17</sup> The ESCO would then offer its customers a wind-based retail electricity product (or portion thereof) at a fixed price, or at a price that – while not fixed – is more stable than alternative product offerings. If unbundling of renewable energy attributes is allowed (as it is in some regions, but not in New York), the product would not need to be labeled “wind” per se, allowing the separate sale of the wind power attributes.

**Financial contracts-for-differences** would represent a purely financial product that may be able to provide similar stability to a bundled electric supply. Under this arrangement, the customer would continue to receive its electricity supply from the default service provider or from a traditional ESCO. The price of this supply would *not* be fixed. A separate, financial contract-for-differences (CFD) would be signed with a wind power generator or intermediary. Under this contract, a *fixed hedge price* would be established (e.g., 5¢/kWh). The customer would then pay

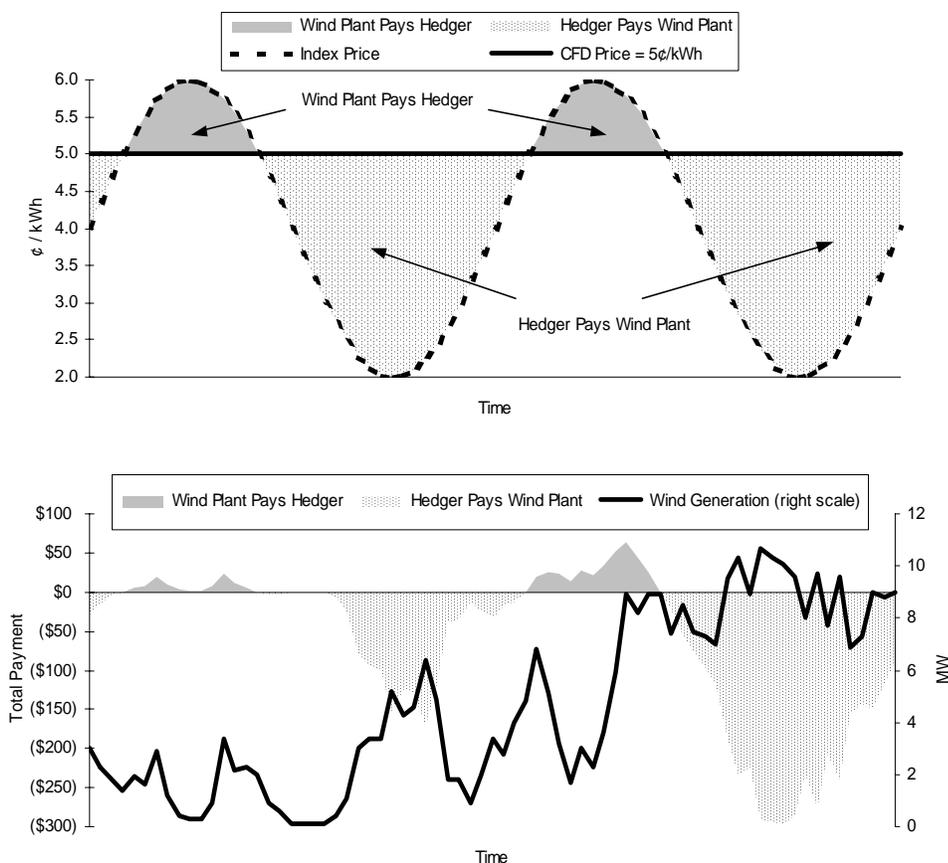
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<sup>17</sup> Through a conversion transaction, generation attributes associated with energy sold by generators into the spot market may be transferred to an ESCO purchasing an equivalent quantity of energy from the spot market during a calendar quarter. Such spot market purchases may then take on the generator’s characteristics for disclosure purposes.



the wind supplier a *floating premium* for each kWh generated that varies depending on the difference between the *fixed hedge price* and a *variable underlying index* at the time of production (Figure 6).<sup>18</sup> If the variable index price is lower than the fixed hedge price, then the customer will pay that difference to the wind power supplier (dotted area in top graph of Figure 6). However, if the variable index price exceeds the fixed hedge price, the wind supplier would actually pay the customer (shaded area in top graph of Figure 6).<sup>19</sup>

**Figure 6: Schematic of Wind Power Contract-for-Differences Set at 5¢/kWh**



As shown in the bottom graph of Figure 6, however, this CFD does not provide a perfect hedge for the customer, due to the intermittent nature of wind power generation.<sup>20</sup> The solid line represents a hypothetical wind generation profile (right axis), while the shaded areas represent total payments under this contract-for-differences (left axis), taking the wind production into account (as well as the index price movements depicted in the top

generation.<sup>20</sup> The solid line represents a hypothetical wind generation profile (right axis), while the shaded areas represent total payments under this contract-for-differences (left axis), taking the wind production into account (as well as the index price movements depicted in the top

<sup>18</sup> The CFD could also be combined with a wind tradable renewables certificate (TRC). In a standard TRC sale, a customer pays a fixed premium for the environmental attributes of wind generation. Under the arrangement proposed here, the customer would pay a *floating* premium that decreases as commodity market prices rise (see Section 0 for a discussion of Community Energy’s efforts to market such a product). In New York’s market, which today does not recognize unbundling of TRCs, a conversion transaction could be priced in a CFD fashion to also serve as a financial hedge.

<sup>19</sup> Note that the fixed hedge price (5¢/kWh) is set slightly above the expected average of the index (e.g., spot market) price, to reflect the fact that wind power is typically more expensive than conventional, spot market power. Thus, on average, the customer is likely to pay a premium for wind power.

<sup>20</sup> Intermittence is not the only problem: if the wind generation profile does not closely reflect the customer’s load or usage profile, then this arrangement will be a similarly poor hedge for the customer. Note that this consideration may not be of concern if the wind CFD represents only a small portion of the customer’s load (i.e., baseload power).



graph, immediately above). As shown, if wind production is low (high) at times when the index price exceeds (falls below) the fixed hedge price, this CFD will provide a poor hedge for the customer. On the other hand, the customer will profit under this CFD if the reverse is true. (It deserves note that similar imperfections exist for bundled renewable electricity service as well, as discussed further in Section 5). This arrangement will, however, provide a perfect hedge for the wind generator *if* the index price is set to equal the price at which the wind plant sells its commodity electricity.

A critical component of this transaction, therefore, is agreeing on the underlying index, which could, for example, be the wholesale spot market price at which the wind plant sells its commodity electricity, or the retail electricity rate faced by the customer (to list the two logical extremes). Obviously, the former will provide a perfect hedge for the wind plant, while the latter will provide the best (though not perfect, due to wind intermittence and generation/load mismatch as mentioned in the previous paragraph) hedge for the customer.

While a perfect *full* hedge for the customer will therefore be difficult or impossible to achieve using a wind CFD, it is perhaps reasonable to assume (i) that the different index prices favored by the customer and generator (e.g., LMPs at different hubs, or wholesale and retail prices) will be positively correlated, and (ii) that C&I customers may be able to absorb a substantial amount of wind generation in their baseload requirements, making such a CFD a potentially attractive proposition as a *partial* hedge (more on this later). Whatever the case, the *direction* of price movement should provide at least some form of imperfect hedge; in Section 6.2 we will evaluate the potential hedge benefit of a wind CFD with an example.

#### **4.4 Industry Experience with Using Wind as a Hedge**

A large number of the green power products sold in regulated and restructured markets in the United States do not offer a truly fixed price for generation service. A variety of green power providers, however, do have some experience in supplying the hedge value of wind to their retail customers. In Appendix A, we summarize several examples, in both regulated and restructured markets, for the purpose of demonstrating in a practical way how the hedge-value of wind power can be delivered to retail customers, the challenges of offering such products, and experience to date. In regulated markets, offering a fixed-price wind hedge is straightforward, and has been implemented successfully, as demonstrated by the experiences of Austin Energy, Eugene Water and Electric Board, and Xcel Energy. The competitive market experiences of Green Mountain Energy and Community Energy, demonstrate offerings that have some of the characteristics of a wind hedge – fixed price and/or long-term. However, unlike monopoly markets, there is as yet no experience with successful delivery of a long-term hedge that benefits both wind generators and end-users. We also discuss in Appendix A experience of customers seeking renewable energy hedge products, as related by the Green Power Market Development Group.



## 5 Challenges Facing Wind Hedge Products

Whether a wind hedge product is financial (e.g., contract-for-differences) or physical (e.g., delivered electricity), this section discusses six challenges to a “perfect” wind hedge: a lack of retail rate volatility, wind intermittence, locational basis difference between wind generators and customers, market resistance to long-term hedges, market resistance to customer switching, and credit risk.

The first three of these factors each risks making wind power an imperfect retail hedge. For financial CFD-oriented products, the risk manifests itself in the selection of an underlying price index that is either imperfect for the customer or imperfect for the generator (discussed earlier in Section 4.3). For delivered energy products, the risk will generally be absorbed by the retailer, who will – for example – be required to purchase and deliver spot-market electricity to its customers during periods of low wind generation.

It deserves note in advance that a perfect match between the location and time of delivery of wind generation with the location and timing of customer load is not absolutely essential for a near-perfect wind hedge product. For example, even if hourly wind generation is not perfectly coincident with hourly customer load, if over the course of a year wind generation has an aggregate commodity value that approximates the aggregate cost of supplying a customer’s load, then the hedge value of wind may be sufficient. As it relates to offsetting fuel costs, this was the finding of the Minnesota PUC, discussed in Appendix A. Similarly, if movements in the LBMP of the customer are reasonably coincident with the LBMP faced by the generator, then locational differences between the generator and the customer may not significantly degrade the value of a wind hedge.

### 5.1 Lack of Retail Rate Volatility

Especially when financial CFD products are offered, retail rate design must be considered. In Section 2.3 we identified a principle barrier to the attractiveness of a retail wind hedge product: the fact that retail electricity rates offered by New York’s electric utilities are rarely an exact match to the wholesale locational prices, and therefore that customers do not uniformly face substantial price volatility. This differential may not be significant in service territories in which the utility bases its rates on the LBMP or an approximation thereof.

Clearly, the existence of retail price volatility is a precursor to the attractiveness of retail hedge products, whether wind-based or not. Wind hedge products are therefore likely to be most attractive for end-use customers in New York that face the highest degree of price volatility. This will make certain utility service territories and certain customer classes far more attractive than others for a hedged product offering. More generally, if a customer switches to an ESCO that offers an LBMP-passthrough rate, this particular issue is no longer a concern; though in this case, the customer is required to switch to a new ESCO, which might otherwise be undesirable.



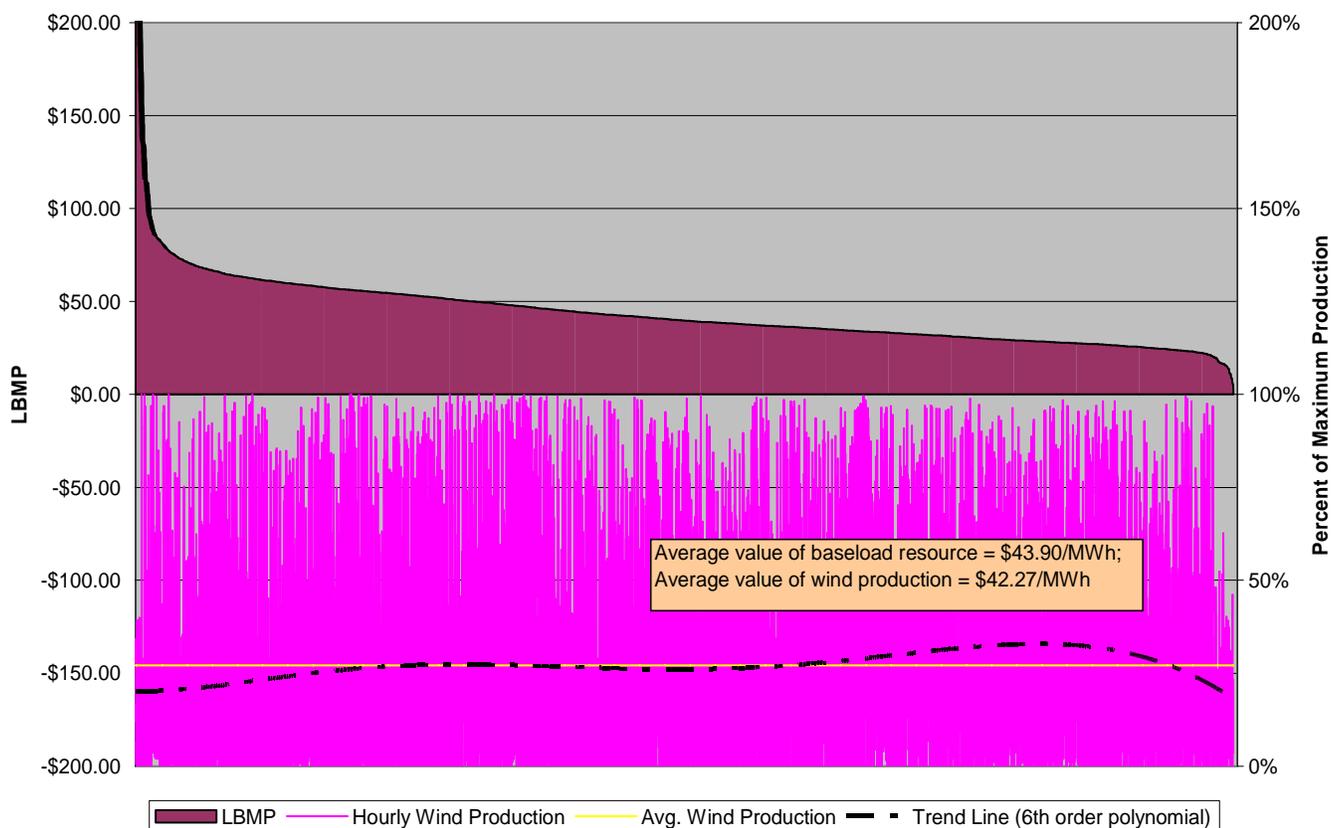
## 5.2 Wind Intermittence

Even where substantial retail rate volatility exists, the wholesale commodity value of the wind generator (as expressed by the wholesale locational market price seen by the generator) will differ on an hour-to-hour basis from the cost of electricity supply seen by the end-use customer. In the extreme, during some hours, wind generation will cease while customer load continues.

Unless the wind generation behind a hedge product happens to be coincident with the customer's load profile, then either the entity selling the product or the end-user (depending on how the product is structured) may face both price and quantity risk. Price risk reflects the unknown

Figure 7

Wind Production vs. Price Duration Curve  
Upstate NY (2001)



level and volatility of wholesale electricity prices encountered when covering any shortfall or unloading any excess wind generation. Quantity risk reflects the fact that electricity consumption will often be higher when prices rise (e.g., due to cooling loads); if wind generation is low during these periods, either the customer or the supplier will be particularly exposed to price volatility. These risks can be seen in the data presented in Figure 7. The figure depicts wind generation from an upstate New York wind farm over the course of a year, along with the LBMP price-duration curve in the same zone. As one might expect, there are numerous times in which wind generation from this plant drops to zero. As also shown, while the annual average value of intermittent wind generation closely approximates (is just slightly less than) the annual average



value of a flat block of supply (an important observation on its own), wind generation is typically somewhat below its annual average when the LBMP reaches its highest levels, exacerbating the quantity risk.

Making the situation more complex is that not only is wind generation unlikely to be coincident with customer load, but the degree of non-coincidence is not perfectly predictable; this is because wind generation itself cannot be accurately predicted well in advance of delivery. If wind generation and customer load were both predictable, a retail hedge provider might be able to plan for the times in which wind generation is low, purchasing commodity electricity at fixed prices to hedge that exposure. The lack of predictability in wind generation and customer load confounds this possibility.

The mismatch of load and generation profiles can be manifested over the short, medium, and long term. Over the short-term, the daily generation profile of wind power in New York will not match customers' load profiles. Over the medium time frame electricity load peaks in the summer months due to the use of air conditioning equipment, while wind generation in New York peaks between autumn and spring.

Finally, over an even longer time frame, it is well known that wind generation might fluctuate by 10% or more from one year to the next simply due to variations in wind resource patterns. For example, a California "wind power index" from 1987 to the present demonstrates output fluctuations of +15% to -30% away from a "normal" wind year (Polasek 2002). Data from Denmark going back to 1979 show a similar range of variability: +16% to -20% ([www.windpower.dk](http://www.windpower.dk)). Such inter-annual variability in wind generation may magnify price and quantity risks because wind generation will not match customer load variations. The risk in this case is that the volume of load that a customer wishes to hedge may, in any given year, differ from the quantity of insurance coverage (wind generation) bought as a hedge. The only realistic ways of "perfecting" the hedge in this case are: (1) to sell wind generation hedge products in a quantity that is de-rated to account for the lowest reasonably expected level of wind generation, or (2) to purchase weather derivatives. Wind risk derivatives are a new product with very limited experience. We discuss the wind risk derivatives further in Section 6.3.

### **5.3 Locational Basis Differential Between Wind Generators and Customers**

Just as generation and load may not be coincident in time, so too might they differ in location. For example, as highlighted in Section 3.3.1, one potential source of disparity between the wholesale price index upon which a financial contract-for-differences (CFD) hedge is based and the retail rate that the hedger pays is the respective physical location of both parties. If the CFD is indexed to the hub where the wind plant delivers its output to the grid, then unless the hedger is served by that same hub at a locational marginal price, the retail rate the customer faces will be based on a different wholesale price that reflects transmission and congestion charges between hubs. The exact same locational basis risk exists for delivered energy products.

Locational basis risk is potentially a major issue in New York. Much of the wind generation is likely to be sited in the western and northern portions of the state, which typically experience low wholesale prices relative to the more populated metropolitan areas in the southern portion of the state. For example, average wholesale energy prices in western New York averaged



\$32.5/MWh in the summer of 2000, and \$39.1/MWh in the summer of 2001. New York City, on the other hand, had an average price of \$57.6/MWh in the summer of 2000, and \$52.6/MWh in the summer 2001. More importantly, the daily and seasonal profile of prices at different hubs will not be perfectly correlated.

As noted in Section 3.3.1, there is one way to combat locational basis risk: by purchasing transmission congestion contracts. Due to the intermittence and lack of predictability in wind generation, however, purchasing transmission congestion contracts can not perfectly hedge transmission congestion costs. The hedge would be particularly expensive if an over-purchase of congestion contracts was used to cover the maximum value of wind production (and thus the maximum rate of transmission utilization). Alternatively, if a TCC hedge was scaled based on average production (and thus average transmission utilization), the transaction would be over- or under-hedged in most hours, so that exposure to LBMP differences would be only partially hedged. In any event, TCCs come in fixed sizes and limited durations that may not match the transaction being hedged.

## 5.4 Market Resistance to Entering Into Long-Term Hedges

To date, retail customers have expressed limited interest in truly long-term hedges (e.g., 10-20 years), or even long-term electricity contracts of any type. In a market research study, Goett et al. (2000) find that while most small/medium C&I customers want to face a fixed electricity price (see findings presented in Section 2.4), most customers dislike being locked into a contract more than they value the price guarantee that the contract provides. For example, the study finds that a supplier would need to discount its price by 0.27 cents/kWh in order to compensate the average customer for their dislike of one-year contracts. On average customers are willing to pay 0.6 and 1 cent/kWh to avoid two and three year contracts, relative to no contract. Despite this, some small/medium C&I customers do prefer a contract, and it is this subset that might value a wind hedge. Goett et al. find that 41% prefer a one-year contract to no contract at all, 32% prefer a two-year contract, and 25% prefer a three-year contract. The authors therefore conclude “there is sufficient variation over customers in their attitudes towards contracts to sustain a variety of contract lengths in a competitive market.”

Experience in the market for green power, and electricity more generally, supports the proposition that customers express limited interest in truly long-term hedges of the type wind can best provide (e.g., 10-20 years). This may ultimately be *the* critical barrier to offering a long-term wind- hedge product. Community Energy, for example, has not yet closed a deal on its long-term tags-based contract-for-differences product described in Section 4.4. Until recently, they have found few customers willing to lock-in to a standard TRC purchase for over 3 years. Other green power suppliers have found similar results. While some marketers report recent increases in large institutional end-user interest in long-term commitments, the depth of this interest remains to be seen.

Partially in response to the near-sighted view taken by most retail customers, retailers have typically restricted their wind-hedge offerings to the short term (e.g., 1-3 years). EWEB’s program, for example, has only guaranteed price stability for 3 years (but again requires no term commitment from the customer), while Green Mountain’s Reliable Rate Plan in Texas provides stability for one year and requires a full-year’s commitment. Austin Energy’s Green Choice program, meanwhile, guarantees price stability for 10 years – one of the longest operable retail



wind hedges on the market – yet does not require any type of long-term commitment from its customers.

The fact that few C&I customers have revealed an interest in hedging over the long-term could partially relate to the considerable uncertainty surrounding newly competitive retail markets. For example, customers may have legitimate fears about locking-in prices over an extended time horizon without having much experience on which to base such a decision. Purchasing competitive power at the retail level is a relatively new phenomenon, and restructuring has been touted as a change that will *lower* rates (and by extension the need for hedging), not increase them (though certainly experience to date does not provide universal support for this hypothesis). Going even further, customers may be concerned that a given retailer offering a long-term hedge product may not be around to honor its end of the bargain in a year or two. Experience in many restructured states – most notably California, where the power marketer shakeout was particularly severe – demonstrates that such a concern is not irrational. More generally, some governmental customers are simply not allowed to enter into long-term contracts for electricity services, while many C&I customers may have corporate policies that largely stymie such long-term contracting.

The fact that most C&I customers have not expressed an interest in truly long-term hedges puts wind power in a bind. While offering short-term wind power hedges might be most attractive to customers, two issues associated with using wind as a short-term hedge arise.

- **Availability of Traditional Hedging Instruments** – “Traditional” hedge instruments (e.g., futures, forwards, options) may be available over the 1-3 year time horizon, making hedging over this period with traditional instruments reasonably inexpensive. This may limit both the need for and appeal of wind as a hedge in the short term. In fact, Green Mountain’s renewable energy hedge products – while billed as a renewable energy hedge – make use of traditional electricity forwards to provide price stability. Thus, while using wind power to hedge short-term retail rate risk may appeal to customers as an “added value” to their green power purchase, such a hedge product is unlikely to compete on cost alone with traditional hedging instruments.
- **The Relative Value of a Long-Term Wind Hedge** – Wind power projects often require long-term (> 10 year) power purchase contracts to ensure reasonable financing terms and, compared to traditional hedging alternatives, the attractiveness of wind power increases with term. If customers only purchase shorter-term hedges, however, then either the wind generator or an intermediary purchasing the wind power output is exposed to price and quantity risks.

To combat customer concerns over long-term hedging, wind hedge products may yet have a few trump cards to play. First, unlike many traditional financial hedges, wind hedge products are backed by a physical asset (i.e., the wind farm). The existence of this highly visible and tangible asset may engender a sense of stability, permanence, and comfort among potential customers that some of the more esoteric financial hedge products have been unable to create. Second, wind hedge products need not be tied to a particular retail supplier for commodity electricity. A contract-for-differences directly with a wind generator may be a viable option that preserves this sense of stability and permanence while (1) not requiring the customer to switch electricity providers, and (2) allowing the customer the option of selecting a low-cost ESCO. These attributes of a long-term wind hedge product may make it attractive relative to the competition,



though more fundamental barriers to customer interest in long-term contracts remain. Of course, continued customer education and experience with rate volatility may combat this barrier over time.

## 5.5 Market Resistance to Customer Switching

More generally, a physical wind hedge product will typically require the customer to switch to an ESCO, unless the incumbent utility is the one offering the product (or a program such as that which exists in the NiMo service territory is redesigned to offer hedged products). This raises barriers to product availability in two ways: many states do not yet offer customer choice at the retail level, while those that do (including New York) often find that the act of switching suppliers is a barrier in and of itself.

A financial wind hedge product, on the other hand, can be overlaid on top of (and independent from) a customer's existing electricity service: the customer continues to receive the same electricity service, yet enters into a wind-based financial contract-for-differences that effectively hedges some portion of retail price risk. Such a product has a distinct advantage over most forms of physical hedge products in that customers can choose it without having to switch suppliers.<sup>21</sup> Of course, in this case, the CFD product will only be an adequate hedge if the retail electricity rate offered by the customer's electricity supplier is variable and reasonably related to the wholesale price index faced by the generator. Otherwise, the customer would have to switch to an LBMP-passthrough rate offered by an ESCO, thereby negating the "switching" advantage of CFD oriented products.

## 5.6 Credit Risk

A regulated commodities exchange is backed by the combined credit of all of its member firms. In addition, commodities exchanges typically "mark to market" all outstanding contracts on a daily basis, and require customers to post both initial and maintenance margin to cover any losses. Thus, exchange-traded futures and options (i.e., "traditional" hedging instruments) pose very little credit risk to the buyer. A wind hedge, on the other hand, may be marketed by a small company with very little or no income diversification (i.e., this may be all they do), and therefore may pose considerable credit risk to the hedger.

This comparison, however, may not be the proper one to make. Most electricity hedging for end-use customers will occur through a traditional ESCO, and/or will involve so-called "over-the-counter" (i.e., bilateral instead of exchange-traded) products. Thus, the stellar credit of commodities exchanges may be largely irrelevant, and instead, the credit risk of the particular counter-party offering a hedge product – whether traditional or wind-based – may be paramount. If an ESCO is offering a traditional hedge product to its retail customers, a key issue for the

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<sup>21</sup> Financial products may also be offered in states that do not allow retail competition (though in such states, which presumably remain regulated, there may not be much price risk to hedge at the retail level).



customers is whether the ESCO has hedged its own position in the market; a failure to do so could cause severe hardship for the customer.<sup>22</sup>

Furthermore, while the company marketing a wind hedge may be small and poorly diversified (e.g., Community Energy), the hedge is, once again, backed by a physical asset that is potentially owned by a creditworthy company (many large, diversified corporations are entering the wind business as project owners).<sup>23</sup> Thus, it is difficult to generalize as to whether or not a wind hedge poses any greater credit risk than a traditional hedge. Instead, credit risk should be evaluated on a case-by-case basis.

Whether or not credit risk for a wind hedge product is higher or lower than for traditional hedge products, it is clear that credit risk is likely to be a major challenge facing both financial and physical wind hedge products. The specific credit risk to which a customer is exposed, however, may vary depending on whether the product is financial or physical. The sanctity of long-term physical wind hedge products will likely depend on the continued viability of the ESCO, while long-term financial CFD hedges will likely be more dependent on the continued viability of the generator (or long-term power purchaser). As the generator owns the physical asset behind the product (i.e., the wind plant) and the retailer does not, financial wind hedge products may face lower credit risk than physical products.

Finally, credit risk must also be considered from the wind generator's perspective. To date, competitive ESCOs have typically not grown strong enough to offer financeable long-term power purchase agreements to wind generators. The experience of Green Mountain Energy, discussed earlier, is illustrative of this barrier. There is clearly an important disconnect between what retailers are able to offer (primarily short-term contracts) and what renewables generators need (long-term contracts). Even if a retailer was able to find several large C&I customers willing to sign 5- or 10-year fixed-price contracts, credit risk from the generator's perspective is likely to remain a major hurdle absent the entrance of credit-worthy intermediaries, or an intermediary providing assignment of such retail contracts as security.

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<sup>22</sup> For example, the run-up in gas prices in the winter of 2000-2001 in New York led to the bankruptcy of one gas marketer and the withdrawal of another marketer from the residential market in Western New York (State Energy Plan 2002). The electricity crisis in California had even more dramatic effects.

<sup>23</sup> Or, in the specific case of Community Energy, the wind power is purchased under a long-term contract by a larger, more diversified, and more credit-worthy company – Exelon.



## 6 Analysis of a Retail Wind Hedge in New York

Conceptually, the cost of hedging retail electricity price risks with conventional hedges and in a comparable manner to using wind power can provide a proxy for wind's value as a hedge to those customers that value price stability. This requires an apples-to-apples comparison, however, an effort complicated by several factors. First, it is difficult to compute the explicit cost or value of a conventional electricity price hedge, as discussed in Section 3.3. In addition, such conventional hedges may only imperfectly hedge retail price risk (for many of the same reasons identified for wind in Section 5, including non-coincidence of load, etc.), and are themselves very thinly traded.

Given some of the challenges to using wind as a retail hedge, as discussed in Section 5, one could attempt to estimate the cost of “perfecting” the hedge that wind power can provide in order to make it comparable to conventional wholesale hedge benchmarks. Some of the mechanisms that could be used to perfect a wind hedge include: purchasing wind risk insurance products<sup>24</sup> to shift the financial consequences of inter- or intra-annual variance in production to third parties; combining wind hedge purchases with conventional hedges or energy call options during seasons in which wind production is low; installing on-site peaking generation to protect the customer against high energy price spikes; or entering swaps with wholesale intermediaries to effectively convert variable and intermittent production streams into fixed blocks of energy. An assessment of the cost of perfecting wind as a hedge may be feasible, but is beyond the scope of this paper. There may also be sharply diminishing returns to perfecting a wind hedge: much of the cost of hedging is likely to be associated with improving the hedge from “pretty good” to a truly fixed price per kWh that will apply under all load conditions. This, along with the fact that a fully hedged position carries its own risks (e.g., if power prices drop), calls into question whether retail customers would really go to the effort to squeeze all risk out of the picture.

We prefer to look at the problem through a different lens: a wind-based hedge at retail may not need to be perfect in order to be effective for customers. Accordingly, in this section we focus primarily on evaluating the effectiveness of wind at hedging volatility and rising prices in the New York market, using scenario analysis. By answering the question of whether wind can be an effective hedge, and ascertaining the degree of effectiveness, we leave unaddressed several additional questions necessary to fully characterize a wind hedge: the cost of the wind hedge, the value of the hedge to retail customers, and the relative cost-effectiveness of a wind hedge compared to alternative hedging options. Demonstrating that wind can provide some value as a hedge, with the knowledge that a hedge has some value, allows us to conclude that the hedge value of wind can provide a potential supplemental revenue stream to a wind generator (although not necessarily of sufficient scale, absent additional value from renewable attributes, to support a New York wind generator's full revenue requirements.

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<sup>24</sup> Such a product is now offered by Entergy-Koch Trading, for example, in the form of financial derivatives linked to a Wind Power Index in the region in which the generator is located (Polasek 2002; Pethick 2003). This product is designed to hedge resource variability, with payments from the insurer to the insured in years of low wind, and from the insured to the insurer in years of high wind. A wind index swap, for instance, could result in payments to or from the insured party based on a negotiated strike price or even spot energy prices. This type of product is new to the market, and to date has not been offered for terms in excess of five years.



We start by exploring the effectiveness of wind power in providing a retail hedge when the generator and the customer load being hedged are located in the same zone. In Section 6.1 we discuss the sensitivity of retail market prices in upstate New York – the region with greatest wind power potential -- to the determinants of electricity price volatility and escalation in that region. In Section 6.2 we assess, through scenario analysis, the effectiveness of a wind power hedge to a large, high load-factor end-user located in the same zone as the wind generator under simplified conditions: a wind production profile that, while intermittent, does not change year-to-year. This analysis is suggestive of the long-term value of wind as a hedge ignoring inter-annual wind resource variability. In Section 6.3 we then qualitatively examine the effect of inter-annual variation in wind production on the usefulness of wind as a hedge. Next, in Section 6.4, we qualitatively consider the value of a wind hedge to large end-users with less steady or lower load-factors, and on a portfolio basis for a supplier, and discuss the types of customers that might see the most value from a wind power hedge. Finally, in Section 6.5 we consider the usefulness of wind as a retail hedge when the generator is located in a different zone than the load, with transmission constraints resulting in different market prices between zones.

## 6.1 Sensitivity of Upstate New York Market Prices to Electric Price Risk Determinants

We start by considering the electricity price risks faced by large New York end-use customers within the same locational pricing region as a wind plant. For the purpose of this discussion, we define a *locational pricing region* as a group of zones among which there are minimal transmission constraints, so that locational prices move in close synchronization. Since the majority of current wind development activity and potential in New York is in the upstate area, largely in a locational pricing region we will refer to as *NY-West* (consisting of NYISO zones A, B, C, D and E), we first concentrate on the determinants of electricity price risk in NY-West. We will return later, in Section 6.5, to discussing the use of wind as a hedge for customers in the higher-price New York City Zone J, which requires consideration of significant transmission bottlenecks and locational basis differences in market prices.

Wholesale electricity prices in the NY-West region are sensitive to fuel price risk, as well as changes in the overall supply-demand balance, lack of demand response, and the bidding behavior of generation owners. These are largely bidirectional risks (that is, they may act to increase or decrease market prices), where hedging brings greater certainty. In addition, market prices in this territory, given a substantial reliance on coal and other fossil-fuel generation, are exposed to a unidirectional risk of increased environmental compliance costs. We consider each of these risks in turn.

**Fuel Price Risk:** The price of natural gas is an important driver of spot market electricity prices in NY-West, although less so than in other parts of the state<sup>25</sup>. For example, a recent Prosym

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<sup>25</sup> Natural gas is projected to have a stronger influence on electricity prices in the *NY-Central* region, which includes NYISO zones F, G, H and I, than in NY-West. The corresponding fractions of natural gas projected to be on the margin in NY-Central are 69% (all hours), over 85% of winter hours, and almost 80% of on-peak hours. This suggests that wind may be more valuable as a hedge in NY-Central. This makes sense based on supply/demand balances in each region, and the relative prevalence of gas-fired generation in New York-Central compared to NY-West, where nuclear and coal generation are on the margin more often.

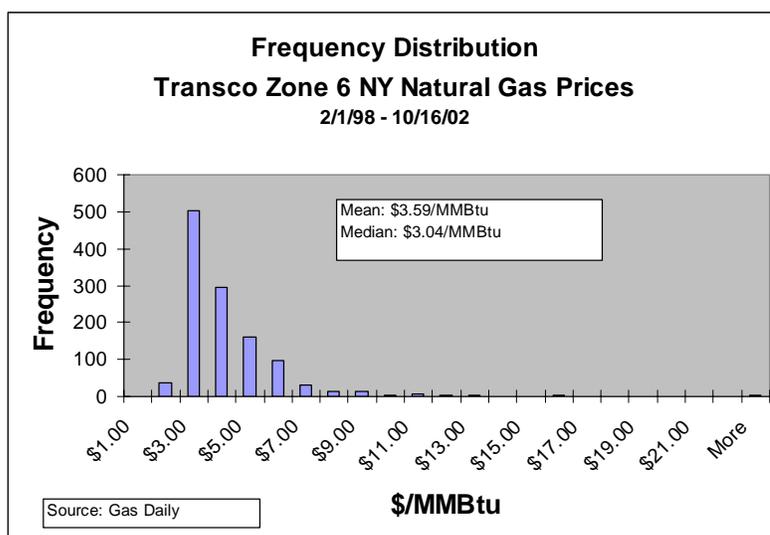


power market simulation<sup>26</sup> projected that natural gas-fired generation would be on the margin (and hence would set electricity prices) in NY-West for 45% of all hours in 2005 (including over 60% of winter hours, and roughly 75% of winter on-peak hours).<sup>27</sup> This information is useful for a first-order approximation of how electricity prices would move in response to natural gas price movements.

As an illustrative example, if natural gas is on the margin 45% of the time in NY-West, a \$1/MMBtu increase in natural gas prices in every hour of the year would imply an electricity price increase of roughly \$3.6/MWh<sup>28</sup> (in practice, somewhat less per MWh for larger gas price changes due to non-linear fuel substitution effects). If a customer's outlook assigned a 25% probability to natural gas prices rising on average \$1.00 per MMBtu, then that customer might attribute a value of about \$0.90/MWh to avoiding such an increase. The value is magnified if a higher probability is assigned to winter price exposure (for instance if the customer has winter-intensive consumption) because of the greater fraction of winter hours whose electricity price is dictated by natural gas prices.

However, in buying a wind hedge, or a conventional fixed price hedge, the customer is foregoing the benefit of any downward movement in prices. Thus a wind hedge would be of more value to a customer for whom the consequences of upward movements in energy costs are particularly onerous, such as those with fixed revenue streams and/or winter-intensive usage. As can be seen in Figure 8, the frequency distribution for natural gas prices over the past several years is significantly skewed, so that for customers ill-prepared to handle electricity price increases, some form of price hedge may have substantial value.

Figure 8



**Supply-Demand Interaction Risks:** Electricity price risks driven by supply-demand imbalance, lack of demand response, or the possible exercise of market power, are also bidirectional risks, and are far more difficult to assess quantitatively than fuel price risk. For example, for a customer with a relatively flat load (a three-shift industrial, for instance), a CFD with a baseload generator in the same region might provide a nearly perfect hedge against these risks. With an intermittent wind generator, the hour-to-hour effectiveness of a wind CFD hedge might be

<sup>26</sup> These results are simulations - the actual effect of natural gas prices on NY prices will depend on many factors, particularly including market behavior.

<sup>27</sup> This reflects winter peaking loads in upstate NY, as well as higher seasonal gas prices putting gas relatively late in the supply stack in winter.

<sup>28</sup> Assuming a 8000 mmbtu/kWh average heat rate for natural gas generation.



expected to be fairly poor, due to the poor hourly match in generation to load and the daily, hourly, and seasonal price spikes. However, as the analysis in Section 6.2 demonstrates, while wind provides a very poor hedge in specific hours, the *annual bill* with a wind hedge can be surprisingly stable. In other words, while wind cannot be counted on as reliably as a more conventional hedge, the actual pattern of prices and production over the last several years (which encompassed a range of electricity market conditions including significant price “spikes”) suggests that its hedge value may be statistically stable if aggregated over a period of time.

Environmental Compliance Cost Risks: Given the prospect that environmental compliance costs for electricity generators could increase through direct (e.g., required retrofits at fossil fuel plants) or less direct (cap and trade regimes for CO<sub>2</sub> or NO<sub>x</sub> emissions, a carbon tax, etc.) means, the purchase of a wind hedge can be thought of as an insurance premium against a unidirectional risk. The value of such a hedge depends heavily on the cost of the required environmental compliance measures, the distribution of the requirements (to all emitters or to specific plants), and the risk of occurrence. As none of these parameters are defined for this general class of risks, and as the perception of risk will differ from customer to customer, placing a value on insuring against this risk is not within the scope of this paper.

A conceptual example of a carbon tax (or, more generally, of a carbon cap and trade regime) may be illustrative. For instance, a wind hedge sized to match load may be an effective carbon hedge because coal, oil, and natural gas are on the margin in virtually all hours in NY-West. For every dollar per ton of emissions tax (or market price of carbon allowances), given the regional generation mix, the exposure to such a tax can be calculated. If it were \$5/MWh, and if you assign a probability of occurrence of 20%; then the value of wind as a hedge is \$1/MWh for every dollar per ton of tax.

A conventional hedge instrument may also be used to insure against this class of risks, and may have similar effectiveness. As discussed in Section 3.3, however, long-term conventional hedges are scarcer and more thinly traded than short term brokered products. Furthermore, conventional hedge transactions often have “regulatory out” clauses that excuse the seller from liability of future changes in law or regulation that are beyond the control of the seller. Since they create no emissions, wind generators are unlikely to be subject to future environmental risk, and therefore have little incentive to seek such out clauses. Therefore, wind power may prove to be an effective means for hedging this class of risk, especially over longer terms.

## 6.2 Hedging an Annual Electricity Bill – Same Zone Analysis

In this section we assess the effectiveness of a wind power hedge purchased from a plant located in NY-West for a large end-use customer in the same region.<sup>29</sup> Key assumptions in our analysis include:

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<sup>29</sup> We note that for such a customer, this pricing may be very similar to taking utility service from Niagara Mohawk, at least historically, although it appears that Niagara Mohawk may have recently changed its procurement practices based on the last few months of data in our analysis. But as noted in Section 2.3, in other territories such as ConEd, utility service does not bear such a close resemblance to a wholesale pass-through service.



- A Niagara Mohawk large end-use customer representative of a typical three-shift industrial customer with moderate daily load fluctuations but no seasonal changes in end-use demand (85% load factor).
- The customer purchases electricity supply under an ESCO's all-requirements, wholesale spot market pass-through pricing structure, under which energy is provided at the local LBMP, ICAP requirements are met at \$2/kW-month, ancillary services are charged at an average price of \$2/MWh, and the supplier charges a retail markup of \$5/MWh.
- The customer executes a financial CFD with a wind generator<sup>30</sup>, indexed to the local LBMP for energy, at a reference price of \$35.33/MWh. This value is arrived at by adding the average spot market value of the wind generator's energy production during the period from May 1, 2000 through December 31, 2002 (\$32.79/MWh) to the per-MWh value of ICAP at \$2/kW-month<sup>31</sup>. We recognize that there are other ways of accomplishing a similar hedge, but this is the most straightforward for illustrative purposes.
- We use one year of actual output from an operating wind farm located in NY-West, and held that production constant from year to year, in both total energy output and hourly profile. The effect of deviation from this profile – annual wind production variability, or wind risk -- will be considered in Section 6.3. The seasonality of production is summarized in Table 1, which shows that wind production during the fall and winter months during the year for which we had actual data was more than twice that for the spring and summer.

**Table 1: Wind Production by Season for a Western New York Wind Farm**

<b>Calendar Quarter</b>	<b>% of Annual Production</b>
January – March	32.4%
April – June	16.8%
July – September	14.3%
October – December	36.5%

The effectiveness of using wind as a hedge in this environment can be tested in two ways: (1) looking forward, by testing combinations of customer load and hedging strategies against hypothetical future market prices; or (2) looking backward, by observing how hedging approaches would have worked under historical prices. For this analysis, we selected the second alternative. Our historical LBMP data set, covering May 2000 through December 2002, provides a significant degree of insight, as the movement in NY-West market prices during that period covers a representative range of experience: extended periods of high and low market prices, as well as seasonal price spikes during both summer and winter periods. This dataset appears to be sufficient to draw some strong general qualitative and directional conclusions. Additional

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<sup>30</sup> While these examples assume a CFD structure, the impacts of a physical delivery structure would be analogous.

<sup>31</sup> The wind generator would receive this revenue for the ICAP credit which it receives, which under NYISO rules approximately corresponds to the plant's annual capacity factor.



analysis under hypothetical future prices is recommended to further support and quantify potential benefits and limitations of a wind-based hedge.

Using the data and assumptions described above superimposed on historical LBMP prices in NY-West, we compared an unhedged all-requirements supply under an ESCO's wholesale spot market pass-through pricing structure with four simple hedging approaches:

(a) **100% wind hedge:** A wind CFD sized at an expected volume of annual wind production that matches the anticipated total annual load of the customer (adjusted for losses). In this case we assume perfect foresight so that the volumes of wind supply and end-use customer load match on an annual basis. Note that this results in wind production substantially exceeding the customer's winter loads, while constituting a partial hedge position in summer months.

(b) **50% wind hedge:** A wind CFD sized at an expected volume of annual wind production equal to 50% of the customer's load. In this case, the wind production volume during winter months approximates the customer's winter load while leaving the customer less hedged in the summer.

(c) **Wind hedge plus conventional block forwards:** A wind CFD sized at an expected volume to meet the customer's winter usage (i.e., so that unlike the first case, there would not be substantial hedge volume in excess of load), combined with a conventional summer seasonal forward block. Such a hedge could take the form of a conventional financial CFD, or a physical purchase of a specified flat block of electric energy from the ESCO at a fixed price. The total combined quantity of the hedge is sized to match 100% of the customer's total expected annual load, with the wind hedge comprising 77.3% of the volume, and the conventional hedge the remainder. We anticipated that that this approach may prove substantially more effective than hedging with wind alone.<sup>32</sup>

(d) **Conventional block forwards:** A conventional annual forward block purchase (presumed to be a financial CFD, but could take other forms), sized at a constant hourly scale to match the customer's annual average load (e.g. sized to match 100% of the customer's total expected annual load). This represents the financial approach that may be used by a number of customer today. It's purpose here is to provide a useful benchmark against which to measure the relative effectiveness of a wind hedge. As with the other hedging approaches, we ignore the absolute cost of purchasing such a hedge (which, as we have suggested in Section 3.3.2, the cost of such a hedge would likely increase in proportion to the term of the hedge).

In each case, the hedges (whether wind or block forwards) were priced to be revenue neutral, i.e. they are based on average historical spot market prices, so as to reveal the hedge effect without introducing any absolute, directional bias.

**Table 2: Relative Stability of Annual Bill**

	All Spot	Spot + 100% Wind
12 months ending 6/01	114%	96%
12 months ending 12/01	104%	102%
12 months ending 6/02	88%	102%
12 months ending 12/02	94%	100%

The annual bill under a wind hedge is surprisingly stable. Table 2 compares the annual bill under spot, and spot + 100% wind scenarios, as a percentage of each scenario's average annual bill, for four staggered 12-month

<sup>32</sup> This strategy may be useful over a several-year period, but due to the unavailability of long-term forwards (or the illiquidity of that market) may not be practical for longer-term hedging.



periods within our historical period.

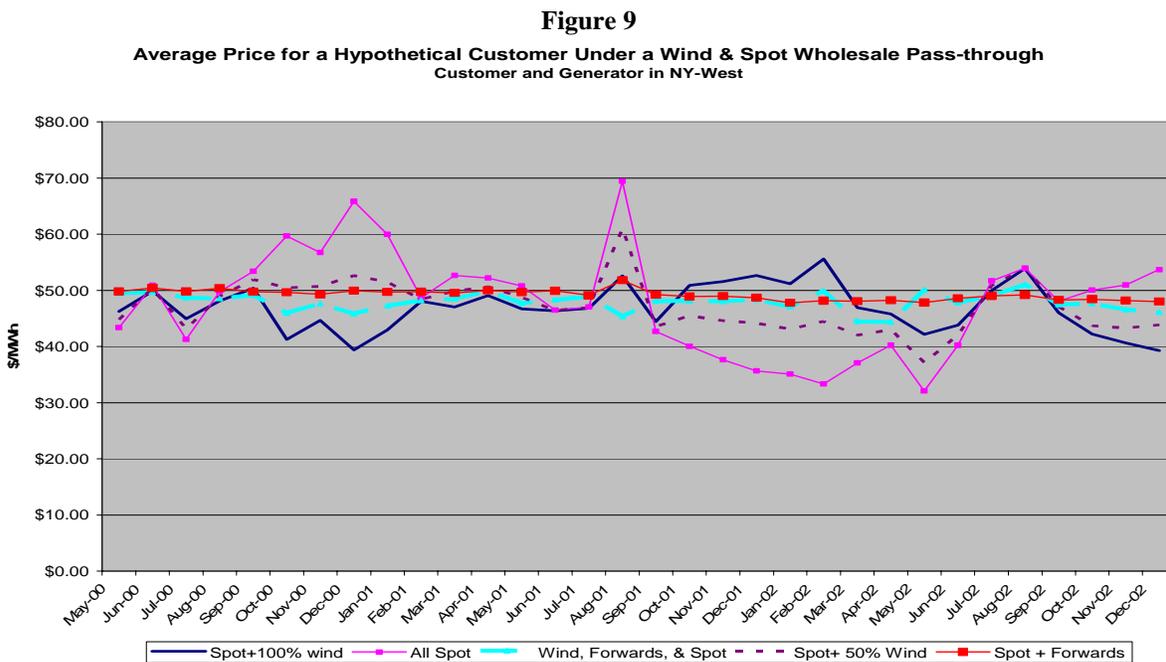
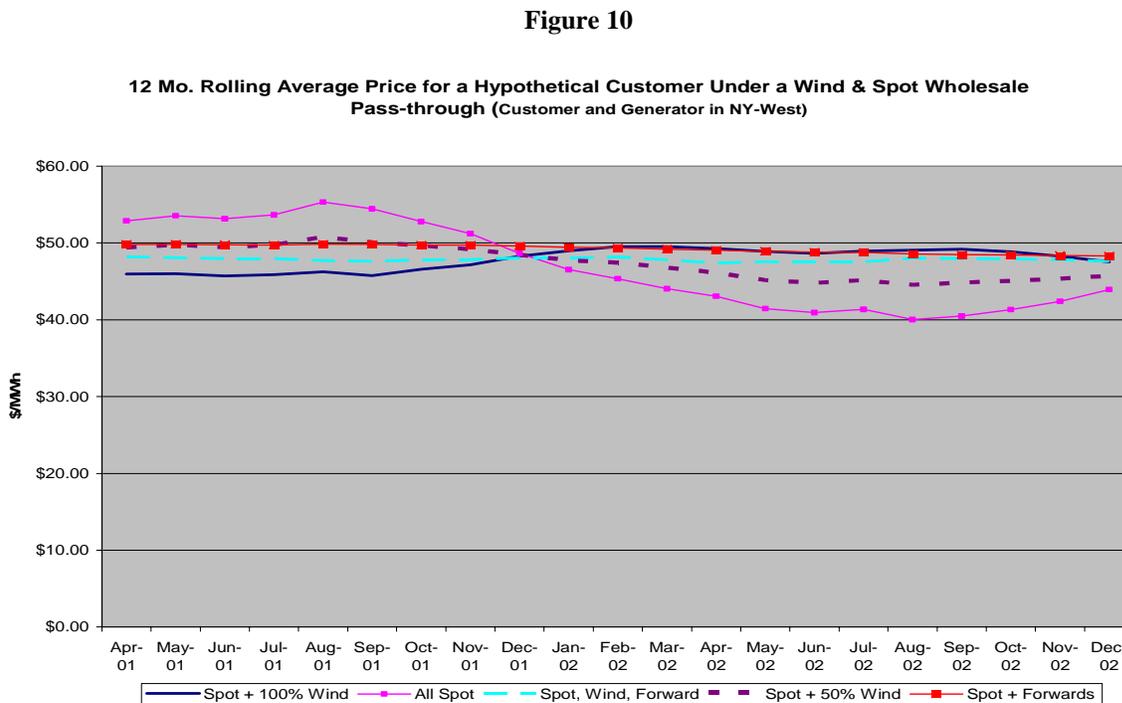


Figure 9 compares the average monthly price to a Niagara Mohawk large end-use customer, while Figure 10 compares the rolling 12-month average price over the historical period.





Finally, Table 3 compares the standard deviations of monthly bills and average price over the historical period.

We first observe that even for this very high load-factor end-use customer, a conventional flat block CFD or similar hedge instrument is a very good, but still not perfect, hedge. Based on this

**Table 3: Comparison of Standard Deviations between Spot and Hedged Electric Supply for High Load Factor Customer**

	All Spot	Spot + 100% Wind	Spot + 50% Wind	Spot + Wind & Summer Forwards	Spot + Conventional Forwards
<b>Standard Deviation of Monthly Average Bill (as % of avg.)</b>	19.9%	7.9%	10.2%	3.9%	2.9%
<b>Standard Deviation of Monthly Average Price (as % of avg.)</b>	19.2%	9.0%	9.8%	3.3%	1.8%

backward-looking analysis, we observe that while there is significant month-to-month variation, wind hedge alternatives appear quite effective at stabilizing monthly and annual electricity prices for a baseload C&I customer in NY-West. Hedge strategies using wind would have dramatically reduced the degree of variation of bills over time and in aggregate, despite volatile spot market prices and intermittent wind production. Since, as we suggested in Section 2.4, a primary motivation for some C&I customers to hedge may be fixed energy budgets, this annual stabilization appears to be an important conclusion.

Although this 32-month historical period is not necessarily representative of future conditions, and therefore does not fully test the effectiveness of the hedge alternatives examined, a number of preliminary conclusions can be drawn from this analysis, informed by the coincidence of production and load discussed in Section 5.2, and the sensitivity of electricity prices to fuel prices discussed in Section 6.1. Based on this data, we believe we can conclude the following:

1. We would expect, upon testing a wind hedge against hypothetical future market prices, to conclude that a simple wind CFD can provide a very good, if somewhat imperfect, hedge against broad market price changes that are not uniform, but affect all months to a significant degree.<sup>33</sup> Such market price changes could result from:
  - Natural gas price changes year-round (e.g., a \$4/MMBtu gas world vs. a \$3/MMBtu gas world);
  - Price changes that affect all months in similar proportions (as might be driven by extended supply shortages);
  - Increases in environmental compliance costs, or
  - Long-term increasing trends in fuel prices.
2. A simple wind CFD might not hedge very effectively against:
  - Seasonal price changes that are not sustained through the year;

<sup>33</sup> At the extreme, we note that a simple wind CFD could be a nearly perfect hedge against a truly uniform electric price increase.



- Long term changes in the seasonal price relationships (e.g., summer prices increase by 20 percent relative to non-summer prices);
  - Extreme hourly spike events.
3. If electricity market price changes tend to occur in periods with high coincidence with wind generation, a partial hedge with a simple wind CFD can be very effective. In NY-West, if sized to meet winter needs, it could provide a degree of insurance against natural gas price exposure in the winter, while leaving the customer relatively unhedged against summer price spike risks.
  4. The addition of a simple forward block fixed-price energy purchase (or CFD) during summer months to a wind hedge sized to match winter usage can greatly improve the effectiveness of the hedge against seasonal price changes. This combination is nearly as effective as a conventional CFD or flat block forward contract.
  5. Despite the intermittency of wind, electricity prices under a wind hedge scenario are surprisingly stable (at least under the conditions that we have tested using historical LBMP patterns).
  6. For purposes of hedging against electricity price risks, this analysis suggests that sizing the hedge to match winter load might be a sound strategy. For all but the most winter-peak-intensive customers, a hedge reflecting a greater fraction of overall usage -for instance matching the annual wind generation to the annual load - may result in overshooting the hedge volume in the winter, adding market risk that may or may not be offset by providing greater hedge coverage during the summer. Given this customer's load shape, as well as the seasonal production pattern of wind in NY-West, the 50% wind hedge was sized better than the 100% wind hedge. In other words, a 100% wind hedge alternative does not significantly reduce the standard deviation of electric prices or bills beyond the 50% wind hedge alternative.
  7. Although our analysis of this historical period suggests that the annual bill can be stabilized effectively using a wind hedge, we can surmise that the more spiky and erratic the hourly LBMP, the more uncertainty that a wind plant will be operating during hours of highest prices, and thus the less effective the hedge will tend to be. This suggests a portfolio approach may maximize the value of wind as a hedge. For example, if an ESCO also has access to peaking generation, it can improve the overall effectiveness of a wind hedge.
  8. There are clearly some expected weaknesses in relying on wind as a hedge. In this case, there is a poor seasonal fit between load and wind generation: wind generation is almost three times as high during peak winter months as the lowest summer months. In the 100% wind hedge case, the wind resource is effectively oversized (relative to the customer's load) in the winter, and undersized in the summer. So, this hedge will have only limited effectiveness in outcomes where summer and winter prices behave differently.

### **6.3 The Effect of Annual Wind Production Variability on Hedge Value**

The analysis in the previous section ignored one important variable: fluctuations in production – both total and among months – from year to year. While wind data in NY-West has not been gathered for sufficient duration at high wind-speed sites to derive accurate statistical measures, experts expect a standard deviation of annual production from long-term mean values in the



range of 8-12% for this region (Bailey 2003).<sup>34</sup> In the previous section we have concluded that a wind CFD between a large end-user with a flat load profile and a generator in the same zone, at least within NY-West, can effectively dampen the volatility in a customer's annual electricity bill. If sized effectively or combined with other strategies, wind hedges may be able to produce results, on an expected value basis, approaching those that could be provided by a conventional hedge purchase of similar duration. Without access to a substantial data set of historical wind production or wind speed at suitable locations, we are unable to precisely quantify the degree to which the impact or value of a wind hedge may or may not be diminished due to inter-annual production variability. Nonetheless, we believe that the historic period assessed in the previous section contains periods with intra-annual variation well surpassing the expected inter-annual variance. Combining insights from our analysis of the historic data set and our expectations for inter-annual wind production variance in NY-West, we can extrapolate the following hypotheses that might be tested with further study:

- The variance in wind production from year-to-year reduces the certainty of the effectiveness and value of the hedge over a short-term horizon, and may produce either a better or worse financial outcome in particular years.
- For long-term trends, however, this effect *may* even out in many cases (for instance, with long-term trends in electricity prices distributed evenly throughout the year). While variations in annual wind production may even out over the long-term, we may not be able to draw the same conclusion about the value of the hedge in many cases, due to variation in electric price volatility between years. A high price year in a low wind year would expose a weakness in the hedge. Conversely, a great wind year in a high price year might produce good financial results.
- Considering shifts from a normal year's production *among months*, we would expect to draw the same types of conclusions as for inter-annual variance, on a smaller scale. Overall, and over the longer term, such variances should not matter much, especially if they are small; but there remains the possibility that even an appropriately-scaled wind hedge (on an expected value basis) may be less effective than anticipated if a poor wind period occurs during periods of high prices.
- The veracity of these preliminary conclusions depends in part on the degree of statistical independence (or positive or negative dependence) between periods of high or low prices and period of high or low wind production. In the Pacific Northwest, this issue was recently raised after a year of both below-normal hydroelectric and wind production.

It is important to note that derivative products are being developed for the wind power industry to insure against wind resource risk (primarily aimed at generators to stabilize cash flows and thereby reduce reserve requirements and financing costs). For example, Entergy-Koch Trading has recently established a suite of derivative products around a regionally-specific Wind Index. While experience with this type of product is limited, Entergy-Koch has expressed openness to

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<sup>34</sup> This projection, extrapolated from the relationship of wind data at low-lying airport measuring sites to hub-height high-wind speed sites, and of wind speed variance to energy output variance in New York, is consistent with findings in other locations: Denmark's wind power index, based on data since 1981, has a standard deviation for annual production of 9-10% (see <http://www.windpower.dk/tour/grid/season.htm>); California's wind can vary within a range of +15% to -30% from a normal year (Polasek 2002).



establishing payment for variances in the Wind Index on either a fixed price or pool spot price basis, and indicated that (based on pricing experience to date) the cost of mitigating the inter-annual wind risk may be as low as 2% of the total revenue to the wind generator. (Pethick 2003).<sup>35</sup>

## 6.4 Hedging Different Retail Load Shapes

So far, we have considered only the usefulness of a wind hedge for a very high load-factor customer. Other types of large C&I customers in NY-West will derive different values from wind hedge alternatives than a customer with the load shape analyzed in Section 6.2; some may find a wind hedge to be of more value, while others may find less value. A lower-load-factor customer will not necessarily find a lower value to a wind hedge; rather, the determining factors will be usage during periods of high volatility, and coincidence of load with wind production. For example, the winter-oriented production shown in Table 2 suggests that facilities with particularly winter-oriented end-uses without corresponding summer load may be particularly well suited for a wind hedge in NY-West. Examples include electric heat customers, ski areas, educational facilities that do not have much summer load, or perhaps even streetlight loads. The converse is also true: customers with summer-peak intensive usage, particularly high air-conditioning loads, may not find a wind-only hedge to be as effective, although if combined with other hedge options, a wind hedge may still have value.

**Table 4: Comparison of Standard Deviations between Spot and Hedged Electric Supply  
For Customer with Average NYISO Load Shape**

	All Spot	Spot + 100% Wind	Spot + 50% Wind	Spot + Wind & Summer Forwards
<b>Standard Deviation of Monthly Average Bill (as % of avg.)</b>	24.7%	14.3%	17.2%	10.7%
<b>Standard Deviation of Monthly Average Price (as % of avg)</b>	18.6%	9.8%	10.0%	3.9%

It is important to note, however, that even for loads that are not particularly well correlated with wind production, wind may provide substantial diversification benefits as part of a portfolio. From this perspective, a customer may wish to consider an undersized wind CFD or similar transaction as a tool that can provide clear hedge value at low risk. Likewise, an ESCO or wholesale supplier might find that using a wind hedge may enhance its ability to offer fixed priced electricity at lower risk.

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<sup>35</sup> This 2% cost is indicative of quotes provided by Entergy-Koch Trading for wind hedges with a fixed payout, i.e. indexed to a constant replacement value in a given year. (Pethick 2003) While Entergy-Koch expressed a willingness to offer a wind risk hedge with a payout settled at an independent wholesale market index such as New York's LBMP prices, we expect that the insurer may seek a larger margin to eliminate price as well as quantity risk in this manner.



It would be straightforward to repeat the analysis in Section 6.2 with a variety of load shapes, but such analysis is beyond the scope of this study, and is not necessary to draw meaningful qualitative conclusions. As an illustrative example, and a proxy for the value of wind hedges in both a portfolio context, and for a customer with *average* load shape, we re-ran the analysis described in Section 6.2, for a customer with a load profile mirroring the aggregate NYISO load profile. The results are summarized in Table 4. As can be seen, based on our backward-looking actual market process, the various wind hedge approaches identified in Section 6.2 reduce the volatility experienced by such a customer substantially, but less effectively (roughly two-thirds as effectively) than in the case of the high-load factor customer considered earlier.

## 6.5 Hedging an Annual Electricity Bill with the Generator and Customer Located in Different Zones

We have demonstrated the usefulness of a wind hedge when the generator is located within the same (NY-West) zone as the customer. However, the highest and most volatile electricity costs in New York State are in New York City (Zone J) and Long Island (Zone K), areas subject to significant transmission constraints and with minimal opportunities for on-shore wind power development. New York City and its suburbs are also where one would expect the highest concentration of customers potentially interested in buying wind as “green power” to reside. The final step of this analysis is to consider the value of a wind hedge when the wind generator is in a different zone from the customer. In particular, we consider the effectiveness of a hedge from a wind plant in NY-West from the perspective of a customer in New York City (NYC).

In New York’s wholesale market structure, when the location of the generator and customer are in different zones, between which there is frequent transmission congestion (characterized by divergent LBMPs), a basis difference is introduced between the generator and customer, as described in Section 5.3. Transmission congestion risk is introduced. While there are tools available to hedge this transmission risk – called transmission congestion contracts (TCCs)- this risk cannot be hedged perfectly due to a combination of wind intermittence, rigid dimensions (size and shape) of TCCs, and the different shapes of wind generation and customer load. Nonetheless, a wind hedge may still be effective enough to provide value to a customer.

We hypothesized that a wind CFD of the type analyzed in Section 6.2 might provide some value as a hedge. We compared the monthly electricity bills and prices (a) for a customer in the NYC zone that purchases electric supply under an ESCO’s all-requirements, wholesale spot market pass-through pricing structure analogous to that described in Section 6.2, except that energy is provided at the NYC LBMP; and (b) for a customer taking a **100% NY-West Wind Hedge**. The hedged customer was assumed to purchase a wind CFD indexed to the NY-West LBMP, sized at an expected volume of annual wind production matching the anticipated total annual load (adjusted for losses), identical to that described in Section 6.2. This approach provides a good hedge for the generator, but perhaps a weaker hedge for the customer than if the customer were in NY-West. The results of this exercise, looking at the same May 2000 through December 2002 historical period of actual LBMP prices in NYC and NY-West used earlier, are shown in Figure 1 and summarized in Table 6.



In comparing the customer's bills under the NYC spot price alone to the 100% NY-West Wind Hedge is that the LBMPs are directionally correlated in most hours, if not tightly correlated in magnitude, so that some hedging effect is seen. Table 5 suggests that the 100% NY-West Wind Hedge would provide reasonable hedge value to the customer, in addition to being a perfect hedge for the generator. The average price and average bills are nearly identical between the two cases, but the standard deviation of monthly bills and prices are cut to 60% of their unhedged value.

We can also hypothesize that a wind CFD or similar transaction indexed to the NYC LBMP may be more effective as a hedge for a customer located in NYC. While the example above - in which the wind generator in NY-West gets paid based on the NY-West LBMP - provides a

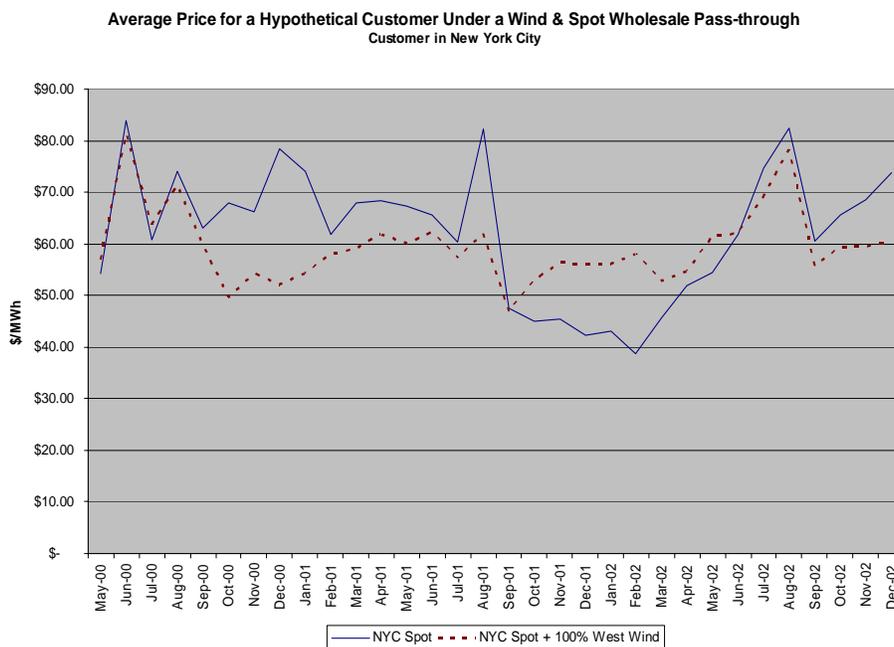
**Table 5: Comparison of Standard Deviations between Spot and Hedged Electric Supply for a Customer in New York City Hedging with a NY-West Wind Project**

	All Spot	NYC Spot + 100% NY-West Wind
Standard Deviation of Monthly Average Bill (as % of avg.)	20.9%	12.7%
Standard Deviation of Monthly Average Price (as % of avg)	20.2%	12.3%

perfect hedge for the wind generator, a CFD indexed to the NYC LBMP from a wind generator located in NY-West exposes the generator to the transmission basis difference between NY-West and NYC zones. For reasons discussed in Section 5.3, it is not apparent that such a basis difference can be perfectly hedged. There are two alternative situations to consider.

In the first case, the wind generator accepts a less-than-perfect hedge, leaving the transmission basis risk unhedged, by receiving the NY-West LBMP energy and capacity revenues for its production and a CFD payment based on the difference between a strike price and the NYC LBMP. Unlike the case in which the CFD is indexed to the LBMP in which the generator is located, in this case the revenue would not match a constant dollar per MWh revenue target. Whether such an arrangement would be attractive to the wind generator, and whether a wind generator with conventional project financing would be able to attract debt financing on such a basis, depends heavily on the level of the negotiated strike price. Our preliminary analysis shows that with this

**Figure 11**





structure, the customer does garner hedge value, but that depending on the strike price chosen and the movement of prices, there could be a net gain or loss to the generator, the customer, or both. A more comprehensive analysis of this situation is beyond the scope of this paper, but is ripe for further study.

In the alternative approach, the generator could attempt to perfect the hedge by getting paid for energy and capacity based on NYC prices. It could do so by scheduling the wind energy into the NYC zone via a bilateral transaction. Congestion is erratic, and during 2000 and 2001, the NYC zone experienced congestion during 54% of all hours, so the congestion cost risk can be severe (Siddiqui et al., 2003). For this structure to make any sense to the wind generator, it would have to attempt to fix the transmission congestion basis risk in order to translate its revenues into the NYC zone as best as it could, through the use of TCCs.<sup>36</sup> During 2000 and 2001, the average hourly cost of congestion into NYC was in the \$8 to \$10 per MWh range. As noted in Section 5.3, TCCs could be an efficient mechanism for hedging a flat block bilateral transaction, but will be poorly matched to wind production or load consumption. However, experience to date in TCC auctions suggests that the market places a premium on certainty to lock in congestion costs (i.e. so far, hedge payments have exceeded actual prices) (Siddiqui et al., 2003). So, based on a limited review of the early years of the TCC market, it may not be particularly cost-effective for a wind generator to hedge locational basis risk. Perhaps by scaling TRC purchases differently by season to reflect seasonal wind generation, the generator might improve TCC utilization sufficiently so that the effects of intermittence might balance out.<sup>37</sup> Whether the transmission basis difference could be hedged with adequate cost-effectiveness to justify this approach is an important question for further analysis, but beyond the scope of this paper. In any event, the TCC market is dictated by periodic auctions, and TCCs do not extend out beyond a few years, so their usefulness for a long-term wind hedge is limited.

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<sup>36</sup> This might be accomplished by either transmitting the wind generator's output into Zone J and paying transmission fees (calculated as the difference in hourly LBMP between zones), and buying a TCC to hedge the cost of doing so; or by simply buying the TCCs, which for a fixed price gives the generator the right to the revenues from use of that transmission.

<sup>37</sup> It is important to note, however, that hedging transmission risk using TCCs requires an additional level of skill and operational involvement beyond the functional capabilities typically staffed by wind generators.



## 7 Conclusions

In this report, we have attempted to assess whether the potential value and effectiveness of wind power as a price hedge in New York is substantial enough to warrant further investigation. We believe we have demonstrated that such further investigation is warranted. We summarize our conclusions here, identifying the barriers to and opportunities for wind power as a hedge instrument in New York State, identifying possible roles for NYSERDA, and suggesting specific areas for further study.

In Section 2, we highlighted the volatility of wholesale electricity prices in New York, and noted that this volatility is driven by a number of factors, including demand fluctuations, the quantity and availability of generation capacity, the generation mix and the incremental costs of marginal generation sources, transmission congestion, lack of demand response, fuel costs, the exercise of market power, and environmental compliance costs. We then note how the structure of retail rate design for some of New York's regulated utilities varies, so that in some territories (Con Ed, for example), the wholesale volatility is dampened somewhat through short-term hedging, or otherwise altered in ways that are not transparent. In such cases, the usefulness of a wind hedge may be undermined unless the customer switches to an ESCO supply alternative that passes through the spot market prices.

We note that a subset of large end-users who may place substantial value on hedging their exposure to electricity price swings, particularly over longer terms, may be limited to those customers (e.g. manufacturing firms) seeking to protect their competitive position in global markets; facilities that face largely fixed energy budgets from year to year, and those that are otherwise risk averse for a variety of reasons. On the other hand, securing a long-term fixed revenue stream of sufficient magnitude to attract debt financing has proven to be a critical hurdle to wind generators. It is the scarcity of such contracts in New York's evolving wholesale competitive markets – utilities are avoiding long-term commitments, ESCOs are typically thinly capitalized – and hence the search by wind generators for alternative sources of long-term contracts with credit-worthy parties, that has motivated this study.

In Section 3, we highlighted conventional hedging strategies used at the wholesale and retail level to provide electric price stability. These include physical hedging tools, such as ownership of generation assets, forward electricity contracts, physical call or put options, and load curtailment. They also include financial hedging tools, such as exchange-traded futures contracts, financial call and put options, and contracts for differences. A different set of tools is available to retail customers. These include combining utility or ESCO generation service with separate financial hedge instruments such as a CFD; entering into a fixed-price electricity contract from an ESCO; or on-site generation and/or load curtailment. We identified the relative advantages and disadvantages of each of these approaches, and concluded that there are shortcomings to all options available to large retail customers (particularly those interested in long-term price hedges). These shortcomings include limited availability of standardized hedge products in sizes small enough for large C&I customers or for terms in excess of 2 years; poor liquidity and high prices of customized hedge offerings; high risk premiums for fixed price electricity contracts reflecting the costs of hedging and a risk premium for any components of the supply that cannot be effectively hedged.

We also reviewed the availability of hedging instruments for each of the determinants of electric price volatility, and where possible, the cost of conventional hedging approaches. We concluded



that (a) hedging individual cost determinants is not always possible (those that cannot be hedged individually can be hedged collectively); and (b) quantifying the explicit cost of hedging various risks in a comprehensive fashion may not be possible due to the lack of data on long-term electricity market expectations. We focused explicitly on the transaction costs of entering into electricity price hedges, and concluded that (due to the lack of liquidity in long-term electric hedges) using financial markets to hedge for longer than a few years can potentially result in significant transaction costs, increasing with the duration of the hedge. The cost of conventional hedging approaches presents a potential proxy for the value of a wind hedge.

In Section 4, we first identify attributes of wind power that provide hedge benefits, including the absence of fuel costs and independence from fuel supply risks, limited exposure to environmental compliance costs, and modularity. Several advantages to using wind to hedge retail price risks are then identified: the interest on the part of wind generators to in offering longer-term hedges than generally available through other means, the ability to offer such a hedge backed by physical assets (perhaps less susceptible to credit risk than alternative sources of long-term hedges), and the ability to leverage the green power sales pitch. We next describe transaction structures that can be used to deliver a wind hedge - bundled electricity service and financial CFDs - and observe that a wind CFD indexed to the LBMP in the generator's zone can provide the generator a perfect hedge, while providing a customer within the same zone, or a zone in which electric prices are positively correlated, at least a reasonable partial hedge. We then summarize the industry experience selling the hedge value of wind power, which to date has been primarily through the bundled product approach. We note that there is evidence of interest in this value, although interest in the long-term hedge - where wind may hold the greatest advantage over conventional means - is largely unexplored. Finally, we discuss each of the barriers facing wind hedge products. These include the lack of retail rate volatility, wind intermittence, locational basis difference between wind generators and customers, market resistance to long-term hedges, market resistance to customer switching (necessary to either access a bundled electricity service, or to link the volatility faced by generator and end-user), and credit risk. We note that the generation pattern typical of an upstate New York wind plant (where most ongoing wind development activity is concentrated) has an expected LBMP market value slightly less than that of a baseload resource, but has production below its average output at the highest price hours of the year. We identify as perhaps the most critical barrier to the wind hedge proposition the limited interest expressed by customers to date in truly long-term hedges of the type wind can best provide. However, it is unclear to what degree this barrier is due to interest in long-term price insurance, or other factors such as resistance to customer switching or concerns over the credit-worthiness of ESCOs - either of which might be bypassed by CFDs offered directly from generators.

Finally, in Section 5, we first conclude that (a) upstate New York wind generation may be well-correlated with exposure to natural gas price movement, particularly during the winter when such prices are most volatile; and (b) New York wind should be particularly effective as insurance against environmental compliance cost risk. Next, we demonstrate, using scenario analyses with historical data, that for a wind generator and high-load-factor customer in the same LBMP zone, a variety of wind hedge approaches can significantly lower price and bill volatility and can stabilize annual electric bills. A combination of wind hedge optimized to winter usage and conventional summer forward block hedge is shown to be nearly as effective as a conventional block forward hedge. Considering year-to-year production volatility, we conclude that - while this wind risk can reduce the certainty of the effectiveness of a wind hedge over a short horizon -



over the long-term this effect *may* in many cases even out, but that the wind hedge's effectiveness is most at risk when a poor wind period occurs during periods of high prices. Considering less ideal load shapes than the high-load-factor industrial customer, we conclude that wind can still provide hedging benefits, although more moderate, to a range of customer types. Finally, in assessing the value of a wind hedge from an upstate New York wind project to a customer in New York City (where a greater prevalence of green power customers might be expected), we find that due to some degree of LBMP correlation between the zones, some hedge value is apparent, although more research is needed to fully explore the options and their implications.

In summary, using actual experience (Section 4) as well as analysis of a hypothetical New York-based C&I customer over the past few years (Section 5), this report has shown that wind power can serve as an effective – though imperfect – electricity price hedge for retail electricity customers. Yet it is difficult to conclude that wind's hedge value alone – i.e., apart from its environmental benefits – is enough to make it a superior resource choice in all situations. In other words, though difficult to quantify, the hedge value of wind power is unlikely to sufficiently cover the full direct cost premium for wind power in New York today.<sup>38</sup> This observation, however, does not mean that wind does not provide significant value as a hedging tool in certain circumstances – value that can factor into the sales pitch of wind sellers if the wind product is structured as a hedge, and the purchase decision of electricity buyers. In fact, it is not clear that less costly hedging alternatives exist, especially over the long term.

Furthermore, wind power has other “green” attributes that are valued by customers, as well as by policymakers and retail electricity suppliers for compliance with policy mandates (such as renewable portfolio standards). Since (in principle) the products and services created by wind generators can be unbundled and sold independently, wind's hedge value perhaps need not support wind's full cost premium above commodity market value; wind's green attributes can also provide premium support. In fact, historically *only* green attributes have provided premium support, while hedge value has gone largely unrecognized, or at least un-quantified and un-monetized. If the market begins to recognize wind's hedge value as well, then the size of the green premium (or alternatively, the need for supplemental public support) may decrease correspondingly. Alternatively, wind's hedge value can simply be identified and marketed as a value-added feature to C&I customers considering making a wind power purchase on “green” grounds.

## 7.1 Summary of Barriers and Opportunities

That renewable energy resources, including wind power, can provide risk reduction benefits to the wholesale electricity market is reasonably uncontroversial. As discussed in Section 4 of this paper, however, translating these benefits into a product offered by an ESCO to a C&I customer is significantly more challenging, whether the product type involves a bundled sale of wind electricity or a financial CFD product. The structure of retail rates often insulates customers

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<sup>38</sup> The premium, or amount of revenue that a wind generator might require above commodity electricity revenue, may be in excess of 1¢/kWh, based on a levelized revenue requirement from 4¢/kWh to over 5¢/kWh at the busbar after production tax credits, compared to wholesale generation revenues in the 3 to 4¢/kWh range based on historical market prices.



from the full impact of wholesale price volatility. Those retail customers who do experience price volatility may be located in a different zone (with a different LBMP) than a wind generator, and/or might have a load profile that does not closely match the diurnal and seasonal production pattern of the wind plant, thereby limiting the effectiveness of a wind hedge. Finally, customers in general may be averse to switching retail suppliers or otherwise entering into long-term hedges for many reasons, including concerns over counterparty credit quality. These barriers to using wind as a retail wind hedge are significant, and should not be underestimated. They suggest that retail wind hedge tools are likely to be, at best, a niche market.

In spite of these barriers, our analysis in Section 5 shows – at least over the period examined – that wind has not been as imperfect a hedge as one might initially suspect given demand and generation profile mismatch. This is particularly worthy of note, considering that alternative means of hedging (e.g., with block forwards) are also far from perfect, and face some of the same barriers listed in the previous paragraph. Furthermore, the availability of such “conventional” hedging instruments over longer terms appears to be limited. Thus, while opportunities to employ wind power as a hedging instrument against retail electricity price volatility do not appear to be pervasive, there are certainly niche applications and certain customer types that merit further attention. These include:

- **Stripping out (unbundling) wind’s hedge value and selling it to customers who value the hedge:** The “hedge” market, which may be broader than (or at least different from) the “green” market, can supplement revenue to wind generators from traditional green power sales, thereby reducing the amount of green power revenue needed to make a project viable. Successfully selling wind’s hedge value could also help to lower the cost of the state’s RPS, were one to be developed.
- **Targeting specific customer types:** Obviously, a wind hedge (or any hedge) adds the most value where retail electricity prices are variable and not isolated from wholesale market fluctuations. Our analysis in Section 5 reveals that the distribution of natural gas prices is significantly skewed to the upside, and that New York’s seasonal wind pattern is heavily weighted towards the winter months. This suggests that customers for whom the consequences of upward movements in energy costs are particularly onerous may be particularly good targets for a wind hedge product. Similarly, those customers with fixed revenue streams and/or winter-intensive usage may especially value a wind hedge. C&I customers located in the same LBMP region as wind generators may see the most value from a wind hedge, though if one can cost-effectively hedge basis risk between LBMP zones, a wind hedge may be just as effective when the generator and the customer are located in different market zones. Based on our limited analysis in Section 6.5, even if one can’t effectively hedge the transmission congestion basis risk, wind may provide moderate hedge value even when generator and customer are not in the same zone. Finally, only those customers that are reasonably certain that they will be in business for a long period of time would likely find a long-term wind hedge product useful.
- **Targeting the government sector:** Government facilities – such as agencies or schools – are a promising customer segment as they often operate under fixed facilities budgets and may therefore value a hedge against rising electricity prices. Furthermore, Executive Order 111 requires government agencies to purchase 20% of their electricity from renewable sources by 2010, making them a logical target for a wind hedge, as opposed to



a conventional hedge. While promising candidates, it deserves note that governmental customers may face significant institutional barriers to contracting long term.

## 7.2 Possible Roles for NYSERDA

This report has shown that wind can offer value as a hedge against volatile and rising retail electricity prices, but that this value will be challenging to exploit. While the private sector is beginning to explore this idea, and in several cases is marketing such a product, public support would no doubt facilitate the development of a market for wind's inherent hedge value. To this end, there are several roles NYSERDA might choose to play going forward.

**Support development of a base of experience with retail wind power hedges.** Perhaps of greatest value NYSERDA could offer would be supporting development of a base of experience with wind power hedging long-term retail rate risk. A few alternatives, with increasing levels of engagement, include:

- ***Support a demonstration project***, in which NYSERDA provides expertise (internal or consultants) to facilitate the development of a retail hedge transaction using wind. Document the approach and results in a publicly available paper, to be replicated (if successful) or learned from (if unsuccessful).
- ***Support product rollout***. Undertake a more comprehensive project by subsidizing a retail ESCO or a wind generator that develops and tries to sell such a product in particular.

**Remove remaining unhedged risks from wind hedge transactions.** By helping to perfect wind hedges, NYSERDA can remove a barrier to parties entering into wind hedge transactions. In addition to helping to build the base of experience, NYSERDA could – without exposing the pioneering customers, marketers or generators to these risks - help quantify the true exposure to these risks, had they not been insured, so that irrational fears of the degree of imperfection can be allayed. Options include:

- ***Fixing transmission costs between zones.*** NYSERDA could fund or insure hedge transactions against the transmission basis differences between LBMP zones (or perhaps even insure against the mismatch between generation and load, which includes basis but also includes load/generation mismatch). As discussed earlier, most of the wind development in New York is likely to occur upstate, whereas perhaps the highest value from a wind hedge could be realized in the metropolitan area of New York City. Helping to remove the financial risk of transmission constraints between these two regions could be a step in opening up this market.
- ***Remove wind risk (e.g. risk of year-to-year variability in production).*** At least one entity is already offering a weather-derivative insurance product in Europe and California to hedge the risk of inter-annual wind variability. Further investigation into the effectiveness and cost of such a product is warranted. In particular, there is not yet any experience using such wind derivative instruments that settle on an LBMP index. NYSERDA could entice one or more firms to offer such a product in New York by sharing some of risk.

In demonstrating that the imperfections of a wind hedge do not fully undermine its value, one could hope that such experience would make parties more willing to enter into such transactions without remaining risks being insured.



**Fund additional areas of study.** NYSERDA might provide support for studies to address further areas of study identified in the following section, as a means of further fleshing out the viability of using wind as a retail price hedge for C&I customers in New York.

### 7.3 Further Areas of Study

While this report provides a detailed overview of many of the major issues involving the use of wind power as a hedge against retail electricity prices for C&I customers in New York, there remain many specific issues and questions that we have not attempted to address or answer. The opportunities for further research that can add the most incremental value to this study include:

- **Conduct a survey of C&I customers' interest in hedging electricity price risk, particularly with a wind-based product:** This report was written under the assumption that there is in fact demand for such a product, but it is not clear that such demand exists. Confirming or refuting this assumption through survey techniques is a logical next step. In particular, we recommend (a) exploring whether consumer interest in long-term hedges increases in markets in which customers have experienced severe volatility, or whether such a product is more appealing in times of concerns of rising prices/volatility; and (b) assessing the institutional barriers that may prevent federal, state, municipal, and institutional customers from contracting over a long enough term to make the hedge worthwhile to both the customer and generator.
- **Assess the effectiveness of a wind hedge when the customer is in a different LBMP zone than the generator:** Section 6.5 briefly dealt with this, but identified areas for further analysis to understand the viability and effectiveness of hedging across LBMP zones.

Perhaps of lower priority, the analysis in this paper could be fine-tuned and extended to test some of the hypotheses raised. None of these analyses need be done before moving forward with support of a product offering. For example:

- **Test the preliminary conclusions reached using historical data through scenario analyses with hypothetical future market price and production data.** While we have hypothesized the effectiveness of a wind hedge under a variety of conditions based upon the historical analysis, these hypotheses could be tested using purpose-built production and price curves.
- **Test the effectiveness of a wind hedge for other retail load shapes:** We have only tested a high-load factor customer with no seasonal usage bias, and the NYISO average load shape, while hypothesizing that a wind hedge would be more effective for some usage patterns and less so for others. Additional analysis could confirm and quantify these assertions.
- **The effect of annual wind production variability on hedge value and effectiveness.** We have held wind production constant in our limited analysis, and have hypothesized how annual wind production variability might degrade or even enhance the effectiveness of a wind hedge on both a short-term and long-term basis. These hypotheses could be tested using a broader range of market price and wind production data. For example, simple scenario analyses could be developed to test a hedge's effectiveness when shocked with very good or very bad wind production months, to simulate good or bad year.



One other area for further study, in the category of implementation detail, would be an investigation of the accounting and tax treatment of financial hedges. Financial Accounting Standards (FAS) 133 and 138 require that corporations report a wide range of derivative instruments on their financial statements, with the gain/loss reported regularly. A concern is that the use of a wind CFD could trigger burdensome accounting requirements that offset or outweigh any hedging benefits. There are certain exceptions to the reporting requirements, including for instruments that hedge committed or anticipated commodity purchases. Our brief review indicates that a wind CFD may qualify for this exception, although the customer may be required to quantitatively demonstrate the effectiveness of the hedge at regular intervals. Further study might involve retaining appropriate experts in energy accounting to establish the accounting requirements for a wind CFD, and the circumstances that might alter these requirements.

Finally, an area for study which is related to our topic, is an assessment of the effectiveness of wind as a hedge against gas price volatility. This paper has focused on wind as a hedge against retail electricity prices. However, since wind production in New York is concentrated in winter months, when the use of natural gas for heating purposes is highest, it is possible that wind generation could also provide a hedge, of sorts, against natural gas prices. This could be explored, for example, by analyzing a wind CFD or similar financial tool in concert with a customer's *natural gas* rather than electric bill. While this would clearly be a secondary benefit to wind's ability to hedge electricity price risk, NYSERDA may nevertheless wish to investigate this possibility further.



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## **Appendix A. Industry Experience with Wind Hedges**

A large number of the green power products sold in regulated and restructured markets in the United States do not offer a truly fixed price for generation service. A variety of green power providers, however, do have some experience in supplying the hedge value of wind to their retail customers. Below we summarize several examples, in both regulated and restructured markets. In each case, we describe the features of the actual or proposed offering, customer response, and challenges faced. See Bird (2003, forthcoming) for a more comprehensive review of experience to date.

Our purpose here is to show in a practical way how the hedge-value of wind power can be delivered to retail customers, the challenges of offering such products, and experience to date. Later sections of this study analyze the barriers and opportunities in more detail, with specific reference to New York, referring back to this section where appropriate.

Because the majority of the wind-hedge products offered in the U.S. to date are delivered as bundled renewable electricity service, four of our five cases highlight this approach. Three of these cases come from integrated utility experience (Austin Energy, Eugene Water and Electric Board, and Xcel Energy), while the third comes from competitive market experience (Green Mountain Energy). A fifth and final case highlights an innovative attempt made by Community Energy to offer a financial contracts-for-differences product. As a Text Box, we also discuss customer experience in seeking renewable energy hedge products, as related by the Green Power Market Development Group.

### **A.1 Austin Energy**

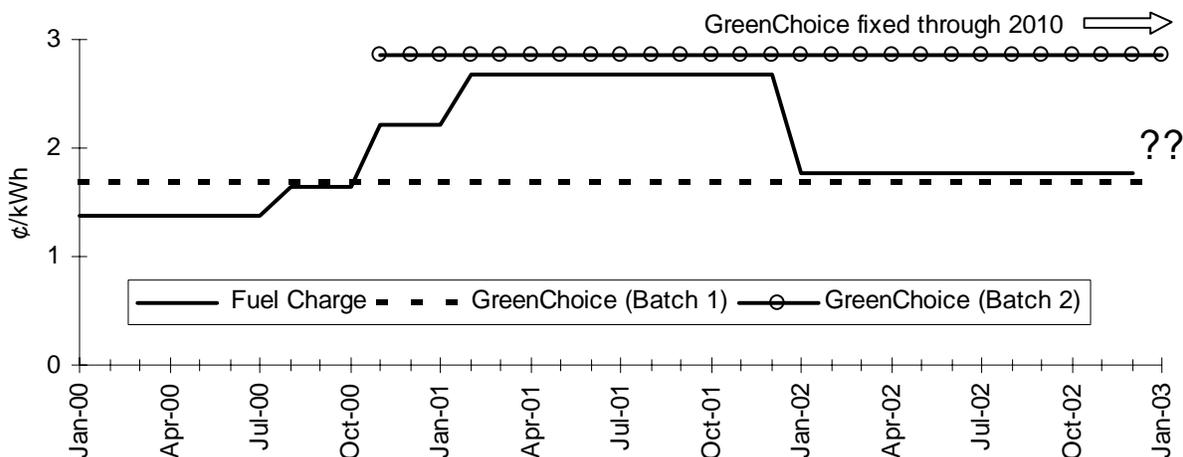
Austin Energy is one of a number of utilities that have developed green pricing programs that shield the green power purchaser from fuel-price volatility. Austin's program was launched in January 2000, and delivers a product that primarily consists of wind power, with lesser quantities of landfill gas and solar. Smaller customers must purchase 100% of their electricity needs from the program, while larger customers may choose to serve just a portion of their needs.

Austin Energy prices its conventional energy as a combination of a base electricity rate and a pass-through variable fuel charge; typical customers are therefore exposed to some retail rate volatility. The price of the green power product (GreenChoice), however, is largely fixed and consists of the same base electricity rate and a fixed GreenChoice rider, the latter guaranteed for 10 years. The GreenChoice rider represents solely the cost of buying wind and other renewable power; administrative and marketing costs of the program are recovered within existing base electricity rates. GreenChoice customers are exempt from the variable fuel charge for the amount of green energy purchased. The "incremental" price of GreenChoice can therefore be viewed as the difference between the GreenChoice rider and Austin's variable fuel charge.



For the program’s initial phase (“Batch 1”), the GreenChoice rider was priced at 1.7¢/kWh (dashed line in Figure 12), a premium of 0.33¢/kWh over the variable fuel charge (solid line in Figure 12). Bird (2003, forthcoming) reports that this low premium was due in part to Austin Energy matching participants’ subscriptions dollar-for-dollar. As natural gas prices rose to unprecedented levels in late 2000, Austin Energy’s historically low fuel charge increased by 61% to 2.21¢/kWh, allowing GreenChoice to be priced at a *discount* of roughly 0.5¢/kWh. Since

**Figure 12: Austin Energy’s Variable Fuel Charge vs. Fixed GreenChoice Charge**



then, the variable fuel charge has risen even higher, to 2.68¢/kWh, before dropping back to its current level of 1.77¢/kWh (which is still slightly higher than the GreenChoice rider, allowing green power to be sold at a discount since November 2000).

In the Fall of 2000, Austin Energy closed “Batch 1” and placed all new customers in “Batch 2,” which carried an unsubsidized GreenChoice rider of 2.85¢/kWh, for an initial green premium of 0.64¢/kWh (see circled line in Figure 12). The subsequent February 2001 increase in the variable fuel charge reduced this premium to only 0.17¢/kWh, though the precipitous January 2002 reversal has since swelled the premium to 1.08¢/kWh – its highest level since program inception (for either Batch 1 or 2).

With over 80 MW of new wind power on line to serve the program, GreenChoice is among the most successful green pricing programs in the United States. Austin Energy has relied heavily on the price-stability benefits of wind power in its marketing of the product. A low, fixed-price offer combined with the promise of rate stability has bolstered demand for green power, particularly among commercial customers, which account for two-thirds of Austin’s green power demand. With the steep January 2002 reduction in the variable fuel charge, a major challenge going forward will be to retain existing and attract new customers in an environment in which green power remains a premium product.



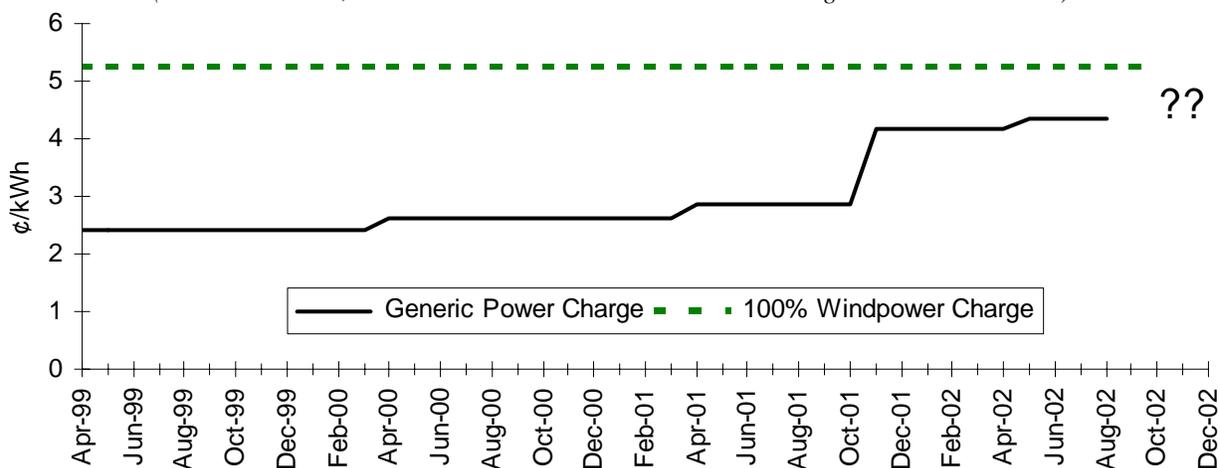
## A.2 Eugene Water and Electric Board (EWEB)

EWEB launched its Windpower program on Earth Day 1999. The product consists entirely of wind power derived from EWEB's 21% ownership stake in Wyoming's 41.4 MW Foote Creek Rim project. All customer classes can sign up for either 10%, 25%, 50%, or 100% Windpower.

EWEB's standard rate structure includes a fixed basic charge, a volumetric delivery charge, and a volumetric energy charge (C&I customers also pay a demand charge). Windpower costs of 5.274¢/kWh are reflected in the energy charge portion of the bill, where they are proportionally blended with the generic energy charge for customers choosing the 10%, 25%, or 50% Windpower option (100% Windpower customers simply pay 5.274¢/kWh). In November 2001, EWEB split the volumetric energy charge into three tiers, and in May 2002, the company added a Power Cost Recovery Surcharge of 0.338¢/kWh intended to remain in place for 3 years to recover the costs of the electricity crisis of 2000/2001. The Windpower portion of a customer's bill has not been affected by either of these changes, or by the multiple rate hikes EWEB has implemented since April 2000. In other words, customers choosing 100% Windpower have paid

**Figure 13: EWEB's Generic Power Charge vs. 100% Windpower Charge**

*(Note: assumes 1,800 kWh/summer month once tiered rates begin in November 2001)*



a flat 5.274¢/kWh on the energy charge portion of their bills since the program's inception. (It does deserve note, however, that EWEB plans to conduct its first full review of the program in the near future, at which point it will decide whether or not to change the Windpower price). Figure 13 depicts the narrowing spread between EWEB's Windpower and generic energy charges for residential customers since the program's inception.

EWEB's goal was to have its Windpower program fully subscribed within three years of the program launch (i.e., by April 2002). While this goal has not been met (roughly one third of the power remains unsubscribed), participation has nevertheless been strong relative to many green pricing programs. More than 2% of all EWEB residential customers signed up for the program in its first month, and this participation rate rose to nearly 4% by the end of the program's first year, where it has since stabilized, and even tapered off slightly over the past year as generic energy charges have risen sharply (thereby adversely impacting those who had chosen one of the partial Windpower options). Commercial participation, on the other hand, has been steadily increasing, and as of March 2002, 80 commercial customers had signed up for the Windpower



program. Data from July 2001 show that most commercial (62%) and residential (55%) customers that have opted to purchase wind power have joined at the 10% level, however, perhaps implying a motive other than achieving price stability.

### A.3 Xcel Energy – Minnesota

On May 29, 2001, the Minnesota Energy Security and Reliability Act was signed into law. This law requires all electric utilities operating in the state to offer their customers a green pricing option. In December 2001, Xcel Energy filed a proposed renewable energy tariff with the Minnesota Public Utilities Commission (the Commission). Two stakeholder groups filed comments on Xcel's proposed program in February 2002, and the Commission met to discuss the matter in April 2002. The comments and discussion generated during this process bring to light some of the issues surrounding the use of wind power as a hedge against retail rates (particularly for integrated utilities); the most pertinent points are summarized below.

Xcel's proposal described a slightly modified version of its "WindSource" program, which it has successfully offered to its (PSCo) customers in Colorado for a number of years. Xcel's proposed pricing methodology in Minnesota would have summed the cost of the wind power, incremental transmission costs (if any), and incremental administrative costs, and then nets that total against the embedded cost of energy (but not "capacity") from its latest rate case. Unlike in Colorado, Xcel's proposed Minnesota program would not have exempted customers from fuel adjustment clauses or any fees charged under an emissions reduction rider. Residential customers would have to commit to the program for a minimum of one year, while commercial customers would have to commit for at least three years.

Stakeholders in the proceeding voiced three major concerns over Xcel's proposed program:

- **Xcel's pricing methodology deducts only the cost of energy, and not the cost of capacity, from its most recent rate case, and therefore participants may be paying more than the incremental cost of wind power.** The Commission concluded that "if there is no credit for capacity costs either to account for the capacity costs built into base rates, or to account for capacity or other benefits provided through renewable resources, WindSource customers may be paying more than incremental cost for their renewable resource." The Commission ultimately approved an agreement reached between the stakeholders and Xcel, in which Xcel will deduct both the cost of energy established in its most recent rate case (i.e., as proposed), as well as the value assigned to the wind capacity in the contract(s) Xcel signs to secure power for the WindSource program (i.e., rather than the capacity value from the most recent rate case).
- **Under Xcel's proposal, participants' energy use would be subject to the fuel adjustment clause (FAC) – intended to capture changes in the price of fossil-fuel inputs – in addition to the green premium.** The Commission ruled to exempt WindSource customers from the FAC, acknowledging that there will be times when the wind is not blowing and WindSource customers will therefore be "free-riding" on Xcel's fossil-fueled portfolio, but pointing out that the reverse will also be true – non-participating customers will occasionally free-ride on WindSource turbines. The Commission argued that these opposing infringements would tend to offset one another over time, and that the impact of any particular WindSource free-ride would be quite small (a) given the limited number of



participating versus non-participating customers, and (b) compared to the burden *unquestionably* placed on WindSource customers if they were required to pay the FAC.

- **WindSource customers should be exempted from any fees charged under an emissions reduction rider (to pay for emissions control equipment on coal-fired power plants).** Since Xcel had not proposed an emissions reduction rider at the time of the hearing, the Commission did not rule on this final comment, but instead required Xcel to raise the issue in the future should it file for approval of an emissions reduction rider.

## A.4 Green Mountain Energy

Compared to utility green pricing programs, competitive green power ESCOs may have a hard time offering a fixed-price product due to credit concerns (by customers and wind power generators) and due to the fact that such ESCOs do not have a large and stable customer base. Nonetheless, in competitive markets green power marketers offering bundled electricity products have on occasion offered hedged green power products that provide a measure of price stability. Perhaps most prominent among these offerings are those of Green Mountain Energy Company.

Green Mountain's first foray in offering a fixed-price product was in Southern California, where, in response to the state's energy crisis, it marketed a 100% renewable energy product (the "Breathe Easy" plan) to residential and small commercial customers beginning in November 2000, in an environment of extremely volatile retail rates. The product was composed of a one-year fixed-price forward contract for conventional power, with renewable energy credits overlaid on top in an amount sufficient to "green" the product to 100% renewable (Blunden 2003). The forward contract included not only fixed-price power, but also fixed-cost ancillary services (unusual in wholesale contracts), enabling Green Mountain to guarantee a price of 8.5¢/kWh through December 31, 2001 (just one year).

Though initially intended as a pilot project, the offering sold out in a matter of days. Green Mountain was unable to procure additional power (and thereby expand the program) at similar terms, however, because the wholesale market was deteriorating so rapidly (Blunden 2003). Though Green Mountain was eventually forced to turn back most of its California customers due to the energy crisis, those who had signed up for the fixed-rate plan were reportedly served at least until December 31, 2001 when the forward contracts expired (Bird, forthcoming).

Green Mountain currently offers a fixed-rate green product in Texas, where in April 2002 the company launched a 100% wind energy product priced at the fixed rate of 8.8-9.4¢/kWh (depending on the utility service territory) plus a \$4.95 monthly service fee (the "Reliable Rate" plan). The mechanics of this product are similar to those described above for Southern California: a one-year fixed-price forward contract for conventional power, with fixed-price green tags overlaid (Kilkelley 2003). Thus, in return for a one-year customer commitment (with a \$25 penalty for early cancellation), the rate is fixed for a 12-month period (though Green Mountain reserves the right to change the monthly service fee, upon 45 days notice). This fixed rate is 0.3¢/kWh higher than the month-to-month service option that Green Mountain offers, under which Green Mountain reserves the right to alter its rates with 45 days notice. A Green Mountain press release notes that 80% of customers surveyed said they would pay more for price certainty.

Green Mountain's approach of overlaying green tags on top of a conventional fixed-price forward contract (rather than contracting for bundled fixed-price renewables) *guarantees* that a



renewables-based hedge product will be more costly than a conventional hedge product. The premium equals the cost of the green tags. While a premium fixed-price product may do well in areas such as Southern California, where the fear of escalating prices was palpable, customer response may be more tepid in locations where concerns over electricity prices are not as pronounced.

More importantly, Green Mountain's approach to offering fixed prices provides little or no more benefit to a renewables generator than does a standard green tags purchase. This fact highlights an important disconnect between what retailers are able to offer (primarily short-term contracts) and what renewables generators need (long-term contracts). With many customers (residential in particular) unwilling to sign contracts for longer than one year, retailers are limited in the types of hedge products they can offer, and hence the types of supply contracts they can sign. Furthermore, even if a retailer is able to find several large C&I customers willing to sign 5- or 10-year fixed-price contracts, credit risk remains a major hurdle. Most competitive electricity retailers – Green Mountain included – are not particularly creditworthy, perhaps engendering a reluctance to sign long-term contracts among both customers and generators alike. On the flip side, a retailer may be unwilling to accept the credit risk from a renewable generator for more than a year.

In the end, perhaps the true value of Green Mountain's offering of fixed-price renewables products is that it demonstrates customer demand for clean, fixed-price electricity, which – though not directly benefiting renewables generators more than any other green tag sale – is ultimately good for renewables.

## **A.5 Community Energy**

Community Energy, Inc. (CEI) is a green power marketer (and wind developer) operating primarily in the Northeastern U.S., with plans to expand into other areas of the country. CEI has been quite successful at marketing the tradable renewable certificates (TRCs) from several mid-Atlantic wind projects to commercial and institutional (e.g., governmental and educational) end users. Many of these projects have 20-year power purchase agreements (PPAs) with Exelon Power Team, a wholesaler who sells the wind power into PJM's spot market, but does not expect the revenue from such sales to cover the full cost of the PPAs. Thus, Exelon has contracted with CEI to market the projects' TRCs to retail customers at prices sufficient to make Exelon's wholesale wind power purchase profitable.

Although CEI has been able to sell a substantial quantity of TRCs associated with these projects, typical contract terms have ranged between one and five years, with an increasing number of customers willing to consider longer terms. Nonetheless, purchases of TRCs have been on much shorter terms than the 20-year life of a wind power PPA. Moreover, though the TRCs themselves have been sold at fixed prices, the purchase of a fixed-price TRC does nothing to hedge electricity commodity purchases for an end-use customer.

Trying to add value to their product (above and beyond the product's "greenness") and meet customer and supplier needs, CEI has been exploring the possibility of offering a wind-based financial contracts-for-differences product (combining TRCs with a financial CFD) with longer terms. As described in Section 4.3, this would involve selling TRCs with a floating premium such that the end-use customer's combined electricity and TRC purchases are hedged. This would make CEI the first to offer such a product. CEI has not completed any sales of this product to date, though the company is still developing some of the conceptual details of the



offering. Whether and how CEI plans to address some of the design challenges mentioned in Section 4.3 and evaluated in Section 5 remains unclear.

### **CUSTOMER EXPERIENCE IN SEEKING A GREEN POWER HEDGE PRODUCT: THE CASE OF THE GREEN POWER MARKET DEVELOPMENT GROUP**

The Green Power Market Development Group (the Group) is a collaboration of 10 large corporations (Alcoa, Cargill Dow, Delphi Corporation, Dupont, GM, IBM, Interface, Johnson & Johnson, Kinko's, and Pitney Bowes) and the World Resources Institute that was formed in 2000 and is dedicated to developing corporate markets for 1,000 MW of new, cost-competitive green power by 2010. According to their website ([www.thegreenpowergroup.org](http://www.thegreenpowergroup.org)), the Group seeks to:

- “Develop strategies to reduce green power costs by using innovative purchasing options, by reducing transaction costs for companies, and by gaining economies of scale through working as a group.
- Reduce market barriers faced by green power suppliers and buyers by providing independent information to potential customers.
- Define the business case for buying green energy products by recognizing the value of renewable energy to diversify energy portfolios.”

As implied by the last bullet, the ability of renewables to hedge against volatile and rising electricity prices is considered by the Group to be a key value proposition that green power can offer. That said, to date only two members of the Group (Kinko's and IBM) have purchased fixed-price green power products – both have enrolled Texas facilities in Austin Energy's GreenChoice program (see Section 4.4 for a description of GreenChoice).<sup>\*</sup> The Group has found that programs such as GreenChoice are not universally replicable throughout the country (or more importantly, in places where these companies' facilities are located) due to renewable resource constraints in some areas, and furthermore are not as attractive in regions of the country dominated by coal or hydropower generation, which tend to be both cheaper and less volatile than gas-fired generation (Hanson 2003).

Nonetheless, the Group has been talking to various load-serving entities and renewable generators about ways to purchase fixed-price power from renewables. One of the most promising instruments appears to be a contract-for-differences, similar to that described in Section 4.3. Such an instrument overcomes some locational barriers (i.e., facilities need not be located close to the generator) and can be less administratively burdensome than either investing directly in projects or contracting for physical delivery (Hanson 2003).

Ultimately, however, price has been a major sticking point. The Group's goal is to seek or create “cost-competitive” green power opportunities, and with wholesale electricity prices depressed in many parts of the country, price stability (and power) can typically be obtained more cheaply using traditional hedging instruments such as forward purchases. Of course, renewable energy may be able to provide price certainty over longer periods of time than can standard hedging instruments, though the Group's appetite for long-term contracts varies by company (and by facility), suggesting that renewables may not always be able to play what may be their strongest hand – long-term price stability (Hanson 2003).

<sup>\*</sup>Other Group members have installed onsite generation, which also provides a certain degree of price stability through peak-shaving and offsetting load.