Utility-Scale Wind and Natural Gas Volatility

Uncovering the Hedge Value of Wind For Utilities and Their Customers

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EXECUTIVE SUMMARY

Prudent investors do not solely invest in junk bonds over treasury bonds; they do not purely chase yield without regard to risk. A portfolio approach applies not only to personal finances, but also to energy investments. While natural gas spot prices are low today, they remain volatile and present a number of risks[1]:

- Unreliable natural gas and electricity market forecasts
- Uncertain power generation costs for IPPs, utilities and regulators
- Unpredictable costs for large customers, especially publicly traded companies that must report to shareholders and industrial consumers who buy directly from the market
- Unexpected Fuel Cost Adjustments (FCA) for residential customers

This paper explores methods of quantifying natural gas volatility by examining theoretical models as well as case studies of utility hedging strategies. Including these volatility risk premiums in the price of natural gas establishes a basis for even comparison with utility-scale wind contracts, which enables smarter decision analysis by regulatory agencies, utilities, and ratepayers. This analysis shows that even without the Federal Production Tax Credit (PTC) and Renewable Portfolio Standards (RPS) power pricing support, wind becomes competitive with natural gas years sooner than is commonly believed, and in many cases is the economic choice for new build generation[2]. Wind competitiveness can be realized without increasing utility hedging budgets by redirecting current hedging cash flows from short-term option strategies into long-term wind Power Purchase Agreements (PPA). Using this methodology, hedging benefits can also be realized at the customer level by large organizations signing direct PPAs and residential customers participating in effective green power programs (GPP). This paper will demonstrate the hedging benefits of utility-scale wind and present practical solutions for utilities and ratepayers alike to decrease risk and encourage further domestic wind development.

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[1] Roesser, Randy. "Natural Gas Price Volatility." Electricity Supply and Analysis Division, California Energy Commision, 2009.

[2]This paper underscores the importance of hedging against gas price volatility risk; however, short-term variability in wind must be acknowledged as an additional risk. PPA pricing models used in this analysis include an average $6/MWh cost to utilities for intermittency integration. A future analysis incorporating more specific costs and wind hedging instruments would be beneficial, as risks associated with wind variability and intermittency range widely by region.

BACKGROUND

Due to the recent, economically viable combination of two technologies - horizontal drilling and hydraulic fracturing – shale gas is expected to grow from 23% of total U.S. natural gas supply in 2010 to 49% in 2035[3]. In Pennsylvania, home of the Marcellus Shale and its 7,725 active wells managed by 67 operators, natural gas production more than quadrupled between 2009 and 2011[4]. Oversupply from Pennsylvania's drilling programs and other large shale plays such as Eagle Ford, Haynesville, Utica, and Barnett, have driven down the price of natural gas. Henry Hub spot prices have plummeted from over $14/mmBtu in 2008 to below $2/mmBtu in 2012[5]. Due to such low natural gas prices, drilling programs are starting to focus on more liquids-rich plays to improve margins[6]; however, many programs are caught continuing to market shale gas below the cost of production due to "use it or lose it" leases[7]. While both the EIA and NYMEX futures market project longer-term prices to settle around $6/mmBtu, natural gas projections often grossly underestimate prices (Figure 1).

> "Ben Franklin said there are two certainties in life: death and taxes. To that, I would add the price volatility of natural gas."
>
> - Jim Rogers, Duke Energy CEO

While all commodities bear volatility risk, natural gas, at twice the volatility of oil prices, is one of the riskiest commodities[8]. Prices of natural gas can be influenced by a number of factors[9]: development of LNG export facilities linking U.S. and overseas gas prices, depletion of conventional gas, offshore access to natural gas resources, seasonal and catastrophic weather, global warming and capital markets legislation, competition with coal prices for electricity generation, and deployment of natural gas vehicles, just to name a few.

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[3] Energy Information Administration. "Annual Energy Outlook." 2012.
[4] Amico, Chris, Danny DeBelius, Scott Detrow, and Matt Stiles. *Shale Play: Natural Gas Fracking in Pennsylvania.* National Public Radio. 2011. http://stateimpact.npr.org/pennsylvania/drilling/ (accessed July 2012).
[5] CME Group. *Henry Hub Natural Gas.* 2012. http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.
[6] Energy Information Administration. *Horizontal Drilling Boosts Pennsylvania's Natural Gas Production.* May 23, 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=6390 (accessed July 2012).
[7] Blanchard, Thomas. "Cheap US Gas Won't Last Forever." Quarterly Gas Revew, Bloomberg New Energy Finance, 2011.
[8] Massachusetts Institute of Technology. "The Future of Natural Gas." MIT Energy Initiative, 2011.
[9] Costello, Ken. "Natural Gas Hedging: Should Utilities and Regulators Change Their Approach." National Regulatory Research Institute, 2011.

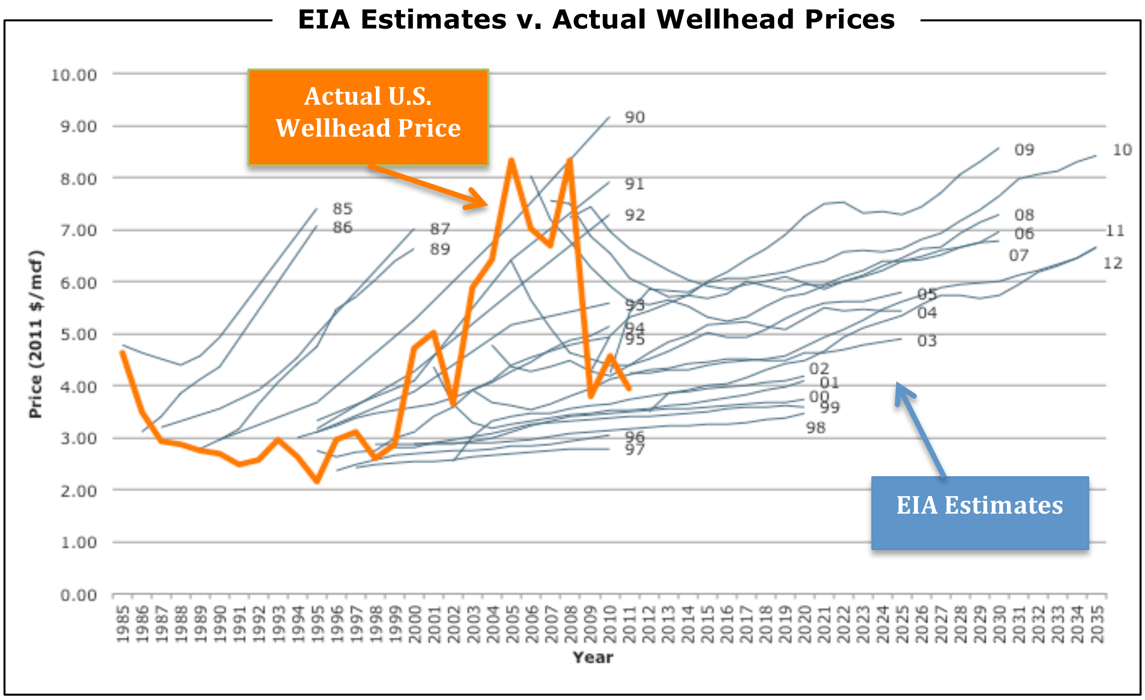

Figure 1: EIA estimates of natural gas prices v. actual, by Annual Energy Outlook publication date[10]

In order to properly compare natural gas with renewables, a volatility risk premium must be added to the price of natural gas. Wind, for example, is typically contracted over 20-30 years through a PPA that provides price certainty for both the producer and consumer. Adding an appropriate long-term risk premium to the price of natural gas would allow for apples-to-apples comparison of two very different cost structures and methods of power generation, thereby encouraging smarter resource planning by utilities and PUCs. Methods of quantifying such a risk premium are explored in this paper by examining both theoretical models and case studies. Despite the challenges posed to wind development – expiring PTC and dwindling RPS-enabled power purchase programs – a fair comparison to natural gas demonstrates the hedging potential of wind in a balanced energy portfolio.

WHAT IS VOLATILITY?

Volatility can be examined in two directions: forward-looking "implied volatility" and backward-looking "historical volatility". Both calculations of volatility are expressed as percentages – historical volatility based on past prices, and implied volatility derived from option prices that expire in the future. Volatility, as it's referred to in financial markets, is not simply a measure of daily or weekly relative

[10] Energy Information Administration. "Annual Energy Outlook." 1985-2012.

price changes, but rather the annualized standard deviation of daily or weekly logarithmic returns.

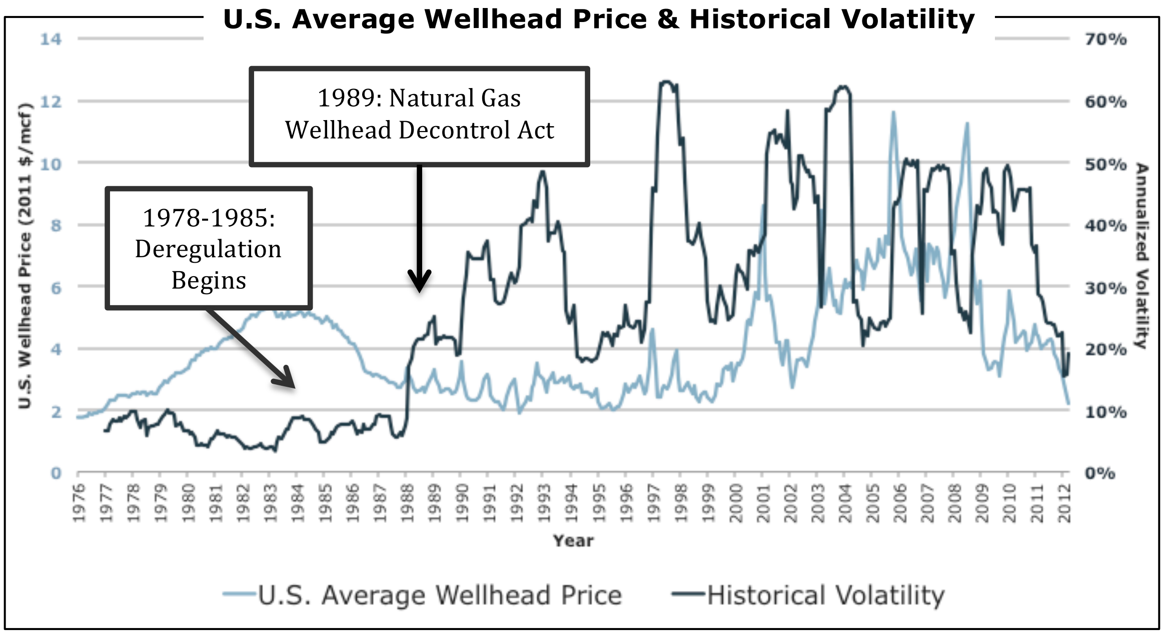

Figure 2: Historical volatility of natural gas prices. With spot prices and historical volatility levels at their lowest in over ten years, there is a current rare opportunity for utilities to lock in low prices at cheaper premiums. Many utilities, however, cannot participate in long-term strategies due to both regulatory restrictions and market liquidity constraints.

Historical Volatility

Historically speaking, natural gas tends to show volatility levels between 20% and 60% (Figure 2). While there has indeed been a period of sustained low prices and low volatility in the 1970s and 1980s, these prices and volatility levels were merely a result of regulation and wellhead price ceilings. The Natural Gas Policy Act of 1978 raised price ceilings and aimed to enable a national natural gas market. In 1985, significant deregulation began which fully removed price ceilings on natural gas at about 50% of U.S. wellheads[11]. In 1989, the Natural Gas Wellhead Decontrol Act eliminated price ceilings at the remaining regulated wellheads[10]. Since the natural gas industry has been deregulated, there has been a consistent trend of volatile natural gas prices.

Implied Volatility

Options on assets are priced by the "five greeks": delta, vega, theta, rho, and gamma. These factors, respectively, represent the sensitivity of the option value to changes

[11] NaturalGas.org. *The History of Regulation.* 2011. http://www.naturalgas.org/regulation/history.asp#wellhead (accessed June 2012).

in the underlying asset's price, volatility, time to expiration, and risk-free interest rate, and the sensitivity of delta to changes in the underlying asset price. Sensitivity to volatility, as measured by vega, is one of the most significant factors in pricing commodity options. In fact, implied volatility levels can be derived from listed option premiums to determine the magnitude of natural gas movements "priced-in" by the options market at a given future date (Figure 3). For example, options are currently pricing in a potential range of $1.18 to $13.80 per mmBtu at the 99% confidence interval by June 2015.

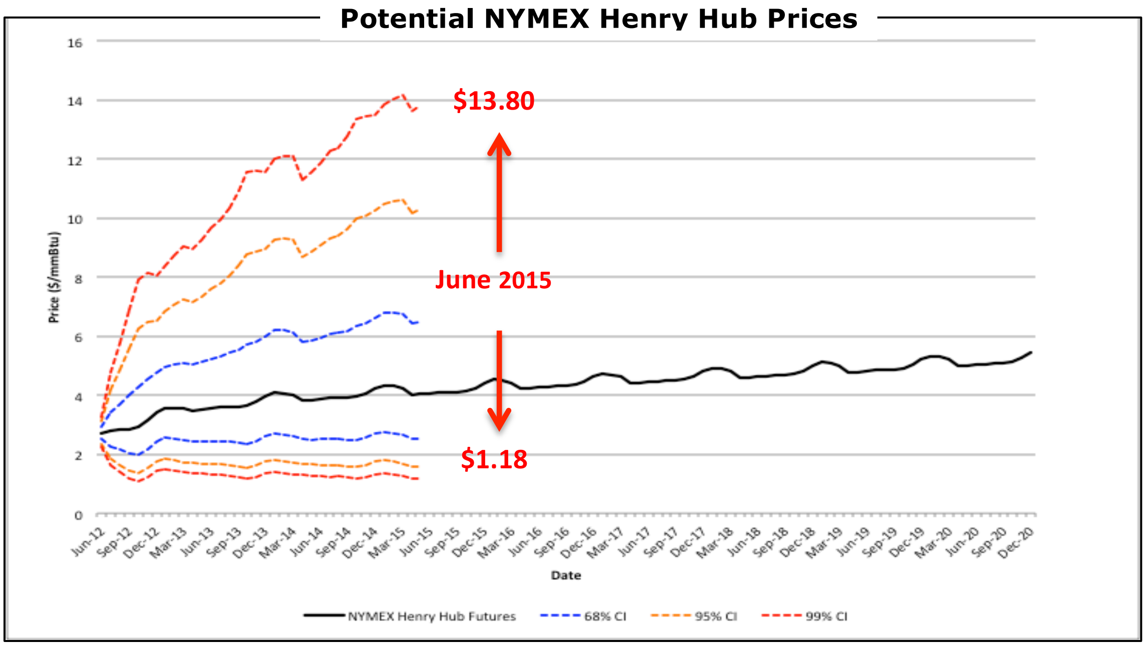

Figure 3: Using implied volatility levels and option premiums to determine future natural gas price ranges at 68%, 95%, and 99% confidence intervals

RISK DISTRIBUTION

Assets generally face two types of risk: risk associated strictly with the underlying asset (alpha), and risk correlated with the broader market (beta). A positive beta value represents a positive correlation with the broader market, whereas a negative beta value represents an inverse correlation. Calculating the beta value of natural gas has previously been attempted, but most studies conducting this analysis were published over 10 years ago (Table 1). It should be noted, however, that results have consistently shown negative beta values[12].

[12] Bolinger, M. and Wiser, R. LBNL 2002. "Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices"

Study	Beta Value
Kahn & Stoft (1993)	-0.78
Awerbuch (1993)	-1.25 to -0.5
Talbot (1993)	-0.45
Bolinger & Wiser (2004)	-0.4 to -0.1

Table 1: Summary of findings of natural gas beta values

Because natural gas is believed to have an inverse relationship with the broader market, consumers of natural gas may have more of a reason to hedge than producers[13]. A producer will be naturally hedged to low prices with a rising market, whereas a consumer will be exposed to high natural gas prices in tandem with a down market (Figure 4). As consumers tend to be more exposed, in this sense, to natural gas price volatility, this paper will focus on hedging mechanisms and solutions for the consumer side: from utilities to industrial, commercial, and residential customers.

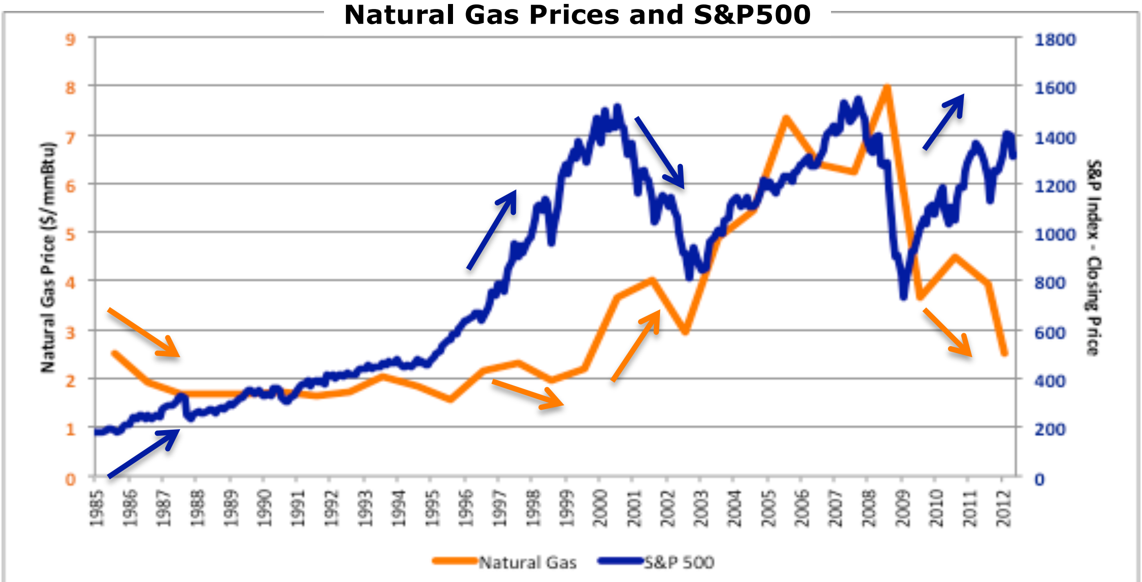

Figure 4: Natural gas prices and their relationship with the broader market: evidence of periods of significantly negative beta.

[13] Bolinger, M. and Wiser, R. LBNL 2002. "Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices"

VOLATILITY PRICING

> "A variety of methods have been used to assess and sometimes quantify the benefits of fixed-price renewable energy contracts relative to variable-price fossil generation contracts, as well as the benefits of electricity supply diversity more generally. These methods have included risk-adjusted discount rates (e.g., Awerbuch 1993); Monte Carlo and decision analysis (e.g., Wiser and Bolinger 2006); portfolio theory (e.g., Bazilian and Roques 2008); market-based assessments of the cost of conventional fuel-price hedges (e.g., Bolinger et al. 2006); and various diversity indices (e.g., Stirling 1994, 2010). Many of these methods have proven controversial, and a single, standard approach to benefit quantification has not emerged."
>
> -NREL Renewable Electricity Futures Study, June 2012

The volatility inherent in natural gas prices should be reflected as a risk premium added to the price of the underlying contract to establish a risk-free price. Only then can one fairly compare natural gas to utility-scale wind, which is offered in fixed-price (read: volatility risk-free) long-term PPAs. While natural gas volatility is evident, quantifying the associated risk is often quite complicated, as noted in NREL's recent Renewable Electricity Futures Study.[14] Theoretical volatility pricing methods can provide a context for comparing fixed-price wind with natural gas, but rather than building on these models, this paper employs an empirical approach based on the knowledge that many regulated utilities already put a price on volatility via their annual hedging budgets. While these budgets may grossly over- or underestimate the true long-term price of volatility, they can provide insight into utility willingness-to-pay and PUC-determined prudence rather than pure valuation – concepts that are key to developing wind as a realistic hedge. Essentially, each utility has its own individual risk tolerance, regulated hedging constraints, and available amount of cash – three inputs that are necessary in determining a wind project's hedging benefit. Using this approach exposes value without requiring new policy or increased spending.

This same empirical analysis can be extended to apply to the retail power purchaser in deregulated markets, where green power programs (GPPs) are more likely to feature fixed green rates, serving as true hedges against the potential of escalating fuel prices (See Austin Energy Case Study, pg. 19).

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[14] NREL. "Renewable Electricity Futures Study." U.S. Department of Energy, 2012.

Theoretical Models

Theoretically, the price of a straddle contract – combined at-the-money call (right to buy) and put (right to sell) options (Figure 5) – should represent the price of volatility. Premiums on these contracts, which can effectively lock-in your future price, are not cheap. Buying straddles on the NYMEX curve just a couple years out costs about 20-25% of the underlying gas, even with current low historical volatility levels[15]. Adding the price of a straddle contract to the underlying gas purchase demonstrates a much higher actual price of natural gas that is less competitive than wind within 2 years (Figure 6).

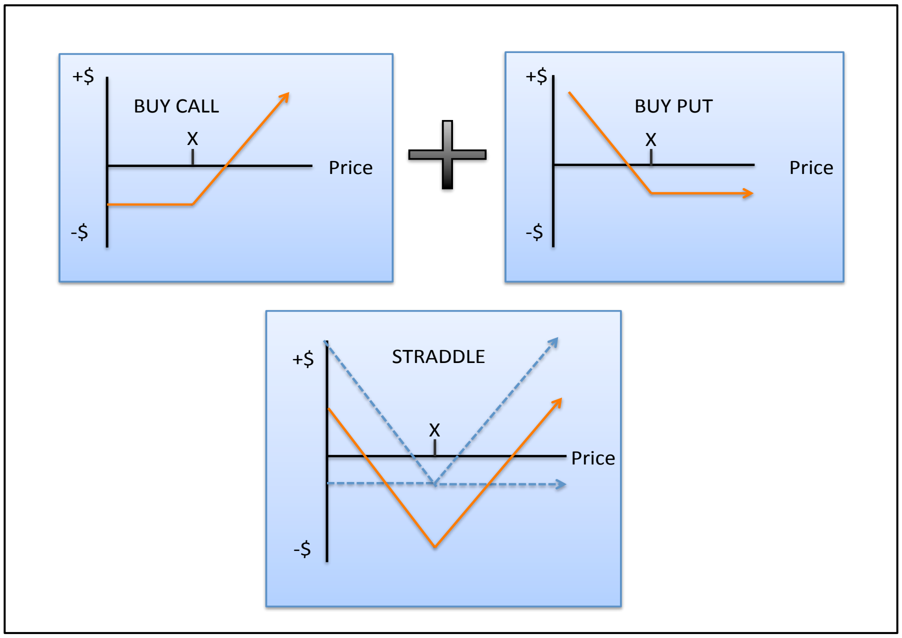

Figure 5: Straddle payoff diagram

[15] CME Group. *Henry Hub Natural Gas.* 2012. http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

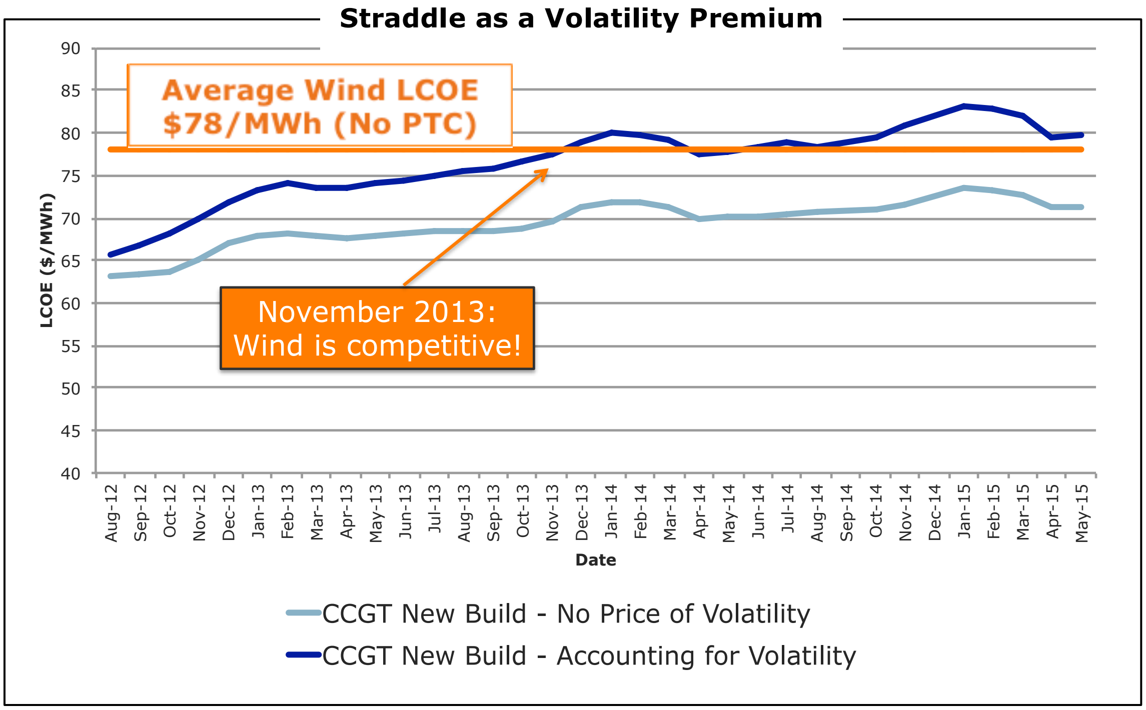

Figure 6: Comparing average wind and CCGT with volatility risk premiums as priced by straddle contracts. For LCOE assumptions, see Appendix.

Realistically, very few natural gas players would enter into a straddle contract. More often, straddles are employed by speculative traders to place bets on the direction of volatility. Consumers of natural gas generally have no incentive to pay an additional premium to protect against downward price movements just as suppliers of natural gas generally have no incentive to pay an additional premium to protect against upward price movements. In other words, the goal of most natural gas players is not to minimize overall volatility, but rather to mitigate one-directional risk. In order to accomplish this, a variety of less-expensive, short-term option strategies are employed as well as less common long-term physical delivery contracts.

Utility Hedging Strategies

Long-term

Because regulated utilities pass-through both the cost of fuel and hedging, risk mitigation plans must be presented and approved by the PUC[16]. Many PUCs restrict utilities to hedging gas volatility risk only three to five years out for three reasons: (1) Natural gas option markets lose significant liquidity after about one to two years which results in high transaction costs and unreliable pricing; (2) Losses on derivative investments could be devastating to both the utilities and ratepayers; (3)

[16] Bean, Patrick, Gregory C. Staple, and Geoff Bromaghim. "Power Switch: A No Regrets Guide to Expanding Natural Gas-Fired Electricity Generation." American Clean Skies Foundation, Washington, DC, 2012.

Margin calls on sold contracts can put utilities in low-cash positions. As examples of case (2), between 2007 and 2009, two California utilities lost a combined $97mm from bad hedges, and from 2006 to 2011, four Michigan utilities incurred a total of $1.6bn in losses from bad hedges[17]. To avoid hitting ratepayers with charges from imprudent derivative bets, PUCs can be quite strict in their approval process. Counter-intuitively, it is the volatile nature of gas prices that is driving the argument to *not* hedge in regulated markets – a phenomenon not seen in any other industry. By restricting hedging time horizons however, utilities are incentivized to maintain long-term risk exposure. Just as adjustable rate mortgages entice homebuyers to take on volatile long-term rates with low up-front costs, natural gas markets seem attractive in the short-run while posing huge risks only a few years out.

Even though participation in fixed-price, physical delivery natural gas contracts could offer medium-term (5-10 year) protection, these contracts are quite rare[18]. As an exceptional case, however, the Public Service Company of Colorado (PSCo) was approved by the Colorado PUC to sign a 10-year deal with Anadarko under the Clean Air Clean Jobs Act[19] (Figure 7). As Colorado sought to retire dirtier coal plants in favor of natural gas, PSCo agreed to obtain an undisclosed quantity of gas from Anadarko from 2011 to 2021 for an average premium of $1.38/mmBtu over EIA forecasts of Cheyenne Hub wellhead prices[20], assuming an $0.185 basis spread from Henry Hub[21]. While $1.38/mmBtu is a hefty premium in itself, PSCo also agreed to pay an additional dollar - named the "Volatility Mitigation Adder" - for any quantity of gas over the contracted amount, taking the all-in premium to $2.38/mmBtu[22]. These premiums reflect what one utility was willing to pay to offset price risk of natural gas over ten years. While these prices could offer a baseline for comparison to wind PPAs, they are still conservative numbers as the PSCo/Anadarko contract offers protection for less than half of the time horizon that a 25-year wind PPA would.

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[17] Costello, Ken. NRRI 2011. "The Future of Natural Gas Hedging: Utilities, Consumer Advocates, and Regulators Weigh In"
[18] Massachusetts Institute of Technology. "The Future of Natural Gas." MIT Energy Initiative, 2011.
[19] Moore, Scott A. "Natural Gas Market Dynamics and Long Term Contracts." Marketing Department, Anadarko, Denver, CO, 2011.
[20] Energy Information Administration. "Annual Energy Outlook." 2012.
[21] Platts. "Gas Daily." 2011.
[22] Premiums calculated over EIA forecasts – Actual forecasts used as basis for this deal are undisclosed

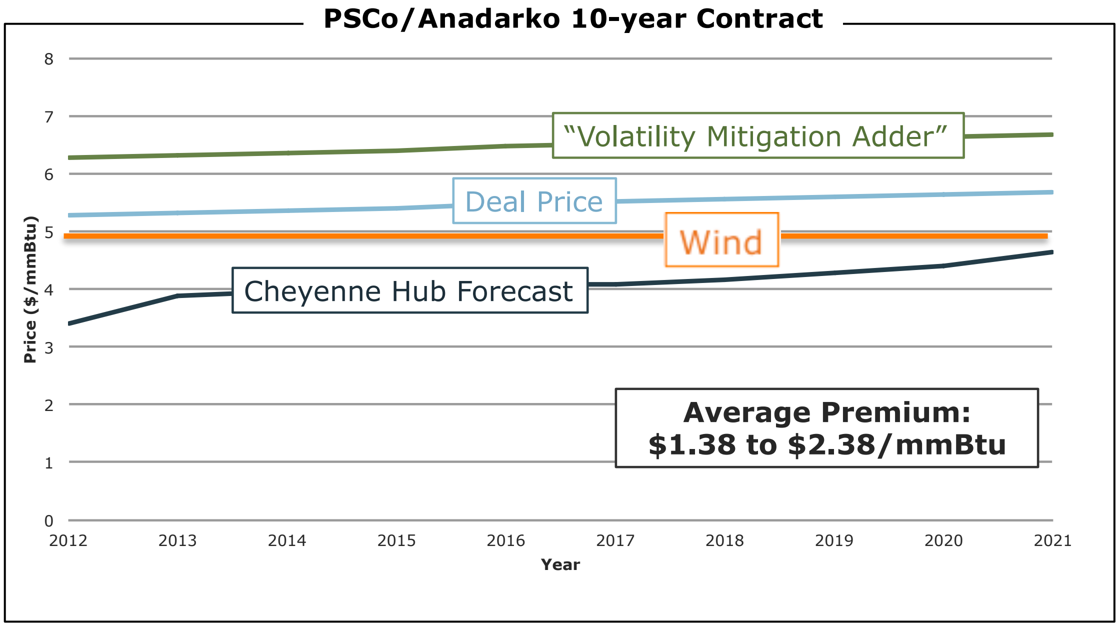

Figure 7: PSCo/Anadarko 10-year contract prices and volatility premiums at Cheyenne Wellhead

Short-term

While utilities are confined to hedging out only a few years in any significant way, they tend to weight their resources heavily in year one, slightly less in years two and three, and very little after that (Figure 8). Because hedging positions are constantly being managed and traded around, a utility following this pattern might be nearly 100% hedged, consistently, for the next 12 months, 50% hedged up to 24 months, 30% in year three, and 10-15% hedged in years four and five.

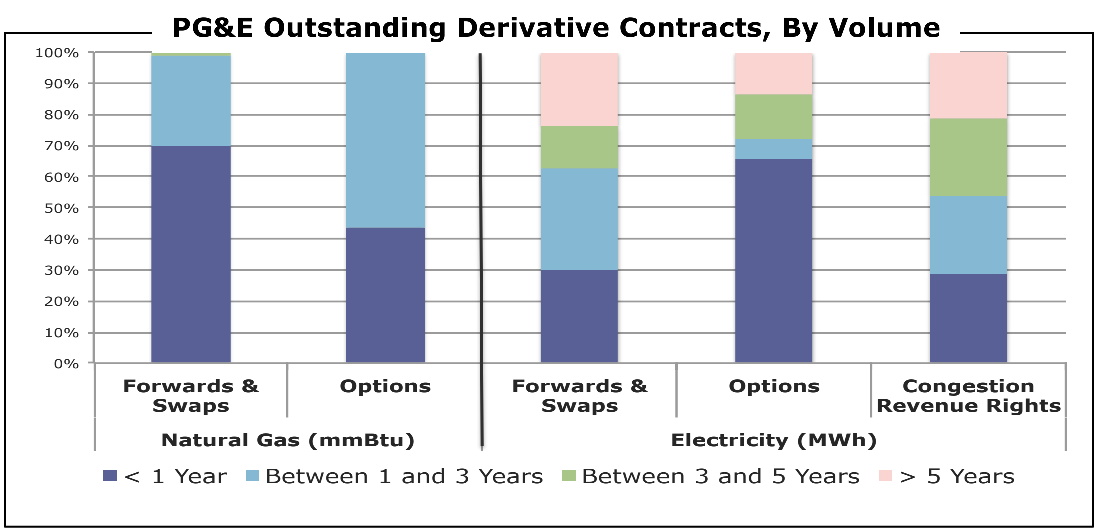

Figure 8: PG&E hedging strategy as documented in 2011 Annual Report[23]. Swaps are agreements between two parties in which the utility pays a pre-determined fixed price in exchange for a floating price. Congestion Revenue Rights are financial instruments that allow the utility to manage the daily cost of congestion based on locational marginal pricing

[23] Pacific Gas & Electric. "2011 Annual Report." 2011.

PG&E and other utilities with developed hedging programs will often buy gas-specific option products to partially de-risk natural gas price fluctuations. These could be vanilla call options, or more regularly, more complicated but less expensive strategies like costless collars, call spreads or three-ways (see Appendix). Each option or combination thereof comes at varying premiums and offers different levels of protection. Utilities with defined hedging budgets will often select which strategy to employ based on NYMEX futures and option premiums offered at the time of investment. PSCo, for example, has an explicit cap of $0.91/mmBtu to spend on short-term strategies for 55% of the gas requirements from November 2011 to March 2012[24] (see PSCo Case Study, pg. 17).

SOLUTIONS

Wind provides significant hedge value for buyers of power to take advantage of. Utilities can integrate a full assessment of long-term volatility in petitions to PUCs to gain approval for new wind investments that will serve as a hedge and protect ratepayers. Rather than building complex models to determine volatility premiums, utilities can simply demonstrate that redirecting a portion of their current hedging cash flows into wind PPA contracts can reduce volatility risk without increasing their annual hedging budget (see PSCo Case Study). If employed nationwide, this could have significant implications for the future of domestic wind development. Large commercial customers can also take advantage of wind's hedge value by signing direct PPAs and including such PPA contracts in their value-at-risk (VaR) calculations to realize a reduction in overall risk exposure. Google, for example, has already signed two wind PPAs with NextEra Energy for its data centers in Iowa and Oklahoma[25]. While residential customers cannot directly and individually sign onto wind PPAs, they can participate in GPPs that reduce their exposure to fluctuating fuel prices. Although many utilities offer programs allowing customers to pay "Green Premiums", only a small number are designed to utilize wind investments as a hedge by replacing the customer's fuel charge with a fixed renewable charge (a "Green Rate") that is not subject to Fuel Cost Adjustments (FCAs)[26]. While some of these programs are offered in regulated markets, there may be more of an opportunity to develop Green Rate programs in deregulated markets (See Appendix 4). One of the premier examples of a GPP Green Rate is Austin Energy's GreenChoice Program (see Austin Energy Case Study, pg. 19). Many other less effective programs offer the option for a customer to pay a set premium for renewables while their base rates are still subject to fluctuating fuel prices (Figure 9).

[24] Public Service Company of Colorado. "Gas Price Volatility Mitigation Plan Approval Form: 2011-12 Gas Purchase Year." Gas Department.
[25] Google. "Google's Green PPAs: What, How, and Why." 2011.
[26] Bird, Lori A., Karlynn S. Cory, and Blair Swezey. "Renewable Energy Price-Stability Benefits in Utility Green Power Programs." National Renewable Energy Laboratory; Applied Materials, 2008.

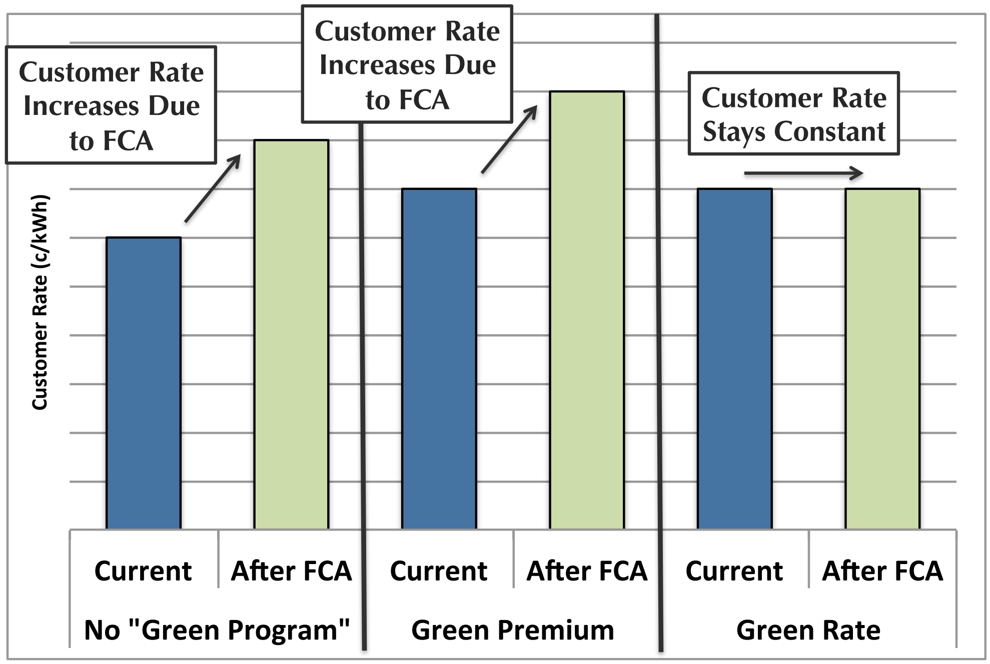

Figure 9: Examples of Green Power Purchase Programs. From left to right: standard customer payments, "Green Premium" programs subject to FCAs, and "Green Rate" programs exempt from FCAs. For a list of sample GPPs exhibiting best practices, see Appendix.

CASE STUDIES

Utility: Public Service Company of Colorado[27]

PSCo, a subsidiary of Xcel, submits annual Gas Price Volatility Mitigation Plans (GVPM) to the Colorado PUC for approval of their hedging strategies for natural gas exposure. For the purchase year of July 1, 2011 to June 30, 2012, PSCo applied and was approved to hedge a maximum of 75% of winter purchase requirements (November-March season). The planned 75% of hedged purchases break down into long-term and short-term strategies. The long-term strategy covers up to 25% of hedged purchases if gas can be acquired at a price below their set floor via storage. This price floor is established by averaging prices from the previous three heating seasons, which for the 2011-2012 plan resulted in a price floor of $5.00. The remaining 75% of hedged gas purchases are delegated to the short-term plan and use the same price floor with a per mmBtu budget of $0.91. Thus, for short-term hedges, up to 91 cents per mmBtu is spent on an option strategy or fixed-price swap. Option strategies targeted are first costless collars, followed by ATM call options, and finally OTM call options as a last resort.

For the 2011-2012 GVPM, PSCo projected a winter supply requirement of about 100 million mmBtus of which 22% was planned to come from storage as a physical hedge and 53% relied on financial hedges – totaling 75% of supply. Short-term hedges on the nearly 53 million mmBtus are determined as the markets move. If a fixed-price swap agreement or costless collar can be obtained for $5.91/mmBtu (price floor plus budget), PSCo will first choose one of these options. If, however, the fixed-price contracts come at a higher price, PSCo will look to buy ATM call options at or less than $0.91/mmBtu premiums. If PSCo cannot buy ATM call options within budget, they will purchase $0.91/mmBtu premium OTM call options with varying strike prices.

PSCo's GVPM for 2011-2012 essentially limits the company to spend no more than $0.91/mmBtu, for a total cap of $30 million on hedging expenses. If PSCo is consistently spending an additional $0.91/mmBtu on natural gas supply that currently costs around $3.00/mmBtu at the wellhead, they are paying a significant 30% premium. If option premiums rise as underlying prices and volatility rebound, PSCo will not even be protected at their floor of $5.00, but rather reliant on OTM call options with higher strike prices. Taking a $0.91/mmBtu premium into account, wind appears significantly more competitive years earlier than previously assumed – nearly breaking even with CCGT new build 2015-2018, and winning out after 2019 (Figure 10a).

[27] Public Service Company of Colorado. "Gas Price Volatility Mitigation Plan Approval Form: 2011-12 Gas Purchase Year." Gas Department.

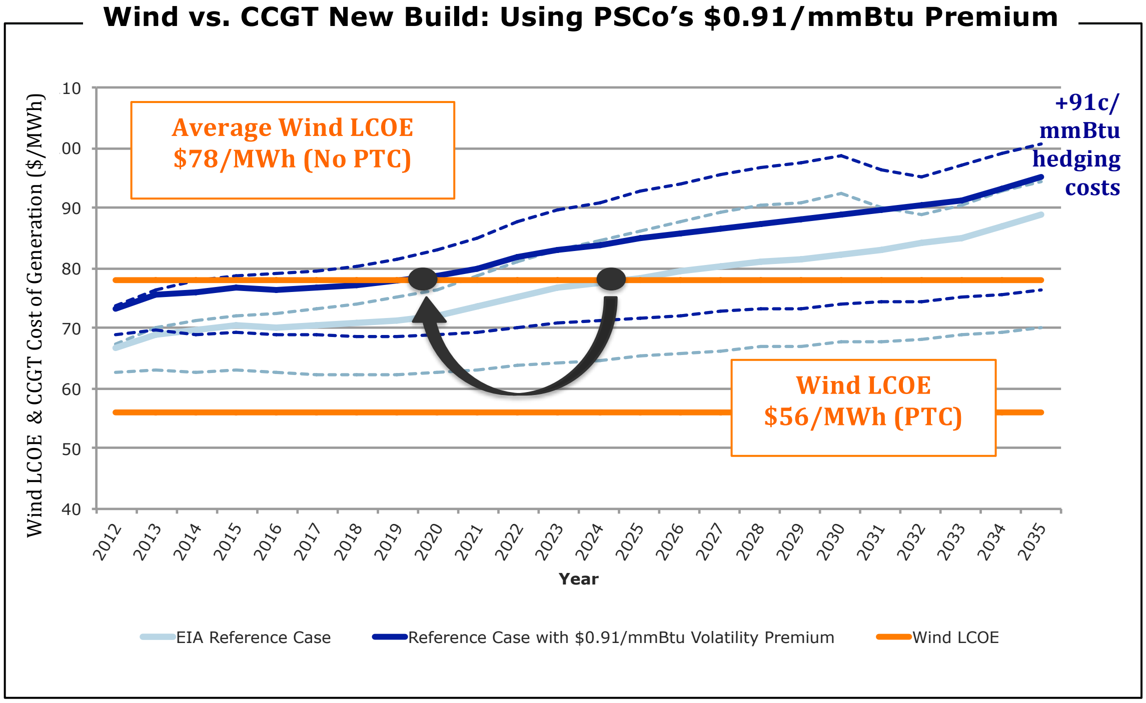

Figure 10a: Demonstration of wind competitiveness when accounting for volatility premiums. Adding PSCo's current $0.91 volatility premium shows wind and CCGT new build breaking even in 2019, as opposed to 2024 if not accounting for this premium. For wind LCOE and CCGT cost of generation assumptions, see Appendix.

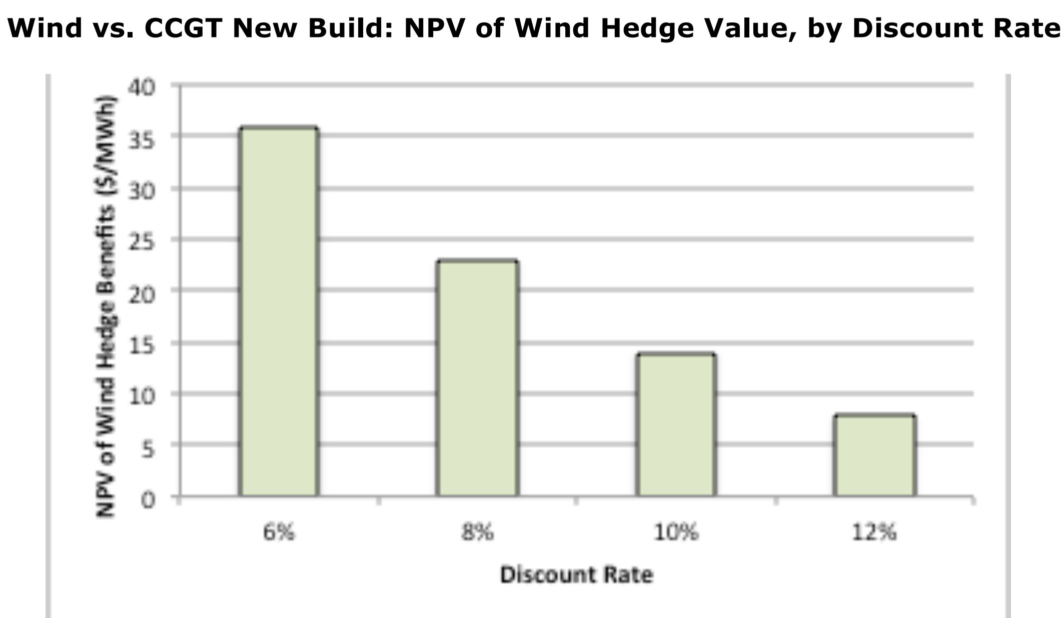

Figure 10b: Net present value of 23-year wind investment over CCGT investment

Industrial and Large Commercial Customers: Altenex Business Model[28]

Altenex takes an innovative approach to natural gas risk mitigation by serving as a "Match.com" of the power portfolio world. Altenex manages a database of renewable projects with its customers – large industrial and commercial organizations that have significant exposure to fluctuating fuel prices. Altenex uses a propriety model to analyze and compare its clients' risk profiles under varying power portfolio allocations that incorporate appropriately selected power purchases from renewable projects in their database. Altenex's model becomes more applicable the higher the dependence on natural gas. For example, large chemical companies that use natural gas as a feedstock and buy directly from the market, or massive data centers that require significant electricity consumption and are poised for further growth. These consumers can use Altenex's model to re-evaluate their value-at-risk under different natural gas and electricity market pricing scenarios.

Commercial and Residential Customers: Austin Energy GreenChoice[29]

Austin Energy's GreenChoice program is often touted as one of the most effective green purchasing programs in the country. Although not required to participate in the Texas RPS program, they offer long-term "batches" that residential and commercial customers can subscribe to in order to support renewables instead of fossil fuels. Each batch is offered for a set term and price that costumers pay in lieu of their traditional fuel charge. This means that GreenChoice subscribers are not subject to fluctuating fuel prices. After Austin Energy's first batch was oversubscribed at 1.7¢/kWh, they met continuing demand by offering a second batch at 2.85¢/kWh. These two batches both expired in March 2011 in the money. In fact, Austin Energy claims that "a batch 1 customer paying 1.7 cents per kWh and averaging 1,000 kWh per month will have saved about $1,300 [over the life of the subscription]"[30]. Batches 3, 4, 5, and 6 have been offered at 3.3¢/kWh, 3.5¢/kWh, 5.5¢/kWh, and 5.7¢/kWh, respectively, compared to a current fuel charge of 3.615¢/kWh. While the most recent batch will not expire until 2021, customers of Austin Energy's GreenChoice program have found the long-term hedge value of renewables to be significant.

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[28] For more information, visit www.altenex.com

[29] Austin Energy. *GreenChoice Energy Rider.* 2012. http://www.austinenergy.com/about%20us/rates/greenChoiceEnergyRider.htm.

[30] Austin News. "Austin Energy GreenChoice Customers: Your Rates May Go Up in March." *Austin Post.* October 26, 2010. http://www.austinpost.org/austin-news/austin-energy-greenchoice-customers-your-rates-may-go-march (accessed 2012).

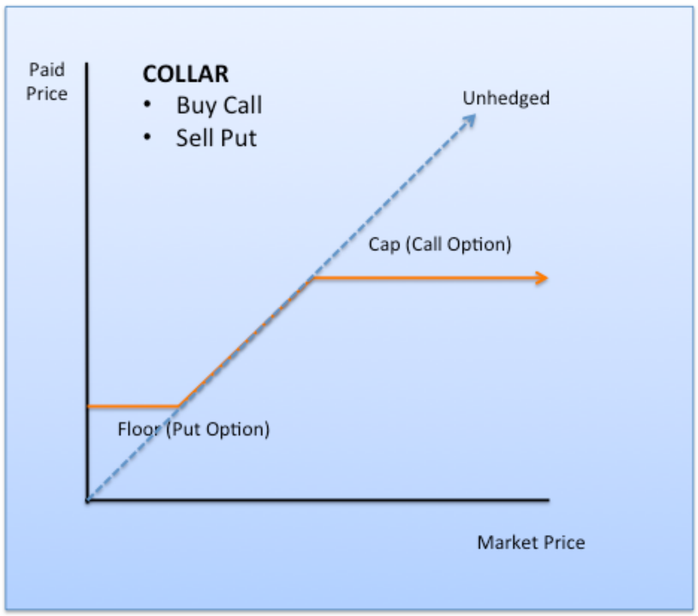
CONCLUSION

Although natural gas prices are depressed, the volatility inherent in the commodity remains and presents risks to consumers at all levels: utilities, industrial and commercial customers, as well as residential customers. Many utilities are already paying to hedge against the risk of an unexpected upward swing in prices in the near-term, but remain exposed in the long run. PUCs in regulated states tend to disapprove of long-term natural gas contracts. It is conceivable, however, they could be convinced to deem wind PPA contracts prudent as they provide a substantial hedge in the long-term, particularly if the PUCs adopt more risk-weighted "lowest cost" review criteria for PPAs or new plant rate-basing. Just as utilities can hedge with new wind project PPAs, large customers can sign direct PPAs as a hedge, and residential customers can participate in green power programs that exempt them from FCAs. These opportunities offer the chance for consumers of energy to both decrease their risk exposure to fluctuating fuel prices, as well as encourage the future development of domestic wind.

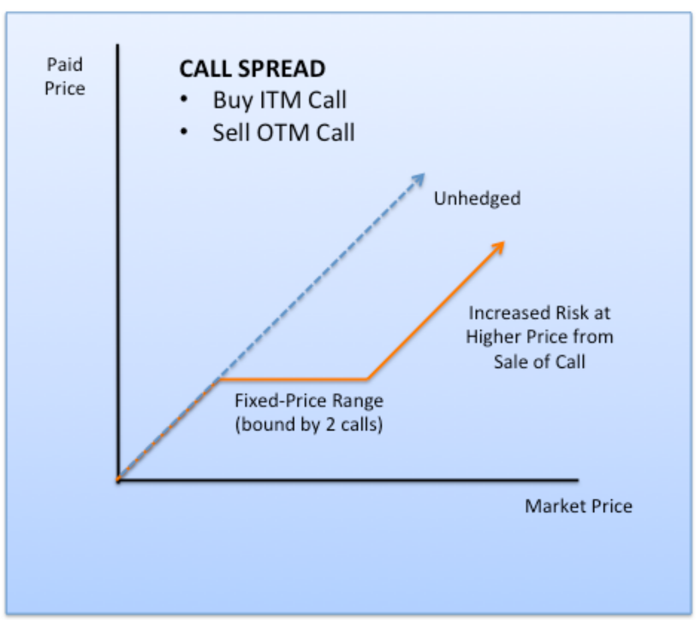
APPENDIX

1. Option Payoff Diagrams:

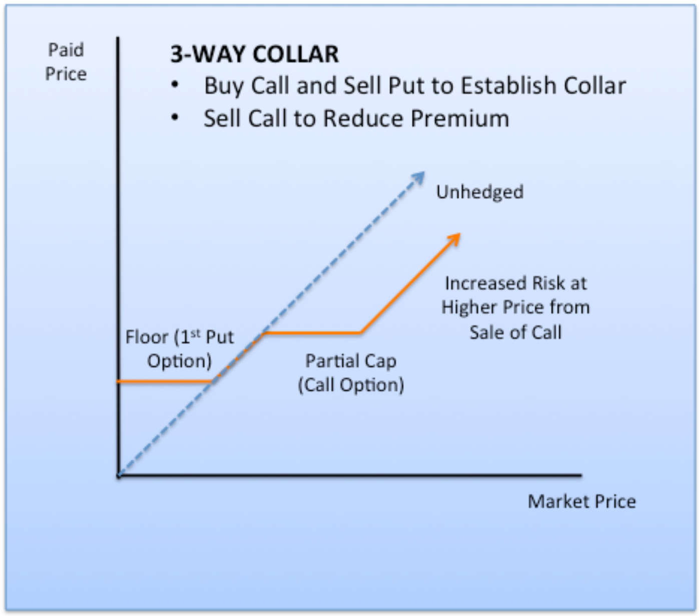
   1.1 Collar Strategy: Buy Call, Sell Put



   1.2 Call Spread Strategy: Buy ITM Call, Sell OTM Call



1.3 Three-Way Collar Strategy: Collar, Sell Additional OTM Put



Note: For all three option scenarios, it is possible to have a "costless" transaction. This means that there is no premium (but perhaps still a broker fee) to transact when the price of selling options is the same as the cost of buying other options within the same transaction (e.g. costless collar = proceeds from sale of put equals cost of purchase of call). To be clear, costless transactions can still eventually "cost" the transacting party if they are out-of-the-money or if they must post margin for future-dated sold contracts. All three transactions above a presented in a costless manner, but in most cases there is a transaction premium and that premium would offset the payoff (orange) line downwards uniformly across the market price axis.

2. LCOE (Wind) and Cost of Generation (CCGT) Assumptions[31]

Future Price of Natural Gas: EIA AEO 2012 Projections
Levelized Non-Fuel Costs of CCGT New Build: $43.5/MWh
Heat Rate of CCGT New Build: 7000 Btu/kWh
Wind LCOE*: $78/MWh without PTC (Includes $6/MWh Intermittency Integration Costs)
Production Tax Credit: $22/MWh

<u>*NOTE:</u> While $78/MWh is used as Wind LCOE Assumption in this paper, wind projects with PTC assistance have been coming online around $30/MWh recently (not including utility wind integration costs, if any).

[31] Lazard. "Levelized Cost of Energy Analysis - Version 6.0." 2012.

3. Sample List of Utility Short-Term Hedging Budgets

Xcel/PSCo (Colorado): $0.55-$1.82/mmBtu, varies by department
Centerpoint Energy (Minnesota): $0.25/mmBtu
Portland General Electric (Oregon): about $0.01/mmBtu, calculated as ½ bid-ask spread (essentially a transaction cost)
Duke Energy Carolinas (North Carolina): $0/mmBtu

4. Sample List of GPPs offering at least partial FCA exemption[32]

Alliant Energy
Austin Energy
Clallam County PUD
Green Mountain Power
Holy Cross Energy
Madison Gas & Electric
Xcel Energy
We Energies

[32] Bird, Lori A., Karlynn S. Cory, and Blair Swezey. "Renewable Energy Price-Stability Benefits in Utility Green Power Programs." National Renewable Energy Laboratory; Applied Materials, 2008.