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Variance Analysis of Wind and Natural Gas Generation under Different Market Structures: Some Observations

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List of Acronyms

ARRA	American Recovery and Reinvestment Act
CCGT	combined-cycle gas turbine
CT	combustion turbine
DRM	downside risk measure
EBITDA	earnings before interest taxes depreciation and amortization
ERCOT	Electric Reliability Council of Texas
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
LMP	locational marginal price
MVPA	mean-variance portfolio analysis
MW	megawatt
MWh	megawatt-hour
NYMEX	New York Mercantile Exchange
O&M	operation and maintenance
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PTC	production tax credit
RTO	regional transmission organization
RoR	rate of return
RE	renewable energy
U	economic utility

Executive Summary

An important area of current research is whether large-scale penetration of variable renewable generation such as wind and solar power pose economic and operational burdens on the electricity system. In such scenarios, this issue has also raised considerable interest in the potential role and value of electricity storage as a method of mitigating variability in generation associated with the inherently variable nature of these forms of generation. At the same time, a number of studies have pointed to the potential benefits of renewable generation as a hedge against the volatility and potential escalation of fossil fuel prices. Prior research and this work suggest that the lack of correlation of renewable energy costs with fossil fuel prices means that adding large amounts of wind or solar generation may also reduce the volatility of system-wide electricity costs.[1] Such variance reduction in overall system costs may be of significant value to consumers due to risk aversion. In contrast to this observation, other studies have focused on returns in restructured markets and noted that, in deregulated markets, baseload natural gas power generation may be relatively more attractive to investors because—unlike wind generation—peak power prices are often strongly correlated to natural gas prices.

The analysis in this report recognizes that the potential value of risk mitigation associated with wind generation and natural gas generation may depend on whether one considers the consumer's perspective or the investor's perspective and whether the market is regulated or deregulated. We analyze the risk and return trade-offs for wind and natural gas generation for deregulated markets based on hourly prices and load over a 10-year period using historical data in the PJM Interconnection (PJM)[2] from 1999 to 2008. Similar analysis is then simulated and evaluated for regulated markets under certain assumptions. Estimating the absolute value, as opposed to the relative value, of variance reduction will also depend on assumptions about risk aversion and other consumer preferences, such as loss aversion, and this is discussed. Some key observations include:

In a deregulated market such as PJM,

- Returns for natural gas generation are partially hedged because power prices are often set by natural gas generation, though with significant seasonal variations.
- Returns for wind generation are better hedged than natural gas generation because wind often operates in off-peak hours, where power prices are much less volatile and less correlated with natural gas prices, whereas natural gas generation operation is focused more heavily during peak hours.[3]
- The impact of incremental net revenue from tax credits, such as production tax credits (PTCs) or other sources of revenue, can have a significant impact on the risk return relationship. In PJM over this period with credits, wind was found to be dominant in

[1] Although the impact of potentially off-setting effects due to operational intermittency resulting from natural variations in wind or solar output over a variety of timescales needs to be carefully considered.

[2] PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia (www.pjm.com).

[3] For wind and natural gas technologies with the cost and performance assumptions used in this analysis.

terms of risk and reward; that is, it had both greatest returns and the lowest risk, as measured by standard deviation of returns.

- More generally, without PTCs investors may benefit from investing in both wind and natural gas generation, with the optimal mixture depending on the investor's risk aversion (and perhaps also loss aversion) preferences due to well-known lack of correlation effects.
- While the opportunity for investors to diversify in broader markets may reduce some of the variance reduction benefits of investing in different electric technologies, it is unlikely to completely eliminate these benefits in the electric sector where power prices are often very volatile and positively skewed, which has implications for financial distress.
- Consumers, especially smaller commercial and residential consumers, may benefit from reductions in the variance of electricity prices due to risk aversion and loss aversion effects.[4]
- The levelized cost of energy (LCOE) of different technologies is not directly comparable if they operate in different hours because the value of electricity differs significantly throughout each day. This variation reflects the daily load profile, with hourly load and hourly power prices also showing strong seasonal effects. This effect can be seen in our analysis of PJM data when comparing the difference in the average annualized hourly price of variable wind generation and dispatchable natural gas generation.

In a regulated market:

- The inherent nature of regulated markets means that producers earn, with some caveats, a utility-designated rate of return. A consequence of this is that the risk associated with fuel costs is passed on to the consumer. The "cost-plus" nature of regulation means that consumers also bear some increased risk associated with poor investment decisions. Consumers are partly compensated for this because the producer may be willing to accept a lower expected rate of return compared to deregulated markets.
- For consumers, who are generally risk averse, the reduced variation in electricity prices (and hence consumer costs) because of wind's lack of correlation with other system costs should have value (as has been suggested by others). Loss aversion also may place a value on variance reduction of electricity prices and consumer costs.
- Simplified mean variance cost optimization techniques using annualized LCOEs for the power sector often fail because the assets within the portfolio are too dissimilar (e.g., baseload versus peaking or either of these versus a variable or non-dispatchable resources such as wind or solar).
- A variance reduction-based technique could, however, be used more broadly under more sophisticated representation of system costs where the hourly operation of the

[4] This could also hold true for large consumers such as utilities if they or regulators realized they could quantify the value of such variance reduction to consumers and get paid by consumers some fraction of this value to do so.

technologies is modeled more explicitly. Specifically for a regulated electric system, the concept of lowest-cost planning could be refined to have an array of "least-cost planning" solutions corresponding to different variances, where the values of the expected annualized system cost and the standard deviation of the annualized system cost are physical properties of the electric system that are completely independent of any risk or loss aversion preferences. The value of variance reduction could then reflect both risk aversion and loss aversion. We discuss explicitly how to estimate the difference in the economic utility between alternative system-based, expected cost-cost variance choices, including the impact of the distribution being positively skewed toward higher costs.

In conclusion, we should point out that while some of the observations and findings may be generally applicable, others are empirical observations for a specific location and a specific time period under specific technology cost and performance assumptions.[5]

[5] For example, within PJM over the same time period, different assumptions about technology performance and cost for wind and natural gas could lead to different risk-return relationships. Similarly, the risk-return relationships may vary outside of PJM, or over different time periods within PJM, because of differences in hourly electricity prices.

Table of Contents

List of Figures

List of Tables

1 Introduction

1.1 Structure of this Report

An important area of current research is whether large-scale penetration of variable renewable generation, such as wind and solar power, pose economic and operational burdens on the electricity system. In such scenarios, this issue has also raised considerable interest in the potential role and value of electricity storage as a method of mitigating variability in generation associated with the inherently variable nature of these forms of generation. At the same time, a number of studies have pointed to the potential benefits of renewable generation as a hedge against the volatility and potential escalation of fossil fuel prices (Bolinger et al. 2002). Prior research and our analysis suggest that the lack of correlation of renewable energy costs with fossil fuel prices also means that adding large amounts of wind (or similarly solar) generation may lead to a reduction in the volatility of the system-wide electricity costs (Awerbuch and Berger 2003). Risk aversion has been investigated in relation to traditional financial markets, in relation to individual versus societal discount rates (Portney and Weyant 1999), and also in relation to technology choices (Roques et al. 2008), but less analysis has been done that compares and contrasts the impact of renewable energy under different market conditions. In this initial report, we consider possible variance-related benefits (and costs) by comparing wind and natural gas generation investments from both a producer and consumer perspective (using annualized returns and monthly and annualized consumer costs respectively) and examine how these outcomes depend on whether these technologies operate in a deregulated or regulated market.

In this analysis, we recognize that the potential value of risk mitigation associated with wind generation and natural gas generation may depend on whether one considers the consumer's perspective or the investor's perspective and whether or not the market is regulated or deregulated. We analyze the risk and return trade-offs for wind and natural gas generation for deregulated markets based on hourly prices (and load) over a 10-year period using historical data in PJM Interconnection (PJM) from 1999 to 2008. PJM is a regional transmission organization (RTO) serving 51 million people in the eastern United States. Similar analysis is then simulated and evaluated for regulated market under certain assumptions. Estimating the absolute, as opposed to the relative, value of variance reduction will also depend on assumptions about risk aversion and other consumer preferences, such as loss aversion, and this is discussed. Though much of our analysis is focused on discrete wind and natural gas generation investments, we also discuss some of the implications of our analysis on system-wide optimization techniques used in the electric sector that place a value on the variance reduction in addition to cost minimization (or profit maximization) on an expected basis.

Section 1 presents the daily average historical prices and price volatility of fossil fuel and power prices in PJM between 1999 and 2008 and reviews some prior work that has looked at the impact of renewable energy on variance reduction of consumer costs and producer returns. Section 2 provides some relevant background material to investment decisions made for wind and natural gas between 1999 and 2008. The report describes a method for estimating producer net cash flows and returns and consumer costs in both deregulated markets and regulated markets. Section 3 presents results for natural gas and wind generation selling into a deregulated market. Section 4 carries out similar analysis assuming the market is regulated, and then compares differences observed between regulated and deregulated markets. Section 4 also discusses the value of variance reduction more generally from both the producer and consumer perspective due to both risk aversion and other factors, such as loss aversion; this includes some consideration of how the difference in overall economic utility between alternative electricity system cost distributions can be evaluated. Section 5 summarizes some of the main findings and conclusions.

1.2 Background

Consumers are often considered to be risk averse.[6] In the context of their heating oil or electricity bills, this would mean that consumers generally prefer a fixed price bill (for given energy usage) to a variable bill with the same expected value on an annualized basis. Because of this, consumers would be expected to be willing to pay a premium for less uncertainty or variance of their fuel or electricity bills. Similarly, producers often place a value on greater certainty of future net cash flows.[7] This assumption lies at the foundation of using discounting in conventional financial valuation techniques such as net present value.[8] Generally speaking, the more uncertain the future net cash flows generated by a physical asset or financial investment, the higher the required expected return to make such an investment attractive. This is one of the reasons why regulated assets such as electric transmission and distribution assets generally earn lower allowed rates of return and why these lower rates of return are acceptable to investors (i.e., the riskiness or uncertainty of the future net cash flows is lower, and this has inherent value to a risk-averse investor).[9] Similar reasons are behind why investors anticipate bonds providing lower expected rates of return than stocks: bond holders have first (though limited) claim on returns generated by a firm and are senior to equity in the capital structure in the event of a firm liquidation or default.[10] Risky private sector investments are not, of course, without benefits and are believed to drive innovation and encourage improvements to operational efficiency, so eliminating or reducing risk is not always desirable. Rather, investors would be expected to want to be (or at least anticipate being) compensated on average for taking greater risks.

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[6] For example, a study by Guiso and Paiella (2005) that measured risk aversion based on the willingness to pay for a risky asset found that "the vast majority of the participants are risk averse… (while) a small proportion (4%) are either risk-neutral or risk seeking" (p. 8). Guiso and Paiella also noted even among the risk-averse there is a lot of heterogeneity in the degree of risk aversion, which shows that preferences do differ significantly across individuals.

[7] For example, many oil producer companies hedge some of their future production output, though the proportion can vary significantly by company. In some cases, such hedging can be a requirement to satisfy their loan covenants. On the other hand, some companies with large annual net cash flows, such as ExxonMobil, do not sell forward in this manner and in fact view their strong debt rating as a competitive advantage. For example, ExxonMobil's (2009) 10-K notes that "the Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact of such change….[The Corporation's] limited derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity" (p. 55). This suggests that ExxonMobil values the fact that its net cash flows, and hence returns, are naturally hedged to significant degrees. Whether or not the firm values what some might consider a diversifiable risk is covered in more detail in Section 3.3.

[8] There are other factors beyond the uncertainty of future cash flows for requiring a premium. Specifically, there has historically been a premium to defer consumption from today to "tomorrow." This risk-free rate is often approximated by U.S. Treasury bills (T-bills), which are often considered to be risk-free because they are backed by the U.S. government.

[9] This is partly because some of the risk has been passed to the consumer.

[10] The actualized (as opposed to *ex ante* anticipated) stock returns of the S&P 500 over the last decade notwithstanding.

In the electric sector, deregulation was driven in part by anticipated improvements in efficiency of investments and their operation, though there has been significant skepticism of both the inherent benefits of and practical problems to capture such benefits, and this is a subject of on-going debate.[11] In the electric sector, changes in fossil fuel prices, especially for natural gas, can directly influence electricity prices, given that natural-gas-powered generation often sets the hourly dispatch price (i.e., is "on the margin").

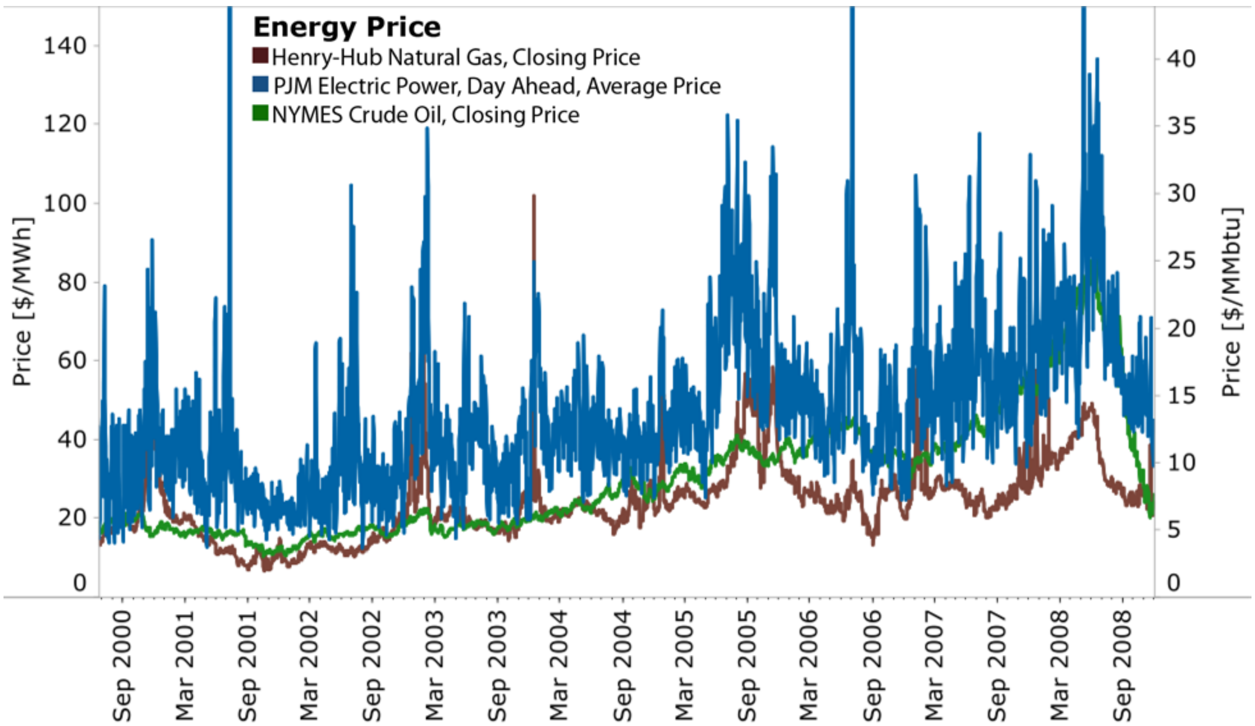

Figure 1-1. Daily price variation of natural gas, oil, and electricity prices (1999 to 2008)

Sources: NYMEX (2009); EIA (2009); PJM (2009)

Figure 1-1 shows the variations in daily natural gas, oil, and electricity prices over a 10-year period, 1999–2008 in three primary U.S. energy markets. The fossil fuel prices and power prices show significant price volatility and are also strongly correlated to each other, which is not unexpected, though on a daily basis there are significant seasonal effects because the hourly price of power, even if set by natural gas generation units, will also be affected by demand (see Table 1-1 and Figure 1-1).[12] For example, increases (or decreases) in daily natural gas prices tend to lead to increases (or decreases) in the daily average of hourly power prices because natural gas generation is often on the margin during peak periods. The correlation and magnitude of this relationship will depend on demand, which in turn is set by many other factors (see, e.g.,

[11] For a more detailed discussion of electric restructuring issues that cover a range of views, see for example, Blumsack et al. (2006), Joskow (2008), and Wolak (2003).

[12] Measures of volatility (as well as the associated expected price) clearly depend on what timescale is chosen (e.g., there may be significant hourly power price volatility during any given day, and significant volatility in the monthly average of hourly prices between months due seasonal effects, and yet such observations might also be consistent with little or no volatility on an annualized basis). How investors and consumers react to volatility will also depend on the timescales chosen.

Karakatsani and Bunn 2008). In general, the daily average of hourly electric power prices has greater volatility than natural gas prices, though this volatility is not likely to be constant throughout the year. Volatility in daily average or hourly peak electricity prices can be expected to be greater during summer months when peak demand is likely to be higher compared to winter months (see Figure 1-1). Further, price volatility depends strongly on what timescale is chosen (e.g., daily, monthly, or yearly), and both the producers' and consumers' attitudes to volatility will depend on the timescale considered. For example, consumers might be expected to be relatively indifferent to monthly fluctuations in their electricity bills that correspond to seasonal differences in demand and price. In contrast, they may be far more concerned with volatility in overall annualized costs or changes in marginal costs (on $/MWh) between two similar periods.[13]

Figure 1-2 shows the multi-year distributions of the absolute and relative volatility of daily natural gas, oil, and power prices. These price distributions are not "normal" but positively skewed toward higher prices. On an annualized basis (as well as shorter timescales), the distribution of power prices and related potential cost drivers to consumers are asymmetric in a way that may adversely affect consumers and society because the "benefit" of lower costs is inherently limited or capped (i.e., prices cannot generally, except in limited special cases, drop below zero). By contrast, higher future fossil fuel and power prices (and hence costs to consumers)—which might be driven, for example by growth of less industrialized nations—are essentially uncapped. Moreover, while the relative volatility of daily prices between each of the different energy commodities is similar, the absolute values and their variance show significant variation over the two 5-year time periods. This supports the view that predicting future prices based on historical information is extremely difficult.

Risk aversion assumes that deviations from an expected value are treated equally whether they correspond to gains or losses. Work pioneered by Tversky and Kahneman (Tversky and Kahneman 1981, Kahneman and Tversky 1979) and many others has shown that people often feel losses more than equivalent gains. This concept is known as "loss aversion," and Kahneman et al. (1991) have observed that the relative difference in value for small or moderate gains and losses of money is often about two to one, though many factors will affect this. Such a view requires that the economic utility associated with either side of the distribution has a different weighting, whereas in the simple application of risk aversion this is not the case. Which side of the distribution corresponds to gain or a loss will depend on what the distribution represents; for example, for a consumer a loss might refer to the right-hand side of the distribution corresponding to a higher than expected dollar per megawatt-hour cost of electricity. In this case, the asymmetric impact of loss aversion to a consumer would reflect the fact that the marginal "benefit" to consumers of lower electricity bills (on a $/MWh basis) is likely to be worth less to a typical consumer than the "loss" associated with a comparable increase in dollar per megawatt-hour cost (relative to some expected cost). We shall apply ideas from both risk aversion and loss aversion in Section 4.

[13] Throughout this text we will be discussing prices and costs, and we have tried not to use the terms in an interchangeable manner. On the other hand, one person's costs can often be another person's prices (e.g., the cost of natural gas to a natural gas generator will depend on the price paid for it) as well as at times being ambiguous (e.g., if electricity prices go up, and the end-user consumer's bill increases has the cost or the price of energy, or both, gone up from the consumers' perspective).

Table 1-1. Correlation of Daily Energy Prices

Henry-Hub Natural Gas Spot Price	PJM Day-Ahead Locational Marginal Price (LMP) (daily average)	0.66
Henry-Hub Natural Gas Spot Price	NYMEX Light Sweet Crude Oil Closing Price	0.71
NYMEX Light Sweet Crude Oil Closing Price	PJM Day-Ahead LMP Price (daily average)	0.61

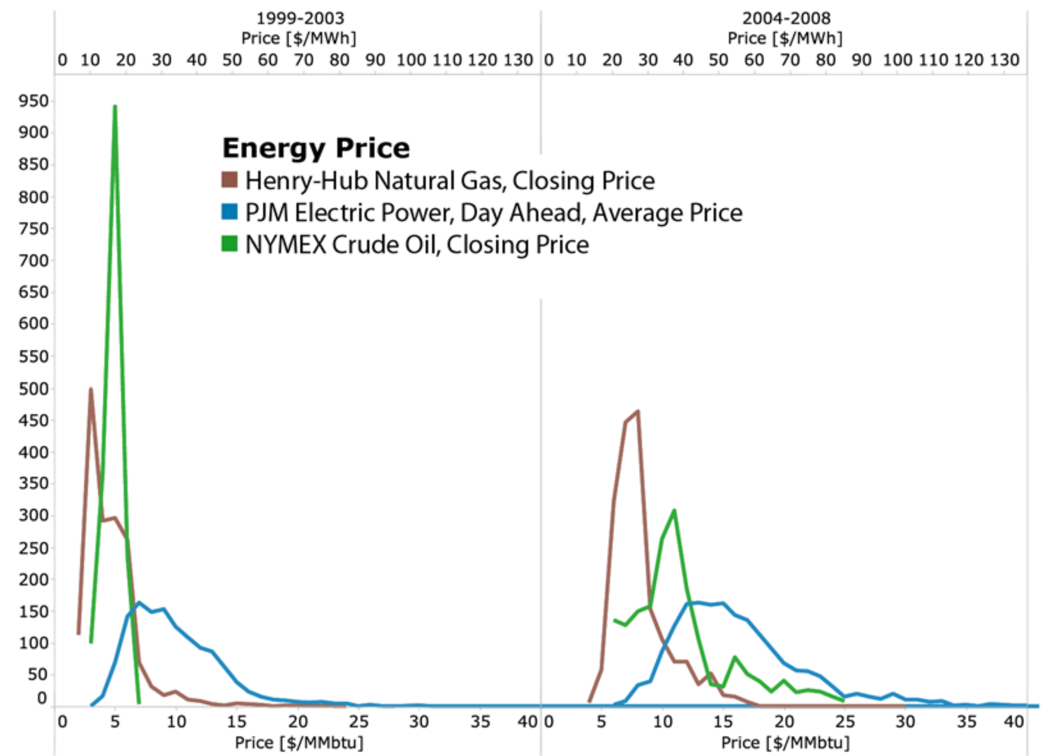

Figure 1-2. Distribution of energy prices separated into two 5-year blocks (1999–2008)

Sources: NYMEX (2009); EIA (2009); PJM (2009)

For society, or at least the risk-averse consumers and producers who make up a large part of it, it would seem that—all else being equal—power generation technologies that can provide electricity without price risk ought to be worth something more than technologies with price risk. Some renewable energy technologies that have this zero-cost fuel characteristic, including wind and solar, are not without revenue risk because output is dependent on when the wind blows or the sun shines. This intermittency may lead to increases in both operational costs and volume, and hence revenue risk, and thus present different risk/benefit profiles to consumers and producers. It may also limit the ability of such renewable energy sources to provide firm capacity.[14] Geographical diversity can mitigate supply variance to some extent because the generation of variable renewable energy in different locations will not be perfectly correlated. Geothermal energy is generally considered a dispatchable renewable resource with low fuel costs.[15]

1.3 Variance Reduction of Portfolio Due to Lack of Correlation of Costs or Returns

The idea that adding wind to an electric system leads to potential benefits through the reduced variance in the system costs was pioneered by the late Shimon Awerbuch (see, e.g., Awerbuch and Berger 2003) through the application of ideas from mean-variance portfolio analysis (MVPA) to electric generation portfolios. MVPA is often used for financial markets to select "efficient" portfolios of stocks and bonds that maximize the expected return for a given risk (usually measured as the standard deviation of the return or a similar metric) or vice versa. For a portfolio with *N* assets, the range of efficient outcomes lies on a curve on the risk-return diagram known as the "efficient frontier." The degree of curvature of the efficient frontier toward lower return for a given risk reflects the correlation of the returns. With perfect correlation, mixes of assets lie on a straight line with no back curvature (the blue line); with no correlation, the mixes are curved backwards (the red curve); and with perfect anti-correlation, the mixes go back linearly. Figure 1-3 shows the return obtained by mixing different combinations of two assets with different returns and variance for different correlations.

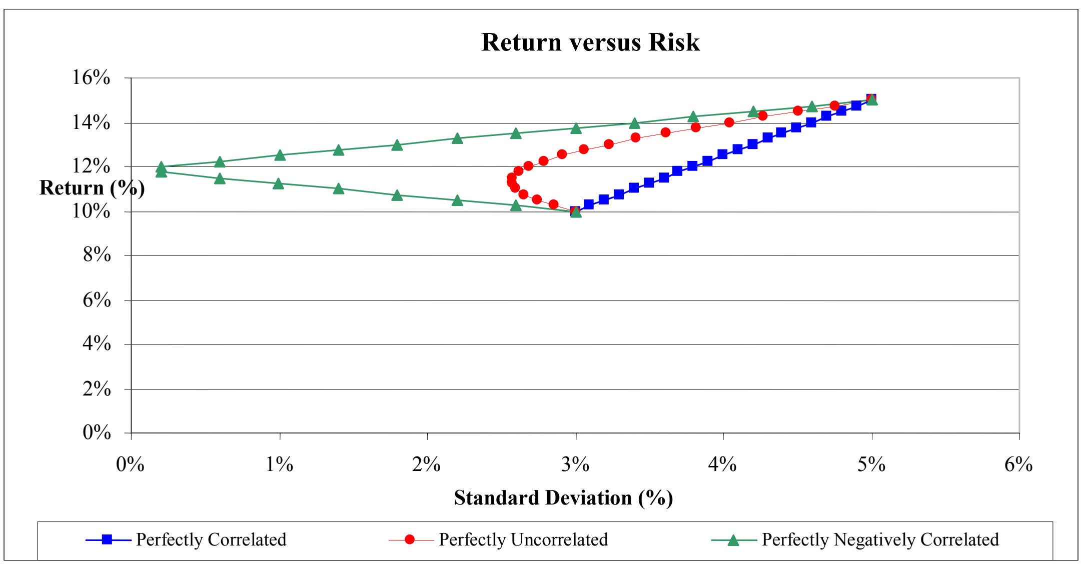

Figure 1-3. Risk and return relationship for mixes of two assets under different correlation assumptions

[14] Dispatchable plants are not without volume-based revenue risk in that they will not dispatch if the electricity price is too low to overcome the variable cost of generating power.

[15] Though over the longer term there may be significant resource risk in terms of the overall amount of usable energy.

The back curvature generated by the lack of correlation of returns of the two assets is attractive to risk-averse investors because it reduces the variance for a given return (compared to the perfectly correlated case). While MVPA theory gives a range of alternative efficient risk-return portfolios corresponding to the combinations of assets that fall on the "efficient frontier," it does not provide any information on which of these portfolios is better. The portfolio preferred by a particular investor will vary depending on the level of risk aversion and other factors, and this is discussed further in Section 4.3.[16]

Awerbuch's essential insight was to see a parallel between a portfolio of stocks and bonds and a portfolio of generation assets (see e.g., Awerbuch and Berger 2003) Specifically, he argued that adding significant amounts of wind generation to an existing electricity system would reduce the variance of the system's annualized electricity costs because the levelized cost of wind is a constant (since the variable cost of wind is zero), and its contribution to the overall system costs are therefore uncorrelated with the rest of the system's fossil fuel costs. This variance reduction, Awerbuch reasoned, should be worth something given that consumers (and many producers) tend to be risk averse. While Awerbuch observed the directional impact of adding wind generation to a generation portfolio with a significant amount of fossil generation, he was aware of and noted the limitations of using such an approach to optimize the overall portfolio because of operational differences of the different technologies.

- For example, a natural gas combustion turbine (CT) is designed to operate for short periods during the more expensive peak hours, while nuclear and coal thermal generation plants tend to operate in a baseload manner around the clock. Therefore, CTs and baseload plants are not providing the same service and would not be expected to have the comparable levelized costs. More generally, the levelized cost of generation depends on utilization, and thus the assumption that utilizations of different dispatchable generation technologies are fixed under different portfolio mixes is unlikely to be valid unless such analysis is restricted to baseload units.[17]

- Relatedly, wind generation suffers from intermittency issues, so that (as we shall show in Section 3.1 and Figure 3-2) the average marginal price (and hence value) of wind generated in any specific hour throughout the year will be different from any form of dispatchable generation.

Overall, this lack of equivalency between the average value of an hour of generation provided by a gas turbine and a baseload plant over the entire year, and either of these types of generation and wind generation, is why applying MVPA will not in general be successful in terms of portfolio optimization using a simple levelized cost of energy (LCOE) approach.[18] As a result, more

[16] Other factors that may be important include the investors' reference point (e.g., the degree to which they can afford to take the risk). An individual with $1 million in the bank might behave quite differently if his or her cash assets were reduced to $1,000 or less. A preference for gains over losses may also be a factor that depends on the person's reference point. The topic of "loss aversion" will be revisited in Sections 4.3 and 5.

[17] Such baseload analysis was done recently by Roques et al. (2008).

[18] A useful way to understand this is to test the accuracy of the simple LCOE algorithm under the assumption that there is no cost uncertainty. This type of simplified optimization would suggest—wrongly—that 100% of the load would be met by a baseload technology with the lowest LCOE. This misses the point that peaking units will also be needed to meet demand during some parts of the day and that building a baseload unit to meet peaking demand is

recent work on portfolio optimization has often restricted comparisons to baseload units, though this approach is still not without some issues (see, e.g., Roques et al. 2008).

Awerbuch's (see e.g., Awerbuch and Berger 2003) approach focused on considering the variance associated with least-cost investment decisions. While this restricts the direct application of the approach to regulated cost-plus markets, this is less of a drawback than might first be imagined because such markets still represent a significant proportion of electric generation capacity in operation in the United States.[19] Deregulated wholesale power markets, on the other hand, in the United States or Europe, such as PJM and ERCOT[20] in the United States and the United Kingdom, respectively, differ in that all generation units bidding into the wholesale power market and then being called on to provide power in a given hour get paid the price of the marginal generation unit for that hour. Hourly price generally varies significantly over a 24-hour period, peaking during the day, and also often exhibits significant weekend versus weekday and seasonal variation.

Peak hourly electricity prices in PJM (and many other markets) are often set by the marginal natural gas generation unit. Because of this, while the daily price of natural gas is often quite volatile, it is less obvious *ex ante* that in such a market, a producer's net revenue from natural gas generation will be more volatile than the net revenue from a wind producer selling into the market.[21] In contrast, consumers buying directly from the hourly spot market will experience the full volatility of the hourly power prices unless they have taken measures to mitigate such risks.[22] The limitation of the original approach to least-cost planning to account for these market-structure-based differences was recognized by Roques et al. (2008), who applied mean variance portfolio analysis to investment returns (rather than electricity costs) in what they term "liberalized" markets for three types of baseload generation (natural gas, coal, and nuclear). As suggested above, Roques et al. (2008) found the correlation between natural gas prices and

likely to be very expensive (i.e., if the capacity factor is lowered, the levelized cost will go up). As a result there is no single levelized dollar per megawatt-hour solution. Moreover, for any given region, an array of baseload plants might be desirable when real factors such as resource availability and coal transportation costs are considered. Such disadvantages can be reduced if one moves to more realistic electricity system models. From a purely statistical perspective, to the degree the risk-free version of the model (e.g., a production cost model) provides a reasonable portfolio solution, adding a variance-based constraint would seem appropriate. That is, a higher system cost might be preferable—to some lower cost solutions—if the variance of distribution is reduced sufficiently. This is discussed further in Section 4.3.

[19] It also represents how some electricity systems model capacity expansion across the entire United States regardless of whether the market is regulated or deregulated.

[20] The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 23 million Texas customers—representing 85% of the state's electric load and 75% of the Texas land area (see e.g., www.ercot.com for more details).

[21] In fact, as we show later, rather counter-intuitively, in PJM the monthly and annual net return for natural gas generation is still more volatile than for wind, even though natural gas often sets the on-peak marginal price. This is because natural gas generation in our analysis dispatches at peak hours where prices are more volatile than during off-peak hours, whereas this effect is cushioned for wind because it operates across the entire 24-hour period, including the less volatile hours during off-peak periods. Note: For common hours of operation, natural gas net revenue would indeed be partially hedged relative to wind.

[22] Customers with a direct bilateral contract to buy wind power would, on the other hand, experience much lower (zero, in fact) price volatility for that fraction of the load that could be met through such a contract. Depending on the structure of the contract, they may experience volume and ultimately cost risk to meet their demand requirements.

power prices reduced a gas generation owner's return-based risks *relative to other baseload generation* such as coal and nuclear. In Section 3, we shall show that in PJM over the period considered, the volatility of monthly and annualized returns for wind generation is lower than for a combined-cycle gas turbine (CCGT) because of the different hours in which the two technologies operate. This finding is based in part on our technology assumptions about conversion efficiency that resulted in the natural gas generation operating mainly during peak hours.[23]

Volatility of returns for specific investments, or a portfolio of diverse power generation technologies, needs to be viewed within the larger context of risk mitigation and risk tolerance. For example, sophisticated producers or large consumers may worry less about the variance reduction benefits due to the use of renewable energy, owing to their ability to diversify away much of this risk though investments in the market, or in a portfolio of power generation technologies. For average consumers, on the other hand, such mechanisms are rarely available, and many consumers in the commercial or the residential sectors are likely to be significantly exposed to these risks in practice. Furthermore, even for large producers or consumers where energy costs or revenues are a large part of their business (e.g., the steel industry, chemical companies, or an electric utility), actions taken to reduce the variance of net cash flows add value if they reduce the chance of financial distress. This is especially true in the electric sector where, as Bessembinder and Lemmon (2002) have noted, the volatility of electricity prices is much higher than the volatility observed for the stock market, and the distribution of price outcomes is not normal but skewed toward higher prices (see also Figure 1-2). More generally, it might be argued that adding large amounts of renewable energy to the electric sector might lead to fundamental structural changes that alter the underlying risk-return outlook for investors or risk-cost outlook for consumers. While potentially beneficial at a plant and portfolio level, under today's market structure, large quantities of zero marginal cost wind power may be detrimental to overall power sector economics, as exemplified by recent incidences of negative marginal pricing, which in part reflects generators being paid \$20/MWh simply for running (Yang 2008). New market structure and rules will likely have to evolve to enable the power markets to adapt to greater quantities of variable generation while maintaining appropriate investment incentives. In Sections 4 and 5, we will return to some of these and related ideas.

[23] This finding reflects the specific technology assumptions we made. Of particular relevance, the relatively high heat rate for CCGT compared to today means that the utilization for the gas generation was low (about 30%), and therefore very different from Roque's baseload assumption (Roques et al 2008).

2 Wind and Natural Gas Generation

2.1 Background

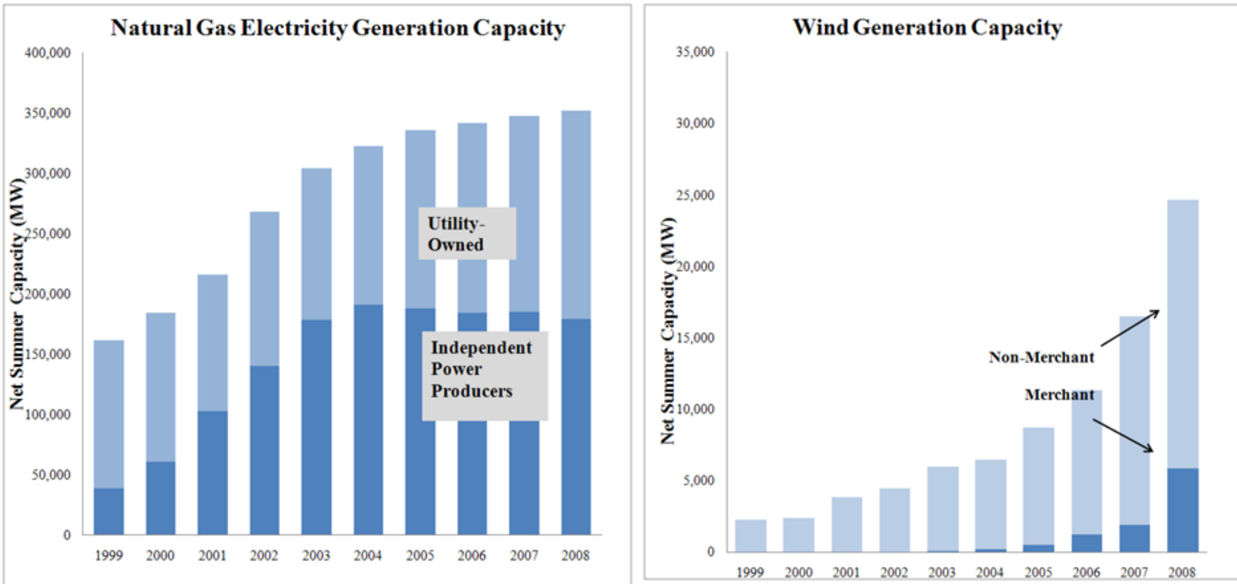

Figure 2-1. Growth in natural gas and wind generation in the United States (1999–2008)

Note: The 10-year period reflects the period of analysis.

Source: EIA (2009)

From Figure 2-1, we see that wind capacity increased rapidly over this 10-year period, from about 2 GW in 1999 to just over 25 GW at the end of 2008, in part stimulated by the availability of production tax credits (PTCs); wind capacity has since grown to 40 GW by the end of 2010. In fact, investments in wind generation have shown a strong stop-start correlation between investments and the ending and extension of these credits.[24] These credits, which were recently extended again to 2012 as part of the 2009 American Recovery and Reinvestment Act (ARRA), are currently worth about $20/MWh.[25] Most of these wind investments, especially in the early years, were for bilateral fixed-price contracts. This often made sense to both the purchaser of the power consumer (often a utility) and the producer because they reduce variance in cost of energy to the utility (and their customers) and returns for the producer. More recently, possibly because of increases in electricity prices and price volatility, more wind investments have been made on a merchant basis where the producer is either partially or fully exposed to market prices.[26]

In contrast, the growth of natural gas generation was much more rapid early on, corresponding to an explosion of interest in gas-fired generation. The absolute scale of growth was nearly an order of magnitude greater for natural gas than for wind. Figure 2-1 shows that natural gas generation

[24] The strong stop-start correlation between tax credits and investment does not necessarily imply such credits are necessary because if a developer believes tax credits will be available the following year, the investor may choose to wait.

[25] For the first 10 years of operation.

[26] A variety of derivatives can mitigate exposure to price fluctuations to some degree, though not without a cost for floors and caps, or by giving up some of the potential upside through the use of collars.

grew from about 150 to 300 GW over the 10-year period, with almost all of this growth coming from the merchant model, where owners sell into a daily spot market for power. After the natural gas generation market crash in the early 2000s, growth has been far more limited and the then-standard business model has been largely abandoned because, as we shall show, the risk-return characteristics were unattractive to the investor. A detailed description of the history of the natural gas boom and bust period is outside the scope of the report and has been covered elsewhere (see, e.g., Rigby 2004). For natural gas generation, the decision to dispatch in any given hour will depend on whether the hourly price of power exceeds the cost of the natural gas needed to generate that power (the "spark spread"), plus associated variable operations and maintenance (O&M) costs is positive. One major driver behind the difficulties faced by gas generators was the collapse of the "spark spread," which can occur if the price of natural gas changes faster than the price of electricity. This effect can be seen in Figure 2-2, which shows natural gas prices, power peak prices, and average peak period spark spread between 1999 and 2008. Though peak power prices tended to be positively correlated to changes in natural gas prices (0.66), the change in power prices was often muted. Moreover, there are clearly seasonal effects at play that impact electricity prices and natural gas prices differently.

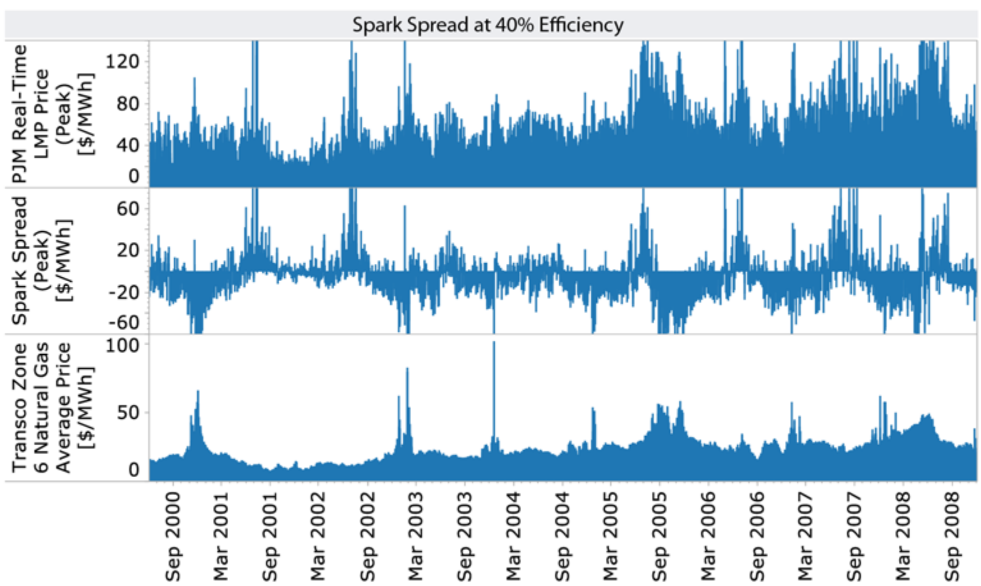

Figure 2-2. Spread between real-time electricity prices and the cost of natural gas for a combined-cycle gas turbine (under 40% efficiency assumption) (1999–2008)

Sources: NYMEX (2009); PJM (2009)

2.2 Methodology

In this study, we first analyze and compare the value and uncertainty of selling electricity generated by wind and natural gas in regulated and deregulated markets from both producer and consumer perspective over a variety of timescales. We assume in all cases the owner operates the generation asset to maximize profits. For wind generation, which has no fuel costs and is variable, this simply means selling whatever it can generate (within cut-in and cut-off wind speeds). In contrast, for natural gas generation, the decision to dispatch in any given hour will depend on whether the hourly price of power ($/MWh) exceeds the cost of the natural gas and variable O&M needed to produce it.

There are two broad classes of natural gas generation: (1) CTs and (ii) CCGTs. CTs are by design relatively cheap to build but inefficient due to the once-through non-cyclical nature of their combustion process, which leads to a lot of waste heat being discarded by the turbine. CCGTs are basically comprised of a CT, but where the waste heat from running a CT is then used to generate steam to drive a conventional thermal electric generator (which uses the heat to boil water at high pressure and this dry steam drives the turbine). The "twice-through" nature of the CCGT leads to a significant increase in efficiency in converting the energy released by burning natural gas to electric power. CTs are often called peaking units to reflect their more limited use. In this study, we focus on CCGTs.

Analytically, this leads to four types of variable-volume energy contracts:

- **Deregulated Wind**—a contract to supply wind-generated electric power at the real-time PJM hourly electricity price. The owner operates for 100% of the time, though the output will be variable (including no power output from a particular wind turbine if wind speeds are too low or too high) and the hourly price received variable.
- **Deregulated Natural Gas (CCGT)**—a contract to supply natural-gas-generated electric power at the real-time hourly PJM electricity price. The price or cost of natural gas is assumed to be the spot market price delivered to an "average" delivery point in PJM.[27] The owner operates the CCGT only when it is economical to do so, that is, when the "spark spread" is positive and at least greater than the variable O&M costs.
- **Regulated Wind**—a contract to supply wind-generated electric power at a fixed price that is set annually based on actual utilization so that the owner recoups a defined fraction of initial capital costs, including a return on capital. The owner operates for 100% of the time, though the output will be variable. For both wind and natural gas cases, we examined two scenarios corresponding to an 8% and 10% real return. Given that the historical rate of inflation over the period averaged 2.5%, this corresponds to a nominal rate of return of 10.5% and 12.5%, respectively.
- **Regulated Natural Gas (CCGT)**—a contract to supply natural-gas-generated electric power at a fixed price that is set annually so that the owner recoups a defined fraction of initial capital costs, including a return on capital. The natural gas used is

[27] We follow PJM market analysis in using Transco Zone 6 Non-New York as a proxy for the cost of natural gas. This price is often $0.50–$2.00/MMBtu or more greater than the price of natural gas at Henry Hub.

assumed to be purchased at spot market price for natural gas delivered to PJM. The owner operates the CCGT only when it is economical to do so. We approximate a regulated market by assuming that the hourly operation of the CCGT is the same as in the deregulated case, though the owner no longer receives the deregulated hourly prices.

Table 2-1 lists the variables used in formulating these contracts and the numerical values assumed for cost parameters. Table 2-2 summarizes how costs were computed. In each case, the producer and consumer revenues are given by:

$$R_t^{(\mathrm{P})} = P_t Q_t - \alpha OC - FQ_t - VQ_t$$

and

$$R_t^{(\mathrm{C})} = -P_t Q_t$$

Additionally, the producer's annual return on capital is calculated as the ratio of their revenue minus overnight capital to their overnight capital cost. Although the regulated contracts have prices set so that yearly revenue exactly balances, the defined annual return on capital, revenue over different time periods (weekly or monthly), does not exactly equal that defined annual return, depending on either the available wind resource or the spark spread. In general, we compute monthly and annual cash flows. The monthly values are of interest because settlement typically occurs over that timeframe and annual values are of interest because the regulated prices in this analysis vary year by year.

Table 2-1. Contract Variables and Price Assumptions[28]

Quantity	Variable	Notes
Contract Price	P_t	
Contract Power	Q_t	
Electricity Spot Price	E_t	
Wind Power Output	W_t	
Natural Gas Power Output	C	
Natural Gas Spot price	N_t	
Natural Gas Efficiency	$\varepsilon \approx 0.42697$	
Producer Revenue	$R_t^{(\mathrm{P})}$	When this is zero, the producer has covered his fixed, variable, and fuel costs plus α of his overnight capital cost.
Producer Return on Capital	$r_t^{(\mathrm{P})}$	
Consumer Revenue	$R_t^{(\mathrm{C})}$	
Annual Fraction of Overnight Capital Cost Required for Producers	$\alpha = 0.10/\mathrm{yr}$	
Overnight Capital Cost (1997$) for Wind	$O = \$1{,}109{,}000/\mathrm{MW}$ installed	
Overnight Capital Cost (1997$) for Natural Gas	$O = \$445{,}000/\mathrm{MW}$ installed	
Fixed O&M Cost (1997$) for Wind	$F = \$25{,}920/\mathrm{MW}$ installed/yr	
Fixed O&M Cost (1997$) for Natural Gas	$F = \$15{,}350/\mathrm{MW}$ installed/yr	
Variable O&M Cost (1997$) for Wind	$V = 0$	
Variable O&M Cost (1997$) for Natural Gas	$V = \$0.51/\mathrm{MW/hr}$	

Table 2-2. Price Formulas for the Four Contracts

Contract	Price Formula
Deregulated Wind	$P_t = E_t$ $Q_t = W_t$
Deregulated Natural Gas	$P_t = E_t$ $Q_t = \begin{cases} C & \text{for } E_t \geq N_t/\varepsilon + V \\ 0 & \text{otherwise} \end{cases}$
Regulated Wind	$P_t = \dfrac{\sum_{\mathrm{year}}[(\alpha O + F)C + VW_t]}{\sum_{\mathrm{year}} W_t}$ $Q_t = W_t$
Regulated Natural Gas	$P_t = \dfrac{\sum_{\mathrm{year}}[(\alpha O + F)C + VQ_t]}{\sum_{\mathrm{year}} Q_t}$ $Q_t = \begin{cases} C & \text{for } E_t \geq N_t/\varepsilon + V \\ 0 & \text{otherwise} \end{cases}$

[28] 1997 capital cost and operation and maintenance assumptions come from an EIA report (1998) and are considered reasonable proxies for investment costs and performance parameters for investments made in 1998.

3 Wind and Natural Gas Generation in a Deregulated Market

3.1 Producer Returns over 10-Year Period (1999–2008)

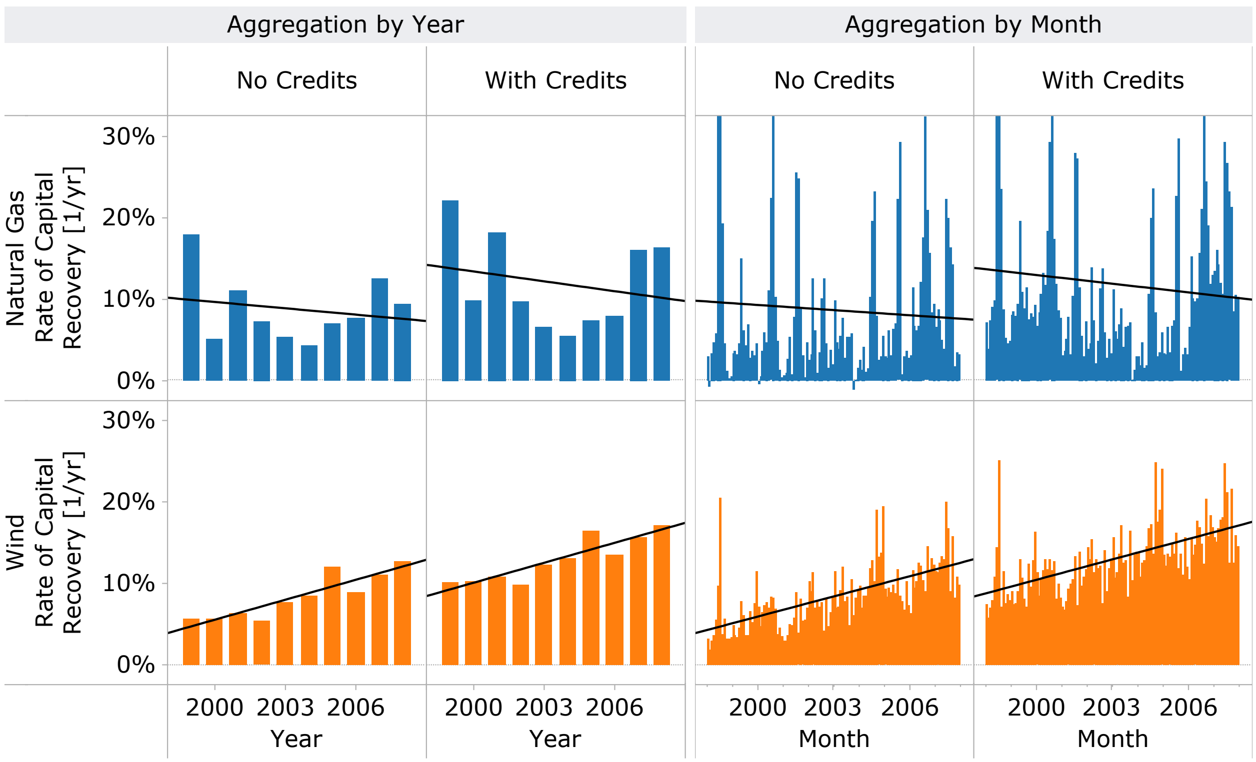

Figure 3-1. Annual and monthly returns for wind and natural gas generation in PJM (deregulated market example) (1999–2008)

Figure 3-1 shows the annualized and monthly returns for CCGT and wind generation both with and without production tax or capacity credits ("credits" in the Figure 3-1 labels) calculated in accordance with the methodology outlined in Section 2.2.[29] For both technologies, when operated in any given hour, the technologies are assumed to receive the hourly PJM real-time price. For wind, this corresponds to any hour the wind turbines are generating, [30] whereas for natural gas it corresponds to hours when the sum of spark spread and the variable O&M cost is positive. For wind, the credit corresponds to a PTC of $20/MWh, while for CCGT the credits correspond to a variable monthly capacity payment. Figure 3-1 shows that the wind annualized return with a PTC included has increased from about 10% to nearly 15% in more recent years. In contrast, the annualized return for natural gas CCGT generation is significantly lower despite the

[29] To separate out the potential effect of financing considerations, we estimate returns based on simple unadjusted net cash flow of earnings before interest, taxes, and depreciation and amortization (EBITDA). This simplification should be recognized when considering additional payments due to tax or capacity credits.

[30] We use the 10-minute wind-power output from a representative site in the Eastern Wind Integration & Transmission study (NREL 2009). The results in Sections 3 and 4 all use this site, and though the details are dependent on the site, the general characteristics and trends are common among representative sites.

much lower assumed capital costs. Over the 10-year period, the average annual returns without and with a capacity payment are 9% and 11.5%, with the value remaining flat or declining over time. Capacity payments can lift the return for natural gas generation owners, but these are also highly uncertain and generally low over this period. Figure 3-1 also shows that volatility in returns for natural gas generation is much higher than wind, both on an annual and a monthly basis. Without credits, the annual volatility for wind and natural gas generation was 2.5% and 3.5% respectively. In contrast, the monthly volatility of wind and natural gas generation was 3.5% and 11.0%, respectively. The higher volatility of monthly returns is largely to be expected, and much of it reflects seasonal variations in demand.

The observation that the returns for wind generation have a lower variance than the returns for natural gas generation is consistent with a wind generation owner being better hedged than an owner of natural gas generation. This is less intuitive than it might seem because, in a deregulated market, the peak price of electric power is often set by natural gas generation (correlation of 0.66), which might be expected to act as some sort of natural hedge for net revenue variability. For example, in a comparison by Roques et al. (2008) of the simulated dispatch of generation assets in the United Kingdom, it was found that the owner of a natural gas generation plant may be better naturally hedged than coal and nuclear facilities because of the correlation between peak power prices and natural gas prices. As discussed by Roques et al. (2008): "…the correlation between electricity, gas and carbon markets [in the U.K.] make[s] 'pure' portfolios of gas plants more attractive than diversified portfolios as gas plants' cash flows are self-hedged" (p. 1832). Roques et al. (2008), however, were considering different types of baseload power generation only (coal, natural gas, and nuclear) and did not consider wind. For wind, our analysis shows the returns were better hedged than natural gas in PJM over this period (given our technology assumptions about wind power output and natural gas generator's heat rate). Three factors that contribute to this are:

- Although positively correlated, peak power prices often "move" much less than the underlying natural gas prices. This can lead to the "spark-spread" for natural gas being squeezed and can impact both operation and net profitability.[31]
- For our technology assumptions in PJM, the natural gas generation is operating in more of the higher and more volatile peak price hours and less of the lower demand, low price hours than wind. Specifically, unlike wind, natural gas is not operating as a baseload plant across all hours as was assumed in the Roques et al. (2008) analysis.
- While wind generates intermittently, its operation is more evenly spread across both peak and off-peak hours than natural gas generation units. As a result, compared to natural gas generation, wind often operates at lower price off-peak hours where the hourly power price is not driven by natural gas and is less volatile.

The effect of these factors can be seen by looking at two related parameters: (1) the annualized average hourly price received for natural gas and wind generation for hours 1 through 24 and (2) the fraction of the time the technology generates in any given hour during the year. This effect can be seen in Figure 3-2 and is discussed in Section 3.2.

[31] However, similar behavior might be expected to be observed in the United Kingdom study.

3.2 Producer Prices and Consumer Costs in a Deregulated Market

The previous section analyzed risk and return from a producer perspective. How does the consumer fare under wind or natural gas generation in a deregulated market? Figure 3-2 (top row) shows the annual average price to producers (2009$/MWh) of power received in a deregulated market for wind and natural gas generation, respectively between 1999 and 2008, and we see that the average annual hourly price of power from natural gas generation is approximately $20–$30/MWh higher from wind than power. It would be wrong, however, to think (at least for small amounts of added wind) that wind power in any given hour during these periods was any cheaper than natural-gas-fired generation in a deregulated market. In a deregulated market, buyers of wholesale power, such as utilities, see only one price in any given hour, and this price is set by the marginal price of the last generation unit to meet demand in that hour.[32] Thus, whether the power is supplied by wind or natural gas, it is supplied at the same market price in any given hour. Overall, it is true that the price of natural-gas-generated power is both higher and more volatile than the price of power supplied by wind on average during any given year, but this is because they are operating in different hours. This can be clearly seen from Figure 3-2 (lower two rows), which shows distributions of the annual average hourly generation utilization (or dispatch fraction) for these two technologies across the day. Wind is used to generate power intermittently across the whole 24-hour period. The variability corresponds to an annual average capacity factor of 39%, which is reasonably similar across all hours though with somewhat higher utilization at night than during the day (see third row in Figure 3-2). In contrast, natural gas generation is dispatchable but restricted to more volatile and higher-priced peak hours when the spark spread is positive. The CCGT was assumed to have gas-to-power conversion efficiency of 43%, which led to an average capacity factor of 30% (though with significant variation between the years, as seen in the second row in Figure 3-2). The costs paid by large consumers and smaller end users are likely to reflect the load-weighted average price of power (whether purchased directly from the wholesale market or passed through by the utility) and therefore is only indirectly linked to the actual running costs of most wind- and natural-gas-generating units.

While not examined in any detail in this report, large-scale renewable penetration in deregulated markets can be expected to add value to consumers through variance reduction when wind or solar penetration is so great that these technologies are setting the marginal price of power[33], though this effect may be somewhat off-set by production effects due to the impact of variability. As mentioned earlier, given that the marginal cost of wind is close to zero (and prices below zero have been observed due to PTCs), market structure rules for capacity payments and other incentives may need to be revisited in such cases to encourage investments in wind that properly reflect societal benefits.

[32] Strictly speaking in PJM there are two separated (though interrelated) markets for day-ahead and real-time power, which will have somewhat different prices in any given hour.

[33] Even when not setting the marginal price of power, large amounts of wind could reduce the hourly price by adding low cost power to the supply curve, especially during peak periods if less efficient, higher-priced peaking natural gas units are no longer needed to meet demand

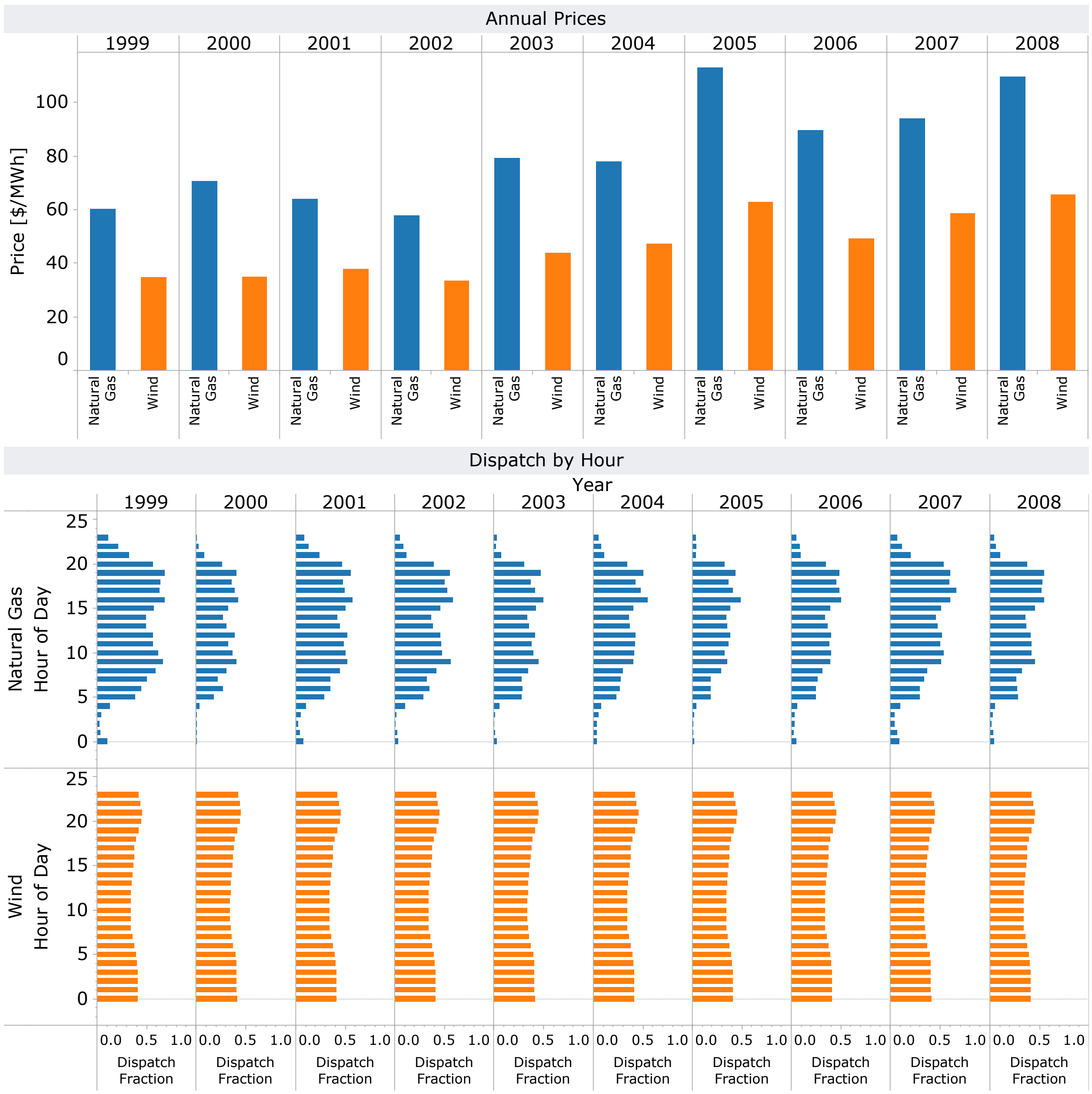

Figure 3-2. Annual average price received for wind and natural gas technology and annual utilization for these technologies over 24-hour period

3.3 Some Cost, Value, and Portfolio Optimization Considerations

Figure 3-2 demonstrates the limitation of using mean variance portfolio theory to determine the optimal generation supply mix based on the simple use of annualized LCOE. While applying mean variance theory may be reasonable when the assets are equivalent (or nearly so), wind and natural gas generation are not equivalent because the two technologies have different utilizations and more generally operate in significantly different hours; this latter distinction is important since even if wind and natural generation had by coincidence the same utilization, they would still operate in very different hours.

The problems associated with directly comparing LCOEs for different technologies have been recently discussed by Joskow (2010), and a number of our observations are consistent with his findings. For example, in the 10-year timeframe of PJM data analyzed, we observe that natural gas units, while utilized less overall than wind (average capacity factors of 30% and 39% for natural gas and wind, respectively), operated in very different hours, with an emphasis on higher priced peak hours. The differences in hours of operation for natural gas generation lead to an average annual hourly output capacity weighted price premium of $20–$30/MWh more for each hour of operation compared to wind (see first row in Figure 3-2). It should be noted that the size of any premium will depend on specific technology assumptions and market conditions and will be location specific. Similar considerations apply when comparing solar energy (whether photovoltaic or concentrated solar thermal power) and wind, with solar potentially having a considerably higher average annual marginal value based on the hours it generates because of the strong temporal relationship between solar radiation and peak load periods.

The average annual hourly price differences and the distribution in average annual utilization over a 24-hour period (shown in Figure 3-2) support the use of models that explicitly use or simulate hourly data over the entire year in valuing generation assets.[34] While the average annual dollar per megawatt-hour value differential between two technologies will depend on many factors, including the specific choices made for the utilization and efficiency, it does not tell you anything about the rate of return (RoR) for these technologies since that will also depend on the technologies' capital costs and operating costs, including any fuel costs. An analysis of RoR for the two technologies is discussed below and in Section 4.2. We find the RoRs without credits quite similar (though with somewhat different risk profiles) despite having very different average revenue per megawatt-hours generated; this in part reflects the fact that natural gas generation needs to cover the cost of natural gas when generating, whereas wind is economic whenever the wind blows.[35]

More generally, because the lowest LCOE solution does not correctly predict the technology portfolio in the risk-free case (in part because it will only predict one baseload technology), it cannot be expected to work when expanded to include uncertainty and correlation effects using mean variance portfolio theory. On the other hand, a private sector financier investing in both wind and natural gas generation will gain a lower variance for a given return because the returns of the wind (or solar) and gas technologies are not perfectly correlated. With no credit for wind or natural gas generation, we see from Figure 3-3 that the natural gas provides a return (the open circle) that is slightly greater than wind (the star) and has a corresponding higher variance. In such circumstances, an investor can reduce their variance for a given return by investing in both types of assets. This is shown in Figure 3-3 where the variance associated with a return in the range of 8.5% to 9.0% can be reduced by about 40% (e.g., from 3% to 2%).

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[34] See, for example, the System Advisor Model https://www.nrel.gov/analysis/sam/ for full description and download option.

[35] Again it should be emphasized that our observations depend on the specific assumptions made. For example, the relatively low utilization for natural gas generation used in this analysis reflected quite a conservative heat rate (corresponding to 43% conversion efficiency in 1998). Significantly higher conversion efficiencies would have been available over much of the period between 1999 and 2008, and this would be expected to lead to changes in observed average price premiums, net revenues, and risk-return relationships.

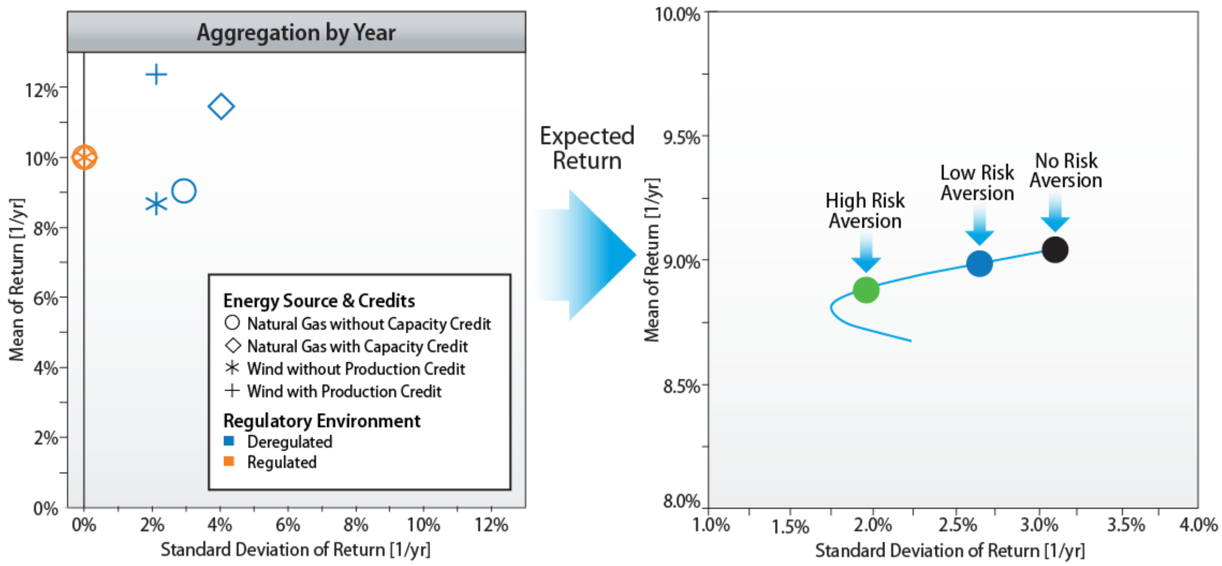

Figure 3-3. Risk-return relationship for wind and natural gas without subsidies

If an investor had no risk aversion (and was risk neutral), then the investor will go for the greatest expected return regardless of any variance. More generally, where an investor chooses to be on the efficient frontier will depend both on the shape of the curve and their risk aversion (see Section 4.3). Figure 3-3 shows how fiscal instruments, such as PTCs or capacity payments, can affect the risk-reward relationship and encourage investment in new generation assets in a market with price caps. The impact of PTCs for wind generation is effectively to keep the risk (i.e., the variance of the returns) the same for a significantly greater expected return since, under PTC, every megawatt-hour generated effectively gets a $20/MWh credit. When both wind and natural gas generation are given PTCs and capacity credits, respectively, investment in wind is dominant over natural gas because wind has both a higher return and a lower risk than CCGT. The difference in risk-return of wind versus natural gas power would be even more pronounced if wind received the PTC or equivalent support and natural gas generation did not receive a capacity credit. In contrast, with no wind subsidy but with a natural gas generation capacity credit available, the risk-return efficient frontier changes substantially in favor of greater proportionate investment in natural gas generation for any given risk-aversion profile.

Figure 3-3 suggests that a risk-averse investor might be wise to invest in both technologies since the variance of the net cash flows (and associated returns) would be reduced. On the other hand, it might be argued that according to standard finance theory this would not be true (or would be significantly less true) if the wind and natural gas generation were owned by separate publically traded companies that made up part of the Standard and Poor's 500.[36] This is because any premium associated with reduction in risk due to such diversification would have already been eliminated (because it assumes the investors in these two companies would be diversified already

[36] The basic idea is that merging a "Holidays in the Sun" firm with a "Holidays in the Snow" firm would not add value despite reducing the variance of the combined firm's net cash-flows because investors could (and it is assumed already would) have eliminated that diversifiable risk by investing in both firms without them merging. This "value additivity" theory assumes neither firm is likely to have any financial distress that might be mitigated by such a merger, but that assumption seems unlikely to be always true in the electricity industry.

in both these companies, as well as more broadly in the market). That no such risk premium is required for unique (as opposed to systematic (or market)) risk is important to consider but is not likely to be fully realized in the electric sector for a variety of reasons. Bessembinder and Lemmon (2002) note that:

> …companies in the power industry are likely to benefit from reducing the risk of their cash flows. [They] may have power price exposures sufficiently large that adverse price changes could lead to corporate default or bankruptcy (p. 1353).

This also seems to make sense when one considers the actual finance distress that many merchant electric-generation companies that were heavily focused on natural gas generation experienced in the early 2000s (see, e.g., Rigby (2004) for a more detailed discussion of some of the financial and market issues facing energy merchant companies in 2003).[37]

> In the last two years, well over $100 billion of energy merchant market capitalization has disappeared as almost everything that could have gone wrong with the nascent energy merchant industry did. In the past year, three companies have filed for bankruptcy. Bond spreads suggest that investors expect more of the same (p. 37).

Presumably adding wind generation their portfolio mix may have reduced the variance of their net cash flows, and this may in turn have reduced chance of financial distress. Lenders often appear more willing to lend, or lend at lower rates, to individual projects that have diversified some of the project-specific net cash flow risk. Projects may do this through aggregation against multiple wind projects due to spread of operational risk, as well as reduced variance of net cash flows from reducing impact of wind speed variations at different locations.

The managers of firms also often appear to value some degree of diversification in practice. For example, from ExxonMobil's (2009) 10-K suggests that the company does not take steps to significantly hedge their net revenues using financial instruments because they believe that they have already substantially mitigated such risk due to the diversity of their holdings.[38] That is, the firm values the reduction variance of net cash flows (over a spectrum of timescales) and associated annual returns that result from its diverse business interests and holdings and does not seem to presume that such risks are irrelevant because their shareholders can be invested in many other oil and gas companies or more broadly in the market. Similarly, smaller oil producers often have to hedge a substantial fraction of the future oil output to satisfy banker covenants.

[37] As Rigby (2004) noted in 2004 "credit ratings for 12 companies owning over 200,000 MW of generation worldwide (Table 1) have fallen from investment grade (in most cases) to low non-investment grade levels. Only AES Corp. and Calpine Corp., whose credit ratings were never investment grade, experienced less credit erosion, but only because they had less distance to fall" (p. 37).

[38] From ExxonMobil's 2009 10-K, "the Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact of such change…[and that it's].. limited derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity" (p. 55).

4 Wind and Natural Gas Generation in a Regulated Market and in Comparison with Deregulated Markets

Whether deregulation or regulation is inherently better in electricity markets is a subject of heated debate and one that we will only touch briefly here. On one hand, regulation is associated with lower rates of return, which for "good" investments would seem to benefit the consumer and be "fair" to the investor. On the other hand, while in deregulated markets investors may require higher rates of return on an expected basis, competition is anticipated to promote innovation of newer and better technologies, reduce the number of bad investments, and improve operational inefficiencies and thus, offer lower overall prices to consumers in the long run. However, even if deregulated markets have the potential to be better for society in principle, in practice it all depends on how appropriate the market design is and its implementation, including regulatory oversight. The market failure observed in California between 2000 and 2001, for example, had many contributing factors, but poor market design and regulatory rulemaking and intervention (or a lack of it) played a significant role in the process (see, e.g., Joskow 2001 and Wolak 2003 for more detailed discussion).[39] Even today in reasonably well-functioning markets such as PJM, aligning incentives to ensure optimal investments has been and remains challenging. Market structure and contract choices matter.

In this section, we explore the differences facing consumers and producers that are part of a "cost-plus" regulatory environment compared to a deregulated market. To do so, we again use the 1999–2008 data to enable a comparative study, and we ask what would have happened if PJM had been regulated over this period. We make the assumption that the wind and gas generation operate in the same hourly manner as in the deregulated market. What differs, of course, is what the owners of each of these technologies get paid to do with payments being adjusted under this approximation so that investors earn a constant rate of return. Because of the relative certainty of return to producers, we shall show that some of the risks previously taken on by the investor are transferred to consumers. This ability to transfer legitimate costs to consumers means that producers may be largely (at least currently) indifferent to reducing the variance of the cost of producing power. Many consumers, on the other hand, would be expected to value variance reduction for the annualized cost of energy (on a $/MWh basis) for both risk aversion and loss aversion reasons.

In modeling a regulated environment, there is really no operational approximation involved in the case of wind because a wind turbine operates whenever wind conditions are favorable, which of course is independent of any market structure assumptions. While some regulated markets may use a more complex cost minimization algorithm that may include other cost components,

[39] For example, under the new rules, consumers in California were guaranteed the right to purchase power at lower prices than before, while their original suppliers were still legally obligated to provide power at this guaranteed lower price if asked. However, to do this, these "suppliers" were required to purchase their wholesale power from newly formed day-ahead, hour-ahead, and real-time markets. Such an arrangement is fundamentally flawed for a number of reasons, including: (1) the "success" of this model is reliant on such deregulation leading to significantly lower prices, and (2) it does not connect consumer demand and behavior to the price they pay for power.

we assume that marginal dispatch is the main cost driver in regulated markets and is reasonable for the purposes of this analysis.[40]

4.1 Comparison of Annualized and Monthly Returns in Regulated and Deregulated Markets

In our analysis, we present two scenarios: one for 8% and one for 10% real returns.[41] Regulation of producer rates of return has an implicit impact on how risks are transferred to consumers. Figure 4-1 shows the standard risk and return diagram that is often used to represent the trade-off between risk and return. Results differ when aggregated monthly or annually.

When considering the yearly aggregation of revenue, we observe that:

- There is no risk to the producer in the regulated case, and returns are identical for wind and natural gas.
- In the deregulated case, without the production tax or capacity credits, the natural gas-based producers see 1%–2% higher returns than wind-based producers but with a slightly higher risk.
- The deviations from the assumption of normally distributed annual returns are minor.
- When the PTC is included, the return for wind-based generation dominates (in the sense of higher return and lower risk) over natural-gas-based electricity production.

[40] For wind, the approach is straightforward. We look at the output over a 10-year period and allow the wind turbines to repay their capital at 10% and fixed and variable O&M. For CCGT, we need to first understand how gas generation would dispatch—and to do so properly would require running a large-scale production-costing model—something outside the scope of this report. Instead, as a reasonable approximation, we assume that dispatch is identical to PJM market gas, but that the unit does not receive the PJM marginal price. Instead, natural gas daily fuel costs used are assumed to be an add-on, and again the generator is allowed to cover fuel costs and fixed and variable O&M costs.

[41] We chose these values to reflect a reasonable range of regulated rates of return.

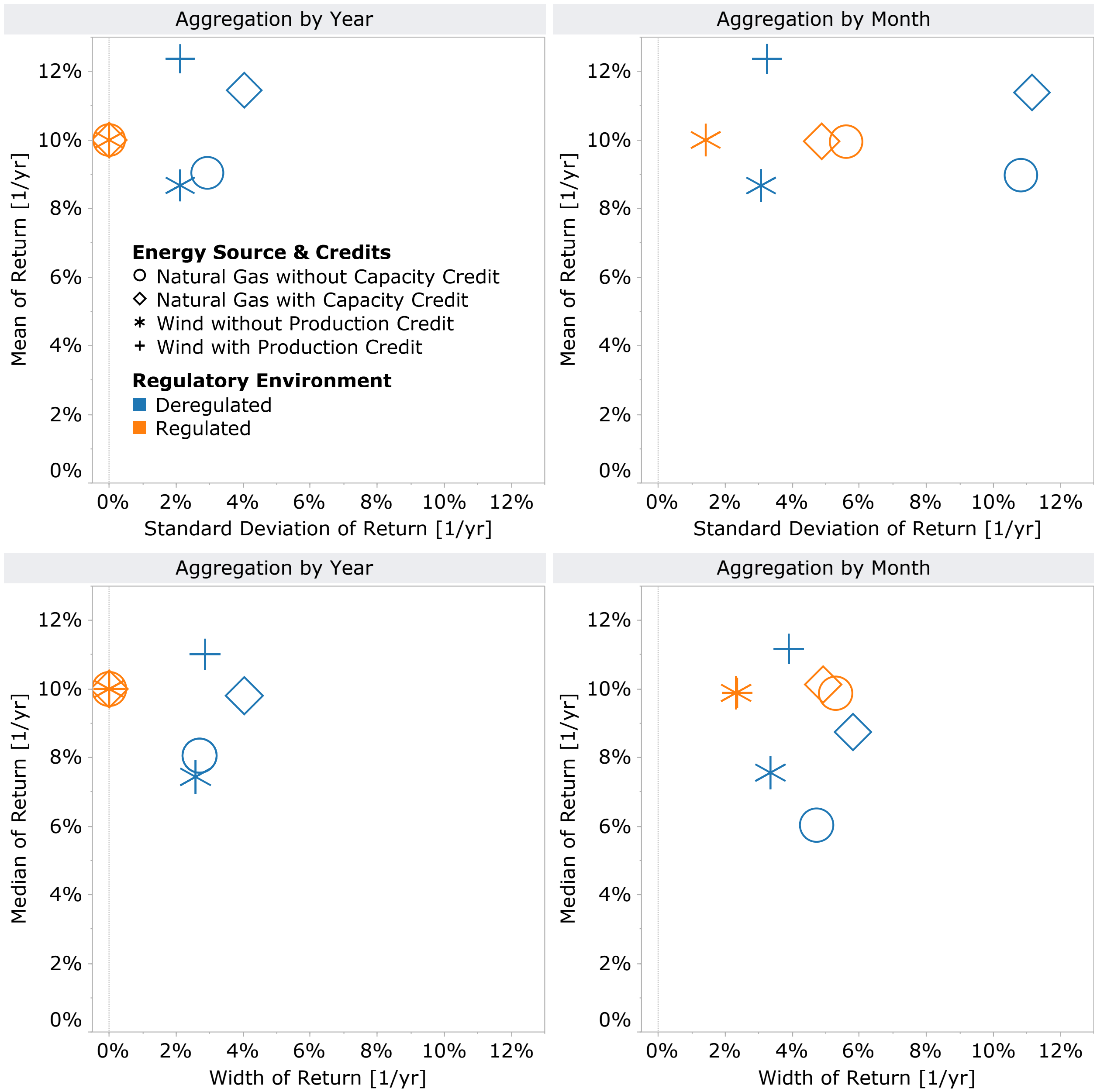

Figure 4-1. Risk versus reward using standard measures (top row) and robust measures (bottom row) from the perspective of a producer

Note: The width in the figure is defined as half the difference between the 15.9 and 84.1 percentiles; for normally distributed data, the width is identical to the standard deviation.

In the case of the monthly aggregation (perhaps more representative of actual cash flows for producers) we reach the following, somewhat different, observations:

- In both regulatory cases, the monthly return risk for the natural-gas-based producer is markedly (about five times) greater than for a wind-based producer, even though the overall expected return is very nearly the same.

- The monthly return distribution for the deregulated case differs substantially from normal (Gaussian) because of a "fat tail" of large, non-normal losses.
- Wind-based production dominates natural-gas-based production in the deregulated case if risk is measured robustly (see the lower right panel of Figure 4-1) because it has both higher return and lower risk.
- Wind-based production with the PTC has higher return at lower or similar risk than natural-gas-based production.

Regarding the question of the normality of the distribution of returns, we interpret the differences between the top and bottom rows as follows: the wind returns and regulated natural gas returns are close to normally distributed because their mean is nearly equal to their median and their width closely coincides with their standard deviation; the deregulated natural gas returns—most prominently when aggregated monthly—have fat tails, as evidenced by their width being smaller than their standard deviation, and have influentially large values of large returns, which skew the distribution because their mean is greater than their median.

Why do we look at monthly returns when annualized returns are the benchmark measure to account for seasonal variation in revenues? One reason is that the magnitude of the volatility in the monthly net cash flow returns is much higher for natural gas generation than wind. In turn, the potential benefits of investing in both technologies to reduce or partially mitigate variability in monthly net cash flow might be underestimated if one simply considered an annualized risk-return approach.

4.2 Comparison of Consumer Costs and Variance in Regulated and Deregulated Markets

In Section 4.1, we compared the risk and return for wind and natural gas generation in regulated and deregulated markets from the producer perspective. We now examine the consumer costs from a similar perspective. Figure 4-2 shows the monthly consumer costs for power from regulated and deregulated markets for natural gas and wind. [42]

In the deregulated market, we see from Figure 4-2 and Table 4-1 that the technology-specific consumer costs (if consumers were able to buy wind or gas separately) and volatility for natural gas generation is much greater than for wind generation (cost $76/MWh versus $47/MWh, volatility $18.5/MWh versus $11.4/MWh). As explained, however, in Section 3.2, these price differences reflect the operational differences of the two technologies. That is, gas generation electricity prices are higher due to the fact that natural gas generation operates in more hours with higher prices than wind. These costs are largely independent of whether a natural gas generator receives a capacity credit or a wind generator receives a PTC because the market price and hence consumer cost in each hour is set by the marginal cost of the last unit dispatched.[43] Of more interest are the differences observed in the regulated markets. While the price of power and

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[42] The monthly consumer costs are based directly on the monthly wholesale load-weighted hourly price in both the regulated and deregulated case. For this reason, the y-axis is label prices. The actual cost to smaller end-user consumers is assumed to be strongly correlated to these prices with some uplifts to reflect size of customer and profit margins due to distribution and other factors.

[43] This is not strictly true for production tax when wind sets the marginal price as power, which has resulted in observed negative prices being set so that wind generators can earn their credits.

volatility from natural gas generation is actually quite similar to the deregulated case ($75/MWh and $19.2/MWh, respectively), the variance of the price of power for the wind technology is reduced to zero, a consequence of wind having no fuel costs. The benefit of reducing wind price volatility from $11/MWh to $0/MWh is partially offset by higher annual costs of $54/MWh. We see, therefore, in a regulated market that the consumer is faced with considerable volatility in gas prices on an annualized basis, whereas the cost associated with wind-generated power has no volatility.[44] The lack of correlation of wind generation with fossil fuel prices leads to an additional reduction in the overall volatility of the system costs when large amounts of wind are added to the system. This attribute of wind and other forms of renewable energy, such as solar, could have value to many risk averse consumers, and yet markets do not currently compensate wind's contribution to reducing the variance of overall system costs. How the value of such cost variance reduction effects could be estimated is considered next in Section 4.3.

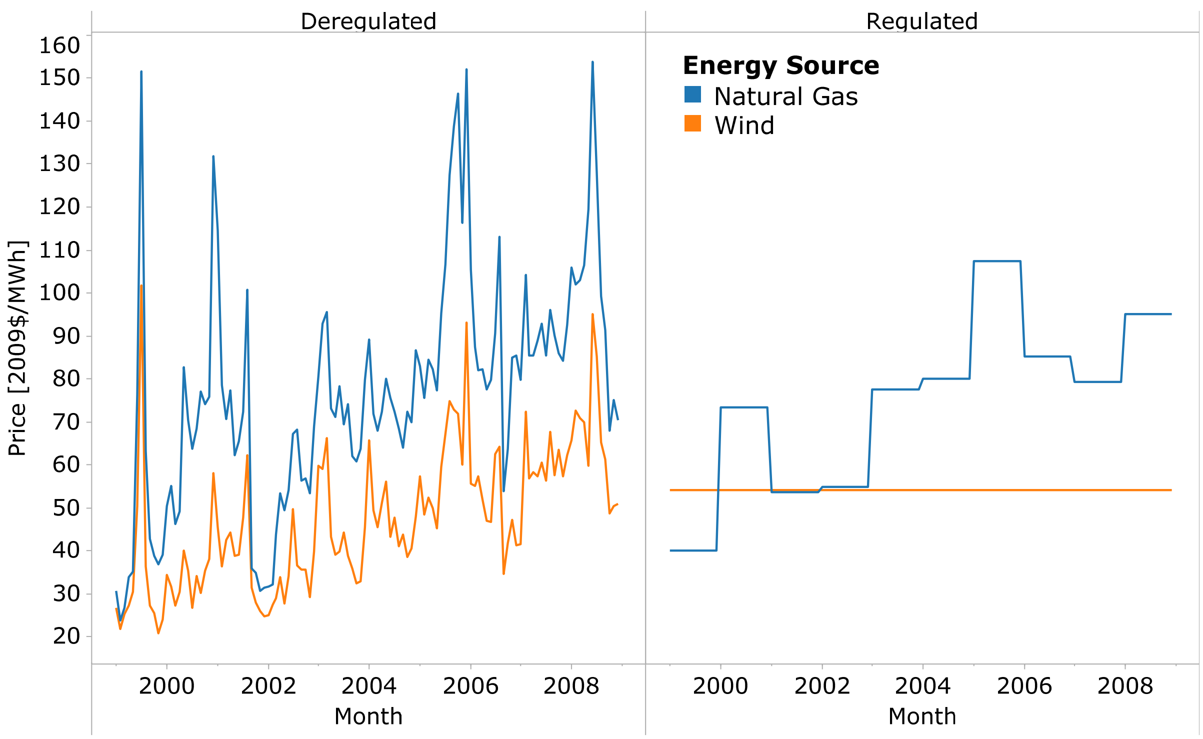

Figure 4-2. Average monthly price ($/MWh) of wind and natural gas generation in deregulated market (PJM) and simulated regulated market (1999–2008)

44 This partly reflects approximation in modeling in that year-to-year changes in wind could lead to changes in utilization, which could impact the annualized ($/MWh) cost of energy.

Table 4-1. Price and Measures of Risk for Wind and Natural Gas Generation in Deregulated and Regulated Markets

Aggregation	Regulatory Environment	Production Method	Metrics	Price (2009$/MWh)	Price Volatility (2009$/MWh)
Yearly	Deregulated	Wind	Mean/std dev	46.95	11.46
			Median/width	45.64	13.82
		Natural gas	Mean/std dev	76.35	18.43
			Median/width	75.19	21.81
	Regulated	Wind		54.11	0.00
		Natural gas	Mean/std dev	74.58	19.22
			Median/width	78.33	20.12
Monthly	Deregulated	Wind	Mean/std dev	47.24	16.24
			Median/width	45.27	16.00
		Natural gas	Mean/std dev	76.82	27.23
			Median/width	75.68	23.70
	Regulated	Wind	Mean/std dev	54.11	0.00
			Median/width	54.11	0.00
		Natural gas	Mean/std dev	74.58	19.22
			Median/width	78.33	20.73

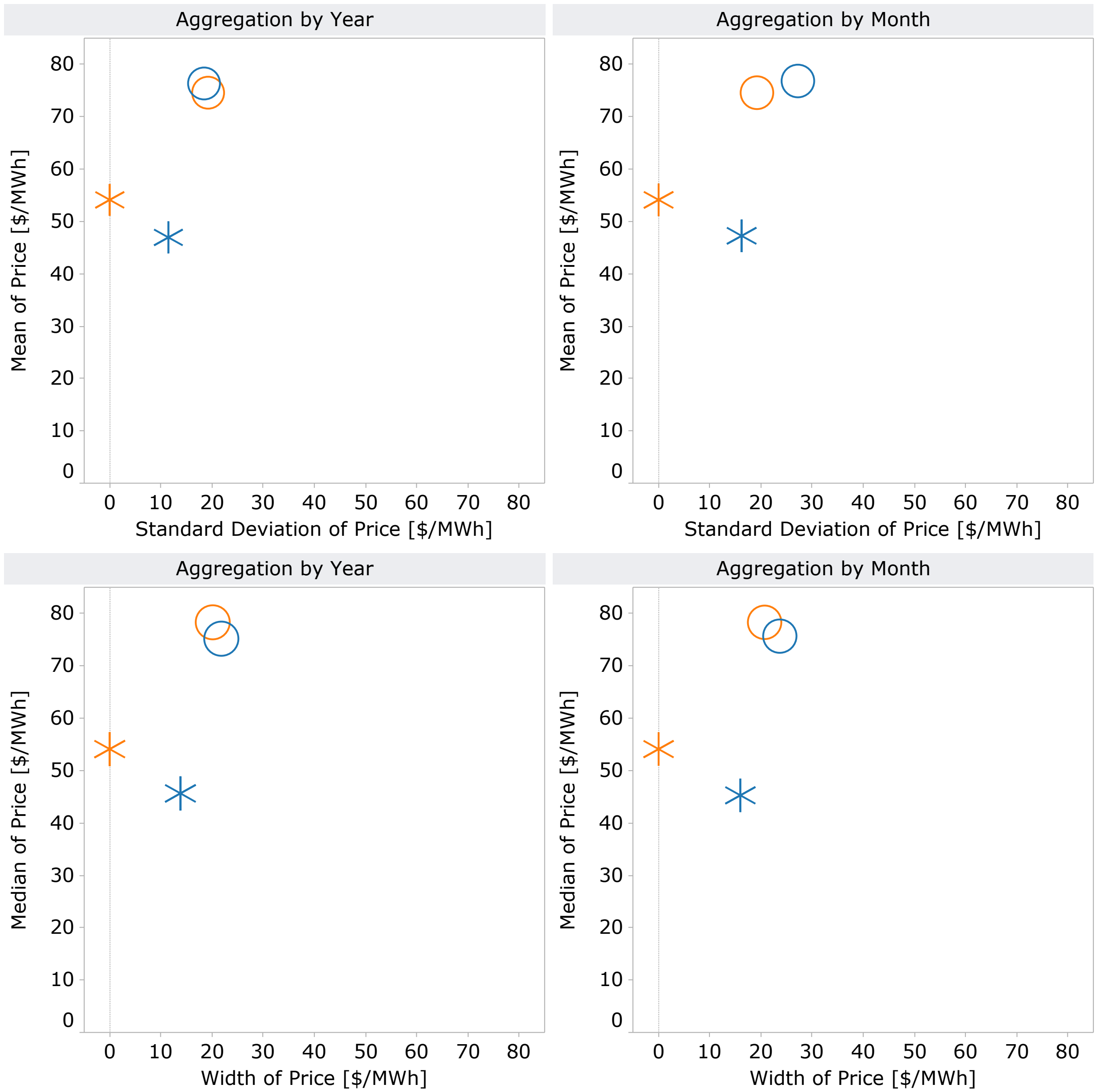

Figure 4-3. Consumer cost versus risk relationships for wind and natural gas generation in deregulated market (PJM) and simulated regulated market

4.3 Some Comments on Investment Decisions and Risk and Uncertainty in the Electric Sector

4.3.1 Investment Decisions Under Risk Aversion and Loss Aversion

Investors are generally assumed to make investments based on risk and return considerations. Finance theory assumes that investors are risk averse; that is, they prefer riskier investments only if compensated for greater uncertainty of outcomes by the anticipation of a greater expected return. We showed that the lack of correlation of returns for wind and natural gas generation bends the risk-return curve backwards, with the straight line in Figure 4-4 showing the change in risk and return with perfect correlation. It is important to realize that both curves are generated by system characteristics and are independent of any individual risk preferences. For both curves, the optimal position on the curve will, however, depend on risk-aversion preferences of the investor.

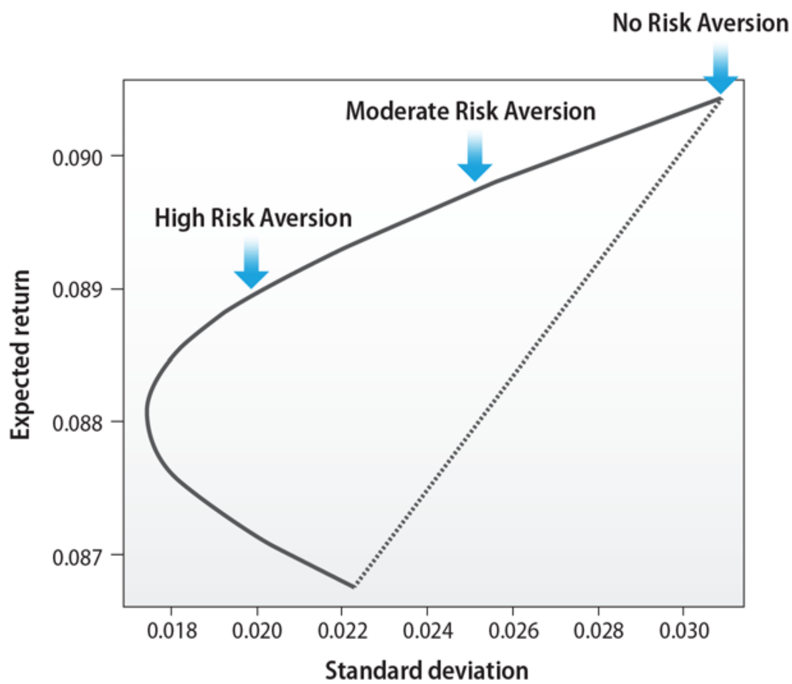

Figure 4-4. Expected return and standard deviation of return for wind and natural gas generation (without PTC or capacity payment)

A standard formulation is that the economic utility, U, of any expected return, $E[r_p]$, is reduced due to variance associated with the return:[45]

$$U = E[r_p] - \tfrac{1}{2}\,\lambda \mathrm{Var}[r_p]$$

where lambda (λ) is a measure of risk aversion and r_p is the return of the portfolio. The interpretation of this formula is straightforward. For a given expected return, the utility is reduced as the variance of the return increases in a simple linear fashion,[46] and the risk premium associated with differences in variance will be given by $\tfrac{1}{2}\,\lambda(\mathrm{Var}[r_1] - \mathrm{Var}[r_2])$, with the special case that the risk premium compared to a risk neutral case will be $\tfrac{1}{2}\,\lambda\mathrm{Var}[r_1]$. Simple discounted cash-flow methods that calculate the present value of an isolated investment utilize a simple discount rate in cash-flow analysis where the magnitude of the discount rate reflects the variance of future cash flows and a preference for consuming now rather than later. However, we use an approach based on more general economic utility that allows for explicit distributions

[45] This is the form used by Roques et al. (2008). In this section, we discuss the economic utility of consumers and producers. This utility will be denoted U and should not be confused with electric utilities.
[46] The variance corresponds to the square of the standard deviation.

because a simple discount rate assumes a normal distribution, which does not fully account for prices, costs, and net revenues that may be asymmetric and positively skewed in the electric sector. This more general framework also allows for explicit examination of the impact of lack of positive correlation between returns or costs as well as for the incorporation of loss-aversion effects.

In prior work, Roques et al. (2008) examined changes in optimal generation portfolios based on correlation considerations under a range of risk aversion (λ) assumptions. They found risk preferences can make a significant difference in determining the best technology asset mix among equivalent generation assets.[47] In general, the greater the risk aversion the more the investor would move down the "efficient frontier" mix to the asset combinations with the lower returns and lower variance. The selected mix as a function of risk aversion is shown in Figure 4-4 (subject to the caveats discussed in Section 3.3).

While such a framework may be plausible for supposedly rational investors, such as electric utilities, the expected utility model has been shown to be less reliable for individual consumers. Prospect theory developed by Tversky and Kahneman (1981) shows that consumers often treat certain losses as more painful than certain but otherwise equivalent gains, and empirically this factor is often about two (Kahneman et al. 1991). The situation is more complicated because the utility of gains and losses depends on reference points, and risk preferences are not independent of the magnitude of the gain or loss. Nevertheless, for "small to moderate" gains and losses, consumers can be considered both loss averse and risk averse. In this case, the utility function can be given by:

$$U(X) = \mathrm{E}[X] - \frac{\lambda}{2}\mathrm{Var}[X] - \mathrm{DRM}[X]$$

The variable X corresponds to the overall portfolio return ($X = r_p$), so that $E[X]$ and Var[X] correspond to the expected value and the variance of the portfolio return, respectively.[48] The value of downside risk measure (DRM) is obtained by integrating the product of the probability density function by the difference in the variable term, X, and the expected value over the entire distribution. This product is multiplied by a constant, θ, that changes value on either side of the expected value to reflect the fact that "losses" are valued more greatly than otherwise equivalent gains. In this way, DRM is given by:

$$\mathrm{DRM}[X] = E[\theta_+(X - \mathrm{E}[X])_+ - \theta_-(X - \mathrm{E}[X])_-]$$

With the notation $(y)_\pm = \begin{cases} y & \text{for } y \gtrless 0 \\ 0 & \text{otherwise} \end{cases}$

Typical values are $\theta_+ = -1$ and $\theta_- = 2$

[47] Where λ was varied from 0.1 to 10.0.

[48] Similar considerations apply to portfolio costs ($X = c_p$) though in this case utility increases for minimizing costs for a given variance rather than maximizing returns for a given variance (or vice versa). See also Jarrow and Zhao (2006).

In effect, the value of DRM reflects the net difference in how outcomes to the left and right of the expected value are perceived as well as the width of the distribution.[49] For a normal distribution, $N(\mu, \sigma)$, these more general expressions become:[50]

$$U(X) = \mu - \frac{\lambda}{2}\sigma^2 - \frac{\theta_+ + \theta_-}{\sqrt{2\pi}}\sigma$$

where μ and σ correspond to the expected value and standard deviation of (in this case) the annualized returns, assuming a normal distribution. Thus, for particular empirically observed combinations of risk and return resulting from different investment mixes, the optimal point on the efficient frontier curve will reflect the maximum utility, which will depend in turn on the individual's risk-aversion and loss-aversion preferences.[51] The utility (for a given expected return) decreases with variance due to both the risk-aversion and the loss-aversion terms (which are squared and linear with respect to standard deviation of returns).

Figure 4-5 illustrates the impact the inclusion of risk aversion and loss aversion on where the optimal mix sits on the efficient frontier. The right-hand figure can be interpreted as follows. In the case without credits, assuming no risk aversion or loss aversion, the expected utility corresponds to the left-hand side of the upper black line. In this case, 100% natural gas generation is the mix with the highest utility. The impact of the risk-aversion and loss-aversion terms is to add a penalty for variance, which reduces the economic utility. This can be seen from the reduction in utility for 100% natural gas generation (asset ratio 0.0) as the impact of risk aversion (blue line), loss aversion (green line), and risk and loss aversion (red line) is added. However, because mixing wind with natural gas generation reduces the variance of the return for a given expected return (up to some limiting mix), the utility increases with the addition of wind up to some maximum utility. In this way, as shown in the left-hand figure in Figure 4-5, the optimal point on the return-return efficient frontier shifts downward. Similar effects are observed when loss aversion is considered or added.

[49] The evaluation of DRM is reminiscent in some ways of Value at Risk (VaR) calculations, though the latter usually considers only the tail of the less desirable "loss" side of the distribution.

[50] The normal distribution assumption is not essential, though any asymmetry may make the integrals more complicated to evaluate analytically. Certainly, the integral for the loss-aversion measure naturally takes account of any asymmetric effects in that values being further from the mean are weighted higher. For asymmetric returns or cost functions more generally that do not have analytic solutions, the probability function could be fitted empirically to the data and then the utility obtained using numerical integration.

[51] Jarrow and Zhao (2006) found for normal distributions the solutions of the efficient frontier when both risk aversion and loss aversion are considered similar to those obtained solely using mean variance portfolio optimization under risk aversion. The effect of this is seen in Figure 4-5.

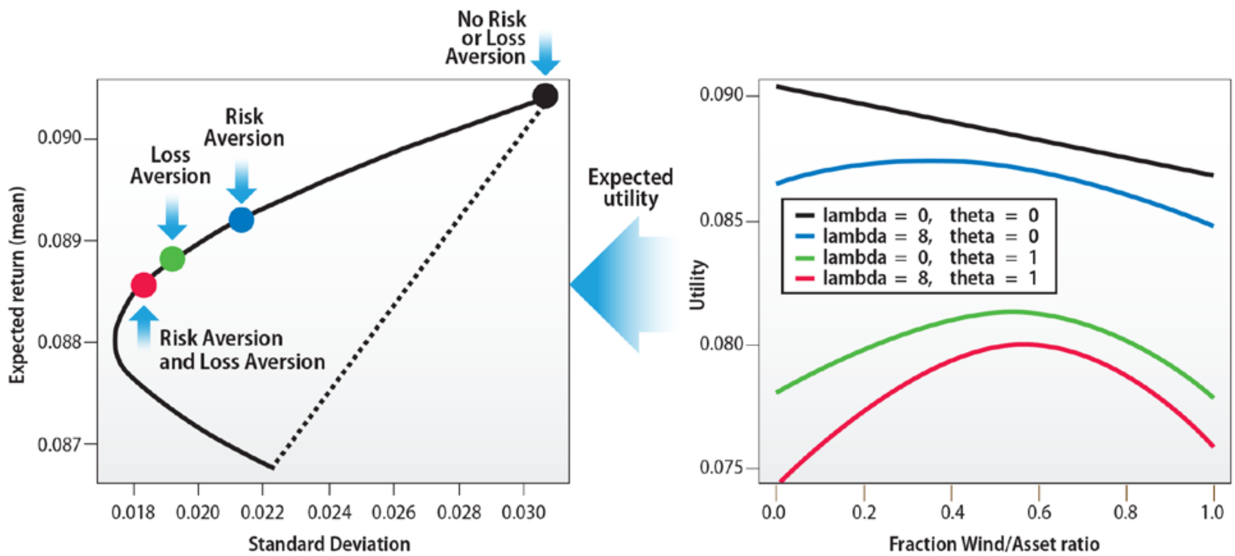

Figure 4-5. Optimal asset mix as a function of risk and loss aversion

4.3.2 Using System Models to Estimate the Economic Value of Alternative Electricity System Cost-Cost Variance Combinations

The foregoing discussion compared risk-return relationships rather than cost-risk relationships. System cost variance reduction is relevant in regulated electric-sector analysis as a potential refinement to traditional least-cost planning.

Figure 4-2 suggests that in the regulated scenario, the significant annualized variation in natural gas prices is likely to be passed through to the consumer in terms of greater variability in the annualized average dollar per megawatt-hours cost of electricity. As previously discussed, adding a large amount of wind (or solar) to an electric system can be expected to reduce the variance in the electric system costs (and hence the variance of similar costs passed through to consumers). We have also discussed, however, why we cannot simply use the simple annualized LCOEs and related cost-variance information for various technologies to determine the impact of the overall portfolio costs from mixing these two technologies because they are not "equivalent" in terms of hourly electricity production. Nevertheless, Awerbuch's idea of an optimal lowest cost portfolio for a given variance shows significant promise (at least for regulated markets) using models with a more sophisticated representation of system costs where the hourly operation of the technologies is modeled more explicitly (see e.g., Awerbuch and Berger 2003). These types of electric-sector production costing models or other cost-based models could then be used to solve the question of what the least-cost build is for a given cost variance.[52] Within

[52] The electric-system-based expected cost-cost variance solutions will map out a similar form to the return-return variance efficient frontier shown in Figures 4-4 and 4-5, except that the upper curve will be inverted if lower variance technologies, such as wind, tend to lead to increasing average expected cost of energy. The overall system cost and cost variance could be divided by generation to give a distribution with a dollar per megawatt-hour expected value and associated variance. As a first approximation, this might be for a single year. More generally, the dollar per megawatt-hour cost-cost variance distribution might be calculated over a much longer time horizon to reflect multi-year investment decisions (with appropriate discounting).

this risk framework, there would not be one lowest cost answer; instead, there would be an array of answers with different minimized costs for difference variance constraints.[53] If the electricity cost distributions are thought to be approximately normal, then the difference between the value of two annualized cost distributions with different expected values would be given by:[54]

$$U(X) - U(Y) = (\mu_x - \mu_y) - (\sigma_x - \sigma_y)\left(\frac{\lambda}{2}(\sigma_x + \sigma_y) + \frac{\theta_+ + \theta_-}{\sqrt{2\pi}}\right)$$

When the economic utility of two distributions is equal, we have

$$(\mu_x - \mu_y) = (\sigma_x - \sigma_y)\left(\frac{\lambda}{2}(\sigma_x + \sigma_y) + \frac{\theta_+ + \theta_-}{\sqrt{2\pi}}\right)$$

which in the case of risk aversion only (and no loss aversion) reduces to

$$(\mu_x - \mu_y) = \frac{\lambda}{2}({\sigma_x}^2 - {\sigma_y}^2).$$

As before, the values of μ and σ are physical properties of the electric system that are completely independent of any risk- or loss-aversion preferences. Selection of "optimal" mixes could be explored for different risk-aversion and loss-aversion preferences using the formulas discussed above. This formula is an illustrative approximation because in practice the cost distribution as shown in Figure 1-2 is likely to be non-normal and positively skewed, which may lead to an increased source of value for technology portfolios that narrow this distribution (compared to the normal distribution approximation). More generally, the utility of different skewed electricity cost distributions (and hence the difference in their utility) could be estimated empirically using numerical integration to a fitted distribution.[55] In this way for a regulated electric system, the concept of lowest-cost planning could be refined to have an array of least-cost planning solutions corresponding to different variances. The preferred solution would likely reflect both consumer

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53 An interesting question is that if such variance reduction is valued, surely the forward price for commodities such as natural gas, should be priced at a premium to the expected future price, and some authors suggest such a premium may exist (Bolinger et al. 2006). Leaving aside the obvious difficulty in accurately estimating future expected values to determine whether or not this is true, if both the producer and the consumer valued variance reduction, then such a premium might be competed away in some cases; the consumer's willingness to pay a premium for a fixed price being mitigated by the producer's willingness to accept a price cut in return for similar price certainty. It is interesting to note that even if the variance premium is competed away under this symmetric bilateral arrangement, it somewhat ironically does not undermine the fact that both parties valued and may have been willing to "pay" for variance reduction.

54 A "loss" is assumed to mean paying a higher than expected cost for energy while a "gain" refers to paying a lower than expected cost for energy. The difference in the value of theta reflects an aversion for losses compared to equivalent gains.

55 An empirical cost-cost variance distribution might be better fitted to such an asymmetric distribution because then costs will not be able to fall below zero and the upper limit is essentially uncapped. If the system cost data can be fitted to a lognormal distribution and general relationship between utility and risk aversion listed at the start of Section 4.3 remains valid, then there is an analytic solution for $E[X]$ and $\mathrm{Var}[X]$. More generally, as indicated earlier, numeric integration can be used to estimate the economic utility of the fitted distribution where no analytic solutions exist.

risk aversion and loss aversion.[56] From the consumer perspective, regulators could then chose how much weight should be placed on such preferences, which may lead to a significant source of additional value for wind and other renewable energy sources with no fuel costs.[57]

[56] Given system-generated values for μ and σ, evaluating the actual differences in utility between different electric system cost-cost variance combinations requires knowledge of λ. If λ is not known, a sensitivity analysis can be done over a range of values for λ. In principle, λ could be determined empirically by designing alternative choices and seeing how people respond. Similar considerations apply to loss aversion.

[57] There are numerous examples of how this type of analysis might be used. For example, when comparing the different expected annualized system costs of successively higher renewable portfolio standard (RPS) levels, any reduction in variance in the annualized electricity cost distribution (which could be generated using a Monte Carlo simulation of runs reflecting the variability in fossil fuel prices) resulting from increased renewable penetration will increase the utility, which in turn may offset partly or completely any differences in total expected systems costs.

5 Summary and Conclusions

This analysis recognizes that the potential value of risk mitigation associated with wind generation and natural gas generation may depend on whether one considers the consumer's perspective or the investor's perspective and whether the market is regulated or deregulated. We analyze the risk and return trade-offs for wind and natural gas generation for deregulated markets based on hourly prices (and load) over a 10-year period, 1999–2008, using historical data in PJM. Similar analysis is then simulated and evaluated for regulated markets under certain assumptions. Estimating the absolute value of variance reduction will depend on assumptions about risk aversion and other consumer preferences, such as loss aversion, and this is discussed. Some key observations include:

In a deregulated market such as PJM,

- Returns for natural gas generation are partially hedged because power prices are often set by natural gas generation. The correlation for power prices and natural gas prices is still quite low, however, and this can significantly mitigate the effect of the hedge, as does the fact that gas generation tends to operate mainly during peak hours, which have more volatile prices. There are also significant seasonal effects reflecting changes in the demand and price of natural gas.
- Returns for wind generation are better hedged than natural gas generation[58] because wind often operates in off-peak hours, where power prices are much less volatile and less correlated with natural gas prices, whereas natural gas generation operation is focused more heavily during peak hours.
- The impact of incremental net revenue from tax credits, such as PTCs or other sources of revenue such as capacity payments, can have a significant impact on the risk return relationship. In PJM over this period with credits, wind was found to be dominant in terms of risk and reward; that is, it had both greatest returns and the lowest risk, as measured by standard deviation of returns.
- More generally, investors may benefit from investing in both wind and natural gas generation, with the optimal mixture depending on the investor's risk aversion (and perhaps also loss aversion) preferences, due to well-known lack of correlation effects without PTCs.
- While the opportunity for investors to diversify in broader markets may reduce some of the variance-reduction benefits of investing in different electric technologies, it is unlikely to completely eliminate these benefits in the electric sector where power prices are often very volatile and positively skewed, which has implications for financial distress.

[58] For wind and natural gas technologies with the cost and performance assumptions used in this analysis.

- Similarly, consumers, especially smaller commercial and residential consumers, may benefit from reductions in the variance of electricity prices due to risk-aversion and loss-aversion effects.[59]
- Large-scale integration of renewable energy could also be expected to add value if wind became the marginal generator on a frequent basis,[60] though this effect may be somewhat offset by integration effects due to the operational and economic factors resulting from the intermittency of wind.[61]
- On a monthly rather than annual timeframe, natural gas generation shows a much greater volatility in returns (in both relative and absolute terms) than wind generation, partly reflecting the predictable relationship between power prices, demand, and natural gas prices. While producers might be more concerned with annualized returns than monthly returns, the much greater volatility of monthly returns also suggests potential benefit of taking actions to reduce variance to mitigate potential financial distress.
- The LCOE of different technologies is not directly comparable if they operate in different hours because the value of electricity differs significantly throughout each day. This variation reflects the daily load profile, with hourly load and hourly power prices also showing strong seasonal effects. This effect can be seen in our analysis of PJM data when comparing the difference in the average annualized hourly price of variable wind generation and dispatchable natural gas generation.
- Bilateral fixed price contracts or PPAs between producer and consumer offer a way of almost eliminating producer price and thereby a significant amount of net revenue risk. Such contracts also go a long way to mitigate some but not all consumer cost risk (because they will still have to buy or sell missing or excess power in a given hour).

In a regulated market:

- The inherent nature of regulated markets means that producers earn, with some caveats, a utility-designated rate of return. A consequence of this is that the risk associated with fuel costs is passed on to consumers. The "cost-plus" nature of regulation means that consumers also bear some increased risk associated with poor investment decisions. Consumers are partly compensated for this because the

[59] This could also hold true for large consumers such as utilities if they or regulators realized they could quantify the value of such variance reduction to consumers and get paid by consumers some fraction of this value to do so.

[60] Market structure rules may need to be modified so that such wind generation units receive sufficient capacity payments to encourage proper investment.

[61] Variations in the amount of wind power generated during a day can be reduced by dispersing wind turbines because wind conditions will vary geographically. For a given daily amount of wind energy, much of the hourly production risk within a day could be eliminated by the use of electricity-storage technologies if the incremental benefits of using storage were cost effective. For example, by storing wind energy during the night and discharging it during the day (subject to transmission constraints), wind production could both be made firm and used to displace expensive peak generation. Integrated wind-storage analysis would need to be done to determine the optimal operation of a storage device under such circumstances.

producer may be willing to accept a lower expected rate of return compared to deregulated markets.

- For consumers who are generally risk averse, the reduced variation in electricity prices (and hence consumer costs) because of wind's lack of correlation with other system costs should have value (as has been suggested by others). Loss aversion also may place a value on variance reduction of electricity prices and consumer costs.
- Simplified mean variance cost optimization techniques using annualized LCOEs for the power sector often fail because the assets within the portfolio are sufficiently dissimilar (e.g., baseload versus peaking or either of these versus a variable or non-dispatchable resource such as wind or solar).
- A variance reduction-based technique could, however, be used more broadly under more sophisticated representation of system costs where the hourly operation of the technologies is modeled more explicitly. Specifically for a regulated electric system, the concept of lowest-cost planning could be refined to have an array of "least-cost planning" solutions corresponding to different variances, where the values of the expected annualized system cost and the standard deviation of the annualized system cost are physical properties of the electric system that are completely independent of any risk- or loss-aversion preferences. The value of variance reduction could then reflect both risk aversion and loss aversion. We discuss explicitly how to estimate the difference in the economic utility between alternative system-based expected cost-cost variance choices, including the impact of the distribution being positively skewed toward higher costs.

In conclusion, we should point out that while some of the observations and findings may be generally applicable, others are empirical observations for a specific location and a specific time period under specific technology cost and performance assumptions.[62] Therefore, care should be taken in drawing any conclusion about the specific comparative risk-return relationship for wind and natural gas generation, both outside of PJM over the specified time period and within and outside of PJM going forward. Sorting out the implications of variance reduction for returns and consumer costs in regulated and deregulated markets for small- and large-scale renewable energy penetration is a broad and complicated topic, and we hope that some of our observations offer a useful contribution to this debate.

[62] For example, within PJM over the same time period, different assumptions about technology performance and cost for wind and natural gas could lead to different risk-return relationships. Similarly, the risk-return relationships may vary outside of PJM, or over different time periods within PJM, because of differences in hourly electricity prices.

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