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Technical Report
NREL/TP-6A20-59065
August 2013

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NATIONAL RENEWABLE ENERGY LABORATORY

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Executive Summary

This study provides a framework to explore the potential use and incremental value of small- to large-scale penetration of solar and wind technologies as a physical hedge against the risk and uncertainty of electricity cost.

The idea that adding renewable energy (RE) to a conventional fossil portfolio generates diversity-related benefits is not new and has been discussed by many others (e.g., Bolinger et al. 2002; Awerbuch and Berger 2003; Bazilian and Roques 2008; Roques et al. 2010). Similarly, there may be related benefits from combining RE and natural gas generation (Lee et al. 2012; Weiss et al. 2013) as well as from combining wind and solar within the RE component of the larger portfolio. The core idea behind the value of diversification, of not putting all the "eggs into one basket"--or in this case electric generation technologies--has widespread acceptance. In finance applications the value of diversification forms the foundation behind the application of mean-variance portfolio (MVP) theory to choose "efficient" portfolios of stocks and bonds (Markowitz 1952).[1] The related concept of quantifying the value of diversity in the electric sector that may result from reducing the risk and uncertainty of the overall system costs over multi-year to multi-decade time horizons is less well understood or accepted (Stirling 1994; Awerbuch and Berger 2003). Adding RE can be expected to reduce the variability of the overall electric system costs over a variety of timescales as natural gas-fired generation is displaced. However, the direct application of MVP theory to "optimize" the mix of generation assets within a generation portfolio is problematic for a number of reasons, including the fact that the operational characteristics of some types of generation assets are dissimilar.

Earlier studies characterizing the impacts of adding RE to portfolios of electricity generators have often used a levelized cost of energy (LCOE) or simplified net cash flow approach. In this study, we expand on previous work by using an hourly production cost model (PLEXOS) to analyze the incremental impact of solar and wind penetration under a wide range of deployment scenarios for a region in the western U.S. We do not attempt to "optimize" the portfolio in any of these cases. Rather, we consider different RE penetration scenarios that might, for example, result from the implementation of a Renewable Portfolio Standard (RPS) to explore the dynamics, risk mitigation characteristics, and incremental value that RE might add to the system.[2]

For our reference case, in which solar and wind make equal contributions (1:1) to total generation on an annual basis, we varied the annual RE generation from about 10% to more than 50% under a range of natural gas price scenarios. We then explored the impact of altering the annual solar-to-wind generation ratio to 3:1 and 1:3 and also varied the ratio of natural gas to coal generation in the fossil generation mix for the 1:1 reference case. We also simulated the variation in electricity costs using a Monte Carlo (MC) simulation approach. This allowed us to characterize the value of variance reduction for customers with different levels of risk and loss aversion and to compare this, at least in the near term, with the use of alternative mechanisms for

[1] "Efficient" refers to portfolios of assets that lie on a curve (the "efficient frontier") where each point represents a portfolio with lowest risk for a given return (over a range of returns). It is the lack of correlation of outcomes (returns in the case of financial assets) that reduces the risk (as measured by the variance of returns) for a given expected portfolio return.

[2] This approach was suggested in Bush et al. (2012).

partially hedging against future price uncertainty. Some market structure issues were also considered.

Some key findings of our analysis include the following:

- Solar and wind generation significantly reduce the exposure of electricity costs to natural gas price uncertainty in fossil-based generation portfolios on a multi-year to multi-decade time horizon.
    - The incremental impact, and any associated marginal value of RE in decreasing electricity cost volatility, declines with increasing RE penetration.
    - The reduction in volatility of electricity costs with increased RE penetration is greater for natural gas-dominated portfolios than for coal-dominated portfolios.
- At low RE penetrations (e.g., 10%–15% annual RE generation) the annualized variable system costs vary widely with the price of natural gas in both our coal-dominated and natural gas-dominated fossil portfolios. For the modified region studied in this report:
    - At 15% RE penetration in the coal-dominated system,[3] a $5/MMBtu variation in natural gas prices (between $4/MMBtu and $9/MMBtu) translates to approximately a $8/MWh range in the variable cost of electricity.
    - For similar RE penetration (15%) in the gas-dominated portfolio, a $5/MMBtu variation in natural gas prices changes the variable cost of electricity by about $35/MWh--a more than three-fold difference compared to the coal-dominant portfolio.[4]
    - In the coal-dominated fossil portfolio the incremental impact of further solar and wind penetration decreases with increasing RE penetration with only small incremental benefits achievable beyond 35% penetration. This is largely because, at these higher levels of RE penetration, very little natural gas generation remains to be displaced.
    - In contrast to the natural gas-dominated portfolio, the saturation effect in electricity cost variance reduction is not observed even at higher RE penetration levels (of over 40%) because a large amount of natural gas generation remains to be displaced.
- In the region studied, a mix of wind and solar provides a better physical hedge against uncertain fuel prices than either wind or solar alone because of the observed anti-correlation in solar and wind generation profiles at time scales ranging from intra-day to seasons.

[3] Where the ratio of coal thermal to natural gas combined cycle gas turbine (CCGT) capacity was approximately 2:1. For the natural gas-dominated portfolio, all coal thermal units were switched out with CCGTs.
[4] The relative ratio of price variation depends not only on the ratio of coal thermal to natural gas plants but also on the cost of coal. Coal prices, even on an energy equivalent basis, vary significantly by location. The cost of coal per MMBtu for Colorado used in the study is amongst the lowest in the U.S.

- Market structure choices are important. Adding RE reduces uncertainty in cost to consumers[5] much more in restructured markets than in regulated markets since natural gas often sets the marginal price in a given hour in restructured markets (particularly during higher-priced peak periods), and this price is then paid to all generators dispatched.
- MC analysis of the impact of natural gas price variations over multi-decade time horizons complements scenario analysis by generating electricity cost distributions that show the likelihood (or "density") of outcomes. These distributions also show that the electricity costs are positively skewed.
    - While the upside risk (lower electricity prices) is largely capped by physical constraints on fuel costs, the downside risk (higher electricity prices) is not. RE may be important to both reduce the overall variance of system costs, as well as provide insurance future price increases, which may be particularly important given the current low natural gas prices (Bolinger 2013).
    - Inter-annual variability in generation is also important since it can lead to deviations from average annual generation of ±10% or more in any year for solar and wind generation. However, while year to year variation in RE generation was not explicitly integrated into the production cost runs used in this study, the impact of such resource variation may be expected to be mitigated over long time horizons as year to year variations will tend to offset each other (Drury et al. 2013).
- We find that much of the MC analysis of natural gas price uncertainty impacts can be done outside of the production cost model by recognizing the stability of the simulated hourly system dispatch for a wide range of natural gas prices. This greatly enhances our ability to perform many simulations which otherwise would be limited by model run times.[6]

The potential benefits of diversified portfolios containing significant solar and wind generation will depend on two main factors. One factor is how much consumers' values lower price uncertainty due to risk aversion, loss aversion, scarcity, or other characteristics. The second factor is the potential cost and effectiveness of alternative financial or physical hedging methods, such as forward contracts, swaps, or physical supply contracts[7], and the timeframe over which these are available; this includes the degree to which price uncertainty risks are mitigated and the

[5] Bilateral contracts within a restructured market, which are common for solar and wind, may mitigate this leverage and have an asymmetrical effect on consumers. This and other market structure-related issues are a focus of our follow-on research.

[6] The wide range that this stability effect was due in part is due to the low coal prices found in the region studied (on a $/MMBtu basis), and so the effect is likely to be less pronounced in many other regions of the U.S. with higher coal prices.

[7] A buyer (or seller) of natural gas (or electricity) can protect itself, or hedge against future price uncertainty by agreeing to an over the counter (OTC) forward contract to buy (or sell) a commodity at some time. The price to be paid at delivery is specified in advance when the contract is made. An alternative way for a buyer to hedge is to buy gas at spot market prices, but also have an arrangement where the buyer pays the third party a fixed price for natural gas and in return receives (or swaps) payments linked to the market price of natural gas (Eydeland and Wolyniec 2003).

extent to which new risks may be introduced (e.g., associated with natural gas transportation constraints, counterparty risks, market liquidity, and others).

The cost of using financial instruments to hedge against future price uncertainty depends in part on whether long-term forward contracts (for natural gas or electricity) contain a premium over expected future prices. Electricity sellers and buyers may both be risk averse, and there is no consensus about the net impact of this on the existence of a forward premium for eliminating price volatility in the United States. Some studies that suggest, at least in the short-term, it may be more cost effective to use financial-hedging instruments often assume (either implicitly or explicitly) there is no risk aversion or other premium in the forward price over the expected futures price. On the other hand, some studies have suggested there may a positive premium over the expected future price due to risk aversion (Bolinger et al. 2002) or due to scarcity or other factors (Borenstein et al. 2007),[8] while others suggest a negative premium (Modjtahedi and Movassagh 2005). The answer may be "all of the above", with the existence and magnitude of a premium (positive or negative) likely to vary with location, commodity, and timescale, while changing over time.

Of particular relevance to RE, it is difficult and rare to be able to lock in financial or physical supply contracts of 10 years or more for natural gas. Such contracts may include premiums that reflect lack of liquidity and counterparty risk (Bolinger 2013).[9] Because of these and other issues, in the longer term solar and wind may be able to provide a physical hedge that is not easily replicated in the financial and physical commodity markets.[10] It also provides insurance value against rising electricity prices in futures where natural gas prices rise or carbon emissions are priced via a tax or some other mechanism. Even in the shorter term, RE may be the better choice for some consumers. While most of this report deals with the system wide effect on the average consumer at a multi-utility level, the preference for cost mitigation and over what timeframes may vary widely by customer type. Size also matters where some residential and commercial customers may decide to install distributed RE in part if their ability to hedge using financial or physical instruments is limited by a lack of knowledge, high transaction costs, or a lack of availability of such instruments.

[8] Graves and Levine (2010) make the interesting observation about how the positively skewed nature of the price distribution for natural gas could explain observed differences between the expected forward price and the observed prices--even if there is no meaningful premium simply due to the expected value of the distribution lying above the mostly likely and the median values.

[9] "Passive" hedging with RE could also provide benefits by affecting a wide range of buyers in a similar manner. This may be helpful because many firms have trouble knowing how to hedge appropriately (possibly overreacting to a crisis and locking in high prices), and this can bring business risks. Alternatively, a firm could hedge in a smart way—while many of its competitors do not—and get "unlucky" if, for example, the prices of inputs fall sharply for the industry. Passive or natural hedging with RE in this way may provide a "cushioning" effect to help mitigate these types of business risks.

[10] The use of rolling, short-term hedging over longer time horizons provides a hedge against evolving market conditions and prices. It does not provide a long-term hedge against future price changes (as might a hedge due to RE).

1 Introduction

The United States has experienced rapid growth in renewable energy (RE) over the last decade, with 47 GW of wind capacity, 4 GW of photovoltaics (PV), and 0.5 GW of concentrating solar power (CSP) at the end of 2011 (Gelman 2012). This growth has been driven by a variety of factors, including technology cost reductions, performance improvements, and federal incentives and state mandates such as the production tax credit (PTC) and Renewable Portfolio Standards (RPSs), respectively. More recently, increased U.S. shale gas production and associated relatively low natural gas prices have increased electric-sector natural gas use and reduced the economic attractiveness of RE relative to natural gas combined cycle gas turbines (CCGTs) (FERC 2012a).

The decision whether to invest in RE, natural gas generation, or a combination of these and other technologies is complex. Arguments in favor of RE, including some level of support, include the failure of the market to internalize many of the external costs associated with conventional generation, the presence and history of subsidies for other energy forms, imperfect market structures, regulatory barriers, and the need to support a diverse range of RE technologies (whose future improvements in cost and performance remain unknown) to prevent lock-in of conventional generation.[11] The purpose of this study is much narrower: it provides a framework to explore the potential use and incremental value of small- to large-scale penetration of solar and wind technologies as a physical hedge against the risk and uncertainty of electricity cost.[12]

The idea that adding RE to a conventional fossil portfolio generates diversity-related benefits is not new and has been discussed by many others (e.g., Bolinger et al. 2002; Awerbuch and Berger 2003; Bazilian and Roques 2008; Roques et al. 2010). Similarly, there may be related benefits from combining RE and natural gas generation (Lee et al. 2012; Weiss et al 2013)[13], as well as from combining wind and solar within the RE component of the larger portfolio. The core idea behind the value of diversification, of not putting all the "eggs into one basket"--or in this case, electric generation technologies--has widespread acceptance. In finance applications the value of diversification forms the foundation behind the application of mean-variance portfolio (MVP) theory to choose "efficient" portfolios of stocks and bonds (Markowitz 1952).[14] Less well understood or accepted is the related concept of quantifying the value of diversity in the electric sector that may result from reducing the risk and uncertainty of the overall system costs over multi-year to multi-decade time horizons (Stirling 1994; Awerbuch and Berger 2003). Adding RE can be expected to reduce the variability (and variance) of the overall system cost over a variety of timescales as natural gas generation is displaced. However, the direct application of MVP theory to "optimize" the mix of generation assets within a generation portfolio is problematic for a number of reasons, including the fact that the operational characteristics of

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[11] See Weiss and Marin (2012) and references contained within for a more comprehensive discussion of this topic.
[12] RE can provide physical asset-backed protection against future price uncertainty.
[13] Lee et al. (2012) discuss how natural gas and RE can complement each other from a system perspective due both to their similarities (e.g., a low carbon source relative to coal) and their differences (e.g., likely impact on the volatility of electricity costs). The dispatch flexibility of natural gas also better mitigates the intermittency issues associated with wind and solar than less flexible coal thermal units (Weiss et al. 2013).
[14] "Efficient" portfolio refers to portfolios of assets that lie on a curve (the "efficient frontier") where each point represents a portfolio with lowest risk for a given return (over a range of returns). It is the lack of correlation of outcomes (returns in the case of financial assets) that reduces the risk (as measured by the variance of returns) for a given expected portfolio return.

some types of generation assets are dissimilar.[15] Awerbuch and others recognized the limitations of the use of levelized cost of energy (LCOE) for MVP optimization for any real system, noting that the approach does not "point to a specific capacity-expansion plan" and that the results are "largely expositional" (Awerbuch and Yang 2007). A related problem with the LCOE-based approach is that the load factors for different technologies are not typically fixed for different portfolios.[16] In this study, we do not attempt to "optimize" the generation portfolio in any of the cases we study. Rather, we consider different RE penetration scenarios, which might, for example, result from the implementation of an RPS, to explore the dynamics, risk mitigation characteristics, and incremental value that RE might add to the system.

A second issue that has been raised related to the incremental value of adding RE is whether alternative options could provide a similar benefit more effectively. Even if electricity buyers are risk averse and value limiting their exposure to price fluctuations, it may be less expensive to use financial instruments, such as forward contracts or swaps[17] (at least over short time horizons) than to install RE. This argument tends to assume there is no risk premium (over the expected future price) paid by the buyer to hold a forward contract for natural gas or power.[18] Whether this is true appears to be unsettled,[19] particularly since the existence and size of any forward premium may vary by location, timescale, electricity market structure, and financial market liquidity.

Diversity is important, even if valuing it is difficult. For example, in the electric sector too little diversity can create reliability and security concerns. Bazilian and Roques (2008), for instance, note the case of the UK electric sector, whose overdependence on domestically abundant coal made it vulnerable to strike action by coal miners. Similarly in the United States, constraints in pipeline capacity for transporting natural gas may pose significant risks from an overreliance on natural gas for electricity generation; for example, extreme weather and limited pipeline capacity in New England early in 2013 led to natural gas prices and wholesale electricity prices tripling

[15] If risk is ignored the use of LCOE under this approach fails to properly optimize the electricity portfolio because it suggests the use of a single technology with the lowest LCOE. This selection of the single lowest LCOE technology does not reflect the realistic "mix" of technologies for any electric system that has to serve real load profiles. It follows that adapting this approach to include risk will also not result in an optimal portfolio. For this reason and others, more recent studies often restrict such "optimization" analysis to baseload generation (see, e.g., Roques et al. 2008).

[16] Because of this, the LCOE for each technology for specified fossil fuel prices will generally not be constant across different portfolios, which is contrary to the assumption often used in this type of analysis. Delarue et al. (2011) recently used a refined optimization algorithm that distinguished between installed power capacity and generated electric energy where the model itself determined the load factors of the different technologies installed.

[17] A buyer (or seller) of natural gas (or electricity) can protect itself against future price uncertainty by agreeing to an over the counter (OTC) forward contract to buy (or sell) a commodity at some time. The price to be paid at delivery is specified in advance when the contract is made. An alternative way for a buyer to hedge is to buy gas at spot market prices, but also have an arrangement where the buyer pays the third party a fixed price for natural gas and in return receives (or swaps) payments linked to the market price of natural gas (Eydeland and Wolyniec 2003).

[18] It also assumes the transactions costs of buying and managing such contracts are low. While this is may be true for many utilities, it may not be the case for all consumers, especially those with low electricity use.

[19] While some studies have suggested there may be a positive premium on the forward price of natural gas (or electricity) over the expected future price due to risk aversion or other factors (Bolinger et al. 2002; Bolinger and Wiser 2008), others studies have suggested the premium is zero or even negative.

compared with their usual levels (Wald 2013).[20] Furthermore, uncertainties over future carbon emission policies and criteria pollutant regulation add risk and uncertainty to fossil fuel-dominated generation portfolios, which could lead to significant economic and social costs due to locking in portfolios dominated by fossil fuel technologies.[21]

Earlier studies that focused on characterizing the impacts of adding RE to portfolios of electricity generators often used an LCOE or simplified net cash flow approach (e.g., Awerbuch and Berger 2003; Lesser et al. 2007; Roques et al. 2008).[22] In this study, we expand on this previous work and a suggested approach by Bush et al. (2012) to demonstrate the use of an 8760 hourly production cost model (PLEXOS) to analyze the incremental impact of solar and wind penetration under a wide range of penetration scenarios. We studied the Rocky Mountain Power Pool (RMPP) region, which covers the state of Colorado and parts of Wyoming and South Dakota, because it has good wind and solar resources as well as significant thermal coal and natural gas generation and because the datasets used in our production cost model analysis were readily available as a result of the Western Wind and Solar Integration Studies (WWSIS) (GE Energy 2010; Lee et al. 2013). The region is also large enough to investigate many of the impacts on the cost of electricity caused by integrating large amounts of RE into existing fossil-based portfolios, while small enough to allow us to run many cases, including Monte Carlo (MC) simulations to investigate the impact of natural gas price generation uncertainty on the cost of electricity.

For the reference case, in which solar and wind make equal contributions to generation on an annual basis (i.e., a solar-to-wind generation ratio of 50:50), we varied the annual RE generation from about 10% to more than 50%.[23] We then explored the impact of altering the proportion of solar-to-wind generation in high-solar and high-wind cases with annual solar-to-wind generation ratios of 3:1 and 1:3, respectively. The impact of changing the ratio of natural gas generation to coal generation in the fossil generation mix was also considered by switching out coal thermal generation units with CCGTs in some scenarios. Some market structure issues were also considered. Further, we simulated the variation in annualized variable electricity costs using an MC simulation approach. This allowed us to characterize the value of variance reduction to a range of customers with different levels of risk and loss aversion and to compare this, at least in the near term, with the use of different financial products as hedges against future price uncertainty.

The remainder of the report is organized into five sections. Section 2 outlines the study methodology and describes the modeling tools, solar and wind data, and natural gas price

[20] For example, for the week ending March 13, 2013, natural gas prices for delivery in Boston were more than \$8.50/MMBtu, while natural gas at the Henry Hub cost less than \$4/MMBtu (EIA 2013a).

[21] An interagency working group (IWG) recently recommended the use of an expected value of \$43/ton in 2020 for the social cost of carbon (SCC) (as well as a number of other scenarios) for inclusion in regulatory impact analysis (assuming a 3% social discount rate) (IWG 2013). Using this value for the SCC leads to an external value for avoided generation by a natural gas-fired CCGT in line with the current PTC for wind. In contrast, the estimated cost of abatement for an advanced natural gas-fired CCGT exceeds the cost of the PTC with a recent estimate by EIA, which puts the incremental cost for CCS at about \$25/MWh (EIA 2013c).

[22] See also Bazilian and Roques (2008) for further examples of analysis using this type of approach.

[23] We used 2006 wind and solar data from the WWSIS study (GE Energy 2010) to determine the installed capacity. The generation is, therefore, only approximate over time due to inter-annual solar and wind variability (Wan 2012; Drury et al. 2013). The implications of this assumption are discussed in Section 4.2.

projections used in the analysis. Section 3 characterizes how varying levels of wind and solar generation impact annualized variable wholesale electricity costs for a range of future natural gas prices and the impacts of varying the mix of natural gas to coal generation capacity and market structure. Section 4 uses MC simulations to characterize distributions of future variable electricity costs for a range of future natural gas prices. Section 5 explores the value of reducing the uncertainty of future electricity costs to various types of customers with different risk- and loss aversion profiles. It also discusses potential price hedging alternatives to RE, such as the use of financial instruments or physical supply contracts, and the potential limitations of these alternatives (e.g., in terms of coverage, availability on longer time horizons, and potential locational, delivery, credit, and other risk-related issues). Section 6 provides a brief review of the study's key findings.

2 Study Methodology

This section describes the scenarios explored in this analysis, the study region, the hourly production cost-modeling tool (PLEXOS), and how portfolios with varying levels of renewable and fossil generation were constructed. We also describe the methodology used to characterize distributions of future natural gas prices, which were used in the MC simulations.

2.1 Model Scenarios

The range of future electricity prices and price uncertainty is sensitive to several factors including future natural gas prices, RE penetration, the mix of wind and solar generation for a given penetration level, the amount and mix of conventional generation (e.g., coal thermal, natural gas CCGTs and combustion turbines [CTs], nuclear, and hydroelectric), market structure, and other factors. We quantified the sensitivity of the future variable cost of electricity and cost uncertainty to several of these factors using PLEXOS over a wide range of natural gas prices (from \$1.5/MMBtu to \$9.2/MMBtu) which represents over 90% of the historical distribution. We evaluated the impact on cost and cost variance of:

1) Increasing the fraction of RE generation (50% wind and 50% solar (or 1:1 ratio) for the reference case on an annualized energy basis) from 10% to 55% in the study region (Section 3.1)
2) Varying the relative contributions of wind and solar generation to the total RE generation mix (Section 3.2) from 3:1 to 1:3 over a similar RE range
3) Varying the mix of conventional generators from a coal-dominated system in the reference scenarios to a natural gas-dominated system (Section 3.3).

For the 50:50 solar-wind reference case, we also investigated (4) the impact of market structure on wholesale variable electricity prices and price uncertainty (Section 3.4). These tasks are outlined in Figure 1.

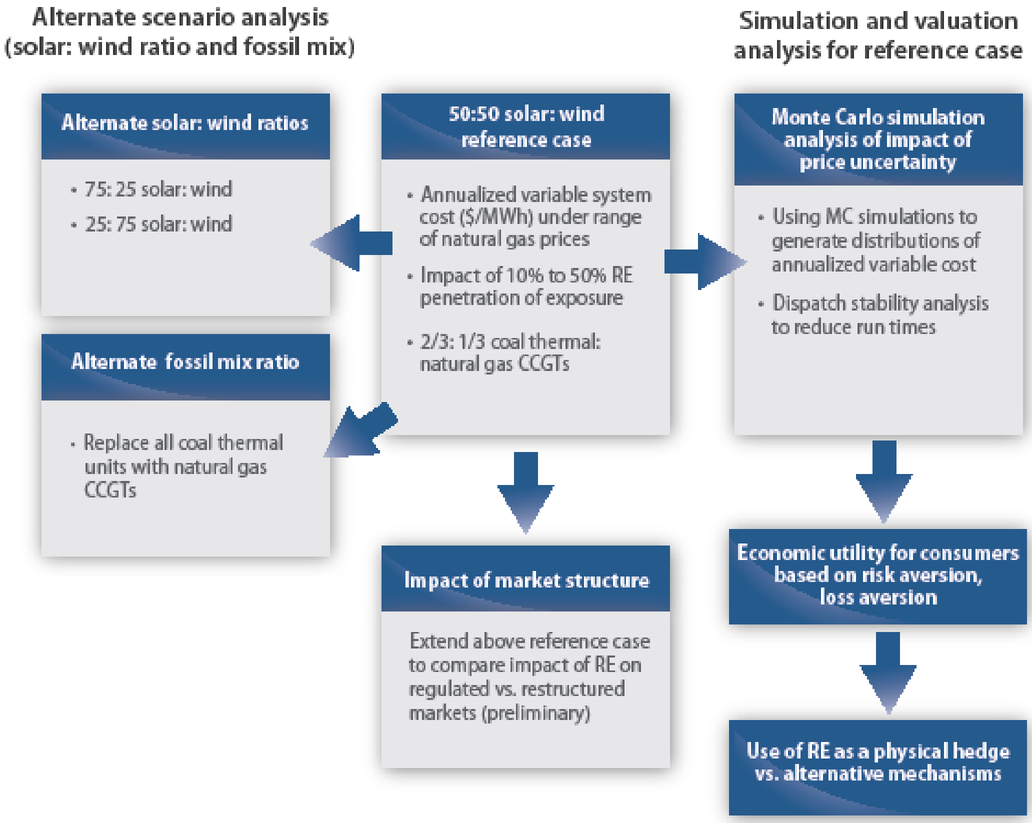

Figure 1. Schematic of main elements of analysis

We also investigated electricity price distributions using an MC simulation approach, which is described in Section 4. This allowed us to characterize the value of variance reduction to a range of customers with different levels or risk and loss aversion and to compare this, at least in the near term, with the potential use of financial products as hedges against future price uncertainty (Section 5).

2.2 Study Region and Modeling Tools

The geographic area for this study is the RMPP, with 2020 projections of the electric load profile, power production utilities, and transmission grid based on projections by the Western Electricity Coordination Council (WECC)[24]. The RMPP region shown in Figure 2 corresponds to all of Colorado and parts of Wyoming and South Dakota. The region includes two balancing areas, Western Area Colorado Missouri (WACM) and PSC, with projected annual loads in 2020 of 28,100 GWh and 50,400 GWh, respectively. Peak loads for the same year are assumed to be 4.4 GW in WACM and 10.1 GW in PSC; the total load for RMPP corresponds to about 2% of overall projected U.S. load in 2020. We chose the RMPP region because it (i) has abundant solar and wind resources (with average PV and wind capacity factors of 20% and 34%, respectively),

[24] The assumptions for the year 2020 are summarized in the *Assumption Matrix for the 2020 TEPPC Dataset* (WECC 2013); the dataset builds on 2017 forecasts from the *2008 Annual Report of the Western Electricity Coordinating Council's Transmission Expansion Policy Committee*, Appendix B (WECC 2008).

and (ii) has a mix of coal thermal and natural gas electric generation. The region was large enough to allow meaningful analysis using a production cost model and yet small enough for us to run many scenarios. We modified the solar, wind, and fossil generation characteristics of this area to explore various RE penetration scenarios.

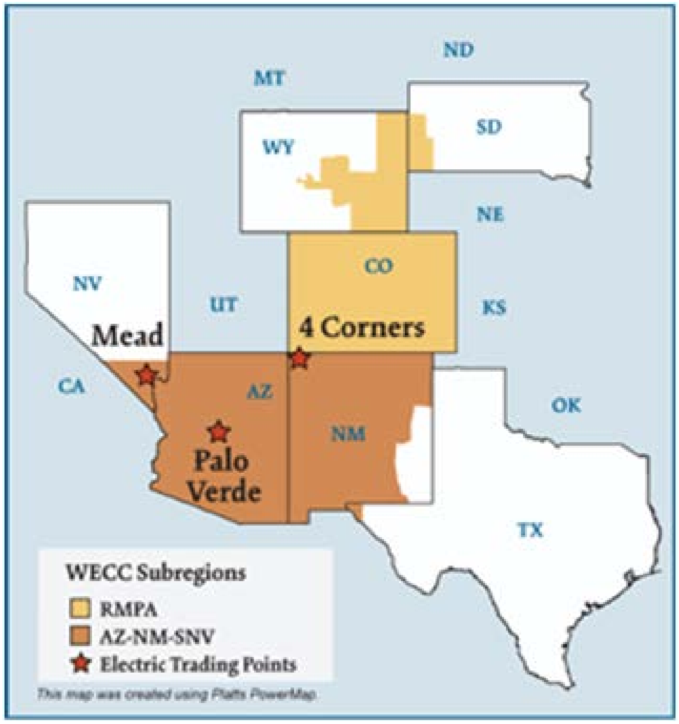

Figure 2. The Rocky Mountain Power Authority (RMPA) (FERC 2012)

We used the power market modeling software PLEXOS[25] to simulate a year of the optimal hourly (8,760) dispatch of fossil and non-fossil generation with different levels of PV and wind generation. The optimal hourly dispatch for any scenario run represents the lowest overall variable system costs for an entire year, calculated based on hourly generation and electricity demand and subject to several system characteristics, including startup and shut-down costs, startup times, and minimum operating windows. Model inputs were based on detailed information representing current and alternative hypothetical scenarios for future power generation facilities, transmission lines, and electric load. The input database of wind and solar resource data (from 2006) was developed for the WWSIS Phase II (WWSIS2) (Potter et al. 2008; Lew et al. 2013). Electricity transmission resources and transmission utilization in the production cost model were aggregated to the Balancing Area level (which corresponds to two regions in RMPP). We simulated dispatch in the RMPP system by assuming that it is isolated from the rest of WECC to suppress large-scale regional changes in power distribution caused by varying RE participation levels. This likely resulted in a conservative estimate of the impact of RE penetration because access to wider geographic resources reduces variability in wind and solar

[25] See e.g.: "PLEXOS for Power Systems." Energy Exemplar, http://energyexemplar.com/wp-content/uploads/brochures/PLEXOSBrochure_Web.pdf.

generation. The impact of broadening the geographic footprint to a much larger area is a focus of ongoing research.

Table 1 shows 2020 generation and capacity by technology for the scenario with 35% RE penetration by generation with equal shares of solar and wind by generation. The PV generation capacity shown in Table 1 is composed of 80% utility (37% single-axis tracking, 43% fixed-axis) and 20% rooftop. Table 1 also shows that the ratio of baseload and intermediate coal-to-natural-gas capacity (using CCGTs) is roughly 2/3 to 1/3. The capacity of gas-fired CTs used for peaking generation and CCGTs are approximately equal.

Table 1. Generation and Capacity by Technology for the 35% 50:50 Solar-and-wind Penetration Scenario

Category	Generation (GWh/year)	Rating (MW)	Capacity factor	Units	% Fossil capacity
Combined cycle gas turbine	3,678	2,579	16.3%	13	22%
Combustion turbine	213	2,735	0.9%	48	23%
Coal	42,996	6,455	76.0%	43	55%
Hydro (including pumped hydro)	4,583	1,412	37.1%	47	—
Wind	13,801	4,590	34.0%	43	—
Photovoltaics	9,543	5,362	20.3%	85	—
Concentrating solar power	4,347	1,504	33.0%	1	—
Other	290	569	5.8%	—	—

In addition to simulating hypothetical expansion scenarios based largely on the existing RMPP system (Table 1), we also explored a significantly modified RMPP system in which coal generation is replaced by CCGTs. To create these natural gas generation-dominated scenarios, each coal plant from the input database was replaced with a CCGT plant of equal capacity. Typical heat rate and startup costs for that size of CCGT plant were then estimated using a simple regression fit (Figure 3). The capacity of CTs remained the same in all scenarios at approximately one-quarter of the overall fossil generation capacity. We did not retire any conventional generation capacity with the addition (i.e., scale-up) of wind or PV generation. For this reason, actual utilization of natural gas CCGT will be artificially low since in practice, capacity of CCGT would be lower (and hence utilization would be higher than shown in Table 1). In the next phase of this study, which likely will involve capital cost issues, we anticipate making retirement decisions as needed. It matters less, however, for this study because the focus is on the variable system costs (and not capital recovery) and because, in meeting demand in any given hour, available RE resources usually displace fossil generation.

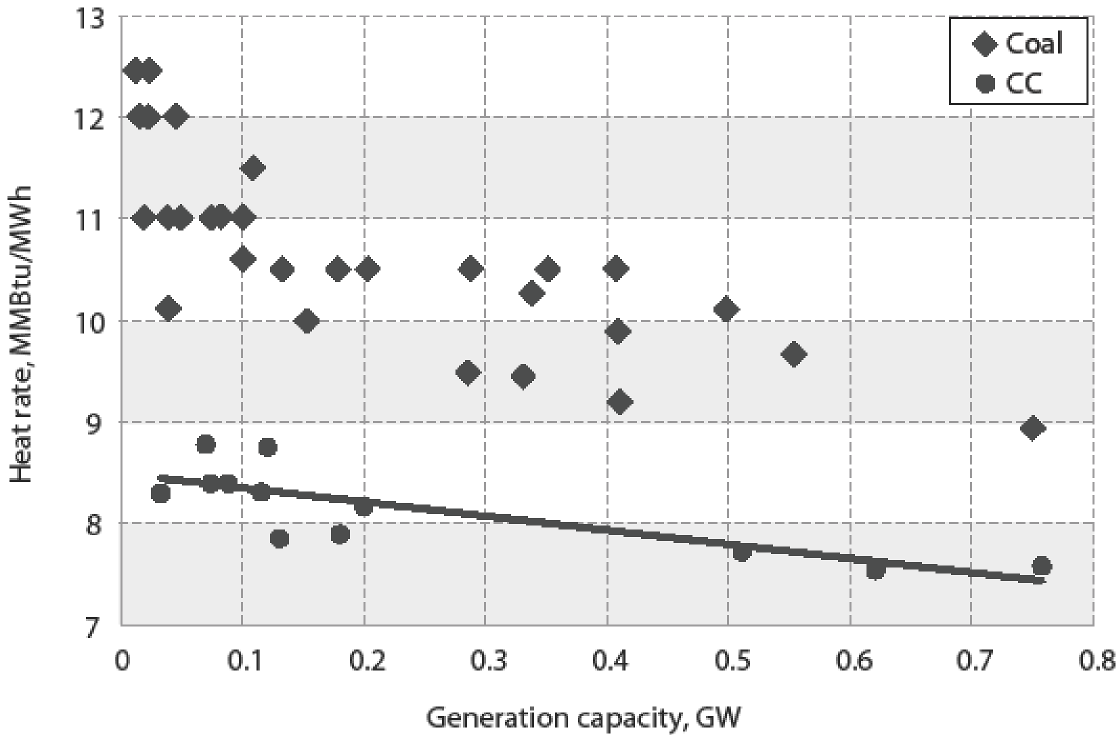

Figure 3. Comparative plots of heat rate capacity for coal and CCGT generators in RMPP

The line represents a linear regression fit used to determine the heat rates of CCGT plants replacing coal generation in several hypothetical scenarios.

Our WWSIS (GE Energy 2010) solar and wind data were from a single year (2006) projected to 2020 while assuming 2006 weather patterns (see Section 5 for a discussion of this assumption's impacts). The data originated from detailed weather simulations (at 10-minute intervals over an approximately 4 km x 4 km spatial grid) that interpolated meteorological measurements over the WECC area, and they were converted to wind, PV (fixed or single-axis tracking), or CSP electric output based on choices of geographic locations and generation technologies made in the WWSIS. The generators (wind and PV) were aggregated geographically to the bus level (Table 1) and to a 1-hour frequency to facilitate computations.

The amount of PV and wind generation capacity needed to meet varying RE generation-fraction targets was achieved by scaling capacity up or down at the site locations on a proportional basis to bring wind and solar generation to the desired level. We did not consider how increases in RE would change the location of installations, and used the approximation that created all the RE penetration scenarios using the same set of solar and wind generation locations.

2.3 Natural Gas Price Distribution Modeling

Accurately estimating future natural gas prices is impossible. One common estimation method employs historical data. The recent largely unforeseen increase in U.S. shale-gas supply, however, has driven natural gas prices below historically based forecasts (to $4/MMBtu or less in 2012).[26] Clearly, the impact of this "recent" information about shale gas is not reflected in much of the historical data –which in turn raises some legitimate concerns about the usefulness

[26] With forward prices 5 years out typically trading somewhat higher at $5/MMBtu or more (EIA 2013).

of past trends for projecting future prices, even more so owing to the recent disconnection of a relatively strong historical correlation between natural gas and oil prices. The inherent difficulty in estimating future natural gas prices is illustrated in Figure 4, which shows that the U.S. Energy Information Administration's (EIA's) natural gas price projections have tended to vary widely over time to be biased toward and trail changes in recent prices, with a lag.

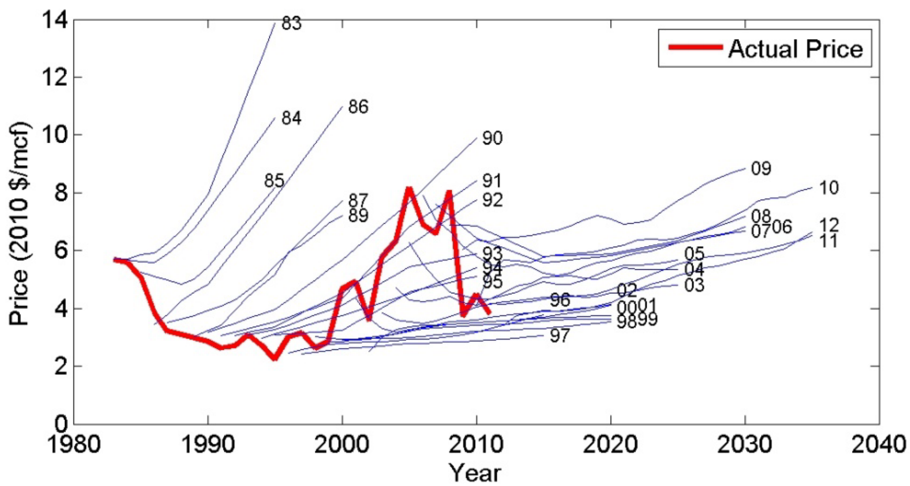

Figure 4. EIA forecasts of U.S. wellhead natural gas prices in various years (blue lines) compared with actual prices (red line)

Source: www.eia.gov.

Natural gas prices in early 2013 might not accurately indicate future trends either. Several factors could put upward pressure on prices, which are currently at or near historical lows. This possibility has been at least partly factored into short-term (5 to 10 years out) forward prices, which are significantly higher than spot prices. In the longer term, natural gas prices could increase for a variety of reasons, such as a greater demand for natural gas (as technologies shift to natural gas or natural gas is converted into liquid fuels), increased U.S. liquefied natural gas (LNG) exports, and tighter environmental or regulatory controls, and other reasons.

This study uses historical natural gas prices to explore the potential impact of future natural gas prices on variable electricity costs for a range of RE penetrations. However, based on preceding discussion we make no claims about the likely accuracy of these projections. Since Colorado utility prices are only available from EIA from 2002 forward, we first looked at Henry Hub data, which are available on a monthly basis from 1997. Figure 5 compares monthly Henry Hub prices to Colorado and Arizona utility prices over the period 1997 to 2011. The prices are strongly correlated, although there are significant differences in certain months. Figure 6 shows a histogram of the same Henry Hub data compared to a simulated log-normal distribution.

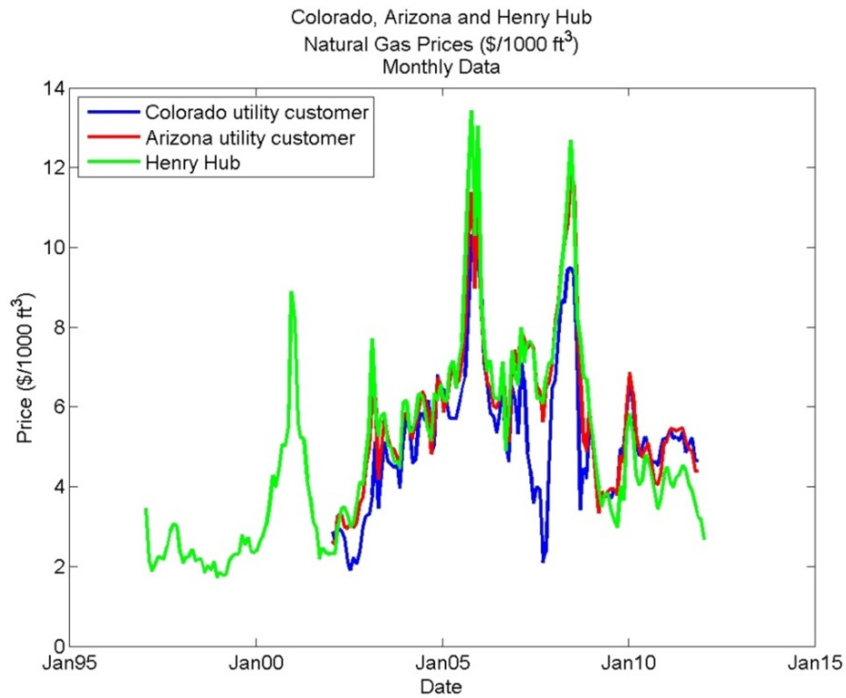

Figure 5. Historical natural gas price data: Henry Hub (1997–2011), Colorado utility prices (2002–2011), and Arizona utility prices (2002–2011)

Source: EIA 2013b

To help assess the impact of adding RE over multi-decade time horizons (to reflect the lifetime of RE technologies), we generated 30 years of simulated monthly natural gas prices using the following methodology:

Define $X_i = \log(Historical\ price\ data)$
Seasonally adjust the data by defining $Y_i = X_i - (monthly\ means\ of\ X_i)$
Employ a maximum likelihood estimator to determine the parameters (α, γ, σ)
$dY_i = \alpha(\gamma - Y_i)dt + \sigma dz_i$, where $dz_i = \epsilon\sqrt{\Delta t_i}, \epsilon \sim N(0,1)$
Simulate 30 years of monthly data using the mean-reverting, seasonally adjusted stochastic model

Table 2 summarizes the parameters estimated for Henry Hub, Colorado, and Arizona. The parameters under "actual *dt*" were estimated using the actual time periods (e.g., the number of days in a month divided by the number of days in the year). The parameters under "*dt* = 1/12" were estimated with the approximation of 1/12 for the time period of each month. The parameters estimated using both approaches agree to two significant digits.[27]

[27] The mean reversion parameter for the Henry Hub data is different than the Colorado or Arizona parameter. This illustrates one of the difficulties in modeling price data. In general, many price time series are non-stationary (e.g., the mean and variance change over time).

Table 2. Stochastic Model Parameters for Henry Hub, Colorado Utility, and Arizona Utility Prices

	Actual *dt*			*dt* = 1/12		
Location	**α**	**γ**	**σ**	**α**	**γ**	**σ**
Colorado	1.532185	0.038892	0.556404	1.539787	0.038675	0.557913
Arizona	1.220383	0.052217	0.423223	1.219653	0.052198	0.423343
Henry Hub	0.444511	-0.036365	0.471478	0.443914	-0.036400	0.471295

Figure 6 shows twenty 30-year monthly MC simulations of natural gas prices (strips of 360 data points: 30 years x 12 months); these are equivalent from a data perspective to 600 (20 x 30) annual 12-month price simulations except that, in the former case, the last price in December for any given year influences the price in January for the next year.[28]

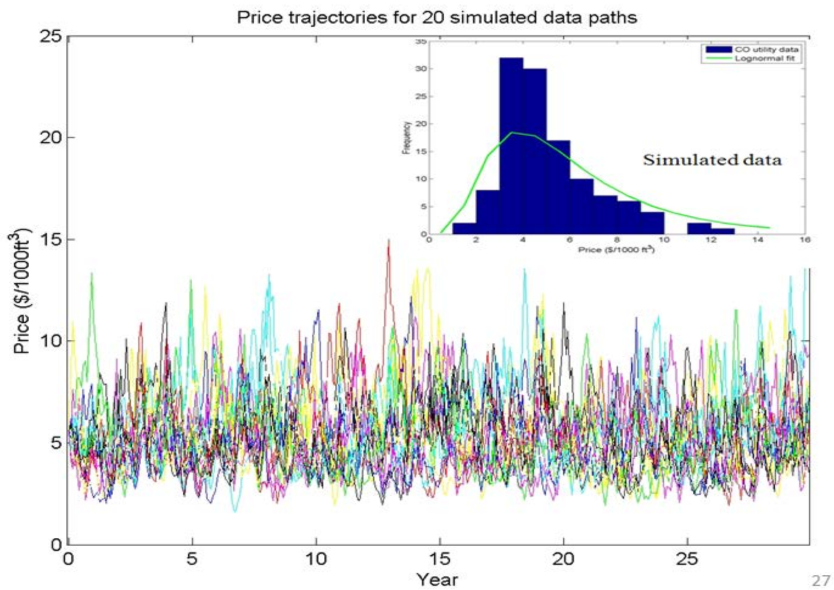

Figure 6. 20 time-series simulations of 30 years of monthly Colorado utility prices

[28] Further discussion of the approach used in modeling natural gas prices can be found in Byrne et al. (2013).

3 The Impact of RE Generation in Reducing the Uncertainty of Future Electricity Prices

The range of future electricity prices and price uncertainty are sensitive to future natural gas prices, RE generation fractions, the relative mix of wind and solar generation, the mix of conventional fossil generators (e.g., coal generators, natural gas CCGTs and CTs), market structure, and other factors. In this section, we quantify the sensitivity of future variable wholesale electricity cost and cost uncertainty to several of these factors using the hourly production cost model (PLEXOS). For a wide range of natural gas prices we evaluate the impact of: increasing the fraction of RE generation (50% wind and 50% solar on an annualized energy basis) from 10% to 55% in the study region (Section 3.1), varying the relative contributions of wind and solar generation to the total RE generation mix (Section 3.2), and varying the mix of conventional generators from a coal-dominated system in the reference scenarios to a natural gas-dominated system (Section 3.3). Section 3.4 explores the impact of market structure on the uncertainty of costs or prices faced by the consumer.

3.1 Impact of Increasing RE Generation on Annualized Variable Wholesale Electricity Cost and Cost Uncertainty—50:50 Contribution of Solar and Wind Energy

To explore the impact of increasing RE generation on the annualized variable wholesale cost of electricity and cost uncertainty, we scaled solar and wind capacity in the RMPP region to reach 10%–55% of total annual generation while maintaining a 50:50 contribution of wind and solar energy. Because of differences in solar and wind capacity factors, the installed capacities for solar and wind in the reference case are significantly different, and the capacity proportion changes with overall penetration to compensate for different curtailment levels.[29] For example, Table 1 shows that average annual wind and solar capacity factors are approximately 20% and 34%, respectively, for the 35% RE generation 50:50 generation scenario. Reaching the RE generation targets requires 6,866 MW of solar capacity and 4,590 MW of wind capacity. In a different year, these generation percentages will vary due to changes in weather.

Figure 7 shows the range of annualized variable cost of electricity ($/MWh) estimated using an hourly production cost model for a range of representative natural gas prices and for RE generation levels increasing from about 10% to 55%.[30] This figure shows that, at low RE penetrations (e.g., 10% to 15% RE), the annualized variable system costs vary widely with the price of natural gas. For 10% RE penetration, a very low natural gas price of $2/MMBtu leads to an annualized variable cost of electricity of approximately $15/MWh. This cost increases to

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[29] Curtailment is defined as excess RE generation not used to meet load. Typically it occurs when demand is low and there are constraints and/or related costs associated with turning down the output of baseload units. It can also arise from other constraints such as transmission limits or environmental requirements to hydro generation, although these constraints were not explicitly considered in this study.

[30] Each simulation (represented by a data point on the figure) was conducted by scaling wind and solar generation to achieve the desired amount of generation from these resources. Because curtailed energy is not taken into account (the horizontal axis on the figure includes only generation toward meeting the load), choosing the right scaling factors for wind and solar sometimes involved several iterations. In this, we paid more attention to keeping the ratio between wind and solar generation (1:1 for the data represented on the figure) than achieving the exact desired amount of renewable generation. This allows (the low gas price) data points on the graph to deviate from the exact (15%, 25%, 35%, and 45%) values.

more than $27/MWh at a natural gas price of $9.2/MMBtu, more than $12/MWh higher. Increasing the natural gas price $5/MMBtu, from about $4/MMBtu to $9/MMBtu, increases the variable electricity cost by approximately $10/MWh.

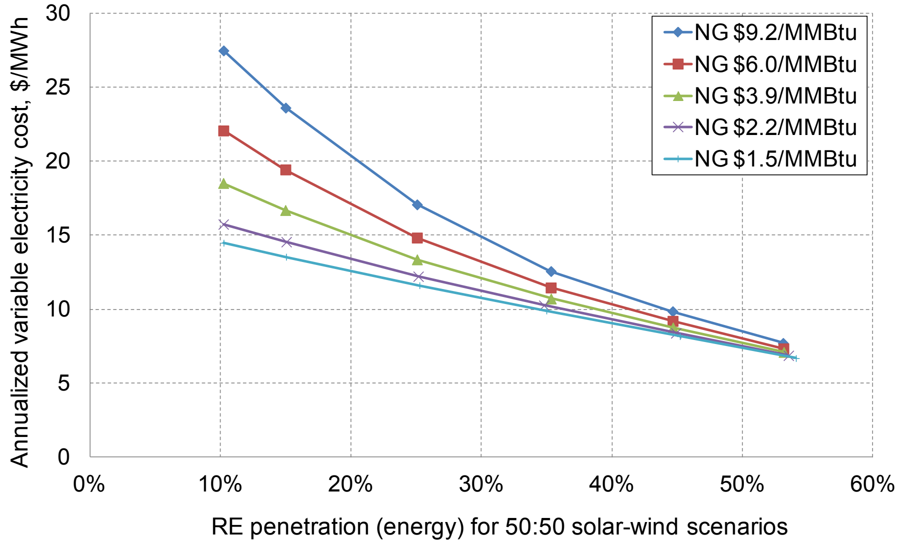

Figure 7. Annualized variable cost of energy ($/MWh) for different natural gas prices under a range of 50:50 solar-wind generation penetration scenarios in RMPP (isolated)

Adding RE generation to the RMPP system significantly reduces the range of variable electricity costs. In addition, the variable electricity cost for any natural gas price declines with increasing RE penetration, which is to be expected since solar and wind have no fuel costs. The changing slope of the variable cost curves shows, however, that the incremental impact of further RE penetration decreases with increasing penetration, and that only small incremental benefits are achievable beyond 35% penetration. Note that these results say little about total system costs, which would include capital-recovery costs for renewable and conventional generator investments and fixed operations and maintenance costs. Whether total system costs would increase or decrease with increasing RE penetration would depend on future cost projections for each generation technology, including technology-specific subsidies, which are outside the scope of this analysis.

The reduction in the range of variable electricity costs with increasing RE penetration can be understood in the following manner. In the low-RE cases, substantial natural gas generation is used throughout the year, only some of which is displaced by solar and wind generation. Because of this, variations in natural gas prices significantly impact annualized system costs. As RE penetration increases, natural gas generation is more frequently displaced by RE, which decreases both the overall variable system costs and the sensitivity of variable system costs to natural gas prices; this displacement is reflected by large drops in utilization for both gas generation technologies when RE penetration increases from 15% to 35% (from 45.5% to 16.9% for CCGTs and from 6.0% to 0.9% for CTs). At 35% RE penetration, the range in variable electricity costs is reduced to about $2- $3/MWh for the natural gas prices explored. Adding RE generation beyond 35% becomes increasingly ineffective at eliminating the remaining natural gas generation because the wind and solar generation occur at the wrong times. This effect can be seen in Figure 8 and Figure 9.

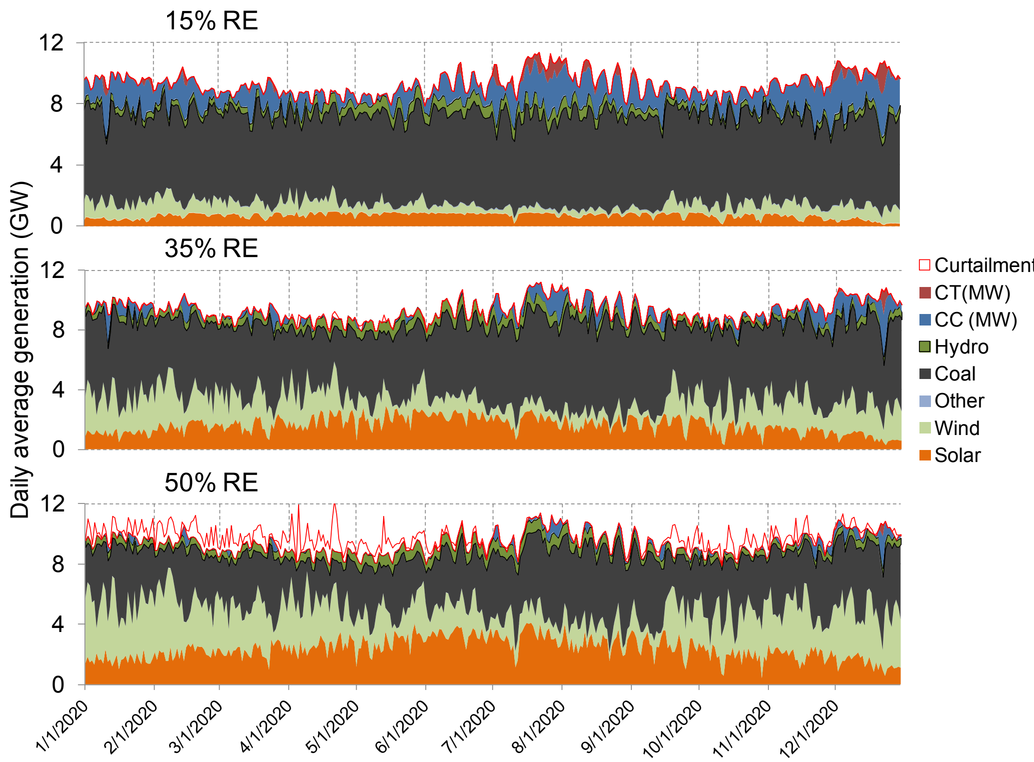

Figure 8. Daily average generation (GW) by technology for an equal mix of solar and wind generation (50:50) for different RE penetration (by percent of generation) scenarios in RMPP isolated

Figure 8 shows the daily generation supply by technology over a one-year period under 15%, 35%, and 50% 50:50 solar-and-wind by generation penetration scenarios. Electricity demand in the RMPP region is represented by the top of the generation stack, wind and solar generation are shown by the two bottom layers, and curtailments are shown by unfilled red lines above the solid generation stack. The three figures reveal information about the daily operation of the system, how it varies over the year, and the impacts of integrating increasing amounts of RE generation. Electricity demand peaks in both the summer and winter. Wind generation tends to be significantly higher than solar generation in winter, while the reverse is true in summer. Overall RE generation is lowest in summer when electricity demand is highest. There is curtailment in the 35% RE penetration scenario during spring and fall, when demand is low and most (but not all) of the CCGT generation is displaced. This curtailment effect, coupled with the inability of RE to eliminate natural gas generation, becomes more apparent in the 50% penetration case.

This curtailment effect can also be seen in Figure 9, which shows the overall generation curtailed as a percentage of total load and how this varies with increasing RE penetration by generation. The curtailed generation increases with RE penetration. As the RE generation fraction increases from 25% to 35%, curtailment increases from near-zero to about 0.2% of total demand. This results in a marginal curtailment of about 2% of new RE generation resources added to the system. As RE generation fraction increases further, total and marginal curtailments increase significantly. For example, increasing RE generation from 35% to 45% increases total curtailment to 1% of demand and marginal curtailment to 8%. Increasing RE generation from 45% to 55% increases total curtailment to 5% of demand and marginal curtailment to 40%.

Curtailment at higher RE penetrations is slightly lower for lower natural gas prices, reflecting increased use of more flexible natural gas generators and decreased use of coal.

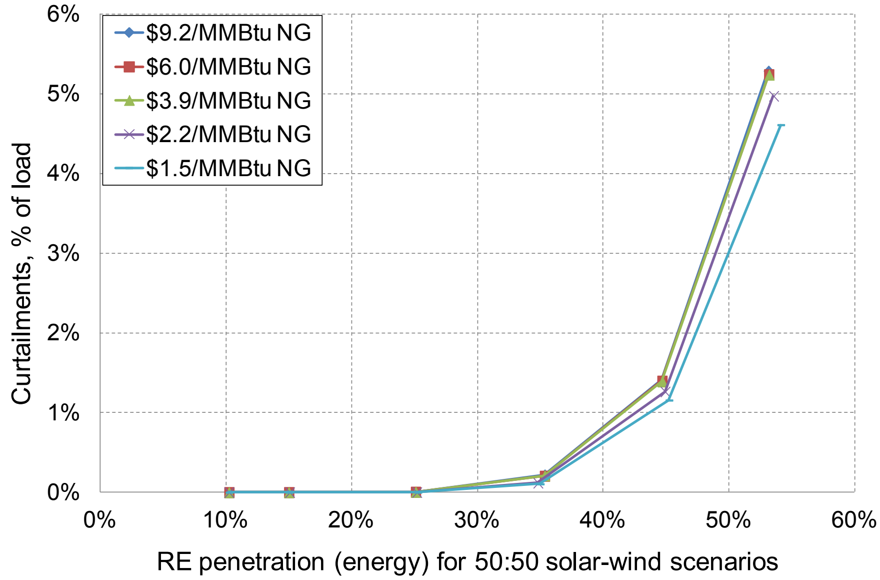

Figure 9. Percentage of generation curtailed with increasing RE penetration in RMPP (isolated)

3.2 Impact of Increasing RE generation on Variable Wholesale Electricity Cost and Cost Uncertainty—Variable Solar and Wind Energy Contributions

This subsection explores the impact of varying the relative contribution of solar and wind energy for meeting the overall RE generation target. Figure 10 shows how the range in variable annualized electricity cost is reduced for different total RE penetration levels as the proportion of solar-to-wind generation is varied. The figure represents the difference in the annualized variable electricity prices for high ($9.2/MMBtu) minus low ($3.9/MMBtu) natural gas prices. In addition to the 50:50 solar-wind reference case, two alternate solar-wind scenarios are shown. The high solar case (High Solar) corresponds to 75% solar and 25% wind (or 3:1 ratio) generation on an annualized energy basis while the high wind case (Low Solar) corresponds to a 25% solar and 75% wind (or 1:3) generation ratio.

Figure 10 shows that the variable cost difference curves for each of the three cases are similar in terms of overall magnitude and rate of decline with increasing RE penetration. However, the 50:50 solar-wind case reduces cost variance the most with increasing RE penetration, and the High Solar case reduces it the least. This suggests that the ability of increased solar capacity to displace natural gas generation during peak periods is more than offset by the impact of combining wind and solar to complement seasonal differences in generation (wind generation peaks in winter and spring, and solar generation peaks in summer) for the isolated region used in this study.

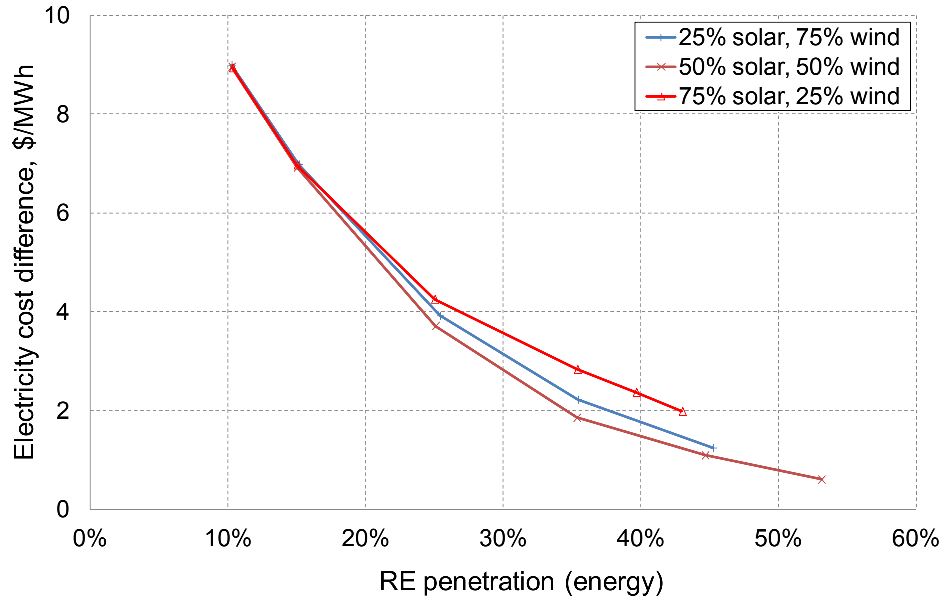

Figure 10. Annual cost variance and cost variance reduction with RE penetration under high ($9.2/MMBtu) and low ($3.9/MMBtu) natural gas prices for different solar-to-wind ratios in RMPP (isolated)

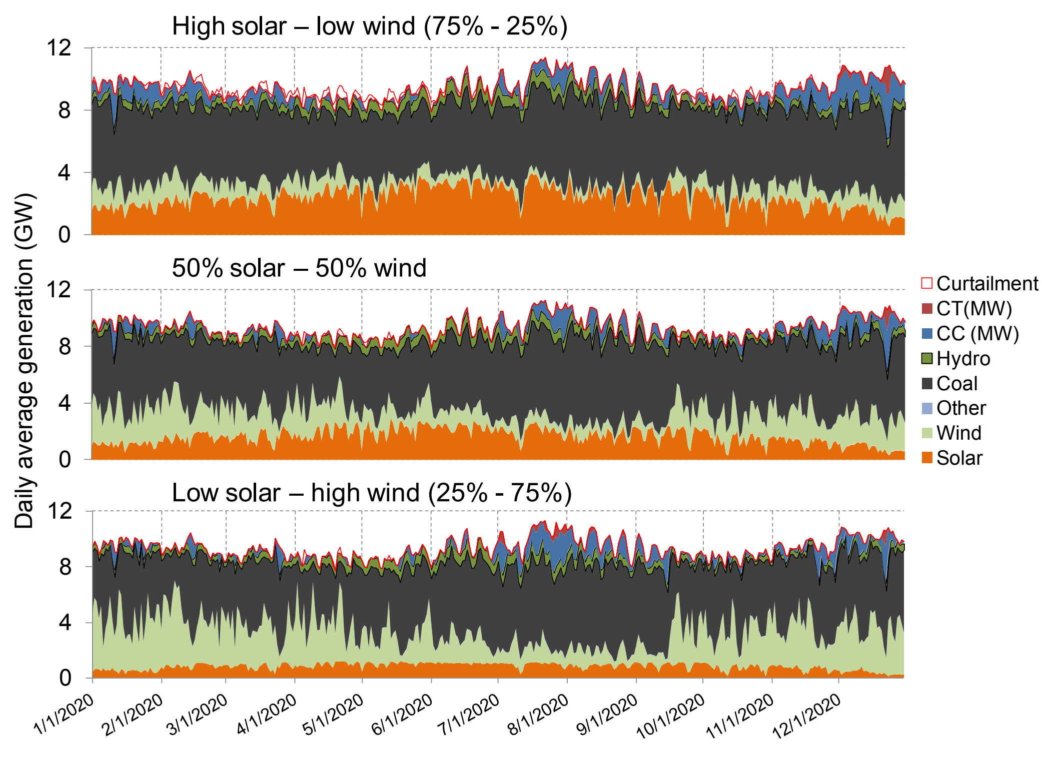

Figure 11. Daily average generation (MW) by technology for 35% overall annual RE penetration for three cases with different solar-wind ratios in RMPP (isolated)

Figure 11 shows the daily energy supply over the year by technology for the three different ratios of solar-to-wind generation (3:1, 1:1, and 1:3). While the total annual RE generation is set to 35% in each case, there is considerable seasonal variation in the daily wind, solar, and overall

RE generation. Wind and solar generation are anti-correlated over several timescales–on a monthly basis (R = -0.64) reflecting more wind during the winter and more solar in the summer, and on a daily (R = -0.36) basis reflecting the fact that solar output peaks during the day, whereas wind can blow both day and night. The impact of these anti-correlations can be seen in Figure 11. In the 50:50 (or 1:1) scenario, the different daily generation characteristics of wind and solar offset each other over the year, so annual variability of daily RE generation is lower than for the high and low solar cases. Adding similar amounts of solar and wind (by annual generation) appears to provide a more effective natural hedge against RE generation variability than either the solar- or wind-dominated cases, which are less effective at displacing natural gas generation.

3.3 Impact of Coal-to-natural Gas Ratios on Annualized Variable Electricity Cost and Cost Uncertainty

In the previous two subsections, we explored the impact of varying the amount and type of RE generation in the coal-dominated RMPP system, finding that the incremental reduction of variable annual system cost and cost uncertainty decreased significantly with increasing RE penetration. These diminishing returns were caused by the limited amount of natural gas generation in the RMPP system that was available to be displaced and the hourly mismatch between RE supply and electricity demand. Here, we investigate the sensitivity of these results to the mix of fossil fuel generators by analyzing a scenario in which all the coal generators in RMPP are replaced by natural gas CCGTs. In this analysis, CCGTs have more ramping flexibility than coal in addition to different marginal cost structures. The methodology and assumptions used to do this were discussed in Section 2.2.

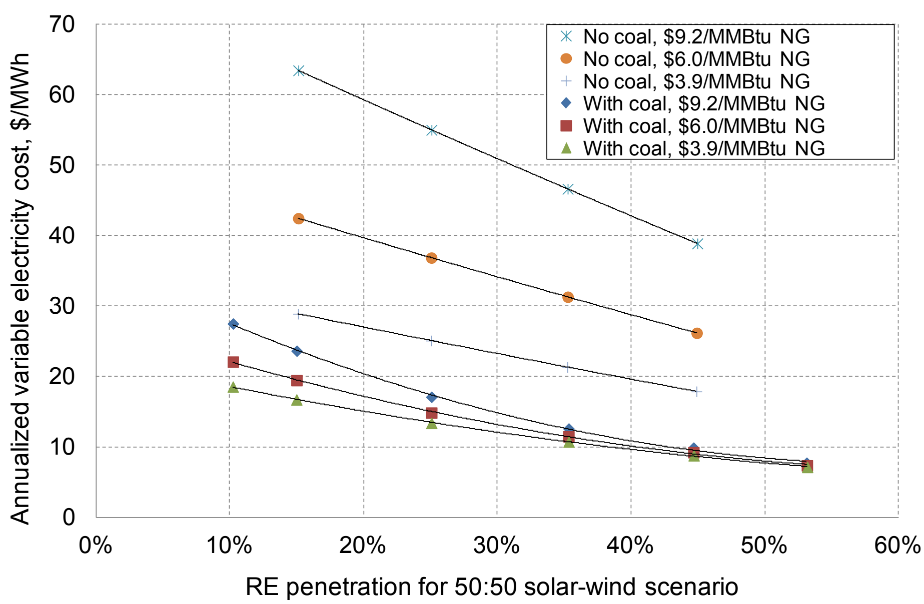

Figure 12. Annualized variable cost of electricity with RE penetration for the 50:50 solar-wind case and coal- and natural gas-dominated fossil scenarios

Figure 12 shows the variable electricity system costs with increasing RE penetration for the reference 50:50 solar-wind case for two scenarios. The original coal-dominant scenario with both coal thermal units and natural gas generation (see Table 1) and a second scenario where all the coal generators have been replaced with CCGTs ("No coal" in the figure legend). Figure 12 shows that the impact of natural gas price uncertainty on variable system costs is much greater in the natural gas-dominated portfolio for all RE penetrations because larger amounts of natural gas generation are present. Because of this, coal generation, even though less flexible operationally than natural gas, also provides a partial hedge against natural prices changes. For example, at low RE penetration (15%), a $5.3/MMBtu variation in natural gas prices increases the variable cost of electricity by about $35/MWh in the natural gas-dominated portfolio but only by about $8/MWh in the coal-dominated portfolio–a factor of 4 difference. The magnitude of this difference in part is due to the low coal prices found in the region studied (on a $/MMBtu basis), and so the effect is likely to be lower in many other regions of the United States.[31]

The effectiveness of RE in reducing the variance of annualized system costs is also less in the natural gas-dominated portfolio because, even at high RE penetration, much natural gas remains to be displaced, and differences in the timing of solar and wind generation matter less. RE displaces some, but not all, flexible natural gas generation even at the highest RE generation fractions, and curtailment is significantly lower. This suggests that the magnitude of the physical hedging effect for any level of RE penetration increases with the share of natural gas generation in the fossil mix.

3.4 Regulated vs. Restructured Markets and the Impact of Market Structure Assumptions on Cost and Cost Variance with Increasing RE

The production cost model used in this study solves for the optimal hourly dispatch of electricity generation resources, which minimizes annualized variable system costs. Because of this, the optimal hourly dispatch is largely independent of market structure assumptions, since in both a regulated and restructured market the generation units should be dispatched in a way that minimizes overall system costs.

On the other hand, the price of power to consumers and the revenues earned by owners of generation assets may be very different in regulated and restructured markets. In a regulated market, the annualized cost of electricity ($/MWh) is calculated to provide generators with payments for incurred fuel costs plus a reasonable return on capital (with adjustments for actual vs. planned fuel costs if necessary). In contrast, capital recovery is not guaranteed in a restructured market where the wholesale electricity price in any given hour is set by the marginal unit, which in turn sets the price paid to all generators dispatched in that hour.[32] Because the marginal hourly price is frequently set by natural gas generators (especially during hours of peak demand), the revenue received by all generators in a restructured market (which in turn affects the cost of energy to consumers) is often much more sensitive to the price of natural gas than in regulated markets.

[31] The EIA estimates the U.S. average cost of fuel and variable O&M for conventional coal thermal plants to be $29.2/MWh, but with a range from $18.6/MWh to $47.4/MWh (EIA 2013c). The region and coal prices used in this study are consistent with the low end of these estimates.

[32] There are some exceptions to this. For example, in energy and capacity markets, capacity payments are available to encourage investment for some peaking units. In addition, in a multi-nodal market with transmission constraints, there may be an array of prices at different locations, known as locational marginal prices (or LMPs).

Figure 13 demonstrates this point by comparing the annualized variable cost of power in a regulated market to the estimated annualized average market price for wholesale electricity in a restructured market. The average market price for the year was estimated by assuming that the price in any given hour was the variable cost of the most expensive unit dispatched to meet demand, and then estimating the load-weighted average price for the year. As discussed in Section 3.1, in a regulated market with 15% RE penetration, a $5/MMBtu variation in natural gas prices can translate into an approximately $8/MWh variation in the variable cost of electricity. For a restructured market, a similar price difference for natural gas leads to an electricity price difference of more than $50/MWh–an increase by a factor greater than 5.

Adding RE in a restructured market also leads to a greater reduction in both the overall variable price of electricity and the uncertainty in electricity prices. For example, increasing RE penetration from 15% to 35% by generation in the restructured case reduces the variation in price by more than $30/MWh (from more than $50/MWh to $20/MWh), which is also greater than a factor of 5 (the decrease observed for the regulated case, about $5 to $6/MMBtu). The variable cost of electricity in the regulated market is also much lower overall than the price of power in the restructured market because it does not contain an adder to allow for capital recovery and a reasonable rate of return (not included in Figure 13). For an “apples-to-apples” comparison, it would be necessary in the regulated case to include such a fixed cost. Even so, while such an adder would shift annualized system costs higher in a regulated market, it should not increase electricity cost sensitivity to natural gas price variation significantly.

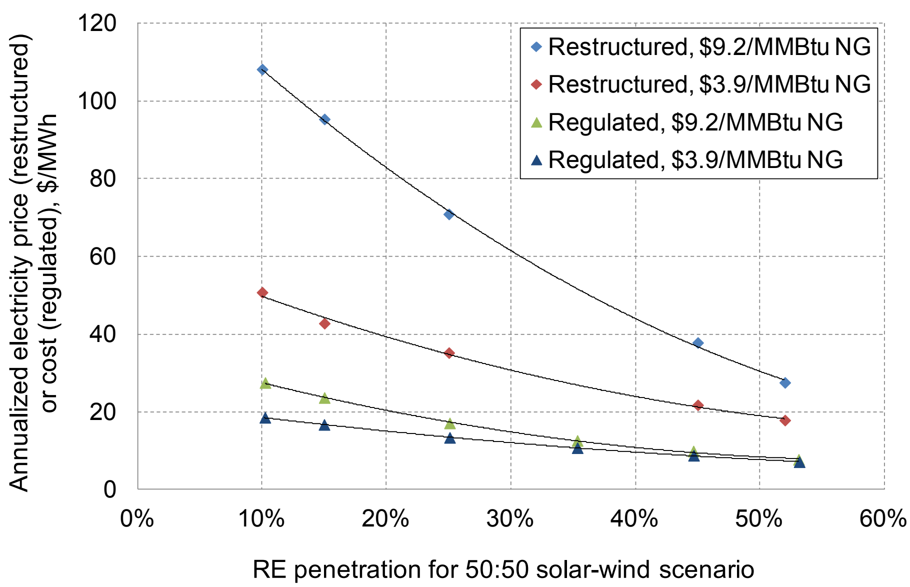

Figure 13. Annualized sensitivity of electricity prices (for restructured market) and annualized average variable cost (for regulated market) under different natural gas price scenarios for different RE penetration levels in RMPP (isolated)

Figure 14 shows this effect on a much smaller timescale and at greater resolution. The figure compares the hourly marginal price for power in a restructured market with the hourly variable cost of electricity in a regulated market over a one-week period for two different natural gas prices ($3.9/MMBtu and $9.2/MMBtu). This is for the 15% RE penetration 50:50 solar-wind reference scenario. Similar to Figure 13, the difference in the observed electricity prices in the restructured market under the two gas prices is more than $40/MWh, while the difference in annualized variable cost in the regulated market is much lower ($5/MWh).

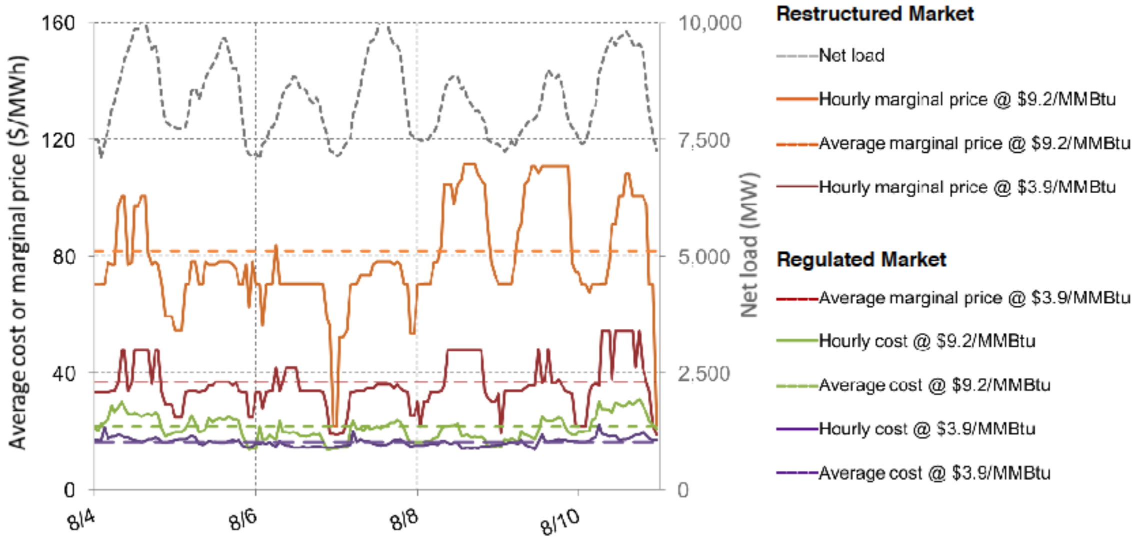

Figure 14. Hourly sensitivity of marginal electricity price and average variable cost under different natural gas price scenarios under low (15%) RE penetration, 2020

The impact of RE on electricity price volatility is substantially different for restructured and regulated markets. This is important because both types of market structure have a substantial presence in the United States (where about 2/3 of electricity is sold in restructured markets and 1/3 is sold in regulated markets), and the continuation of such bifurcation cannot be ruled out in the future. In practice, even in restructured markets the vast majority of wind and solar generation is sold under long-term bilateral contracts with fixed-price (or index-linked) power purchase agreements (PPAs); this is not, however, reflected in Figure 13 and Figure 14. The presence of such bilateral contracts in restructured markets may significantly lower the impact of gas price volatility on both consumer costs and investor risk. Our ongoing research is examining the risks and rewards faced by investors and consumers in restructured vs. regulated markets, including the relevance and role of bilateral contracts.

4 Characterizing the Impact of RE Generation on the Annualized Variable Cost of Electricity and Cost Uncertainty using MC Simulations

In this section, we extend the natural gas price sensitivity analysis discussed in Section 3 by characterizing the impact of RE penetration on the uncertainty of electricity costs using MC simulations of natural gas prices. The resultant shape and density of the different electricity cost distributions add detail to earlier discrete price sensitivity analyses, and this enables a better understanding of the likelihood and impact of adverse cost outcomes. This may be important because the historical distribution of natural gas prices is asymmetric and positively skewed toward higher prices (Section 2.3), which in turn will lead to similar effects for annualized variable electricity costs generated by the production cost model.[33]

4.1 The Stability of Optimal Production Cost Model Dispatch to a Range of Natural Gas Prices

In principle, MC simulation analysis using a production cost model requires estimating the future distribution of natural gas prices, and then drawing from this distribution hundreds (or thousands) of monthly natural gas prices in sets of 30 or more years, to generate the associated electricity cost distributions. If computation time were not an issue, the impact of each future natural gas price scenario could be simulated directly using the production cost model, and this process would be repeated for all RE penetration fractions and other scenarios of interest. However, we focus here on exploring the stability of optimal dispatch solutions calculated using the hourly production cost model for a range of natural gas prices. Dispatch stability observed over a wide range of gas prices allowed us to significantly reduce the number of runs that need to be done within the production cost model.

Figure 15 suggests that the optimal hourly dispatch solution for one year (calculated using the hourly production cost model) does not significantly vary over a wide range of natural gas prices. The graphs in the left column show the hourly amount of natural gas used over the year for the 50:50 solar-wind reference case under low (15% top row) and high (50% bottom row) RE penetration scenarios, with the natural gas price set at \$3.9/MMBtu. The graphs in the right column show the same scenarios but with a higher natural gas price set at \$9.2/MMBtu. The hourly natural gas use (or off-take) is a good proxy for the generation from natural gas units. In the high 50% RE penetration scenarios, the use of natural gas decreases substantially throughout the year (compared to the low RE cases), reflecting greater displacement of natural gas generation. While the use of natural gas—and the optimal dispatch of natural gas generators—is significantly different for the low and high RE penetration scenarios (top vs. bottom rows), each of these distinct dispatch profiles is similar for both high and low natural gas prices (right vs. left columns).

[33] Again we stress the MC analysis is based on a proxy for the future distribution of natural gas prices since the true distribution of future prices is unknown. Structural regime changes that have shifted the price in the past may not be matched by similar events going forward. In the context of portfolio optimization--which we do not attempt in this paper--Stirling (1994) has raised concerns against the potential to misuse "risk and probabilities" estimates to replace ignorance or lack of knowledge about future outcomes.

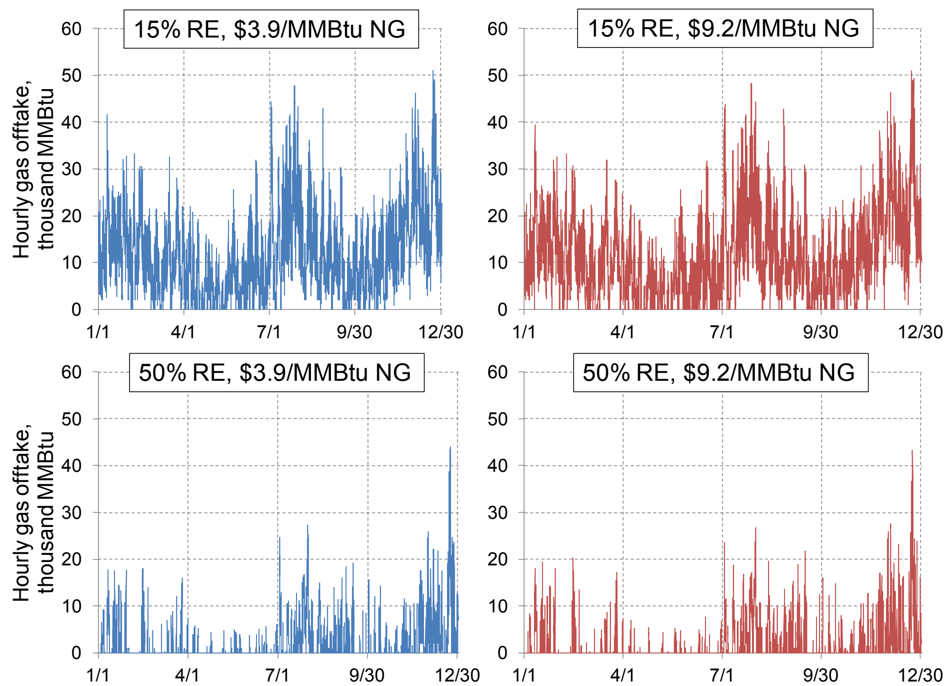

Figure 15. Hourly gas use over one year (2020) under different natural gas price and RE penetration scenarios, 50:50 solar-wind scenario in RMPP (isolated)

Figure 16 contains three pairs of graphs that show the daily generation for coal thermal units and natural gas CCGTs and CTs for a range of natural gas prices (from $1.5/MMBtu to $9.2/MMBtu). The scatter plots in the left column compare the daily generation from each type of technology at moderate and high natural gas prices ($3.9/MMBtu and $9.2/MMBtu). The scatter plots in the right column compare daily generation at lower natural gas prices ($1.5/MMBtu and $3.9/MMBtu).

Figure 16 shows that the average daily generation is greater for coal than for CCGTs, and both these technologies operate far more frequently than do CTs; this is consistent with earlier discussion and Figure 8. The daily dispatch over the year for coal, CCGTs, and CTs is similar at the two higher natural gas prices (left column), shown by the points lining up in 1:1 agreement (on a line that bisects the plane at 45°). Consistent with this, we find very strong correlations in generation output for coal, CCGTs, and CTs (1.0, 0.99, and 0.98, respectively) for these prices. The operational relationship is clearly weaker for the lower pair of natural gas prices (right column). The points are more scattered, and the correlations are much lower, for coal, CCGTs, and CTs (0.88, 0.74, and 0.77, respectively). The higher dispersion and reduced correlation is expected at very low gas prices because the variable cost of CCGT generation may become comparable to or lower than coal generation, resulting in coal and gas units switching places in the supply stack.[34] This analysis supports the idea of using a single PLEXOS run between $3.9/MMBtu and $9.2/MMBtu for all natural gas prices within this range, which leads to a huge reduction in the number of required runs. Broader examination of the impact of alternative

[34]In 2012, natural gas prices fell below $4/MMBtu, enabling a significant amount of natural gas to displace coal, although this trend is expected to reverse in 2013 as natural gas prices recover from these extreme lows and move closer to the forward price of $5–$6/MMBtu.

dispatch assumptions (Table 3) allowed us to use only five separate PLEXOS runs for each MC simulation of natural gas prices.

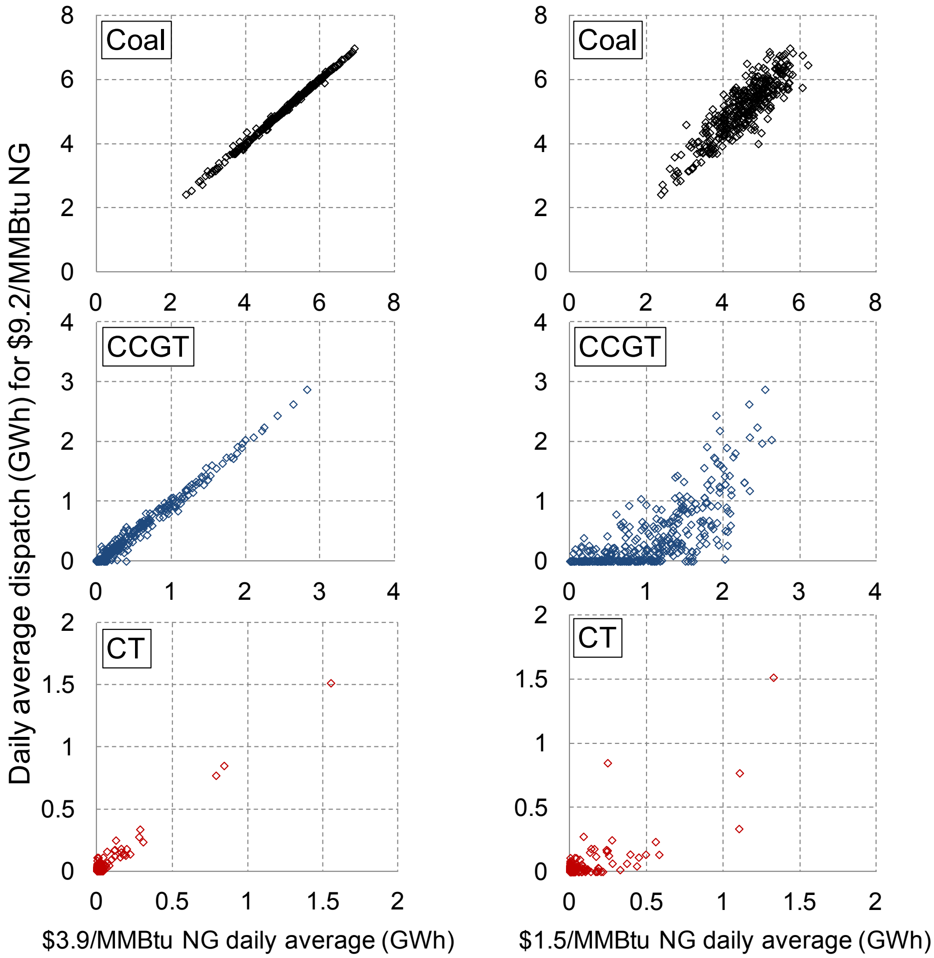

Figure 16. Comparison of daily average dispatch for coal, CCGT, and CT technologies for different pairs of natural gas prices in RMPP (isolated)

Table 3 shows the annualized variable cost of electricity for a range of natural gas prices ($1.5–$9.2/MMBtu) calculated using three dispatch strategies:

1) Without any approximation using the optimal dispatch solved for in the hourly production cost model for each of the five natural gas price scenarios
2) An approximation that uses the optimal dispatch for $1.5/MMBtu for all five gas price scenarios
3) An approximation that uses the optimal dispatch for $9.2/MMBtu for the five gas price scenarios.

We find that the use of a single optimal hourly dispatch solution calculated for $9.2/MMBtu natural gas can be used to estimate annual variable electricity prices to within 0.4% accuracy for natural gas prices (down to $2.2/MMBtu) and within 1.3% accuracy for natural gas prices (down to $1.5/MMBtu). The optimal dispatch solution calculated for $1.5/MMBtu is less accurate for representing variable electricity prices for higher natural gas prices; this is likely because, at very low natural gas prices, the variable cost of CCGTs can be lower than that of coal generators, but this dispatch order does not hold for higher natural gas prices (e.g., \$3.9/MMBtu and above). In general, the optimal dispatch solutions for the five natural gas prices shown in Table 3 can represent optimal dispatch for natural gas prices between those in the table (by interpolation) and beyond the upper and lower bounds of prices in the table (by extrapolation).

Table 3. Impact of Alternative Dispatch Assumptions on the Annualized Cost of Electricity

	Annual Variable Electricity Prices (\$/MWh)			Error	
Natural Gas Price (\$/MMBtu)	Optimal dispatch	Dispatch using \$1.5/MMBtu	Dispatch using \$9.2/MMBtu	in \$1.5/MMBtu dispatch	in \$9.2/MMBtu dispatch
1.5	14.49	14.49	14.68	0.0%	1.3%
2.2	15.75	15.96	15.82	1.3%	0.4%
3.9	18.53	19.55	18.61	5.5%	0.4%
6	22.08	24.07	22.12	9.0%	0.2%
9.2	27.49	30.97	27.49	12.7%	0.0%

Our finding—that the optimal dispatch solutions generated using the hourly production cost model PLEXOS are relatively stable (less than 1.5% error in impact on annualized costs) over a wide range of natural gas prices—allows us to use only a limited number of PLEXOS runs for each scenario and to run most MC simulations outside the model.[35]

4.2 Annualized Electricity Cost Distribution

Figure 17 shows the distributions of annualized variable electricity cost (\$/MWh) generated using MC simulations of natural gas prices under different RE penetration levels for the 50:50 solar-wind reference case. The results are similar in many ways to those shown for the scenario analysis in Figure 7 and discussed in Section 3. As RE penetration increases, the annualized variable system cost and the variance of this system cost decrease. These cost-probability distributions show the positively skewed asymmetric nature of the outcomes; the most likely outcome is often significantly below the mean (or expected value). This means that, while the upside risk (of lower costs) is largely capped, the downside risk (of higher costs) is not. This may be particularly important given the current low natural gas prices (Bolinger 2013).[36]

For comparison, the natural gas input price distribution is also shown (in common \$/MWh units). The "width" of outcomes for natural gas prices is much greater than the variation in the system costs--even in the low RE penetration case. This reflects the fact that the system has much more coal thermal generation than natural gas CCGT, which will tend to be dispatched before natural gas. Table 4 shows some of the characteristics of the distributions. As the renewable energy penetration increases both the standard deviation (srdev) and coefficient of variation (coefvar) in electricity costs declines. This also leads to a significant reduction in the difference between the mean and the 95th percentile electricity costs. The distributions are all positively skewed with

[35] These findings may, to some degree, be region dependent. To some extent, these finding may be dependent on the low cost for coal energy in the region used in this study. At higher coal prices, the natural gas price at which the order of the supply curve starts to change may be significantly higher than found in this study.

[36] In many ways, there is a much greater chance of upward rather than downward movement, although some of this is already reflected in the forward price being \$1–\$2/MMBtu higher than the recent spot price, which has fallen below \$4/MMBtu.

some variation with RE penetration. The greatest variation, seen in the 10% RE scenario, between the 95th and mean electricity prices remains under $5/MWh. However, this variation would be higher in portfolios with greater fractions of natural gas generation. [37] The difference may also be greater in the future years because regime changes – of unknown timing or impact - in supply or demand or both could lead to much higher or much lower expected natural gas (and hence electricity cost) trajectory than is reflected by using the mean of the historical distribution. More generally, production models such as PLEXOS tend to underestimate price volatility that arises due to scarcity especially in restructured markets.

Figure 17 shows the uncertainty in variable system costs over a single year. Over a longer timeframe (e.g., 20 or 30 years), the distribution for the average annualized cost of electricity over the longer period will tend to be lower than for any given year, since lower cost "good years" will tend to offset higher cost "bad years." This reduced variability may be mitigated to the degree that the future mean of natural gas price "moves" due to regime changing events and one ends up on a lower or higher price path for a sustained period.[38] RE can provide insurance against future outcomes in the United States where supply and demand tighten and natural gas prices rise.

The uncertainty in the variable cost of generation in any given year will be somewhat greater than suggested in Figure 17 because of the inter-annual variability of solar and wind generation. Drury et al. (2013) found that simulated annual PV generation can naturally vary by up to ±15% from mean performance in any given year, with annual PV standard deviations ranging from ±3% to ±7% depending on location. However, this year-to-year solar variability is likely to be smoothed over longer timeframes, and 20-year samples of inter-annual PV variation were found to be reduced by more than 80% relative to annual variability, leading to a 20-year standard deviation of about ±2%. Similar inter-annual variability of wind generation is also likely to occur. One recent study on the inter-annual variability of wind at U.S. wind farms over a 7- to 10-year period found annual variations of up to ±15%–20% and standard deviations of ±8%–13% (Wan 2012), although this variation may be significantly reduced when aggregated over a large number of wind farms. The plus or minus variation in RE generation in any given year compared to the "average" means that years of lower wind, which are less well hedged, will tend to be compensated largely by years in which the hedge is better than average.[39]

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[37] By way of illustration, for a system with 100% natural gas CCGT and a conversion efficiency of 50%, the variable cost distribution at low RE would be about double the "width" of the natural gas distribution in Figure 17 (natural gas prices of $10 and $30/MWh would translate to variable costs of $20 and $60/MWh, or more).

[38] Two important caveats apply to this idea. First, the mean-reverting nature of the distribution implies that the price in any given year is dependent on prior years' values, and as a result over longer periods will tend to oscillate around the mean. In the real world the expected mean of the future natural gas prices has changed a number of times in the past, most recently with lower prices due to the availability of shale gas. In other words, the mean in non-stationary over time and changes to the mean going forward are also possible, and so 20 years out in the future the customer may actually be on the lower side or the upper side of the annual price distribution. It should also be emphasized that the customer will not experience the entire probability distribution (as a series of "trials"). Rather, a customer will experience 20 observations from the single year distribution over 20 year period and only one from the 20-year average distribution (see also Stirling 1994).

[39] The impact of inter-annual variability of solar and wind is one of the focuses of our ongoing work. Unlike the natural gas price mean, the solar and wind means may be more stable and less dependent on prior years, though climate change may lead to shifts over longer periods.

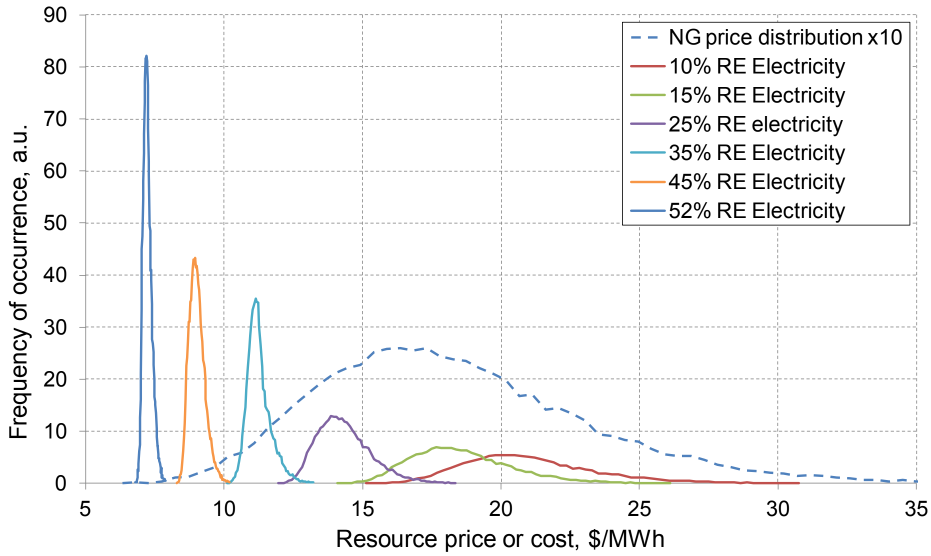

Figure 17. Annualized variable electricity system costs for different RE penetrations based on MC simulations using underlying natural gas price distribution in RMPP (isolated)

Table 4. Characteristics of the Natural Gas Price and Variable Electricity Cost Distributions

	NG	RE 10%	RE 15%	RE 25%	RE 35%	RE 45%	RE 52%
Mean	5.30	20.90	18.49	14.29	11.23	9.01	7.23
Stdev	1.43	2.36	1.84	0.98	0.43	0.29	0.16
95h percentile - mean	2.61	4.35	3.37	1.80	0.82	0.53	0.30
CoefVar	0.27	0.11	0.10	0.07	0.04	0.03	0.02
skewness	0.38	0.39	0.37	0.37	0.49	0.34	0.39

5 The Potential Use and Value of Solar and Wind as a Physical Hedge against Cost Risk

The prior sections analyzed how increased RE penetration reduces the uncertainty of future electricity system costs—and how solar and wind together may provide a more stable hedge than either one alone. To understand the potential basis for the incremental value and cost effectiveness of RE as a partial physical hedge against price volatility, it is useful to consider the following:

- How to estimate the incremental value of RE to consumers in reducing their price exposure and how this marginal value varies with increasing penetration (e.g., due to saturation effects as more of the natural gas generation is displaced)
- Whether buyers interested in reducing their exposure to future price risk actually need to pay for such a hedging benefit or if they may find cheaper methods to replicate this effect, at least over some timescales at some locations.[40]

There are also some broader diversity-related security and other macroeconomic-related benefits of including RE within the generation portfolio. This includes the potential benefits from not relying on too few technologies and/or fuel sources. This issue is discussed in more detail in the concluding subsection 5.2.

5.1 Economic Utility of Risk and Loss Aversion for Consumers

If consumers are risk averse, then the real cost or economic utility (or disutility since it reflects a loss) paid for by the consumer depends not only on the expected annualized cost, but also on the uncertainty of annualized future costs. This loss in economic utility (U) can be represented by:

$$U[V] = \mathrm{E}[V] - \frac{\lambda}{2}\mathrm{Var}[V]$$

where V represents the annualized variable cost of electricity. The reduction in utility to the consumer has two terms: the expected cost or $\mathrm{E}[V]$ (which will be negative for a payment by the consumer) together with a second negative term that increases with the uncertainty of these costs (as measured by the variance of the distribution). In practice, the overall loss in utility is, of course, at least offset by the benefits provided to the consumer through the purchase and use of the electricity. The λ (lambda) term reflects the level of risk aversion so that, in the limiting case where the consumer is risk neutral (and $\lambda = 0$), the utility is simply equal to the expected cost (the flat line in 18). For a given level of risk aversion, the larger the variance of the distribution, the greater the reduction in utility. This utility-based approach enables quantification of the impact of increasing RE penetration, as discussed by Awerbuch (Awerbuch 2006), and others, and is similar to ideas that have been proposed for integrated resource planning (Logan et al. 1994). Figure 18 also shows how, for a given level of risk aversion, the marginal increase in utility declines with penetration, which is consistent with the saturation effects described in Section 3.

[40] This is a little misleading in the sense that our paper focuses on the incremental value associated with adding RE to a system, and we have not dealt with the broader economic question about the optimal amount of RE to be added to a system when all relevant costs and benefits are considered.

Another potential concern for consumers is that bad outcomes (which in this case would correspond to higher-than-expected costs) might be weighted more than "equivalent" benefits (or gains) associated with similar reductions in costs from the expected value. This phenomenon is known as "loss aversion" and has been the subject of considerable investigation in the field of behavioral economics (see, e.g., Kahneman and Tversky 1979). The loss aversion term modifies the utility function to consumers to include a downside risk measure (DSM) to become:[41]

$$U[V] = \mathrm{E}[V] - \frac{\lambda}{2}\mathrm{Var}[V] - \mathrm{DSM}[V]$$

where $\mathrm{DSM}[V]$ corresponds to the DSM

$$\mathrm{DSM}[V] = \int_0^{\infty} [\theta_+(V - \mathrm{E}[V])_+ - \theta_-(V - \mathrm{E}[V])_-]\mathrm{dV}$$

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

The value of the DSM term is obtained by integrating the product of the probability density function by the difference in the variable term, *V*, 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. Unlike risk aversion, which treats variations about the expected value symmetrically, with loss aversion the value of DSM 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).[42] The origin of loss aversion to input prices can be quite rational if wide swings in natural gas prices affect a firm profits asymmetrically. In such cases, hedging can generate economic value even if the cost of natural gas with and without the hedge is unchanged on an expected basis. This methodology may also provide some justification to those who view one reason for investing in RE as a way of providing some degree of insurance against future cost increases that might arise from changes in natural gas prices or the imposition of a carbon tax.

Figure 18 shows the gain in utility as a function of RE penetration under different assumptions of risk and loss aversion for the 50:50 solar-wind reference case discussed in Section 4. The figure shows that the marginal value of more RE in reducing price exposure declines rapidly, reflecting the displacement of existing gas generation assets. The value to specific customers or society more generally, which depends on assumptions about their level of risk and loss aversion, ranges from nearly $10/MWh down to zero in our illustrative example. In a natural gas-dominated fossil mix (as opposed to coal-dominated), the expected benefits of variance reduction in consumer costs would increase with the proportion of natural gas generation in the mix. As discussed earlier, if the mean remains stable over long time periods there may be a significant reduction in uncertainty over a multi-decade horizon. However, in practice structural changes have occurred

[41] This approach to estimating the utility-based cost to consumers for electricity was outlined in Bush et al. (2012) and is similar to an approach for valuing portfolios of financial instruments suggested by Jarrow and Zhao (2006).
[42] Loss aversion is not necessarily fixed and, for an individual, will depend on how losses or gains affect his or her existing wealth (or some other reference point).

in the past that have led to significant changes in natural gas prices, most recently associated with the discovery of increased shale gas resources. RE can provide insurance to mitigate the impact of future scenarios where structural changes lead the production cost of natural gas to rise significantly to meet supply.

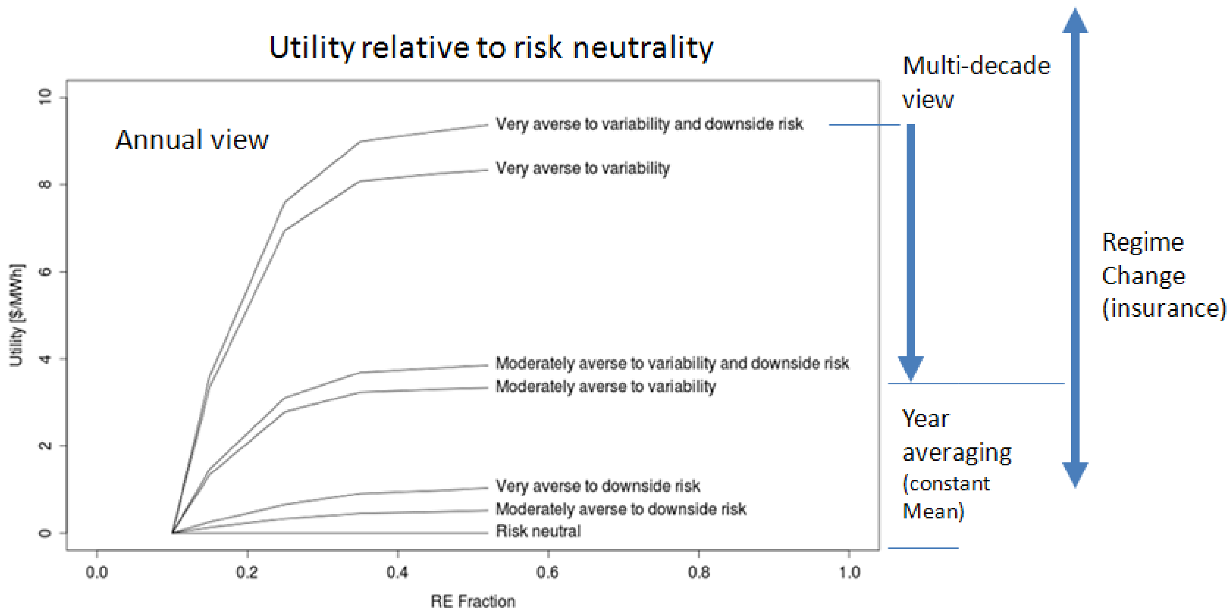

Figure 18. Utilities of various RE mixes for different attitudes towards risk and impact of time horizon (illustrative)

While investors, such as electricity producers, are generally considered risk averse, the degree to which their customers are risk averse appears to be less certain. Customers who are also investors can be generally expected to be risk averse. For example, a merchant CCGT plant is an investor because it sells power but also a customer because it buys natural gas as an input, the price of which can have a substantial impact on the profitability of the plant, business, as well as industry more generally.[43] Similar considerations might apply to many other companies for which the cost of fuel or electricity is a significant input to the cost of goods or services sold, such as aluminum smelters, data centers, or airlines. On a smaller scale, many owners who install PV systems may do so at least in part to protect themselves against future electricity price increases. On the other hand, being locked into fixed prices for long periods can also bring business risks if market prices change significantly, and many industries that hedge (e.g., airlines or biofuel manufacturers) tend to do so over shorter time horizons.[44]

More generally, the acceptable level of electricity cost-cost risk and loss aversion applicable for a particular customer, firm, or investor will depend on many factors, including their overall exposure to other risks, the structure and degree of integration of the firm (e.g.,

[43] For a discussion of how a combination of events led to the collapse of the merchant natural gas industry in the early 2000s, see Rigby (2004).
[44] In this way, these companies are hedged against changes in relatively short-term, multi-year situations, but not with long-term prices, since, when the time comes to periodically renew a multi-year hedge, the new forward price will reflect current market conditions and may be substantially different from the original hedge price. On the other hand, this may have some advantages in keeping costs in line with the market.

horizontal/vertical integration, geographic diversity), opportunities for risk pooling and inter-temporal cross subsidies, cash-flow considerations, business models, timeframes considered (20 years, 1 year, seasonal, or weekly), as well as the possible availability, cost, and effectiveness of alternative hedging opportunities provided by financial or physical supply instruments.

5.2 The Cost of Hedging and Alternative Methods

The value of a particular investment must be compared with the value of the next best alternative, not with the status quo of doing nothing. For this reason, the incremental economic value of displacing an old thermal coal plant with wind should be compared to the best alternative investment, which might be a natural gas CCGT. Similarly, at least for short to moderate timescales (1–10 years), utilities might hedge against price volatility at very low cost using financial instruments (such as forward contracts and swaps), other long-term contracts on natural gas, or forward electricity contracts.[45] In other words, there may be cheaper and better methods to replicate the hedging impact of RE by using financial or physical supply instruments (Graves and Livinova 2009).[46] In the longer term, however, solar and wind may be able to provide a physical hedge that is not easily replicated in the financial or physical supply markets because of lack of availability, liquidity, and counterparty risk (Bolinger 2013; Graves and Litvinova 2009). It is worth noting, however, that the periodic (or rolling) renewal of shorter term hedges of few years provides protection against local market conditions, rather than the longer term price changes that RE could mitigate.[47]

In the short to moderate term, the cost effectiveness of using various types of financial or physical supply instruments will depend on a number of interrelated factors including: 1) whether or not the forward price includes a risk or other forward “premium” over the expected future price of the commodity; 2) the timeframe over which such instruments or contracts are available and their liquidity at different locations; 3) their effectiveness as a hedge for power (rather than just natural gas) prices, including delivery considerations; and 4) other risks such as counterparty risk.

<u>Origin of the forward price premium?</u> Whether or not the forward prices for natural gas or electric power have positive or negative premiums over the expected future prices is somewhat controversial and may depend on a number of factors, including those listed above (Bolinger and Wiser 2008; Borenstein et al. 2007; Bolinger 2013). In terms of a potential risk premium, if the buyers of natural gas (or electricity) are more risk averse than the sellers, they may be “more willing” to pay a premium for a fixed price over the expected future price (compared to the seller being willing to sell at a discount for a fixed price), in which case the net risk premium may be positive. On the other hand, if the sellers are more risk averse than the buyers, the forward premium may be negative. If the buyers and sellers are both equally risk averse, then there may be no risk premium. In this case, while the risk premium may have been competed away, both parties still find the fixed-price contract valuable (and gain utility from it). Whether or not there

[45] This view typically assumes there is no risk premium in the forward price over the future expected price.

[46] This is a little more nuanced than it sounds because our paper discusses incremental benefits of RE, so there are no additional costs involved. Whether the RE hedge is more or less effective than the use of financial contracts is a somewhat different question.

[47] And that of course may be an appropriate risk mitigation strategy for many businesses where mitigating cost swings with respect to near term market conditions to their goal.

is a positive or negative premium due to risk or other factors does not appear to have a single definitive answer.

Is there a premium over the expert future price due to risk aversion or other factors? Bolinger and Wiser (2008) compared natural gas price forecasts to the prices of various futures contracts for natural gas over a 5- to 10-year period and suggested there may be a positive premium ranging from \$0.5–\$2.4/MMBtu, equivalent to \$4–\$17/MWh assuming a highly efficient gas-fired plant. Borenstein et al. (2007) support the idea of a positive forward premium for natural gas in at least some U.S. locations, but they argue this is due to lack of liquidity in delivered natural gas rather than "traditional" risk aversion.[48] On the other hand studies have suggested the U.S. forward premium for natural gas may be zero or even negative (Modjtahedi and Movassagh 2005). Graves and Levine (2010) note that the shape of the distribution matters and the expected future price of natural gas could be greater than the most likely observed future price (that is, have a "positive difference" of sorts) without implying any risk (or other meaningful) premium. Rather, this positive difference would reflect the fact that price distribution is positively skewed and so the mean value of the distribution (the expected value) will be greater and lie to the right of the peak of the distribution (which corresponds to the most likely value).

Recent work also suggests that there may be a premium for electricity forward prices (Redl and Bunn 2011; DeBenedictis et al. 2011). Redl and Bunn (2011) listed a number of factors that may lead to positive premiums for fixed electricity prices, including natural gas price forward premiums, price volatility, reserve margins, scarcity, and skewedness of the distribution and market power.[49]

How effective are financial instruments? The effectiveness of using forward contracts for natural gas or power as a hedge against price exposure is also relevant. A natural gas futures or forward contract is an indirect hedge on one of the main drivers of power prices, but it is not a perfect hedge because the price of power for the system also depends on other factors (such as the cost of other fuels [including coal], the timeframe over which the futures contract is available, and market structure). In addition, for utilities that generate a large of amount of their electricity using natural gas, it is not enough to purchase the natural gas; the gas also must be delivered, and there may be significant risk or costs associated with ensuring delivery, particularly at periods of high demand when the system may be stressed.[50] Figure 19 shows the impact of pipeline transmission constraints in the Northeast (from the South and West) coupled with bad weather (and future expectations of such weather). These factors led both spot and near-term forward natural gas prices to effectively disconnect from the "shale driven" prices of less than \$4/MMBtu

[48] For our purposes, the value of RE does not depend on the source.

[49] DeBenedictis et al. (2011) estimated an average 5% risk premium in the electricity forward price for delivery in the Mid-Columbia hub in the Pacific Northwest—although the monthly value varied widely, including changing its sign. Some of the difficulty in knowing the sign or magnitude of a risk premium, or perhaps reflecting difficulties in estimating it, is that this 5% premium was an average over 12 months, whereas the estimated monthly risk premium varied from less than -5% to more than 20%.

[50] Take, for example, the case of a peaking unit that is rarely run but needs to run when the system is stressed. To ensure that gas is available, such a unit would need to purchase fixed transmission capacity, which introduces a considerable cost if the unit is rarely run. Alternatively, there is real risk under interruptible transmission that it will not be able to run when most needed.

seen around much of the rest of the United States while also inducing significant price volatility (from $4 to more than $12/MMBtu near Boston).[51]

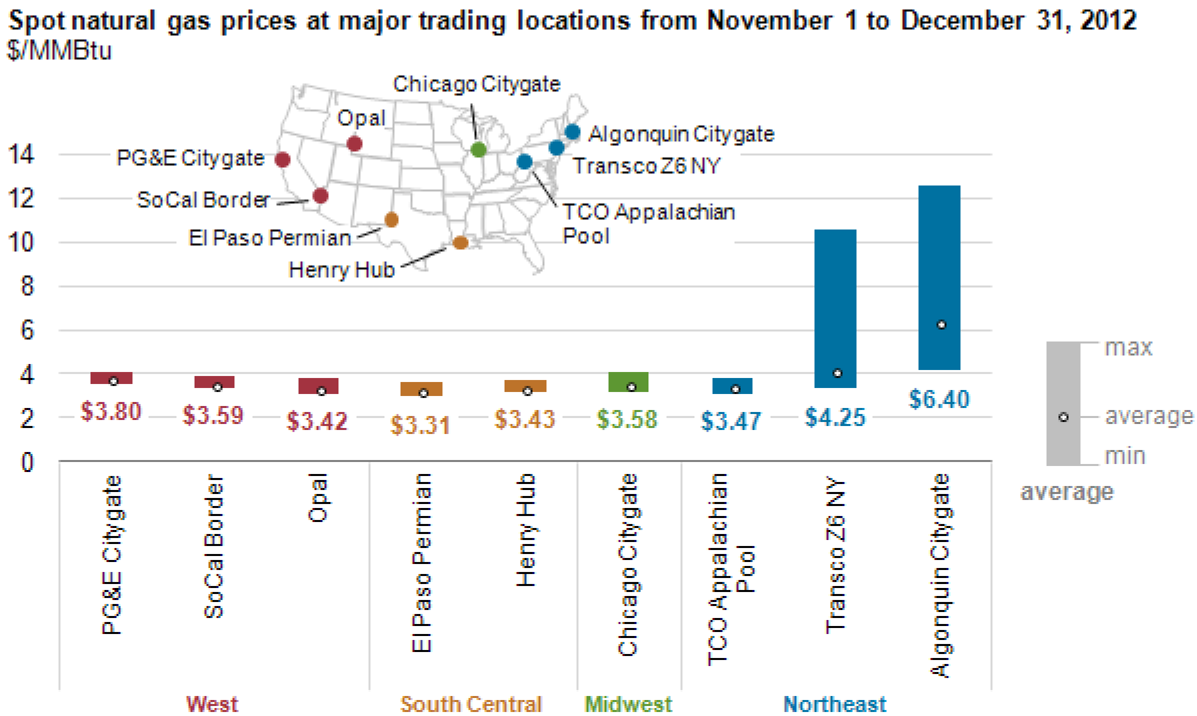

Figure 19. Premium for natural gas spot prices in the Northeast compared to other locations during winter 2012/13 (EIA 2013a)

Hedging using electricity forward prices is more direct, although again the effect of these instruments may still be approximate because they may only be available at limited locations with limited resolution for limited time horizons that only approximately reflect the more granular hourly price profile characteristic of electricity. In addition, many of the potential issues associated with the use of natural gas forward contracts, including both liquidity and counterparty risk issues, may have a significant influence on the electricity forward price (Redl and Bunn 2011).

On the question of whether forward premiums for natural gas or electricity are positive, zero, or negative, the answer may be “all of the above.” The existence of a forward premium (positive or negative) may vary by location, timescale, market structure, and weather. This area requires additional research, particularly focused on the actual behavior of buyers and sellers.

[51] At the end of December 2012, the natural gas future prices for delivery to Boston in January, February, and March were approximately $10, $8, and $6/MMBtu. During this time, the Henry Hub price (Louisiana) remained roughly flat at less than $4/MMBtu. The premium in Boston of $6/MMBtu for January fell to about $2/MMBtu for March. Over this same period, New York City had a smaller premium over the Henry Hub of about $2/MMBtu in January, with prices becoming comparable in March. Other factors contributing to this price increase were lower LNG imports and reduced production from the Canadian Sable field (EIA 2013a).

6 Summary and Conclusions

This study investigated the impact on the variable cost of generation of adding RE generation to fossil portfolios under a number of scenarios. For the reference (50:50 solar-wind) case, we varied the annual RE generation from about 10% to over 50%, with solar and wind contributing equally to generation on an annual basis. We then explored the impact of altering the annual solar-to-wind generation ratio to 3:1 and 1:3. The impact of changing the ratio of natural gas to coal generation was also considered by switching out coal thermal generation units with CCGTs in some scenarios. Some market structure issues were also considered. Some key observations are outlined below

Solar and wind generation significantly reduces the exposure of electricity costs to natural gas price uncertainty in fossil-based generation portfolios on a multi-year to multi-decade time horizon. The incremental impact, and any associated marginal value of RE in decreasing electricity-cost volatility, declines with increasing RE penetration. The reduction in volatility of electricity costs with increased RE penetration is greater for natural gas-dominated portfolios than for coal-dominated portfolios.

At low RE penetrations (e.g., 10%–15% annual RE generation), the annualized variable system costs vary widely with the price of natural gas in both our coal-dominated and natural gas-dominated fossil portfolios. For similar RE penetration (15%) in the gas-dominated portfolio in the region studied a $5/MMBtu variation in natural gas prices changes the variable cost of electricity by about $35/MWh in the gas-dominant portfolio--a more than three-fold difference compared to the coal-dominant portfolio.[52]

In the coal-dominated fossil portfolio, the incremental impact of further solar and wind penetration decreases with increasing RE penetration, with only small incremental benefits being achievable beyond 35% penetration. In contrast in the natural gas-dominated portfolio, the saturation effect in electricity cost variance reduction is not observed even at higher RE penetration levels (of over 40%) because a large amount of natural gas generation remains to be displaced.

In the region studied, a mix of wind and solar provides a better physical hedge against uncertain fuel prices than either wind or solar alone, because of the observed anti-correlation in solar and wind generation profiles at time scales ranging from intra-day to seasons.

Market structure choices are important. Adding RE reduces uncertainty in cost to consumers[53] much more in restructured markets than in regulated markets since natural gas often sets the marginal price in a given hour in restructured markets (particularly during higher-priced peak periods), and this price is then paid to all generators dispatched.

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[52] The relative ratio of price variation depends not only on the ratio of coal thermal to natural gas plants but also on the cost of coal. Coal prices vary significantly by location and the cost of coal per MMBtu for CO and used in the study is amongst the lowest in the United States.

[53] Bilateral contracts within a restructured market, which are common for solar and wind, may mitigate this leverage and have an asymmetrical effect on consumers. This and other market structure-related issues are a focus of our follow-on research.

MC analysis of the impact of natural gas price variations over multi-decade time horizons complements scenario analysis by generating electricity cost distributions that show the "density" of outcomes and how the electricity distribution is positively skewed. We find that much of the MC analysis of natural gas price uncertainty impacts can be done outside of the production cost model by recognizing the stability of the simulated hourly system dispatch for a wide range of natural gas prices. This greatly enhances our ability to perform many simulations, which otherwise would be limited by model run times.[54]

The potential benefits of diversified portfolios containing significant solar and wind generation will depend on two main factors. One factor is how much consumers value lower price uncertainty due to risk aversion, loss aversion, scarcity, or other characteristics. The second factor is the potential cost and effectiveness of alternative financial or physical hedging methods, such as forward contracts, swaps, or physical supply contracts, and the timeframe over which these are available; this includes the degree to which price uncertainty risks are mitigated and the extent to which new risks may be introduced (e.g., associated with natural gas transportation constraints, counterparty risks, market liquidity, and others).

The cost of using financial instruments to hedge against future price uncertainty depends in part on whether long-term forward contracts (for natural gas or electricity) contain a premium over expected future prices. Electricity sellers and buyers may both be risk averse, and there is no consensus about the net impact this has on the existence of a forward premium for eliminating price volatility in the United States. Some studies suggest that, at least in the short term, it may be more cost effective to use financial hedging instruments; these often assume (either implicitly or explicitly) that there is no risk aversion or other premium in the forward price over the expected futures price. On the other hand some studies have suggested there may a positive premium over the expected future price due to risk aversion (Bolinger et al. 2002) or due to scarcity or other factors (Borenstein et al. 2007), while others suggest a negative premium (Modjtahedi and Movassagh 2005). The answer may be "all of the above", with the existence and magnitude of a premium (positive or negative) likely to vary with location, commodity, and timescale, while changing over time.

Of particular relevance to RE, it is difficult and rare to be able to lock in financial or physical supply contracts of 10 years or more for natural gas, and such contracts may include premiums that reflect lack of liquidity and counterparty risk (Bolinger 2013).[55] Because of these and other issues, in the longer term solar and wind may be able provide a physical hedge that is not easily replicated in the financial and physical commodity markets.[56] It also provides insurance value against rising electricity prices in futures where natural gas prices rise or carbon emissions are priced via a tax or some other mechanism. Even in the shorter term, RE may be the better choice

[54] This range of stability of dispatch is partly due to the low coal prices found in the region studied (on a $/MMBtu basis), and so the effect is likely to be less pronounced in many other regions of the United States.

[55] "Passive" hedging with RE could also provide benefits by affecting a wide range of buyers in a similar manner. This may be helpful because many firms have trouble knowing how to hedge appropriately (possibly overreacting to a crisis and locking in high prices), and this can bring business risks. Alternatively, a firm could hedge in a smart way—while many of its competitors do not—and get "unlucky" if, for example, the prices of inputs fall sharply for the industry. Passive or natural hedging with RE may provide a "cushioning" effect to these types of business risk.

[56] The use of rolling, short-term hedging over longer time horizons provides a hedge against evolving market conditions and prices. It does not provide a long-term hedge against future price changes (as might a natural hedge due to RE).

for some consumers. While most of this report deals with the system wide effect to the average consumer at a multi-utility level, the preference for cost mitigation and over what timeframes may vary widely by customer type. Size also matters where some residential and commercial customers may be more likely to decide to install distributed RE if their ability to hedge using financial or physical instruments is limited by a lack of knowledge, high transaction costs, or a lack of availability of such instruments.

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