LBNL-53587

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

# Accounting for Fuel Price Risk:

## Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation

# Executive Summary

Mark Bolinger, Ryan Wiser, and William Golove

Lawrence Berkeley National Laboratory
1 Cyclotron Rd., MS 90-4000
Berkeley, California 94720

Environmental Energy
Technologies Division

August 2003



The work described in this study was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-ACO3-76SF00098.

## Acknowledgements

Work reported here was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy of the U.S. Department of Energy under Contract No. DE-ACO3-76SF00098. The support and encouragement of Susan Holte and Jack Cadogan of the U.S. Department of Energy is particularly acknowledged.

This report has benefited from the comments of Philip Budzik and Joseph Benneche (Energy Information Administration), James Read and Richard Goldberg (The Brattle Group), Brandon Owens (Platts Research & Consulting), and James Jensen (Jensen Associates). In addition, the following individuals commented on earlier incarnations of this work (prepared for the proceedings of *WINDPOWER 2002* and *ACEEE 2002 Summer Study on Energy Efficiency in Buildings)*: Shimon Awerbuch (SPRU, University of Sussex), Jack Cadogan (DOE), Devra Bachrach (NRDC), Frank Felder (Independent Consultant), Bob Grace (Sustainable Energy Advantage), Tom Hoff (Clean Power Research), Susan Holte (DOE), Mark Litterman (Portland General Electric), Amory Lovins (Rocky Mountain Institute), Elliot Mainzer (Bonneville Power Administration), Ross Miller (California Energy Commission), Kevin Porter (Exeter Associates, Inc.), Richard Price (Technology & Management Services, Inc.), and Osman Sezgen (Berkeley Lab). Finally, this work has also benefited from the comments of various conference attendees and seminar participants at *WINDPOWER 2002*, *ACEEE 2002 Summer Study on Energy Efficiency in Buildings*, *The University of California Energy Institute Seminar Series*, and the *NARUC 2003 Winter Committee Meetings*. Of course, any remaining omissions or inaccuracies are the authors' sole responsibility.

# Executive Summary

### *Introduction*

Against the backdrop of increasingly volatile natural gas prices, renewable energy resources, which by their nature are immune to natural gas fuel price risk, provide a real economic benefit. Unlike many contracts for natural gas-fired generation, renewable generation is typically sold under *fixed-price* contracts. Assuming that electricity consumers value long-term price stability, a utility or other retail electricity supplier that is looking to expand its resource portfolio (or a policymaker interested in evaluating different resource options) should therefore compare the cost of fixed-price renewable generation to the *hedged* or *guaranteed* cost of new natural gas-fired generation, rather than to *projected* costs based on *uncertain* gas price forecasts. To do otherwise would be to compare apples to oranges: by their nature, renewable resources carry no natural gas fuel price risk, and if the market values that attribute, then the most appropriate comparison is to the *hedged* cost of natural gas-fired generation.[1]

Nonetheless, utilities and others often compare the costs of renewable to gas-fired generation using as their fuel price input long-term gas price forecasts that are inherently uncertain, rather than long-term natural gas forward prices that can actually be locked in. This practice raises the critical question of how these two price streams compare. If they are similar, then one might conclude that forecast-based modeling and planning exercises are in fact approximating an apples-to-apples comparison, and no further consideration is necessary. If, however, natural gas forward prices systematically differ from price forecasts, then the use of such forecasts in planning and modeling exercises will yield results that are biased in favor of either renewable (if forwards < forecasts) or natural gas-fired generation (if forwards > forecasts).

In this report we compare the cost of hedging natural gas price risk through traditional gas-based hedging instruments (e.g., futures, swaps, and fixed-price physical supply contracts) to contemporaneous forecasts of spot natural gas prices, with the purpose of identifying any systematic differences between the two. Although our data set is quite limited, we find that over the past three years, forward gas prices for durations of 2-10 years have been considerably higher than most natural gas spot price forecasts, including the reference case forecasts developed by the Energy Information Administration (EIA).[2] This difference is striking, and implies that

[1] To the extent that it displaces gas-fired generation, development of new renewable generation may also *reduce* future gas prices to all sectors of the economy. Furthermore, long-term fixed-price renewable energy contracts may involve *less* credit risk than long-term fixed-price natural gas contracts (i.e., “conventional” hedges, such as gas forwards and swaps) of similar duration. Thus, separate from the “hedge value” of renewable energy discussed in this report, long-term fixed-price renewable energy contracts may provide incremental value over natural gas forward and swap contracts in the form of lower gas prices and reduced credit risk. These potential benefits – which are not included in our analysis – may become increasingly important over longer contract terms of 15-25 years.

[2] It deserves mention that reviewers of a draft of this report from the EIA have characterized their efforts as *projecting* natural gas *costs*, rather than *forecasting* natural gas *prices*. In other words, the EIA reference case assumes that weather and inventory patterns, as well as regulations – all of which can greatly impact market prices – remain “normal” (by historical standards) throughout the forecast period. In this sense, the EIA reference case “forecast” does not necessarily represent the *expected* or *most likely* future market price, and perhaps not even a market price at all. This subtle distinction is discussed in the full report; here we simply note that we use EIA

resource planning and modeling exercises based on these forecasts over the past three years have yielded results that are biased in favor of gas-fired generation (again, presuming that long-term price stability is desirable). As discussed later, these findings have important ramifications for resource planners, energy modelers, and policymakers.

***Natural Gas Prices Are Highly Variable***

For better or worse, natural gas has become the fuel of choice for new power plants being built across the United States. According to the EIA (2003), natural gas combined-cycle and combustion turbine power plants accounted for 96% (138 GW out of 144 GW total) of the total generating capacity added in the U.S. between 1999 and 2002. Looking ahead, gas-fired technology is expected to account for 80% of the 428 GW of new generating capacity projected to come on line through 2025, increasing the nationwide market share of gas-fired generation from 17% in 2001 to 29% in 2025 (EIA 2003).

With increasing competition for natural gas supplies, it is likely that gas prices will be as or more volatile than they have been in the past. Figure 1 shows first-nearby natural gas futures prices on a daily basis going back to the inception of trading on the New York Mercantile Exchange (NYMEX) in April 1990. While the "twin peaks" of December 2000 and February 2003 clearly dominate the graph and make the rest of the price history look comparatively tame, the reader should keep in mind that many of the "lesser" price spikes during the early 1990s represent doublings or more in price.

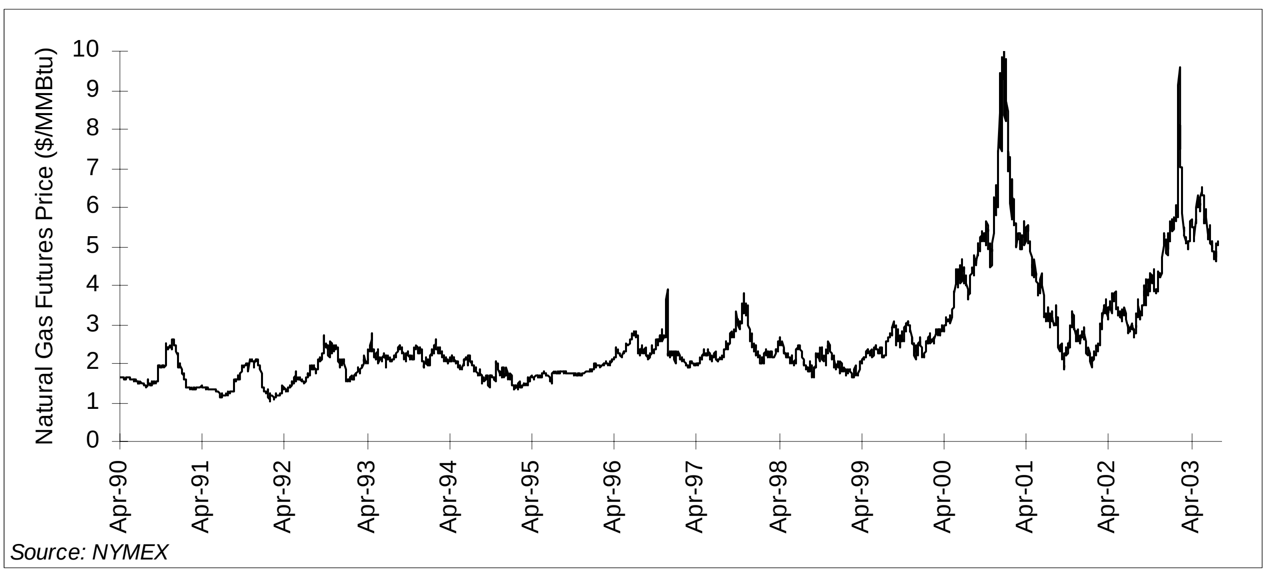


**Figure ES-1. NYMEX Natural Gas Futures Prices (First-Nearby Contract)**

As implied by Figure ES-1, not only have gas prices increased in recent years, but so has gas price volatility. Figure ES-2 shows the annualized 90-day standard deviation of daily percentage

reference case gas price forecasts because they are publicly available, have been widely vetted, and are commonly used by the EIA and others as a "base case" price scenario in policy evaluations and modeling exercises. As a control, we also look at other non-EIA gas price forecasts that may not suffer from this ambiguity.

changes in gas futures prices, along with its one-year (i.e., 252-day) moving average to smooth out seasonality. Though highly seasonal in nature, the general increase in volatility, particularly since 1996, is clear. Near-record-high volatility, combined with price levels that are more than double the historical average, mean that in absolute terms, an unprecedented number of dollars are now at risk.

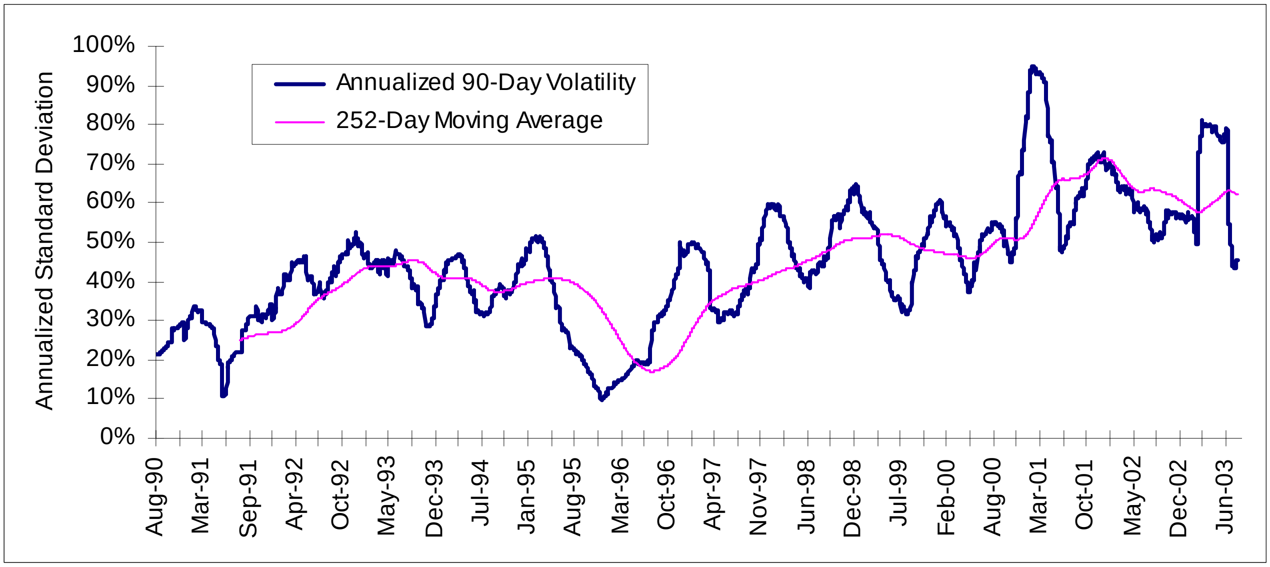


**Figure ES-2. Historical Volatility of Natural Gas Futures Prices (Continuous 1st Nearby)**

This is particularly noteworthy considering that gas price volatility, which has attracted a great deal of recent attention, is a major contributor to wholesale electricity price volatility. The cost of natural gas can account for *more than half* the levelized cost of energy from a new combined cycle gas turbine, and *more than 90%* of its operating costs (EIA 2001). Moreover, gas-fired plants are often the marginal units that set the market-clearing price for *all* generators in a competitive wholesale market, allowing natural gas price volatility to directly flow through to wholesale electricity price volatility.

Unless they are hedged, gas price increases can therefore directly impact competitive wholesale electricity prices, particularly if gas-fired units are on the margin. And with the market share of gas-fired generation projected to nearly double by 2025, the impact of gas price volatility on wholesale electricity price volatility is likely to increase as well. Clearly, the variability of gas prices poses a major risk to both buyers and sellers of gas-fired generation.

***Traditional Natural Gas Hedging Instruments Can Be Used to Mitigate Risk***

Renewable energy resources such as wind, geothermal, biomass, solar, and hydro power are often sold on a fixed-price basis, providing a hedge against volatile natural gas prices. Nonetheless, it is also true that natural gas price risk can be hedged through traditional gas-based hedging instruments. In order to achieve a fuel price risk profile similar to that of fixed-price renewable generation, either the buyer (under spot, indexed, and tolling electricity contracts) or seller (under fixed-price electricity contracts) of gas-fired generation must hedge away natural gas price risk.

Accordingly, to hedge natural gas price risk, a retail electricity supplier can either invest in renewable generation (which is immune to gas price risk), choose among a number of gas-based financial and physical hedging instruments, or purchase *fixed-price* gas-fired electricity (in which case the *generator* may wish to hedge using gas-based financial or physical instruments).[3] Financial gas-based hedges include futures (or, more generically, forwards), swaps, options on futures, or some combination or derivation thereof (e.g., collars). Physical hedges include long-term fixed-price gas supply contracts and natural gas storage.

As shown below in Figure ES-3, each of these hedging instruments falls into one of two categories: those creating a flat payout pattern that is immune to price movements in either direction (gas futures, swaps, and fixed-price physical supply, as well as fixed-price renewable generation), and those creating a contingent payout pattern that protects against adverse price movements while allowing participation in favorable price movements (gas options and storage). In other words, all of the hedging instruments under consideration can protect gas consumers against a gas price increase, but only options and storage allow the consumer to benefit from a gas price decrease as well.

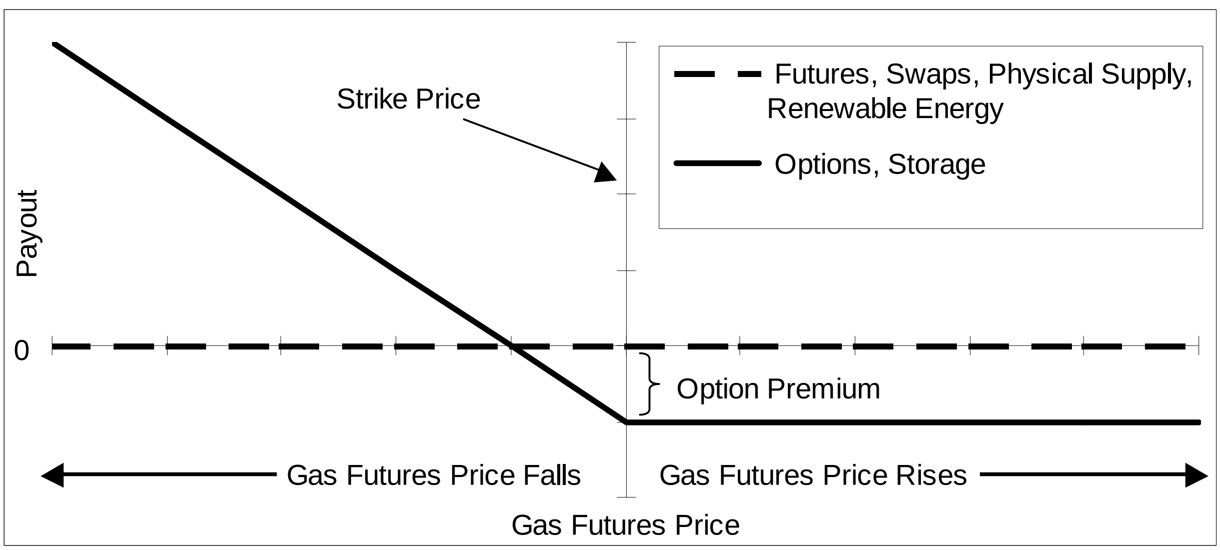


**Figure ES-3. Payout Patterns for Various Hedging Instruments (hedge plus underlying)**

To fairly evaluate fixed-price renewable and variable-price gas contracts on an apples-to-apples basis (presuming that long-term price stability is valued), we must look to those instruments that provide a hedged payout pattern similar to that of renewables – i.e., flat and symmetrical, immune to both gas price increases and decreases. As shown in Figure ES-3, such instruments

[3] Similarly, investments in energy efficiency (e.g., through demand-side management), or even coal or nuclear power (with fuel costs that are quite stable compared to natural gas), may provide an equivalent natural gas price hedge. Though not explicitly targeted as such, much of the discussion in this paper is also applicable to these other energy, or demand reduction, resources.

include gas futures, swaps, and fixed-price physical supply contracts, but not options or storage. The prices that can be locked in through these instruments are therefore the appropriate fuel price input to modeling and planning studies that compare – either explicitly or implicitly – renewable to gas-fired generation (again, presuming that long-term price stability is valued).

***Forward Gas Prices Have Traded at a Premium to EIA Reference Case Price Forecasts***

As has been noted, however, utilities and others conducting such studies tend to rely primarily on uncertain long-term forecasts of spot natural gas prices, rather than on prices that can be locked in through futures, swap, or fixed-price physical supply contracts (i.e., "forward prices"). This practice raises a critical question: how do the prices contained in uncertain long-term gas price forecasts compare to actual forward prices that can be locked in? If forward prices systematically differ from long-term price forecasts (e.g., if there is a cost to hedging, or if the forecasts are out of tune with market expectations), then the use of such forecasts in resource acquisition, planning, and modeling exercises will yield results that are biased (again, assuming that long-term price stability is desirable) in favor of either renewable (if forwards < forecasts) or natural gas-fired generation (if forwards > forecasts).

The data necessary to conduct this analysis are deceptively simple: a forward gas price and a gas price forecast, ideally generated at the same time. While long-term gas price forecasts are relatively easy to come by (e.g., the EIA forecasts are publicly available and updated every year), long-term forward prices – and in particular those of sufficient duration to be of interest, given the 15-25 years of relative price stability offered by most contracts for renewable generation – present a greater challenge. Despite our best efforts to obtain a larger sample, our analysis is limited to comparisons from the past three Novembers (November 2000-November 2002), and for terms not exceeding 10 years. Specifically, our limited sample of forward contracts and price forecasts includes:

- 2-, 5-, and 10-year natural gas swaps offered by Enron in November 2000 and 2001, compared to reference case natural gas price forecasts from the Energy Information Administration's (EIA) *Annual Energy Outlook 2001* and *2002*, respectively;
- the six-year NYMEX natural gas futures strip from November 2002, compared to the reference case gas price forecast contained in *Annual Energy Outlook 2003*, and;
- a seven-year physical gas supply contract between Williams and the California Department of Water Resources signed in November 2002, again compared to the reference case gas price forecast contained in *Annual Energy Outlook 2003*.

Each of these comparisons reveals that forward natural gas prices have traded above EIA reference case price forecasts during this three-year period, sometimes significantly so. Figure ES-4 consolidates the resulting premiums (in terms of \$/MMBtu and ¢/kWh, assuming a heat rate of 7,000 Btu/kWh) from each of these comparisons into a single graph.

As shown, the magnitude of the empirically derived premiums (i.e., relative to EIA reference case forecasts) varies from year to year, contract to contract, and by contract term, ranging from

$0.4-$0.8/MMBtu ($0.6/MMBtu on average), or 0.3-0.6¢/kWh (0.4¢/kWh on average).[4] One cannot easily extrapolate these findings beyond the last three Novembers, or to contract terms longer than those examined. Nonetheless, it is at least apparent that utilities and others who have conducted resource planning and modeling studies based on EIA reference case gas price forecasts over the past three years have produced "biased" results (i.e., presuming that long-term price stability is valued) that favor variable-price gas-fired over fixed-price renewable generation, potentially to the tune of ~0.3-0.6¢/kWh on a levelized basis.

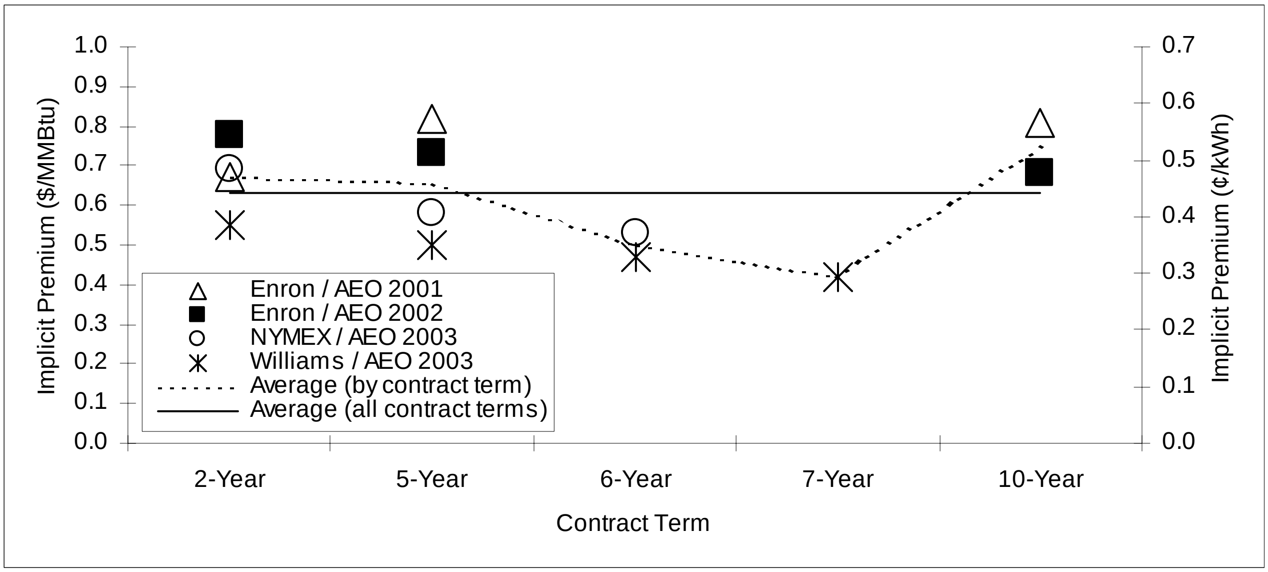


**Figure ES-4. Composite Premiums in $/MMBtu and ¢/kWh (assuming 7,000 Btu/kWh)**

***Many Other Gas Price Forecasts Have Been Even More "Biased" Over the Last Three Years***

Given that they are publicly available, highly documented, and widely reviewed and used (even by utilities) in modeling exercises and resource planning processes throughout the country, EIA reference case gas price forecasts are a reasonable starting point for our purposes. The EIA's forecasts, however, are by no means the only long-term gas price forecasts available to market participants. Among others, PIRA Energy Group, DRI-WEFA, and Energy and Environmental Analysis (EEA) all provide proprietary long-term gas price forecasts to utilities and others.

Obviously, unless these other forecasts are in close agreement with EIA reference case forecasts, the spread between them and forward gas prices will be different from that measured against EIA reference case forecasts. In order to assess how the premiums presented in Figure ES-4 would change had we compared forward prices to some forecast other than the EIA's, we looked at a number of different long-term gas price forecasts, sourced from the EIA's own forecast comparisons (contained in each year's *Annual Energy Outlook*), as well as from various utility integrated resource plans. With few exceptions, the EIA reference case forecast has generally

[4] We emphasize that these premiums are benchmarked against EIA reference case gas price forecasts, and that the magnitude – and perhaps even the sign – of the premiums will change if our sample of forward prices is compared to price forecasts that differ from the EIA reference case.

been higher – and often substantially so – than most other forecasts that have been used by utilities and others trying to predict gas prices over the last three years.

These findings suggest that the premiums observed relative to the EIA reference case forecasts would be *even larger* when comparing forward prices to some of the other commonly used gas price forecasts. For example, had we compared the November 2001 10-year natural gas swap to the gas price forecast contained in Idaho Power's resource plan, we would have observed a 10-year levelized premium of $1.29/MMBtu – i.e., *nearly twice as large* as the $0.68/MMBtu benchmarked against the EIA reference case forecast. This translates to a 0.9¢/kWh difference at an aggressive heat rate of 7,000 Btu/kWh; had Idaho Power opted to use forward market data rather than forecast data, comparisons between renewable and gas-fired generation may have looked significantly different. With most other forecast comparisons yielding similar results (though not as large in magnitude), it is clear that utilities and others that have used these other (i.e., non-EIA) forecasts to compare fixed-price renewable to variable-price gas-fired generation over the past three years have obtained results that are *even more* "biased" in favor of gas-fired generation than those resulting from EIA-based reference case comparisons (again, presuming that long-term price stability is desirable).

***Possible Explanations for the Empirical Premiums Between Forwards and Forecasts***

How can one explain the existence of price premiums as high as $0.8/MMBtu over 10 years relative to EIA reference case gas price forecasts, or *even higher* relative to other gas price forecasts? At least three different explanations could either partially or wholly account for such sizable differences between natural gas forwards and forecasts:

1) **Hedging is not costless.** If this is true, then one might expect forward natural gas prices to trade at a premium relative to industry-standard forecasts of future spot natural gas prices, with the premium representing the incremental cost of hedging. Such incremental costs could reflect the presence of a risk premium, caused either by *negative net hedging pressure* (i.e., gas consumers hedging more than gas producers) or *systematic risk in natural gas prices*, as measured by the Capital Asset Pricing Model (CAPM). Alternatively, the incremental cost of hedging could reflect high *transaction costs*, manifested in wide bid-offer spreads that ensure that the long (short) hedger always pays (receives) more (less) than the "true" (e.g., mid-market) price. Under this explanation (that hedging is not costless), the premiums presented in Figure ES-4 might be considered the "hedge value" of renewable generation; i.e., renewable generation provides price stability without incurring these "incremental" hedging costs.

2) **The forecasts are out of tune with market expectations.** Under this explanation, the gas price forecasts (not just the EIA's reference case, but instead virtually all of the forecasts we have examined) themselves are at issue, and are biased downwards relative to the market's expectations of future gas prices at least over the last three years. If this is true, then our empirical observations of premiums may not necessarily indicate that there is an incremental cost of hedging per se. In other words, forward prices may in fact be unbiased estimators of future spot prices, and the premiums we have observed may simply be due to the use of

forecasts that have been seriously out of tune with market expectations over the last three years. This, of course, calls into question the use of these forecasts for *any* purpose over the last three years, and strongly suggests replacing forecast prices with forward prices where available.

3) **Other data issues are driving the premium.** Two other data problems might also be of some concern. First, the forward prices we sampled might be distorted upwards (e.g., due to thin markets and/or price manipulation), which could artificially create or inflate a premium over price forecasts. Second, if we sampled forward prices earlier or later in time than when the forecasts were generated, then the observed premiums could simply be the result of a fundamental change in market expectations in the interim.

Each of these three potential explanations for the existence of empirical premiums is theoretically plausible, yet perhaps not fully satisfactory on its own; it is perhaps more likely that two or more of these (and maybe other) explanations working in combination are driving our empirical findings of a premium.

Regardless of the explanation for (or interpretation of) our empirical findings, however, the basic implications of our study remain the same: *one should not blindly rely on gas price forecasts when comparing fixed-price renewable to variable-price gas-fired generation contracts.* If there is a cost to hedging – whether related to net hedging pressure, CAPM, transaction costs, or some combination of the three – gas price forecasts do not capture and account for it. Alternatively, if the forecasts are at risk of being biased or out of tune with the market, then one certainly would not want to use them as the basis for investment decisions or resource comparisons if a better source of data (i.e., forwards) existed. Accordingly, assuming that long-term price stability is valued, in both cases the most comprehensive way to compare resource options would be to use forward natural gas price data as opposed to natural gas price forecasts. Over the last three years, at least, it appears as if the use of forward gas prices would have significantly shifted the balance away from natural gas and toward renewable energy, relative to forecast-based comparisons.

### *Implications for Resource Planners, Analysts, and Policymakers*

These findings have important implications for utility resource planners, energy modelers and analysts, and policymakers:

**Utility Resource Planners**
While our examination of utility integrated resource plans revealed that many utilities do in fact incorporate actual forward market prices (i.e., the price at which they could lock in gas prices) into their gas price forecasts, they typically do so for only the first few years of what are commonly 20-year forecasts. Since the value of price stability does not disappear after a few years, further action may be warranted.

Assuming that long-term price stability is valued, what steps can a utility or, more generally, anyone comparing fixed-price renewable to variable-price natural gas generation, take to move towards an apples-to-apples comparison? Because of the challenges in extrapolating our findings to other forecasts, hedge durations, and time periods, we *do not* recommend blindly adding \$0.4-\$0.8/MMBtu, or 0.3-0.6¢/kWh, to any forecast, for any duration. We emphasize that these premiums were derived relative to EIA reference case gas price forecasts over a limited three-year period that may or may not represent "normal" market conditions, and for contract terms ranging from 2-10 years. Any attempt to directly apply these particular premiums outside of these parameters may be questionable, especially if better data is available at the time.

Because of the difficulty in extrapolating our results to different circumstances, below we develop process recommendations for resource planners. At least three approaches are possible:

1) **Use and extend the forward curve for natural gas:** As noted earlier, utilities have already begun to incorporate gas forward prices into their gas-price forecasts. This is a good start, but many of these utilities only rely on a year or two of forward price data. Subject to data availability, utilities (or others making resource comparisons) could extend the period over which their resource plans (or comparisons) rely on actual forward market gas prices rather than uncertain price forecasts. Given the availability of NYMEX futures price data, extending the use of forward prices to at least 6 years would seem like a first step. Beyond 6 years, forward price data may be harder to come by. Where forward price data from actual contracts are not publicly available, utilities and others may have access to (or be in a position to solicit) data that are not in the public domain; broker quotes may also suffice as a way of extending the use of forward data to 10 or even 20 years.

2) **Place the onus on the generator:** Natural gas-fired generators may be willing to internalize any cost of hedging (or alternatively, take on fuel price risk) and offer a long-term fixed-price electricity contract, much like renewable energy typically provides. While fixed-price renewable energy may still have some incremental "hedge value" (from placing downward pressure on gas prices, and potentially mitigating credit risk), a fixed-price gas-fired electricity contract is otherwise comparable to fixed-price renewable energy, thereby obviating the need for a utility or regulator to collect forward gas price data for the purpose of substituting into a forecast. Along these lines, utilities could follow the example of Xcel Energy in Minnesota, which – as directed by the Minnesota PUC – has worked with stakeholders to develop a method for unbiased treatment of renewable generation in its bid evaluation process. Specifically, in all-source solicitations, Xcel requires "that bidders who submit fuel-indexed or tolled fuel pricing in a proposal must also submit an otherwise identical proposal that contains fixed fuel pricing for at least 10 years." (Xcel Energy 2001) Though obtained during the solicitation rather than the planning phase, this information, along with other provisions, enables Xcel to more closely approximate a true apples-to-apples comparison between renewable and other forms of generation.

3) **Adjust the forecast:** Finally, as a last resort, if forward market prices are not available over the entire planning horizon, and soliciting comparable fixed-price electricity bids from gas-fired generators is not realistic, utilities may wish to adjust forecasted gas prices upwards to account for the fact that forward prices have, potentially for reasons discussed above, traded above price forecasts over the past three years. While the analysis in this report suggests that

an adjustment ranging from \$0.4-\$0.8/MMBtu (0.3-0.6¢/kWh at a heat rate of 7,000 Btu/kWh) is a reasonable starting point, we emphasize that these premiums were calculated with respect to EIA reference case price forecasts over the past three years, for terms ranging from 2-10 years. If using a different base gas price forecast, a higher or lower adjustment may be warranted. Likewise, this historically derived premium may well vary in the future, and may vary with contract terms above 2-10 years. For these reasons, the two previous approaches are preferable to this one. That said, if the two previous approaches are not possible, this approach may still be better than simply relying on forecast data, which – at least over the last three years – has been shown to be significantly below forward prices.

**Energy Modelers and Analysts**

It remains to be seen which, if any, of the explanations for empirical premiums discussed in Chapter 6 are "correct," and the implications for energy modelers and analysts vary based on the explanation under consideration. If there truly is a cost to hedging natural gas price risk with traditional instruments, and renewable energy can mitigate fuel price risk at a cost that is lower than that incurred through those traditional hedging instruments (and the market recognizes this), then the supply of renewable generation may increase at faster rate than that estimated by current national energy forecasts, leaving forecasts of renewable generation biased downwards. If instead the premiums observed in Chapter 4 are attributable to gas price forecasts that are biased downwards or are otherwise inconsistent with market expectations of future spot prices, then energy modelers will no doubt want to investigate the cause of the discrepancy between their forecasts of natural gas prices and the market's expectations of those same prices. In either case, if long-term price stability is valued, energy analysts should ideally compare the cost of renewable generation against the cost of gas-fired generation using forward gas prices as the relevant fuel cost.

**Policymakers**

While the root cause of the empirical premiums we have observed in this paper remains unclear, the fact that renewable generation provides long-term price stability is beyond reproach. As long-term price stability is undoubtedly valued to some degree by end-use customers, the "hedge value" of renewable generation should help to justify continued and new policy support for renewables. For example, if future work confirms the hedge value of renewable energy, policymakers should begin to explore practical mechanisms (such as those discussed above) to incorporate that value into decision-making processes, thereby enabling renewable energy to capture the value of the price stability benefit it provides to the market.