# Renewable Energy as a Hedge Against Fuel Price Fluctuation

How to Capture the Benefits

Commission for Environmental Cooperation

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## Executive Summary

In a time of fuel price fluctuation, the use of renewable energy may offer, along with environmental benefits, greater stabilization of electricity costs. The pricing volatility of fossil fuels, along with the difficulty of forecasting fossil fuel prices, puts energy customers and providers at risk from fluctuating energy rates. As an alternative, this paper explores the potential for renewable energy to serve as a financial "hedge," reducing exposure to fuel price risk. Renewable energy generation brings with it the price stability benefits of free-fuel generation from emerging technologies such as solar, wind, small hydro, and geothermal sources. Renewable energy costs tend to be stable or decreasing over time, compared to rising or fluctuating costs for fossil fuel. With certain factors in place, it has been demonstrated that renewable energy can be effectively priced at or below the cost of conventional sources.
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As the paper presents, renewable energy can serve as a financial hedge in two key ways that result in both public and private benefit:

- Since renewable energy resources (with the exception of biomass) do not require purchased fuel, the operating costs over time are highly predictable, as opposed to fossil fuel markets.
- Renewable energy reduces the demand for non-renewable resources, potentially easing prices of fossil fuels.

The paper goes on to detail the practices through which renewable energy can provide hedging solutions for utilities or other load-serving entities at the utility-scale, and can also provide price stability benefits for retail customers who receive price-stable purchasing terms or install renewables on-site. Utilities and electric service providers can tap into the price hedge value of renewables by:

- Basing their evaluation of future natural gas prices not on forecasts but on forward prices.
- Including future regulatory risk as a factor when evaluating non-renewables.
- Including renewable energy in an integrated resources plan analysis or as a critical part of the supply portfolio.
- Buying renewable energy or renewable energy certificates through Contracts for Differences.

Individual electric customers can obtain the price stability benefits of renewable energy by:

- Installing on-site renewable energy generation.
- Buying renewables though a pricing structure that is based on the long-term price of the renewable energy and is not tied to fossil fuel prices.

Section I of the paper presents various data points depicting the volatility and unpredictability in electricity markets, primarily due to wildly fluctuating natural gas prices. The second section describes the price stability benefits of free-fuel renewable energy resources. Section III ties together the preceding sections by elaborating the concept of renewable energy serving as a financial hedge. Finally, the last section further examines renewable energy's price-stabilizing potential through the following case studies: the California Renewable Portfolio Standard, the Solar Services Model of SunEdison, Austin Energy's Stable Rate Green Tariff, the Public Service Company of Colorado 2003 Least-Cost Resource Plan, and the City of Calgary's Contract for Differences.

## Introduction

Energy consumers – residential and non-residential alike – are concerned about the volatility of energy prices. Enter the term “volatile energy prices” into the Google website and you receive over a million hits. Similarly, public opinion polls show that energy users are in favor of building more renewable resources. But how can individual energy customers and their providers tap into this opportunity to encourage more renewables and provide greater stability to their electricity prices? And how can regulators and policymakers encourage this to happen? Those questions are addressed in this paper.

This paper demonstrates the benefits of renewable energy as a hedge against electricity market fuel price fluctuation. The paper considers how regulators and electricity customers may address this opportunity either as a socialized cost/benefit scenario (by including renewable energy in the rate base), on an individual customer basis (through green pricing options that convey price stability benefits, via on-site installation of renewable energy generation technology under different business models, and through fuel switching), or through several approaches simultaneously.

Throughout this paper, the term renewable energy generation refers to the “green” or “emerging technologies” such as solar, wind, small hydro, and geothermal sources. The term “hedge” used in this paper uses in the traditional generic meaning, referring to the activity of reducing the exposure to price risk.

## I. The Problem of Pricing Volatility

This section of the report provides an overview of available data demonstrating the effects of fossil fuel price volatility on electricity markets and provides a forecast of future prices.[1] It is safe to say that all of North America is dependent upon fossil fuels, and that the pricing volatility of these fuels puts energy customers and providers at risk from fluctuating energy rates.

In 2002, the United States' energy consumption was supplied by 39 percent petroleum, 24 percent natural gas, and 23 percent coal.[2] Similarly, electricity generation in the U.S. in 2005 was sourced by 49.7 percent coal and 18.7 percent natural gas.[3] Therefore, even slight fluctuations in the price of fossil fuels can have wide-reaching impacts.

In Mexico in 2004, 82 percent of electricity generation came from conventional thermal sources (of the thermal feedstock, fuel oil represented 44 percent, natural gas represented 33 percent and coal represented 12 percent), 10 percent came from hydroelectricity, 4 percent came from nuclear power, and 4 percent came from other renewables. However, nearly all private generators operate capacity fired by natural gas. As a result, the general trend in overall feedstock consumption has seen a decline in petroleum-based fuels and a growth in natural gas and coal.[4]

In Canada, 58 percent of electricity generation comes from hydroelectricity, followed by coal (19 percent), nuclear (12 percent), natural gas (6 percent), oil (3 percent), and other renewables (2 percent).[5] Canada and the United States have an extensive electricity trade, and the electricity networks of the two countries are heavily integrated.

The volatility of natural gas prices has made headlines in recent years. The build-up of natural gas-fired power plants in the last twenty years has increased North America's dependence on natural gas. The combination of tight supplies, high demand, and unpredictable factors, such as weather, results in widely varying price points for natural gas. As we witnessed last year, two hurricanes in the Gulf Coast shut in (reduced available output) over 90 percent of offshore U.S. gulf coast natural gas production, significantly affecting North American natural gas markets and reducing production by 20 percent.[6] Currently, about 19 percent of U.S. electricity generation is fueled by natural gas – up from 14 percent just a decade ago.[7] Dependence on natural gas – and the volatility of natural gas prices – varies regionally and temporally, but on the whole is increasing.

The following set of graphs depicts historical and forecast price data for natural gas and coal. The first graph below shows average annual U.S. natural gas prices for the electricity sector for

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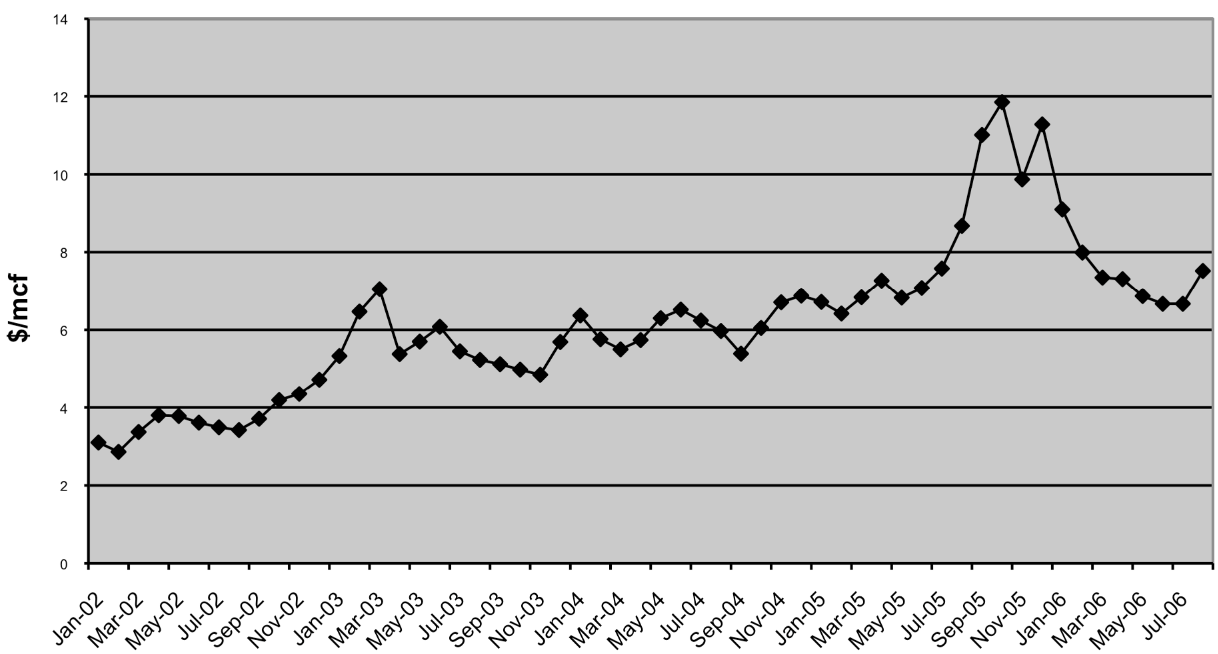
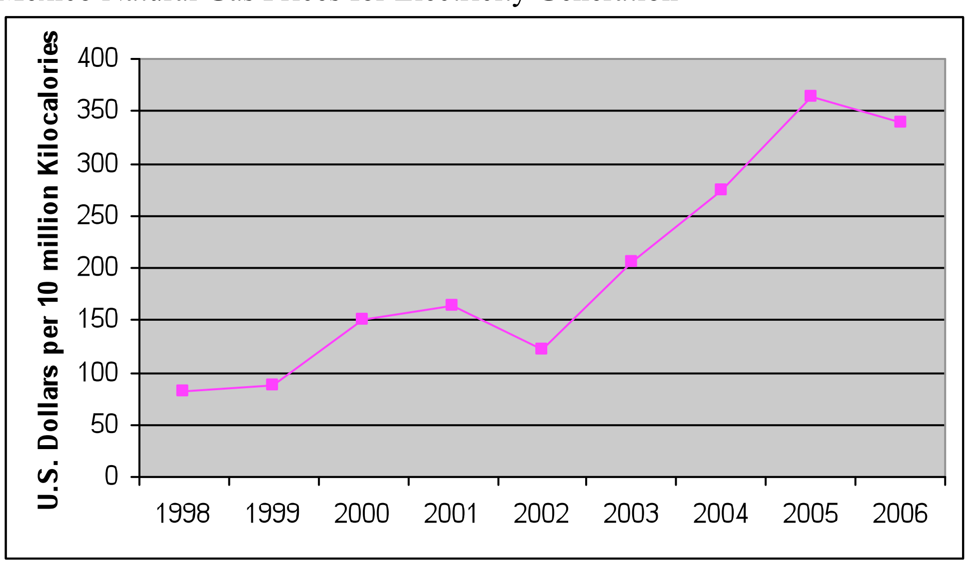
[1] Though many of the tables are using U.S. data, the purpose is illustrative with similar volatility effects in other geographic areas dependent upon natural gas as a power plant fuel.
[2] http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/figh1.html
[3] http://www.eia.doe.gov/fuelelectric.html
[4] http://www.eia.doe.gov/emeu/cabs/Mexico/Full.html
[5] http://www.canelect.ca/en/Pdfs/HandBook.pdf
[6] http://www2.nrcan.gc.ca/es/erb/CMFiles/Final_Ex_Sum_ENGLISH206NZG-19012007-3845.pdf
[7] http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html

the past five years.  Prices in 2002 began around $3 per thousand cubic feet, and then more than doubled to $7 in a year's time.  Following a few years of relative stability, prices spiked again in the winter of 2005/06 and then retreated.

**U.S. Natural Gas Electric Power Prices**

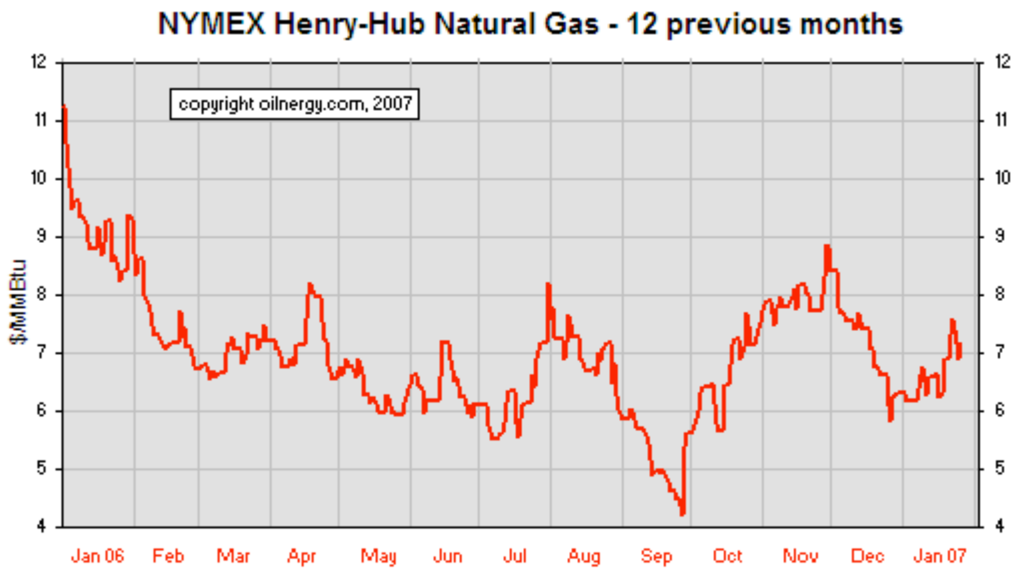



Mexico Natural Gas Prices for Electricity Generation




http://www.eia.doe.gov/emeu/international/ngasprie.html

National data and time-aggregated data tend to present a smoother view of what is actually happening in the market. Though the graph above, based on national averages and monthly price points, still demonstrates considerable volatility, we present below a more localized and more granular reporting frequency to demonstrate the actual marketplace volatility. The following graph shows prices for the past year at Henry Hub in Louisiana, the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).

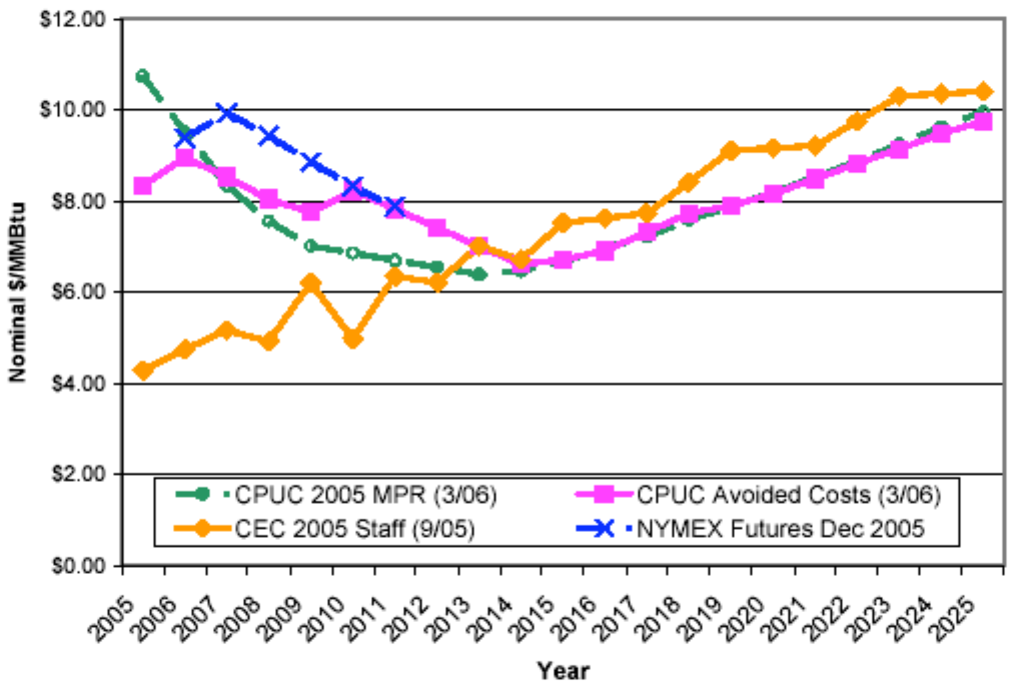


Source: http://www.oilnergy.com/1gnymex.htm

When estimating the future price of natural gas, experts recommend referencing current NYMEX futures prices. The graph below provides a number of forecasts including NYMEX.[8] An important implication is that government numbers are solely forecasts are made by economists, while the NYMEX futures are financially binding contractual deals. In terms of financial outcomes, there is a significant difference between the two, as the government can/will revise a forecast while a NYMEX contract leaves one party financially liable for the term of the contract. What is most telling about the graph is how divergent the forecasts are, showing the unpredictability of future natural gas prices. Mark Bolinger and Ryan Wiser at Lawrence Berkeley National Laboratory have done an excellent job of comparing the U.S. Department of Energy's Annual Energy Outlook price forecasts of natural gas prices to the actual forward prices as found on NYMEX. Bolinger and Wiser expose the off-target government forecasts, concluding that the Energy Information Administration (EIA) grossly over-projected the price of gas in the late 1980s, and, conversely, has grossly under-projected the price of gas since the mid-1990s. The latest annual summary can be found here: http://eetd.lbl.gov/ea/emp/reports/53587_memo.pdf

[8] http://eetd.lbl.gov/EA/EMP/reports/61580.pdf

**Figure 5. Comparison of Natural Gas Forecasts**




Source: Presentation by Richard McCann at 2006 Integrated Energy Policy Report Midcourse Review Committee workshop, August 22, 2006, *Comparison of Natural Gas Price Forecasts*

Source: http://www.energy.ca.gov/2006publications/CEC-100-2006-001/CEC-100-2006-001-CMF.PDF

Prices for natural gas in Canada have faced similar trends of upward prices and volatility, though slightly less so than in the United States due in part to a strong Canadian dollar, and also the absence of severe weather-related disruptions as experienced in the southern United States. The two key North American natural gas price hubs are the Intra-Alberta Market in Alberta (AECO) and the Henry Hub in Louisiana (NYMEX). Gas purchased on NYMEX typically trades at a $0.50 to $0.80/MMBtu premium relative to AECO.[9]

Mexico has adopted a policy of pricing natural gas based on the Houston price adjusted for transport cost. This is an application of the Little-Mirrlees Rule and results in the market for gas in Mexico having essentially the same character as the Houston market. Pemex behaves as a price taker and inasmuch as Mexico is importing gas from the United States, the price of gas to Mexican consumers reflects the marginal cost of transport to Mexico.[10]

Coal, despite its reputation as the stable workhorse of the electricity industry, has not been immune to pricing volatility in recent years. While the national average price for coal may seem to be relatively stable over time, that is not the case when coal prices are given a closer look.

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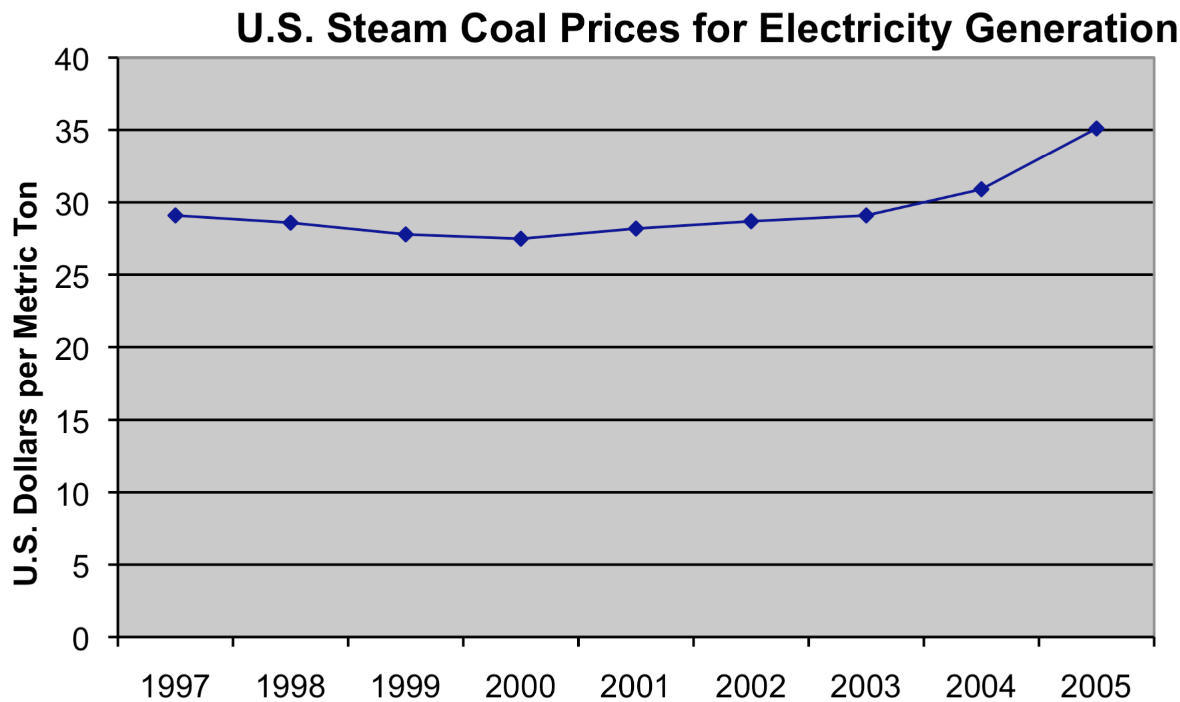
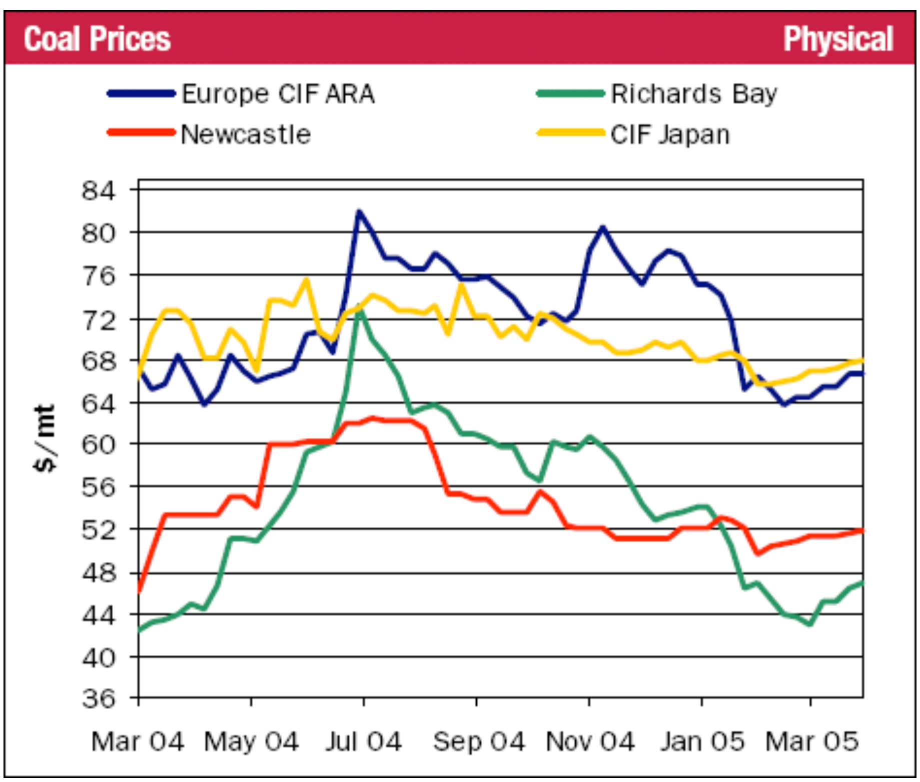
[9] http://www2.nrcan.gc.ca/es/erb/CMFiles/2005_Review_and_Outlook_English206PFM-02022007-2605.pdf
[10] http://www.ksg.harvard.edu/m-rcbg/repsol_ypf-ksg_fellows/Papers/Rosellon/IMPLICATIONS%20OF%20THE%20ELASTICITY%20OF%20NATURAL%20GAS%20.pdf



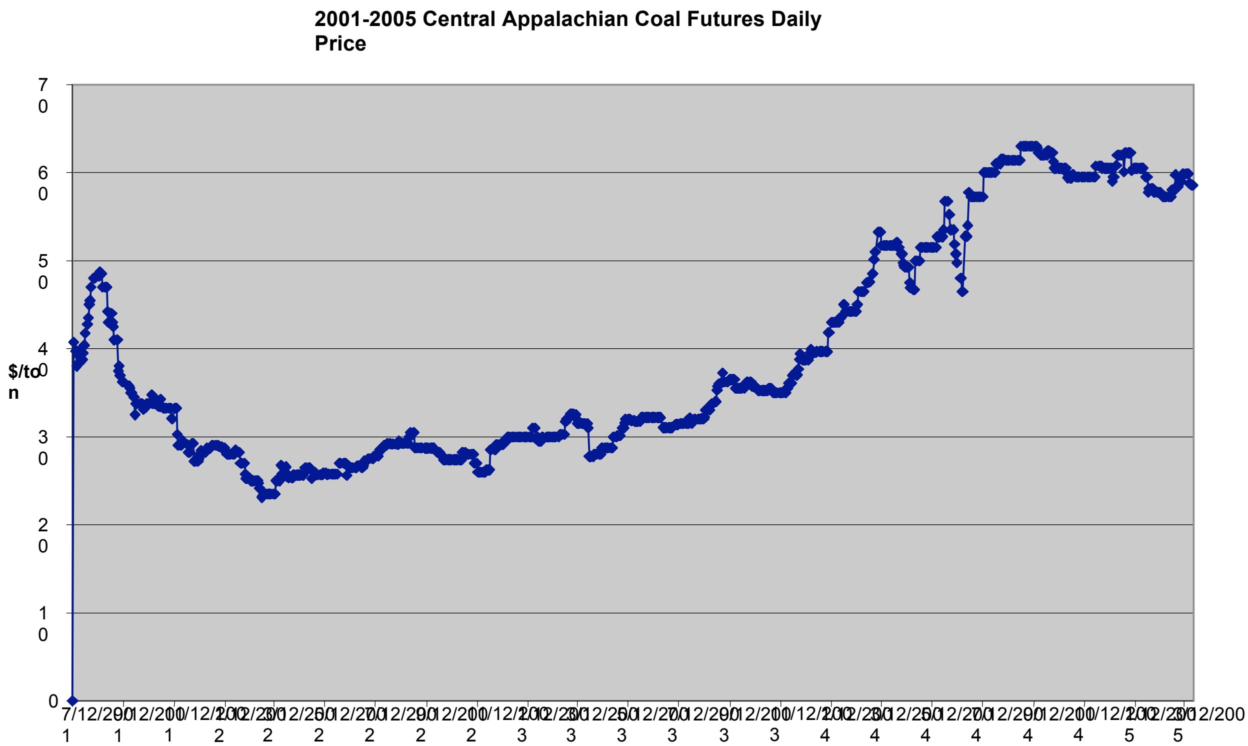

The graph below from Platts demonstrates worldwide coal price volatility, which was due to China's growing appetite for coal, weather events that limited transportation of coal, and declining production in the U.S.[11]




[11] http://www.platts.com/Coal/Resources/News%20Features/coal_prices_2005/chart1.html

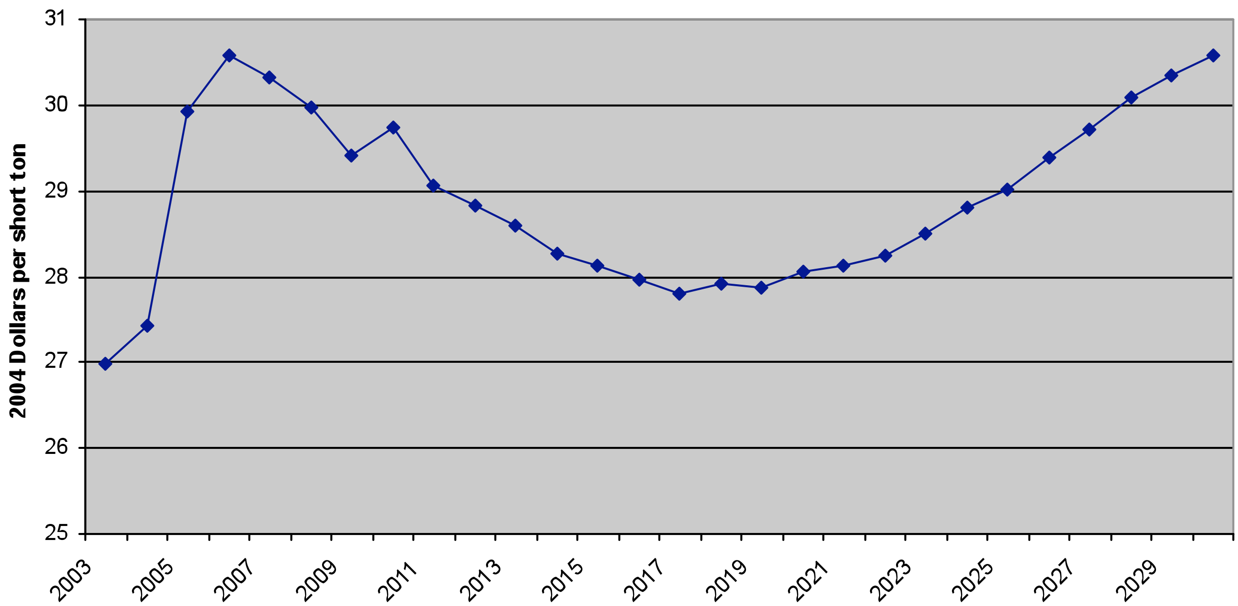
In addition to price volatility, coal also carries considerable regulatory risk. In May 2006, Synapse Energy Economics conducted a review of the projections of 10 modeled analyses of costs of federal CO2 emissions limits and found that while it is difficult to pinpoint exactly what the future carbon-regulatory costs on coal will be, those future costs will certainly exist. [12]

Finally, we have the two forecasted prices of coal, both displaying considerable upward movement. The first graph displays actual coal futures prices over time, based on actual settlement prices. The second is a graph of projected coal export prices.




[12] http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.Climate-Change-and-Power.pdf

**Projected Annual Price of U.S. Coal Exports**



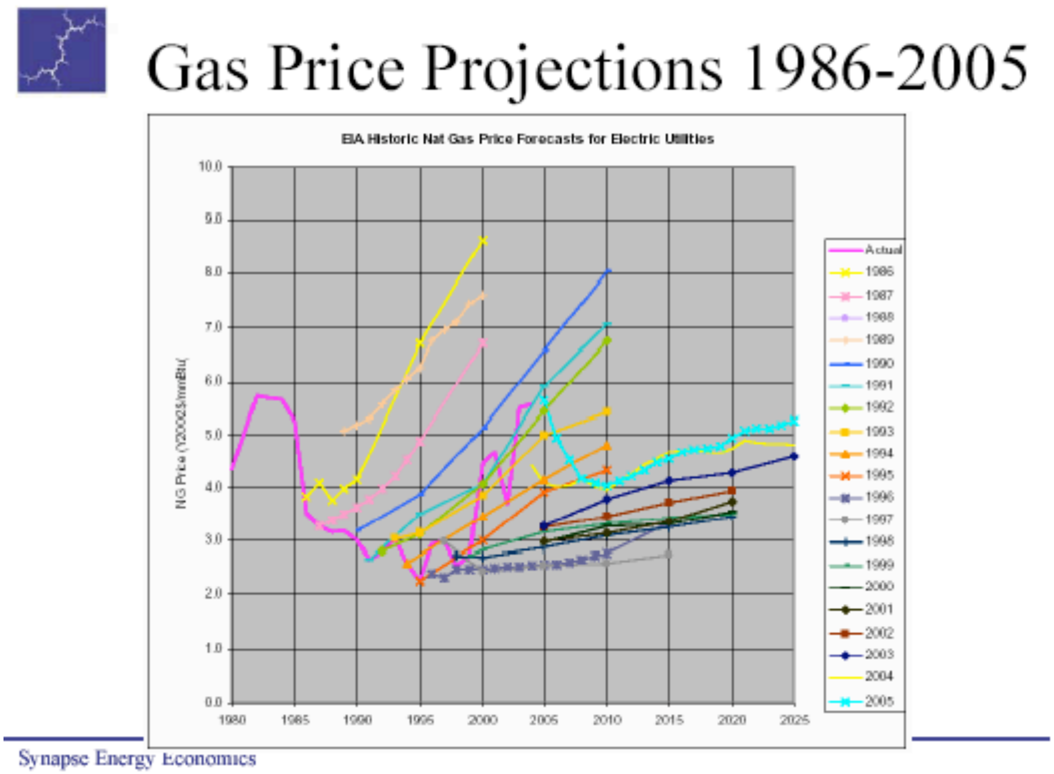

Oil prices have not only seen wide price swings recently, but in decades past as well. However, oil prices are not particularly instructive for this analysis since oil is not a major fuel source for electricity generation in the United States and Canada. Most of the existing generating capacity in Mexico is oil-fueled, but many of these power plants will be converted to utilize natural gas.[13]

History has shown that there is little relation between forecasts and actual prices. Forecasts cannot take unforeseen events – such as war, change in government, hurricanes or the effects of low precipitation on hydropower – into account. One report by the California Energy Commission stated, "The best assumption about all forecasts for commodities as volatile as natural gas is that they will be wrong."[14] Synapse Energy Consulting proved this theory true and put it in graphical form with its collection of gas price projections since 1975.[15]

[13] http://www.cslforum.org/mexico.htm

[14] http://www.energy.ca.gov/2006publications/CEC-100-2006-001/CEC-100-2006-001-CMF.PDF This document also has nice graphs of natural gas price forecasts.

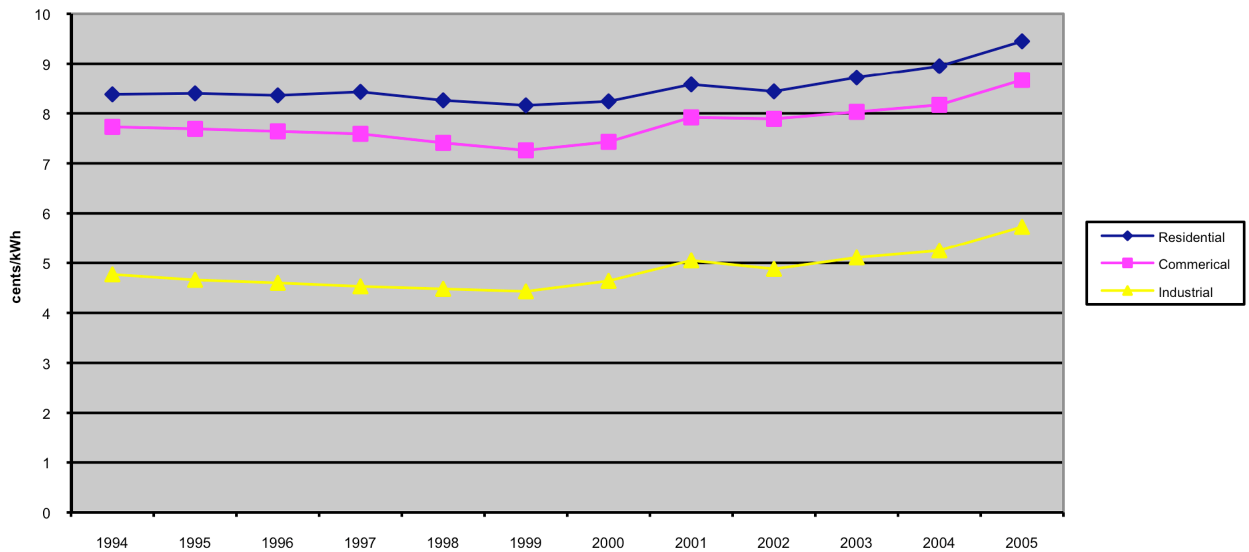
[15] http://www.synapse-energy.com/Downloads/SynapsePresentation.2006-01.Forecasting-and-Using-Carbon-Prices-in-a-World-of-Uncertainty.pdf



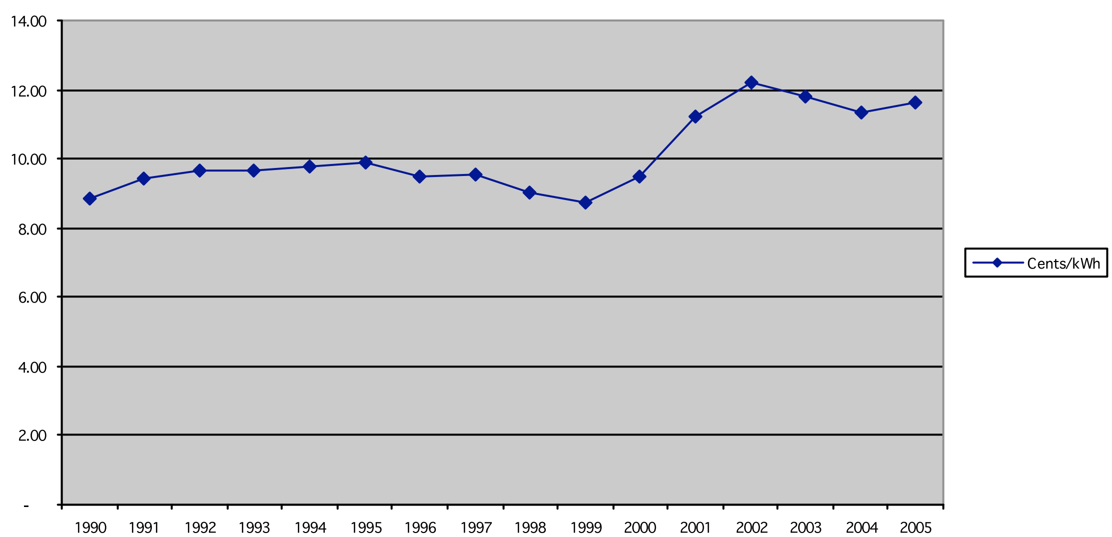

This unpredictability bolsters arguments in favor of renewable energy. Not only is there demonstrated volatility in fossil fuel markets, it is also coupled with a poor ability to forecast future prices.

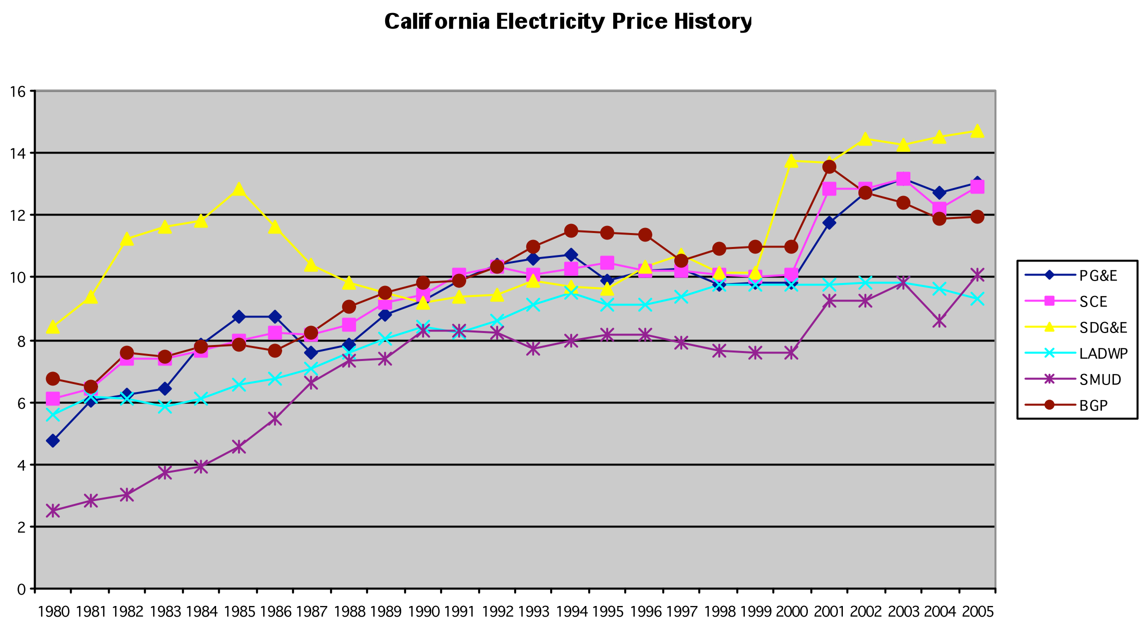
The final piece of the data puzzle to consider is the price of electricity. As with the previous charts, the less granular the data, the less volatility is exposed. As an example, we present below the average historical national price, California's historical average price, then the historical average price by utility in California. Moving from graph to graph you will see increasing volatility, though these graphs cover overlapping time periods. Getting a finer level of granularity is difficult since the contracts signed by electric utilities are typically not available to the public.

**Average U.S. Retail Price of Electricity**




**California Electricity Prices**

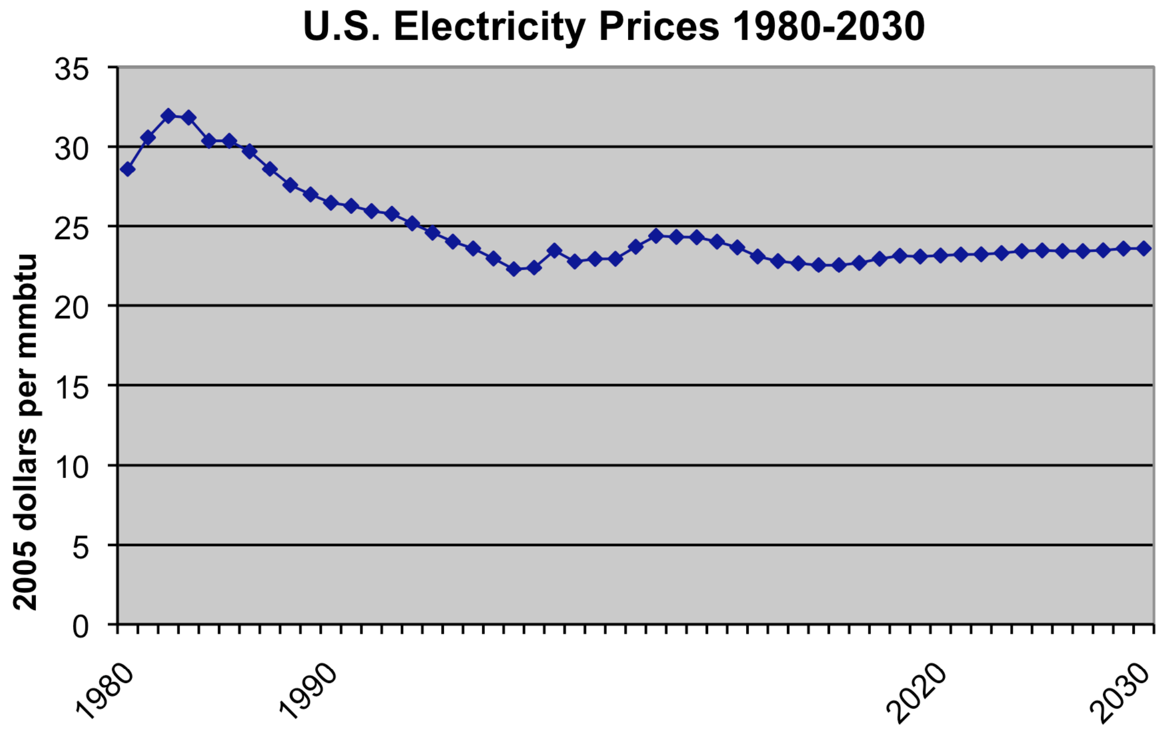





It was well publicized that California wholesale electricity prices went from $35 MWh to $375 MWh during 2000.

Given the volatility depicted by the graphs of electricity prices presented above and the inaccuracy of forecasting prices, we wonder how much faith should be put in the EIA's extremely stable electricity price forecast. Future natural gas prices are very difficult to predict for any nation. In theory, prices for non-renewable resources would rise in real terms over time. However, there are many mitigating factors. Technology improvements tend to reduce production costs, increase the efficiency of gas-using equipment, reduce gas demand, and reduce prices. Lower relative prices for other fuels may cause fuel switching away from natural gas, causing lower gas demand and prices. Finally, new supply areas and sources, such as northern Canada, liquefied natural gas, and coalbed methane, could increase supply thereby lowering prices."[16] Any of the mitigating factors may be superseded by events such as extreme weather, unexpected regulatory impacts, or acts of terror. Forecasts are made in a static environment, and it is impossible to predict some events that will have a major affect on price.

[16] http://www2.nrcan.gc.ca/es/erb/prb/english/View.asp?x=448#p12




Price volatility is a significant concern for electric utilities, their customers, and their shareholders. Market volatility not only affects rates, but also increases the other risks utilities face: transmission constraints, cost and availability of emissions allowances, blackout risk, political risk of cost recovery, and the ability of customers to pay. Price volatility in wholesale electricity markets can be handled in a variety of ways in terms of how electric utilities and their regulators manage financial risk. Typically, electricity consumers face stable prices determined by the administrative procedures of their state regulatory agency. Prices are set so as to compensate the vertically integrated regulated utilities for investments they made, with ratepayers, rather than shareholders, shouldering the risks. Price volatility and fluctuating contract prices are typically handled in fuel adjustment clauses, which address the cost of fuel risk. These allow utilities to recover increasing fuel expenses that occurred in a prior period. Typically, these rate cases are based on retroactive assessments of the utility's portfolio, so these are “hindsight” regulatory fixes, not prospective risk reduction strategies.

Some regions that have undergone deregulation have different means of handling volatility of electricity markets, but those are the exception. In many cases, regulators adopt policies that encourage greater price stability, such as encouraging long-term electricity contracts, price caps, reducing dependence on spot markets, and encouraging fuel supply diversity. As this paper demonstrates, renewable energy procurement is another tool in that toolbox.

## II. The Price Stability Benefits of Renewable Energy

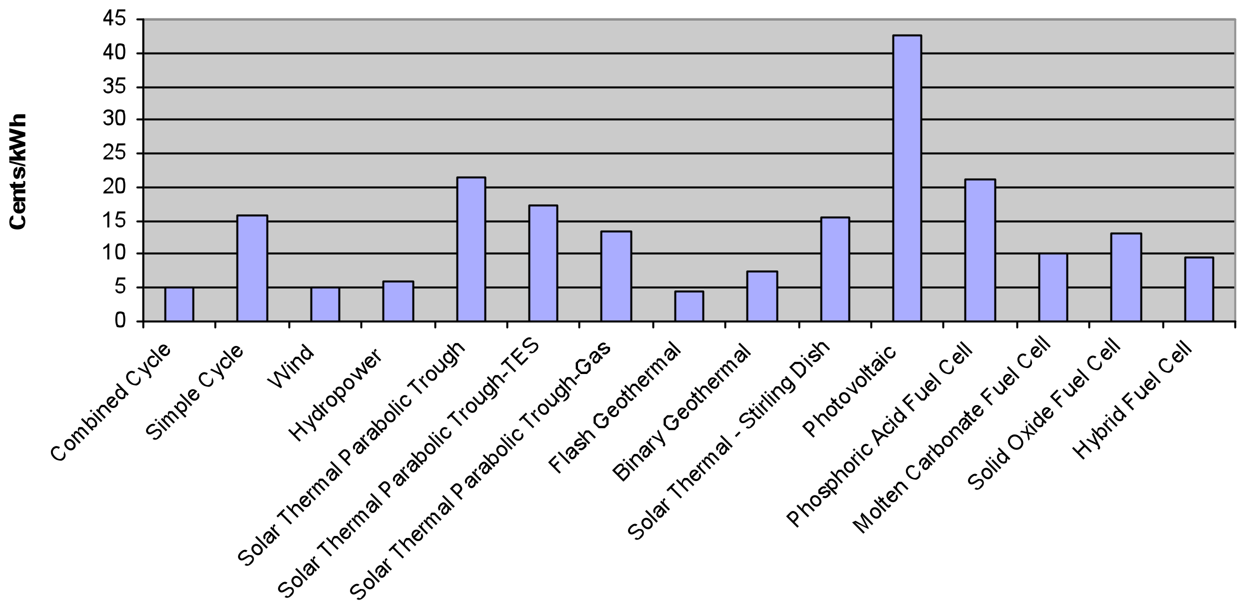
The increased reliance on natural gas has been concurrent with increased renewable energy generation, which brings with it the price stability benefits of free-fuel generation from solar, wind, hydro, and geothermal sources. This section of the report examines available data demonstrating the price stability benefits of renewable energy. Renewable energy costs tend to be stable or decreasing over time, compared to rising or fluctuating costs for fossil fuel. The report presents below examples of levelized renewable energy generation costs by technology. While this does not lend itself to a direct comparison of fuel prices as presented above, it is important in illustrating the price stability of free-fuel renewables as compared to the volatile pricing of fossil fuels. It is also important to note that the delivery characteristics of the generation also affect price. For example, some technologies provide bulk power supply that competes against wholesale electricity prices (e.g. geothermal) while others (e.g. solar PV) usually compete against retail prices.

Energy consumers often ask the question “when will clean, renewable resources like solar and wind power be cost-competitive with non-renewables like natural gas and coal?” Increasingly, the answer to that question is “now.” The past few years have seen the arrival of a watershed moment in electricity pricing, at least in some regions of the United States. Prices of renewable energy sources can, in some regions and for some technologies, now be competitive with non-renewable sources of electricity. While this cost-competitiveness is mostly limited to areas where natural gas and electricity prices are high, where renewable resources are abundant, and where renewable energy promotional policies are in place, it has been demonstrated that renewable energy can be effectively priced at or below the cost of what otherwise would be contracted.

The costs of electricity are based on a number of factors such as fuel prices, capital costs, operations and maintenance requirements, siting issues, and permitting. Electricity prices are further affected by supply/demand curves, subsidies, contract terms, and so on. As demonstrated earlier in the report, since there are so many factors that affect costs and prices in electricity markets, it is very difficult to simplify energy prices in an apples-to-apples price comparison of various electricity sources. This section of the report provides the best publicly available pricing points for renewable energy generating options, and discusses pricing trends of renewable energy as compared to fossil fuels.

Our research found a few resources that have calculated the levelized costs of electricity from various technologies and fuel sources. The California Energy Commission study gives a single estimated pricing point per technology, while the World Bank study gives a price range. The graph below was created from California Energy Commission data.

Levelized Costs of Electricity Production by Technology




Source: California Energy Commission, 2003.

The World Bank report provides a wealth of data and condenses its analysis into the illustrative figures below.[17] The figures show in cents per kWh the average levelized costs for various renewable energy technologies. The first figure is for medium-sized systems and the second figure is for larger utility-scale systems. The bars represent the sensitivity range (low to high) with the point where the two colors meet representing the average.

17 http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/EXTRETOOLKIT/0,,contentMDK:20751106~menuPK:2069872~pagePK:64168445~piPK:64168309~theSitePK:1040428,00.html

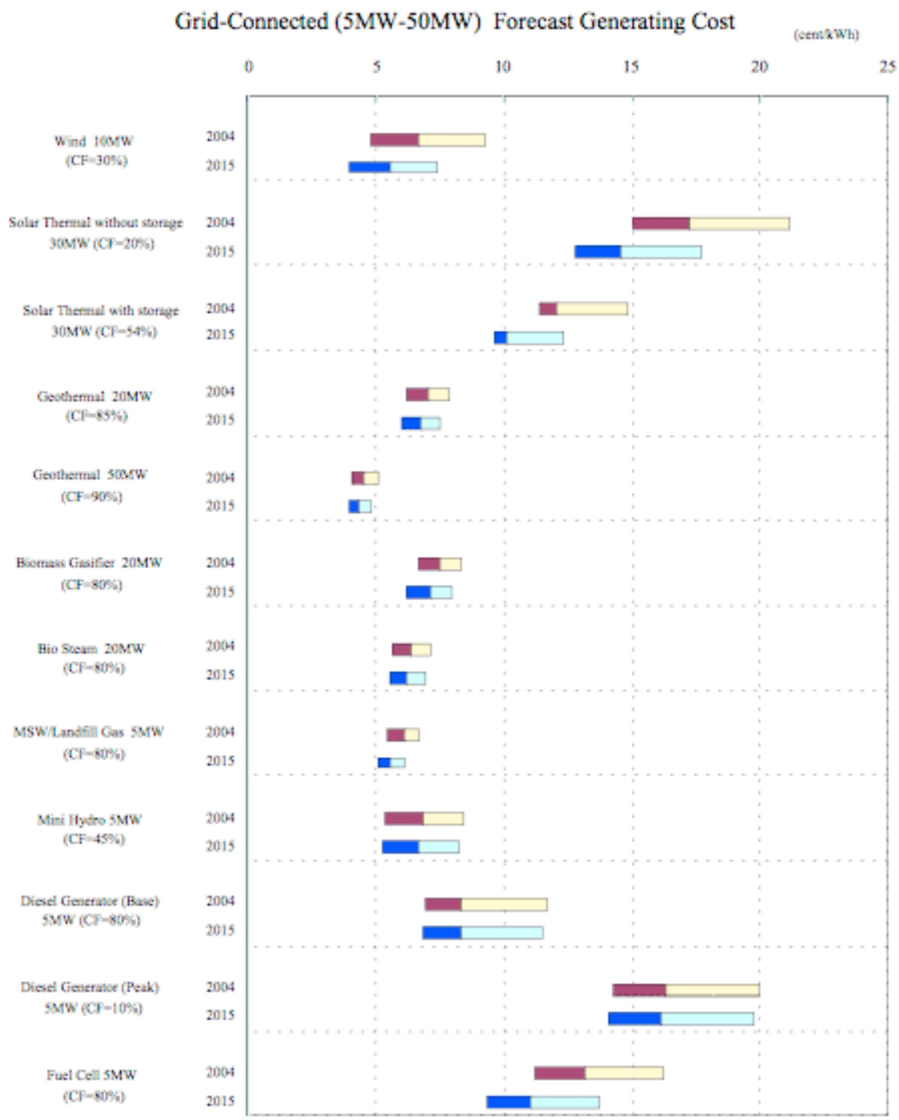



**Figure 4: Electricity Costs: Small Grid-Connected Generation Technologies (2004 & 2015)**

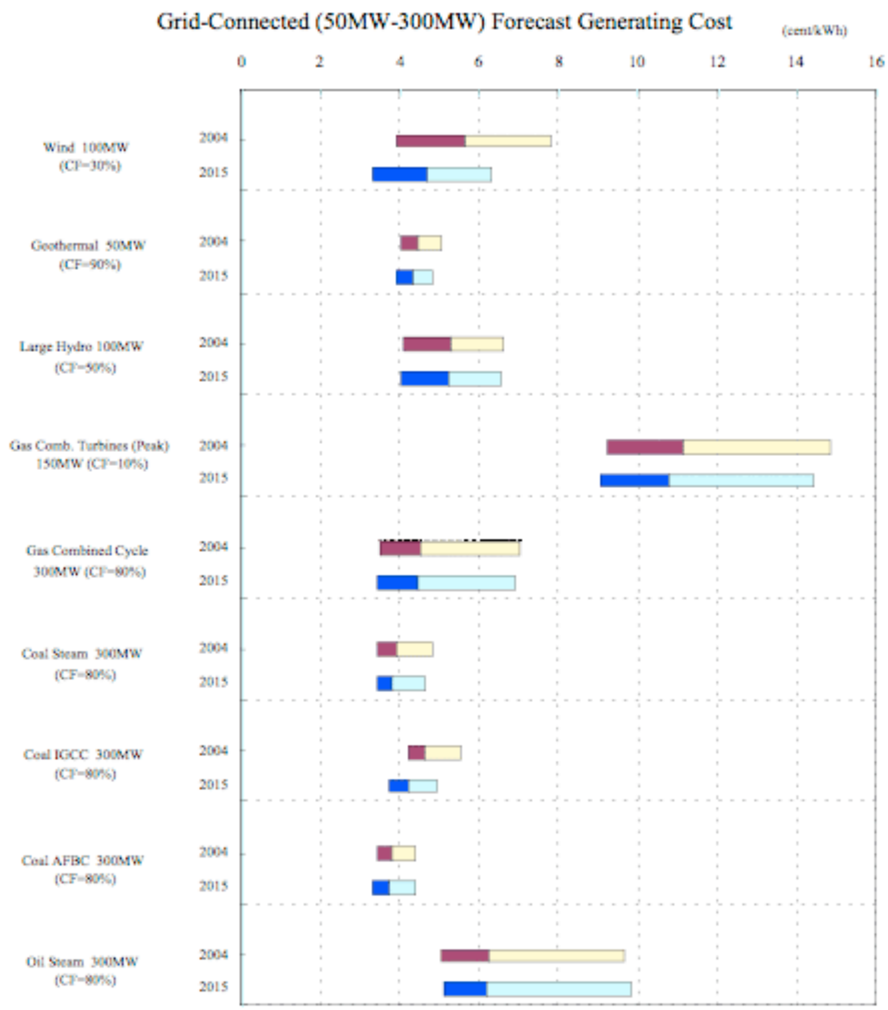



**Figure 5: Electricity Costs: Large Grid-Connected Generation Technologies (2004 & 2015)**

Both the World Bank and California Energy Commission studies agree that of the various types of emerging renewable energy, wind and geothermal are the most cost competitive with fossil fuels for generating electricity. For illustrative purposes, we now take a closer look at cost data for renewable energy applications in the United States. Though these numbers will be different for Mexico and various Canadian provinces, they should follow similar patterns even though the costs at different geographic locations may fall at different points on the cost curves.

<u>Wind</u>

According to the American Wind Energy Association, over the last 20 years, the cost of electricity from utility-scale wind systems has dropped by more than 80 percent.[18] The cost of wind has risen in recent years from roughly $1100 per kW installed to perhaps $1800 - $1900 per kW. Most people attribute this higher cost to rising concrete and steel prices, but a recent report by Ryan Wiser also suggests a weak dollar, a shortage of turbines, and a movement

[18] http://www.awea.org/faq/wwt_costs.html

toward increased manufacturer profitability.[19] In the early 1980s, when the first utility-scale turbines were installed, wind-generated electricity cost as much as 30 cents per kilowatt-hour. Now, state-of-the-art wind power plants can generate electricity for less than 5 cents/kWh with the Production Tax Credit in many parts of the U.S., a price that is competitive with new coal- or gas-fired power plants. The cost of wind energy varies widely depending upon the wind speed at a given project site, and a large wind farm is more economical than a small one.

Geothermal[20]

Real levelized costs for geothermal electricity generation are 4.5-7 cents per kilowatt-hour. Delivered costs depend on ownership arrangements, financing, transmission, the quality of the resource, and the size of the project. Geothermal plants are built of modular parts, with most projects including one or more 25-50 MW turbines. Geothermal plants are relatively capital-intensive, with low variable costs and no fuel costs. Usually, financing is structured so that the project pays back its capital costs in the first 15 years, delivering power at 5-10¢/kWh. Costs then fall by 50-70 percent, to cover only operations and maintenance for the remaining 15-30 years that the facility operates.

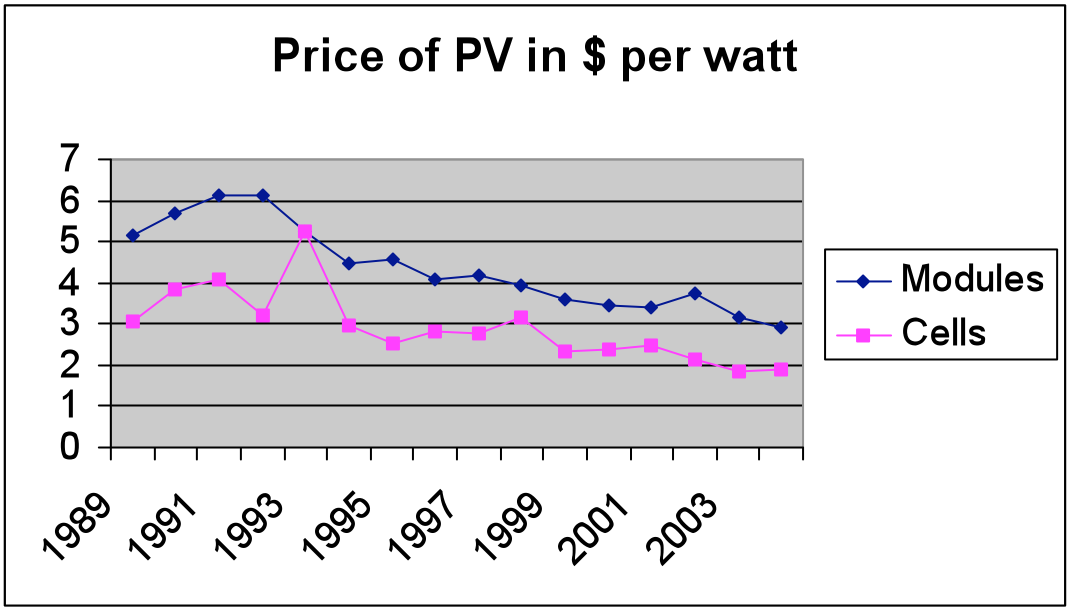
Solar

The website solarbuzz.com offers solar electricity benchmark price indices, comparing the levelized costs of solar to average retail electricity prices. As of January 2007, they estimate the levelized costs of PV as follows:

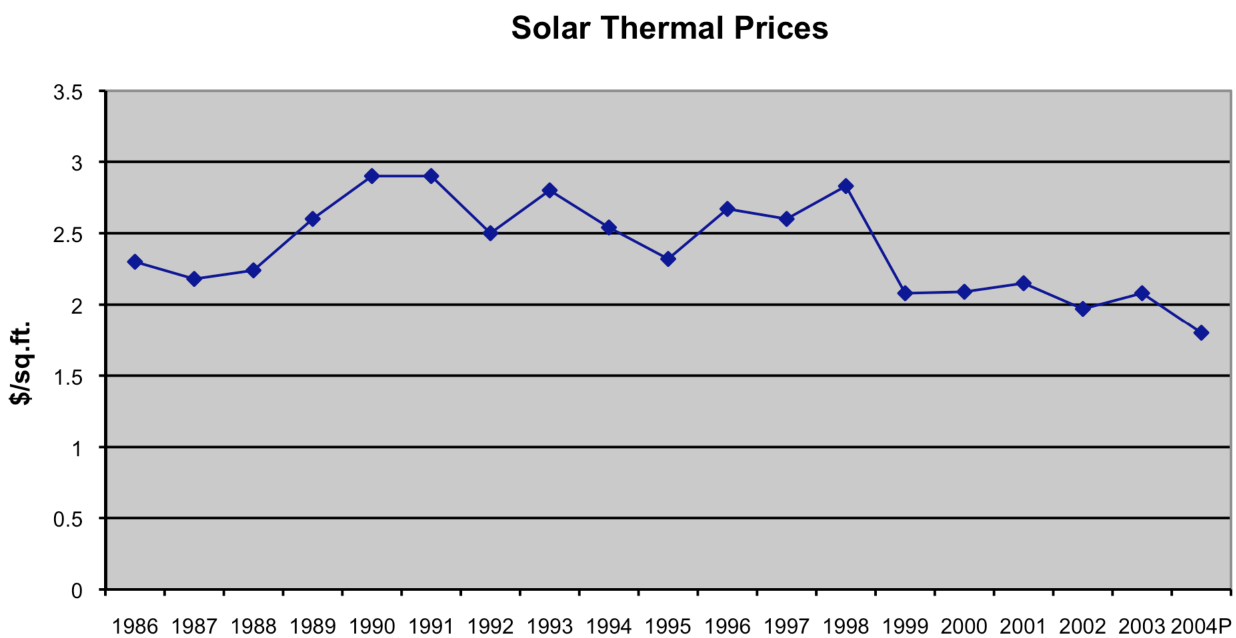
| | Size of system | System Cost | Sunny Climate price | Cloudy Climate price |
|---|---|---|---|---|
| Residential | 2 kW | $17,838 | 37.30 cents kWh | 82.05 cents kWh |
| Commercial | 50 kW | $342,782 | 27.48 cents kWh | 60.47 cents kWh |
| Industrial | 500 kW | $2,485,098 | 21.42 cents kWh | 47.12 cents kWh |

These prices do not take rebate programs into account, but show that solar PV prices need to drop considerably before becoming cost-competitive with fossil fueled generation. However, the graph below shows that PV prices have been on the decline over the past two decades.

[19] http://eetd.lbl.gov/ea/EMS/reports/ann-rpt-wind-06.pdf
[20] source: http://www.rnp.org/RenewTech/tech_geo.html




Similarly, solar thermal technology prices have been on the decline, as shown in the graph below.



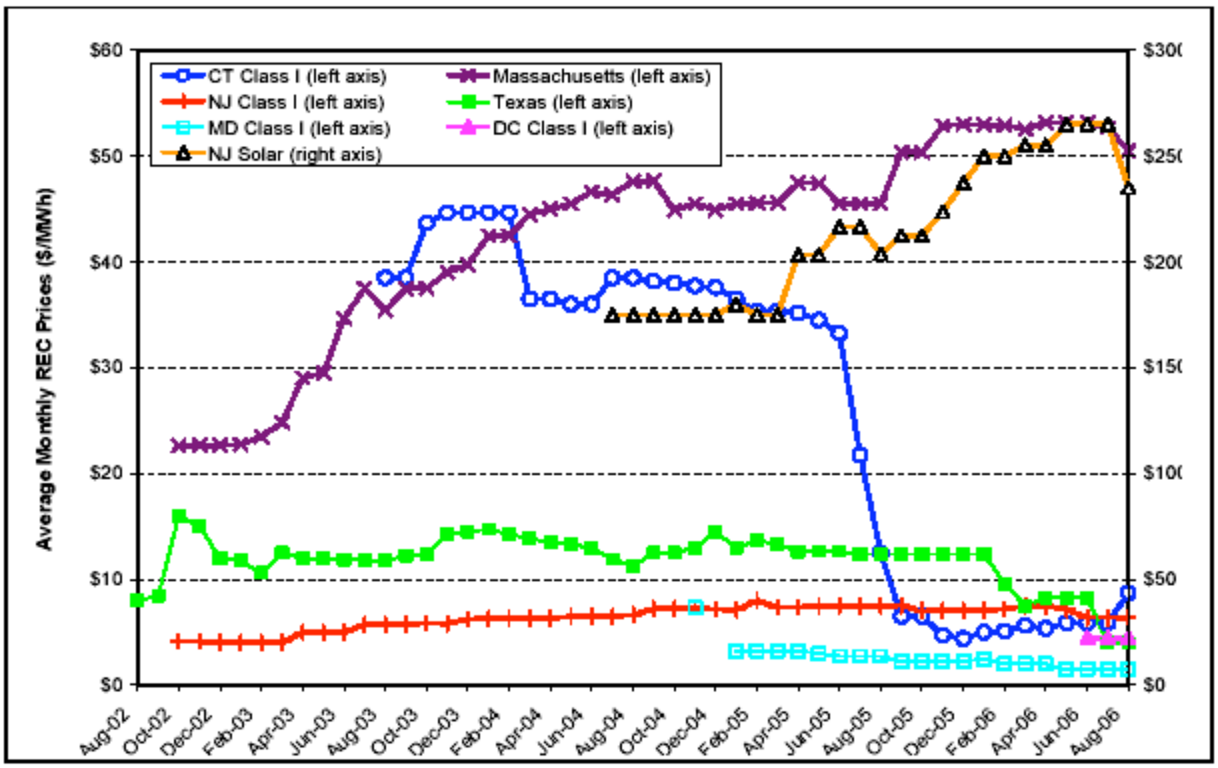

One important trait of solar related to energy costs is that solar tends to be a peak generation source. The power generation curve for solar PV fits well with the peak power demand curve.[21] Therefore, each MWh of solar PV generation provides great social benefit in reducing marginal demand when marginal prices are highest.

[21] For example, see http://www.state.mn.us/mn/externalDocs/Commerce/Relationship_between_solar_generation_and_electric_demand_111003025625_Solarpaper11-03.pdf

Renewable Energy Certificates

Some may look to prices for Renewable Energy Certificates (RECs) as an indicator of the price of renewable energy. Renewable Energy Certificates are often thought of as a tool to bridge the price gap between renewables and fossil fuels. However, REC prices are influenced by a number of factors such as the balance of supply and demand, penalties for non-compliance with renewable portfolio standards, and whether or not the RECs are sold into voluntary or compliance markets. The graph below summarizes the Monthly Market Updates for RECs provided by the brokerage firm Evolution Markets. The graph shows the tremendous volatility, regional price disparity, and illiquidity of REC markets.

**Figure 10. Monthly Average Renewable Energy Certificate Prices**




Source: Evolution Markets, Inc. Data Bank (http://www.evomarkets.com/index.html), compiled by Lawrence Berkeley National Laboratory. October 2006.

Source: http://www.energy.ca.gov/2006publications/CEC-100-2006-001/CEC-100-2006-001-CMF.PDF

The authors of this paper see a very important role for RECs in helping to finance new renewable energy facilities, and for documenting compliance with Renewable Portfolio Standards, but do not see REC prices as a meaningful indicator of renewable energy costs nor generally as a risk mitigation tool unless a special contracting scheme is used to capture that value (e.g. a Contract for Differences).

Comparison to Fossil Fuels

Perhaps the best proxy for the hedge value of renewable energy is the cost of securing natural gas or coal supplies over time at a fixed price. The report "Power Price Stability: What's it Worth" concluded that the combined cost of meeting gas deliverability requirements through the use of gas storage and of fixing future gas prices using options is \$5.20 per megawatt hour as a lower bound (i.e. actual cost would likely be higher), and estimated that \$5.50/MWh represents a proxy for the value of the physical hedge provided by renewables.

Some regions are so dependent on natural gas that natural gas prices become strongly correlated with electricity prices. This is certainly the case in Texas. The Association of Electric Companies of Texas reports that as the marginal fuel for electric generation in the Electric Reliability Council of Texas (ERCOT) is natural gas, wholesale power prices are 98 percent correlated with the price of natural gas.[22]

As presented earlier in the graphs of coal forward prices and price projections, coal prices are also on an upward trend, making renewable energy investments look increasingly more attractive to electricity providers and customers alike.

The point is often made that renewables, while price stable, are more expensive than conventional power. Therefore, renewable power may be less volatile, but consistently more expensive, than conventional power - resulting in a hedge that guarantees you always pay more. In practice, this gap does not always exist and is quite geographically and/or temporally specific. There are a number of case studies demonstrating how renewables are in some regions price-competitive with conventional power, and even Integrated Resource Plans that have identified renewables as least-cost in all-source bidding (see the case study " Public Service Company of Colorado 2003 Least-Cost Resource Plan," in this report). Moreover, as this report argues, there are other monetizable values of renewables that may bridge the cost gap between renewables and conventional sources in cases where renewables are "more expensive." Of course, there are cases where renewables are clearly more expensive even when other values are considered. This report is not suggesting that the hedge value of renewable energy will make renewables the best financial deal in all cases.

[22] http://www.aect.net/documents/2003/20030306_IP_WholesaleRising.pdf

## III. How Can the Price Stability Benefits be Conveyed to Customers?

The first section of the report presented various data points that painted a landscape of volatility and unpredictability in electricity markets, primarily due to wildly fluctuating natural gas prices. The second section offered the price stability benefits of free-fuel renewable energy resources. This section ties those two parts together by presenting conceptual ideas of how renewable energy can provide a hedge. A number of practices are presented, and those are further examined in case studies. In general, there are two key ways that renewable energy provides a financial hedge:

1. Since renewable energy resources (with the exception of biomass) do not require purchased fuel, the operating costs over time are highly predictable, as opposed to fossil fuel markets.
2. Renewable energy reduces the demand for non-renewable resources, potentially easing prices of fossil fuels.

The first point suggests an approach through which an energy supplier or even individual energy consumer can privately benefit from the price stability of renewable energy. The second point depicts the public benefits that renewable energy provides for all energy consumers. This section of the report will cover both the individual and the socialized price stability benefits that renewable energy provides.

### Utility and Energy Marketing Models

Renewable energy can provide hedging solutions for utilities or other load serving entities at the utility-scale, and can also provide price stability benefits for retail customers who receive price-stable purchasing terms or install renewables on their side of the meter. Several means of tapping into the price stability benefits of renewables, both for electricity providers and their customers, are explored below.

<u>Long-term Fixed Contracts with Non-residential Customers</u>

Long-term contracts are an increasingly attractive option for both providers and consumers. Electric utilities and retail electricity providers can tap into their customers' interest in price stability and environmental protection by offering a renewable energy option at a fixed, long-term (5–10 year) price. The report by World Resources Institute's Green Power Market Development Group entitled "Developing Next Generation Green Power Products for Corporate Markets in North America" explains in detail how this can be accomplished, and provides a case study.[23] Our report also contains a case study of Austin Energy, the most successful proponent of this approach.

Renewable energy projects often require a longer-term (>10 year) power purchase contract to ensure reasonable financing terms because of their up-front capital intensity. Renewable-generated electricity can therefore offer a longer-term hedge than many of the conventional hedging strategies, which often focus on short-term markets. Even where long-term

[23] http://pdf.wri.org/gpmdg_corporate_6.pdf

conventional hedges are available, these markets are often thinly traded so transaction costs would be expected to increase, creating a higher benchmark against which a renewable power hedge would be measured.

In contrast to gas-fired generation, long-term contracts for renewable energy are typically offered on a fixed-price basis. To obtain a similar hedge with gas-fired generation (using gas forwards) over the last four years, one would have to pay a substantial premium relative to the most commonly used gas price forecasts in the USA. (Reference 1)

Some customers may choose to hedge only a portion of their electricity use. For example, a company may have the alternative of selecting a supply option of 20 percent renewables and 80 percent system power. This arrangement may be palatable when renewables carry a small price premium over the current cost of system power. The company may see a 20 percent hedge as an attractive offering, since they may be concerned that system power costs will rise, and will be willing to pay a small premium for renewables to diversify their energy portfolio and limit their exposure to fossil fuel price increases. On the other hand, some companies may opt for a 100 percent renewable option even when the price per MWh is higher than for system power; they may wish to make environmental claims and/or they may see the increased price stability and certainty of their operating costs as being worth the price premium.

This product type also tends to work well for the utility/marketer and/or generator, because in the signing of a long-term fixed price contract with the customer, they receive financial stability they can take to the bank.

There have been some barriers in the United States to long-term contracting for renewable energy. Some utilities may be resistant to sign because of their experience of signing PURPA QF[24] contracts with escalator clauses, only to experience a downturn in energy prices, leaving utilities with stranded costs. Also, as demonstrated in the era leading to California's energy crisis, it is much more difficult to get long-term contracts in restructured or restructuring markets because loads may shift to a competitor, or because regulators or legislators with anti-competitive concerns may discourage or prohibit utilities from entering into long-term contracts.

Adjustments to Monthly Bills

Some electric utilities that offer their customers a green pricing option have begun extending the price-stability benefits of renewable energy to their customers by exempting those customers from fuel adjustment clauses. When utilities apply fossil fuel rate increases, they may opt to exempt their green pricing customers, thereby passing along the price stability benefits of renewables to their renewable energy customers. This exemption may mean that the advertised price of renewables is higher than the effective price, as the customer's bill will include a zeroed-out line for fossil fuel adjustments as well as a price premium for renewables. In other words, when fuel prices increase, the effective green power premium falls. By bundling the hedge value of renewable energy with a green power product offering, the hedge may provide additional

[24] A Qualifying Facility (QF) is a generating facility, typically a small renewable energy facility, which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978.

value to a green power purchaser. With renewable energy products that offer benefits beyond the traditional environmental sales pitch, customer demand for green power may increase. A number of electric utilities in the United States offer this type of green pricing product, including Alliant Energy, Clallam County PUD, Edmond Electric, Eugene Water and Electric Board, Green Mountain Power, Holy Cross Energy, Madison Gas & Electric, OG&E Electric Services, We Energies, and Xcel Energy. These are some of the most successful green pricing programs in the United States, according to the National Renewable Energy Laboratory's Green Power Network.[25]

The utility green pricing examples cited above are all in regulated utility markets. The approach described above may be impossible in restructured markets where the utility provides transmission and distribution only and is not responsible for supply. In those cases, the competitive electricity marketer may choose to offer a price-stable renewable energy option.

Contracts for Differences (CFD)

Contracts for differences, like long-term contracts, can provide hedging benefits both to the buyer and the seller. It may be possible to finance projects in the absence of a utility Prospective Purchaser Agreement (PPA) if large, creditworthy end-users, such as universities or government agencies, make long-term commitments (i.e. 10 years or more) to purchase stand-alone RECs or RECs bundled with energy. For example, a REC contract for differences would provide price stability to the buyer and revenue security to the seller. While it provides budgeting certainty for the end-user, most are uneasy about making long-term budget commitments for energy.

A green CFD is a financial contract that allows a customer to support renewable energy development, acquire RECs, and hedge against fluctuating electricity rates—but does not involve the customer receiving physical power. [26] Rather, the contract sets up an exchange of payments between a power consumer and a renewable generator that hinges upon an agreed price for power.

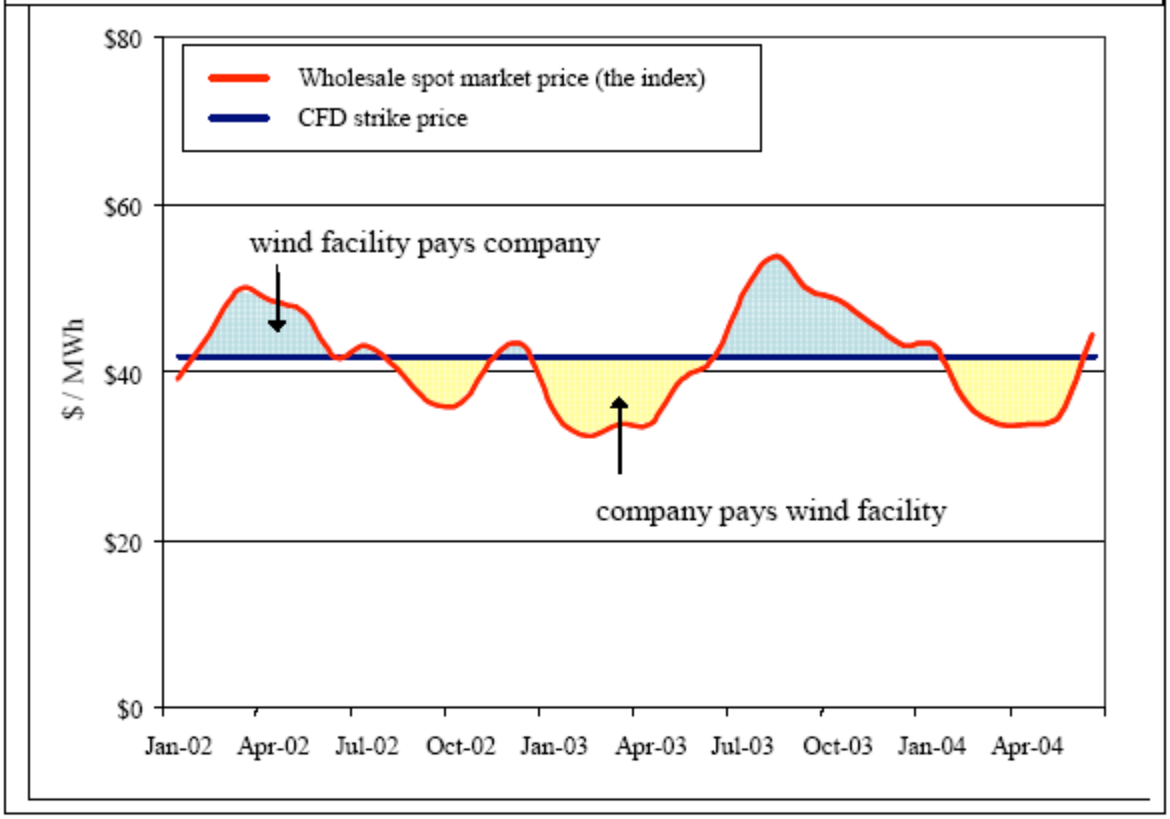
The contract for differences is a purely financial product. Under this arrangement, the customer continues to receive its electricity supply from the default service provider or from a traditional energy services company (ESCO). The price of the supply would not be fixed. A separate, financial CFD is signed with a renewable generator or intermediary. Under this contract, a fixed hedge price is established (e.g. $0.05/kWh), also referred to as the strike price. The customer would then pay the renewable supplier a floating premium for each kWh generated, which varies depending on the difference between the fixed hedge price and a variable underlying index at the time of production. If the variable index price is lower than the fixed hedge price, then the customer will pay that difference to the renewable supplier. However, if the variable index price exceeds the fixed hedge price, the renewable supplier would pay the customer. This provides a benefit to both parties—the generator gets revenue certainty, while the buyer gets a hedge against volatile or rising electricity prices, as well as the RECs.

[25] http://www.eere.energy.gov/greenpower/markets/pricing.shtml?page=3

[26] See case study on the City of Calgary, Alberta, Canada later in this report.

**Figure 1: How a Green CFD Works**

w a green contract for differences w




Source: Robert C. Grace et. al.
[http://www.mtpc.org/renewableenergy/public_policy/DG/resources/2005-05-16-AWEA-Grace-WIndHedge.pdf](http://www.mtpc.org/renewableenergy/public_policy/DG/resources/2005-05-16-AWEA-Grace-WIndHedge.pdf)

Such a CFD is a perfect hedge for a renewable generator if the generator sells the energy into the same spot market to which the CFD is indexed. If renewable energy production is low (high) at times when the index price exceeds (falls below) the fixed hedge price, however, this CFD will provide a poor hedge for the customer. On the other hand, the customer will profit under this CFD if the reverse is true. While a perfect full hedge for a customer is not possible, renewables may provide an acceptable and attractive hedge if the prices faced by the generator and the customer are positively correlated, and production and consumptions patterns are reasonably well aligned.

Contracts for Differences is not an easy financial model for the layperson to comprehend. It is a relatively new financial model for renewable energy applications and there are few retail examples yet. Therefore, it may be a market-savvy model with limited application.

Fuel Switching from Fossil to Renewable Fuels

Fuel switching involves utilizing renewable fuels instead of fossil fuels when fuel prices reach a tipping point. Renewable fuels are basically various types of biomass. This strategy can be used by utilities or by commercial/industrial customers with on-site generation. For example, a facility running diesel generators could fuel-switch to biodiesel when petroleum-diesel prices reach a certain price point. Conversely, a facility may opt to use biomass fuel when biofuel prices drop below a certain point – for example, following a storm when organic debris may be in ample supply.

## Customer Side of the Meter Models

Adjustment to monthly bills and on-site options are primarily retail customer solutions.

On-site Solar Service Model

Solar power has suffered for the last few decades from being "the next big thing" without ever becoming widely adopted by consumers. While the cost of solar power has come down tremendously in the last three decades, solar still makes up only a small fraction of a percent of electricity consumed.[27] This is in large part due to solar's large up-front capital costs, which result in long payback periods for buyers.

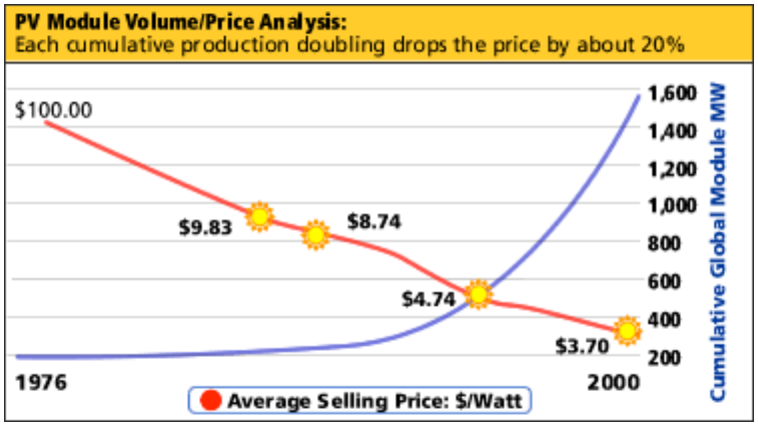
A new approach to financing solar is beginning to remove solar's front-loaded financial barriers, while allowing the customer to capture the price-stability benefits that solar provides. This model, pioneered by SunEdison (see case study on page 32) is known as "solar energy services." The traditional model of a solar installer is to sell and install the equipment and perhaps make arrangements for financing. With the solar services business model, the vendor owns, installs, operates and maintains the solar power plants at the customer's facility, while the customer benefits from predictable energy prices without paying high initial capital outlays. This also simplifies the process for the customer, since SunEdison provides a turnkey service.

It is worth noting that in some cases solar service providers offer to peg solar electricity rates at a level below retail. While that approach does signify savings for the customer it does not address price volatility. Solar service providers want to offer customers a variety of pricing points to meet individual customer needs, and some customers may prioritize comparative savings over price stability.

On-site Generation

Generating renewable energy onsite, particularly solar, is an increasingly popular way for customers to take control of their energy costs. With the costs of solar photovoltaic equipment decreasing over time, coupled with rising electricity costs and low interest rates, on-site generation is becoming more economical every year.

[27] Solar power generated 534,000 MWhs in the U.S. in 2003 of 3,883,185,000 total generation, or 0. 01%.



Source: Solar Energy Industries Association, http://www.seia.org/images/learnmore/smalldoubling.gif

Wind power, hydropower, geothermal and biomass can also be suitable renewables for on-site production but tend to be more site-specific. Since renewable energy sources (excluding biomass) are fuel free, their costs are predictable. Every MWh generated on-site is one fewer purchased from an electric supplier, whose rates may be based on volatile fossil fuels. Companies whose operation creates suitable biofuels as a by-product, such as agriculture, water treatment, and the pulp and paper sector, have ample opportunities to turn the waste stream into an on-site fuel source. In some cases, this may reduce disposal fees while creating a stable source of clean energy.

The distributed nature of onsite generation also provides public benefits. Distributed generation can decrease transmission requirements, thereby increasing the reliability of the grid.

Time-of-use Metering Combined with Solar Net Metering

Many electric utilities now offer time-of-use rates as a way to encourage customers to reduce their electricity consumption during peak hours. With time of use rates, a customer's electric rates will vary during the day (typically as "peak" and "offpeak", though there may be more gradations). Electricity used during peak hours will be more expensive than the standard rate, while energy used off-peak will be less than the standard rate.

Net metering, for consumers with generators on their side of the meter, allows electricity to flow in either direction through a bi-directional meter. When the customer's generation exceeds his/her use, electricity from the customer's facility flows into the utility's distribution grid.

Operating a solar PV system with the combination of net-metering and time-of-use rates can be an effective way to use renewable energy to reduce and stabilize energy cost because solar PV typically generates at maximum capacity during peak pricing hours. Therefore, a customer may be able to use PV to run the meter backwards during peak hours, generating credits with its electric utility. When the sun is not shining, the customer is buying power from the utility and the meter spins forward. The correlation between hours of sun and peak electricity prices is key to achieving price stability with this model.

## Policy-Driven Models

Renewable Portfolio Standards

Renewable Portfolio Standard (RPS) policies are aimed at increasing the contribution of renewable energy in the electricity supply mix. Renewable Portfolio Standards typically require that a certain percentage of a utility's overall or new generating capacity or energy sales must be derived from renewable resources. The RPS is generally intended to create a stable and predictable market for renewable electricity that maximizes the benefits of renewable generation while minimizing costs.

About half of U.S. states have an RPS program, while three Canadian provinces have a renewable energy mandate and seven provinces and three territories have 'RPS-like' energy targets.[28] When established, advocates for the law often include price stability as a key benefit. Preliminary evaluations of RPS laws indicate that RPS programs have some price stabilizing benefits. A recent report reviewed 28 distinct state- or utility- level RPS cost impact analyses completed since 1998.[29] The survey found that renewable energy provides significant price stability benefits by being a fuel-free energy source as well as reducing demand for fossil fuels, which effectively lowers prices for fuels such as natural gas and coal. Specifically, the report found that, in the year that each modeled RPS policy reaches its peak percentage target, base-case retail electricity rate increases of no greater than one percent were projected for 70 percent of the 28 RPS cost studies. In six of those studies, electricity consumers were expected to experience cost savings as a result of the RPS policies being modeled.

A recent study by Center for Resource Solutions of California found that that gas prices would be reduced by an average of $0.02-0.06/MMBtu during the 2011-2020 timeframe (see the case study at the end of this report for more detail), and other studies concur.[30] A study of Virginia assumes that each MWh of renewable generation will result in three dollars of consumer savings, and a study of Maryland models two scenarios in which natural gas prices are assumed to fall by 2 percent and 4 percent relative to the reference case forecast – all as a result of implementing a renewable portfolio standard. In fact, experts find that consumer natural gas bill savings are sometimes projected to be large enough to eclipse the electricity bill impacts of some RPS policies.[31]

Whether managing investments or energy supply, a diverse portfolio is desirable because diversity reduces risk. Adding renewable resources to the electricity generation portfolio reduces the risks posed by over-reliance on a single source of electricity and reduces costs when the costs of producing electricity from nonrenewable sources are high.

[28] "Fostering Green Power Markets: Opportunities for Growing the North American Green Power Market." Commission for Environmental Cooperation, 2006.
[29] http://eetd.lbl.gov/EA/EMP/reports/61580.pdf
[30] See Bolinger, Chen and Wiser. 2007.
[31] See Bolinger, Chen and Wiser. 2007.

## Integrated Resource Planning

Integrated resource planning (IRP) is a framework for utilities to identify the best (and in many cases the cleanest) portfolio of electricity supplies at the lowest price over the timeframe of the plan. IRP offers a way to compare a wide range of resource alternatives in a balanced manner. Resource plans began as a way to identify the least cost sources of energy supply. However, over time, some states have required consideration of social costs (i.e. environmental externalities) and demand side measures to reduce load. Recently IRP has been used to conduct more sophisticated risk assessment.

While resource plans differ from one utility to the next, most are structured according to the following common basic framework:

1. Development of peak demand and load forecasts;
2. Assessment of how these forecasts compare to existing and committed generation sources;
3. Identification and characterization of various resource options to fill a forecasted resource need;
4. Analysis of different resource portfolios under base case and alternative future scenarios; and
5. Selection of a preferred portfolio and creation of a near term action plan.[32]

In markets with retail electricity competition, resource planning is often referred to as portfolio management.

Renewable energy resources were once barely considered in utility resource plans. However, a number of recent western resource plans, including Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, Public Service Company of Colorado, San Diego Gas and Electric, and Puget Sound Energy include sizable renewable additions that are independent of RPS obligations.[33] In aggregate, 3,380 MW of wind and 270 MW of other renewables not required by an RPS are planned by western utilities. This change reflects the fact that renewable resources and particularly wind power are increasingly found to be a useful contributor to low-cost, low-risk portfolios. It is also worth noting that many utilities in the United States are either subject to, or expect to be subject to, a state and/or federal Renewable Portfolio Standard that would require the utility to provide at least a specified minimum amount of renewable energy to all customers, so there may be overlapping motivations for renewable energy development.

Utilities' inclusion of renewable energy in resource plans is primarily motivated by:

1. Improved economies of wind power;
2. Growing acceptance of wind and other renewables by electric utilities; and
3. Increasing recognition of inherent risks in fossil-based generation portfolios (for example, natural gas price risk and environmental compliance risk).

[32] http://eetd.lbl.gov/ea/EMS/reports/58450-summary.pdf
[33] See case study on Public Service of Colorado's IRP later in this report.

Increasing the inclusion of renewable energy in integrated resource planning offers the opportunity to reduce a utility's exposure to certain electricity sector risks. As mentioned above, renewable energy can act as a hedge against natural gas price risk and risk of future environmental regulations, most notably carbon regulation. Those IRPs that have evaluated natural gas and carbon risks are now regularly finding that wind power and other renewable energy options are a beneficial contributor to a low-cost / low-risk portfolio. However, the efficacy of including renewable energy in resource planning depends to a large extent on cost and performance assumptions for renewable energy technologies, the treatment of risks and the range of candidate portfolios considered.

If renewable resources are not accurately or adequately represented in utility portfolios, or if a broad range of options is not considered, the outcome could be suboptimal. A review of western resource plans found that most utilities constructed candidate resource portfolios by hand and featured resources that passed initial cost or performance screening tests. This process may allow human bias to influence the outcome. The review also found that, in many cases, a full range of renewable energy technologies was not evaluated; rather, utilities limited their analysis to wind and, in some cases, geothermal energy. In addition, the utilities limit the amount of renewable energy additions in order to limit integration costs related to wind energy. The review found that for utilities subject to an RPS, none of the plans reveal any analysis that looks at whether renewable energy additions above and beyond the RPS would have financial merit. Each of the utilities subject to an RPS essentially consider the RPS to be the sum total of their planned renewable energy commitments, effectively capping planned renewable energy additions at the RPS. This puts an artificial ceiling on the potential benefits of renewable energy.

Also important to consider are cost and performance assumptions made for various renewable technologies including the total modeled cost of the renewable resource, transmission expansion costs, integration costs and the impact of the production tax credit (PTC) on wind costs. Many utilities calculate the PTC impact in a pre-tax rather than after-tax manner, thereby significantly understating the true value of the PTC to most wind projects.

The treatment of risks may also affect the degree to which resource plans rely on renewable energy versus more conventional sources of electricity production. Resource plans generally evaluate the following risks:

1. Natural gas price uncertainty
2. Wholesale electricity price uncertainty
3. Variations in retail load and departing load (the latter being a particularly acute risk for utilities in an RPS state where direct access is possible)
4. Hydropower output variability (i.e. drought)
5. Environmental regulatory risks

Short-term variability in gas prices can be mitigated with gas storage, fuel switching, and natural gas hedge contracts (forwards, futures, swaps, and options). Hedging long-term natural gas price risks is much more difficult. The most obvious approach to mitigating long-term natural gas price risk is through ownership or purchase of electricity sources whose price is not tied to that of natural gas (i.e. coal, nuclear, or renewable energy). As mentioned above, these sources provide two hedge benefits:

1. By replacing variable-price gas-fired generation with fixed-price electricity production, these sources directly reduce exposure to gas-price risk.
2. By reducing demand for natural gas, these sources may relieve gas supply pressures and thereby reduce natural gas prices.

Renewable energy has the added benefit of reducing exposure to environmental regulatory risk, which will be described below.

The treatment of "base case" gas prices and price uncertainty in the resource plans may have an impact on the degree to which these plans rely on renewable energy. The higher the base case forecast, and the more significant the expected price uncertainty, the more value a utility may place on renewable energy.

There is a high degree of uncertainty in forecasting gas prices. Therefore, it is important that resource plans evaluate different candidate resource portfolios under a wide range of natural gas prices and scenarios. There are a wide variety of approaches to applying gas prices to candidate portfolios. Few resource plans subject all candidate portfolios to stochastic gas prices; most only apply prices to a subset of "finalist" candidate portfolios. This is important because the later in the planning process this analysis is applied, the greater the potential for suboptimal results because low-risk portfolios may be screened out based on cost prior to this analysis.

In Mexico, in compliance with the Ley del Servicio Público de Energía Eléctrica (LSPEE) Act's least cost principle, the Comisión Federal de Electricidad (CFE) would pay renewables for their long-term avoided costs including the value of the long-term price stability.

Future environmental regulation is the second type of risk that can be reduced by increasing renewable energy in resource planning. Laws and regulations governing the environmental impacts of electricity are likely to change. Future requirements are likely to be more severe than they are today. Traditional air pollutants (SOx, NOx, mercury, particulate matter) may be more tightly regulated and new state or federal carbon regulations may be implemented.

Utility-owned fossil projects and long-term power purchase agreements may be subject to these downside regulatory risks. However, renewable energy is likely to be unaffected. Purchasing or owning renewable energy assets may reduce utility exposure to these environmental compliance risks. Therefore, those utilities that consider seriously the risk of future environmental regulations will prefer new renewable energy to new fossil generation, all other things equal.

Some states are requiring utilities to take this risk into account during resource planning. Utilities operating in Oregon under the jurisdiction of the Oregon Public Utilities Commission are required to consider the impact of a range of externality values on choice of portfolio. California utilities are required to apply carbon adders in resource planning and bid evaluation and to only allow purchases/investments in electricity generation that is at or below a specified emission level.

The way in which utilities evaluate and balance expected costs and risk of candidate portfolios is particularly important for renewable energy, which is generally characterized by low risk and potentially higher initial costs. Utility regulators understand that a utility's shareholders may have a very different set of customer risk preferences than its customers. In particular, in cases where fuel costs are automatically passed through to the customers in electricity rates, utility shareholders may see little shareholder value in mitigating fuel price risk. Utilities should, but rarely do, take into account customer preferences regarding cost-risk tradeoffs.

Public Benefit Funds

A public benefits fund (PBF, or "fund") is a revenue stream most commonly financed through an ongoing surcharge on consumer electric bills (e.g., a "green tariff"), but also occasionally established through lump-sum cash transfers required by state legislation or regulatory settlements. It is used to directly support projects and activities in the electricity sector that provide important public benefits or overcome market barriers. Roughly half the states in the US have established PBFs to promote investments in energy efficiency and/or renewable energy technologies.

States have typically created renewable PBFs with a common goal in mind: to help protect, preserve, and grow nascent renewable energy markets that might be in jeopardy as the electricity industry is restructured. Accordingly, many of these funds were established in states as they opened their electricity markets to retail competition. In some cases, state regulators have authorized the creation of renewable PBFs (e.g., New York, Pennsylvania). PBFs have also arisen from utility merger or environmental settlements (e.g., Illinois Clean Energy Community Foundation, Xcel Energy's Renewable Development Fund in Minnesota). An ancillary benefit of these programs is that they provide cost-stabilizing new sources of renewable energy.

Do these programs provide substantial quantities of renewable energy? Review of current practices seems to indicate that they do.

- The Energy Trust of Oregon (the non-profit administrator of Oregon's PBF) has set a goal to meet 10 percent of Oregon's electricity load through renewable generation by 2012. This translates into support for 450 average MW of new renewable generation; according to their annual report, the Energy Trust is nine percent of the way towards meeting this goal.

- The Massachusetts Technology Collaborative (the quasi-public administrator of Massachusetts' renewables PBF) has a goal of supporting the installation of 750-1000 MW of new renewable capacity by 2009. This goal overlaps considerably with the state's renewables portfolio standard that will require the construction of around 500 MW of new renewable capacity by 2009 and shows the complementary role PBFs and RPS can play.

- New Jersey's 2003 PBF annual report lists specific long-term goals of supporting 300 MW of new, in-state renewable capacity by 2008 and increasing in-state solar generation to 120,000 MWh/year by 2008.

In the United States, PBFs were originally created as a relatively simple way to equitably collect revenues to continue public benefits programs that might go unfunded in a restructured or competitive electricity industry. However, partly due to their success and simplicity, PBFs are now considered appropriate for either restructured or conventional utility systems. Although renewable PBFs have been important to the commercialization of renewable energy technologies in the United States, they are not a panacea for all barriers to renewable energy. While PBFs are able to support small, distributed generation technologies (e.g., rooftop PV), modest funding levels and an inability to offer power purchase agreements will limit the ability of PBFs to support large, utility-scale projects (e.g., wind farms). Therefore, PBFs should be deployed in combination with, rather than in lieu of, other policy approaches. Many states with both a renewable PBF and an RPS are finding that the two complement, rather than compete with, each other. In this way, PBFs can be an important element in a portfolio of policy approaches deployed to bring renewables into the mainstream.

Regarding the "potency" of the hedge value of renewables, it is important to state the assumption that the hedge value of renewable energy is only as effective as it is pervasive. A few solar panels on a skyscraper or even a few percent of utility supply from a renewable source is not going to work financial wonders for customers because the consumers will continue to be exposed to volatile fossil fuel prices for the vast majority of their needs. This point is not a criticism of the hedge value of renewables, it is just a reminder that scale is an important factor in delivering benefits.

# IV. CASE STUDIES

## CASE STUDY: California Renewable Portfolio Standard

California's RPS, enacted in 2002, is one of the most aggressive in the world. Originally, California's RPS required retail sellers of electricity to purchase 20 percent of their electricity from renewable resources by 2017. California subsequently accelerated this goal of 20 percent renewables to 2010, and set the state's 2020 goal at 33 percent. The California Renewable Portfolio Standard, along with other California policies and regulations on the electricity sector, provides California energy consumers with an increasing amount of price-stable and low-risk electricity, reducing California's dependence on natural gas and coal.

One analysis of the California RPS found that under a 33 percent RPS, gas prices would be reduced by an average of $0.02-0.06/MMBtu during the 2011-2020 time period.[34] A study by the Union of Concerned Scientists concluded that if average annual natural gas prices are $4 per million Btu through 2010, the original 20 percent California RPS would save consumers money, an amount reaching $918 million (in $2001) by 2010.[35] With natural gas prices of $5 per million Btu, the RPS would reduce consumers' bills even more, with an overall savings of $1.8 billion ($2001) by 2010.

One issue that was subject to much debate during the crafting of California's RPS rules was whether or not renewable energy certificates (RECs) from facilities outside California would be eligible, particularly if the RECs were unbundled from the underlying electricity. Unbundled RECs would reduce transmission costs by relieving the need to wheel power into the state, but would not convey the price stability benefits to California electricity customers. The state resolved to allow only RECs that are bundled with electricity that is imported into the state. While this may increase cost per MWh for Californians, it also will provide greater cost stability insurance.

[34] http://www.resource-solutions.org/lib/librarypdfs/Achieving_33_Percent_RPS_Report.pdf
[35] http://www.ucsusa.org/clean_energy/clean_energy_policies/powering-ahead-a-new-standard-for-clean-energy-and-stable-prices-in-california.html

## CASE STUDY: The Solar Services Model of SunEdison

Jigar Shah, CEO of SunEdison, describes SunEdison's approach to meeting commercial customer needs:

> None of them want to own a power plant - it's just not core to their business. But they want solar power to lower energy costs through predictable pricing, and to improve the state of their environment. They want a solution with little or no disruption to their existing business.[36]

SunPower installs large commercial PV systems, with a customer list that includes Whole Foods, Macy's and Staples. Shah describes the price hedge benefits of SunEdison's contract with Whole Foods:

> We offered a contract that locked in electricity rates for 10 to twenty years. That removes volatility from their utility bills and provides a hedge against increasing rates in the electricity market. So that's a strong business rationale. There is literally no other solution on the market where you can lock in part of your electric utility costs for that length of time.

In 2004, Staples signed contracts for two 280 kW on-site solar PV projects at two of its distribution centers in California, covering about 10 percent of the facilities' loads. Staples signed a ten-year, fixed-price power purchase agreement (PPA) with SunEdison, with the option to renew in five-year intervals. The solar services model provides Staples with several benefits. The PV systems reduce the amount of power Staples buys from its retail electricity provider during the peak (and most expensive) hours of the day. They reduce the company's greenhouse gas emissions, helping Staples to meet one of its major environmental goals. The negotiated price for power is competitive with market rates, and the fixed price provides a hedge against retail electricity price increases. Furthermore, Staples avoids capital expenditures and maintenance costs for the PV system.[37]

Through the use of the solar services model, SunEdison provides customers with a no-hassle, fixed-price, long-term contract for solar power that can be cost-competitive with the customer's electric utility.

[36] http://marketinggreen.wordpress.com/tag/business-model/
[37] Information regarding the Staples contract with SunEdison excerpted from http://www.thegreenpowergroup.org/pdf/case_studies_Staples_2.pdf

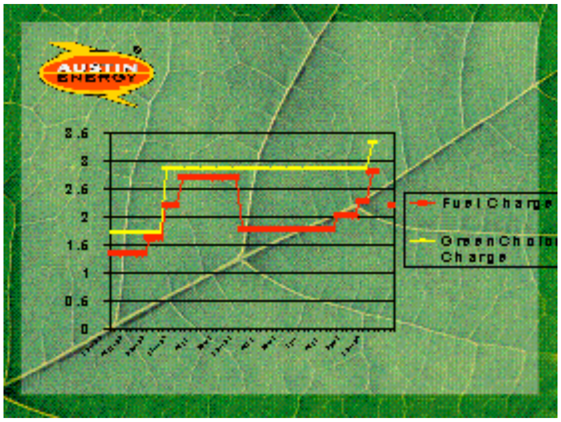
CASE STUDY: Austin Energy's Stable Rate Green Tariff

Austin Energy, a regulated municipal utility serving Austin, Texas, has one of the most successful Green Pricing programs, supporting more new renewables than any other utility program in the US. The National Renewable Energy Laboratory ranked it number one in sales in 2002, 2003, 2004, and 2005. Austin Energy launched the nation's first long-term (ten-year) fixed-price green power product for both commercial and residential customers in 2000. In designing the product, called GreenChoice®, Austin Energy locked in its own long-term fixed-price contracts for wholesale power from a variety of renewable energy projects. The price for that electricity will remain the same for the life of those contracts, allowing GreenChoice customers a way to hedge against fossil fuel price volatility.

Participants in the GreenChoice program see the electric bill standard fuel charge (currently 2.80 cents per kWh, but it is subject to fuel adjustment) replaced by a GreenChoice charge of 3.30 cents per kWh of electricity used. This replacement means that customers typically pay about one-half cent more per kWh to help support the renewable energy power provided by GreenChoice. The flat green rate provides customers with a price hedge against volatile fossil fuel prices. While fossil fuel prices are unstable, GreenChoice is offered at a fixed rate.

GreenChoice® is approximately 80 percent wind, 18 percent landfill gas, and two percent small hydropower, all of which is generated in Texas. An Austin Energy electric bill typically includes four different charges: fossil fuel, energy (overhead and transmission), peak demand, and taxes. The fossil fuel charge is typically variable. In the past, Austin Energy adjusted the fuel charge about once per year to reflect fossil fuel costs, but these adjustments became more frequent starting in 2000 with the volatility of natural gas prices. In the past four years, Austin Energy has had to increase its fuel charge several times in relatively short intervals. With the GreenChoice® product, though, the normal fossil fuel charge is replaced by a "green power charge" proportional to the amount of renewable energy that a customer chooses to buy.

The GreenChoice program was authorized by the Austin city council in 1999 and the program was launched in 2000. The initial rate was set at 1.7 cents per kilowatt hour. This rate fully recovered the costs of the original green power sources and was subsidized up to $1 million. Ten months after launching its program, Austin Energy had fully subscribed its initial 40 MW of new renewable supply and had to contract for additional renewable supply. Austin's second offering was not subsidized and was priced at 2.85 cents per kWh. This represented the contract price for the wind and did not include congestion or ancillary service costs, which were not anticipated. At the end of 2003, Austin Energy increased the green power rate to 3.3 cents per kilowatt hour. This new rate covered the wind contract price, congestion costs and ancillary services costs. The new rate applies to new program subscribers only; current subscribers continue to pay the lower green power rates established in earlier phases of the program.At the same time, standard fuel charge rates were changing as well, making the difference between standard service and green pricing larger or smaller (See Table 1). At one point, the price of their renewable energy product was lower then the price of their default service, creating a "negative premium" for green power customers.




Austin Energy offered two batches of green power, each available in April 2001 but at different prices. The green power charge for Batch 1, which was subsidized by the City of Austin, was 1.7 cents/kWh. Batch 1 totaled 100,000 MWh/year and was fully subscribed six months prior to actual availability. Batch 2 totaled 260,000 MWh/year with a green power charge of 2.85 cents/kWh. Batch 2 was fully subscribed by January 2004, at which time Austin Energy began offering a third batch of green power.

In contrast to the fixed green power charges, Austin Energy's fossil fuel charges have ranged between 1.3 and 2.8 cents/kWh (*Figure 3*). These fluctuations generally follow changes in the price for natural gas, which is widely used in Texas for electricity generation and other industrial purposes. Austin Energy, in particular, uses natural gas for 30 percent of its power generation. As the fossil fuel charge rises above 1.7 cents/kWh, customers that signed up for Batch 1 green power pay less for renewable energy than they would for conventional energy. Even without the government subsidy, Batch 2 green power sells at near parity with conventional power and may be less expensive in later years depending on changes in natural gas prices.

The experience of IBM illustrates the hedge value of GreenChoice®. In March 2001, IBM signed a five-year contract for 5.25 million kWh per year from Batch 1. At the time, the company predicted that the green power would actually cost a premium of $30,000 per year, but opted for the purchase anyway due to three leading factors. First, the fixed-price nature of the contract provided a hedge in the face of unpredictable energy markets and IBM believed that the contract would pay off eventually. Second, the cost stability provided by the contract made it easier for the company to manage its energy budget. Third, buying green power was an opportunity for the company to reduce the greenhouse gas emissions associated with its business operations.

Austin Energy's fuel charge for conventional power spiked in 2001 and IBM saved $20,000 in its first year in the program. During 2002 and 2003, GreenChoice® cost slightly less than conventional power. The fossil fuel charge rose again in 2004 and IBM saved over $60,000 for the year. Given the business benefits it provides, GreenChoice® quickly has become the nation's largest green power program among regulated utilities, and is almost double the size of the second-largest program in terms of MWh sold per year. However, the Austin Energy approach has not yet been widely replicated. Only a handful of utilities in the U.S. have developed green electricity programs that protect customers from some variable charges. To build successful green pricing programs and meet the interests of commercial and industrial energy buyers, utilities should review the Austin Energy experience and consider approaches to integrating green power hedge value into their offerings.

Some information taken from Aulisi and Hanson. "Developing Next Generation Green Power Products for Corporate Markets in North America". http://pdf.wri.org/gpmdg_corporate_6.pdf

**CASE STUDY: Public Service Company of Colorado 2003 Least-Cost Resource Plan**

The 2003 Public Service Company of Colorado Least Cost Resource Plan is distinct from other integrated resource plans in several ways. First, the plan called for building 500 MW of new wind generation by the end of 2006. This plan was created before the Colorado Amendment 37, requiring a certain percentage of resources to come from renewable energy, was passed or put into effect. The inclusion of renewable energy was based on the value of including renewable energy within the PSCo portfolio. Secondly, while most utilities construct candidate portfolios by hand featuring resources that are regionally available and pass initial cost or performance screening tests, PSCo used a capacity expansion model to determine the combination of resources that would best meet their needs. Lastly, PSCo included the possible risk of increasingly stringent future regulations regarding sulphur dioxide, nitrogen oxides and mercury, a rare inclusion among IRPs.

The PSCo Least Cost Resource Plan was filed with the Colorado Public Utilities Commission on April 30, 2004. It included a planning horizon from 2003 through 2033 and an acquisition period of 2003 – 2013. The plan called for the utility to develop or acquire 3600 MW of electric generating power by 2013 to replace expiring contracts or meet additional demand. Eighty percent of this new generating capacity was to be competitively bid. The capacity was broken out as follows:

1. 500 MW of renewable energy, primarily from wind power;
2. Development of a 750 MW coal fired plant, of which Xcel was to own 500 MW; and
3. An all-source bid process to secure 2600 MW of new capacity from natural gas, other fossil fuel-fired generation, additional renewable energy, or demand reduction.

While most utility resource plans feature resources that pass an initial cost or performance screening test, the Public Service Company of Colorado 2003 Least-Cost Resource Plan utilized a capacity expansion model from the start to construct an optimal portfolio. Under this model, no candidate portfolios were developed. Instead, for each scenario examined, a capacity expansion model optimized a single portfolio based on user-defined market conditions and constraints. PSCo then imposed constraints on each of the potential new resources that it modeled due to the computational challenges of modeling hundreds of thousands of possible resource combinations available. PSCo limited the maximum amount of wind power that could be added in any year to 320 MW (modeled as four 80 MW projects), with a cumulative cap of 2000 MW over the thirty-year planning horizon. The model allowed two of the four candidate wind projects to be added even if not needed for capacity purposes, as long as the inclusion of such projects resulted in energy savings.

PSCo's initial plan ran a capacity expansion model under four different gas price scenarios - $3, $4, $5, and $6/MMBtu gas (2003$).[38] PSCo presents numerous optimal portfolios that vary depending upon assumptions about future market conditions and natural gas prices. Over the ten-year resource acquisition period (from 2003-2013), optimal wind power additions ranged from 240-1120 MW at an assumed $3/MMBtu real gas price, from 240-1440 MW at $4/MMBtu

[38] For price context, Henry Hub prices on Wednesday, January 31 2007 (the time of this draft) averaged $7.75 per MMBtu.

gas, from 640-1440 MW at $5/MMBtu, and from 1040-1440 MW at $6/MMBtu gas. Noting a degree of discomfort (in terms of reliability concerns and integration costs) with the amount of wind capacity called for at the upper limit of these ranges, PSCo imposed exogenous constraints on the model to make the optimization more tractable. These constraints play a significant role in determining the outcome of the modeling exercise. Ultimately, the utility chose to move forward with a solicitation for 500 MW of wind projects able to come on-line before the end of 2006. If acquired, the 500 MW, along with 222 MW of existing wind capacity, would increase wind's penetration on PSCo's system to about 11 percent of peak load.

As mentioned above, the cost and performance assumptions for renewable energy included in planning models will have a significant effect on whether or not renewable resources are developed. Costs can be divided into direct and indirect. Direct costs include busbar costs, which are defined to be the cost of wind power at interconnection, including levelized capital costs and operations and maintenance expenditures, as well as the value of the production tax credit. PSCo's levelized capital and O&M costs seem to be towards the higher end of the range.

The value that utilities place on the federal production tax credit (PTC) can have a significant effect on how renewables are treated in IRPs. While it appears that many utilities have understated the value of the PTC by accounting for it in a pre-tax rather than after-tax manner, PSCo explicitly modeled this part correctly. In its initial IRP filing, it simply assumed a busbar cost for wind that was inclusive of the PTC (rather than breaking the PTC out). However, in its settlement with stakeholders, PSCo calculated the cost of additional wind capacity assumed not to benefit from the PTC by starting with the PTC inclusive busbar cost and backing out the value of the PTC yielding an equivalent "no-PTC" busbar cost. Unfortunately, PSCo overvalued the PTC in this calculation, which led to a "no-PTC" busbar cost that was too high relative to the PTC-inclusive cost, thereby hurting wind's competitiveness in this analysis.

Indirect costs include transmission and integration costs. The PSCo plan anticipates that wind will be developed within its own control area and does not reflect any transmission costs. Wind integration costs represent the impact of incorporating, as available, wind power into the grid. PSCo estimates integration costs as $2.50/MWh for the first 480 MW at nine percent of peak load wind penetration and $7/MWh for the next 320 MW at 14 percent of peak load wind penetration. The initial $2.5/MWh cost estimate was based on an average of literature review. In settlement with stakeholders, the cost increased for the next 320 MW based on an assumption that costs will increase with higher levels of penetration.

The most rigorous method for determining a project's contribution to meeting capacity needs is effective load carrying capacity (ELCC). PSCo did not use ELCC to determine capacity in its 2003 LCP; instead, it used a method adopted by the Mid-Continent Area Power Pool (MAPP) to assign a 10 percent capacity credit to wind in Colorado. The period of interest is the peak hour plus three contiguous hours during the peak month of the year, and the median hourly wind output during this period sets the capacity value. It appears that this value may have been on the low side.

In determining the risk posed by future environmental regulation, PSCo considers the possibility of both carbon regulation and regulation for other pollutants. This seems to be rare in most IRPs, in that many utilities look at carbon regulation only and ignore potential future regulation for other pollutants. For its initial IRP, PSCo assumes a cap and trade with a cap year of 2000, a start year of 2009, and three scenarios with \$0/ton, \$5/ton, and \$9.9/ton with no probability weighting for any scenarios. The PSCo settlement plan assumes cap and trade, with cap year of 2000, a start year of 2009, and a base case model with 100 percent probability at \$7.20/ton. PSCo considers the possibility of increasingly stringent future regulation of criteria pollutants (SOx, NOx, mercury, particulate matter) in its original resource plan. Assumed cost of complying = SO2: \$796/ton (levelized 2003 \$/ton); NOx: \$796/ton; and Mercury: \$9,954/ton.

Resource Acquisition Process

In February 2004, Xcel Energy announced the construction of a new 750 MW coal-fired generating unit at an existing facility, Comanche Station in Pueblo Park. In April 2004, PSCo filed the 2003 Least Cost Resource Plan. The Colorado Public Utilities Commission (CPUC) consolidated review of the Comanche coal plant with the Least Cost Planning (LCP) and wind power plant review. In August 2004, the CPUC approved the RFP process for the 500 MW of renewable energy. PSCo requested an accelerated decision on the renewable energy in order to be able to take advantage of the federal production tax credit. Once the RFP process was approved, PSCo issued an RFP for up to 500 MW of wind to be on-line by the end of 2006. When the PTC was extended only to the end of 2005, PSCo accelerated the projects to come on-line by the end of 2005. They short-listed three projects totaling 400 MW of new wind generation, but in late March 2005 signed contracts with only two projects, totaling 129 MW.

During the review process for the LCP and Comanche station plant, 28 organizations, agencies, and other groups intervened in the consolidated hearings. The CPUC held three weeks of public hearings on the LCP in November 2004. On December 17, 2004, the Colorado Public Utilities Commission approved an all-inclusive settlement agreement regarding the Least-cost Resource Plan. The settlement agreement was endorsed by a variety of parties, including the CPUC staff, Colorado Office of Consumer Council. Southwestern Energy Efficiency Project, Sierra Club, Environmental Defense, Western Resource Advocates, Tri-State Generation and Transmission Association, and others. Under the settlement, PSCo would move forward with the building of the new Comanche plant, but would install state-of the art emissions reduction equipment on all generating units at the Comanche Generating Station, reducing total sulfur dioxide and nitrogen oxide emissions at the station despite increasing total production. The company would also expand energy conservation programs by undertaking best efforts to acquire 320 MW of total demand reduction over 10 years, accelerate a feasibility study of additional renewable energy resources, work with environmental organizations to identify programs to reduce GHG emissions, provide donations to local Pueblo community to reduce diesel bus emissions from school districts, fund mercury reduction efforts at a local steel mill, and participate in Pueblo sustainable economic development discussions.

In late February 2005, PSCo issued an all-source RFP for 2500 MW from dispatchable, non-dispatchable and demand-side resources. Renewable energy is eligible to compete in this solicitation. In December 2005, PSCo announced intent to acquire 775 MW of additional wind generation to be in service by the end of 2007, 1300 MW of existing and new natural gas generation to be in service between 2007 and 2012 and 30 MW of energy efficiency and conservation from third parties. Xcel committed to spend \$196 million to achieve 320 MW of energy efficiency and conservation through 2013 with third party or company-sponsored programs.

If the proposed wind energy projects are successful, Xcel Energy would become the largest provider of wind energy to customers in the U.S. and would also meet non-solar Amendment 37 requirements for 2015 – seven years early.

As of October 2006:

- Construction continues on the 750 MW Comanche 3 coal-fired generation unit.
- The All-Source RFP Bid Evaluation process for 2007-2012 is complete. PSCo has executed power purchase contracts for three wind facilities totaling 775 MW and five gas-fired facilities totaling 1300 MW. Therefore, PSCo has completed contracts for resource additions to meet customers' forecasted electricity demand through 2012.
- Continuing evaluation and negotiation of bids offered for 2013.
- Negotiating contracts for a 3.2 MW LFG facility and a 0.22 MW hydro facility.

## CASE STUDY: Contract for Differences – City of Calgary, Alberta, Canada

The concept of green Contracts for Differences (CFD) has been put into practice in Alberta, where wind- and biomass-based CFDs have been structured in the wake of market deregulation. Wholesale electricity market restructuring began in Alberta in 1996. In 2000, power prices spiked, at one point reaching a 500 percent increase over prices at the start of the year. Price volatility was hitting power markets throughout western North America due to a combination of factors, including the California electricity crisis, natural gas price increases, capacity and transmission issues, and gaming by market participants. As Alberta moved to full deregulation for both wholesale and retail markets in January 2001, energy buyers understood the value of hedging against electricity price volatility.

In September 2001, Calgary Transit of the City of Calgary began a 10-year green CFD based on wind power. The wind generator is VisionQuest, a division of the TransAlta power company. In addition, the retail power supplier, ENMAX, serves as an intermediary owing to its existing customer relationship, although it has no risk exposure in the contract. Calgary Transit partnered with VisionQuest to develop "Ride the Wind!," a program that uses wind-generated electricity to power its commuter CTrains.

There are 12 windmills located in southern Alberta that generate the wind power. The amount of power equivalent to that used by the CTrain is sent to the main power grid. The CFD covers a load of 26,000 MWh per year and is indexed to Alberta's spot electricity market (there is only one spot market in the province). The strike price for the contract is in the range of 7 cents Canadian per kWh. Since contract inception, the spot price for power has fluctuated above and below the strike price, meaning both parties have made and received payments.

Although the CTrain itself does not produce CO2 emissions, the supply of electricity used originally for CTrain traction power was supplied by coal- or natural gas-powered facilities that do produce greenhouse gases. Using wind-generated power, CTrain has been able to reduce CO2 emissions by 26,000 tonnes annually. As the CTrain lines are extended, the savings in emissions will also increase. It is expected that the "Ride the Wind!" program will increase power costs by less than one-half of one cent per passenger.

Since the implementation of the "Ride the Wind!" initiative in 2001, Calgary Transit has been the proud winner of two prestigious awards. In 2001, it won a Federation of Canadian Municipalities CH2M HILL Sustainable Community Award for its leadership in renewable energy. Calgary Transit was also the recipient of a 2001 Pollution Prevention Award in the innovations category, presented by the Canadian Council of Ministers of the Environment, and a 2004 Corporate Recognition Award from the Canadian Urban Transit Association (CUTA).

The CTrain is now 100 percent emissions free. It is the first public light rail transit system in North America to power its train fleet with wind-generated electricity[39].

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[39] *Some information sourced from Calgary Transit web site, http://www.calgarytransit.com/environment/ride_d_wind.html*

## V. Program Recommendations/Conclusion

Renewable energy is best known to the public for its environmental benefits. However, fossil fuel price increases in recent years have drawn attention to renewable energy as a price-stabilizing technology. Following is a summary of key points on why renewable energy is a price hedge, and how electricity providers and their customers can tap into that hedge benefit.

- Fossil fuels have experienced, and continue to experience, unpredictable and volatile prices. In order to lock into long-term, fixed-price contracts for fossil fuels, a considerable premium must be added to the supply contract.

- Renewable energy is mainly sourced from free fuels such as wind, sunshine, waterways, and geothermal sources.

- There is little correlation between forecast and actual prices. The problem is such that we have both high volatility and little ability to forecast.

- Coal prices have been easier to accurately forecast, but coal is associated with major environmental and regulatory risks. It is difficult to predict how coal could be constrained by potential greenhouse gas regulations or how this could affect prices.

- Utilities and electric service providers can tap into the price hedge value of renewables by:
    - Basing their evaluation of future natural gas prices not on forecasts but on actual forward prices.
    - Including future regulatory risk as a factor when evaluating non-renewables.
    - Including renewable energy in IRP resource plan analysis or as a critical part of the supply portfolio.
    - Buying renewable energy or renewable energy certificates (RECs) through Contracts for Differences.

- Individual electric customers can obtain the price stability benefits of renewable energy by:
    - Installing on-site renewable energy generation.
    - Buying renewables though a pricing structure that is based on the long-term price of the renewable energy (and is not pegged to fossil fuel prices).

Renewable energy is already making a difference in providing price stability benefits, not only for renewable energy consumers, but for all energy consumers. According to the American Wind Energy Association, by the end of 2006 wind energy use will save over 0.5 billion cubic feet (Bcf) of natural gas each day, relieving some of the current supply shortages.[40] As fossil

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[40] http://www.awea.org/pubs/factsheets/EconomicsOfWind-Feb2005.pdf

fuel prices appear to be on a continued upward price trend, and as price spikes have been the norm in the industry, we expect renewable energy to be an increasingly attractive option for utilities and individual electricity consumers.

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