Risk Analysis of Procurement Strategies for Residential Standard Offer Service

A Report to the Maryland Office of People's Counsel

Resource Insight, Inc.
Jonathan Wallach
Paul Chernick

Synapse Energy Economics, Inc.
David White
Rick Hornby

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Study Approach

The Electric Customer Choice and Competition Act of 1999 mandated that Maryland's utilities provide a transitory standard offer service ("SOS") to residential customers at prices that reflected market rates. Since 2004, in accordance with the terms of a Commission-approved settlement agreement, Maryland's investor-owned utilities have relied on short-term full-requirements contracts with wholesale suppliers to fulfill their obligations under the 1999 law.

The passage of Senate Bill 1 in 2006 (Chapter 5, Acts of 2006 Special Session) changed the standards for the provision of residential SOS, imposing a permanent obligation on utilities to serve consumers from a portfolio of resources that provides electricity at the "best price" and that avoids "excessive price increases" (Md. Public Utility Companies Article §7-510(c)(4)(ii)). The mandate is no longer to provide reasonably priced service for the short transition to retail competition, but to ensure that SOS is the lowest-cost and least-risk service achievable over the long term.

To meet this new obligation, Maryland's utilities will need to engage in a planning process that evaluates resource portfolios not just on the basis of *expected* future cost, but also in terms of the risk of *unexpected* future costs in excess of expected cost. Every portfolio strategy entails risk to consumers; the challenge set by Senate Bill 1 will be to identify the strategy that minimizes expected costs at an acceptable level of risk.

This study represents a first step toward meeting that challenge. It offers a methodological approach for modeling uncertainty in the forecasted values of major drivers of portfolio cost, such as fuel prices, and for measuring quantitatively the portfolio risk associated with forecast uncertainty. In addition, this study describes a modeling analysis of long-term costs and risks for a variety of illustrative resource portfolios. These resource portfolios were selected in order to assess the long-term costs and risks associated with the current SOS procurement approach, to evaluate the impact of relying on spot purchases to serve residential SOS load (as is currently under consideration by the Maryland Public Service Commission in Case No. 9117), and to explore the trade-offs between cost and risk from procurement of a diversified mix of resources to serve residential SOS load pursuant to the requirements of Senate Bill 1.

The authors developed a simulation model for this analysis that quantifies *uncertainty* around forecasts of portfolio costs——i.e. the probability that future costs will be either above or below expected forecasted values. The model then measures the *risk* of bad outcomes associated with that forecast uncertainty—i.e., the probability that future costs will exceed expected forecast values by substantial margins. Forecast uncertainty is captured by modeling input values for major cost drivers as probabilistic distributions around expected values. The simulation model uses these probabilistic inputs to generate 1,000 forecasts of annual portfolio costs over a twenty-year planning horizon, with each forecast reflecting a unique combination of forecast paths for the probabilistic input values. Thus, the model generates not just one, but a distribution of 1,000 twenty-year forecasts of portfolio costs. The expected portfolio cost from this method reflects the average over the entire distribution of 1,000 cost forecasts; portfolio risk is measured based on a portion of the distribution representing high-cost outcomes.

The authors characterized seven different supply and demand resource options, and then assembled varying mixes of these resource options into the following six different candidate portfolios for simulation modeling:

1. **Business As Usual ("BAU").** This portfolio assumes a continuation of the currently approved procurement mechanism, with its laddered acquisition of two-year full-requirements contracts.
2. **Spot-Based Supply ("Spot").** This portfolio consists solely of one-year spot-based full-requirements contracts. We model this portfolio to evaluate the impacts on long-term cost and risk of relying on spot-market purchases of energy to serve residential SOS load.
3. **Clean BAU.** This portfolio is designed to assess the incremental cost and risk impact from the addition of efficiency and renewable resources to the BAU portfolio. It consists of a mix of two-year full-requirements contracts, savings

from energy-efficiency programs, and fifteen-year contracts indexed to the cost of new wind resources.

4. **Demand-Side-Management–Wind–Natural Gas ("DWN").** This is one of three portfolios designed to illustrate the trade-offs between long-term costs and portfolio risk associated with a diversified portfolio of energy efficiency and short-, medium-, and long-term supply contracts. The DWN portfolio consists of a mix of two-year full-requirements contracts, five-year fixed-block contracts, energy efficiency, fifteen-year wind-indexed contracts, and fifteen-year contracts indexed to the cost of new natural gas combined-cycle ("NGCC") plant.
5. **Demand-Side-Management–Wind–Coal ("DWC").** The DWC portfolio consists of the same mix of resources as the DWN portfolio, except that fifteen-year contracts indexed to the cost of new pulverized-coal plant replace the fifteen-year NGCC-indexed contracts in the portfolio.
6. **Demand-Side-Management–Wind–Natural Gas–Coal ("DWNC").** This portfolio combines fifteen-year NGCC-indexed and coal-indexed contracts in the resource mix.

Conclusions

The results of this study lead to the following conclusions regarding the current SOS procurement approach and alternative procurement strategies.

First, short-term market-priced contracts expose consumers to excessive costs and risks. Continued reliance on short-term market-priced contracts, such as under the current approach or with a spot-based alternative, is likely to be both the most expensive and the riskiest option for serving residential SOS load.

Of all the candidate portfolios considered in this study, the BAU and Spot portfolios produce the highest expected annual costs in almost every year of the planning horizon, as well as the highest expected net present value ("NPV") cost over all twenty years of the planning horizon. See Figures ES-1 and ES-2.

Figure ES-1: Expected Annual Portfolio Costs

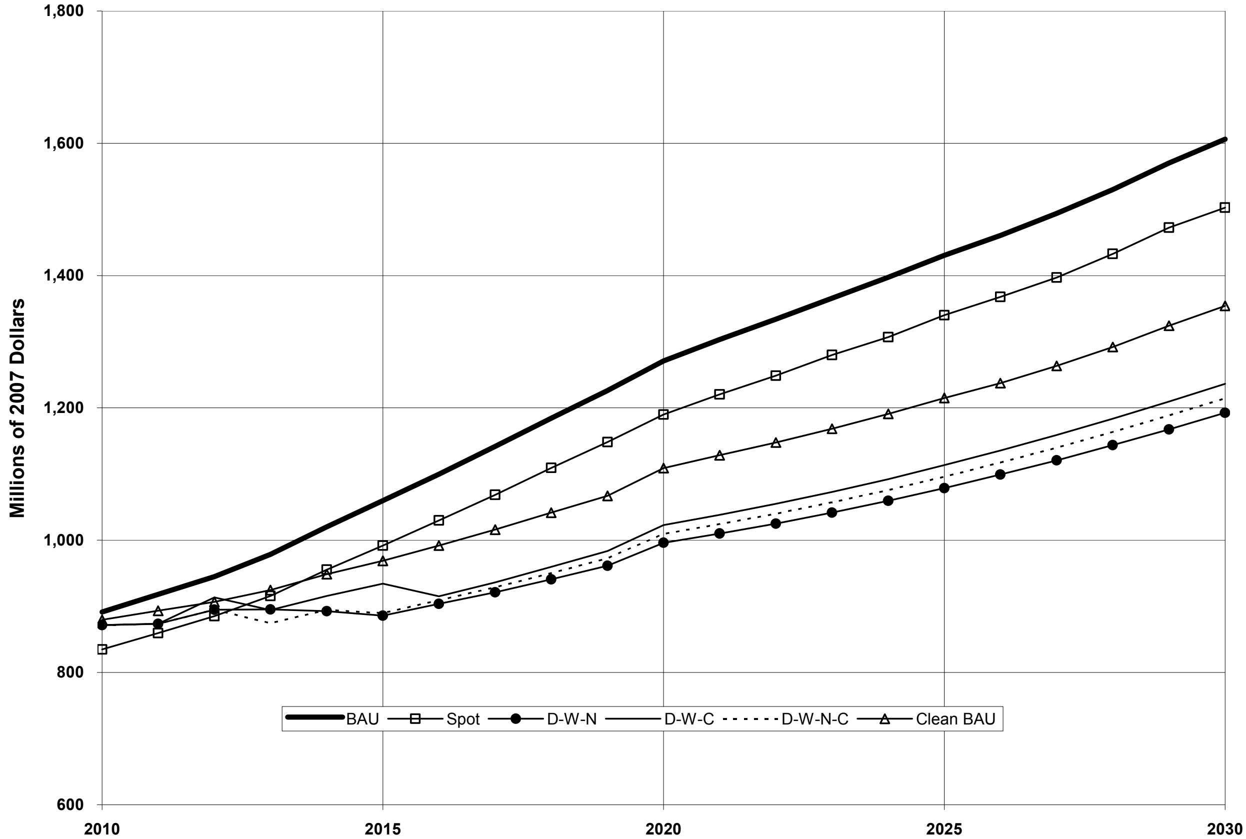
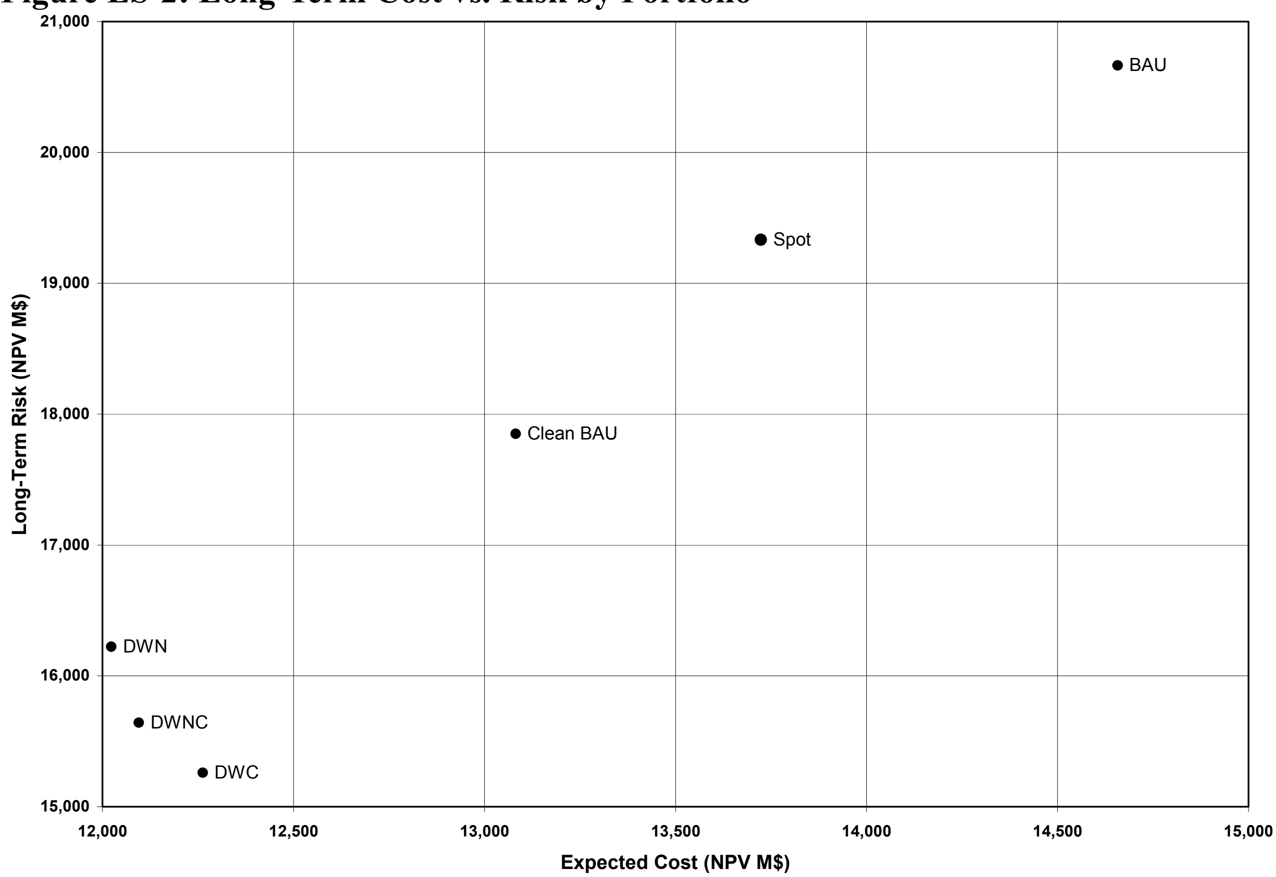


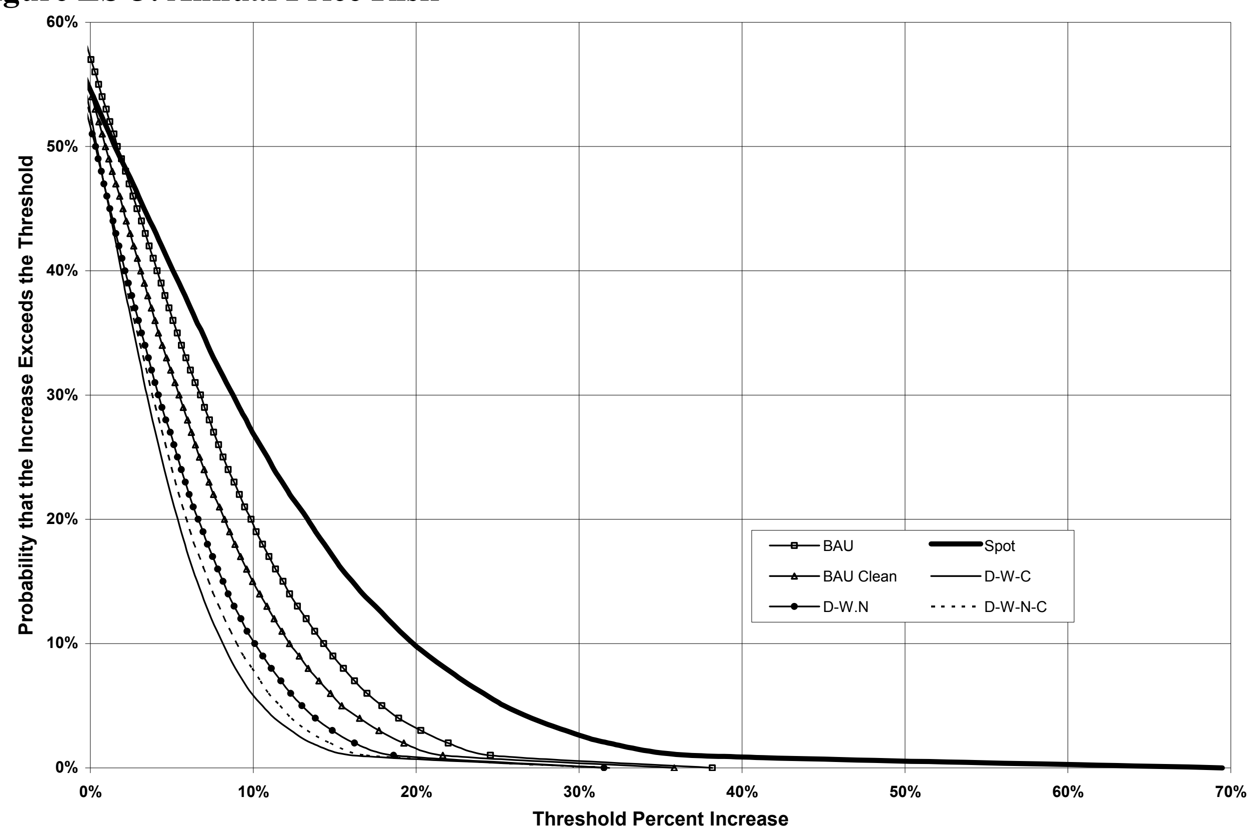
Figure ES-2: Long-Term Cost vs. Risk by Portfolio



The BAU and Spot portfolios not only have the highest expected costs but also pose the greatest long-term risk over the planning horizon; see Figure ES-2. (Long-term risk is measured in terms of the costliest 10% of the 1,000 forecasts of portfolio NPV costs.) While there is a one-in-ten chance that the cost of the most-diversified portfolios (i.e., DWN, DWC, and DWNC) will increase by $4 Billion, or about 30%, it is just as likely that the cost of the BAU or Spot portfolios will increase by $6 Billion, or about 41%.

Second, the potential cost savings from spot purchases are too small to justify the likely increase in price risk. While a spot-based portfolio may be slightly less expensive than the current approach, because of a lower price premium for supplier risk, these savings are likely to come at the cost of greater annual price risk. There is a 3% probability under the current procurement approach that prices will increase by more than 20% in any year of the planning horizon; see Figure ES-3. In contrast, there is a 10% likelihood of an annual price increase in excess of 20% under a spot-based approach, more than triple the odds under the current approach. Spot purchases would allow consumers to avoid a small risk premium on two-year full-requirements supply, but at the cost of dramatically increasing the likelihood that price volatility will reach levels that are contrary to the public interest.

Figure ES-3: Annual Price Risk



Third, consumers benefit from the procurement of clean resources. Adding energy efficiency and wind resources to the BAU portfolio improves overall portfolio performance, reducing both expected cost and long-term risk. These clean resources lower expected portfolio costs by substituting for more-expensive market-priced contracts. They also reduce long-term risk, since their costs are uncorrelated with the wholesale market prices that drive the costs of the market-priced contracts that remain in the Clean BAU portfolio.

Fourth, portfolio diversification lowers costs and mitigates risks to residential SOS customers. The reduction to portfolio risk is especially dramatic. As noted above, there is a 10% probability that the NPV costs of the most-diversified portfolios (i.e., DWN, DWC, and DWNC) will increase on average by 30%. In contrast, there is an equal likelihood that the NPV cost of the BAU portfolio will increase by 41%. In other words, if the diversified portfolios and BAU portfolio had the same expected NPV cost, the diversified portfolios would still have lower NPV costs than the BAU portfolio at the 10% probability level. This suggests that portfolio diversification would reduce the risk of portfolio costs in excess of expected costs, even if portfolio diversification did not lower costs on an expected-value basis.

Our analysis provides strong evidence that modifying the current SOS procurement approach to allow acquisition of a diversified portfolio of demand and supply resources would both reduce costs and mitigate risks to residential SOS customers. This analysis also illustrates the potential for trade-offs between costs and risk with different approaches to portfolio diversification. It is our hope that Maryland's utilities will build on these findings as they fulfill their statutory obligation to minimize the cost of serving residential SOS load over many years of an uncertain future.

2. Introduction

The Electric Customer Choice and Competition Act of 1999 deregulated electric-utility generation service in Maryland and eliminated the long-standing obligation for Maryland's electric utilities to provide generation service to ratepayers at cost-of-service rates. In place of cost-based generation service, the restructuring statute mandated that Maryland's utilities provide a transitory standard offer service ("SOS") to residential customers at "a market price that permits recovery of the verifiable, prudently incurred costs to procure or produce the electricity plus a reasonable return" (Md. Public Utility Companies Article §7-510(c)(3)(ii)(2)).

Starting in 2000, Maryland's investor-owned electric utilities fulfilled their obligations under the 1999 restructuring statute by providing standard offer service to residential customers at rates established by Commission-approved settlement agreements. In 2004, again in accordance with Commission-approved settlement agreements, Potomac Electric Power Company and Delmarva Power and Light started charging for residential SOS at the cost of wholesale power supply acquired through competitive solicitations. Baltimore Gas and Electric and Allegheny Power followed suit in 2006 and 2007, respectively.

Since initiation of competitive procurement of market-priced supply in 2004, Maryland's utilities have relied solely on short-term full-requirements contracts with wholesale suppliers to serve residential SOS load. With terms ranging from four months to three years, these full-requirements contracts require sellers to supply energy, capacity, ancillary services, losses, and any other electrical services (other than transmission and distribution services) necessary to deliver power to the customer's meter to serve that customer's load at all times. Moreover, these contracts oblige sellers to provide full-requirements service at prices that are fixed at the start of the contract term, thereby requiring suppliers to assume the risk of increases in the market price to provide full-requirements service over the life of the contract.

As the events of 2006 starkly revealed, the protections against price volatility offered by fixed pricing do not extend beyond the life of the contract. Dramatic changes in PJM's wholesale markets over the last eight years have substantially increased market price levels and price volatility. Residential SOS customers have been fully exposed to these adverse market trends as full-requirements contracts roll over and are re-priced to reflect prevailing market conditions.

Enacted in response to the SOS price shocks of 2006, Senate Bill 1 (Chapter 5, Acts of 2006 Special Session) changed utilities' obligations to provide residential SOS, imposing a permanent obligation on utilities to serve consumers from a portfolio of resources that provides electricity at the "best price" and that avoids "excessive price increases" (Md. Public Utility Companies Article §7-510(c)(4)(ii)). The statutory mandate is no longer to provide reasonably priced service for the short transition to retail competition, but to ensure that SOS is the lowest-cost and least-risk service achievable over the long term.

To achieve the objective of a long-term, lowest-cost, least-risk SOS, Maryland's utilities will need to engage in a long-range-planning process that is designed to identify the mix of supply, demand-side-management ("DSM"), and transmission resources that maintains reliability (and advances other public-policy goals) at minimum expected cost and at acceptable risk under conditions of uncertainty. In other words, the planning process will need to evaluate resource portfolios not just on the basis of *expected* future cost, but also in terms of the risk of *unexpected* future costs in excess of expected cost. Accordingly, this integrated planning process will need to be designed to measure quantitatively portfolio risk arising from forecast uncertainty, determine the impact of resource additions on portfolio risk, determine the relationship between expected costs and portfolio risk for each resource portfolio, and identify preferred resource portfolios and near-term procurement targets that minimize expected costs at acceptable levels of risk.

This study represents a first step toward the implementation of such an integrated planning process in Maryland. It offers a methodological approach for modeling uncertainty in the forecasted values of major cost drivers (such as fuel prices) and for quantitatively measuring portfolio risk associated with forecast uncertainty. Moreover, this study provides a modeling analysis of costs and risks for a variety of illustrative resource portfolios over a twenty-year planning horizon.

The simulation model developed for this analysis is designed to explicitly account for uncertainty in the forecasted values of major cost drivers (such as fuel prices), and to measure quantitatively the combined impact of uncertainty in cost drivers on portfolio cost. Forecast uncertainty is captured by modeling input values for these cost drivers as probabilistic distributions around expected values. The simulation model uses these stochastic inputs to generate a multitude of "futures," reflecting different combinations of forecast paths for these stochastic input values, with each future yielding a unique long-term portfolio cost.[1] Thus, the simulation modeling generates a distribution of cost outcomes, with the expected portfolio cost reflecting the average over the entire distribution of outcomes and portfolio risk measured based on a portion of the distribution representing high-cost outcomes.

Table 1 summarizes the composition of the resource portfolios that we evaluated through simulation modeling. We designed these portfolios to simulate the long-term costs and risks associated with the current SOS procurement approach and alternative procurement strategies.

Table 1: Resource Portfolios

Portfolio	Composition
Business As Usual ("BAU")	Annual rolling procurement of two-year full-requirements contracts[a]
Spot	100% of energy requirements met with spot purchases, with additional costs for market products needed to provide full-requirements service
Clean BAU	Mix of two-year full-requirements contracts, energy efficiency, and fifteen-year contracts indexed to cost of new wind resources
DSM-Wind-Natural Gas ("DWN")	Mix of two-year full-requirements contracts, five-year fixed-block contracts, energy efficiency, fifteen-year wind-indexed contracts, and fifteen-year contracts indexed to new natural-gas combined-cycle (NGCC) plant
DSM–Wind–Coal ("DWC")	Same as DWN, with fifteen-year contracts indexed to new pulverized-coal plant substituting for fifteen-year NGCC-indexed contracts
DWNC	Combination of DWN and DWC

[a]Although the current approach procures contracts twice a year, we assumed annual procurement to simplify the modeling effort.

This study is not intended to be, and in fact falls far short of, the type of comprehensive planning analysis that utilities need to engage in to meet their obligations under Senate Bill 1. The authors designed this analysis to show how to

[1]A stochastic variable is an input variable whose value is subject to random variation in the simulation modeling.

quantify uncertainty and measure risk, to indicate the long-term costs and risks associated with the current procurement approach, and to illustrate some of the trade-offs between cost and risk associated with alternative procurement strategies and portfolio diversification. Maryland's utilities must take the next step by developing an integrated resource plan that minimizes the cost of serving residential SOS load over many years of an uncertain future.

3. Modeling Approach

The primary objective of the modeling analysis is to forecast expected annual costs, and the distribution of cost outcomes around those expected costs, for a variety of resource portfolios for serving residential SOS load.[2] For this analysis, the authors structured the resource portfolios to meet forecasted demand for Potomac Electric Power Company's residential customers, and simulated costs for those portfolios over a twenty-year planning horizon starting in 2010.[3] All cost inputs and results are expressed in constant 2007 dollars.

Our goal was not to develop a fully-specified least-cost integrated resource plan for PEPCo's residential class, but to evaluate the potential trade-offs between expected costs and portfolio risks associated with the current procurement process and alternative portfolio approaches. As such, we did not engage in a comprehensive evaluation of demand-, transmission-, and supply-resource options, as is typical for an integrated planning process. Instead, we characterized a limited set of indicative resource options, and assembled these resource options into a set of "candidate portfolios" designed to illustrate the cost and risk trade-offs associated with portfolio diversification.

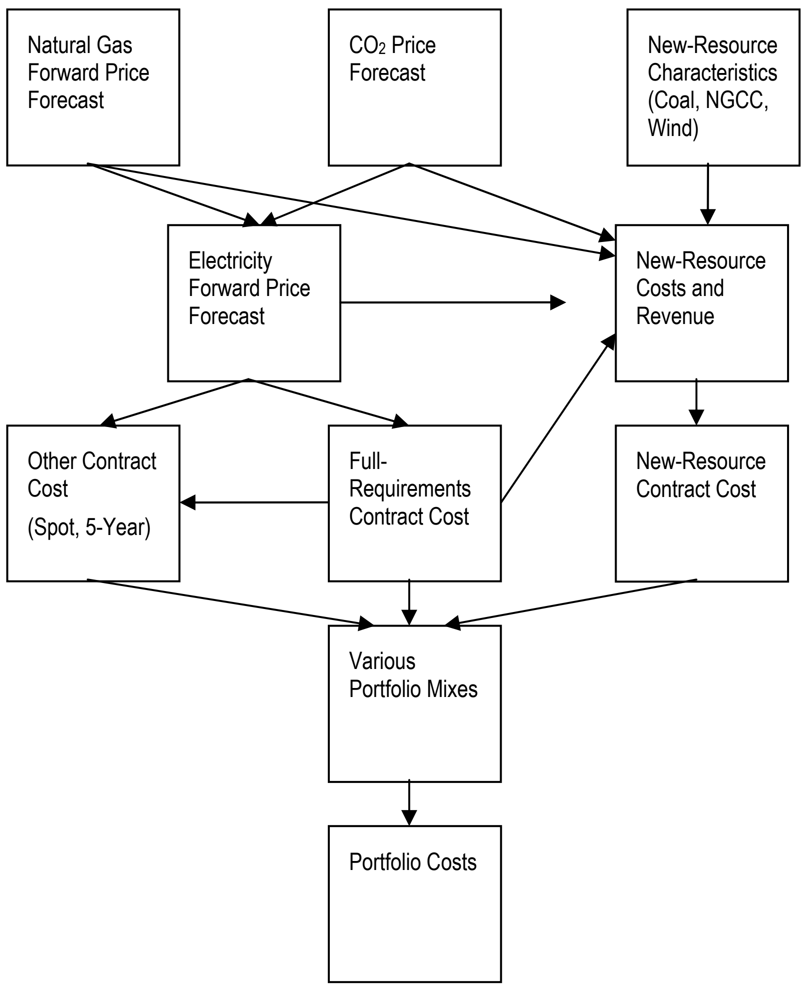
Figure 1 provides a schematic of our approach to modeling portfolio costs. We modeled all supply resources as purchased-power contracts, with contract prices assumed to be indexed to either wholesale market prices or to the costs

[2]More precisely, our analysis forecasts costs for a portfolio that provides full-requirements service, whether that portfolio consists solely of full-requirements contracts or of a mix of wholesale products that are the equivalent of a full-requirements contract.

[3]The model simulates costs through 2030, to allow for twenty years of stochastic changes from the 2010 base-year input data.

of new generation investments. In order to price market-based contracts, the simulation model developed for this analysis simulates annual PJM Western Hub forward and spot energy prices over the twenty-year planning horizon. For contracts indexed to new generation, the simulation model is designed to forecast annual capital and operating costs for the underlying generation resources. The forecasts of both wholesale-market prices and annual generation costs, in turn, are driven by forecasts of input-fuel prices, carbon-mitigation costs, and other underlying operating costs.

Figure 1: Modeling Framework



The analysis captures forecast uncertainty by modeling natural gas and CO_2-allowance prices as stochastic variables. These two variables are treated stochastically because they are expected to be primary drivers of uncertainty in future wholesale electric energy prices. In addition, the model includes random variation in the derivation of wholesale electric forward and spot prices.

We did not model uncertainty in the construction costs, or fixed operating costs, of new plants. Although future construction and fixed operating costs are uncertain today, the modeling analysis assumes that such costs will be set prior to plant construction in the purchased-power contracts indexed to these new resources. Since our analysis neither assumes nor proposes a commitment to any particular resource at any particular cost at this time, it is not necessary to model uncertainty in the future acquisition cost for a new-resource contract.

We also did not explicitly model uncertainty in the balance between supply and demand, and in particular the impact on market prices of unexpected changes in that balance. For example, an unexpected reduction in supply versus load might lead to a spike in energy prices. Such an unexpected tightening could be due to an unexpected increase in load, the failure of expected capacity to materialize, the unexpected retirement of existing capacity, plant deratings, unusually long outages of capacity, delays in transmission additions, increased sales to adjacent regions, or reduced purchases from adjacent regions. The model captures the effect of these variations in the demand-supply balance with a single random variable applied to the forecast of PJM Western Hub forward prices, representing the historical dispersion of electric prices around the price explained by natural gas prices.[4]

Annual costs for each of the candidate portfolios are simulated using an Excel-based model with Monte Carlo–simulation capability. Using a Latin Hypercube sampling technique, the spreadsheet model generates 1,000 forecasts (i.e., “futures”) of annual portfolio costs over a twenty-year planning horizon, with each forecast representing a series of annual random draws from the user-specified probability distributions for the stochastic cost inputs.[5] In each year of each of these 1,000 forecasts, the stochastic cost values from these random draws are combined with deterministic cost inputs to derive the annual cost for each resource included in the candidate portfolio; the annual resource costs are then summed to derive the annual portfolio cost. Thus, each model run for a candidate portfolio generates a distribution of 1,000 cost outcomes for each year of the twenty-year planning horizon.

[4]That random variable also captures changes in market prices due to changes in market rules, environmental constraints, SO_2- and NOx- emissions prices, and any other factor that has caused historical variation in electric energy prices.

[5]Latin Hypercube sampling is a form of stratified sampling that reduces the number of iterations for a Monte Carlo simulation to obtain reasonably accurate statistical results.

We evaluated the performance of candidate portfolios in terms of both expected costs and portfolio risk over the twenty-year planning horizon. The expected cost of a candidate portfolio is calculated as the average cost over the entire distribution of cost outcomes. We measured and compared long-term portfolio costs on the basis of expected twenty-year net present value ("NPV") costs, i.e., the net present value over the twenty-year planning horizon of expected annual costs.

We measure portfolio risk in terms of the likelihood of bad outcomes in an uncertain future, as determined by the distribution of cost outcomes. For example two portfolios might have very similar expected costs, but a very different range of cost outcomes: one with significant variation in cost outcomes in excess of expected cost, and the other showing little such variation. For the purposes of this analysis, we formulated the following two summary measures of portfolio risk:[6]

- **TailVaR$_{90}$** measures long-term portfolio risk over the planning horizon. TailVaR$_{90}$ is a measurement of the NPV values for the costliest 10% of the 1,000 futures. For any portfolio, it is derived by first calculating the twenty-year NPV cost for each of the 1,000 futures. The portfolio TailVaR$_{90}$ is then calculated as the average of the 100 highest NPV values from the 1,000 futures.
- **Exceedance probability** is a summary measure of annual price volatility over the twenty-year planning horizon. For each portfolio, exceedance probability measures the probability that year-to-year price changes will exceed a particular threshold percentage level.[7]

[6]These risk measures are used by the Northwest Power and Conservation Council to evaluate long-range resource plans (NPCC 2005).

[7]In this case, the threshold level is a real, i.e., net of inflation, price increase, since all costs in the modeling analysis are expressed in constant 2007 dollars.

4. Stochastic Variables

Natural Gas Prices

Average annual natural gas prices have increased significantly over the last decade. They have also shown considerable variability on a month-to-month and year-to-year basis. Figure 2 illustrates these historical trends. We are now in a period of high and volatile natural gas prices. This pattern is likely to continue, as reserves of natural gas in North America are declining at the same time that demand is increasing and world oil prices are at record high levels.

The authors developed a stochastic model of natural gas prices in PJM by analyzing the historical data on forward prices for two-year natural gas contracts. In essence, we modeled random variation in the forecast of annual changes of gas forward prices based on the distribution of historical annual price changes for two-year contracts for gas delivered to PJM.[8] For the purposes of this analysis, we assumed that gas contracts would be procured five months in advance of contract delivery, and that contracts would be priced at the sum of NYMEX forwards for Henry Hub and Texas Eastern Zone M-3 basis swap.[9]

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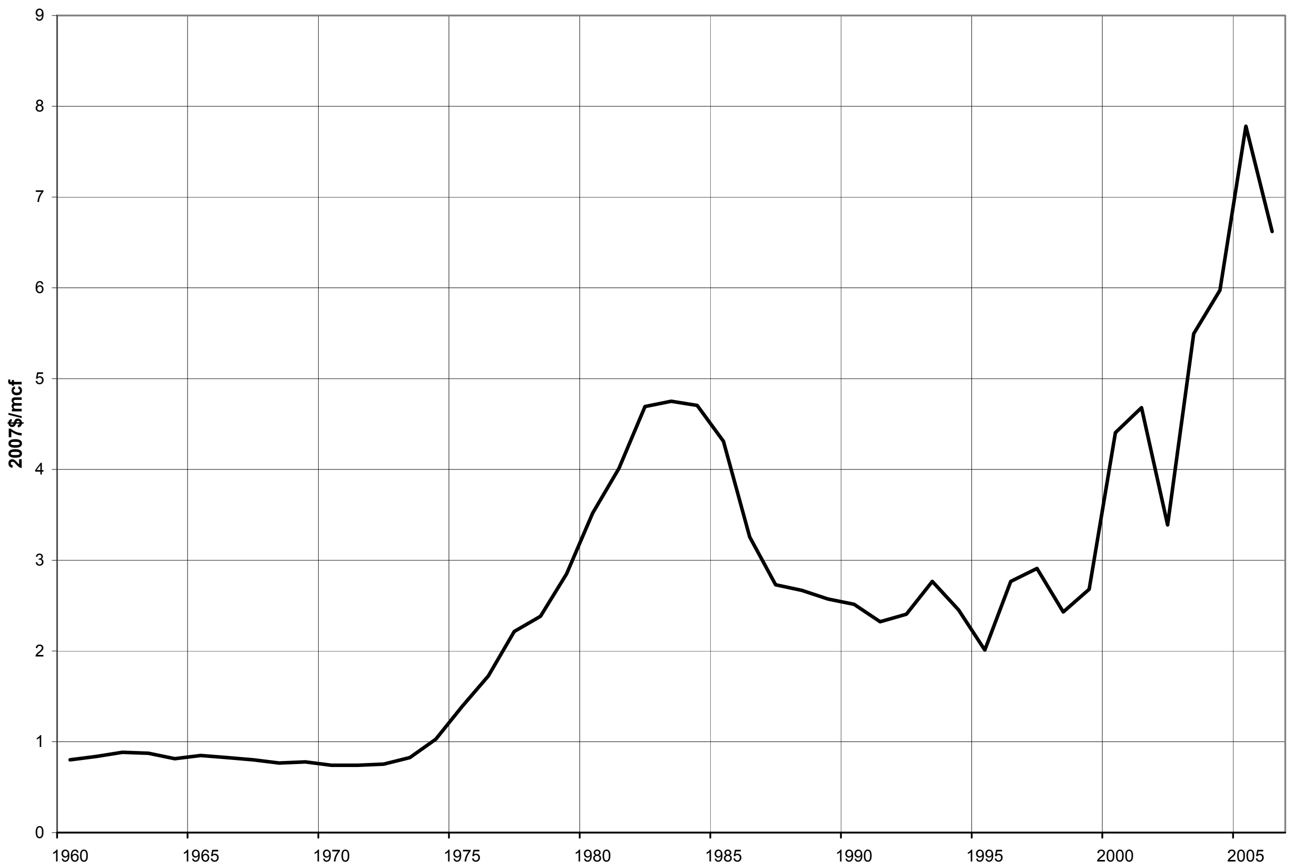
[8]We examined price volatility for two-year strips because, as discussed later in this section, our modeling analysis forecasts forward prices for two-year electric energy contracts based on a forecast of forward prices for two-year gas contracts.

[9]We assumed a five-month lag between procurement and delivery in order to model price uncertainty associated with the lag under the current SOS procurement approach.

We examined historical year-over-year changes in forward prices separately for the first year and for the second year of a two-year strip. For the first year, we analyzed forward prices, and the year-over-year changes in those prices, for a one-year strip starting five months in the future. For example, as of December 12, 2002 (the first date for which we have the Zone M-3 forwards), the one-year strip for May 2003 through April 2004 was priced at \$4.85/MMBtu. One year later, on December 12, 2003, the one-year strip for May 2004 through April 2005 cleared at \$5.75/MMBtu, or 18.4% higher than the previous year's strip. Our analysis indicates that these year-over-year changes range from −20% to +80%.

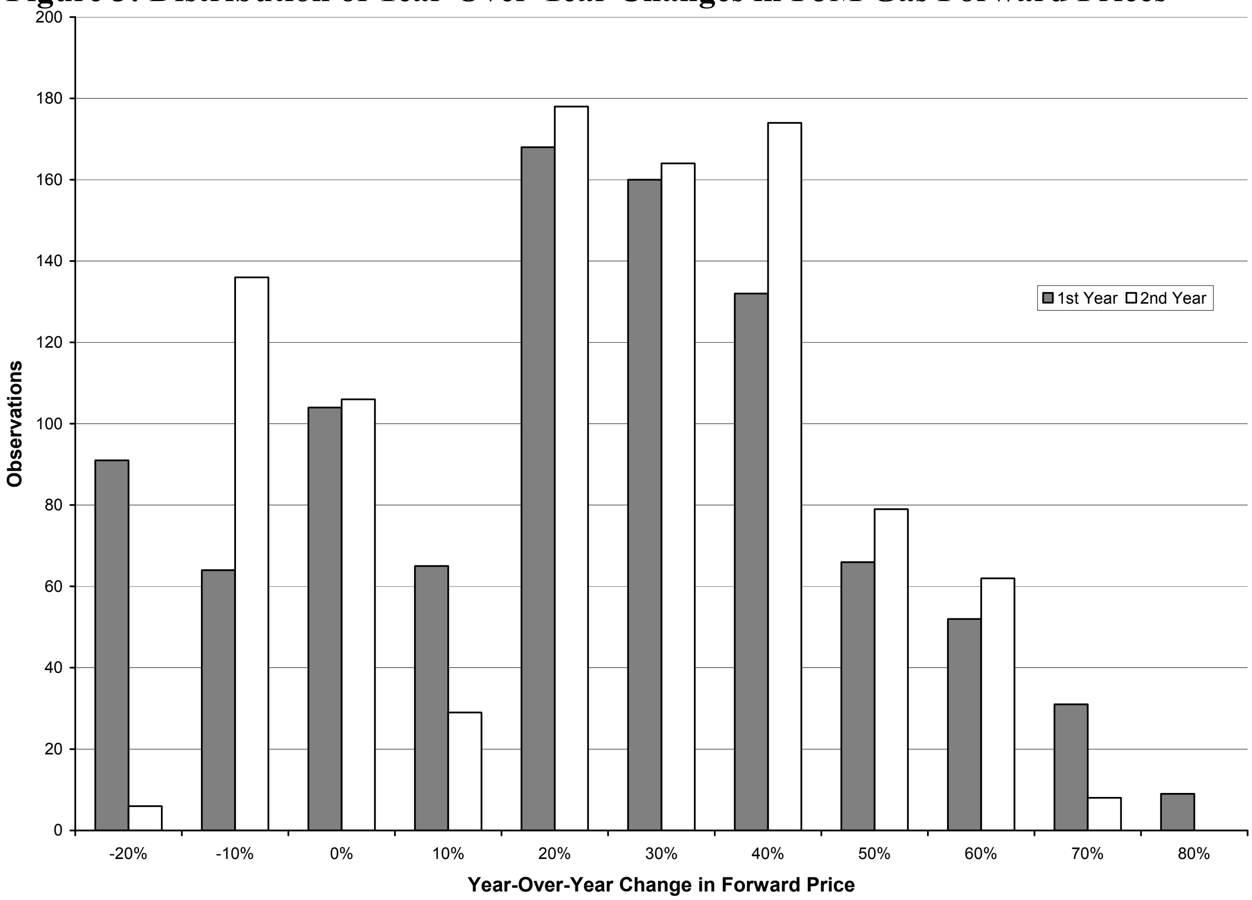
Figure 2: U.S. Wellhead Natural Gas Prices



For the second year, we computed year-over-year changes in forward prices for a one-year strip starting seventeen months in the future. The range of annual price changes for the second year of a two-year strip was comparable to that for the first year of that two-year strip.

Figure 3 provides the distribution of year-over-year changes in forward prices for the for the first and second years of a two-year strip based on all available data through August of 2007.

Figure 3: Distribution of Year-Over-Year Changes in PJM Gas Forward Prices



Our data on forward prices for gas delivered to PJM are limited to the period 2002–2007. Forward prices for earlier trading dates are available for contracts at Henry Hub, but not for contracts at mid-Atlantic delivery points. To test whether the period 2002–2007 was representative of the longer historical record, we computed the average annual change, and the standard deviation around that average, in forward prices for the first year and for the second year of a two-year contract at Henry Hub. We calculated these price changes for the periods 1992–2007 and 2002–2007. As with our analysis of contracts for delivery to PJM, we assumed that the Henry Hub contracts would be purchased five months in advance of the start of contract delivery.

Henry Hub forward prices for both the first and second year of a two-year contract grew more slowly on average in the 1992–2007 period than in 2002–2007, but the volatility in the growth rates was higher in the longer period. See

Table 2. Hence, we may have understated the volatility of gas prices, compared to the last fifteen years, by basing our distribution of annual price changes on data for the 2002–2007 period.

Table 2: Annual Change in Forward Prices for Two-Year Gas Contracts

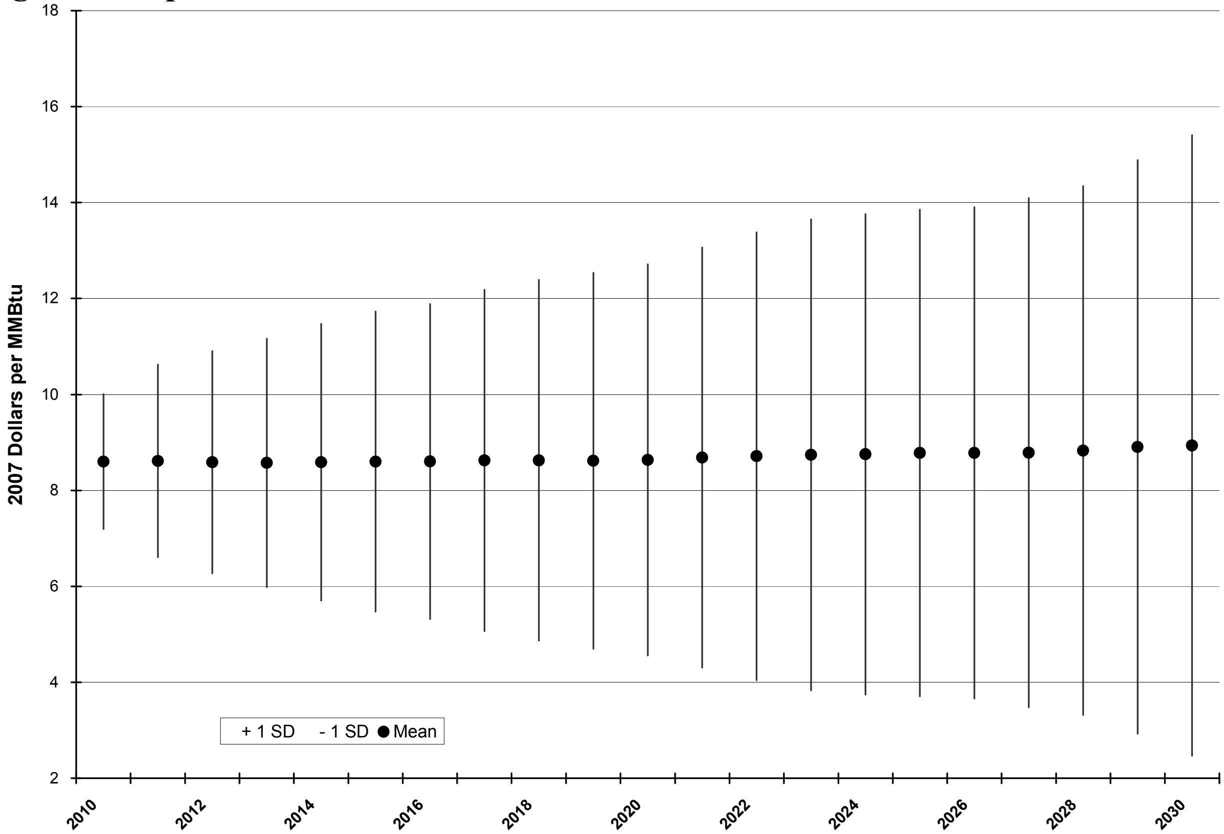
	First Year	Second Year
Henry Hub 1992–2007		
Average:	15.1%	19.1%
Standard deviation:	27.0%	20.6%
Henry Hub 2002–2007		
Average:	20.4%	31.6%
Standard deviation:	23.9%	12.8%
Delivered to PJM 2002–2007		
Average	17.2%	18.7%
Standard deviation	24.5%	21.5%

Based on the historical distribution of year-to-year price changes, we forecast annual price changes using a triangular distribution.[10] We adjusted this statistical distribution so that the expected prices for delivered gas would track recent NYMEX futures prices and would grow after 2010 at a real escalation rate of about 0.1%, the rate predicted in the reference case of the Department of Energy's 2007 Annual Energy Outlook (U.S. EIA 2007a). This price forecast retains the price volatility experienced in the last several years, but not the rapid growth in price. The resulting projection of annual natural gas prices follows a random walk with drift (at a rate of 0.1% per year).

Figure 4 provides the expected values, and standard deviations around those expected values, of the 1,000 forecasts of annual natural gas prices.

[10]We used the same distribution based on first-year price changes to model random variation in annual prices changes for both the first and second year of a two-year contract, due to the fact that the historical distributions for the first and second years were similar and that the data for the second year was much more limited.

Figure 4: Expected Natural Gas Prices with Standard Deviations



Carbon-Emission Allowances

We assume that regulations will be implemented during the first five years of the planning horizon requiring fossil-fueled electric generators to comply with limits on carbon dioxide emissions. We model those regulations as a cap-and-trade system with an associated market for carbon-emission allowances.

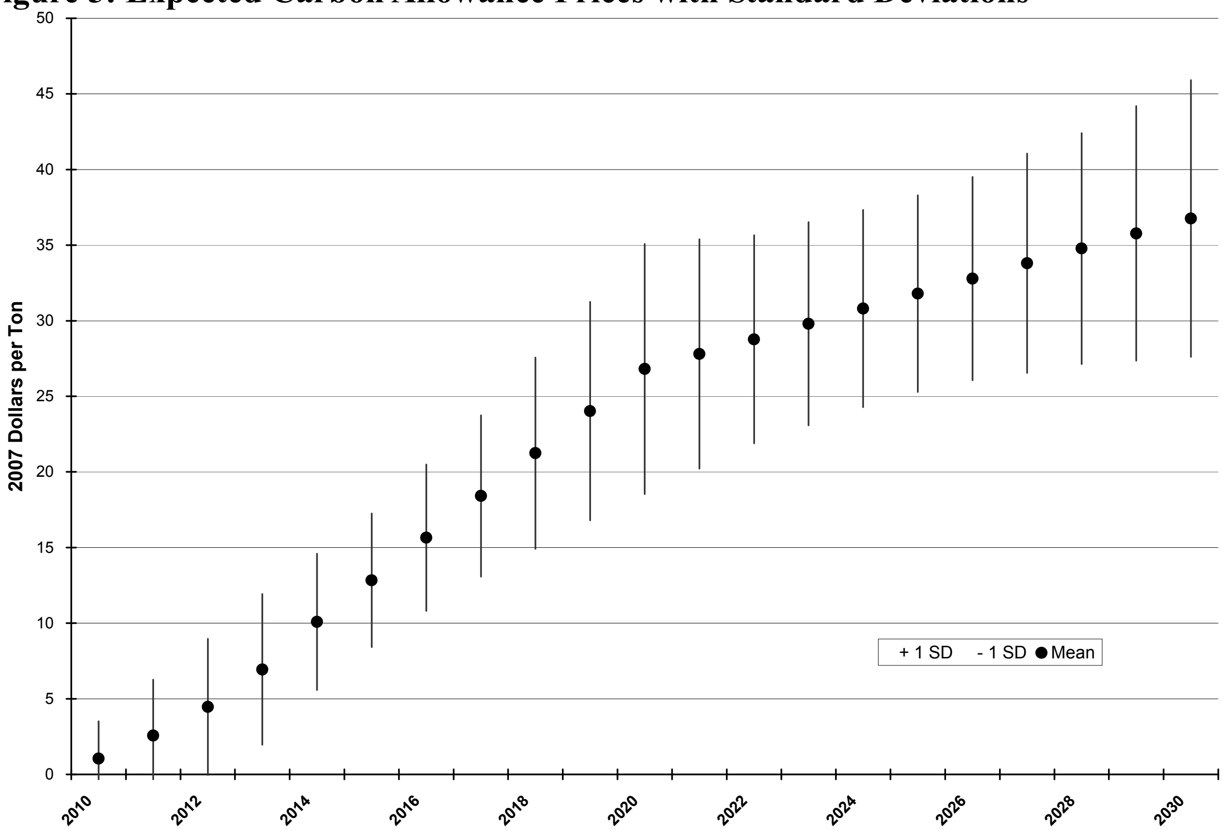
Our forecast of carbon-allowance prices reflects both regulatory and market uncertainty. The basis for this forecast is Johnston, Hausman, Sommer et al. (2007), who studied the likely costs of compliance associated with proposed greenhouse-gas legislation. They developed projections of carbon-mitigation costs for Low, Mid, and High regulatory scenarios using a number of public studies that considered possible future regulations and technology costs.

For this modeling analysis, we converted the carbon-mitigation cost projections for those scenarios into a distribution, such that 90% of the simulated outcomes were within a range bounded by the Low and High regulatory-scenario prices.

In addition, we modeled uncertainty around the start year for regulation of CO_2 emissions and uncertainty in year-to-year market conditions.

Figure 5 provides the expected values, and standard deviations around those expected values, of the 1,000 forecasts of annual prices for carbon allowances.

Figure 5: Expected Carbon Allowance Prices with Standard Deviations



Forward Prices for the PJM Western Hub

The simulation model generates 1,000 forecasts of annual prices for on- and off-peak fixed-block forward contracts for delivery at the PJM Western Hub. These forecasts, in turn, are driven by stochastic forecasts of market prices for natural gas forward contracts and for CO_2 allowances, along with assumptions derived from historical data regarding the relationship between gas and electric forward prices in on- and off-peak periods.[11]

[11]This relationship between clearing prices for contemporaneous gas and electric forward contracts is often referred to as the “implied heat rate” or “spark spread.”

In essence, the model generates in each year of each of the 1,000 futures: (1) a forecast of forward market prices for two-year gas contracts; and (2) an estimate of the market price for CO_2 allowances. The model applies on- and off-peak spark spreads to the forecasted gas forward prices, adds CO_2-compliance costs based on assumptions regarding the mix of marginal resources, and then applies a random variable reflecting load and supply uncertainty to derive a forecast of electric forward prices.

Using a regression analysis of recent gas and electric forward prices, we derived the following formulas for estimating PJM Western Hub electric prices as a function of forecasted annual prices for natural gas forward contracts:

- On-peak \$/MWh = 9.1 × gas forward price (\$/MMBtu)
- Off-peak \$/MWh = 3.8 × gas forward price (\$/MMBtu) + 20

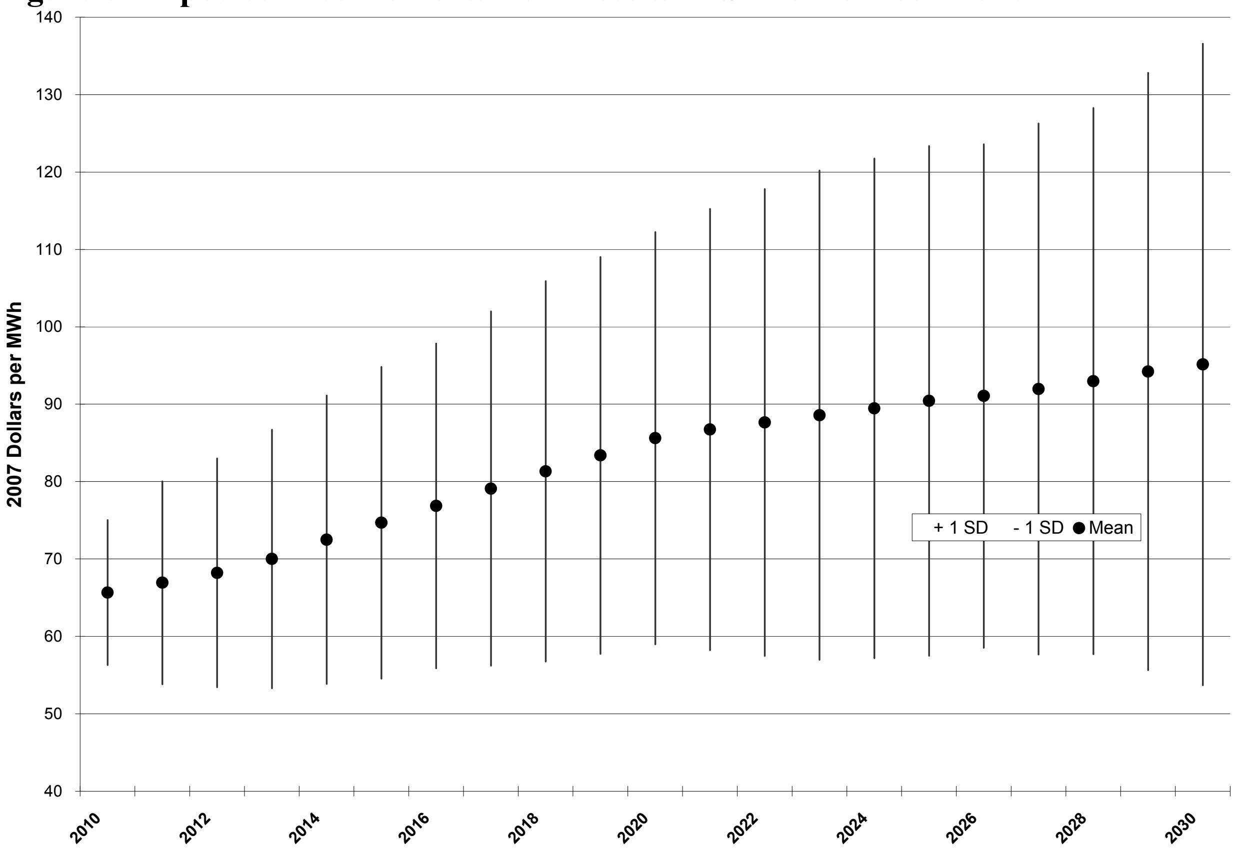
In each year of each of the 1,000 futures, the simulation model applies these formulas to the price forecast for gas forwards to derive on- and off-peak electric prices.

These electric prices are pre–carbon-mitigation, since the formulas reflect electric-gas price correlations for a historical period prior to implementation of carbon-mitigation regulations. The simulation model therefore adds an annual estimate of the cost of carbon allowances, based on that year's forecast of the carbon-allowance price and our assumptions regarding the marginal fuel mix and the efficiency of the marginal units. For the on-peak period, we assume that 80% of the marginal energy is from natural gas, at an average heat rate of 9,100 Btu/kWh, and 20% is from coal, at an average heat rate of 10,000 Btu/kWh. For the off-peak, we assume that 25% of the marginal energy is from natural gas, at an average heat rate of 7,000 Btu/kWh, and 75% of the marginal energy is from coal, at an average heat rate of 10,000 Btu/kWh.

Finally, we add a random annual variation in forward electric prices, based on the historical dispersion of electric prices around the price explained by the average correlation between electric and natural gas forward prices (as reflected in the formulas discussed above.) The forward spark spread (the ratio of electric to gas prices) has varied from year to year, in ways that cannot be explained by gas prices. These variations may result from changed expectations for coal and oil prices, SO_2 and NOx allowance prices, plant efficiencies and variable O&M (which may be driven by environmental retrofits and requirements), generator market power, and the effects of changing market rules, as well as changes in the load-supply balance due to changing expectations for capacity (due to additions, re-ratings and retirements), maintenance schedules, load growth (due to the economy and forecast weather, among other factors), and inter-regional purchases and sales. The model account for these various factors by adding to both on- and off-peak electric forward prices in each forecast year a random variable with a triangular distribution that ranges from an 8% reduction to an 8% increase in the forecasted price.

Figure 6 provides the expected values, and standard deviations around those expected values, of the 1,000 forecasts of annual forward prices for contracts for delivery at the PJM Western Hub.

Figure 6: Expected Electric Forward Prices with Standard Deviations



Spot Prices for the PJM Western Hub

For each forecast year for each of the 1,000 futures, the simulation model derives an annual average price for spot-market purchases at the PJM Western Hub by applying a multiplier to the forecasted annual price for PJM Western Hub forward contracts. The multiplier in any forecast year is determined by an annual random draw from a distribution of multipliers; we derived this distribution based on an analysis of historical ratios of spot to forward market prices.[12] For reasons discussed below, we assume a distribution mean of 1.0, i.e., that the expected value of annual average spot prices in any year will equal the forecasted forward price for that year.

We derived the distribution of multipliers based on an analysis of the relationship between average spot and forward prices over various twelve-month periods between October of 2003 and November of 2007. For each twelve-month delivery period, we calculated two price averages and then took the ratio of those two averages. First, we calculated the twelve-month average of the on-peak hourly prices in the day-ahead market for the PJM Western Hub. Second, we calculated the twelve-month average of the clearing prices for NYMEX-traded PJM Western Hub on-peak monthly forward contracts.[13] For this latter calculation, we assumed that the twelve monthly forward contracts would be procured at one time, five months in advance of the start of the twelve-month delivery period, as under the current procurement approach for residential SOS load.[14]

Table 3 provides, for each twelve-month delivery period, (1) the spot and forward price averages and (2) the resulting ratio of spot to forward prices. The first delivery period runs from October of 2003 to September of 2004; May of 2003 was the first full month of NYMEX trading of PJM forwards, so October is the earliest feasible start date when assuming procurement five months in advance. Each successive delivery period starts one month later than the previous period, with the last period ending in November of 2007, corresponding to the last twelve-month period for which spot prices were available at the time of the analysis.

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[12]This distribution captures the risk of price volatility assumed by consumers with a spot-based full-requirements product. However, it does not fully reflect the total portfolio risk assumed by consumers due to the correlation between load and price. Consumers face not just the risk that spot prices will be higher than expected, but that these unexpectedly high prices will occur at times of abnormally high demand. Hence, *cost* volatility will be greater than *price* volatility.

[13]We did not analyze off-peak prices, because there is a limited history for NYMEX trading of off-peak forwards. Also, trading volume for off-peak forwards has been thin. Nonetheless, the ratio of on-peak to off-peak forward prices closely matches the ratio of on-peak to off-peak spot prices. Thus, we expect that the ratio of off-peak spot to forward prices would be comparable to the on-peak ratio.

[14]To simulate procurement five months in advance of delivery, we used the clearing prices for the trading date five months prior to the start of the twelve-month delivery period.

Table 3: Historical Ratios of PJM Spot to Forward Prices

Delivery Period		Delivery Period Average Price On-Peak Day-Ahead	On-Peak Forward	Day-Ahead-to-Forward Price Ratio
Oct-03	Sep-04	48.57	49.01	−1%
Nov-03	Oct-04	49.70	51.34	−3%
Dec-03	Nov-04	50.50	44.65	13%
Jan-04	Dec-04	50.73	43.46	17%
Feb-04	Jan-05	49.87	43.18	15%
Mar-04	Feb-05	49.63	41.34	20%
Apr-04	Mar-05	50.59	41.81	21%
May-04	Apr-05	51.13	42.21	21%
Jun-04	May-05	50.83	46.16	10%
Jul-04	Jun-05	52.38	46.90	12%
Aug-04	Jul-05	55.29	49.41	12%
Sep-04	Aug-05	59.96	51.53	16%
Oct-04	Sep-05	64.77	51.87	25%
Nov-04	Oct-05	68.91	56.15	23%
Dec-04	Nov-05	71.07	54.31	31%
Jan-05	Dec-05	75.42	54.04	40%
Feb-05	Jan-06	76.07	53.33	43%
Mar-05	Feb-06	76.98	55.76	38%
Apr-05	Mar-06	77.26	61.99	25%
May-05	Apr-06	77.58	57.76	34%
Jun-05	May-06	77.42	53.70	44%
Jul-05	Jun-06	76.80	57.92	33%
Aug-05	Jul-06	76.09	60.38	26%
Sep-05	Aug-06	75.59	66.66	13%
Oct-05	Sep-06	70.53	62.18	13%
Nov-05	Oct-06	66.33	63.17	5%
Dec-05	Nov-06	64.76	68.43	−5%
Jan-06	Dec-06	60.72	72.28	−16%
Feb-06	Jan-07	59.94	84.28	−29%
Mar-06	Feb-07	61.20	90.77	−33%
Apr-06	Mar-07	61.65	88.53	−30%
May-06	Apr-07	62.55	93.40	−33%
Jun-06	May-07	63.89	90.68	−30%
Jul-06	Jun-07	64.84	87.01	−25%
Aug-06	Jul-07	64.43	75.14	−14%
Sep-06	Aug-07	63.56	81.90	−22%
Oct-06	Sep-07	65.41	86.46	−24%
Nov-06	Oct-07	67.65	78.79	−14%
Dec-06	Nov-07	68.45	79.39	−14%

Average	7%
St Dev	24%
Minimum	−33%
Maximum	44%

The ratios of spot to forward prices for the twelve-month delivery periods range from a maximum of 44% to a minimum of −33%, with an average over all delivery periods of 7% and a standard deviation around that average of plus or minus 24%. In other words, on average, spot prices for a twelve-month period exceeded forward prices for that same period by approximately 7%. However, there is significant variation around that average, as indicated by the fact that the standard deviation of the price difference is more than three times the average difference.

Although the historical analysis shows an average 7% difference between spot and forward prices, we assume for the purposes of forecasting spot prices that forward prices forecasted in the simulation model are unbiased estimators of actual average annual spot prices. Given the limitations in the underlying historical data, and the wide variation in the experienced ratios, it is not possible to predict with any reasonable certainty that spot prices will be either greater or less than forward prices.[15] There is simply too much variability in the small historical sample to forecast a difference between average spot and forward prices with a reasonable degree of confidence.[16]

For the purposes of forecasting spot prices as a function of forward prices, we therefore assume a mean value of 1.0 for the distribution of multipliers. We model uncertainty around this expected value by assuming a triangular distribution with limits of plus or minus 1.20.[17]

Figure 7 provides the expected values, and standard deviations around those expected values, of the 1,000 forecasts of annual market prices for PJM Western Hub spot purchases.

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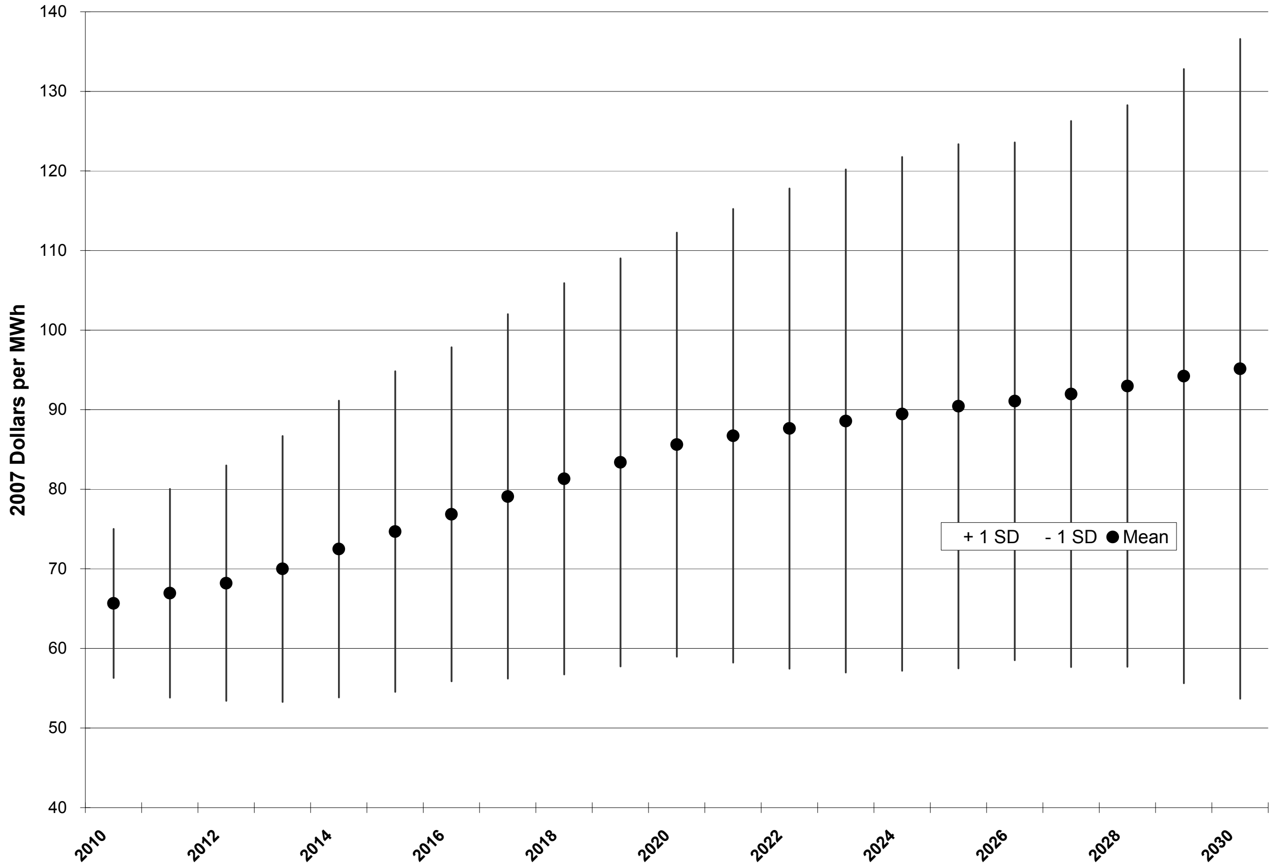
[15]In fact, we find no difference when we take the average of the historical ratios over just the four non-overlapping twelve-month delivery periods between October of 2003 and November of 2007.

[16]Statistical testing of the historical data indicates that the difference between the mean of historical twelve-month average spot prices and the mean of historical twelve-month average forward prices is not statistically significant.

[17]These limits correspond to a standard deviation of approximately 8%.

Figure 7: Expected Electric Spot Prices with Standard Deviations



5. Resource Options

Overview

The authors characterize the following supply and demand options for incorporation in candidate portfolios:

- Two-year full-requirements contracts.
- Spot-based one-year full-requirements contracts.
- Energy-efficiency portfolio.
- Five-year fixed-block contracts for a constant amount of energy in every hour of each year of the contract.
- Fifteen-year contracts indexed to the cost of new gas combined-cycle ("NGCC"), pulverized-coal, or land-based-wind resources.[18]

Contract prices for the full-requirements and five-year contracts are assumed to be indexed to wholesale market prices. Our estimates of prices for all supply options include additional costs associated with "firming up" the supply contract to provide full-requirements service to residential SOS customers.[19]

[18]We assume that contract deliveries for the gas- and coal-indexed contracts are determined by economic dispatch of the underlying new resource. Deliveries for the wind-indexed contracts are determined assuming a capacity factor of 35%.

[19]These estimates do not include costs or revenues associated with auction-revenue rights, compliance with the Renewable Portfolio Standard, or transmission and distribution losses, since these costs are the same for all resource options.

Two-Year Full-Requirements Contracts

Under the currently approved SOS procurement mechanism, Maryland's utilities acquire two-year contracts for full-requirements wholesale supply to serve residential SOS load. Full-requirements wholesale supply includes the supply of energy, capacity, ancillary services, and any other electrical services other than transmission and distribution services necessary to deliver power to the customer's meter to serve that customer's load at all times.

For the purposes of forecasting costs for full-requirements contracts, the analysis assumes that contract prices reflect the following costs:

- on- and off-peak fixed-block forward energy contracts at PJM Western Hub,
- spot energy purchases and sales for matching the residential load shape,
- congestion from PJM Western Hub to the PEPCo zone,
- installed capacity,
- ancillary services,
- transaction origination and administration,[20]
- contract risk.

The simulation model calculates a full-requirements contract price for each forecast year for each of the 1,000 futures. In each year, the model generates a two-year forecast of prices for on- and off-peak fixed-block forward contracts at the PJM Western Hub, and then calculates an around-the-clock ("ATC") forward energy price by taking the weighted average of the forecasted on- and off-peak forward prices.[21] In order to represent the impact of rolling procurement under the current approach, the model calculates the ATC forward price in the current forecast year as the average of (1) the first-year price for the current forecast year's two-year forecast and (2) the second-year price for the prior planning year's two-year forecast.[22]

[20]Suppliers incur a variety of transaction costs, including costs for bid preparation, credit guarantees, PJM and utility account management, accounts-receivable financing, and legal and regulatory affairs.

[21]The on- and off-peak prices are weighted by the number of hours in the on- and off-peak periods, respectively.

[22]Although the current approach procures contracts twice a year, we assume annual procurement to simplify the modeling effort.

The model derives the additional costs for load-following, congestion, and ancillary services by applying user-defined percentage adders to the ATC forward price, adds the input value for capacity cost, and then calculates risk and transaction costs based on a user-defined percentage adder.

Our estimates of the percentage adders for load following, congestion, ancillary services, and risk and transaction costs, and our estimate for the cost of capacity, are as follows:

Load Shape Adder 14%

Congestion Adder 14%

Ancillary Services Adder 2%

Risk and Transaction-Cost Adder .... first year of contract 5%
second year of contract 10%

RPM Capacity Cost $29/MWh

We derive a load-shape adder of 14% based on the historical ratio of load-weighted average to hour-weighted average Western Hub day-ahead energy price.[23] Likewise, we estimate a congestion adder of about 14% from the historical ratio of PEPCo zonal day-ahead energy price to Western Hub day-ahead energy price. We estimate the adder for ancillary-services at 2%, again from historical relationships.

Capacity costs are assumed to be constant at a value reflecting PJM's updated estimate of the gross Cost of New Entry for the RPM capacity market (Pasteris 2007).[24] Finally, we apply a premium for risk and transaction costs of 5% in the first year and 10% in the second year of the contract.

Spot-Based Full-Requirements Service

In Case No. 9117, the staff of the Maryland Public Service Commission recommended that the Commission consider relying on purchases of spot-market power to serve residential SOS load (Sands 2007, 10–11). We evaluate the

[23]The numerator in this ratio is the twelve-month average of hourly Western Hub prices in the day-ahead market, weighted by PEPCo's residential hourly load. The denominator is the simple average over the same twelve months of hourly Western Hub day-ahead prices.

[24]We use PJM's current estimate for the offsetting Energy & Ancillary Services credit to derive an updated net Cost of New Entry.

long-term costs and risks associated with such an approach by modeling procurement of a full-requirements product that is priced to reflect the cost of spot-market purchases of energy.

The simulation model estimates prices for spot-based one-year full-requirements contracts in a similar fashion as for two-year full-requirements contracts: a forecast of energy prices is adjusted to account for the costs of congestion, load shape, capacity, ancillary services, and risk and transaction costs. In this case, however, the energy component of the spot-based contract is assumed to be priced at the forecasted annual spot price for energy at the PJM Western Hub, rather than at the forecasted forward price as for the two-year contracts.

With the exception of the adder for risk and transaction costs, we use the same values for the percentage adders and for the cost of capacity as employed for pricing the two-year full-requirements contracts. We assume an adder value of 3% for the risk and transaction costs.

Energy Efficiency

The modeling analysis assumes new energy-efficiency savings in each year equivalent to 1.5% of annual energy requirements. This estimate is based on the level of savings experienced to-date and planned for the future in states that are national leaders in energy-efficiency initiatives. Based on our review of efforts in such states as Vermont, Massachusetts, California and New York, we find that the best programs have been saving approximately 1% or more of residential energy usage annually. In response to higher supply costs, tight capacity reserves, and increased concern about global warming, some states are ramping up their energy-efficiency programs. For example, Vermont is planning to increase its savings for 2008 by 140% over recent levels, bringing its annual residential savings to about 2.4% annually.

In Maryland, the “15 by 15” savings target in Governor O’Malley’s EMPower Maryland initiative represents a more-aggressive savings level than assumed in our modeling analysis. A recently released study by the American Council for an Energy Efficient Economy (Eldridge, Elliott, Prindle, et al. 2008) indicates that the EMPower Maryland targets are reasonable and achievable by 2015.

We also assume that annual savings of 1.5% of energy requirements can be achieved at a cost of 3.5¢ per saved kWh. Again, this cost assumption is consistent with the cost of achieved savings in other jurisdictions. In Maryland, Eldridge, Elliott, Prindle, et al. (2008, 27) estimate a cost of 3.9¢ per saved kWh. In addition, the Baltimore Gas and Electric Company has proposed a portfolio energy-efficiency programs that the Maryland PSC Staff (2008, 2) estimates will cost about 2¢ per saved kWh.

Although we assume that new installations of efficiency measures will yield *incremental* savings of 1.5% in any year, the modeling analysis reduces *cumulative* savings to reflect the fact that incremental savings from one year's installations will not persist at 1.5% levels over time.

Incremental savings levels decline over time for two reasons. First, savings achieved from new installations in one year, when expressed as a percentage of load, will decline in later years as load grows over time. The modeling analysis recognizes this relatively small effect by assuming in each forecast year a 1% decline in cumulative savings from prior years.

Second, the absolute magnitude of incremental savings will decay over time, as the installed efficiency measures reach the end of their useful lives, become worn out or obsolete, or are discarded as part of a renovation. To reflect this second effect, we phase out incremental savings linearly over twelve years, starting eight years after installation. For example, we assume a constant level of savings from 2010 installations during the eight-year period from 2010 to 2017. After 2017, we assume that savings from 2010 installations decline by 1⁄12 per year, with the result that no savings from these installations remain after twenty years.

The combined effect of these two adjustments is substantial. After twenty years, these adjustments reduce pre-adjustment cumulative-savings levels from 30% to about 17%.

Five-Year Fixed-Block Contracts

We explore the impact on portfolio performance of medium-term market-priced contracts through the characterization and modeling of a five-year fixed-block energy contract. This contract is assumed to be energy-only, to provide a constant amount of energy in every hour of every year of the contract term, and to be priced at the wholesale market price for energy.

Similar to the treatment of two-year full-requirements contracts, energy deliveries from five-year fixed-block contracts are priced at forecasted market prices for five years forward. In each year of the planning horizon for each of the 1,000 futures, the model does a random draw from the distributions for natural-gas-price changes and carbon-allowance prices. These random draws, in turn, determine the forecast of market prices for the next five years. This five-year forecast sets the annual prices for a five-year contract procured in that year. This process is then repeated in the next planning year, in order to derive a new five-year forecast of market prices for pricing five-year contracts procured in that next planning year.

We estimate the additional costs associated with "firming up" the five-year contract to provide full-requirements service by modeling that contract as a financial hedge. That is, we assume that residential load requirements are met with two-year full-requirements contracts. The energy deliveries from the five-year contract, in turn, are assumed to be sold into the wholesale market, with the market price received, net of the contract price, applied as an offset to the full-requirements contract price.[25] Consequently, the annual cost of "serving" load with a five-year contract is calculated as the two-year full-requirements contract cost plus the five-year contract cost minus the market revenues received for the sale of the output of the five-year contract.

Although both purchases and sales of contract deliveries are priced at the forecasted energy market price, the calculated value of the net-revenue offset to full-requirements price can still differ from zero. This is due to our explicit modeling of forecast uncertainty. As noted above, annual contract prices for a five-year contract procured in any planning year are set at that planning year's five-year forecast of market prices. In other words, contract prices are locked in at the outset of the contract, based on a single forecast of market prices derived from a single set of random draws on the stochastic variables. In contrast, the annual price received for sale of contract power into the wholesale market is determined one year at a time, using a different forecast of market prices in each contract year, with each year's forecast derived from a unique random draw on the stochastic variables.[26]

[25]In any year, that offset—market price less contract price—may have a positive or negative value.

[26]In addition, our modeling approach introduces random variation between purchase and sale prices by assuming that purchases are priced at *forward* prices, while sales are priced at *spot* prices. Although the modeling analysis sets spot prices equal to forward prices on an expected-value basis, we model random variation around that expected value when forecasting average annual spot prices in each year of the planning horizon.

New-Resource Fifteen-Year Contracts

Cost and Performance Assumptions

While we assume that short- and medium-term contracts will be priced based on forward market prices, we estimate prices for long-term contracts based on the expectation that such prices will reflect the costs to construct and operate new resources. For the purposes of the modeling analysis, we therefore assume that fifteen-year contracts with new resources will be priced to recover a new plant's capital-recovery costs (including financing) and operating costs (both fuel and non-fuel, including emissions allowances) over the term of the contract.

We characterize three different fifteen-year contracts, indexed to the costs of new natural-gas combined-cycle, pulverized-coal, and land-based wind resources. Table 4 summarizes our cost and performance assumptions for these three generation technologies

Table 4: New-Resource Cost and Performance Assumptions

	Pulverized Coal	NGCC	Wind
Capital Costs ($/kW)[a]	2,500	1,000	2,250
Fixed Operating Costs ($/kW-yr.)[b]	26.7	11.3	29.3
Maximum Capacity Factor	85%	85%	30%
Base Year Fuel Price ($/MMBtu)	2.00	8.60	-
Heat Rate (Btu/kWh)[c]	9,500	7,500	-
Variable O&M Costs ($/MWh)[b]	4.4	2.0	-
NOx Rate (lbs./mmBtu)[d]	0.08	0.02	-
SOx Rate (lbs./mmBtu)[d]	0.05	-	-
NOx Cost ($/ton)[e]	1,704.8	1,704.8	-
SOx Cost ($/ton)[e]	680.4	680.4	-
CO_2 Rate (lbs./mmBtu)	208	117	-

[a]Coal and NGCC from industry press reports; wind from Levitan & associates (2007, 87 (Table 9)).

[b]From U.S. EIA (2007b, 77 (Table 39)), inflated to 2007 dollars.

[c]Coal heat rate based on Woods, Capicotto, Haslbeck et al. (2007 4 (Exhibit ES-2)); NGCC heat rate derived from data in U.S. EIA (2006) on 2006 performance for combined-cycle plant in PJM.

[d]Based on data provided by Woods, Capicotto, Haslbeck et al. (2007 18 (Exhibit ES-22)) and in U.S. EIA (2007b, 84).

[e]Based on data provided by Hornby, Swanson, Drunsic et al. (2008 5-19 (Exhibit 5-11)).

Finance Assumptions

Non-utility power producers have significant flexibility in structuring finance terms for new generating plant backed by long-term utility contracts. We based our finance assumptions on industry-press reports of project financing, such as those typically reported in *Power Finance and Risk*.

We assume a 50-50 debt-equity split, which appears to be near the center of the reported range of capital structures for long-term financing arrangements. Debt for power-supply projects has been priced from 150 to 450 basis points over the London Interbank Rate ("LIBOR"), which was running about 5.5% at the time of this analysis, for total debt costs of 7% to 10%. We assume an 8% debt rate, to reflect the possibility that current pricing is based on expected LIBOR rates closer to the 1998–2006 average of about 4.1%. Publicly available data on required equity returns is scant. We therefore assume a 13% return on equity, based on allowed returns of 10–11% for distribution utilities and a higher risk premium for non-utility generation. Finally, we assume a combined Federal and State income-tax rate of 40%.

Our finance assumptions appear to be consistent with, albeit higher than, those assumed in the recently released study of supply options by Levitan & Associates for the Maryland Commission. Levitan & Associates (2007, 79 (Table 78)) reports finance assumptions for long-term contracts that entail greater leverage and lower cost for both debt and equity than assumed for our modeling analysis.

Our assumptions also appear reasonable in comparison with those adopted by the Connecticut Department of Public Utility Control. The DPUC in its Order in Docket 07-08-24 (12/14/07) recently solicited proposals for contracts with new peaking plants. Respondents will be allowed to offer prices based on equity ratios of as much as 60% and rates of return on equity of as much as 10.75%, subject to adjustments to track future changes in allowed utility return. Debt costs will be determined by market conditions. The DPUC received initial expressions of interest from seven suppliers, suggesting that its financial constraints are feasible for projects backed by long-term sale contracts.

Annual Contract Cost

The simulation model calculates annual contract cost as the sum of the following:

- levelized capital cost,
- fixed and variable O&M,
- fuel cost,
- SOx-, NOx-, and CO_2-emissions costs.[27]

[27] We assume that wind-based contract costs are reduced by a production tax credit of $18/MWh in the years 2010 through 2019.

Levelized capital costs are derived based on the input assumptions for capital cost and plant finance. Fixed and variable O&M are also based on input values. Annual costs for fuel are derived by combining the forecasted price for input fuel with input assumptions for fuel conversion rates. Likewise, annual carbon costs are derived by combining the forecasted market price for carbon allowances with input assumptions for carbon emission rates.

Full-Requirements Price

As with five-year fixed-block contracts, we estimate the additional costs associated with "firming up" a fifteen-year contract to provide full-requirements service by modeling that contract as a financial hedge. Thus, the annual cost of providing full-requirements service with a fifteen-year contract is calculated as the two-year full-requirements contract cost plus the fifteen-year contract cost minus the market revenues received for the sale of the output of the fifteen-year contract.[28]

Our estimate of annual contract costs and revenues depends on our forecast of annual contract deliveries. For wind-indexed contracts, annual deliveries are determined based on an assumed capacity factor of 35%. For gas- and coal-indexed contracts, we assume that deliveries are determined by the economic dispatch of the underlying resource. Our estimate of annual deliveries for these conventional-resource contracts therefore depends on our estimate of the annual economic operating level of the underlying resource.

For the gas- and coal-indexed contracts, the simulation model employs a series of calculations to derive the underlying resource's economic capacity factor in each forecast year for each of the 1,000 forecasts. Essentially, in each forecast year, the model simulates the economic dispatch of the underlying resource, based on that year's forecast of energy market prices and that year's forecast of the resource's operating costs (i.e., fuel, variable O&M, and emissions costs.) Using historical data, the simulation model calculates hourly market prices from the forecasted annual market price. These hourly prices are then compared against the estimate of operating costs to determine the capacity factor of the underlying resource under economic dispatch.

[28]Unlike for the five-year contracts, we assume that the fifteen-year contracts generate revenues from the sale of plant capacity into the RPM market. In addition, we assume that wind-indexed contracts generate revenues from the sale of renewable energy credits at a market price of $20/MWh.

6. Candidate Portfolios

The authors assembled six different candidate portfolios using varying mixes of the resource options described in the previous section. We selected these particular portfolios for analysis with our simulation model in order to assess the long-term costs and risks associated with the current SOS procurement approach, to evaluate the impact of relying on spot purchases to serve residential SOS load (as is currently under consideration by the Maryland Commission in Case No. 9117), and to illustrate the trade-offs between cost and risk from portfolio diversification.

The six candidate portfolios are as follows:

1. **Business As Usual ("BAU").** This portfolio assumes a continuation of the currently approved procurement mechanism, with laddered acquisition of two-year full-requirements contracts. Although the current approach procures contracts two times a year to serve 25% of residential load, we assume procurement occurs only once a year for 50% of residential load, in order to simplify the modeling effort.
2. **Spot-Based Supply ("Spot").** This portfolio consists solely of one-year spot-based full-requirements contracts. We model this portfolio to evaluate the impacts on long-term cost and risk of relying on spot-market purchases of energy to serve residential SOS load.
3. **Clean BAU.** This portfolio is designed to assess the incremental cost and risk impact from the addition of efficiency and renewable resources to the BAU portfolio. It consists of a mix of two-year full-requirements contracts, energy efficiency, and fifteen-year contracts indexed to the cost of new wind resources.

4. **Demand-Side-Management–Wind–Natural Gas ("DWN").** This is one of three portfolios designed to illustrate the trade-offs between long-term costs and portfolio risk associated with a diversified portfolio of energy efficiency and short-, medium-, and long-term supply contracts. The DWN portfolio consists of a mix of two-year full-requirements contracts, five-year fixed-block contracts, energy efficiency, fifteen-year wind-indexed contracts, and fifteen-year contracts indexed to the cost of new natural gas combined-cycle ("NGCC") plant.
5. **Demand-Side-Management–Wind–Coal ("DWC").** The DWC portfolio consists of the same mix of resources as the DWN portfolio, except that fifteen-year contracts indexed to the cost of new pulverized-coal plant replace the fifteen-year NGCC-indexed contracts in the portfolio.
6. **Demand-Side-Management–Wind–Natural Gas–Coal ("DWNC").** This portfolio combines fifteen-year NGCC-indexed and coal-indexed contracts in the resource mix.

The BAU and Spot portfolios consist solely of full-requirements contracts. Table 5 provides the resource mix assumed for the four other candidate portfolios, with the contribution of each resource in the portfolio expressed as a percentage of annual energy requirements in each year of the planning horizon.

All four of these multi-product portfolios include efficiency savings that reach a maximum of about 17% of annual energy requirements after thirteen years. In addition, all four of these portfolios include supply from fifteen-year wind-indexed contracts, which we assume to be phased in over six years. Because additional system costs are incurred when adding large amounts of wind generation, we assume a maximum contribution from wind contracts equivalent to 12% of energy requirements. See Table 5.

Table 5: Resource Mix of Candidate Portfolios

	Clean BAU Portfolio			DWN Portfolio						DWC Portfolio						DWNC Portfolio					
	DSM	*Wind*	*2-Yr*	*DSM*	*Wind*	*Coal*	*NGCC*	*5-yr*	*2-Yr*	*DSM*	*Wind*	*Coal*	*NGCC*	*5-yr*	*2-Yr*	*DSM*	*Wind*	*Coal*	*NGCC*	*5-yr*	*2-Yr*
2010	1.5%	2.0%	96.5%	1.5%	2.0%	0.0%	0.0%	10.0%	86.5%	1.5%	2.0%	0.0%	0.0%	15.0%	81.5%	1.5%	2.0%	0.0%	0.0%	10.0%	86.5%
2011	3.0%	4.0%	93.0%	3.0%	4.0%	0.0%	0.0%	20.0%	73.0%	3.0%	4.0%	0.0%	0.0%	35.0%	58.0%	3.0%	4.0%	0.0%	0.0%	20.0%	73.0%
2012	4.5%	6.0%	89.5%	4.5%	6.0%	0.0%	10.0%	30.0%	49.5%	4.5%	6.0%	0.0%	0.0%	45.0%	44.5%	4.5%	6.0%	0.0%	10.0%	30.0%	49.5%
2013	5.9%	8.0%	86.1%	5.9%	8.0%	0.0%	20.0%	30.0%	36.1%	5.9%	8.0%	20.0%	0.0%	45.0%	21.1%	5.9%	8.0%	20.0%	10.0%	30.0%	26.1%
2014	7.4%	10.0%	82.6%	7.4%	10.0%	0.0%	30.0%	30.0%	22.6%	7.4%	10.0%	20.0%	0.0%	45.0%	17.6%	7.4%	10.0%	20.0%	10.0%	30.0%	22.6%
2015	8.8%	12.0%	79.2%	8.8%	12.0%	0.0%	40.0%	20.0%	19.2%	8.8%	12.0%	20.0%	0.0%	35.0%	24.2%	8.8%	12.0%	20.0%	20.0%	20.0%	19.2%
2016	10.2%	12.0%	77.8%	10.2%	12.0%	0.0%	40.0%	15.0%	22.8%	10.2%	12.0%	40.0%	0.0%	15.0%	22.8%	10.2%	12.0%	20.0%	20.0%	15.0%	22.8%
2017	11.6%	12.0%	76.4%	11.6%	12.0%	0.0%	40.0%	15.0%	21.4%	11.6%	12.0%	40.0%	0.0%	10.0%	26.4%	11.6%	12.0%	20.0%	20.0%	15.0%	21.4%
2018	12.7%	12.0%	75.3%	12.7%	12.0%	0.0%	40.0%	15.0%	20.3%	12.7%	12.0%	40.0%	0.0%	15.0%	20.3%	12.7%	12.0%	20.0%	20.0%	15.0%	20.3%
2019	13.7%	12.0%	74.3%	13.7%	12.0%	0.0%	40.0%	15.0%	19.3%	13.7%	12.0%	40.0%	0.0%	15.0%	19.3%	13.7%	12.0%	20.0%	20.0%	15.0%	19.3%
2020	14.6%	12.0%	73.4%	14.6%	12.0%	0.0%	40.0%	15.0%	18.4%	14.6%	12.0%	40.0%	0.0%	10.0%	23.4%	14.6%	12.0%	20.0%	20.0%	15.0%	18.4%
2021	15.3%	12.0%	72.7%	15.3%	12.0%	0.0%	40.0%	10.0%	22.7%	15.3%	12.0%	40.0%	0.0%	10.0%	22.7%	15.3%	12.0%	20.0%	20.0%	10.0%	22.7%
2022	16.0%	12.0%	72.0%	16.0%	12.0%	0.0%	40.0%	5.0%	27.0%	16.0%	12.0%	40.0%	0.0%	10.0%	22.0%	16.0%	12.0%	20.0%	20.0%	5.0%	27.0%
2023	16.4%	12.0%	71.6%	16.4%	12.0%	0.0%	40.0%	10.0%	21.6%	16.4%	12.0%	40.0%	0.0%	10.0%	21.6%	16.4%	12.0%	20.0%	20.0%	10.0%	21.6%
2024	16.8%	12.0%	71.2%	16.8%	12.0%	0.0%	40.0%	10.0%	21.2%	16.8%	12.0%	40.0%	0.0%	10.0%	21.2%	16.8%	12.0%	20.0%	20.0%	10.0%	21.2%
2025	17.1%	12.0%	70.9%	17.1%	12.0%	0.0%	40.0%	10.0%	20.9%	17.1%	12.0%	40.0%	0.0%	10.0%	20.9%	17.1%	12.0%	20.0%	20.0%	10.0%	20.9%
2026	17.3%	12.0%	70.7%	17.3%	12.0%	0.0%	40.0%	10.0%	20.7%	17.3%	12.0%	40.0%	0.0%	10.0%	20.7%	17.3%	12.0%	20.0%	20.0%	10.0%	20.7%
2027	17.4%	12.0%	70.6%	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%
2028	17.4%	12.0%	70.6%	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%
2029	17.4%	12.0%	70.6%	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%
2030	17.4%	12.0%	70.6%	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%

The DWN, DWC, and DWNC portfolios assume that the contribution from NGCC-indexed or coal-indexed contracts, or both, are phased in over time. During the phase-in period, five-year fixed-block contracts contribute as much as 45% of annual energy requirements, depending on the portfolio. This contribution declines to between 5% and 15% of annual energy requirements once the conventional-resource fifteen-year contracts are fully phased in. The fifteen-year contracts ultimately account for a maximum contribution to annual energy requirements of 40%.[29] Finally, we assume that sufficient two-year full-requirements contracts are procured each year to serve the outstanding energy requirements in that year.

[29]For the DWNC portfolio with both coal and NGCC, each resource type provides a maximum of 20% of the annual energy requirement.

7. Simulation Results

Expected Cost

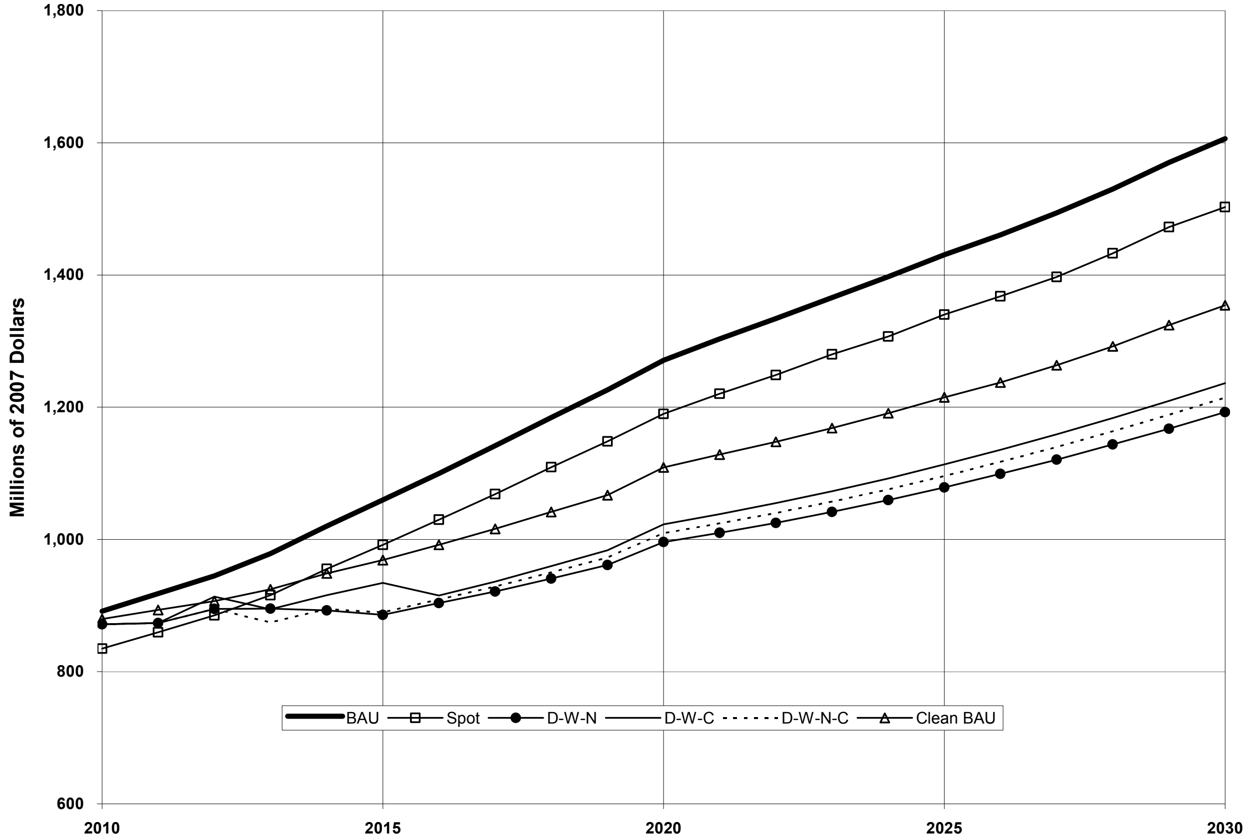
As discussed in Section 3 above, the authors used a spreadsheet model with Monte Carlo–simulation capability to forecast annual costs for each of the six candidate portfolios. Each model run for a candidate portfolio generates 1,000 forecasts of annual portfolio costs over a twenty-year planning horizon, with each forecast representing a series of annual random draws from the probability distributions for the stochastic variables. As a result, the model generates for each candidate portfolio an expected annual cost, and a distribution of 1,000 cost outcomes around that expected cost, for each year of the planning horizon. In addition, the model calculates the net present value of the annual costs for each of the 1,000 forecasts, the expected value of the 1,000 discounted annual costs, and the distribution of discounted values for the 1,000 forecasts.

Table 6 and Figure 8 provide the twenty-year forecasts of expected annual costs for each of the six candidate portfolios. On an expected-cost basis, the BAU portfolio produces the highest annual cost in every year of the planning horizon. Expected annual costs for the Spot portfolio are consistently 6% less than for the BAU portfolio. This result is an artifact of two of our modeling assumptions discussed in Section 4. First, we adopted a distribution for spot energy prices that results in an expected value in each year that is equal to the forecasted forward energy price. Second, except for the adder for risk and transaction costs, we assume the same percentage adders to convert the energy price into a full-requirements price for both the two-year forward-based and the one-year spot-based full-requirements contracts. Thus, on an expected-value basis, the difference in annual costs between the BAU and Spot portfolio is largely explained by the assumed difference in the percentage adders for risk and transaction costs.

Table 6: Expected Annual Portfolio Costs with Change from Business as Usual
(Millions of Dollars)

		Spot		**Clean BAU**		**DWN**		**DWC**		**DWNC**	
	BAU	*Cost*	*%Δ BAU*	*Cost*	*%Δ BAU*	*Cost*	*%Δ BAU*	*Cost*	*%Δ BAU*	*Cost*	*%Δ BAU*
2010	$892	$835	−6.4%	$880	−1.3%	$872	−2.2%	$872	−2.2%	$872	−2.2%
2011	918	859	−6.4%	893	−2.7%	873	−4.9%	873	−4.9%	873	−4.9%
2012	945	885	−6.3%	907	−4.1%	895	−5.3%	914	−3.3%	895	−5.3%
2013	978	916	−6.4%	924	−5.5%	895	−8.5%	894	−8.6%	875	−10.6%
2014	1,020	955	−6.4%	948	−7.0%	893	−12.5%	916	−10.2%	895	−12.3%
2015	1,060	992	−6.4%	969	−8.6%	886	−16.4%	934	−11.8%	890	−16.0%
2016	1,100	1,030	−6.3%	992	−9.8%	904	−17.8%	915	−16.8%	909	−17.3%
2017	1,142	1,069	−6.4%	1,016	−11.0%	921	−19.3%	936	−18.0%	929	−18.6%
2018	1,184	1,109	−6.4%	1,042	−12.1%	941	−20.6%	960	−19.0%	950	−19.8%
2019	1,226	1,148	−6.4%	1,067	−13.0%	961	−21.6%	984	−19.8%	973	−20.7%
2020	1,271	1,190	−6.4%	1,109	−12.8%	996	−21.6%	1,023	−19.5%	1,009	−20.6%
2021	1,304	1,220	−6.4%	1,129	−13.4%	1,010	−22.5%	1,038	−20.3%	1,024	−21.4%
2022	1,334	1,249	−6.4%	1,148	−14.0%	1,025	−23.2%	1,055	−20.9%	1,040	−22.0%
2023	1,366	1,280	−6.3%	1,169	−14.4%	1,042	−23.7%	1,073	−21.4%	1,057	−22.6%
2024	1,398	1,307	−6.5%	1,191	−14.8%	1,059	−24.2%	1,092	−21.8%	1,076	−23.0%
2025	1,431	1,340	−6.3%	1,215	−15.1%	1,079	−24.6%	1,113	−22.2%	1,096	−23.4%
2026	1,460	1,368	−6.4%	1,237	−15.3%	1,099	−24.7%	1,136	−22.2%	1,117	−23.5%
2027	1,494	1,397	−6.5%	1,263	−15.4%	1,121	−25.0%	1,159	−22.4%	1,140	−23.7%
2028	1,530	1,433	−6.4%	1,292	−15.6%	1,144	−25.3%	1,184	−22.6%	1,164	−24.0%
2029	1,570	1,472	−6.2%	1,324	−15.6%	1,168	−25.6%	1,209	−23.0%	1,189	−24.3%
2030	1,606	1,503	−6.4%	1,354	−15.7%	1,192	−25.8%	1,236	−23.0%	1,214	−24.4%

Figure 8: Expected Annual Portfolio Costs



Replacing two-year full-requirements contracts with energy-efficiency savings and fifteen-year contracts indexed to new wind plant dramatically reduces expected annual costs. By the end of the planning horizon, expected annual costs for the Clean BAU portfolio are almost 16% less than for the BAU portfolio.

Further diversification into medium- and long-term contracts lowers costs even further. Expected annual costs for the DWN, DWC, and DWNC portfolios are 20%–26% less than for the BAU portfolio in the second half of the planning period.[30]

Table 7 provides expected NPV costs for each of the six candidate portfolios, based on the distribution of discounted annual costs for the 1,000 futures. As discussed above, this distribution is derived by calculating for each of the 1,000 futures the net present value of annual costs over the twenty-year planning horizon. The expected value is thus the mean of the 1,000 values for NPV cost.

[30] Savings relative to the BAU portfolio are less in the early years of the planning horizon, reflecting the assumed phase-in of the fifteen-year contracts.

Table 7: Long-Term NPV Cost and TailVaR$_{90}$ Risk by Portfolio

Portfolio	Expected Cost ($M)	Difference from BAU: Million Dollars	Difference from BAU: Percent	TVaR$_{90}$ ($M)	Spread Between TVaR$_{90}$ and Expected Cost: Million Dollars	Spread Between TVaR$_{90}$ and Expected Cost: Percent
BAU	14,657			20,664	6,007	41%
Spot	13,723	(934)	−6%	19,333	5,609	41%
Clean BAU	13,082	(1,576)	−11%	17,849	4,767	36%
DWN	12,023	(2,634)	−18%	16,223	4,200	35%
DWC	12,263	(2,395)	−16%	15,259	2,997	24%
DWNC	12,095	(2,562)	−17%	15,643	3,548	29%

The BAU portfolio—representing continuation of the current procurement approach—is the most expensive of the candidate portfolios on an expected-value basis, at a discounted cost of about $14.7 Billion. See Table 7. Relying on spot-based full-requirements contracts to serve residential SOS load is estimated to reduce expected NPV cost by approximately 6%, reflecting our assumption that spot purchasing shifts price risk from suppliers to consumers and thus reduces the risk premium on those spot purchases.

Adding energy efficiency and new wind resources to the BAU portfolio substantially reduces the expected value of discounted costs. The expected NPV cost for the Clean BAU portfolio is about $1.6 Billion, or 11%, less than for the BAU portfolio.[31]

The candidate portfolios with a diversified mix of energy efficiency and short-, medium-, and long-term supply contracts produce the greatest expected savings relative to the BAU portfolio. Savings relative to the BAU portfolio ranged from $2.4 Billion, or 16%, for the DWC portfolio to $2.6 Billion, or 18%, for the DWN portfolio.

Portfolio Risk

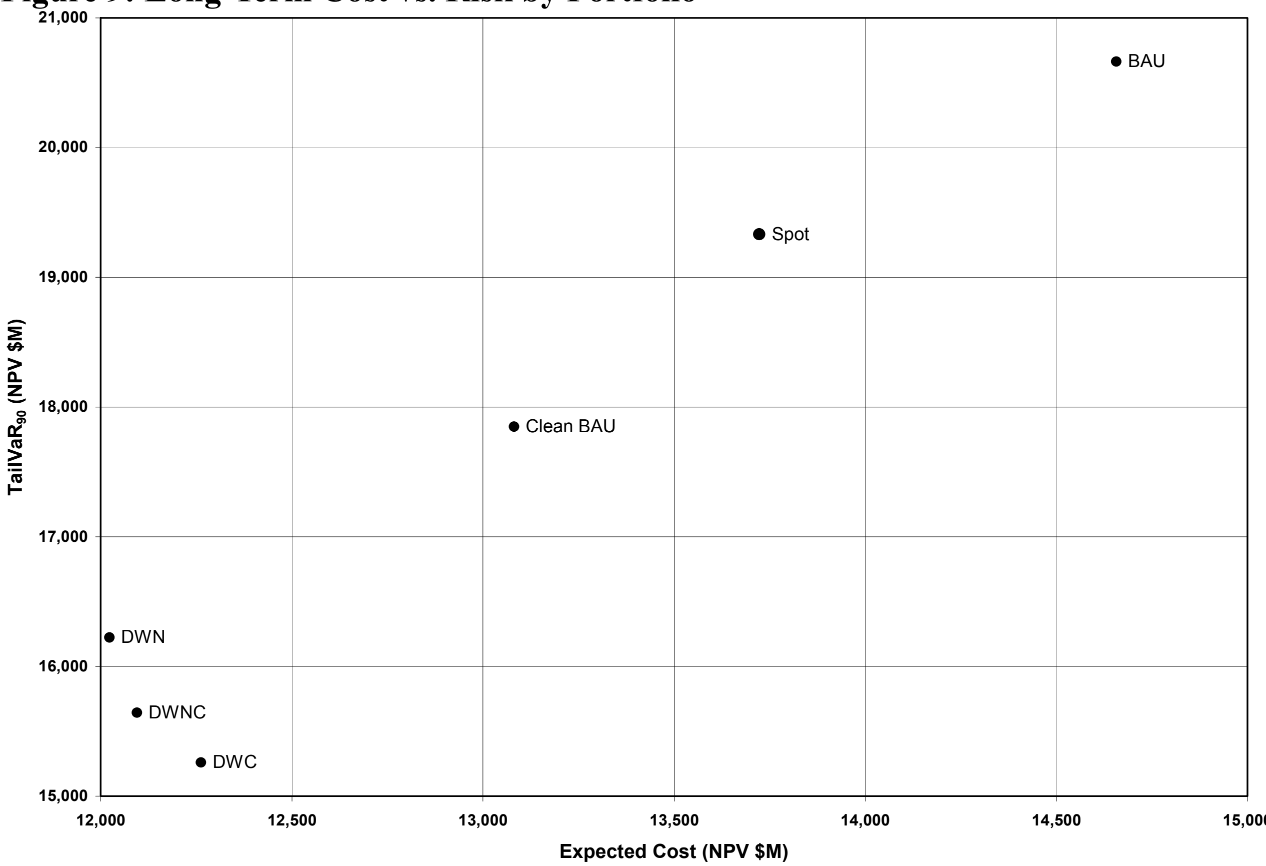
Table 7 also provides the estimate of the TailVaR$_{90}$ for each of the six candidate portfolios. As discussed in Section 3 above, TailVaR$_{90}$ measures long-term portfolio risk over the planning horizon. It is the average of the 10% highest NPV values from the 1,000 futures. In general, the lower the expected NPV cost, the lower the TailVaR$_{90}$ value; see Table 7. The diversified portfolios

[31] Although not shown here, energy efficiency accounts for the bulk of these cost savings; adding just energy efficiency to the BAU portfolio reduces expected NPV costs by about 8 percent.

(DWN, DWC, and DWNC) are the exception, where expected NPV costs and $TailVaR_{90}$ values are inversely correlated. However, the differences among the diversified portfolios are small, and these portfolios as a group have both lower expected costs and risks compared to the other three portfolios.

Figure 9 plots expected NPV cost against $TailVaR_{90}$ to illustrate the tradeoffs between long-term cost and risk for the diversified portfolios. The DWN portfolio, with fifteen-year gas-indexed contracts, is expected to have the lowest long-term cost, but the highest risk, among the diversified portfolios. In contrast, the DWC portfolio, with fifteen-year coal-indexed contracts, is expected to have the highest cost, but lowest risk.

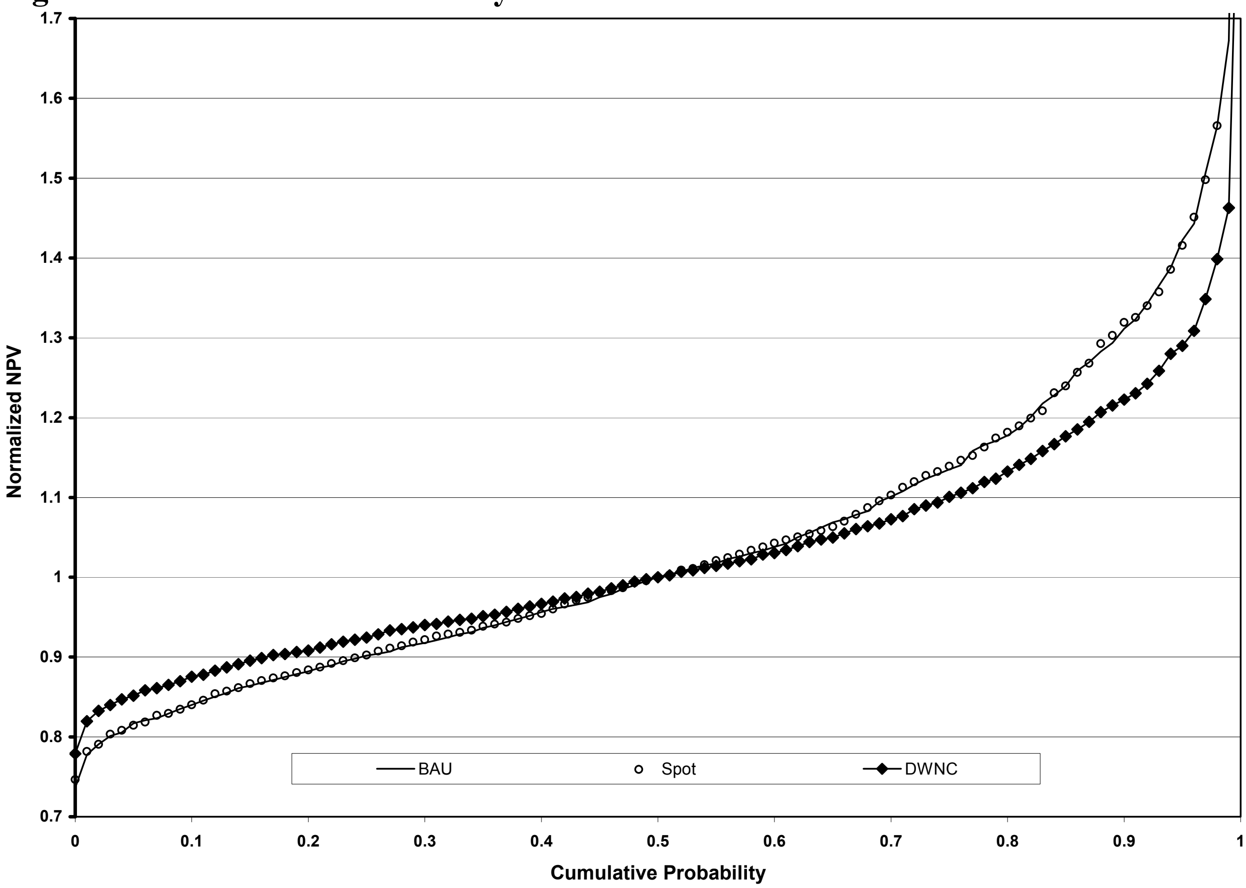
Figure 9: Long-Term Cost vs. Risk by Portfolio



In addition to $TailVaR_{90}$ values (the average of the NPV values for the costliest 10% of outcomes), Table 7 shows the spread between expected NPV cost and $TailVaR_{90}$ for each of the six candidate portfolios. The spread results indicate that, except for the Spot portfolio, $TailVaR_{90}$ values are declining faster than expected NPV costs. In other words, the distribution of NPV costs (at least, the right tail of the distribution) narrows with diversification of the BAU portfolio.

This effect is illustrated in Figure 10, which provides the normalized cumulative probability distributions for the BAU, Spot, and DWNC portfolios. These distributions show the ratios of the NPV cost for each of the 1,000 forecasts to the expected NPV cost for all 1,000 forecasts. The distribution for the DWNC portfolio is markedly narrower than the BAU portfolio distribution, meaning there is a narrower range of deviation from expected cost. In contrast, there is no apparent difference between the shapes of the BAU and Spot distributions.

Figure 10: Cumulative Probability of Portfolio NPV Costs



The normalized NPV of the Spot portfolio closely tracks that of the BAU portfolio.

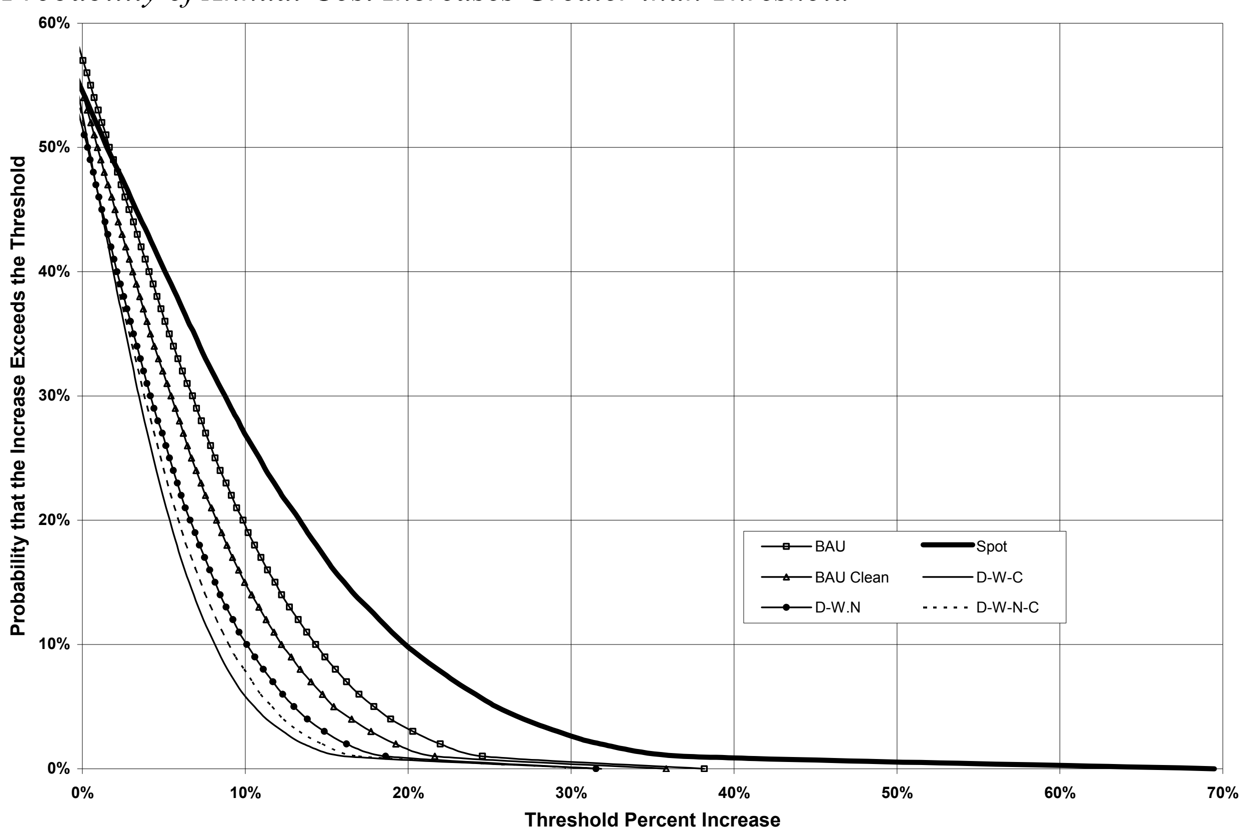
As discussed above in Section 3, we also measure portfolio risk in terms of *exceedance probabilities,* defined as the probability that year-to-year price changes will exceed a particular threshold percentage level. Figure 11 provides the exceedance probability curves for each portfolio, based on the distribution of costs for all years of the planning horizon for the 1,000 futures.[32] The y-axis

[32]In other words, Figure 11 shows the probability of a particular price increase occurring in any of the twenty years of the planning horizon.

represents the probability of such a future occurring; the x-axis represents the price change. For example, in the case of the BAU portfolio, there is a 3% probability (y-axis) of a price increase (x-axis) of 20% or greater. The relative riskiness of the six candidate portfolios is generally the same whether measured in terms of $TailVaR_{90}$ or in terms of exceedance probabilities. The notable exception is the Spot portfolio, which has the highest risk of annual price increases, but only the second highest $TailVaR_{90}$ risk.

Figure 11: Annual Price Risk

Probability of Annual Cost Increases Greater than Threshold



8. Conclusions

This study quantifies uncertainty around forecasts of portfolio costs and measures the risk associated with that forecast uncertainty. This analysis leads to the following conclusions regarding the costs and risks associated with the current SOS procurement approach and with alternative portfolio approaches.

First, *short-term market-priced contracts expose consumers to excessive costs and risks.* Continued reliance on short-term market-priced contracts, such as under the current approach or with a spot-based alternative, is likely to be both the most expensive and the riskiest option for serving residential SOS load. The extreme riskiness of the BAU portfolio is indicated by the fact that the $6.0 Billion spread between its TailVaR_{90} and its expected cost exceeds that of all other portfolios, and is about 68% greater than the average spread for the most-diversified portfolios (i.e., DWN, DWC, and DWNC; see Table 7).[33] In other words, while there is a one-in-ten chance that the cost of the most-diversified portfolios will increase by about $3.8 Billion, or about 30%, it is just as likely that the cost of the BAU portfolio will increase by $6.0 Billion, or about 41%.

Second, *the potential cost savings from spot purchases are too small to justify the likely increase in price risk*. While a spot-based portfolio may be slightly less expensive than the current approach, because of a lower price premium for supplier risk, these savings are likely to come at the cost of greater annual price risk. For example, the risk of an annual price increase in excess of 20% is 3% under the current approach, but more than triple that under a spot-based approach; see Figure 11. In other words, reliance on spot purchases to serve residential SOS load will likely impose too much price risk for the small

[33]As described in Section 3 above, TailVaR_{90} is calculated as the average of the 100 worst outcomes (in terms of NPV cost) out of the 1,000 forecasts for each candidate portfolio.

amount of potential savings. Spot purchases would allow consumers to avoid a small risk premium on two-year full-requirements supply, but at the cost of dramatically increasing the likelihood that price volatility will reach levels that are contrary to the public interest.

Third, *consumers benefit from the procurement of clean resources.* Adding energy efficiency and wind resources to the BAU portfolio improves overall portfolio performance, reducing both expected cost and long-term risk. These clean resources lower expected portfolio costs by substituting for more-expensive market-priced contracts. They also lower long-term risk, since their costs are uncorrelated with the wholesale market prices that drive the costs of the market-priced contracts that remain in the Clean BAU portfolio.

Fourth, *portfolio diversification lowers costs and mitigates risks to residential SOS customers.* This effect is dramatic. As noted above, the average spread between expected cost and TailVaR_{90} for the DWN, DWC, and DWNC portfolios is only 60% of the spread for the BAU Portfolio. Moreover, the spread as a percentage of expected cost is lower for the diversified portfolios than for the BAU portfolio. This suggests that the TailVaR_{90} would still be less for the diversified portfolios than for the BAU portfolio, even if the two portfolios had the same expected cost.

Our analysis provides strong evidence of the cost and risk-mitigation benefits of portfolio diversification for residential SOS customers. At the same time, the analysis illustrates the potential for trade-offs between costs and risk with different approaches to portfolio diversification. Our analysis is not, however, a blueprint for building a diversified resource portfolio to serve residential SOS load. That blueprint—a long-range procurement plan—should be based on the results of a comprehensive, integrated planning process that forecasts portfolio performance under conditions of uncertainty, using the best available data on resource costs and characteristics and system conditions. Moreover, that blueprint should be modified over time to reflect experience from actual resource procurements and in light of changing market conditions.

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