



# Maryland Offshore Wind Report

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**National Wildlife Federation and  
Environment Maryland**

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## Executive Summary

Diversifying risk is a valuable objective for the electricity market. Current purchasing strategies in the wholesale electricity market involve substantial risk that prices could become much higher than are generally anticipated. Adding resources with little or no price volatility would reduce this risk.

Most people understand the concept of risk diversification as it relates to financial markets. Diversification ensures that risk is spread among different asset classes so that while one asset class may be losing value in the short term, it is likely that other assets are gaining value. Investors are protected from short-term price volatility, and can stay fully invested in the market for the long-term. Energy portfolios should be viewed the same way. While the majority of electricity contracts are with fossil fuel-based generators that may offer the lowest prices in the short-term, relying too heavily on those types of contracts leaves us vulnerable to future price disruptions.

Offshore wind power acquired through a long-term power purchase agreement is a zero or low risk resource. Once the contract is negotiated and approved, the cost is mostly known for the duration of the contract. Having this type of resource as a part of our energy portfolio can be a smart financial strategy, even with a price premium.

### Problems with Official Price Forecasts

In contrast to what Maryland has experienced in recent years, official forecasts of electricity prices from the U.S. Department of Energy (DOE) suggest only gradual and slight increases in costs for the coming decades. The base case forecast ignores a number of factors that could cause prices to increase dramatically.

- Current forecasts assume that there will be no new regulation of CO<sub>2</sub> from power plants. DOE price projections only take into account policies that are already on the books, ignoring the likelihood that policies adopted in the future will impact prices. Although federal carbon legislation did not pass last year and might not pass in the coming years, there is some likelihood that there will be federal carbon regulation within the term of a wind power purchase agreement. Also, the Regional Greenhouse Gas Initiative (RGGI), in which Maryland participates, could include stronger limits on global warming emissions from power plants.
- DOE assumes that there will be negligible retirements of coal-fired power plants over the next two decades. Of the 23,000 megawatts (MW) of coal generation capacity in the region, only 800 MW of retirements are assumed for the 2010-2035 time period. This is an unlikely scenario that differs significantly from other projections that examine potential emission regulation scenarios and other factors that could impact the retirement of coal plants.
- Natural gas, which historically has had high price variability, plays an outsized role in setting the price of electricity in Maryland. During times of high demand, the cost of generating power at natural gas plants determines the overall cost of electricity. Even though natural gas supplied just 5% of Maryland's electricity in 2008, it was the single largest factor determining electricity prices that year. Increases in natural gas prices could greatly impact electricity prices if historical price volatility returns.

## Risk Diversification Analysis

Maryland can reduce the risk of electricity price spikes by diversifying its electricity generation mix. Adding 600 MW of wind generation capacity, equal to 5% of the state's total generating capacity, would reduce the risk by 5% of an unexpected increase in price. This improvement in price stability comes at a modest 3% increase in wholesale prices. This is a benefit that can be achieved now under current market conditions and environmental regulations.

Under the assumption of more stringent environmental regulations that may cause coal plants to retire and shift the generation mix from coal to greater use of natural gas and nuclear, the results show that offshore wind can be added at essentially no cost while reducing the overall risk of price increases.

Rather than treating future electricity prices as known quantities, this analysis includes consideration of realistic variations in electricity prices. Using current and historical operating costs—and excluding potential carbon regulation—this analysis calculates the overall price level and price variability of different electricity generating mixes. Selecting a mix with more wind and less fossil fuel raises price slightly while decreasing risk.

## Conclusion

The one- to three-year contracts that electric utilities currently sign with electricity suppliers are unable to protect consumers from the risk of longer-term price increases. Requiring utilities to sign longer contracts with electricity generators, particularly those that produce power from sources such as wind that are not vulnerable to price spikes, can help to protect consumers from sudden short-term price increases and potential long-term volatility of certain pricing determinants, such as natural gas and other fuel costs.

# 1. Introduction

Renewable energy has a variety of potential benefits that have been discussed by a number of parties.<sup>1</sup> In general, these benefits can be categorized into five groups:

- Economic Development—renewable energy is a market (buyer) for equipment, services, and land;
- Environmental—renewable energy features reduced (or no) air emissions and water usage compared to non-renewable energy;
- Energy Security—renewable energy is a domestic energy source that does not use imported fuels for supply and reduces overreliance on a single fuel source<sup>2</sup>;
- Climate Change—as a possible secondary benefit, renewable resources help combat climate change and its concomitant negative effects on infrastructure and the economy; and
- Energy Price—renewable energy generators displace demand for higher marginal cost generators, thereby reducing electricity prices in bid-based, least-cost dispatch markets, such as PJM, and reducing the price of fossil fuels due to reduced demand.

In this report, we discuss only the last group of benefits. Depending on the type of renewable power and the location, renewable facilities can be more costly than traditional fossil-fuel technologies, such as natural gas combined cycle facilities, if one considers only current pricing environments (and the presence of no carbon regulation, for example). However, renewables have little or no marginal cost and are usually bid into markets at zero or low price levels, thereby displacing higher-cost generators. Though the actual displacement amount per megawatt hour (“MWh”) may be small for incremental additions of renewable resources, the overall displacement benefit can be large when multiplied by the electricity demand or load. We acknowledge this benefit, but this is not the focus of this report.<sup>3</sup>

Another price-related benefit that is frequently mentioned but not generally accounted for in system planning or integrated resource plans is the ability of renewables to hedge future price volatility. For example, a December 2008 report prepared for the Public Service Commission<sup>4</sup> analyzed a number of resource options, including onshore and offshore wind options, in terms of their net benefit to ratepayers. The analysis was deterministic; thus the results were based on a set of parameters and inputs that were assumed to be known with 100% certainty over the planning horizon, which was 30 years for the report. The analysis does account for uncertainty through the usual approach of defining alternative scenarios (for example, for fuel prices) and recalculating the results, but such an approach only approximates the potential for cost and price risk over a lengthy planning horizon.

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<sup>1</sup> See, for example, <http://www.nrel.gov/docs/fy05osti/37602.pdf>.

<sup>2</sup> As a recent example, Texas suffered rolling blackouts in February 2010, largely due to unavailability of natural gas (due to high heating demands) and planned outages at many plants. Production from wind facilities, which were unaffected by either factor, helped serve load during the blackout hours.

<sup>3</sup> This benefit is referred to as the “price suppression” effect and has been well documented in a number of studies. See for example, the 2009 PJM study, “Potential Effects of Proposed Climate Change Policies on PJM’s Energy Markets.” In that study, PJM concluded (on p.2) that “15,000 MW of wind offers wholesale market price reductions of \$4.50-6/MWh, translating to reductions in annual market-wide expenditures of \$3.55 billion to \$4.74 billion versus not having that wind in place.” For additional examples of recent studies of price suppression, see the recent review of price suppression studies done by the Pennsylvania Department of Environment Protection and available at this site: [www.themarea.org/downloads/price-suppression-v2.doc](http://www.themarea.org/downloads/price-suppression-v2.doc).

<sup>4</sup> *Analysis of Resource and Policy Options for Maryland’s Energy Future*, Prepared by Levitan & Associates, Inc. and Kaye Sholer LLP for the Maryland Public Service Commission, December 2008.

Maryland, of course, features deregulated wholesale and retail electricity markets. Decisions to invest in certain resource options have largely been transferred from the local distribution companies (“LDCs”) to market mechanisms. Indeed, the December 2008 study described in the previous paragraph was conducted as part of an overall effort to evaluate deregulation and restructuring and assess options for re-regulation. As such, a recommendation to pursue offshore wind will, in all likelihood, necessitate some sort of government action, such as the issuance of a request for proposals from wind developers, given the inability of current market mechanisms—notably, energy, capacity, and renewable energy credit (“REC”)—to provide enough incentives and revenue assurance for developers to finance and build new offshore facilities.

The purpose of this report is to discuss the potential hedge value of renewable resources, such as offshore and onshore wind, as a component of an overall portfolio of generating resources. Despite the fact that Maryland statute requires that the Commission consider volatility when procuring standard offer supplies<sup>5</sup>, outside of enactment of a renewable portfolio standard (“RPS”) and support through state purchases of renewables and subsidies to smaller-scale projects, there has not been a concerted effort to support offshore wind or other large renewable projects that can reduce the long-term risk of high prices to ratepayers. It is the risk of long-run price volatility that will be examined in this report.

By way of introduction we first discuss the history of electricity prices in Maryland, using a variety of sources and review the generation supply portfolio over time. The overall goal with this introductory review is to understand major pricing determinants that have caused changes in prices over time. The focus is to understand longer-term changes in prices (from season-to-season or year-to-year) vs. intraday or intraseasonal prices that may be largely affected by weather and other non-controllable events.

Following this review of historical price performance, we will document publicly available price outlooks and the electric supply portfolio that is underlying these forecasts. The goal here is not to adopt a particular forecast but to establish a “reference” case for prices and generation supply portfolios that we can use to compare against an alternative resource portfolio. In addition to the fuels and technologies used for generation, we will examine other assumptions in the forecast and discuss risks in the forecast.

We then discuss the concept of risk-adjusted electricity costs of different resource options and examine the impacts on long-term risk-adjusted electricity costs of adding offshore or onshore wind resources.

### *A. Electricity Prices in Maryland*

As is well known in deregulated states, customers typically pay (and see on their bills) distinct charges for a number of services:

- Generation of electricity (usually known as supply service), which covers the payments to the owners of power plants,
- Transmission of electricity, which covers the transmission of energy from the generating plants to the LDC’s system and is embedded in supply service for some LDCs and customer classes,

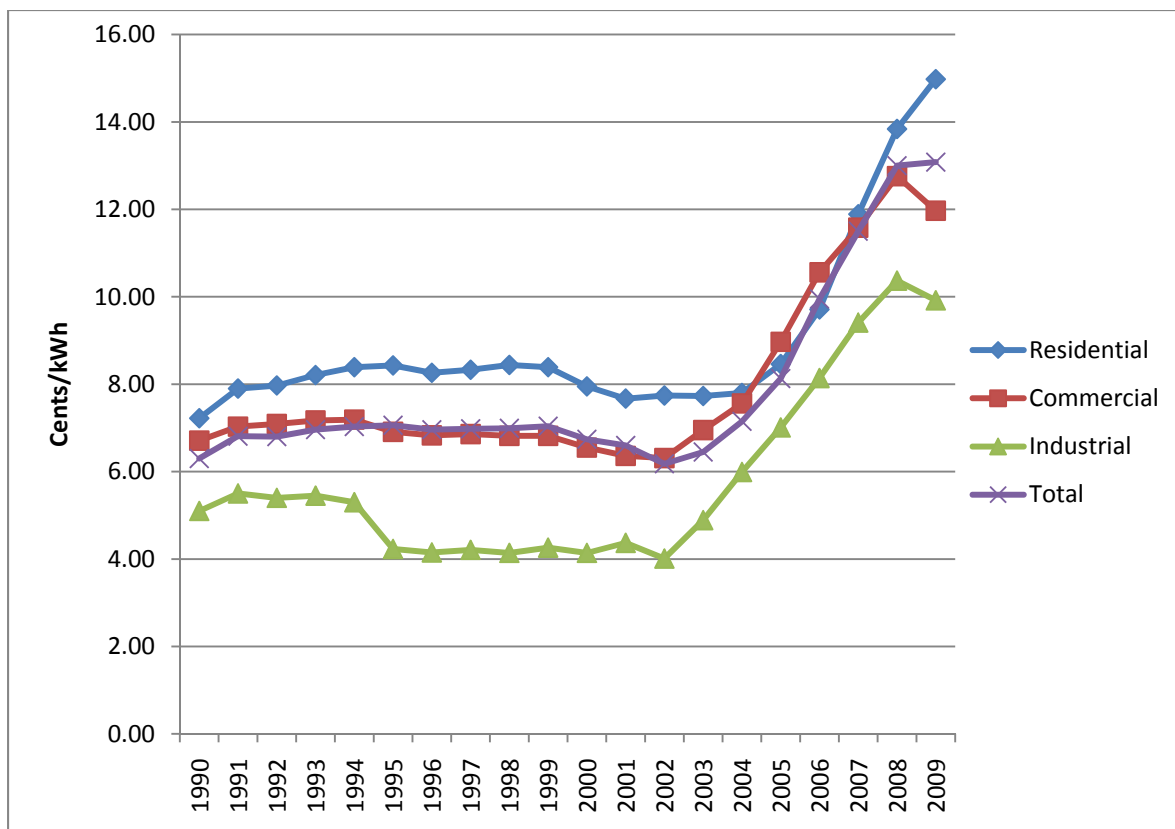
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<sup>5</sup> Md. Code 7-510 (c)(4)(ii). Also, see “Risk Analysis of Procurement Strategies for Residential Standard Offer Service.” A Report to the Maryland Office of People’s Counsel, Resource Insight, Inc. and Synapse Energy Economics, Inc., March, 2008, that examined the benefits of introducing renewable energy (and energy efficiency) to standard offer supply in terms of reduced portfolio cost once natural gas and carbon price risks were considered.

- Delivery of electricity (usually known as delivery service) that pays the LDC for delivery of power from the higher voltage transmission system, and
- Taxes and various surcharges that are used to pay for renewable and energy efficiency programs and adjust or reconcile certain accounts.

Though changes in any of these components affect the prices paid in Maryland, the focus of this report will be on examining the cost and volatility of the prices paid for supply service. Deployment of certain technology or resource options only has minor impacts on the other components and supply service comprises a majority of the overall electricity price or bill paid by customers.<sup>6</sup> Exhibit 1 shows electricity prices for each customer group and for Maryland customers as a whole.

Exhibit 1—Maryland Electricity Price by Customer Type, 1990-2009



Source: EIA

The exhibit shows that electricity prices were relatively flat from 1990 to the 2002-2004 time period, depending on the customer group, and have since risen quite dramatically for all customer groups. These price increases followed deregulation and sharp increases in fuel prices, which were eventually transferred to customers, following expiration of price caps. The economic recession and the steep decline in electricity demand and fuel prices caused prices to decline somewhat in 2009 for some customer classes.

Price volatility apparently increased following deregulation and may continue to occur as we go forward. Indeed, a detailed explanation of price movements is beyond the scope of this document and is not

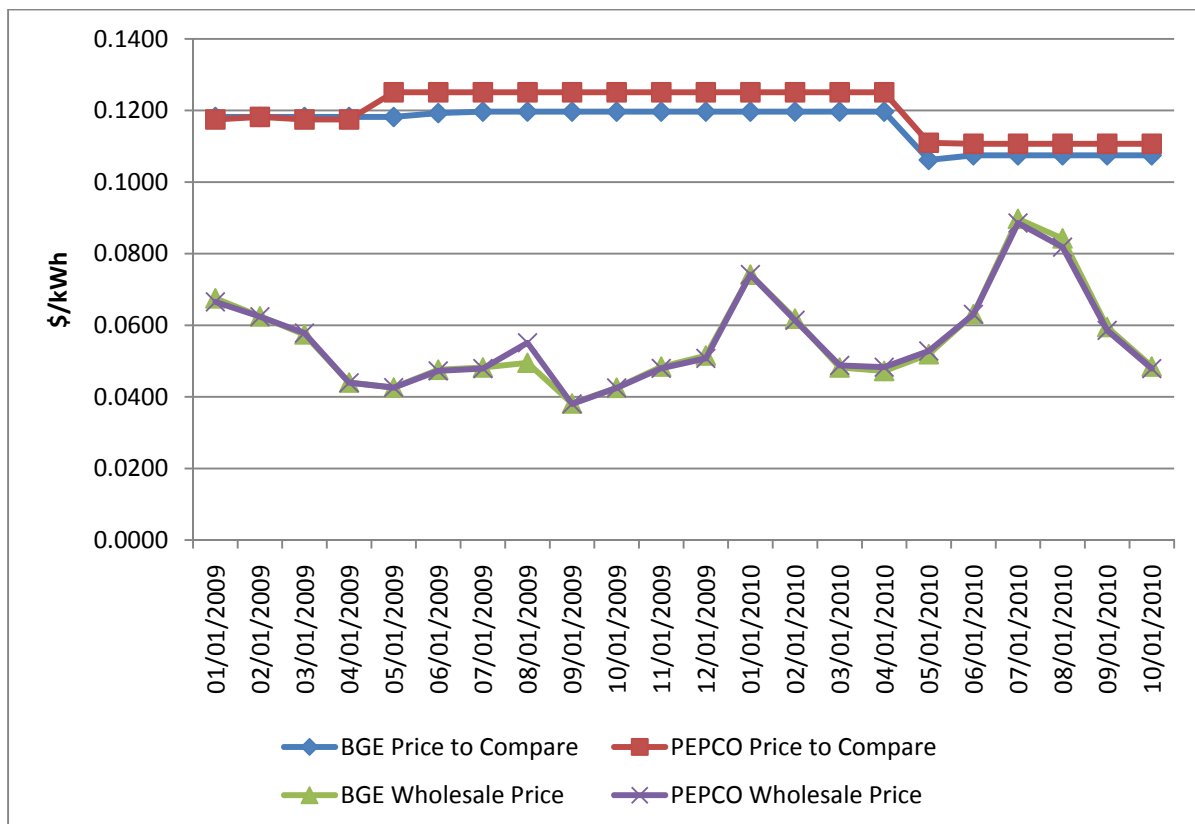
<sup>6</sup> For example, Pepco calculates that over 74 cents of every dollar from residential ratepayers goes to pay for supply service, compared to 19.2 for distribution, 4.0 for surcharges, and 2.3 for transmission.

See [http://www.pepco.com/\\_res/documents/MDDollarGraph112.pdf#zoom=75,0,0](http://www.pepco.com/_res/documents/MDDollarGraph112.pdf#zoom=75,0,0)

straightforward given the many factors that can influence changes in retail prices. As discussed above, over 90% of a customer’s retail electric bill or price is due to either supply or distribution services, thus changes in these two components similarly account for a large majority of the changes in retail prices. We set aside changes in distribution costs since large year-to-year changes tend to be lumpy (following rate cases) with small annual adjustments thereafter, and assuming efficient regulation, there should not be high long term volatility in distribution costs or prices. As a result, our focus is on the examination of supply service pricing data, and as discussed later in the report, the underlying cost characteristics of different generating technologies and resource portfolios that lead to different price levels.

Supply service in Maryland can be provided either by the utility through standard offer service that is purchased from wholesale suppliers or through competitive procurements for 2-year contracts for 25% of the load (for residential and small C&I customers); larger C&I customers generally receive SOS service via 3-month procurements for 100% of the load with the largest customers on hourly supply service. Thus, for the smaller customer classes, SOS prices reflect a blend of products procured at different times, which ultimately serves to reduce the potential for extreme swings in prices, and usually well in advance (5 months) of actual product delivery. Exhibit 2 compares the utilities’ price to compare for residential service, which is similar to standard offer and is used to assist customers in shopping for power, to monthly wholesale energy market prices. As shown in the exhibit, SOS prices are much more stable (and less volatile) than wholesale prices. In addition, there is little or no relationship between the SOS prices and the monthly prices, and the premium or adder above wholesale prices shows wide fluctuations.

Exhibit 2—Comparison of Price to Compare to Wholesale Prices for Maryland Utilities  
2009-2010



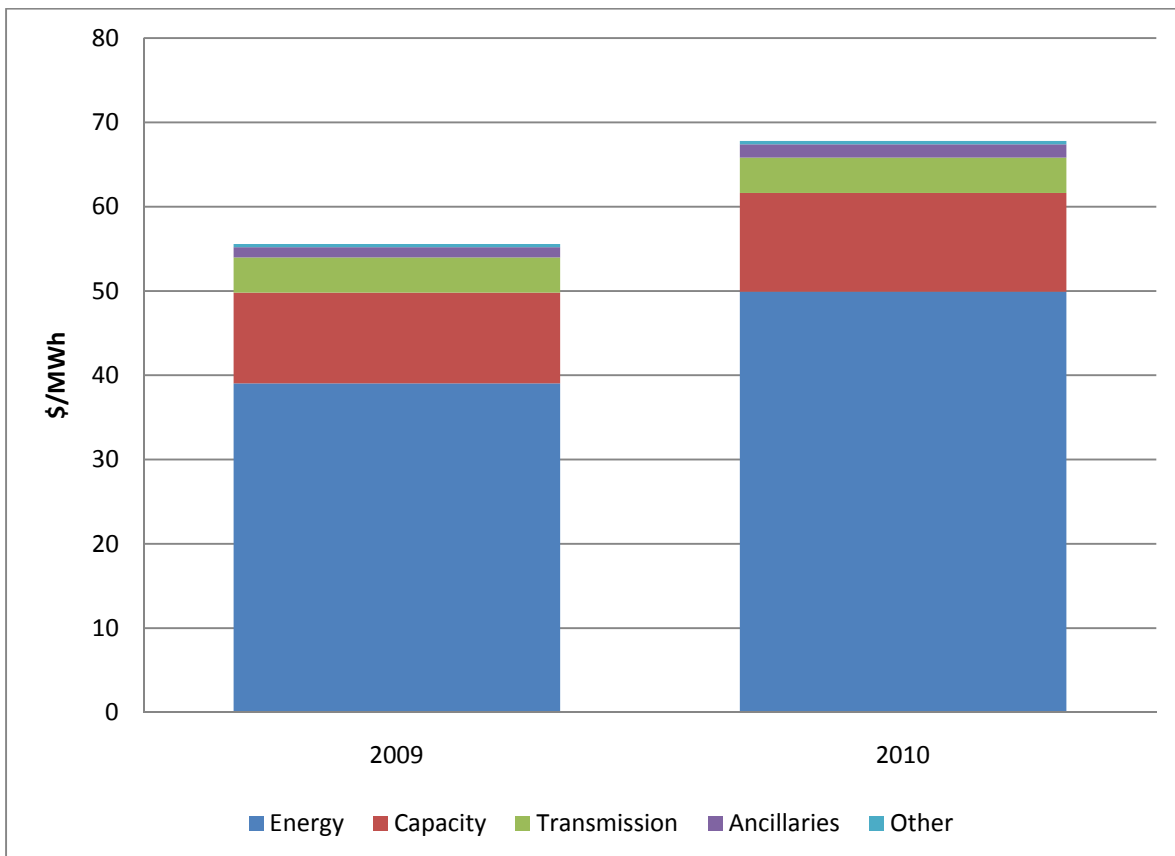
Source: BGE, PEPCO, Clearpoint

Another complication to consider when reviewing SOS prices is that standard offer service is a full-requirements product that contains a number of components: the price of wholesale power—energy, capacity, transmission, ancillary services and other PJM costs—a wholesale to retail markup by the supplier, line losses, and risk premiums for the potential for customer migration. Changes to any of these components have caused and will continue to cause the majority of changes in the prices ultimately paid by ratepayers, but changing the mix of generation will only impact a subset of these components. For example, the selection of resource portfolio will have little or no impact on retail markups of wholesale power, line losses, or risk premiums. On the other hand, there may be benefits to introducing long-term contracts, especially with resources that have no or low fuel risk, to the SOS supply portfolio, which we discuss in a later section.

### B. *Historical Pricing Determinants*

Based on the above discussion, we concentrate on the price of wholesale power, the price of which is largely determined by generation expenses. Ultimately, the total price paid for wholesale power is largely, except for transmission service charges and payments to transmission owners, used to support existing generators and provide incentives for developers to invest in new generation. Exhibit 3 below shows the components of wholesale power price in 2009 and 2010 (through September).

Exhibit 3—Wholesale Price Components, 2009-2010



Source: PJM

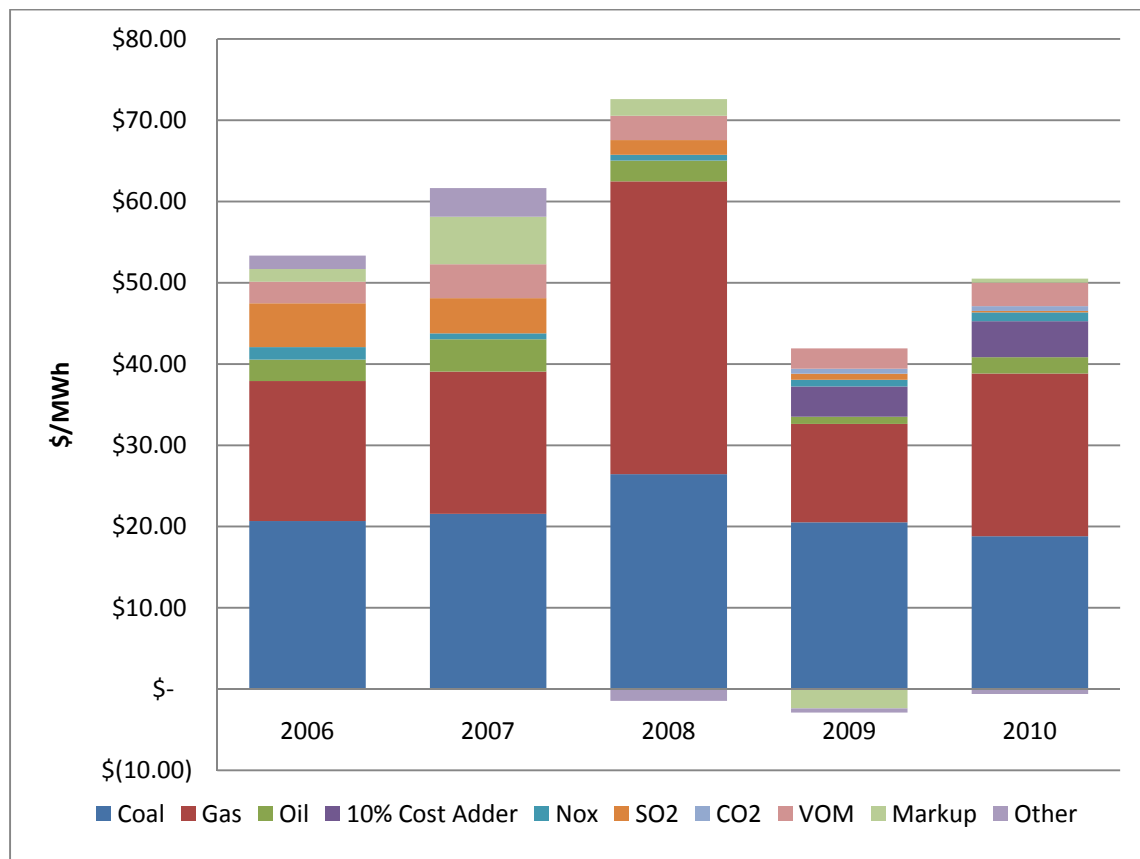
Exhibit 3 shows that energy and capacity market payments comprise the majority of wholesale electric costs and thus will be the focus of our discussion<sup>7</sup>. The exhibit also shows that capacity prices have increased in 2010 from 2009 levels and, as discussed below, are expected to continue to increase for most regions in the eastern PJM area.

One component that is not shown in the graph but will be discussed below is the presence of transmission system congestion which causes prices (locational marginal prices or “LMPs”) to vary from location to location.

### 1. Fuel Cost

Fuel cost is the major determinant of price. Exhibit 4 below shows the components of annual real time LMPs. These data have been load-weighted and represent the annual average cost of power throughout the entire PJM region.

Exhibit 4—Components of Annual PJM Load-Weighted, Average LMPs, 2006-2010



Source: PJM

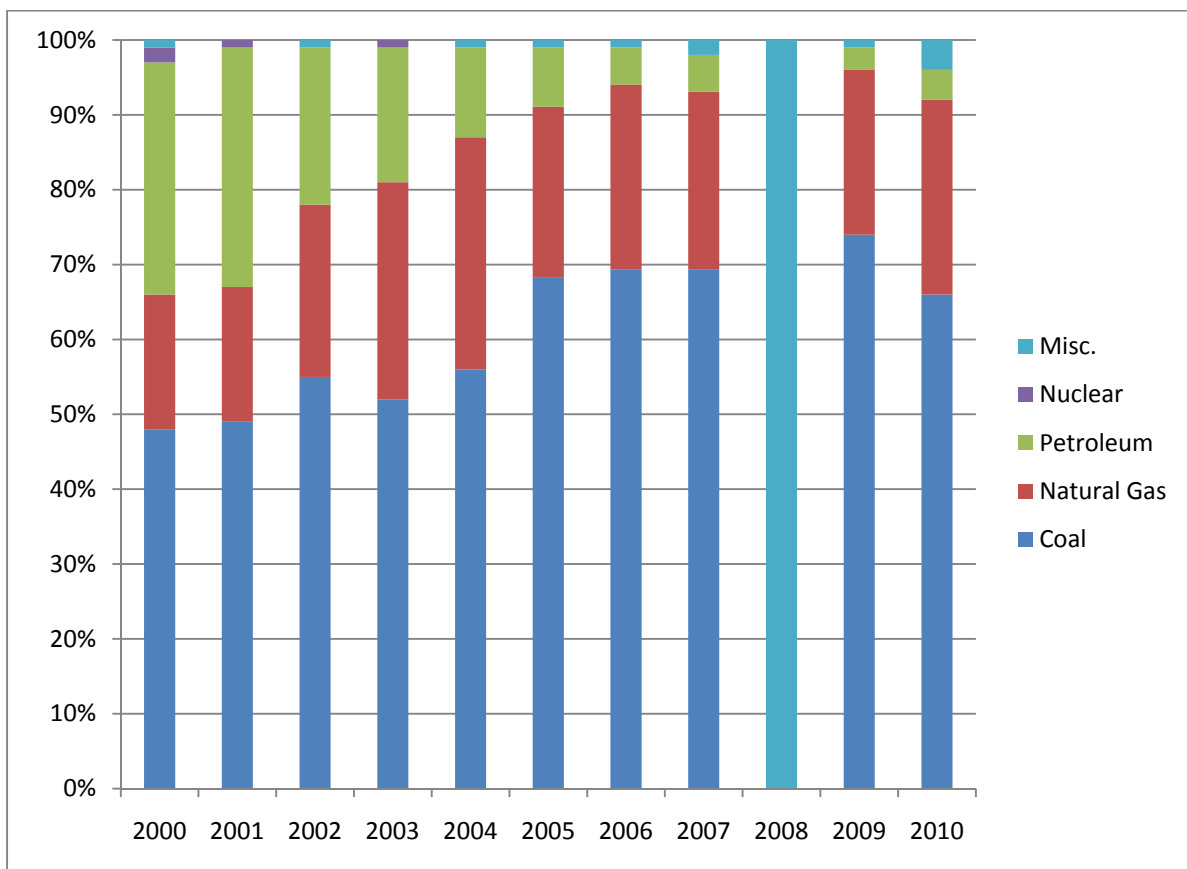
The data clearly indicate that coal and natural gas prices are the major determinants of LMPs. The heavy use of coal in the PJM region is indicated by the role that coal prices play. Emissions prices also affect LMPs, as shown by the data for NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub>. The reduction in SO<sub>2</sub> prices can clearly be seen as its influence on overall LMPs has fallen significantly since 2006, with almost no role in 2010, despite

<sup>7</sup> It is important to note that load is mostly (65-70%) served through self-supply (where load-serving entities use their own generation to meet load) with some served through bilateral transactions (between a load-serving entity and a wholesale supplier). Spot market transactions have been responsible for about 20% of all transactions over the past three years. Nevertheless, spot market prices provide a benchmark that influences bilateral terms and determines the revenues received by self-supplied resources.

the continued use of coal in the PJM region.<sup>8</sup> CO<sub>2</sub> emission prices begin to have a role on electricity prices with the start of the RGGI program in 2009 but the low value for RGGI allowances leads to almost no impact on electricity prices. Variable Operations and Maintenance (“VOM”), which are essentially zero for many renewable resources, are responsible for a relatively similar percentage of costs over the years. Finally, beginning in 2009, we see the presence of a “10% adder” as a cost determinant. Generators were allowed to include a “10% cost adder” to their supply offers in order to account for uncertainty in determining the costs that underlay their offers.<sup>9</sup> The above data provide useful data points from which basic conclusions can be drawn regarding the impact of emission and fuel prices on LMPs (and thus overall electricity prices) in PJM and Maryland.

Exhibit 5 provides additional data concerning the type of fuel (and plant) that sets the marginal price and supports the data in the prior exhibit.

Exhibit 5—Type of Fuel Used By Marginal Units, 2000-2010



Source: PJM

Note: 2008 Data unavailable from PJM

Coal-power plants continue to drive PJM prices during a majority of time, even in the presence of reduced natural gas prices in 2009 and 2010. Since 2000, natural gas plants have increased their presence as marginal units, while petroleum-powered plants’ role in setting prices has diminished significantly. We would expect the increased penetration of natural gas plants as marginal units to continue, especially under conditions of relatively low natural gas prices and increased pressures on coal units to mitigate their air and water emissions. Finally, even though natural gas plants are not marginal

<sup>8</sup> SO<sub>2</sub> prices may rise in the future as the EPA revisits its current environmental rules and regulations that affect SO<sub>2</sub> levels.

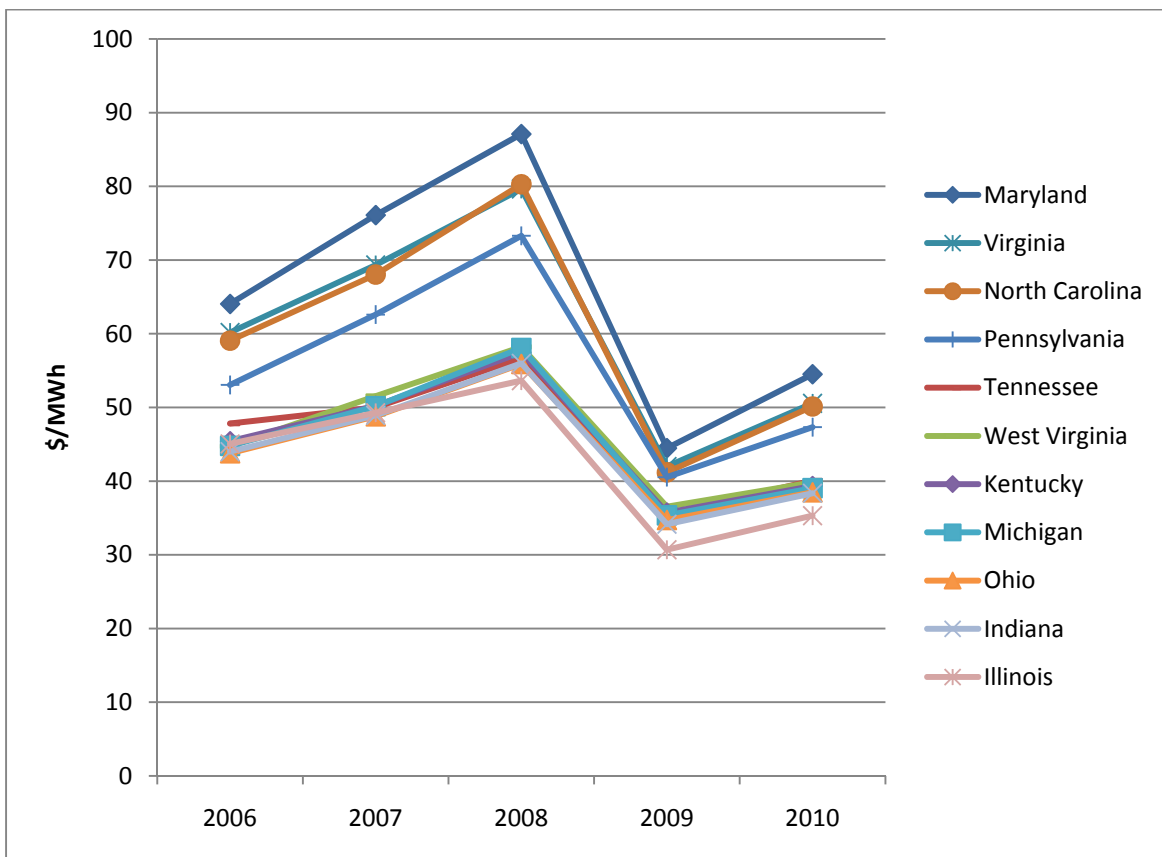
<sup>9</sup> Per the PJM tariff, all capacity resources (including generators) are required to make cost-based offers, but can also (but not instead) make market-based offers.

much of the time, they are marginal much more frequently than coal plants during high-load, high-price times, hence the larger role played by natural gas in determining prices during some years (as shown in Exhibit 4).

## 2. Load Growth/Congestion Issues

The energy prices discussed above were for the entire PJM region but do not consider the impact of transmission system congestion that may affect certain areas of the larger PJM region. Under no transmission congestion, the cheapest power plants could be used to meet load in all areas thereby causing prices to be the same throughout the region. Under real world conditions, however, load growth over time in certain areas and the lumpiness and long-lead time in building transmission infrastructure results in local loads exceeding the ability of the transmission system to deliver the cheapest power available. As a result, loads in certain zones may be served by higher-cost generators that are located either in the zone or whose power can be delivered by the existing transmission system.

Exhibit 6—Real-Time, Load-Weighted, Average LMP by State, 2006-2010



Source: PJM

The data show that Maryland, over the past five years, has had the highest average annual energy prices in the PJM region.<sup>10</sup> Though fuel mix may be responsible for a small portion of the premium, it is more likely that differential has occurred as a result of transmission congestion and the inability of electricity from lower-cost generation to be transmitted to Maryland. Expansion of in-state or intrazonal generation projects, such as offshore wind deliverable to the BGE or DPL zones in Maryland, has the

<sup>10</sup> Other Eastern states (Delaware, New Jersey, and D.C.) have costs similar, though lower, to Maryland and were excluded from the exhibit.

potential to reduce this premium and provide energy market or LMP price suppression benefits to Maryland ratepayers.

### 3. Market Rules and Regulations

Wholesale electricity markets are governed by the specific rules and regulations that are promulgated by the various ISOs and RTOs and ultimately approved by the Federal Energy Regulatory Commission (“FERC”).

In this section, we only describe one significant market rule change—the adoption of the reliability pricing mechanism (“RPM”) as the capacity market. Capacity markets and the revenues they provide were meant to help fill the “missing money” gap between the full costs to maintain and operate a plant for peak conditions and the revenues received from energy markets that only exhibit these peak conditions for a limited number of hours (and where prices are capped by FERC at \$1000/MWh).<sup>11</sup> In the RPM design, capacity prices are determined through annual base residual auctions (“BRAs”) for certain locations based on a number of factors, including the ability of a zone (known as locational delivery areas or “LDAs”) to meet its load requirements with its own internal generation, prior auction clearing prices, and other factors that PJM determines are important to maintain reliability. Exhibit 7 shows the relevant LDAs for Maryland.

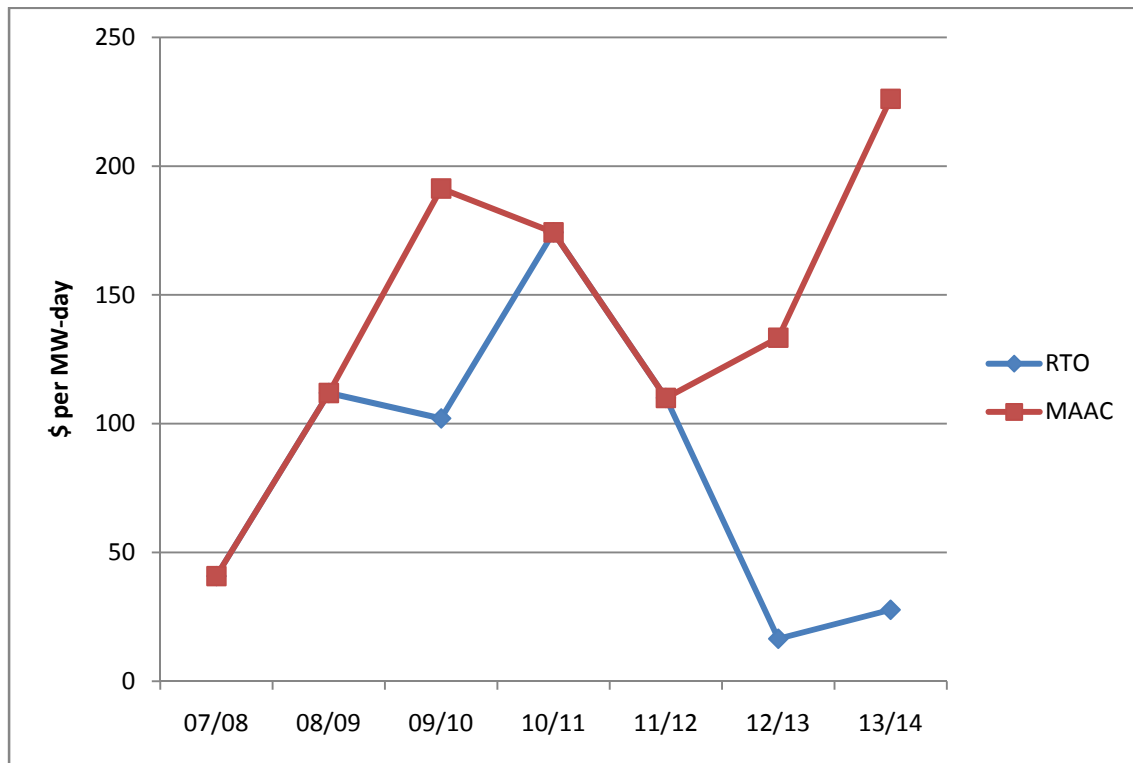
#### Exhibit 7—Maryland Locational Delivery Areas

RTO => MAAC => SWMAAC => BGE  
 RTO => MAAC => SWMAAC => PEPCO  
 RTO => MAAC => EMAAC => DPL => DPL S  
 RTO => Western PJM =>APS

Exhibit 7 displays an important design element of the RPM—nesting of zones or LDAs, which essentially means that prices in small or more localized zones can only pay the same or higher capacity payments. Thus, even if there were no reliability problems in a smaller zone, such as BGE, but the larger zone (SWMAAC or MAAC) showed some reliability concerns, ratepayers in the BGE zone, for example, would have to pay the MAAC price. This design element is significant for evaluating the capacity price suppression impacts of generation facilities, including offshore wind. In the presence of high capacity prices in a larger zone, generation additions would have to be large enough and/or located in the correct location to alleviate the reliability concerns at the larger zone level. Such a finding mitigates the potential for single offshore wind project additions (even if large) to influence capacity prices paid by Maryland ratepayers, which is different from the prior conclusion regarding energy prices. Exhibit 8 shows history of capacity prices for the RTO region as a whole and the MAAC region, in which Maryland resides.

<sup>11</sup> See for example, Joskow, Paul L, “Capacity Payments in Imperfect Electricity Markets,” December 5, 2007 (revised). Available at <http://econ-www.mit.edu/files/2095>,

**Exhibit 8**—Capacity Market Prices, Base Residual Auctions, RTO and MAAC, 2007/8-2013/14



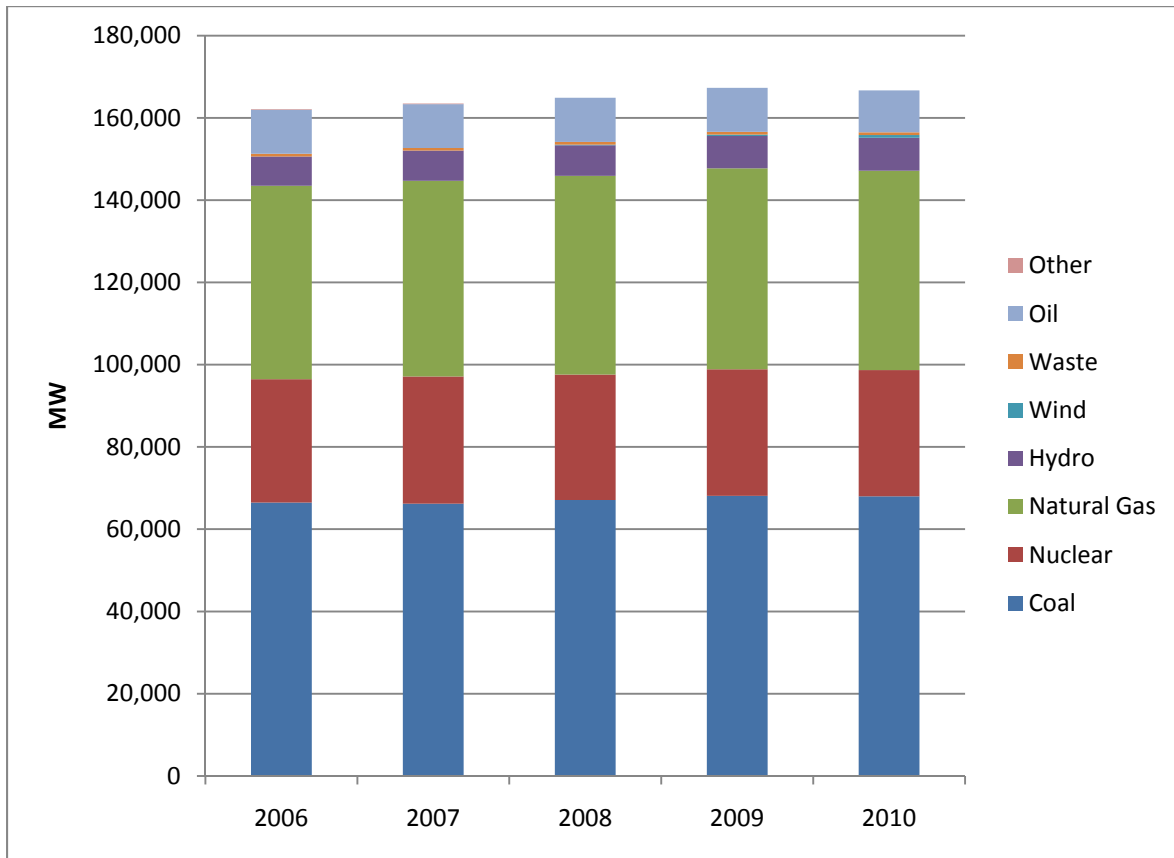
Source: PJM

As can be seen, capacity prices started low for the BRA covering the 2007/2008 deliverability year but have since increased significantly for the MAAC region. At the same time, prices in the larger RTO region have fallen to levels below those in 2007/2008. These later prices (for the 2011/12 and later years) have not yet been paid by ratepayers but will eventually be allocated and charged to ratepayers through generation charges.

### *C. Electricity Supply Portfolio*

Finally, we discuss the resource portfolio that has been responsible for the pricing behavior discussed in the prior sections. The supply mix can be described in terms of installed capacity (MW or gigawatts) or generation (MWh or GWh), the latter of which was introduced in the fuel cost section above. For the purposes of this document, the latter is more crucial since it is a greater determinant of overall prices; though, as we saw above, capacity market payments have the potential to be an increasing component of electricity prices in certain PJM areas, including Maryland. Exhibit 9 shows the installed capacity in PJM over the last five years.

Exhibit 9—Installed Generation Capacity in PJM, 2006-2010

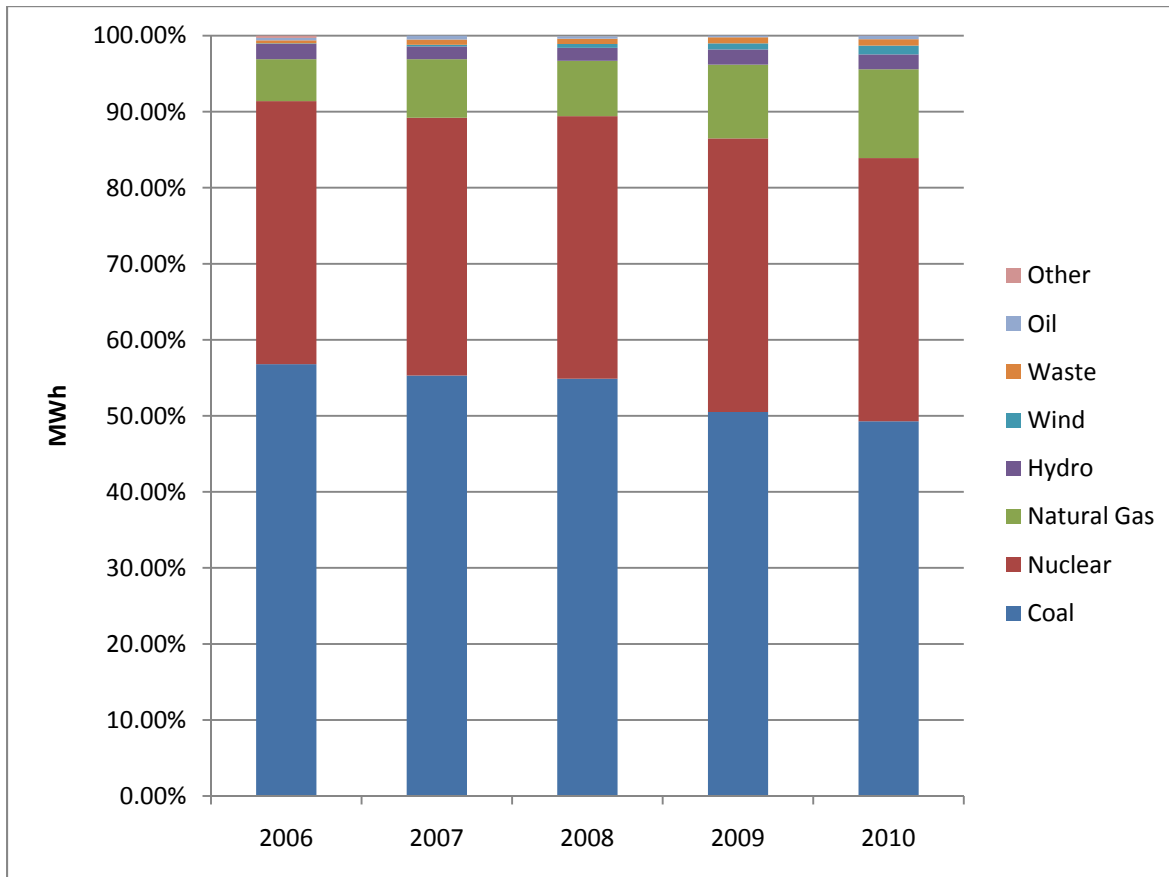


Source: PJM

The data show that the mix of generators in the PJM region has been quite consistent, with a slight increase in the amount of natural gas capacity. These figures are for installed capacity, thus intermittent resources that generally provide only a portion of their nameplate capacity as a capacity resource, would be discounted relative to fossil fuel generation, for example. Even after accounting for this factor, however, renewable generation outside of hydro remains a minor source of power in the PJM region. Finally, note that overall installed generation capacity has increased very slightly, which is not the expected consequence given the high capacity prices discussed above. Unfortunately, the RPM only provides short-term (one year or three-year, under certain restrictive conditions) revenue commitments, which apparently is not enough assurance for developers to invest in new generating facilities.

Exhibit 10 shows the generation fuel mix for the entire PJM region.

Exhibit 10—Generation Fuel Mix, 2006-2010

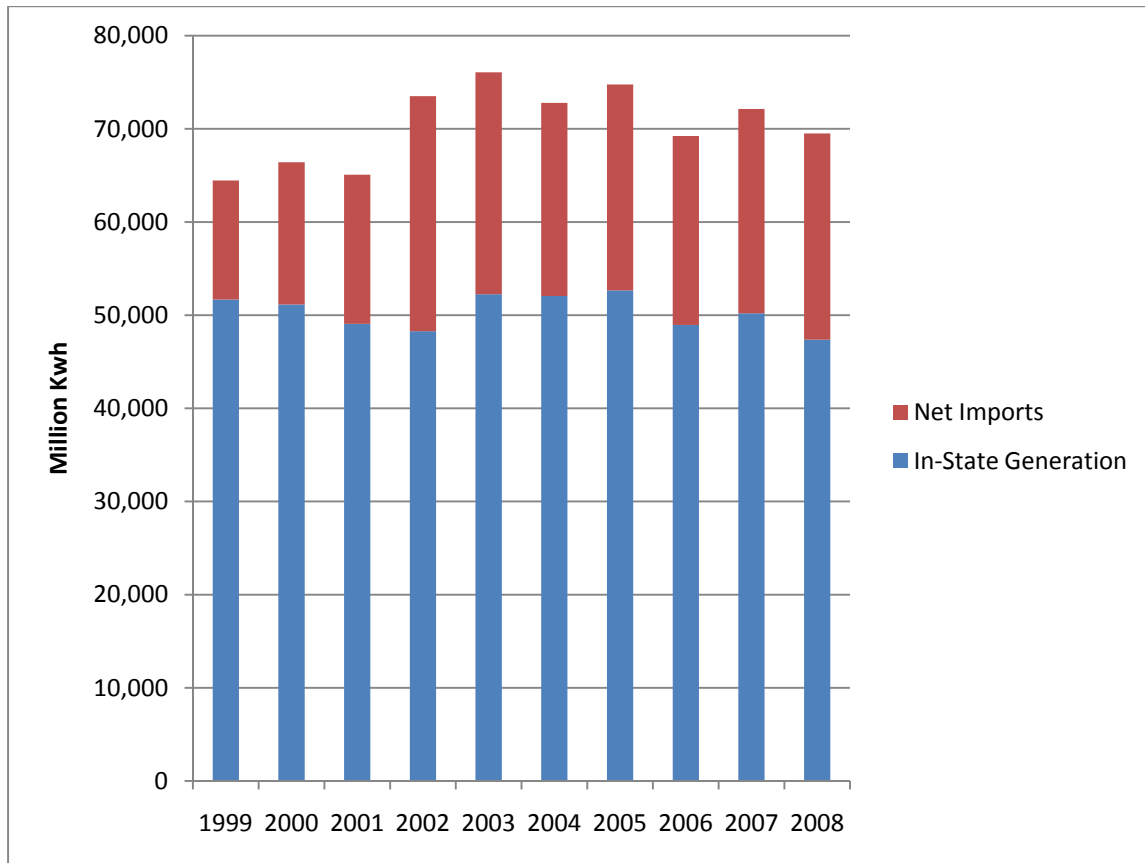


Source: PJM

Data for the last five years show that natural gas has gradually displaced coal. In 2006, coal was responsible for about 57% declining to under 50% in 2010, which was partly affected by fuel switching from coal to natural gas due to the low natural gas prices that started following the financial collapse in August/September of 2008. Whether this trend in natural gas generation continues is unknown but potentially creates a greater risk in price volatility in the PJM region than has been experienced in the past.

Though the data in Exhibit 10 are useful and provide a good overview of the generation sources and fuels serving Maryland load, it is more useful to consider the fuel mix of generators located in Maryland. This is especially important because of the presence of transmission system congestion that does not allow Maryland to call upon generation from any location. Exhibit 11 shows the role of imported energy in meeting Maryland's electricity demands.

Exhibit 11—Maryland In-State Generation and Electricity Imports, 1999-2008



Source: EIA

The exhibit shows that in-state generation has met a lower percentage of in-state demand during the most recent few years compared to 1999. Maryland is typically one of the top 5 importing states in the U.S. and without any significant new in-state generation capacity expected, this trend should continue. Data prior to 1999 show that in-state generation played a larger role in the 1990-1995 time period, but there does seem to be some consistency in the percentages since 2003, with out-of-state generation providing between 28 and 32% of total demand during these years.

Ultimately, it is not possible to determine precisely the fuel mix that is consumed by Maryland electricity users, since the path of electricity flows cannot be controlled. Though it is likely that Maryland imports come from neighboring export-heavy states, such as Pennsylvania, West Virginia, and Virginia, there is no way to determine this in an exact manner; moreover, Maryland generators also export power to the District of Columbia and Northern Virginia.<sup>12</sup> As a result, we approximate the current resource mix by applying the PJM system mix that was showed above to the import portion of Maryland electric supply. The resource mix is shown in Exhibit 12.

<sup>12</sup> "Ten-Year Plan (2007-2016) of Electric Companies in Maryland," State of Maryland Public Service Commission. Sage Energy / La Capra Associates

Exhibit 12—Maryland Generation Fuel Mix, 2006-2008

Average 2006-2008	
<b>Coal</b>	57.9%
<b>Nuclear</b>	30.8%
<b>Gas</b>	4.9%
<b>Hydro</b>	3.3%
<b>Wind</b>	0.1%
<b>Other Gases</b>	0.5%
<b>Oil</b>	1.0%
<b>Other Renewables</b>	1.5%

Source: PJM, EIA, La Capra Associates

Assuming that the imported electricity has the same mix as the PJM region results in a calculated fuel mix for Maryland that is slightly more nuclear-intensive (increasing from 29.3% to 30.8%) and a little less coal-intensive (decreasing from 58.9% to 57.9%). Natural gas usage increases the most (on a percentage change basis) changing from 4.0% to 4.9%, because the PJM region fuel mix uses almost double the natural gas to generate an average kWh or MWh. We use this fuel mix as a measure of the status quo in Maryland in analysis of risk-adjusted electricity prices below.

## 2. Forecasted Electricity Prices

We briefly describe electricity prices as forecasted by the Department of Energy's Energy Information Administration ("EIA"). Each year, EIA produces a national 25-year forecast of energy prices, including electricity prices, and a whole host of other energy statistics. This forecast is known as the Annual Energy Outlook ("AEO"). The full forecast is generally available in March of each year and provides comprehensive forecasts for all fuels at regional (but not state) levels. In addition, the forecast is well documented and is used as a benchmark for many private forecasts. Though the complete 2011 forecast (with different alternative cases) will be available in March 2011, the reference case forecast is available and will be discussed below.<sup>13</sup> The goal of this section is not to endorse or adopt this forecast in part or in whole. Rather, we wish to examine the assumptions underlying the major determinants described above and how potential risks in these assumptions were handled in the forecast.

### A. Reference Case Maryland Electricity Price Forecast

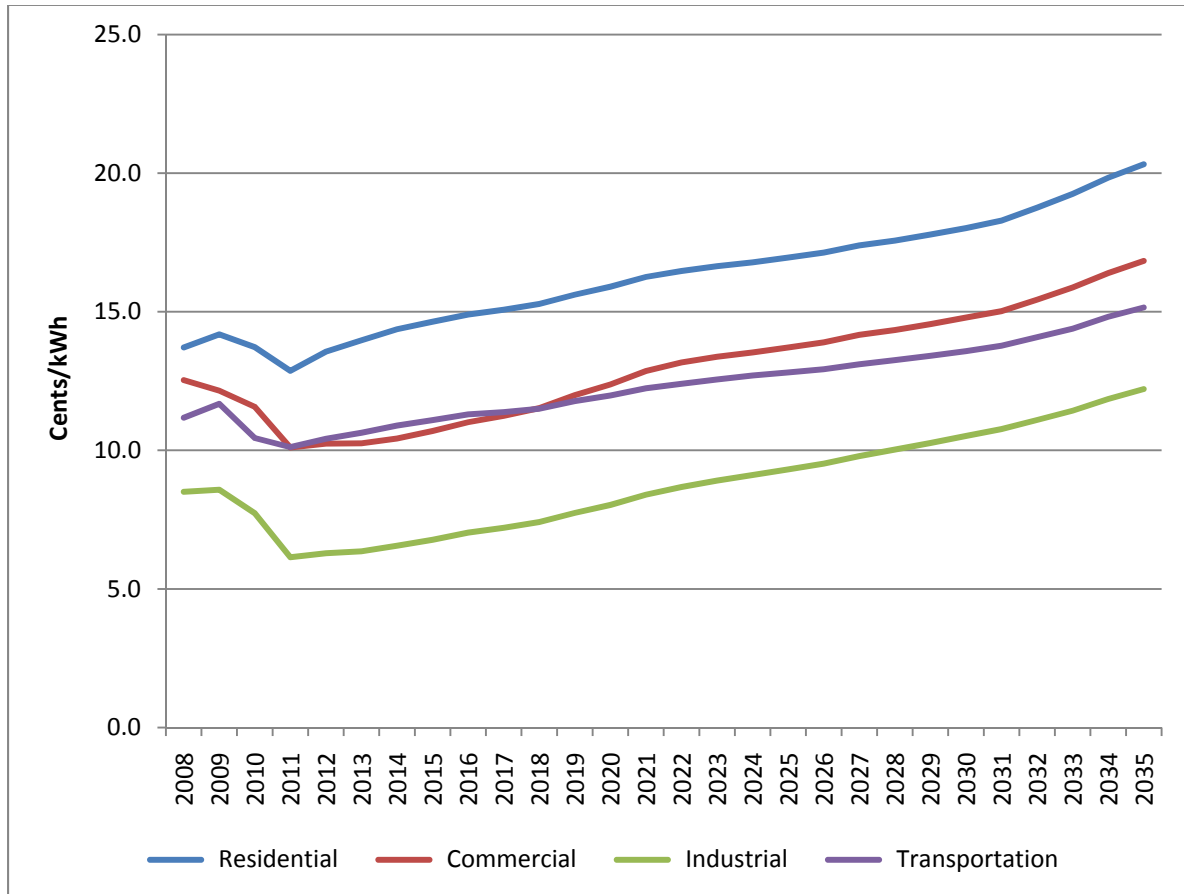
Starting with the 2011 forecast, EIA has updated the definitions of its electricity regions. State level forecasts are not available in the AEO, but the regional forecasts have generally provided good proxies. For the 2011 forecast, most of the state of Maryland will be included in a region called Reliability First Corporation, East (or "RFC East"). RFC is one of the nine NERC-defined<sup>14</sup> reliability zones that includes the entire state of Maryland and *generally* covers the entire PJM region with some exceptions. The RFC East region, as defined by EIA, essentially covers the eastern PJM region and thus does not include parts of Western Maryland. For our purposes, this is more than adequate since the majority of load (and prices) are determined by activity in Eastern Maryland and the adjoining states of Delaware, New Jersey,

<sup>13</sup> Alternative cases provide interesting sensitivity results and are used to assess different risk factors. Though not critical for the purposes of this document, the selection of which cases to pursue typically provides insight to current policy considerations and focus at the federal level. For example, the head of EIA announced in early February that they have been asked to produce an alternative forecast that removes all renewable subsidies.

<sup>14</sup> NERC stands for the North American Electric Reliability Council, which is an organization of U.S. and Canadian grid operators and is certified by the FERC to establish and enforce electric system reliability standards for transmission systems.

and Eastern Pennsylvania. Exhibit 13 shows the AEO 2011 forecast for total electricity prices for different customer classes in the RFC East zone. Consistent with Exhibit 6 above, we would expect Maryland forecasted prices to be slightly higher than these region-wide forecasts<sup>15</sup>.

**Exhibit 13—Electricity Prices by Customer Type,  
Reliability First Corporation East Region, 2008-2035**



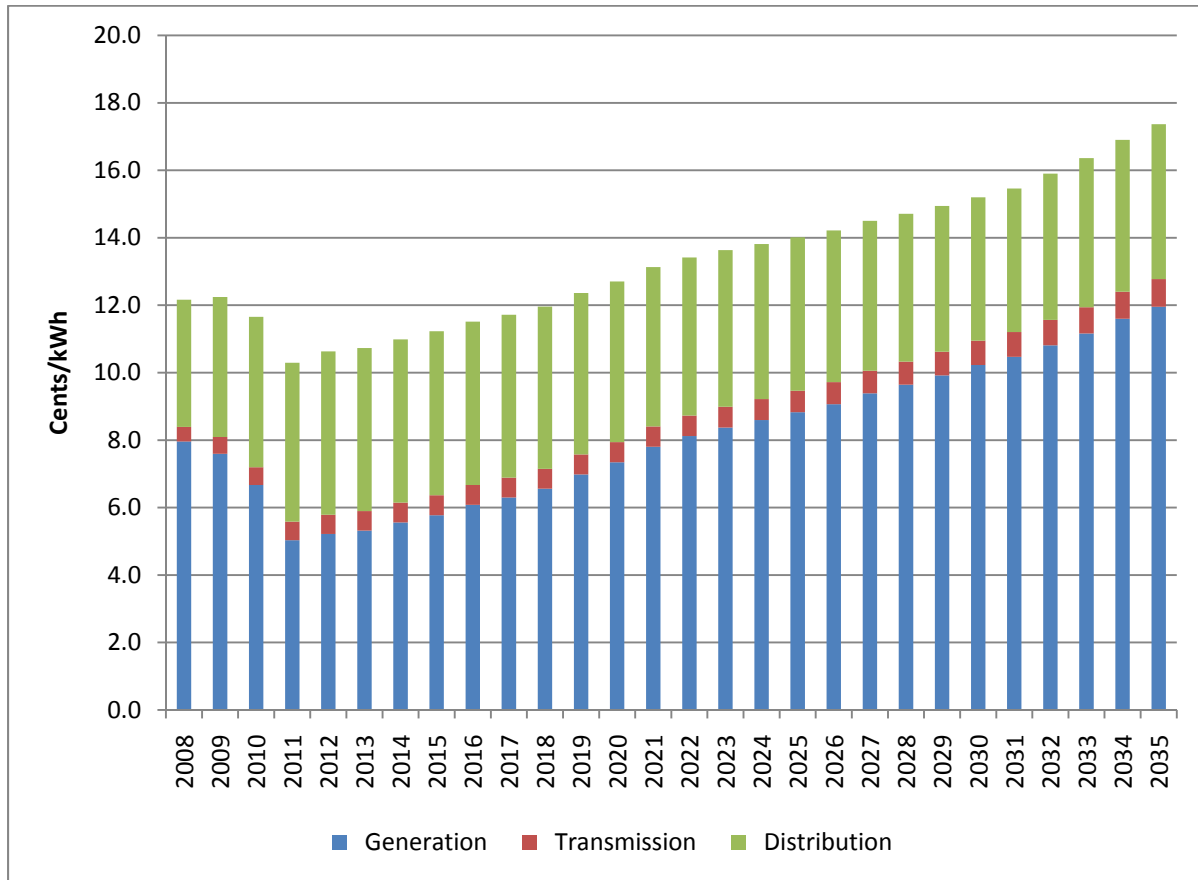
Source: EIA AEO 2011

Consistent with these types of forecasts, the AEO 2011 forecast shows relatively steady increases starting in 2011, following the collapse in prices due the economic downturn. The forecast shows a return to higher prices, but unlike the historical data shown Exhibit 1, the rates of increase are quite muted, averaging less than 1.5% per year for all customer types. More importantly, for later analysis, the forecast assumes very little variability in the price trajectory and assume “perfect foresight” in the various underlying assumptions.

Exhibit 14 breaks down the average price paid by all customers into generation, transmission, and distribution service components. Not surprisingly, most of the changes over the forecast period occur due to changes in generation costs, though transmission costs increase at the fastest rate (2.0% average annual increase). Distribution costs are forecasted to be essentially flat over the forecast period.

<sup>15</sup> All forecasts from the AEO 2011 include historical data for 2008, 2009 and part of 2010. As such, the forecast covers the period 2010-2035.

**Exhibit 14**—Electricity Prices by Service Component, Reliability First Corporation East Region, 2008-2035

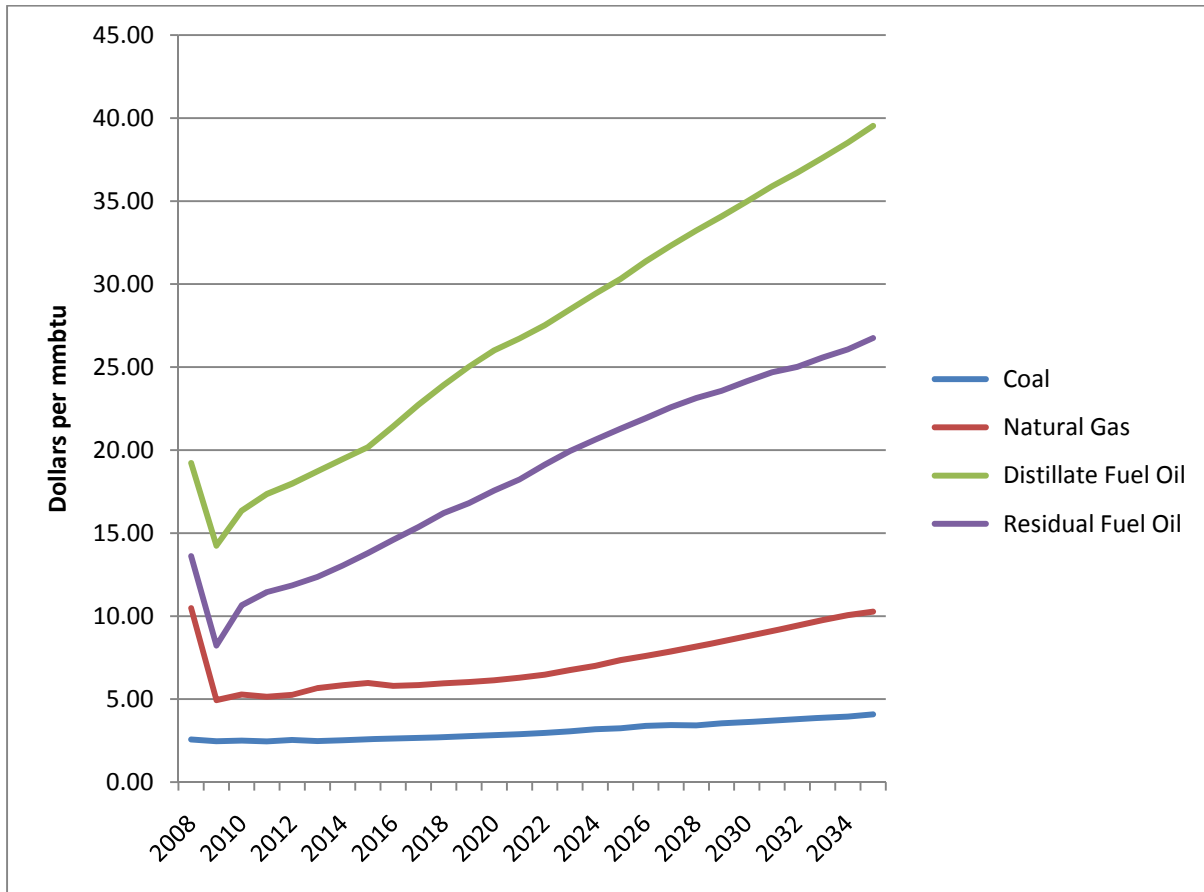


Source: EIA AEO 2011

### B. Fuel Price Risks

Due to its importance in determining electricity prices, we examine the underlying fuel forecasts to the overall and generation price forecasts shown above. Exhibit 15 shows the fuel prices forecasted for use in generation.

Exhibit 15—Fuel Prices for Electricity Generation,  
Reliability First Corporation East Region, 2008-2035



Source: EIA AEO 2011

The AEO 2011 assumes relatively rapid and large increases in world oil prices, which get passed onto petroleum-powered generators in the RFC East region. However, because oil is not a significant fuel for generators in the region—something that is not expected to change—the impacts of these increases are not relevant. Rather, much of the change in electricity prices can be attributed to coal and natural gas prices. However, the annual percentage increases in coal prices and natural gas are both lower than the increase in generation costs shown in Exhibit 13, implying (a) increased efficiencies in generation heat rate through upgrades or addition of newer, more efficient plants, (b) reduced costs in other variable components, such as O&M or emissions costs, (c) reduced electricity demand, or (d) some combination of these three factors.

AEO 2011, compared to the prior year's (AEO2010) forecast, assumes a higher level of technically recoverable shale gas, thereby depressing natural gas prices overall. Due to this higher supply of relatively cheap (or cheaper) natural gas, it takes until 2022 for natural gas prices to increase more rapidly.

### C. Carbon/Emissions Regulation Assumptions

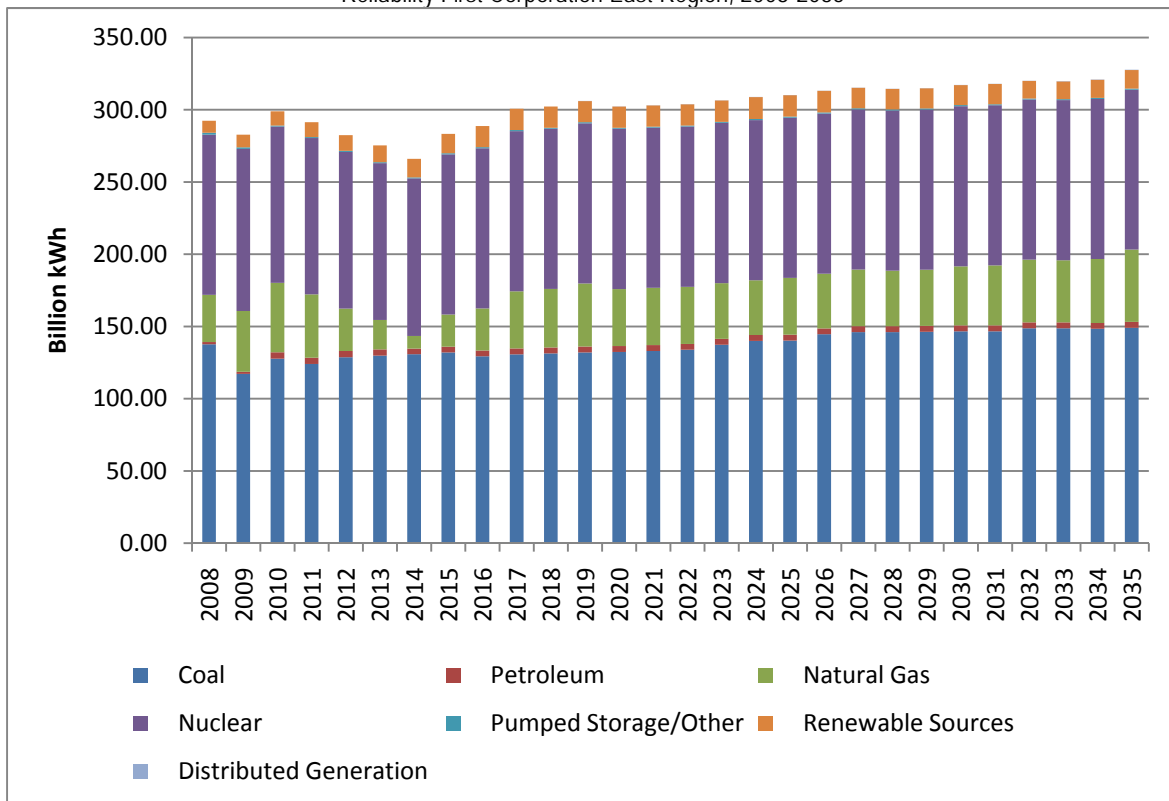
As mentioned above, the price of emissions is a minor determinant in past electricity prices, but the potential for emissions prices to influence electricity prices going forward can be high under certain assumptions. The EIA, as its practice, does not make such assumptions in its reference case. Reference

cases are generally based on regulations and laws in place as of October of the year prior to the forecast. As a result, the AEO 2011 forecast only includes the emissions regulations that were in place as of October 2010, which includes at least the current round of the RGGI program (with compliance years through 2012), but it is not known (without seeing the full release of the forecast) whether future compliance periods are also included. Even if RGGI were continued indefinitely, RGGI allowance prices have been low and are expected to stay low even under more stringent caps that would apply in later compliance periods. The same conclusion applies to regulation of other air emissions, notably SO<sub>2</sub> and NO<sub>x</sub>.

### D. Forecasted Supply Mix

Exhibit 16 shows the generation fuel mix for the RFC East region for central station generation (does not include distributed generation located at end-use sites)<sup>16</sup>. The data is slightly different than for the PJM region (Exhibit 10) because of the differently defined regions. Thus, for example, 2010 data for the RFC East region shows a mix (approximately) of 43% coal, 16% natural gas, and 36% nuclear, compared to the data in Exhibit 10 that showed values of 49%, 12%, and 35%. For current purposes, the trend in Exhibit 13 is more important than overall levels.

Exhibit 13—Generation Fuel Mix (Non-End Use),  
Reliability First Corporation East Region, 2008-2035



Source: EIA AEO 2011

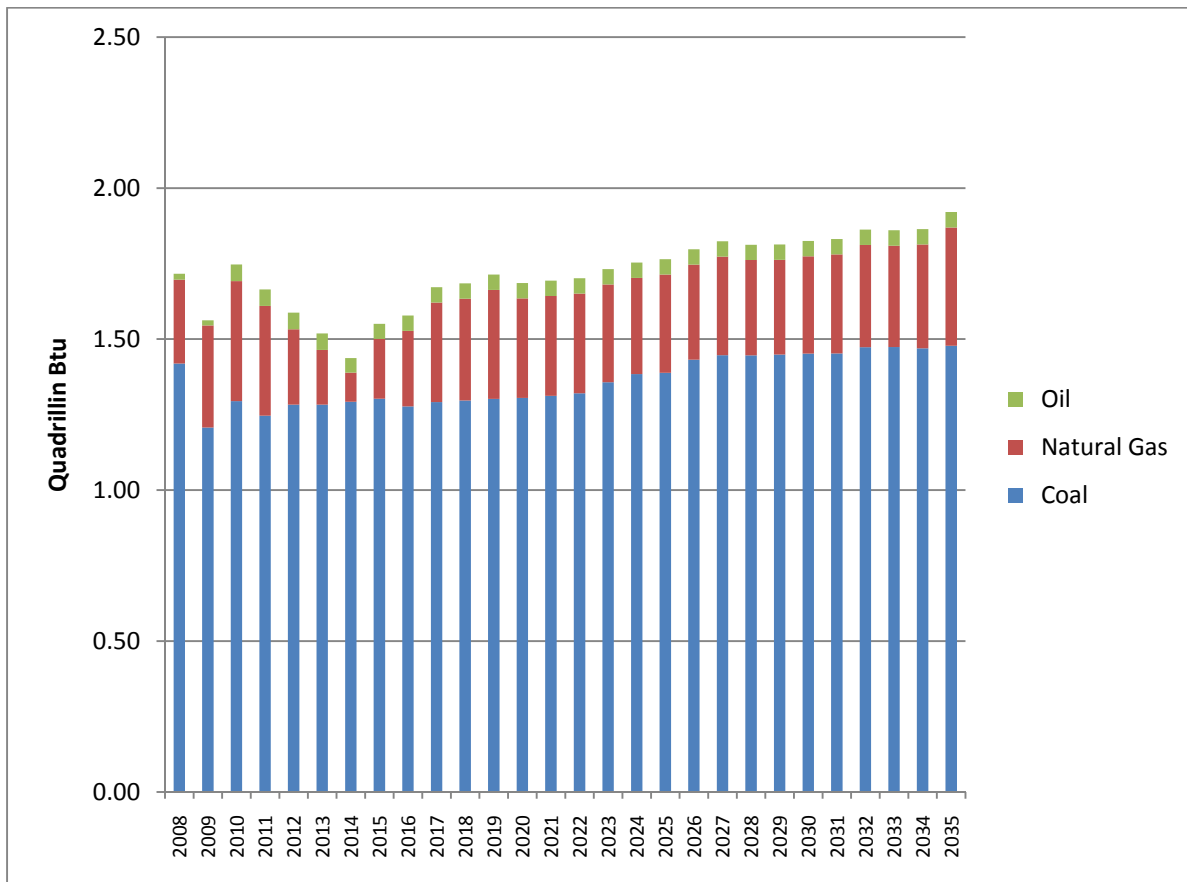
Though there is some fluctuation in the fuel mix, coal maintains its prominence in the regional generation fuel mix. Underlying this finding is the assumptions on coal plant retirements in the forecast. Out of over 23,000 MW of coal generation capacity in the RFC East region, only 800 MW of cumulative retirements are assumed or forecasted over the 2010-2035 time period. As we discuss below, this

<sup>16</sup> Growth in distributed generation, including renewable technologies, such as solar, is forecasted to be much higher than for central station generation (6.7% average annual growth rate, compared to 0.6% for central station generation).  
Sage Energy / La Capra Associates

assumes status quo carbon or emissions regulation and differs significantly from other outlooks that examine potential regulation scenarios and the impact on the retirement of coal plants throughout the PJM region.

Exhibit 17 shows generation fossil fuel usage implied by the fuel mix of Exhibit 16.

Exhibit 17—Generation Fuel Usage,  
Reliability First Corporation East Region, 2008-2035

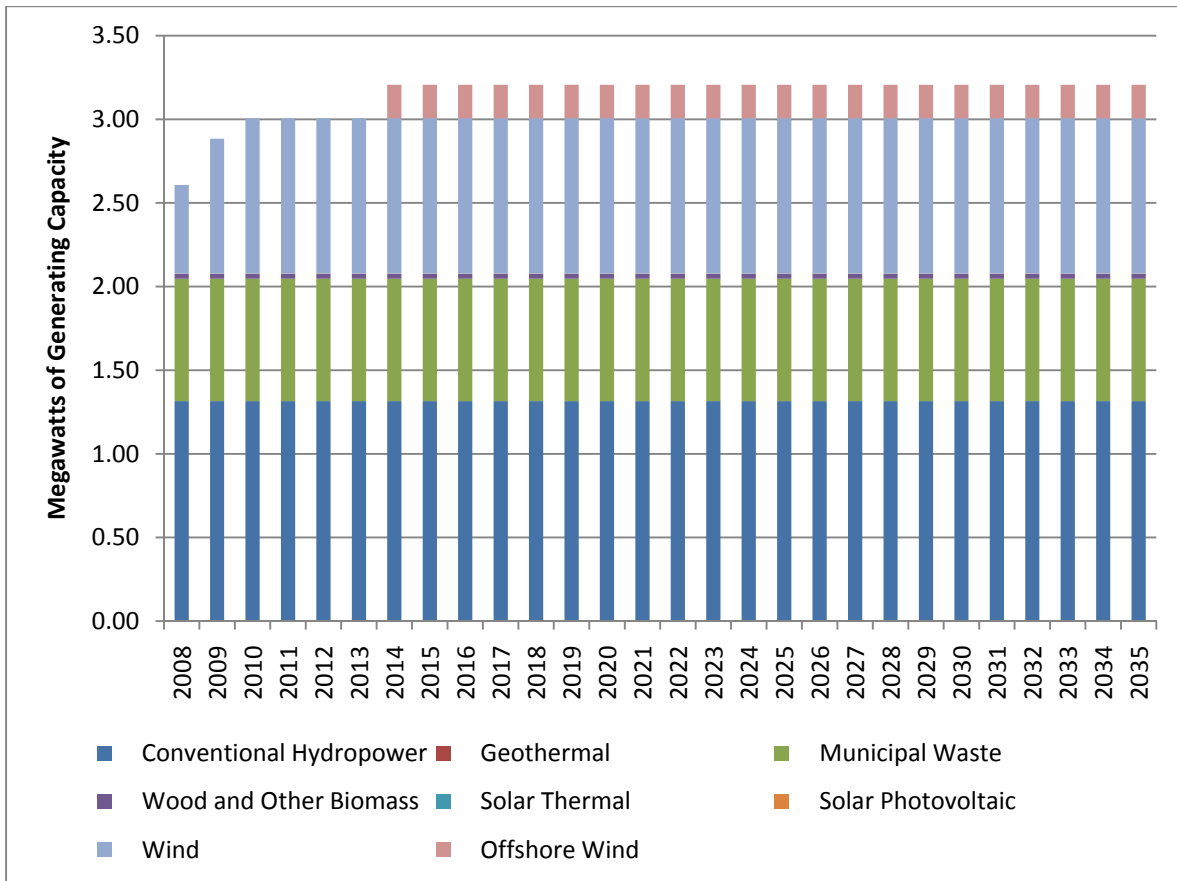


Source: EIA AEO 2011

Coal use not only continues to dominate fuel usage but actually increases as demand for electricity (along with little retirement of existing coal plants) requires continued heavy use of coal in the RFC East region. Consumption of coal actually increases faster than that of natural gas over the entire forecast period.

Exhibit 18 shows the forecast for renewable generating capacity in the RFC East region. The first thing that stands out is the lack of renewable resource addition over the forecast period. Only 200 MW of offshore wind is assumed to be added throughout the entire period. It is probably that this addition is based on some assumptions about on-line dates of existing projects in the pipeline, such as the Bluewater project off the coast of Delaware, rather than based economically based capacity expansion. No other renewable additions (on the utility side of the meter) are assumed.

Exhibit 18—Renewable Generating Capacity in the Reliability First Corporation East Region, 2008-2035



Source: EIA AEO 2011

### 3. Risk-Adjusted Electricity Prices

The electricity prices discussed above (both actual and forecasted) were not adjusted for risk or potential changes in forecast expectations. Obviously, actual prices do not need to be adjusted for potential unknowns, but price forecasts, especially over long-term periods, need to account for potential risks in the underlying pricing determinants. As discussed above, one way to account for this risk in planning and investment decisions is to examine a few cases (reference, high, and low) with a different set of underlying assumptions. The 2010 AEO forecast, discussed above, utilized such an approach, and the sensitivity cases for the 2011 AEO forecast will be released soon.

Another approach is to explicitly model potential risk by utilizing various metrics, such as historical standard deviation or variance, to adjust electricity prices for future risks. As discussed above, modeling exercises like the AEO are deterministic in nature and are only as good as the underlying assumptions. If future conditions deviate significantly from forecasted assumptions, for fuel prices and emissions prices, as examples, then the output results are ultimately not useful. Unfortunately, decision makers and policy makers tend to assume that such perfect foresight is possible and that under currently forecasted conditions—low natural gas prices, for example—higher cost generation options, such as offshore wind, are not economic and thus should not be pursued. This focus on least-cost planning is common. Many integrated resource planning (“IRP”) efforts recommend resource expansion decisions on the

minimization of delivery or generation costs and only include renewable options to meet specific environmental goals.<sup>17</sup>

In Maryland, and most states in PJM, public utility commissions no longer require IRP, as generation expansion and resource mix decisions have been left to market participants with various revenue streams provided by the different PJM markets (energy, capacity, and, for eligible technologies, renewable energy credits or “RECs”). Rather than invest in contracts with generation resources that are not susceptible to fuel risk or the risk of increased environmental costs, load serving entities (both utilities that procure for standard offer load and competitive suppliers) in Maryland instead generally only offer (by choice or by legislative or regulatory mandate) short-term products (less than one year and usually no more than 3 years) to their customers. Electricity prices can generally be hedged (through futures markets) in this shorter time period, but these hedges may be ultimately above market if one considers risks from a longer term perspective.

There have been studies that have addressed this lack of accounting for risks in electricity prices and their determinants over the long term. As one example, there was a study done for the Maryland OPC (introduced above in footnote 5) that modeled potential uncertainty in the drivers of standard offer portfolio cost, such as fuel prices, and how the current SOS procurement approach of laddered two-year full-requirements contracts exposes consumers to “excessive costs and risks”<sup>18</sup>. The authors compared alternative approaches to providing standard offer, such as using fifteen-year contracts for different resources, including wind, and expanded energy efficiency to meet a portion of load. Expected long-term costs of these alternative approaches were lower than reliance on short-term contracts (status quo) or spot markets even though some resources, such as wind, have higher capital costs than expected market prices. In sum, when one considers the long-term risk of price changes, additions of long-term contracts for resources whose costs are unrelated to changes in fuel prices actually reduces expected long-term portfolio costs under certain assumptions for future potential volatility of electricity prices.

The discussion below explores the applicability of this important finding from a different perspective—rather than examine the costs of meeting SOS load, we wish to compare current and forecasted resource mixes to a resource mix with additional offshore wind and examine how the risk-adjusted costs of different mixes are affected by including offshore wind. In addition, and more importantly, the analysis below includes the correlation between certain resource options and pricing determinants, such as fuel prices, rather than just including this relationship in lower expected price variations. Overall, the goal is to illustrate the portfolio diversification benefits of offshore wind rather than determine a definitive resource plan or electricity cost estimates over time.

### A. *Portfolio Theory Applied to Electricity Supply*

The discussion and methodology below follows the work of Awerbuch<sup>19</sup>, who published on the use of portfolio-based approaches as an alternative to the least-cost approaches that are found in IRPs and underlie much of the energy modeling work, such as the AEO forecast described above. Based on historical data for a variety of pricing determinants, such as fuel costs, Awerbuch showed that even

<sup>17</sup> For example, see Dominion’s 2010 Report of Its Integrated Resource Plan, Executive Summary, p. 1-4. Public version is available at [http://www.dom.com/about/conservation/pdf/2010\\_integrated\\_resource\\_plan.pdf](http://www.dom.com/about/conservation/pdf/2010_integrated_resource_plan.pdf). Also, see “Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans.” Ryan Wiser and Mark Bolinger, LBNL-58450 Journal, August 2005.

<sup>18</sup> See p.3.

<sup>19</sup> Awerbuch, Shimon. 2000. *Getting It Right: The Real Cost Impacts of a Renewables Portfolio Standard*. Public Utilities Fortnightly, February 15, 2000; Awerbuch, Shimon and Berger, Martin. 2003. *Applying Portfolio Theory to EU Electricity Planning and Policy*, IEA/EET Working Paper, February 2003. Awerbuch, Shimon. 2006. *The Role of Wind Generation in Enhancing Scotland’s Energy Diversity and Security: A Mean-Variance Portfolio Optimization of Scotland’s Generating Mix*. January 2006.

though certain generation technologies, such as wind, appear more costly when examined through a least-cost planning framework, they actually reduce overall portfolio cost when added to an existing portfolio that contains resources that are subject to uncertainty in these pricing determinants. In summary, Awerbuch promoted the use of mean-variance portfolio (“MVP”) theory, which underpins modern portfolio theory (“MPT”) and is used extensively in the financial industry to design investment portfolios based on maximizing return for an expected level of risk. MPT advances the conclusion that a diversified portfolio will outperform a single asset (or type of asset) over time due to diversification of risk. That is, as assets whose returns are not highly correlated to an existing portfolio of assets are added, overall portfolio variance (or risk) is reduced. Thus, as more assets are added to the portfolio, covariances, which measure how two assets’ returns move together, become more important in determining the overall portfolio’s risk than the individual risk of the assets. The same insights can be used to examine supply portfolios—greater fuel diversity or diversification of generating assets, if properly conducted, can reduce the overall risk of a supply portfolio and help reduce long-run costs.

Our interest is in examining the level of electricity costs associated with different resource portfolios and the potential benefits of diversification that can be achieved by adding offshore wind to existing portfolios. We discuss the application of portfolio theory to electricity supply using the pricing data for Maryland from Exhibit 6. Though additional data points would add robustness to our analysis (as we discuss below), we use annual pricing data for the last five years to illustrate the benefits of diversification. In order to conduct our analysis, we utilized a simple Excel-based model that calculates the returns and risks of different portfolios and determines the set of efficient generation mixes by examining their risk-adjusted prices.

Earlier in the document, we reviewed the mix of generation that is installed in PJM and Maryland and dispatched to meet loads in both those areas. For purposes of risk-adjusted electricity prices, we only examine the generation (or fuel) mix. Both PJM and Maryland fuel mixes were dominated by two generation types—coal and nuclear—with PJM featuring a slightly higher use of natural gas and showing an increase in natural gas usage. For purposes of the current discussion, we consider the current fuel mix as a single generating technology and compare it to a relatively risk-free technology, such as offshore wind.

Over the 2006-2010 time period, wholesale energy market prices averaged about 6.24 cents/kWh (in 2009 \$) over the 2006-2010 time period, which is the value used for expected price<sup>20</sup>. As mentioned above, there are a number of other elements involved in determining the final prices paid by consumers, but this component accounts for the majority of costs and the most potential variability in electricity prices. In order to model prices using portfolio theory, we took the inverse (or reciprocal) of the price— $0.162 = 1/6.24$  cents—to calculate expected returns. The value of 0.162 is the return (in kWh) per year for each cent invested (or spent) on electricity. Lower cost resources return more kWh per cent and thus have higher returns. Offshore wind, on the other hand, is assumed to have a much higher cost per kWh and thus a lower return. Though this value was assumed rather than derived from a review of actual or potential offshore wind contracts it is consistent with some of the recent data and analysis on the costs of offshore wind power purchase agreements.

It is important to remember that the value of 6.24 cents consists solely of cost related to purchasing wholesale energy delivered to Maryland and is significantly below the price that retail customers would pay for standard offer service or competitively provided supply. Other wholesale cost components—see Exhibit 3—such as capacity market, transmission, and ancillary services costs are not included in this

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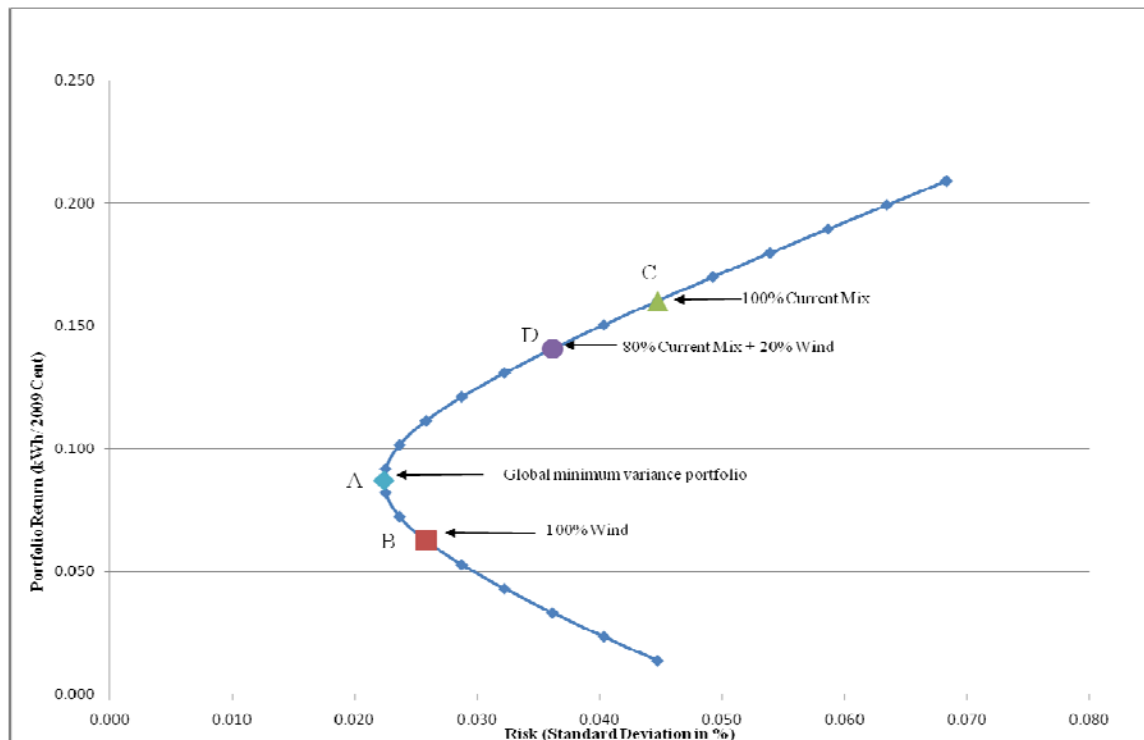
<sup>20</sup> Expected values can be calculated in many different ways (to account for limited sample sizes, for example), but for current purposes we assume that the average of historical prices is an accurate estimator.

figure. In addition, no retail price adders (as discussed in the introductory section) were likewise included.

The next important metric is the variance of the cost or price of the generating technology. Using the prices converted to returns (as discussed above), we calculated the variance of these returns. For offshore wind, and for this illustrative example only, we assumed (arbitrarily) for illustration purposes that the variance was one third that of the current mix. In actuality, the variance of offshore wind prices may be much lower given the predominance of upfront, capital costs in the overall cost picture. Next, the standard deviation is simply the square root of the variance and is an illustration of the year to year risk in the return. Finally, we calculate the related metrics of covariance and correlation. Correlation is the better understood of the two and measures how two variables (in this case the cost of generating technologies) move together—correlations can vary between -1.0 and 1.0, indicating perfect negative and positive correlation, respectively. For this case, we assume a correlation of zero between the two generating technology costs.<sup>21</sup> It is important to note that variance (and risk) is still positive for each generating technology and for combinations of the two. Covariance measures how *variances* (or year to year changes in returns) are correlated. With a zero correlation, the covariance of two generating technology returns or costs is also zero.

Exhibit 19 plots the various risk/return combinations for different portfolios consisting of different levels of the current generating mix and offshore wind.

Exhibit 19—Illustration of Return/Risk Relationship for Different Generation Portfolios



Source: Exhibit 6, La Capra Associates, Sage Energy

<sup>21</sup> This is a simplifying assumption that we will relax somewhat below and implies that the costs (and components, such as operating and maintenance costs) of two generating technologies generally do not move together. For example, offshore wind and non-renewable generating technologies may use similar inputs for operations and maintenance (labor, equipment, materials) whose costs may move upward together.

The blue line indicates the various portfolios with different weights for each generating technology.<sup>22</sup> The portion of the line above the minimum variance portfolio (Point A) is usually called the efficient frontier and represents a set of efficient mixes from which investors, planners, or policymakers can choose. The efficient frontier is the set of points at which it is not possible to improve both risk and price; an improvement in one factor results in a degradation of the other. Portfolio mixes below this point are not efficient. Point B, for example, represents a portfolio that is 100% wind and 0% current mix. Such a portfolio should never be selected since both risk can be reduced and return improved by moving up to point A, which represents a portfolio of 48% current mix and 52% wind. It is important to note that all choices above this point are equally efficient, and whether one portfolio is preferred over another depends on the decision-makers' preferences for risk relative to return. For example, the current mix (indicated by Point C) is just as efficient as Points A and D. However, there is no guarantee that historical prices will continue to provide returns as shown by Point C, since that portfolio represents the efficient mix with the greatest risk. As a result, it may be prudent to accept lower returns (and higher prices) for a portfolio that incorporates a greater mix of the generating technology with lower risk (in this case offshore wind), implying a move from Point C to Point D. The table below shows the various mixes discussed above along with the return (or price) and standard deviation (or risk) for each portfolio.

Portfolio	Current Mix %	Wind %	Expected Return (kWh/cent)	Price (cents/kWh)	Standard Deviation
<b>Point A</b>	48	52	0.108	9.34	0.025
<b>Point B</b>	0	100	0.063	16.0	0.026
<b>Point C</b>	100	0	0.160	6.24	0.045
<b>Point D</b>	80	20	0.141	7.11	0.036

Even assuming a high cost of 16 cents/kWh for the relatively risk-free generating technology, incorporation of this technology into the resource portfolio yields a greater percentage reduction in risk than increase in price. As shown in the table, movement from Point C to Point D yields a 14% increase in costs, but a 20% reduction in risk.

We can use the above framework to examine any number of sensitivity cases. For example, what if the price of the lower-risk generating technology falls to 14 cents/kWh with the same risks as the previous case? The table below shows the result of the analysis.

Portfolio	Current Mix %	Wind %	Expected Return (kWh/cent)	Price (cents/kWh)	Standard Deviation
<b>Point A</b>	43	57	0.109	9.14	0.024
<b>Point B</b>	0	100	0.071	14.0	0.026
<b>Point C</b>	100	0	0.160	6.24	0.045
<b>Point D</b>	80	20	0.142	7.02	0.036

Not surprisingly, as the cost of the less risky generating technology falls, it becomes more preferred over the riskier technology. As a result, the Wind % in the table increased from 52% to 57% for the minimum

<sup>22</sup> An elongated version of the frontier is shown for discussion purposes. In reality, points below the 100% Wind and above the 100% Current Mix are not feasible, since they assume that there could be negative portions of generation mix. For example, the point below Point B with 0.04 for a standard deviation contains a mix of 140% Wind and -40% Current Mix.

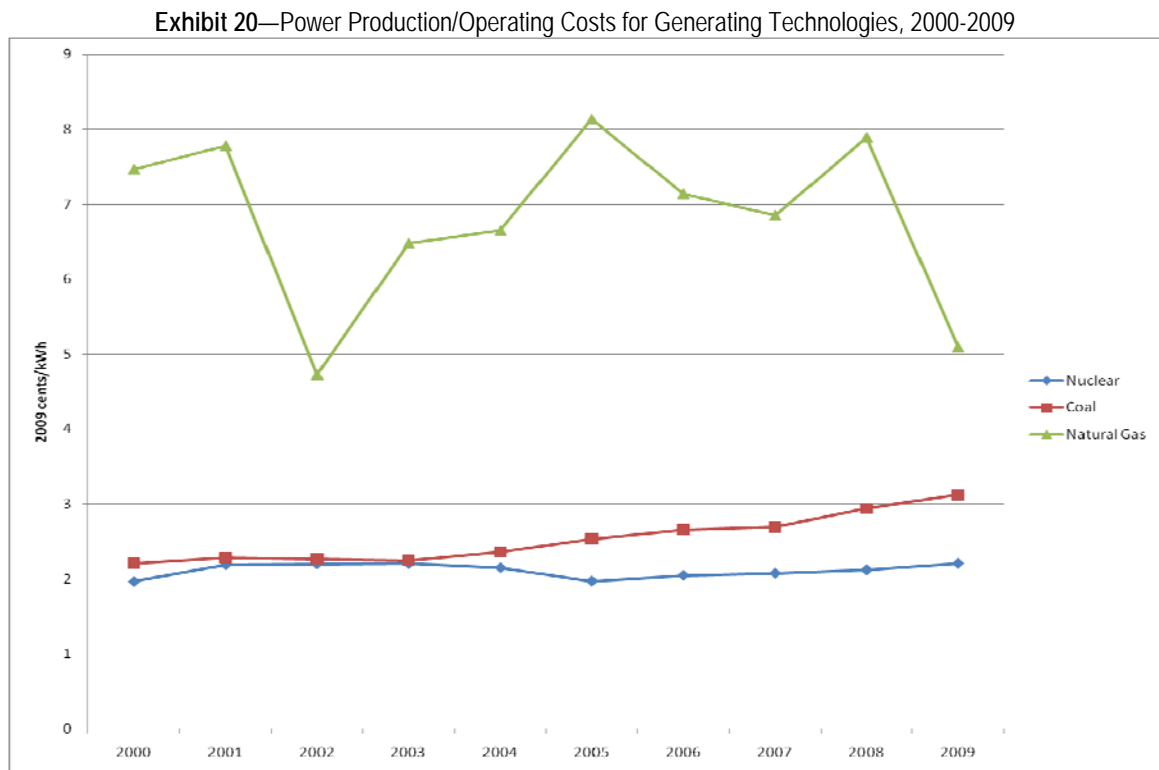
variance portfolio (Point A), which reduced the overall portfolio price and risk. In addition, the movement from Point C to Point D now yields a 12.5% increase in costs for a 20% reduction in risk.

Indeed, as the difference in costs between the relatively riskless asset and the risky asset falls, risk reduction benefits of the riskless asset relative to its costs increase. We show this point in a later part of the report when examining offshore wind in a higher-cost environment due to higher natural gas and coal-generated electricity prices.

This reduced risk of higher prices is a key benefit of introducing less risky generating technologies into an existing generation mix that is mostly composed of price-risky technologies or whose prices are set by technologies with price risk, such as in electricity markets where marginal units set the market clearing price (and the price ultimately paid by consumers). This reduction in risk holds even if the price of the less risky technology is high relative to the current mix.

## B. Conventional Generation and Offshore Wind Portfolios

In this section, we expand the above analysis to consider the current fuel mix in Maryland in order to examine the efficiency of the current fuel mix compared to fuel mixes that reside on the efficiency frontier and the impacts of adding small increments of offshore wind. The above analysis assumed that the current mix with no offshore wind and generation mixes including various amounts of offshore wind were both equally efficient and on the efficient frontier. Moreover, rather than use Maryland LMPs, we examine cost data for different generating technologies. Ideally, we would rely on cost data specific to Maryland generation, but these data were not readily available. As a result, we used national-level data for variable O&M, emissions, and fuel costs, which, as discussed above (see Exhibit 4) are the major determinants of LMP. Exhibit 20 shows these data for the three major fuels used in PJM and Maryland. Costs are shown in constant (2009) dollars to assist comparison.



Source: EIA, Ventyx Velocity Suite, La Capra Associates

Though data are shown annually, fuel costs, which are responsible for the majority of variability in the data, were available monthly. Thus, monthly estimates were available to calculate variances and covariances in order to conduct our portfolio analysis. Unlike the analysis above, which featured a limited number of data points, use of monthly data increased the statistical validity of the modeling exercise.

Not surprisingly, natural gas-powered generation has the highest power production costs per kWh over the 2000-2008 time period. We utilize historical data for gas prices rather than the price path presented in the AEO 2011 forecast (Exhibit 15) for a couple of reasons: (a) there is considerable uncertainty regarding potential environmental impacts of continued shale gas exploration and the concomitant price impacts that may occur; and (b) the AEO forecast does not account for the potential variability in natural gas prices, which has been prevalent over the past decade and is likely to continue even if overall natural gas price levels are lower. This issue of variability in fuel prices (and thus potentially electric prices) on a going forward basis is important, since reductions in the volatility of fuel prices over time lowers the need for diversification of fuel price risk. Power production costs for nuclear and coal are much lower than gas but coal prices have increased significantly (on a percentage basis) compared to nuclear costs.

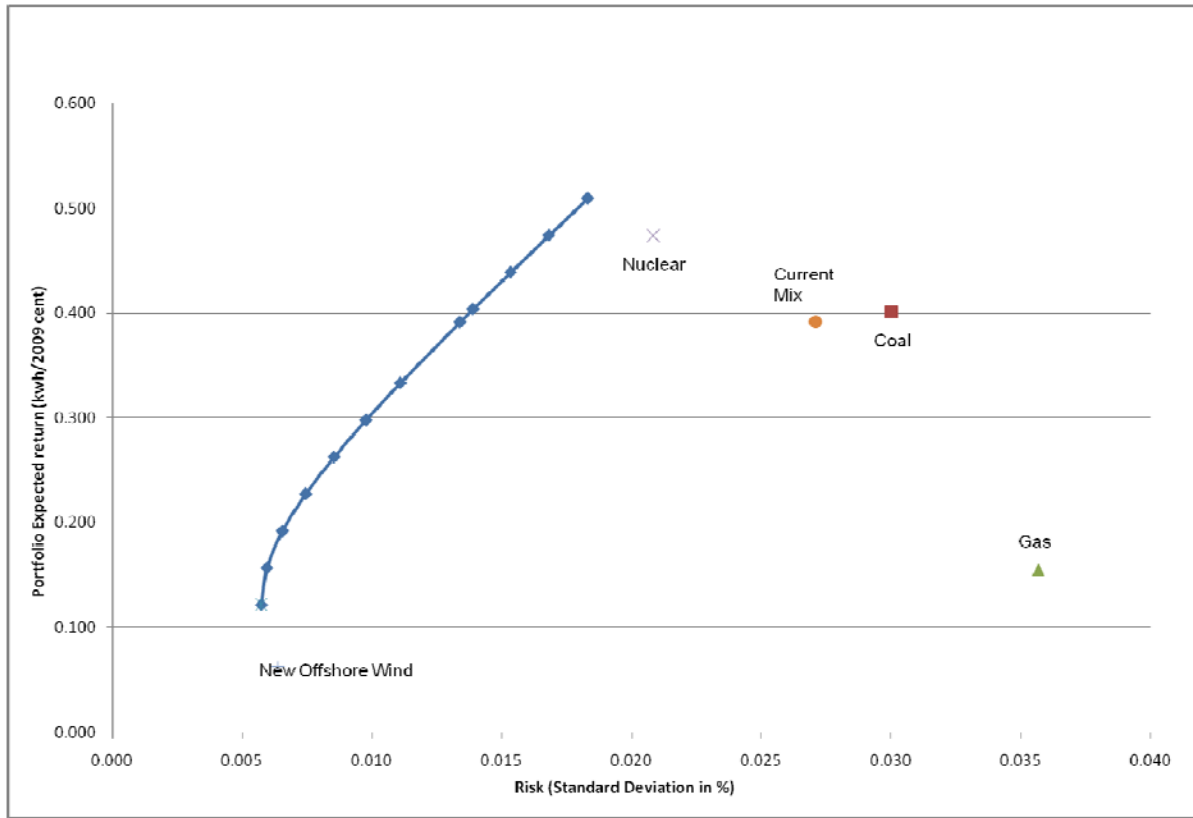
It is important to note that carbon costs are not included in the above data stream, and we did not include any carbon allowance prices in the analysis below; costs of other emissions (NO<sub>x</sub>, SO<sub>x</sub>, etc.) are included. At the current time, the RGGI program has a relatively minor impact on power production costs for coal facilities and the future of the RGGI program in terms of budget amounts and allocations is currently being debated among the RGGI states. On the national level, carbon regulation or legislation may eventually resurface, but, like RGGI, it is unclear what will be the form and impact of policies or laws affecting carbon. Indeed, this uncertainty in the future price of carbon is another form of price volatility that adds further support to addition of relatively risk-free resource options, such as offshore wind, that would not be negatively affected by carbon prices.<sup>23</sup> The modeling framework used in this document allows us to incorporate carbon price volatility but was excluded in the analysis in order to concentrate on fuel price and O&M expense volatility.

Exhibit 21 shows the efficient frontier that was calculated using the production cost data from the previous exhibit. We modeled the volatility of the three major generation types responsible for almost 95% of the Maryland fuel mix. The remainder of the fuel mix was modeled as having the characteristics of the system mix. Oil, despite having the highest volatility and prices of all the fuels, was not used since oil-powered generation only accounts for 1% of the current mix and is not expected to play a larger role in future mixes. Offshore wind was modeled using a 14.5 cent starting price, in order to account for potential capacity revenues and retail adders, with a 3.5% annual (nominal) escalator. Conversion of this price stream to a fixed dollar amount in 2009 dollars yields approximately 16 cents per kWh, which was the value used in the analysis displayed in Exhibit 19.

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<sup>23</sup> See, for example, "Volatile CO<sub>2</sub> Prices Discourage CCS Investment." The Brattle Group, January 2009. In this report, the authors state that CO<sub>2</sub> price volatility is likely to exceed that of natural gas.

Exhibit 21 —Risk Return Tradeoff for Different Fuel Mixes Utilizing Historical (2000-2008) Cost Data



Source: La Capra Associates, Sage

Unlike Exhibit 19, Exhibit 21 shows only the efficient frontier, thus excluding mixes that are not optimal (or below the point of the minimum variance portfolio). The lowest point on the efficient frontier represents the optimal mix of resources (or portfolio) with the lowest risk but also the lowest return (and thus highest price). Though portfolios on the efficient frontier are equally efficient, risk increases along with increases in the price of the portfolio for portfolios higher up on the curve. Not all portfolios on the efficient frontier, as calculated using only operating costs for this example, may be realistic. The minimum variance portfolio consists of mostly wind (80%) and nuclear (12%) since these resources individually have the lowest risk but, more importantly, wind costs have been assumed to be uncorrelated with the operating costs of the other resources. Such a mix may be optimal in terms of the risk-return tradeoff based on the operating cost data in Exhibit 20, but obviously would raise issues of system reliability and stability. In addition, the current fuel mix was developed over time and involved consideration of all costs—including capital and financing costs—in the development of power generation. The modeling framework utilized in this report would permit such an analysis but is beyond the scope of the current analysis. Overall, the goal in this example is not to suggest that the Maryland or PJM system mixes should migrate to specific mixes on the efficiency frontier, but to examine the risk-return impact of adding incremental amounts of wind resource to current mix under certain assumed operating cost characteristics.

We also show a number of other mixes that are located to the right of the efficiency frontier and are thus considered inefficient compared to those on the frontier. In addition to portfolios that consist of 100% of each fuel or generating type, we show the current mix in terms of its risk and return. Largely due to the fact that we are only examining operating costs, the current mix is not as efficient as mixes on the frontier, which generally feature portfolios with much higher nuclear use than the current mix. Greater mixes of nuclear generation would in almost all cases require additional capital investment in

the form of new nuclear facilities, which would require us to consider capital and financing cost risk as well. Though this is an important point, we can still use the results in Exhibit 21 to examine the impacts of adding incremental amounts of wind (shown in the table below).

	<b>% Change in Power Production Price</b>	<b>% Change in Risk</b>
<b>Add 200 MW Wind</b>	1%	-2%
<b>Add 400 MW Wind</b>	2%	-3%
<b>Add 600 MW Wind</b>	3%	-5%

The table shows that adding various quantities of wind (nameplate capacity) to the current mix increases overall portfolio cost but also reduces overall risk, thus confirming the results shown by the earlier illustrative example. This risk benefit is frequently not considered or only mentioned in passing when examining additions of offshore wind to the current mix; the modeling framework used in this document allows us to quantify the risk-reduction benefits of adding relatively small amounts of offshore wind to a current resource portfolio in Maryland consisting of over 12,000 MW. Based on historical operating costs (and not including any impacts of potential carbon pricing schemes and other environmental regulations), the analysis shows that addition of offshore wind now can have beneficial reductions in risk of higher prices with relatively minor increases in the cost of long-term LMPs.

This reduction in risk has real value. As an illustration, we assume 10 cent average or expected electricity price with a standard deviation of 4 cents. Further assuming that the population of possible prices follows a normal distribution, there is a 1/3 (or about 34%) chance of prices being between 10 and 14 cents and (about) a 48% chance of being between 10 and 18 cents. If we reduce the standard deviation by 5% for example, these ranges change from 10.3 to 13.8 and 10 and 17.6 cents. This reduction in uncertainty allows for better planning and potentially reduces costs.

### *C. Impact of Offshore Wind on Prices under Alternative Efficiency Frontiers*

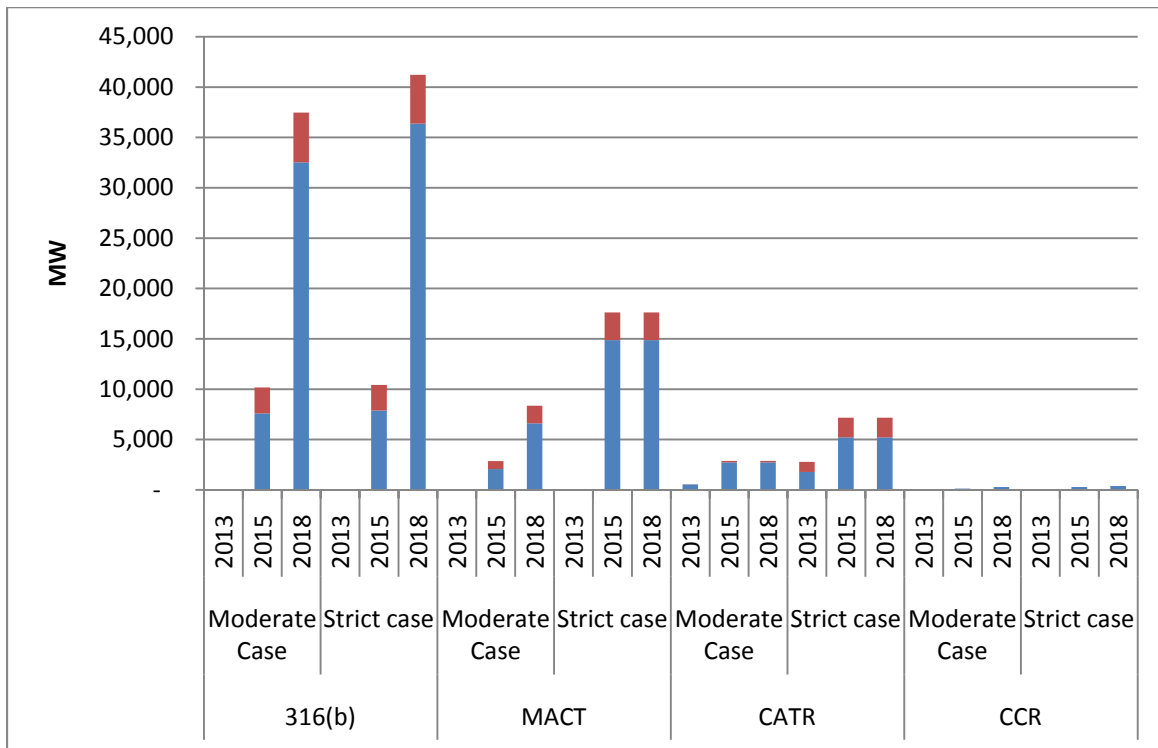
The above analysis utilized historical data to categorize future prices (and returns) and risks in changes in these prices and returns. However, there is considerable uncertainty concerning the mix of conventional, fossil fuel generation in the PJM region and Maryland in the future. In particular, though the above analysis showed that adding offshore wind to the current mix right away is prudent, the decision to do so may look better if stricter environmental controls, notably in the form of carbon and other air emissions (and possibly water) regulations are implemented. In this section, we examine an additional scenario that incorporates some of these risks of additional environmental controls. Though we do not explicitly model carbon regulation, the environmental risks we do model can serve as a proxy for more stringent carbon controls. This alternative scenario includes higher costs for coal and natural gas than indicated by use of historical data.

#### **1. Carbon/Environmental Regulation Risks**

As discussed above, the 2011 AEO base case forecast produced by the EIA does not include any environmental regulations or controls that are not now currently in place or in the process of being promulgated. Such an assumption is one factor that leads to the forecast outcome (or input) of essentially no retirements of existing coal plants in the Maryland/Eastern PJM region and increasingly larger coal use as a percent of the total generation fuel mix (see Exhibit 17). As an alternative, there have been recent studies that have examined the potential impacts of future environmental regulations (non-carbon) on the nation's coal fleet. NERC, from the perspective of a reliability organization,

examined the potential capacity reduction from derates and retirements induced by application of various EPA regulations<sup>24</sup>: (a) Section 316(b) of the Clean Water Act, which sets new standards for cooling water intake structures; (b) Maximum Achievable Control Technology (“MACT”), which is expected to set more stringent standards for mercury, acid gases, heavy metals, and organics; (c) Clean Air Transport Rule (“CATR”), which is to replace Clean Air Interstate Rule (“CAIR”) and serves to reduce SO<sub>2</sub> and NO<sub>x</sub>; and (d) Coal Combustion Residuals (“CCR”), which relates to disposal of coal ash and other residuals. Exhibit 22 shows the potential capacity reductions for the U.S. under two different regulatory cases.

Exhibit 22—Potential US Capacity Reductions Due to Each Potential EPA Regulation



Source: NERC

Data are also available for NERC sub-regions and data for the region most related to PJM—the RFC sub-region—show significant potential reductions in capacity. For example, of the 37,475 MW reductions due to 316(b) in 2018 under the moderate case, 7,035 MW are located in the RFC zone.

A December 2010 Brattle study<sup>25</sup> provides an additional look at the impacts of environmental regulations, as described above, on capacity in the U.S. and PJM. According to the Brattle study, 15-26% of PJM’s coal capacity (or 12-19 Gigawatts) is vulnerable to retirement by 2020. In order to model the economics of retirements, the study necessarily examined potential increases in capital (equipment) costs to coal operators (due to capital investments to meet compliance with the regulations), expected to range from \$12-46/MWh. The study also examined the impacts on natural gas prices, which would be expected to increase by \$1.50-2.50/mmbtu in the 2010-2020 time period as demand for natural gas-powered generation increases the demand for natural gas as a generating fuel. We use these cost

<sup>24</sup> NERC 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations, October 2010. Full report available at: [http://www.nerc.com/files/EPA\\_Scenario\\_Final.pdf](http://www.nerc.com/files/EPA_Scenario_Final.pdf)

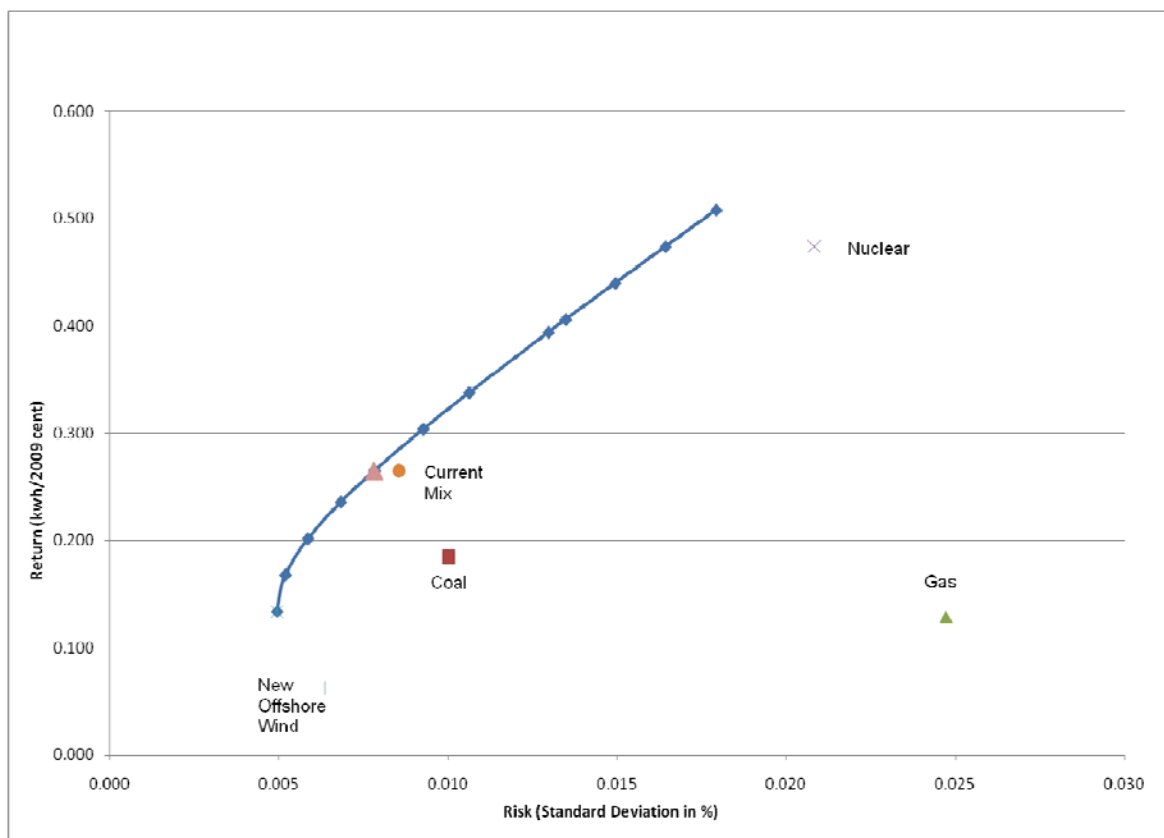
<sup>25</sup> Potential Coal Plant Retirements Under Emerging Environmental Regulations, December 8, 2010. Brattle Group. Sage Energy / La Capra Associates

impacts to re-calculate the efficiency frontier and examine the risk-return benefits of adding offshore wind to the portfolio.

## 2. Alternative Efficiency Frontier Analysis

Exhibit 23 shows a new efficient frontier using the prior power production costs, adjusted for the cost impacts of more stringent environmental regulations. As in Exhibit 21, in Exhibit 23 we show the current mix and risk-return data for portfolios entirely composed of single fuels or generating types. A comparison of this exhibit with Exhibit 21 shows that the nuclear and offshore wind risk-return data points did not change—environmental controls were not expected to change the price or price risk of these two technologies. On the other hand, coal and gas costs were affected. Specifically, both the return and risk of gas and coal technology fell, which makes sense for coal costs, since additional compliance costs are expected to increase the price of coal generation but will probably not materially affect the volatility of power production costs. Turning to gas costs, the return for gas plants decreases (thereby implying more expensive gas generation). Though increased demand for gas may also increase gas price volatility, we did not model volatility beyond levels included in historical data. Overall increases in natural gas prices, however, were still modeled in the analysis.

Exhibit 23—Risk Return Tradeoff for Different Fuel Mixes Under More Stringent Environmental Regulation



Source: La Capra Associates, Sage

As before, we wish to examine the impacts of adding additional amounts of offshore wind to the current mix. Exhibit 22 shows that under the changed gas and cost levels (to account for potential environmental regulations), the current mix, as shown by the center symbol, is now closer to the efficiency frontier. Prices have risen (shown by lower returns) but risk has also fallen (as compliance costs were added but underlying volatility levels did not change). Given the closeness of the current mix to the frontier, we can now examine the impacts of sliding to the left to a point on the efficiency

frontier. Simply sliding left reduces risk but does not increase price, resulting in a superior mix at no additional cost. The table below compares the generational fuel proportions of the current mix to the optimal mix (indicated by the triangle on the efficiency frontier).

	Coal	Gas	Nuclear	Other	Offshore Wind
<b>Current Mix</b>	58%	6%	31%	5%	0%
<b>Optimal Mix</b>	35%	18%	36%	5%	7%

Moving from the current mix to the optimal mix—recall that this is only one example of an optimal mix since there are an infinite number of optimal portfolios along the efficiency frontier—involves increasing the proportion of offshore wind from 0% to 7% and increasing nuclear and gas proportions while reducing the role of coal in the fuel mix.

Overall, this alternative case shows that offshore wind can be added to a current mix, given additional changes to the fuel mix to account for increased environmental compliance costs and impacts of more stringent environmental regulations, and not raise overall portfolio costs but at the same time reducing risk. It is important to note that this alternative case evaluates the current mix under an alternative risk-return tradeoff that differs from historical experience. Indeed, assumptions about the risk-return tradeoff for different generating technologies and each cost component, and, most importantly, how these costs and changes in these costs vary among the different technologies, are the key assumptions underlying this analysis. As these assumptions change, efficiency frontiers (and the set of optimal mixes) will change as well.

## 4. Suggestions for Future Work

There are important caveats to the above analysis. First, the portfolio cost analysis only considered power production or costs that vary with the amount of energy produced. Though this is a reasonable assumption for a generating fleet consisting of existing plants, there are other significant costs, such as financing and capital, which are involved with creating a desired portfolio and were not examined in this report. A fuller analysis, which would utilize the same framework, would consider all these costs and differentiate costs among existing and new generating capacity additions, such as, for example, using expectations for levelized costs over a 20-year time period.

Second, and related, the portfolio costs were assumed to be weighted average of power production costs, but deregulated wholesale markets in PJM are uniform-price auctions or environments where marginal units set the price paid for all units (vs. pay-as bid, where generators get paid what it costs them to generate). In essence, we were utilizing a levelized cost approach for examining power production prices. Over the long run, we would expect that market prices would approximate these costs, but portfolio prices calculated using the approach in this report cannot be directly compared to short-term prices, such as prices for a year or even a few years time.

Third, we did not model operating or technical feasibility (or the political feasibility) of the various potential mixes. Indeed, some of the mixes found on the efficient frontier are either unfeasible from a technical perspective—for example, reliability criterion would not be met or there might be constraints to siting certain plant types or the availability of a fuel or resource—or from a political perspective, where expansion of certain technology types, such as nuclear, might not be possible in certain areas. The current modeling framework can calculate efficient frontiers that only contain feasible mixes by

adopting constraints that limit the mixes to feasible combinations of generating resources, but additional work would be necessary to determine the specific constraints that would be used.

Finally, the risk profiles of different generating resources and extent of correlation among costs of different generating resource are key considerations. In this report, we assumed that offshore wind costs were essentially riskless or that contracts for offshore wind could be developed that eliminate risk (through, for example, fixed price contracts or prices that change by a fixed amount each year). We also assumed that offshore wind costs were unrelated to changes in the costs of other generating technologies. These assumptions may not always hold. For example, though we assumed a known wind price, uncertainty in construction and O&M costs for offshore wind may be more risky than assumed here.

## 5. Concluding Observations

In sum, analysis of the benefits of offshore wind needs to include its potential to reduce the risk that generating prices for the overall generating mix will be higher than expected. Excluding the risk-reduction or hedging value of offshore wind underestimates the value of non-volatile resources, such as offshore wind.

Offshore wind may be currently more expensive than some generating technologies, but it lowers the risk of increased costs, and under certain conditions, these risk benefits can be achieved with little or no cost increase over current mixes. One of these conditions is more stringent environmental regulation of carbon and other air and water emissions from older, fossil-fuel (notably coal) power plants. Carbon (and other) emissions regulation is one key to improving the economics of offshore wind relative to the current fuel mix in the PJM region. However, additional environmental regulation also increases uncertainty for affected generators. Avoiding this uncertainty has a value that goes beyond avoiding the additional costs that may be necessary. Avoidance of this uncertainty in environmental compliance costs and impacts is another benefit of offshore wind.

The caveats previously mentioned can be addressed in a more expansive application of the methodology described herein. The important overall conclusion in this report is that additions of a generating resource with a relatively riskless cost profile can reduce the risk of price increases, despite the cost disadvantage of the riskless generating technology relative to existing generators. Thus, adding offshore wind is an important diversification strategy that yields risk-reduction benefits to a generating portfolio that features fuel and other costs that have the potential to increase over the long term.