

Potential Effects of Proposed Climate Change Policies on PJM's Energy Market



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Executive Summary

Although there have been many national macroeconomic studies on the long-term economic impacts of various climate change control policies, there have been very few analyses of the near-term price impacts to consumers in given states and regions. PJM Interconnection (PJM), the independent electric grid operator serving the Mid-Atlantic and parts of the Southeast and Midwest regions of the country, is uniquely positioned to model the short-term impact of various climate change control policies on both the price and dispatch of electricity in the region we serve. PJM's independent analysis is not intended as a substitute for those longer-range, macro-level analyses; rather it is primarily designed to provide a depiction of near-term impacts in 2013 on the PJM wholesale power market and the associated possible impact on consumer electric bills during the first years under a climate change policy. Nor is this study intended to suggest or propose policy, the clear province of the legislative and regulatory processes.

The purpose of this study is to examine the short-term impacts of potential climate change policies, as represented by prices on carbon dioxide (CO₂) emissions, to provide a better understanding of the potential range of effects on PJM Energy markets to market participants, regulators and policymakers. It is hoped that information gathered by this effort will inform the discussion as the issues associated with climate change policy continue to be deliberated in Washington and elsewhere. In particular, the paper focuses on wholesale prices, market-wide wholesale power costs, bills paid by retail customers, changes in generation mix by fuel type, and reductions in CO₂ emissions in the PJM footprint. Additionally, the impact of demand reduction and wind power penetration scenarios on changes in LMP, wholesale power costs, consumer power bills, generation mix, and emissions that result from climate change policy are also examined.

The study links its results to the analyses of the Energy Information Administration (EIA) and the Environmental Protection Agency (EPA) of the Lieberman/McCain Bill (S.280), the Bingaman/Specter Bill (S.1766) and the Lieberman/Warner Bill (S.2191) introduced in the 110th Congress. These proposals may form the basis for legislation considered in the 111th Congress.

PJM used the simulation modeling framework and data that it used to perform the market efficiency studies in the 2007 Regional Transmission Expansion Plan (RTEP) with the addition of CO₂ prices in an effort to isolate the effects of CO₂ prices, gas prices, demand reductions and wind power penetration on market outcomes. Moreover, PJM has examined in more detail scenarios of CO₂ and natural gas prices that closely match CO₂ and natural gas prices derived in EIA and EPA analyses to understand the potential effects of legislative policies on the PJM Energy Market.

Impact on Prices, Costs and Emissions

Given the CO₂ prices and natural gas prices that can result from implementation of climate change policy, PJM's analysis demonstrates that:

- Holding all other factors constant, the increase in average wholesale electricity prices in the PJM region corresponds to approximately 75 - 80 percent of the CO₂ price in dollars per short ton (2,000 pounds versus a metric ton of 2,204 pounds). This increase results from the fact that coal units, on average, emit approximately one short ton of CO₂ per megawatt-hour (MWh) and coal units determine the price of energy about 70 percent of the time in the PJM Market.
- At CO₂ prices of \$10, \$40, or \$60 per short ton, typical residential customers using 750 kilowatt-hours (kWh)/month could see increases in their monthly bills up to approximately \$6 (\$72 annually), \$23 (\$276 annually), or \$34 (\$408 annually) respectively assuming all wholesale cost increases are passed through on a dollar-for-dollar basis.
- Regardless of the higher electricity prices that could result from CO₂ prices, the increased market penetration of energy efficiency and some types of demand response can reduce total consumption and customer costs for electricity, and in turn mitigate the wholesale price impacts, and result in additional CO₂ emission reductions.
 - Reductions in consumption for energy of two percent, five percent, and ten percent in the PJM region can result in mitigating price increases by as much as \$4/MWh, \$9/MWh, and \$17/MWh, respectively depending on the price of natural gas. This corresponds across the PJM region to reductions in total costs for electricity by as much as \$3 billion-\$4 billion, \$6 billion-\$11 billion, and \$10 billion-\$18 billion per year, respectively, depending on the price of natural gas.
 - Reductions in consumption for energy of two percent, five percent and ten percent in the PJM region can result in corresponding additional CO₂ emissions reductions up to of 14 million, 34 million and 60 million short tons, respectively, in 2013.
 - Only at relatively low CO₂ prices of \$10/ton and a natural gas price of \$6.44/ million British Thermal Units (mmBtu) in the study, can the increase in wholesale price and market-wide expenditures be completely offset through reductions in consumption of five percent or greater.

The Addition of Wind Capacity

PJM has also modeled separately the impact of an addition of 15,000 MW of wind capacity, most of which is in the western part of PJM. Consistent with historical experience and expectations concerning the number of overall projects proposed versus those actually constructed, PJM used the assumption that only about a third of the approximately 43,000 MW of wind power in the interconnection queue will go into commercial operation by 2013. PJM examined impacts on prices, emissions, and generation mix.

- 15,000 MW of wind capacity displaces about 43,000 GWh (gigawatt-hour) of fossil-fueled generation with about 60 percent of the displaced generation being coal and the remainder being natural gas and oil-fired units.
- 15,000 MW of wind offers CO₂ emissions reductions of almost 35 million short tons in the absence of any CO₂ price,
- 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.

PJM Results in the Context of Legislative Proposals

PJM has taken the aforementioned general results and linked them to the analyses of the three major legislative measures analyzed by the EIA and EPA.

- EIA and EPA analyses of the Lieberman-McCain (S.280) and Bingaman-Specter (S.1766) bills under base assumptions indicate a CO₂ price close to \$10/short ton in 2013. The impact on the PJM Energy Market would be to see power price increases of approximately \$7.50/MWh, with market-wide expenditures to increase approximately \$5.9 billion, and emissions reductions from PJM sources of almost 6 million tons. The increase the bill of a typical electricity customer could be up to \$5.58 monthly or \$66.96 annually.
- EIA and EPA analyses of the Lieberman-Warner (S.2191) bill under base assumptions, or assumptions indicating that the availability of lower carbon generation sources may be limited, results in CO₂ prices close to \$20/short ton in 2013. The impact on the PJM Energy Market could be power price increases as high as \$15/MWh, and market-wide expenditures increase by as much as \$12 billion, while providing emission reductions from PJM sources of approximately 14 million tons. The impact on a typical customer's bill could be as high \$11.19 monthly or \$134.28 annually.

Other analyses performed by EIA and EPA examined the outcomes resulting from major legislation under alternate sets of assumptions. In analyses assuming the availability of CO₂ offsets are limited, CO₂ prices could rise as high as \$40/short ton to \$60/short ton. The findings demonstrate that:

- At a price of about \$40/ton, as modeled by EPA for the Lieberman-McCain Bill (S.280) in the absence of offsets, the impact on the PJM Market would be power price increases up to \$30/MWh, market-wide expenditures increasing up to \$23 billion and emissions reductions from PJM sources up to 66 million tons. The impact on a typical customer's bill could be as high \$22.28 monthly or up to \$267.36 annually.
- At a price of just over \$60/ton as modeled by EPA for the Lieberman-Warner bill (S.2191) in the absence of offsets, the impact on the PJM Market would be power price increases of approximately \$45/MWh and market-wide expenditures increasing up to \$36 billion. However, gas prices also rise to nearly \$10/mmBtu as shown by EIA, emissions reductions from PJM sources are only 25 million tons. The impact on a typical customer's bill could be up to \$34.16 monthly or \$409.92 annually.

The range of possible impacts from climate change policy on power prices and expenditures, dispatch of generating units, and emissions are quite large and sensitive to many different assumptions regarding details of legislation and future operating conditions. PJM conducted this study to provide a better understanding of the

potential range of effects of climate change policy on PJM Energy markets to market participants, regulators and policymakers. For example, with 2013 forecasts of natural gas and coal prices, the switch from coal to combined cycle natural gas would not occur until CO₂ prices would reach approximately \$40 per short ton. However, at gas prices about 50 percent higher to \$10/mmBtu, a CO₂ price of \$80/short ton would be required to induce a switch from coal to combined cycle natural gas.

The level of an emissions cap or the ability to use emissions offsets and corresponding changes to natural gas and coal prices can dramatically impact wholesale and retail prices for electricity. However, as illustrated in the PJM analysis, increasing penetration of energy efficiency and some demand response in the region can greatly mitigate price impacts and foster greater emissions reductions in the initial years of climate change policy implementation.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.

1. Introduction and Purpose¹

Eleven bills were introduced in the 110th Congress addressing climate change through the reduction of greenhouse gas (GHG) emissions.² Of these bills, nine were designed to reduce GHG emissions on an economy-wide basis while two others focused solely on achieving reductions in the electric power industry. The policy of choice appears to be cap-and-trade as nine of the bills propose caps on GHG emissions. A straight carbon dioxide (CO₂) tax is proposed in two of the bills.

Regardless of whether the climate change policy implemented is a cap-and-trade program or a tax program, the cost of CO₂ allowances or a tax on CO₂ will be reflected in the supply offers of PJM Energy Market participants.³ The addition of these costs will in turn affect wholesale clearing prices within the PJM region and could, over time, affect the generation mix being dispatched, as well as the direction of electrical flows on the transmission system.

Changes in wholesale prices will also impact prices for electricity ultimately paid by customers, whether they are residential, commercial, institutional or industrial users of electricity. PJM Interconnection (PJM), as the independent electric grid and market operator serving the Mid-Atlantic and parts of the Southeast and Midwest regions of the country, is uniquely positioned to model the short-term impact of various climate change control policies on both the price and dispatch of electricity in the region we serve.

The purpose of this whitepaper is to examine the short-term impacts of potential climate change policies, as represented by prices on CO₂ emissions, to provide a better understanding of the potential range of effects on PJM Energy markets to market participants, regulators and policymakers. . It is hoped that information gathered by this effort will inform the discussion as the issues associated with climate change policy continue to be deliberated in Washington and elsewhere. In particular, the paper focuses on wholesale prices (represented in the PJM region as locational marginal prices or LMPs), market-wide wholesale power costs,⁴ and bills paid by retail customers⁵ as well as changes in generation dispatch and reductions in CO₂ emissions in the PJM footprint.

¹ The development of the analysis presented in this study was led by Dr. Paul Sotkiewicz, Senior Economist and the Market Simulation Department in the Market Services Division at PJM.

² Resources for the Future (RFF) provides a summary of 11 bills introduced and two draft circulating in the 110th Congress. See <http://www.rff.org/News/Features/Documents/CCBills110thCongress.pdf>. According to the United States Energy Information Administration (EIA) carbon dioxide emissions accounted for 83 percent of GHG emissions in 2007. See <http://www.eia.doe.gov/oiaf/1605/ggrpt/index.html>.

³ According to PJM Manual 15: Cost Development Guidelines, Version 08, 10/16/2007, (<http://www.pjm.com/documents/manuals/-/media/documents/manuals/m15.ashx>) at 11, suppliers may include the costs of sulfur dioxide and nitrogen oxide allowances as part of their fuel related costs. On the consent agenda of the January 22, 2009 Members Committee meeting, a proposal to allow CO₂ allowance costs to be treated in the same way as sulfur dioxide and nitrogen oxide allowances are treated. See <http://www.pjm.com/Calendar%20Events/PJM%20Calendars/Meeting%20Events/2009/January/22/mc.aspx>.

⁴ Wholesale power costs are defined as the load-weighted average LMP multiplied by energy for load (consumption) for the year.

⁵ The analysis here assumes wholesale costs are passed through on a dollar for dollar basis. Ultimately, the cost increase faced by end-use customers will be determined by the relevant retail electric regulatory authority.

This whitepaper will also examine the impact of demand reduction and wind power penetration scenarios on changes in LMP, wholesale power costs, consumer power bills, generation mix, and emissions that result from climate change policy. The whitepaper then ties its results to Energy Information Administration (EIA) and Environmental Protection Agency (EPA) analyses of three specific proposals, namely the Lieberman/McCain Bill (S.280), the Bingaman/Specter Bill (S.1766) and the Lieberman/Warner Bill (S.2191), as these proposals may form the basis for legislation considered in the 111th Congress.

Focus on Short-term Impacts

This analysis examines the impact of climate change legislation on wholesale and retail prices in 2013. There are two main reasons to focus on such short-term impacts of potential climate change legislation. One is the fact that in most cases, if any of the bills in Congress were to become law, the effective date would not be until 2012 or 2013. PJM already forecasts through its planning process peak demand and total consumption in future years and uses that information as a key input to its Regional Transmission Expansion Planning (RTEP) process. Also as part of the planning process, PJM uses fuel price forecasts from sources, such as EIA. To simulate potential short-term impacts of climate change policy on the PJM Energy Markets, PJM added a price on CO₂ emissions as a proxy for different climate change policy outcomes into existing market simulation models already used in the RTEP process.

Moreover, in the short-term, PJM has a good idea about new generation that is likely to come on-line between now and the 2012-2013 and builds that into the planning models. The second reason for this paper's short-term focus is that attempting to forecast demand, fuel prices, penetration of demand response and energy efficiency, and the entry of new generation technologies further out into the future inherently involves making many assumptions, which can be the subject of extensive debate.

PJM's analysis is not intended as a substitute for longer range, macro-level analyses conducted by EIA and EPA; rather it is primarily designed to provide a depiction of near-term impacts on wholesale power prices and possible impact on consumer electric bills during the first years under a climate change policy that is specific to the PJM Energy Market. Nor is this study intended to suggest or propose policy, the clear province of the legislative and regulatory processes.

PJM's Analysis Regarding Proposed Legislation

To perform its analysis, PJM has set up several scenarios using inputs from models used to conduct the market efficiency analyses in the 2007 RTEP Report⁶ based upon the price of natural gas, the price of CO₂ allowances, and different levels of forecast peak demand and load for energy for the year 2013 to better understand the potential effects of as yet to be defined climate change policy. To place the PJM analysis into a policy context, the paper highlights how the scenarios run by PJM correspond to the results of the analyses performed by the EIA and the EPA on specific bills introduced in the 110th Congress and consequently their effects on LMP, wholesale power costs, generation mix, and emissions reductions in the PJM Energy Market.

⁶ A copy of the 2007 RTEP Report can be found at <http://www.pjm.com/documents/reports/rtep-report.aspx>

Summary of Effects on PJM Energy Markets

The design details of climate change policy, such as the level of mandated emissions reductions and the availability of CO₂ offsets, will affect the CO₂ price and in turn will affect the LMP, wholesale power costs, customer bills, generation mix and emissions reductions. Load-weighted average LMP increases, holding all other factors are constant, by approximately 75 percent to 80 percent of the modeled CO₂ price due to coal remaining on the margin for about 70 percent of the time. Widespread switching from coal to combined cycle natural gas is not to be expected until a CO₂ price of around \$40/short ton is reached in the base gas price scenarios.⁷ This threshold increases as natural gas prices increase. At prices below these switching thresholds emissions reductions are limited to displacing only the most inefficient, coal, oil, and gas steam generating units. The increases in LMP, wholesale market costs, and consumer bills can be offset by the penetration of wind resources as well as energy efficiency or demand response actions that reduce the overall consumption of power while also achieving larger emissions reduction than would otherwise occur. In terms of legislation introduced into the 110th Congress analyzed by EIA and EPA, wholesale price impacts are estimated to be \$15/MWh or less.

Organization of the Paper

The remainder of the whitepaper is organized as follows. Section 2 discusses the modeling strategy and key assumptions of the analysis, as well as briefly summarizes the differences between the PJM analysis and the EIA and EPA analyses. Section 3 previews the full analysis by examining the CO₂ price at which it becomes less expensive to dispatch combined cycle natural gas generation over coal generation, which has implications for changes in generation mix and emissions reductions. Section 4 provides the results of the PJM analysis with respect to scenarios reflecting natural gas prices, levels of demand reductions and wind penetration. Section 5 outlines three legislative bills introduced in the 110th Congress, summarizes the results of the associated analyses from EIA and EPA on those bills and links the results of those bills to PJM scenarios used in the PJM analysis. Section 6 describes the estimated effect of the three legislative bills on the PJM Energy Market. Section 7 summarizes the key findings and conclusions.

2. Modeling the Impact of Climate Change Policy on the PJM Energy Market: Placing Scenarios into a Policy Context

PJM Modeling and EIA and EPA Modeling

The analyses of the various climate change bills discussed above employed different modeling strategies. The EIA analyses use the National Energy Modeling System (NEMS) which provides very detailed modeling of each energy sector with different modules for each sector. The sector modeling is done on a national level and does not get into the detail of hourly or daily commitment or dispatch decisions of individual RTOs or systems. There is also a macroeconomic module in NEMS to account for broad impacts on the national economy from various

⁷ The base gas price scenarios assume a gas price of \$6.44/mmBtu as used in the market efficiency analyses in the 2007 RTEP Report. In the high gas price scenarios (\$10/mmBtu), the threshold CO₂ price at which combined cycle natural gas displaces coal on a large scale is about \$80/ton.

policy changes. The base case assumptions used by EIA are the same forecasts and assumptions used in the EIA Annual Energy Outlook to model and forecast what might happen into the future. Consequently, as policy changes are examined in NEMS, input prices like natural gas and coal prices can change in response to the policy changes of interest.

The EPA employs two different models that model the entire U.S. economy by sector in which the energy sector is modeled and analyzed at a very broad, national level, but not down to the detail of various energy sectors seen in the NEMS model used by EIA. It is out of the broad modeling framework used by EPA that the CO₂ allowance prices are derived, as well as changes to various fuel prices. To get at electricity sector details, EPA uses the Integrated Planning Model (IPM) which broadly models the electricity sector, but does not get down into the detail of the daily commitment or dispatch decisions, nor does it model specific transmission assets or generating units. IPM can be used to simulate or estimate broad regional trends, but not down to the detail at the RTO level such as PJM.

The PJM analysis models the daily commitment and dispatch decisions based on specific generating unit costs from publicly available databases while accounting for a detailed modeling of the PJM transmission system. In this way PJM can analyze the effect on load-weighted average LMP, wholesale market costs, changes in generation mix and PJM specific emissions levels based on the allowance price and gas price outputs of the modeling efforts already undertaken by EIA and EPA. PJM's analysis provides greater granular focus and detail on the potential effects of climate change policy that is not possible in the broader modeling efforts for reasons of analytical and computation complexity.

PJM Modeling Paradigm, Assumptions, and Scenarios

The primary analytical tool used in the analysis is the PROMOD model from New Energy Associates (NEA). PROMOD is a market simulation tool which simulates the hourly commitment and dispatch of generation to meet load while recognizing and maintaining transmission system security limits. The underlying source of PROMOD data is contained in Powerbase, which is a separately licensed tool from NEA containing data that includes generating units and generating unit characteristics, fuel costs, emissions costs, load forecasts and a power flow case for modeling the transmission system topology and transmission system limitations. The Powerbase database contains a base fuel cost forecast for each fuel type.

The potential effects of climate change policy on the PJM Energy Market are modeled as year-long dispatch simulations at the following range of CO₂ prices in dollars per short ton⁸: \$0, \$10, \$25, \$40, \$60, and \$100. The range of prices chosen fall within the range of CO₂ prices derived in the analyses conducted by EIA and EPA. The price of \$0/short ton corresponds to there being no climate change policy, while the price of \$100/short ton was chosen as a worst case scenario.

The base forecast for gas and oil prices is based on NYMEX futures prices and long-run forecasts from Platts and EIA and was used in the market efficiency analyses in the 2007 RTEP report. In addition, a high gas price scenario was chosen based on natural gas prices during the first half of 2008,⁹ the potential rise in gas prices

⁸ A short ton is 2000 pounds. A metric ton is 1000 kilograms or 2204 pounds.

⁹ During the first half of 2008 delivered gas prices to electric power generation ranged from approximately \$8.50/mmBtu to over \$12/mmBtu prior to the recent collapse in prices. See <http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm>

due to increased gas demand with switching from coal to natural gas and the historic forecast error of gas prices four to five years out as reported by EIA.¹⁰ The natural gas prices for all of PJM for 2013 are \$6.44mm/Btu in the base gas price case and \$10mm/Btu in the high gas price case.¹¹ The base forecast for coal prices used in the PJM simulation modeling for 2013 in \$/mmBtu were \$2.30 for the Mid-Atlantic region, \$1.54 for ComEd, \$1.97 for the western region and \$2.43 for the southeastern region of PJM.¹²

Four demand forecast scenarios examine the effects of changing consumption on market outcomes under climate change policy scenarios. These include the actual demand forecast for 2013 by PJM and used in the 2007 RTEP Report, and three others representing reductions of 2 percent, 5 percent, and 10 percent in both peak demand and total MWh consumption from the 2013 forecast.¹³ Table 1 provides the load for energy in each demand forecast scenario.

Table 1: Demand (Load for Energy) Scenarios in GWh for 2013

Forecast Demand	Forecast minus 2%	Forecast minus 5%	Forecast minus 10%
788,922	773,144	749,476	710,030

In addition to the demand scenarios, PJM has also run a wind power penetration scenario where 15,000 MW (nameplate capacity) is in service by 2013. The amount of wind generation for this scenario is based on the approximately 43,000 MW of wind capacity in the interconnection queue, and PJM's experience and expectation that approximately one-third of the wind capacity in the queue will eventually go into commercial operation.¹⁴ The wind in operation in the model is assumed to operate at a 33 percent capacity factor.¹⁵ Moreover, most of this

¹⁰ See United States Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of Projections in Past Editions (1982-2006)*, Report DOE/EIA-0640(2006), March 2007, Table 8 at <http://www.eia.doe.gov/oiaf/archive/analysispaper06/index.html>. For gas price forecasts made four to five years out from 1996 to 2001, the range of forecast deviations was -17.1 percent to -64.4 percent or an average of -45.5 percent.

¹¹ These are commodity prices. The delivered gas prices will depend on the basis differential for that location.

¹² These coal prices are averages for the region. Each coal unit faces its own delivered price.

¹³ The most recent forecast accounting for the recent economic downturn shows about a 1.5 percent decrease in load for energy from the forecast used in the 2007 RTEP. See <http://www.pjm.com/committees-and-groups/committees/pc/20090121/20090121-item-06-load-report-draft.pdf>.

¹⁴ Wind in the queue as of January 21, 2009 counting only projects that are active. See <http://pjm.com/planning/generation-interconnection/generation-queue-active.aspx>.

¹⁵ The capacity factor is equal to the actual output of the unit divided by the output of unit if it ran at its maximum capacity in every hour of the year. This modeled number is different than the capacity value assigned to wind for reliability purposes which is based on wind's capacity factor during summer peak hours. See PJM Manual 21: Rules and Procedures for Determination of Generating Capability, Revision 07, June 1, 2008, (<http://www.pjm.com/documents/manuals/-/media/documents/manuals/m21.ashx>) at 17.

wind for modeling purposes is in the western part of PJM with the heaviest concentration of wind generation in the queue.¹⁶

Finally, it is also assumed that two of the three 500 kV (kilovolt) transmission upgrades found in the 2007 RTEP and all upgrades in the 2006 RTEP will be in service by 2013 for all scenarios.¹⁷

In total PJM ran 55 scenarios, 48 of which examine the interaction of six CO₂ prices, two natural gas prices and four demand scenarios. Six other scenarios examine the penetration of 15,000 MW of wind at the six CO₂ prices, base gas price, and forecast 2013 demand. One last scenario models a CO₂ price of \$20/ton at the base gas price and 2013 forecast demand.¹⁸

3. Cost of CO₂ Reductions from Coal to Gas Re-dispatch: Preview of Potential Impacts

Prior to running any simulation scenarios, it is possible to get a general notion for the potential effects of climate change policies on LMP, generation mix and potential CO₂ emissions reductions in the short-term at different allowance prices or tax levels. This can be achieved by calculating the CO₂ price at which it becomes less expensive to dispatch a natural gas combined cycle facility in place of a coal unit resulting in CO₂ emissions reductions. To dispatch a combined cycle natural gas unit before a coal unit, the fuel cost plus the CO₂ cost of the combined cycle natural gas unit must be less than the fuel cost plus the CO₂ cost of the coal unit. This CO₂ price is also known as the marginal cost of CO₂ abatement, or the cost of reducing CO₂ emissions by one ton by dispatching lower emitting generators in place of higher emitting generators. Table 2 below shows the characteristics of the representative combined cycle gas and coal units used to estimate this "breakeven" CO₂ price.

Table 2: Characteristics of Representative Generating Units

	Combined Cycle Gas	Pulverized Coal
Heat Rate (mmBtu/MWh)	7.000	10.000
Emissions Rate (tons CO ₂ /mmBtu)	0.059	0.103
Emissions Rate (tons CO ₂ /MWh)	0.413	1.030

¹⁶ However, for the 15,000 MW wind scenario, it is assumed that much of the wind capacity planned offshore of New Jersey and Delaware is in place.

¹⁷ Those upgrades include the 502 Junction-Mt. Storm-Meadowbrook-Loudon 500 kV circuit also known as TrAIL, Amos-Bedington-Kempton 765kv and 500 kV circuit, and the Susquehanna-Lackawanna-Jefferson-Roseland 500 kV circuit. See 2007 RTEP Report at 54-55.

¹⁸ This scenario matches up well with some of the results of the EIA and EPA modeling.

Employing the natural gas and coal fuel prices mentioned previously and using the characteristics from Table 2, the CO₂ prices at which the cost to dispatch the representative natural gas combined cycle unit is equal to the costs to dispatch the representative coal unit are presented in Table 3 by PJM region.

Table 3: Marginal Cost of Abatement (\$/short ton)

Re-dispatch from 10 mmBtu/MWh Coal to 7 mmBtu/MWh Gas Combined Cycle			
		Gas price (\$/mmBtu)	
Region	Coal Price (\$/mmBtu)	\$6.44	\$10.00
Mid-Atlantic	\$2.30	\$35.80	\$76.21
ComEd	\$1.54	\$48.13	\$88.53
West	\$1.97	\$41.15	\$81.56
South	\$2.43	\$33.69	\$74.10

Table 3 shows a general trend that the higher the natural gas price, all else equal, the greater is the marginal cost of abatement. Stated another way, as the price of natural gas price rises, a higher CO₂ price is required to equate the dispatch costs of a combined cycle natural gas unit to a coal unit. For example, at a delivered price of coal of \$2.30/mmBtu in the Mid-Atlantic and a delivered price of gas of \$6.44/mmBtu under the base gas price scenario, the marginal cost of abatement is \$35.80/short ton of CO₂, but at the \$10/mmBtu gas price, with the same coal price, the marginal cost of abatement rises to \$76.21/short ton of CO₂.

Moreover, Table 3 also shows that the lower the coal price, all else equal, the greater is the marginal cost of abatement. That is as coal prices decrease a higher CO₂ price is required to equate the dispatch costs of a combined cycle natural gas unit to a coal unit. For example, at a delivered price of gas of \$6.44/mmBtu and a delivered price of coal in the Mid-Atlantic of \$2.30/mmBtu the marginal cost of abatement is \$35.80/short ton of CO₂. However, at a lower coal price of \$1.54/mmBtu in ComEd, and the same gas price, the marginal cost of abatement rises to \$48.13/short ton of CO₂.

Table 3 indicates at CO₂ prices below approximately \$35-40/ton, the only changes in generation mix (and associated emissions reductions) will come from displacing coal units that are less efficient than the representative coal unit from the dispatch when the gas price is at \$6.44/mmBtu. As a result, the level of expected emissions reductions is relatively low at the lower CO₂ prices. However, in the transition of CO₂ prices from \$40-\$50/ton, more widespread displacement of coal by combined cycle natural gas will be observed along with associated emissions reductions.

However, as natural gas prices rise to \$10/mmBtu in Table 5, the threshold CO₂ price at which it is less expensive to dispatch the representative combined cycle natural gas than the representative coal unit increases substantially to over \$80/ton in all but the Mid-Atlantic region of PJM. And consequently emissions reductions at lower CO₂ prices will be limited to the displacement of coal, oil, and gas steam that is less efficient than the

representative coal unit. At the \$10/mmBtu gas price, the transition of CO₂ prices from \$80-\$90/ton will result in greater displacement of coal units more efficient than the representative coal unit and greater associated emissions reductions than would be observed at lower prices.

It is also possible to gauge the approximate effect of CO₂ prices on the wholesale power price or LMP. Currently, coal generation is on the margin 70 percent of the time¹⁹ and emits just over one ton of CO₂ per MWh as shown in Table 2. If coal remains on the margin 70 percent of the time, in 70 percent of the hours the LMP will increase by about the same value as the price of a CO₂ allowance. In hours where gas (24 percent of hours in 2007) oil (5 percent of hours in 2007) is on the margin, the increase in LMP due to CO₂ prices will be lower.²⁰ Overall, it is not surprising to see the load-weighted average LMP over the course of a year to increase by an amount almost as great as price of CO₂ emissions.

The degree to which re-dispatch of combined cycle gas in place of coal can take place, and consequently emissions reductions from re-dispatch, is limited by the relative capacity levels of coal and combined cycle natural gas. At the end of 2007, there was just over 66,000 MW of coal-fired capacity and 23,000 MW of natural gas combined cycle capacity.²¹ Consequently, even at CO₂ prices high enough for natural gas combined cycle to displace coal regardless of efficiency, coal-fired generation would still be required to meet demand, and emissions reductions from running combined cycle gas in place of coal would reach its maximum. The only remaining emissions reductions available in the short-term would be to displace coal with natural gas combustion turbines, which would require CO₂ prices close to or in excess of \$100/ton.²²

In summary, the greater the relative cost of natural gas to coal, the higher is the CO₂ price required to make the natural gas combined cycle units less expensive to dispatch than the representative coal unit, and to achieve emissions reductions from re-dispatch. Moreover, it is likely that the increase in LMP on average will be close to the price attached to CO₂ emissions. Finally, the magnitude of emissions reductions obtainable from re-dispatching of combined cycle gas in place of coal is limited due to the fact that combined cycle capacity is only one-third of coal-fired capacity.

4. Results of the PJM Analysis

The results of the PJM analysis show market-wide trends and averages under various CO₂ prices for gas price, demand level and wind scenarios. This section will first address the base gas and high gas price scenarios without regard to demand reductions or wind power penetration, which will follow in a subsequent examination. For each scenario, the PJM analysis focuses on changes in load-weighted average LMP, wholesale power costs, the bills paid by a representative consumer, emissions within the PJM footprint, and changes in generation mix by fuel type.

¹⁹ See the PJM Market Monitoring Unit (MMU) *2007 State of the Market Report: Volume 2 Detailed Analysis*, March 11, 2008, Table 2-32 at 33.

²⁰ *Id.* at 33.

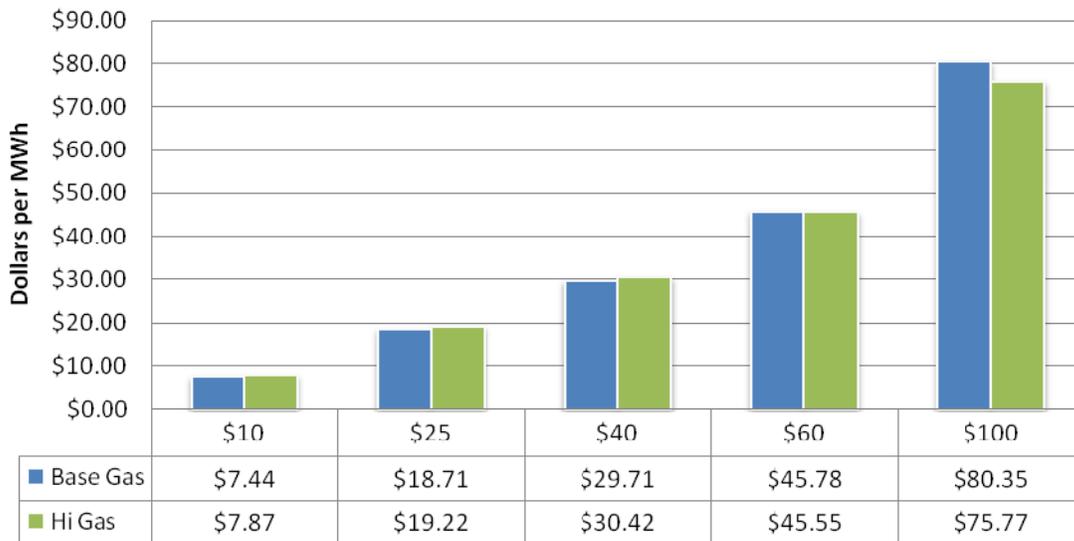
²¹ *Id.* at 145, Table 3-30 and at 151, Table 3-37.

²² At the base gas price of \$6.44/mmBtu, the cut-off would be around \$100/ton. At gas prices of \$10/mmBtu, a CO₂ price in excess of \$150/ton is required to make it economic to dispatch combustion turbines before coal.

Base Gas and High Gas Price Results

The base gas and high gas scenarios take as given the forecast demand for 2013 with no additional wind penetration. Regardless of the price of natural gas, the load-weighted average LMP increases by approximately 75 to 80 percent of the CO₂ price in both the base gas and high gas cases. The increase in LMP in dollars per MWh at each CO₂ price can be viewed in Figure 1.

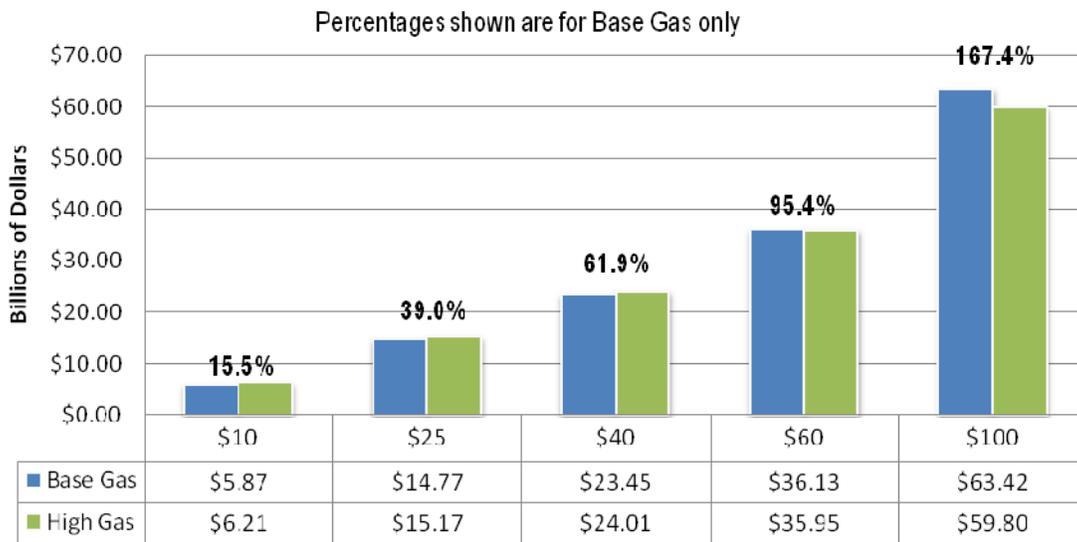
Figure 1: LMP Increase by CO₂ Price and Gas Price



Translating the increases in load-weighted average LMP into market-wide wholesale power costs results in an increase of \$5.87 billion (approximately 15.5 percent) at a CO₂ price of \$10/ton to an increase of approximately \$36 billion or 95.4 percent in the base gas case.²³ The increases in wholesale power costs in dollar and percentage terms can be seen in Figure 2. Just as was the case with LMP increases, the gas price has little effect on the change in wholesale power costs.

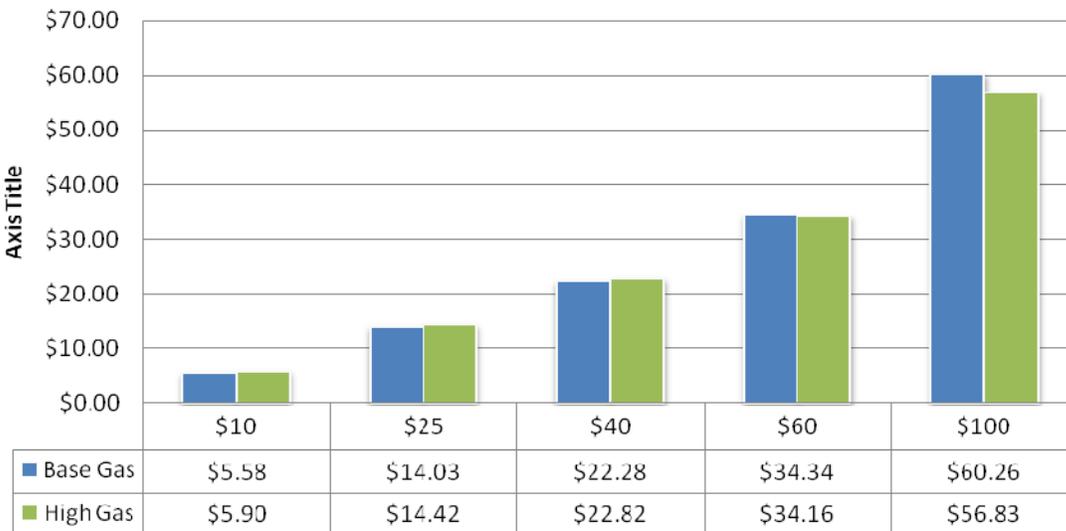
²³ Wholesale power costs in the base gas case without any CO₂ price is \$37.88 billion, and in the high gas case it is \$47.36 billion.

Figure 2: Increase in wholesale Power Costs by Gas Price and CO₂ Price



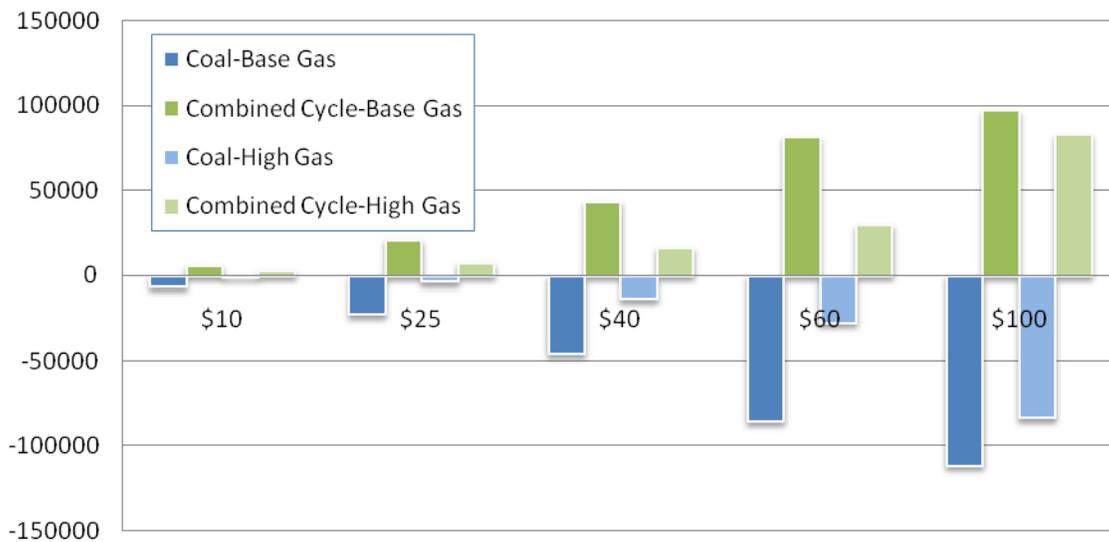
From the perspective of representative residential consumers using 750 kWh, the load-weighted average LMP increase translates to an increase on their electricity bill, assuming a dollar for dollar pass-through of wholesale cost increases, of up to \$5.58/month (\$66.96 annually) at a CO₂ price of \$10/ton to \$22.28/month (\$267.39 annually) at a CO₂ price of \$40/ton up to \$34/month (\$412.02 annually) at a CO₂ price of \$60/ton. The results for monthly bill increases can be seen in Figure 3.

Figure 3: Increase in Monthly Bill of a residential Customer using 750 kWh



As noted above, the changes to the generation mix, re-dispatching combined cycle gas generation in place of coal will depend upon the natural gas price. At lower CO₂ prices, \$10/ton and \$25/ton in the base gas case and up through \$60/ton in the high gas case, there is relatively little change in coal and combined cycle generation as seen in Figure 4. Displacement of coal by combined cycle gas starts picking up at a CO₂ price of \$40/ton as expected in the base gas case. However in the high gas case, it is only between CO₂ prices of \$60/ton and \$100/ton that switching from coal to combined cycle starts to occur.

Figure 4: Change in Coal and Combined Cycle Generation by Price



Emissions reductions follow a pattern similar to that of the change in generation mix in that as there is increasing switching to combined cycle gas from coal, emissions reductions become more pronounced. Under base gas costs emissions reductions from the 2013 baseline emissions²⁴ range from about 5.59 million tons (1.1 percent reduction) at a CO₂ price of \$10 to reductions of almost 58 million tons (11.3 percent reduction) at a CO₂ price of \$60/ton. In the high gas cost scenarios, emissions reductions from the 2013 baseline emissions range from just over 2 million tons (0.5 percent reduction) at a CO₂ price of \$10 to reductions of just over 25 million tons (4.9 percent reduction) at a CO₂ price of \$60/ton. Clearly, the price of natural gas matters in terms of emissions reductions. Emissions reduction tonnage and percentage comparisons can be seen in Figure 5.

²⁴ 2013 baseline emissions were simulated to be 510.9 million tons in the base gas case and 516.3 million tons in the high gas case.

Figure 5: Emissions Reductions by Gas and CO₂ Price



Demand Reduction Scenario Results

One possible way to mitigate the increase in load-weighted average LMP, related wholesale market costs, and consumer power bills is through reducing the consumption of power through energy efficiency or some demand response actions. Table 4 shows the potential magnitude of the mitigation.

Table 4: Amounts by Which Price and Cost Increases are Mitigated²⁵

	Load Reduction Percentage		
	2%	5%	10%
LMP (\$/MWh)	\$2-\$4 per MWh	\$5-\$9 per MWh	\$11-\$17 per MWh
Wholesale Power Cost	\$3-\$4 billion	\$6-\$11 billion	\$10-\$18 billion
Consumer Bill	\$1-\$3 monthly	\$4-\$6.50 monthly	\$7-\$12.50 monthly

With respect to reducing wholesale power costs the reduced LMP is accompanied by the assumed decrease in consumption providing greater force to reducing costs.

²⁵ Amounts depend upon the CO₂ and natural gas price. Savings are generally greater in the high gas case. Consumer bill savings only reflect the reduced LMP since the measured consumption for the consumer remains 750 kWh.

In addition to the mitigating effects on LMP, wholesale power cost, and customer power bills, demand reductions also have the effect of further enhancing emissions reductions through the displacement of fossil generation. The results of this can be seen in Table 5.

Table 5: Amounts by Which Generation is Displaced and Additional Emissions Reductions Achieved²⁶

	Load Reduction Percentage		
	2%	5%	10%
Coal	6,741 GWh	18,376 GWh	41,972 GWh
Combined Cycle Gas	6,555 GWh	15,685 GWh	28,587 GWh
Additional CO ₂ Reductions (tons)	10-14 million	29-34 million	58-64 million

Wind Penetration Results

With the addition of 15,000 MW of nameplate wind capacity to the system can have mitigating effects on increases in LMP, wholesale power costs, and consumer power bills, while enhancing emissions reductions. The effect on LMP, wholesale power costs and customer bills can be seen in Table 6, while the impact on generation and emissions can be seen in Table 7.

Table 6: Amounts by Which 15,000 MW of Wind Mitigates Price and Cost Increases

	15,000 MW Wind
LMP (\$/MWh)	\$5-\$5.50 per MWh
Wholesale Power Cost	\$4-\$4.5 billion
Customer Bill	\$3.50-\$4 monthly (\$42-\$48 annually)

With respect to emissions levels, the introduction of 15,000 MW of wind capacity provides an additional 34 million to 37 million tons of CO₂ reductions. The mechanism by which wind achieves additional emissions reductions is identical to demand reductions in that wind displaces fossil fuel generation resources. However, unlike demand

²⁶ Displaced generation is at a CO₂ price of \$0/ton in the base gas case. Additional CO₂ reductions depend upon gas price and CO₂ price.

reductions which resulted in displacing almost equal amounts of coal and combined cycle gas generation, wind displaces predominantly coal.²⁷

Table 7: Generation Displaced and Additional Emissions Reductions Achieved by 15,000 MW of Wind

	15,000 MW Wind
Coal	26,303 GWh
Combined Cycle Gas	13,009 GWh
Additional CO ₂ Reductions (tons)	34-37 million

5. Overview of Proposed Legislative Analyses and Impacts in PJM Markets

Of the eleven bills related to climate change introduced into the 110th Congress, three have garnered the greatest attention based upon the analyses that have been requested by Congress, and conducted by the Energy Information Administration (EIA) and the Environmental Protection Agency (EPA).

S.280 introduced by Senators Joseph Lieberman (I-CT) and John McCain (R-AZ) covers approximately 78 percent of total GHG emissions in 2005, targeting sources with greater than 10,000 metric tons of CO₂ equivalent per year. S.280 targets emissions to be stabilized at 2004 levels from 2012-2019, with step change decreases occurring about every decade. Allowance prices are allowed to move freely based on allowance market conditions.

An EIA analysis of S.280²⁸ indicates that in 2013 (second year of compliance) CO₂ allowances prices would be close to \$14/metric ton (\$12.70/short ton)²⁹ with a natural gas price of \$6.10/mmBtu. Sensitivities around the availability of CO₂ offsets might drive CO₂ allowance prices as high as \$18/metric ton (\$16.33/short ton) and gas as high as \$6.34/mmBtu if offsets are limited. CO₂ allowance prices could be as low as \$8.50/metric ton (\$7.71/short ton) and gas down to \$5.78/mmBtu if offsets are unlimited. EPA analyses reveal similar numbers for allowance prices, although in one case (with no offsets allowed), the CO₂ allowance price could be as high as \$40 in 2015.³⁰

²⁷ This occurs because wind runs mostly in off-peak hours when coal is more likely to run than combined cycle gas.

²⁸ See United States Energy Information Administration, *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, January 2008 [http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf\(2007\)04.pdf](http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf) and associated output files at <http://www.eia.doe.gov/oiaf/servicerpt/csia/index.html>.

²⁹ A short ton is equivalent to 2000 pounds while a metric ton is 1000 kilograms or 2204.6 pounds.

³⁰ See United States Environmental Protection Agency, *EPA Analysis of the Climate Stewardship and Innovation Act of 2007*, July 16, 2007 <http://www.epa.gov/climatechange/downloads/s280fullbrief.pdf> and associated spreadsheets with outputs at <http://www.epa.gov/climatechange/downloads/dataannex.zip>. EPA's analyses of the various bills do not uniformly report CO₂ prices for each year as EIA does. The closest year to 2013 reported for all runs is 2015.

S.1766 introduced by Senators Jeff Bingaman (D-NM) and Arlen Specter (R-PA) covers approximately 86 percent of 2006 GHG emissions. S.1766 allowed emissions will be approximately 8 percent above 2006 emission levels beginning in 2012, at 2006 levels by 2020, 1990 levels by 2030, and 60 percent below 1990 levels by 2050. The allowed level of emissions is reduced in each year in contrast to S.280 in which allowed emissions remain the same over a specified period and are reduced in a step-wise manner. Allowance prices are effectively capped at \$12/metric ton (\$10.89/short ton) Technology Accelerator Payment (TAP) in 2012 and the cap increases at 5 percent per year after inflation in each year thereafter. Emissions in excess of the cap must pay the TAP charge for that year for each ton of CO₂ emitted in excess of allowed emissions.

EIA analysis indicates in the early years the implicit allowance price cap is not binding with an allowance price of about \$11/metric ton (\$10/short ton) and with gas prices close to \$6/mmBtu in 2013. The cap will be binding in subsequent years with emissions exceeding the targets set out in S.1766.³¹ EPA analysis shows similar results to the EIA analysis in terms of allowance price in 2015. However, an EPA sensitivity analysis of S.1766 without the allowance price cap indicates allowance prices would be \$27-29/metric ton (\$24.50-\$26.31/short ton).³²

S.2191 introduced by Senators Lieberman (I-CT) and Warner (R-VA) covers approximately 87 percent of 2006 GHG emissions. The reduction targets set by S.2191 are by far the most stringent of the three bills analyzed by EIA and EPA with 2012 allowed emissions at 7 percent below 2006 emissions levels and declining by 1 to 1.5 percent per year. The result is that in 2030 emissions will be 39 percent below 2006 levels and 72 percent below 2006 emissions levels in 2050. Unlike S.1766 CO₂ allowance prices are allowed to move freely, and are highly dependent upon the availability, commercialization, and deployment of renewable energy resources, carbon capture and sequestration (CCS), and new nuclear units, as well as the availability of CO₂ offsets.

According to the extensive analysis performed by EIA³³ the CO₂ allowance price is at \$18/metric ton (\$16.33/short ton) and the gas price is \$7.16/mmBTU under the assumption CO₂ offsets and new nuclear, renewable, and CCS technologies are available at a reasonable cost. However, if new nuclear and renewable units, and CCS are not available or at a high cost, then the allowance price rises to \$23-\$27/metric ton (\$20.86-\$24.50/short ton) and gas prices increase slightly to about \$7.50/mmBtu. If offsets are limited, regardless of the availability of technologies, allowance prices increase to about \$47/metric ton (\$42.63/short ton) and gas prices rise about \$9/mmBtu.

³¹ See United States Energy Information Administration, *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007*, January 2008 at [http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf\(2007\)06.pdf](http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf) and associated output files at <http://www.eia.doe.gov/oiaf/servicerpt/lcea/index.html>.

³² See United States Environmental Protection Agency, *EPA Analysis of the Low Carbon Economy Act of 2007*, January 15, 2008 http://www.epa.gov/climatechange/economics/pdfs/s1766_EPA_Analysis.pdf

Spreadsheets with Output <http://www.epa.gov/climatechange/economics/pdfs/DataAnnex.zip>

³³ See United States Energy Information Administration, *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007*, April 2008 at [http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf\(2008\)01.pdf](http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf) and the associated output files at <http://www.eia.doe.gov/oiaf/servicerpt/s2191/index.html>

EPA analysis of S.2191 showed a much wider variation of CO₂ allowance prices and very little change in gas prices are shown in the EPA analysis.³⁴ Much like the EIA analysis, the ability to use CO₂ offsets drives much of the variation. Base case prices for allowances in 2015 range from \$22-\$40/metric ton (\$20-\$36.29/short ton) depending on the model. If unlimited offsets can be used, then the allowance price falls to \$11/metric ton (\$10/short ton) in 2015. If no offsets at all can be used, then the allowance price rises to \$77/metric ton (\$70/short ton) in 2015. This rise is much greater than the \$55/metric ton (\$50/short ton) modeled by EPA if new nuclear, renewable, and CCS are not available.

Overall, the details of climate change policy will help determine the price of CO₂ allowances. The EIA and EPA analyses show the drivers of CO₂ prices and natural gas prices that will affect wholesale prices as reflected in PJM's Energy Markets:

- The more stringent the mandate for emissions reductions contemplated by the legislation, the higher is the CO₂ price. Reductions under the Lieberman-McCain bill (S.280) are less stringent than those contemplated under the Lieberman-Warner bill (S.2191). This results in CO₂ prices of approximately \$10/ton under the Lieberman-McCain bill, and \$20/ton under the Lieberman-Warner under similar assumptions.
- The presence of a safety valve price such as that contemplated by the Bingaman-Specter bill (S.1766) can help keep CO₂ prices down, but also implies emissions reduction targets will not be met.
- Assumptions about the availability or costs of technologies such as CCS, nuclear, or renewables are not as big a driver for CO₂ or gas prices in the short-term as in the long-term.
- The availability of the use of CO₂ offsets for compliance is a large driver of CO₂ prices in the short-term. Eliminating the use of offsets entirely could lead to CO₂ prices as much as three to four times higher, and natural gas prices that are up to 50 percent higher than if offsets were allowed as originally contemplated in legislation.

Linking Analysis Scenarios to Pending Legislation

The goal of the PJM analysis is to analyze the wholesale energy market effects of various climate change policies, as proxied by a price on CO₂ emissions, holding all other factors constant. The choice of round numbers for CO₂ prices and the intervals chosen was for the ease of exposition and analysis. Subsequently, sensitivity analysis were done by examining the effect of different gas prices, different levels of power consumption, or different levels of wind penetration to see how these would affect the outcomes in the wholesale power market under various CO₂ prices.

Moreover, to provide consistency with the 2007 RTEP, the base cases assumed the same natural gas and coal prices. In contrast, in the EIA and EPA analyses of S.280, S.1766, and S.2191, it is important to understand that the CO₂ allowance prices and natural gas prices that result from those analyses are endogenously determined

³⁴ See United States Environmental Protection Agency, *EPA Analysis of the Lieberman-Warner Climate Security Act of 2008*, March 14, 2008 http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf

Spreadsheets with Output <http://www.epa.gov/climatechange/downloads/DataAnnex-s2191.zip>

and will have different combinations of CO₂ and gas price for each scenario run. This will make it difficult to isolate the effects of CO₂ prices alone, holding all else equal, on the PJM markets and systematically to run sensitivity analyses on reductions in energy consumption and wind penetration. Consequently, some scenarios run in the PJM analysis, while close in many cases to the results of EIA and EPA analyses, do not match up exactly.

Results of EIA and EPA analyses of the S.280 and S.1766 centered around natural gas prices near \$6/mmBtu³⁵ and CO₂ allowance price at or slightly above \$10/short ton. The PJM 2013 scenario that best corresponds to the study results of S.280 and S.1766 is the base gas price of \$6.44/mmBtu combined a CO₂ price of \$10/short ton at the 2013 forecast demand and load for energy.

Given the implicit CO₂ allowance price cap under S.1766, a PJM 2013 scenario of \$10/mmBtu gas with a \$10/short ton CO₂ allowance price at various levels of demand provides some alternative outcomes under S.1766.

In its analysis of S.280, EPA ran one scenario in which offsets were not available resulting in a CO₂ allowance price of \$40/metric ton. The PJM 2013 scenario that best corresponds to this outcome is the base gas price of \$6.44/mmBtu at a CO₂ allowance price of \$40/short ton.

With respect to S.2191, EIA analysis of the bill under base case costs for new nuclear, renewable resources, as well limited availability or high costs for these technologies resulted in a range of gas prices between \$7.16/mmBtu and \$7.60/mmBtu and an allowance price range of \$18-\$27/metric ton. This would correspond most closely to the PJM 2013 scenario of base gas with a \$20/short ton allowance price at the PJM forecast demand.

Under S.2191, scenarios under which offsets were limited, the allowances price rose to around \$47/metric ton with gas prices around \$9/mmBtu. The PJM 2013 scenario that corresponds most closely to this outcome is the \$10/mmBtu gas with a \$40/short ton allowance price. The EPA analysis of S.2191 without any offsets at all resulted in an allowance price of \$77/metric ton which corresponds most closely to PJM 2013 scenarios with CO₂ allowance price at \$60/short ton.

³⁵ EIA in its analyses reports delivered gas prices to electric generators separate from wellhead gas prices. In contrast, EPA only reports wellhead prices as an index to 2005 wellhead prices. Those prices would be closer to \$5/mmBtu, but if transportation is accounted for, the delivered cost is around \$6/mmBtu.

Table 8: Legislative Analyses and Corresponding PJM 2013 Scenarios

Legislation and Analysis Assumptions	Closest Corresponding PJM 2013 Scenario
Lieberman/McCain, core assumptions	\$10/short ton CO ₂ , Base gas
Lieberman/McCain, no offsets available	\$40/short ton CO ₂ , Base gas
Bingaman/Specter core assumptions	\$10/short ton CO ₂ , Base gas
Bingaman/Specter, no Technology Accelerator Payment (safety valve price)	\$25/short ton CO ₂ , Base gas
Lieberman/Warner, core assumptions	\$20/short ton CO ₂ , Base gas
Lieberman/Warner, limited availability or high cost new nuclear, renewable and CCS	\$25/short ton CO ₂ , Base gas
Lieberman/Warner, no international offsets, domestic offset allowed	\$40/short ton CO ₂ , High gas
Lieberman/Warner, no offsets of any type	\$60/short ton CO ₂ , High gas

6. Results for Legislative Scenarios

Lieberman/McCain (S.280) Results

The results under the core assumptions for Lieberman/McCain correspond to the \$10/ton CO₂ price and base gas scenario. The consequent impacts on the PJM Energy Market are to see LMP rise close to \$7.50/MWh and see wholesale power costs increase 15.5 percent with resulting emissions reductions of 1.1 percent as seen in Table 9. As has been discussed above, a \$10/ton price is not enough to induce re-dispatch from coal to combined cycle gas to achieve emissions reductions.

In one analysis run by EPA under the scenario of no offsets being permitted, the CO₂ price could get close to \$40/ton under Lieberman/McCain. In this scenario, this would be enough to induce more re-dispatch from coal to combined cycle gas, resulting in greater emissions reductions as seen in Table 9. However, the LMP impact is close to \$30/MWh and wholesale power cost impact is an almost 62 percent increase.

Table 9: Estimated Effects of Lieberman/McCain (S.280) on the PJM Market

	LMP (\$/MWh)	Wholesale Costs (\$billion)	Coal Generation (GWh)	Combined Cycle Gas (GWh)	CO ₂ Emissions (millions tons)
Core	7.44	5.87 (15.5%)	-6,198 (-1.3%)	5,808 (9.4%)	-5.59 (-1.1%)
No offsets	29.71	23.45 (61.9%)	-45,290 (-9.7%)	43,486 (70.4%)	-33.65 (6.6%)

Bingaman/Speter (S.1766) Results

The results derived under the core assumptions of Bingaman/Speter correspond to the PJM scenario of \$10/ton CO₂ and base gas prices in the same way seen with the Lieberman/McCain proposal. This result is due to the Technology Accelerator Payment (TAP) which acts as a safety valve price near \$10/ton. However, if that safety valve cap were to be relaxed, EPA derived a CO₂ price of close to \$25/ton. In this case PJM LMP would increase almost \$19/MWh, with wholesale market costs increasing 39 percent as shown in Table 10. And while the higher CO₂ price induces greater switching from coal to combined cycle gas, only the most inefficient coal units are being displaced and large scale displacement does not take place.

Table 10: Estimated Effects of Bingaman/Speter (S.1766) on the PJM Market

	LMP (\$/MWh)	Wholesale Costs (\$ billion)	Coal Generation (GWh)	Combined Cycle Gas (GWh)	CO ₂ Emissions (millions tons)
Core	7.44	5.87 (15.5%)	-6,198 (-1.3%)	5,808 (9.4%)	-5.59 (-1.1%)
No TAP	18.71	14.77 (39.0%)	-22,176 (-4.8%)	20,967 (34.0%)	-18.18 (3.6%)

Lieberman/Warner (S.2191) Results

Unlike the other two bills examined by EIA and EPA, the Lieberman/Warner proposal under core assumptions results in a higher CO₂ price of close to \$20/ton. The effects on PJM are shown in Table 11 are in between the results for shown in Table 10. Under a scenario in which technology alternatives such as carbon capture and sequestration (CCS) and nuclear and biomass energy are limited, the CO₂ price increases to approximately \$25/ton with similar results discussed for the Bingaman/Speter bill without the safety valve.

However, there are two scenarios modeled that limit offsets. In the scenario limiting international offsets, the corresponding PJM scenario is \$40/ton CO₂ and the high gas price case. LMP increases by about \$30/MWh with a 62 percent increase in costs, much like Lieberman/McCain without offsets, but the gas price is now higher

resulting in less re-dispatch from coal to combined cycle gas and lower emissions. The reason gas prices might rise in this situation where offsets are limited is that switching to gas is the next best option for meeting emissions target thereby putting price pressure on gas.

Finally, another scenario where offsets are eliminated completely leads to a CO₂ price in excess of \$60/ton with the high gas price.³⁶ Even at this higher CO₂ price, the high gas price does not result in the kind of fuel switching and emissions reductions that were observed under Lieberman/McCain with a lower CO₂ price, but also a lower gas price as seen in Table 9. LMP increases about \$45/MWh and wholesale power costs increase by 76 percent.

Table 11: Estimated Effects of Lieberman/Warner (S.2191) on the PJM Market

	LMP (\$/MWh)	Wholesale Costs (\$billion)	Coal Generation (GWh)	Combined Cycle Gas (GWh)	CO ₂ Emissions (millions tons)
Core	14.92	11.78 (31.1%)	-16,817 (-3.6%)	15,781 (25.6%)	-14.18 (-2.8%)
Limited Alternatives	18.71	23.45 (61.9%)	-22,176 (-4.8%)	20,967 (34.0%)	-18.18 (3.6%)
No int'l offsets	30.42	24.01 (50.7%)	-13,183 (-2.8%)	16,487 (31.2%)	-14.40 (-2.8%)
No offsets	45.55	35.95 (75.9%)	-27,207 (-5.8%)	29,796 (56.4%)	-25.26 (-4.9%)

7. Summary and Conclusions

The short-term effect of the proposed climate change policies on the PJM Energy Markets examined in this white paper are dependent upon the outcomes of those policies in terms of the price of CO₂ allowances. Additionally, the price of natural gas, the prospects for reductions in power consumption, and penetration of new wind resources in the presence of a climate change policy will also influence the effects on the PJM Energy Markets.

Given the CO₂ prices and natural gas prices that can result from the implementation of a climate change policy the general effects on PJM's Energy Markets that could be expected are the following:

- Regardless of the gas price, and holding all else equal, the increase in load weighted average LMP is about 75 percent of the CO₂ price in \$/short ton. The reason for this is that coal remains the marginal generating resource for close to 70 percent of the hours and coal has an approximate emissions rate of one ton per MWh.

³⁶ EPA does not report gas prices yearly or in 2015 for some of their models. Given the lack of offsets, a high gas price was assumed given that gas demand would likely increase as other avenues for emissions reductions were closed.

- At CO₂ prices of \$10, \$40, or \$60 per short ton, typical residential customers using 750kWh (kilowatt-hour)/month could see increases in their monthly bills up to \$5.58 (\$66.96 annually), \$22.28 (\$267.39 annually), or \$34.34 (\$412.02 annually) respectively in the base gas price scenario assuming a dollar for dollar pass through of wholesale cost increases to retail customers.
- Under the base gas price (\$6.44/mmBtu), widespread switching from coal to combined cycle natural gas, and large changes in generation mix, will not begin until CO₂ prices reach the level of \$35-\$40/ton. At that point, the first coal units to be displaced would be in the Mid-Atlantic and the Southern part of the PJM footprint.
- As gas prices increase, all else equal, the CO₂ at which widespread switching from coal to combined cycle gas begins to take place increases. At the high gas price run in the analysis (\$10/mmBtu), widespread switching would occur at approximately \$75-\$80/ton.

Under many of the legislative scenarios examined, LMP could increase by as much as \$45/MWh and wholesale power costs (market-wide) increase by as much as \$36 billion at a CO₂ price of \$60/ton and a gas price of \$10/mmBtu. However, under base case assumptions, the price and cost impacts of the three legislative proposals examined here would lead to at most a \$15/MWh increase in LMP.

- EIA and EPA analyses of the Lieberman-McCain (S.280) and Bingaman-Specter (S.1766) bills under base assumptions indicate a CO₂ price close to \$10/short ton in 2013. The impact on the PJM Energy Market would be to see power price increases of approximately \$7.50/MWh, with market-wide expenditures to increase approximately \$5.9 billion, and emissions reductions from PJM sources of almost 6 million tons. The increase the bill of a typical electricity customer could be up to \$5.58 monthly or \$66.96 annually.
- EIA and EPA analyses of the Lieberman-Warner (S.2191) bill under base assumptions, or assumptions indicating that the availability of lower carbon generation sources may be limited, results in CO₂ prices close to \$20/short ton in 2013. The impact on the PJM Energy Market could be power price increases as high as \$15/MWh, and market-wide expenditures increase by as much as \$12 billion, while providing emission reductions from PJM sources of approximately 14 million tons. The impact on a typical customer's bill could be as high \$11.19 monthly or \$134.28 annually.

Other analyses performed by EIA and EPA examined the outcomes resulting from major legislation under alternate sets of assumptions. In analyses assuming the availability of CO₂ offsets are limited, CO₂ prices could rise as high as \$40/short ton to \$60/short ton. The findings demonstrate that:

- At a price of about \$40/ton, as modeled by EPA for the Lieberman-McCain Bill (S.280) in the absence of offsets, the impact on the PJM Market would be power price increases up to \$30/MWh, market-wide expenditures increasing up to \$23 billion and emissions reductions from PJM sources up to 66 million tons. The impact on a typical customer's bill could be as high \$22.28 monthly or up to \$267.36 annually.
- At a price of just over \$60/ton as modeled by EPA for the Lieberman-Warner bill (S.2191) in the absence of offsets, the impact on the PJM Market would be power price increases of approximately \$45/MWh and market-wide expenditures increasing up to \$36 billion. However, gas prices also rise to nearly \$10/mmBtu as shown by EIA, emissions reductions from PJM sources are only 25 million tons. The impact on a typical customer's bill could be up to \$34.16 monthly or \$409.92 annually.

Such a price and bill shock can be mitigated through energy efficiency or demand response actions that reduce future power consumption while helping reduce CO₂ emissions at the same time.

- Reductions in consumption due to energy efficiency or demand response move the market down to a lower cost marginal unit in general, resulting in lower LMP increases.
- Reductions in consumption due to energy efficiency or demand response reduce wholesale power costs through both the reduced LMP and reduced consumption.
- At a CO₂ price of \$10/ton and gas price of \$6.44/mmBtu, increases in LMP and wholesale power costs can be largely offset by a 10-percent reduction in electricity consumption.
- At higher CO₂ prices, the effects of energy efficiency and demand response actions can reduce LMP by as much as \$4/MWh at a 2-percent load reduction to as much as \$17/MWh for 10-percent load reductions.
- The effect of energy efficiency and demand response actions can reduce market-wide wholesale power costs by up to \$4 billion for a 2-percent load reduction to as much as \$18 billion for a 10-percent load reduction.
- While reducing LMP and wholesale power costs, load reductions due to demand response and energy efficiency actions also reduce CO₂ emissions by an additional 14 million tons for a 2-percent load reduction to as much as 60 million tons for a 10-percent load reduction.

Increasing penetration of wind power examined shows the potential for mitigating price and cost increases while providing additional emissions reductions. With 15,000 MW of wind capacity installed:

- Wholesale market price reductions of \$4.506/MWh, translating to reductions in annual market-wide expenditures of \$3.55 billion to \$4.74 billion versus not having that wind in place.
- Displacement of about 43,000 GWh (gigawatt-hour) of fossil fueled generation with about 60 percent of the displaced generation being coal and the remainder being natural gas and oil-fired units.
- CO₂ emissions reductions of almost 35 million short tons in the absence of any CO₂ price.

The design and details of climate change policy and underlying natural gas costs will have the greatest influence on the outcomes of climate change policy and the resulting effects on PJM's Energy Markets. While LMP, wholesale power costs, and customer bills will increase. However, as illustrated in the PJM analysis, increasing penetration of energy efficiency and some demand response in the region can mitigate price and cost impacts and foster greater emissions reductions in the initial years of climate change policy implementation.