Analysis of the Potential Impacts of an Advanced Energy Portfolio Standard (AEPS) in Ohio

Final Report

Prepared for

The Cleveland Foundation

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Executive Summary

Study Background

Several parties have recommended the implementation of an Advanced Energy Portfolio Standard (AEPS) in Ohio as a means of encouraging the development of an advanced energy industry in the state. While many recognize the potential for economic benefits to Ohio, other stakeholders, particularly industrial customers, are concerned that such a policy may increase electricity prices for Ohio customers. In order to address these concerns, The Cleveland Foundation commissioned ICF International (ICF) to analyze the potential impacts of a hypothetical AEPS on electricity prices (and other economic factors related to the electricity sector) in Ohio.

The Cleveland Foundation based the AEPS modeled in this study on an AEPS recently passed by the Pennsylvania legislature. The key aspects of the Ohio AEPS modeled for this study are:

- Advanced energy resources are defined as wind resources (both onshore and offshore), biomass (IGCC), low-impact hydro, landfill gas, and solar photovoltaics (central station and distributed). So-called “clean coal” technologies were not included in this study, only because their addition would have required considerable additional analysis.
- The AEPS is assumed to begin in 2010, requiring 1 percent of all electricity sold at the retail level in Ohio to be generated from qualifying advanced energy resources. The hypothetical AEPS reaches its maximum level by 2024, at which point 8 percent of all Ohio electricity sales must be derived from advanced energy sources. A set-aside is assumed for solar photovoltaics (PV), in which one-half percent of the total electricity sold at the retail level by 2024 must be derived from PV.

Most other assumptions on future energy growth rates and advanced energy resource costs were obtained from public sources, mainly the U.S. Department of Energy’s Annual Energy Outlook.

The study uses ICF’s Integrated Planning Model (IPM®), a capacity planning and dispatch model for the electric power sector relied upon by many public and private sector clients in the U.S., to assess the potential impact of an Ohio AEPS on wholesale energy markets, not only in Ohio but in other regions as well.

The hypothetical Ohio AEPS is examined under business-as-usual conditions, and also under the assumption that a Federal carbon policy is put into place in the future.

Summary of Key Findings

This study examines the impact of an Ohio AEPS on wholesale electricity prices, as a proxy for the impacts on Ohio retail electricity prices.

The upper bound of wholesale electricity price impacts due to an AEPS are estimated by the combined impact of (1) changes in marginal firm wholesale prices (including energy and capacity prices) and (2) the aggregate value of Renewable Energy Credits (RECs) – the premium required to generate the return on capital necessary to finance investments in advanced energy resources – when allocated to all electricity sold in Ohio.

In the absence of a carbon policy, this upper-bound wholesale electricity price increase as a result of the assumed Ohio AEPS is forecasted to be virtually zero in 2013, and about $0.0030 (less than one-third of a cent) per kWh by 2025. For perspective, these changes in wholesale prices can be evaluated relative to Ohio's average retail electricity prices of $0.0708 (7.08 cents) per kWh in 2005 (as reported by the EIA).

Should a carbon policy be in place similar to that modeled here, the AEPS in Ohio would have an even smaller impact on wholesale electricity prices in Ohio: about 1/10th of a cent ($0.001) per kWh by 2025. The impact of an AEPS under carbon constraints is smaller because the assumed Federal carbon policy stimulates considerable investment in advanced energy resources due to their low or no carbon emission impacts, irrespective of the presence of an AEPS.

Exhibit ES-1 presents forecasted changes in wholesale electricity prices due to an AEPS in Ohio, both with and without a Federal carbon policy in place.

Exhibit ES-1: Summary of Wholesale Electricity Price Impacts of Ohio AEPS

	AEPS (No Carbon)			**Carbon Policy and AEPS**		
	2013	**2020**	**2025**	**2013**	**2020**	**2025**
Average REC Costs (cents per kWh of electricity sold in Ohio)	ε	0.12	0.24	0.01	0.04	0.13
Firm Wholesale Market Price Impacts (cents/kWh sold in Ohio)	-ε.	0.11	0.06	0.01	-0.01	-0.03
Combined Wholesale Electricity Price Impact (cents/kWh) (Firm Wholesale Price + Average REC Costs)	- ε	0.22	0.30	0.03	0.02	0.10
Illustrative Retail Electricity Price Impacts (%)						
Combined Wholesale Price Impact as % of 2005 Average Ohio Retail Electricity Prices	- ε %	3.1%	4.3%	0.4%	0.3%	1.5%

Notes: (1) Negative numbers indicate a decline in prices in the policy case relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

An AEPS in Ohio would reduce regional air emissions, including SO_2, NO_x and mercury. However, because these pollutants are currently or proposed to be regulated through national and regional cap and trade programs, an Ohio AEPS would generate little or no net emissions benefits nationally.

Even in the presence of a carbon policy, an Ohio AEPS is forecasted to incrementally reduce Ohio air emissions in most of the years. However, the incremental emission reductions due to AEPS are estimated to be smaller in the presence of a carbon policy than without a carbon policy. This is because the carbon policy itself, without an AEPS policy in Ohio, promotes cleaner energy generation, resulting in lower emissions than what would have occurred in the absence of a carbon policy.

The assumed Ohio AEPS is projected to reduce CO_2 emissions both at the Ohio level and at the national level.

Exhibit ES-2 summarizes the air emissions impacts of an Ohio AEPS.

Exhibit ES-2: Potential Air Emissions Impacts of AEPS

	AEPS			Carbon Policy and AEPS		
Pollutant	**2013**	**2020**	**2025**	**2013**	**2020**	**2025**
Incremental Emission Impacts						
Mercury (lbs) in Ohio	-14	-61	-34	-25	-17	56
NO_x (Short tons) in Ohio	-516	-840	-17	-374	-599	1,089
SO_2 (Short tons) in Ohio	-781	-1,152	424	1,757	-2,238	3,319
Net CO_2 impacts (1,000 short tons of CO_2)						
Ohio	-292	-3,269	-4,724	-520	-1,263	367
U.S.	-543	-5,573	-6,247	-1,750	21	878
Percent Change in Emissions (relative to the Reference Case)						
Mercury in Ohio	-0.2%	-1.1%	-0.8%	-0.4%	-0.3%	1.4%
NO_x in Ohio	-0.2%	-0.4%	- ε %	-0.1%	-0.3%	0.6%
SO_2 in Ohio	-0.1%	-0.2%	0.1%	0.2%	-0.3%	0.6%
CO_2 in Ohio	-0.1%	-0.9%	-1.2%	-0.1%	-0.4%	0.1%
CO_2 in the U.S.	- ε %	-0.2%	-0.2%	-0.1%	ε %	ε %

Notes: (1) Negative numbers indicate a decline in emissions in the policy case relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Other impacts of the policy include the following:

- Wind, biomass and landfill gas are among the lowest cost advanced energy resources, and are projected to be among the new resources added in Ohio in the future. To meet the assumed Ohio AEPS, over 1 GW of wind resources and nearly 970 MW of biomass resources are forecasted to be added by 2025, along with over 600 MW of solar PV to satisfy the solar PV ”set-aside”.
- The advanced energy resources that are forecasted to be constructed displace new fossil fuel-fired capacity that was projected to have been constructed in the absence of the policy. Because the added advanced energy resources typically operate at lower capacity factors

than their fossil counterparts, the amount of advanced energy resource construction exceeds the declines in fossil capacity construction.

- Ohio coal production is not significantly affected by the assumed Ohio AEPS across the years, with or without a Federal carbon policy in place.

Table of Contents

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Analysis of the Potential Impacts of an AEPS in Ohio

I. Background and Introduction

Several parties have recommended the implementation of an “Advanced Energy Portfolio Standard” (AEPS) in Ohio. Proponents view an Ohio AEPS as an economic development mechanism to encourage the emergence of an advanced energy industry in Ohio with significant job creation potential, and also as a means of achieving environmental benefits for Ohio’s citizens through reduced air emissions associated with electricity generation.

Other stakeholders have objected to an AEPS in Ohio on the grounds that it might increase electricity prices for Ohio customers. This is of particular concern to industrial customers that use large quantities of power, as these companies typically face intense competitive pressures in their markets, and hence may suffer reduced profits from being unable to pass along energy price increases to their customers.

In order to address these concerns, The Cleveland Foundation commissioned ICF International (ICF) to analyze the potential impacts of a hypothetical AEPS on electricity prices (and other economic factors related to the electricity sector) in Ohio.

The remainder of this report is organized as follows: The study methodology is briefly summarized below, followed by a discussion of key findings of this study. Supplementary results of this study are reported in Appendix A, followed by a detailed description of the modeling framework adopted in this study in Appendix B and of the assumptions in Appendix C.

A. Advanced Energy Portfolio Standard Assumptions

Although 21 states and the District of Columbia have already implemented some form of an AEPS, no specific advanced energy portfolio standard has yet been promulgated in Ohio. This study examines a hypothetical AEPS for Ohio, largely modeled on the advanced energy portfolio standard that was passed by Pennsylvania’s legislature in late 2004.

Pennsylvania’s AEPS was used by The Cleveland Foundation as a guiding template for developing the Ohio AEPS assumed for this study. Clearly, a wide variety of alternative AEPS proposals other than the one modeled herein could be considered for Ohio. However, The Cleveland Foundation determined that the hypothetical AEPS modeled in this study was a reasonable general representation for purposes of estimating the potential price and emission impacts in Ohio that would be associated with an AEPS that might realistically be implemented in Ohio.

For the purposes of this study, the following requirements are assumed for an Ohio AEPS:

- "Advanced energy” resources are defined as wind resources (both onshore and offshore), biomass (IGCC), low-impact hydro, landfill gas, and solar photovoltaic (PV) (central station and distributed). While Pennsylvania’s law has a broader definition of eligible resources (such as waste coal), such resources are not assessed in this study, only because a broader definition of the eligible resources would have required extensive further data gathering and development beyond the scope of this current exploratory effort. Since the expansion of the definition of advanced energy to other types of qualifying resources would only serve to expand the feasible set of compliance possibilities, the electricity price impacts presented herein could only be lower if other forms of advanced energy resources were additionally allowed and modeled (assuming there is no set-aside for these expanded options).

- The hypothetical AEPS for Ohio is assumed to begin in 2010, requiring 1 percent of all electricity sold at the retail level in Ohio to be generated from qualifying advanced energy resources. The AEPS reaches its maximum level by 2024, at which point 8% of all Ohio electricity sales must be derived from advanced energy sources. This rate of expansion of the AEPS, and the ultimate percentage requirement at the conclusion of the 15 year phase-in, are generally consistent with the AEPS that was adopted in Pennsylvania. Also as in the Pennsylvania AEPS, a so-called "set-aside" is assumed for solar PV, in which 0.5 percent of the total electricity sold at the retail level by 2024 must be derived from PV.

- For the Ohio AEPS, it is assumed that eligible advanced energy resources may be acquired from anywhere within Ohio and from neighboring power systems within which generators which service Ohio operate.

Exhibit 1 summarizes the requirements of the assumed Ohio AEPS policy, presenting the proportion of electricity sales to be met by advanced energy resources.

Exhibit 1: Hypothetical Ohio Advanced Energy Portfolio Standard (AEPS) (Share of electricity sales to Ohio consumers)		
Year	AEPS including Solar PV	Solar PV Standard
2010	1.0%	0.0013%
2011	1.5%	0.0013%
2012	2.0%	0.0013%
2013	2.5%	0.0013%
2014	3.0%	0.0203%
2015	3.5%	0.0203%
2016	4.0%	0.0203%
2017	4.5%	0.0203%
2018	5.0%	0.0203%
2019	5.5%	0.2500%
2020	6.0%	0.2500%
2021	6.5%	0.2500%
2022	7.0%	0.2500%
2023	7.5%	0.2500%
2024 and beyond	8.0%	0.5000%

B. Study Methodology

In order to estimate the potential price and emission impacts of an AEPS in Ohio, ICF conducted a detailed analysis of how the electricity industry would be affected by the requirements of the assumed AEPS by using its Integrated Planning Model (IPM®). IPM is a capacity planning and dispatch model for the electric power sector, based upon engineering and economic fundamentals, that simulates the deregulated wholesale market for electricity. IPM simulates the operations of every generator in the continental U.S. with regional detail. The model is an optimization model that determines the least-cost method of meeting national level energy and peak demand requirements for a specific period of time, recognizing power system constraints and environmental requirements over the entire planning horizon. These constraints and requirements include national or regional air emission programs, transmission constraints, fuel market constraints, regional reserve margin requirements, and renewable or advanced energy portfolio standards. A more detailed description of the IPM modeling structure is included in Appendix B of this report.

The AEPS assumed for Ohio is explicitly modeled in IPM as a minimum generation requirement from eligible technologies and resources that must be satisfied in each year. The model also projects the premium [typically called the Renewable Energy Credit (REC) price] that is required to encourage the development of advanced energy resources that otherwise would not come into the market. The REC price thus represents the additional payment required, in addition to other energy and capacity payments, to generate the return on capital required to finance the investments to bring these resources onto the system. The REC value is determined by the market conditions, the level of demand for qualifying advanced energy resources (the AEPS level), and the economic and technological characteristics of the eligible resources.

As noted above, eligible advanced energy resources may be acquired from anywhere within Ohio and from neighboring power systems within which affected generators serving Ohio operate. However, in estimating the electricity price impacts of the AEPS, it is assumed that all costs associated with all advanced energy resources implemented to meet the requirements of the Ohio AEPS are borne only by Ohio customers.

Key assumptions and inputs required by IPM were developed based upon direction from The Cleveland Foundation. These included key drivers such as electricity demand and future technology cost and performance characteristics. To the maximum extent practicable, these assumptions were based on publicly available information [such as the Annual Energy Outlook prepared by the U.S. Department of Energy's Energy Information Administration (EIA)], with remaining other inputs developed as required by The Cleveland Foundation. These assumptions are described further in Appendix C of this report.

Based upon these inputs, ICF used IPM to develop Business-as-Usual projections of future wholesale electricity system operations through 2025 assuming all other known regulations are in place [importantly for Ohio, the Clean Air Interstate Rule (CAIR)], but without any AEPS in place for Ohio (the "Reference Case"). In addition, ICF developed a "Policy Case" that applied the above-noted AEPS generation requirements to the Reference Case, in order to simulate the potential impacts of an AEPS in Ohio through 2025.

The differences between the appropriate reference and policy cases indicate the potential impacts of the assumed Ohio AEPS given the assumptions used here and outlined in Appendix C. Key differences analyzed included:

- Costs, including wholesale electricity (energy and capacity) prices, and the value of the advanced energy credit (hereinafter referred to as the REC credit, because of the common usage of this term across the industry)
- Changes in emissions of pollutants, including regional SO_2 and NO_X emissions, and regional and national level CO_2 emissions
- Changes in electric system capacity and dispatching, in terms of installation of new generation and operation of the system
- Impacts on Ohio coal production

C. Potential Carbon Policy

Since many observers speculate that carbon limitations will be adopted in some form by the U.S. government in the near future in order to address the growing concerns about global climate change, the potential impacts of an Ohio AEPS were also examined under the assumption that a national level carbon emissions policy would soon be implemented in the U.S.

Because the terms and conditions of potential future carbon limitations are unclear, The Cleveland Foundation reviewed various carbon legislation alternatives that have been proposed, and developed a hypothetical carbon policy to estimate representative impacts of an Ohio AEPS if a somewhat aggressive Federal carbon policy were in place[1].

The hypothetical carbon policy assumes that carbon emissions from the U.S. power sector are required to be reduced to 1990 levels by 2030. Interim carbon emissions targets include 2006 levels by 2015, and 2000 levels by 2020. Exhibit 2 summarizes the key elements of the hypothetical carbon policy assumed for this study.

For estimating the incremental impacts of Ohio AEPS under the assumption of a future Federal carbon policy, the reference (no Ohio AEPS) case with a carbon policy (also referred to as "Carbon Policy/Reference Case") is compared to a case with both a carbon policy and an Ohio AEPS (also referred to as "Carbon Policy/AEPS Case).

Exhibit 2: Assumed National Carbon Policy for Carbon Policy Cases

Starting Year	2015
Affected Units	Electric Power Sector Units ≥ 25 MW
Policy	CO_2 Emissions limit with trading (national cap-and-trade); use of offsets from other sectors not allowed.
National CO_2 emissions limit for electric power sector	2006 levels by 2015-2019 2000 levels by 2020-2024 1997 levels by 2025-2029 1990 levels by 2030-2035

[1] A relatively aggressive carbon policy assumption was developed to create a contrast relative to an ongoing "no carbon policy" scenario, which was modeled in the Reference Case and Policy Case as discussed above.

II. Key Findings

This section summarizes the key findings of this study. Although the modeling analysis was conducted through 2027, in order to simplify the narrative, the focus of discussion is on just two years, 2013 and 2025.[2] More detailed results, including forecasts for all modeled years, are provided in Appendix A of this report.

A. Electricity Price Impacts

IPM is a wholesale electricity market model, and hence does not model retail electricity prices. Historically, cost recovery and allocation of costs among customer classes in Ohio have been subject to the jurisdiction of the regulatory authority in Ohio, the Public Utilities Commission of Ohio (PUCO). With the deregulation of electricity markets in Ohio, there has been movement to market-based rates and in the transition period between regulation and open markets, the PUCO has established interim rates to ensure a smooth transition to competitive markets. Given the modeling framework used and these market and regulatory uncertainties, forecasts of the effects of an Ohio AEPS on retail electricity prices in Ohio are beyond the scope of this study.

Nonetheless, it is possible to scope the potential impacts of an Ohio AEPS on Ohio retail electricity prices by examining the forecasted impacts of an Ohio AEPS on Ohio wholesale electricity prices. To evaluate the merits of AEPS in Ohio from a policy perspective, it is useful to assume that PUCO treatment of AEPS-related costs (as well as distribution-related costs, the key difference between wholesale and retail electricity prices) will remain the same as historical practices through the forecast horizon. Under these assumptions, one can reasonably assess the potential impacts on retail electricity prices by using forecasted changes in firm wholesale electricity prices as a proxy[3]. This would most closely approximate a competitive market price. Other ratemaking approaches may result in different impacts. For example, a revenue requirements approach would be based on average production cost increases, and would generally be lower than the impacts discussed here.

Exhibit 3 presents forecasted changes in wholesale electricity prices due to an AEPS in Ohio, both with and without a carbon policy in place.

The upper bound of wholesale electricity price impacts due to an AEPS can be estimated by adding together the sum of (1) changes in marginal "all-in" wholesale (energy plus capacity) prices and (2) the aggregate value of RECs per unit of electricity sold in Ohio.

[2] All years from 2010 to 2027 are accounted for in the analysis, because IPM is a "forward-looking" model (i.e., IPM makes investment decisions based on the discounted present value of future expected costs). The years for which quantitative estimates were produced included 2011, 2013, 2016, 2020 and 2025. See Appendix A for detailed results.
[3] Firm wholesale electricity prices represents the marginal wholesale electricity price ($/kwh) plus the wholesale capacity price ($/kW-year) spread over all electricity sales.

In the absence of a carbon policy, this "combined" wholesale electricity price increase in Ohio is forecasted to be virtually nil in 2013, and about $0.0030 (less than one-third of a cent) per kWh by 2025. For perspective, these changes in wholesale prices can be evaluated relative to Ohio's average retail electricity prices of $0.0708 (7.08 cents) per kWh in 2005 (as reported by the EIA).

Under a carbon policy, which many observers expect to be in place for much of the forecast horizon of this study, the implementation of the assumed AEPS in Ohio has an even smaller impact on wholesale electricity prices in Ohio: about 1/10th of a cent ($0.001) per kWh by 2025. Because the carbon policy itself, even in the absence of an AEPS, stimulates investment in advanced energy resources due to their low or no carbon emission impacts, logically the incremental impacts of AEPS are much smaller when a carbon policy is in place.

The dynamics underlying these estimated results are complex, and are best understood by considering each of the two economic components in isolation.

Exhibit 3: Summary of Electricity Price Impacts of Ohio AEPS

	AEPS (No Carbon)			**Carbon Policy and AEPS**		
	2013	**2020**	**2025**	**2013**	**2020**	**2025**
REC Premium (cents/kWh)						
Average REC Costs (cents per kWh of electricity sold in Ohio)	ε	0.12	0.24	0.01	0.04	0.13
Energy + Capacity Market Price Impacts (cents/kWh)						
Impact on wholesale energy and capacity market prices per kWh of electricity sold in Ohio	- ε	0.11	0.06	0.01	-0.01	-0.03
Combined Wholesale Electricity Price Impact (cents/kWh)						
Energy & Capacity price impact + Average REC Costs	- ε	0.22	0.30	0.03	0.02	0.10
Illustrative Retail Electricity Price Impacts (%)						
Combined Wholesale Price Impact as % of 2005 Average Ohio Retail Electricity Prices	- ε %	3.1%	4.3%	0.4%	0.3%	1.5%

Notes: (1) Totals may not add up due to rounding. (2) ε is a small positive quantity less than the displayed significant digits.

The REC Premium

The value of RECs, expressed in cents per kWh of eligible generation, indicates the incremental payment (over and above prevailing wholesale electricity prices in the market place) that is required to finance the investments in new qualifying capacity to satisfy the Ohio AEPS. REC prices thus facilitate the entry of advanced energy resources that may be more expensive than electricity generated from current (or expected future business-as-usual) resources by providing a price premium that reflects the difference in costs between the business-as-usual resource and the advanced energy resource.

Because the hypothetical Ohio AEPS provides specifically for a solar PV minimum generation requirement, there are two REC prices in this analysis: one for solar PV specifically, and one for all other qualifying advanced energy resources (such as wind, biomass, etc.).

Absent a carbon policy at the Federal level, forecasted non-solar PV REC prices are zero until 2016. In other words, the assumed Ohio AEPS is found to be effectively "non-binding" for the first several years of the policy. A greater amount of advanced energy generation than required by the AEPS is indicated to be brought on line, because these advanced energy resources are found to be economic given the knowledge that AEPS is required in the future. This response of building renewables and other eligible resources in amounts that exceed the level required by the AEPS reflects the economic value of these resources in complying with the Clean Air Interstate Rule (CAIR), which comes into force in 2009. Owners of existing generation sources must reduce emissions to comply with CAIR at that time, regardless of the Ohio AEPS. Investing early in advanced energy resources that produce much lower emissions allows both requirements to be met more economically.

In 2025, the non-solar REC price is estimated at 1.30 cents per kWh generated, with the solar PV REC price being significantly higher (at 29.6 cents per kWh generated) due to the relatively high costs of solar PV. The fact that REC prices are non-zero indicates that, in the later years of the forecast horizon absent a carbon policy, the AEPS policy will be the primary driver for stimulating investment in advanced energy resources in Ohio.

In the Carbon Policy/AEPS Case, the non-solar REC prices are less than half a cent per kWh generated in 2013 and zero in 2025. The carbon policy is found to drive a higher level of advanced energy resources as a compliance option in the later years, thus stimulating no additional action to comply with the AEPS, with consequently no economic premium indicated to be required. The forecasted solar PV REC prices, although much higher than the non-solar REC prices (at 27.8 cents per kWh in 2025), are lower than in the absence of a carbon policy. Because solar PV generation helps the system to comply with the carbon policy due to its zero emissions, the incremental REC premium required to bring the PV generation to the system in the presence of a carbon policy is estimated to be lower than when there is only an AEPS policy without a carbon policy.

In all cases, the total REC premium paid to all eligible generation would be spread across all retail sales in Ohio, regardless of the source of the generation or where the REC was generated. Thus, the average impact of REC premiums across Ohio's entire retail customer base is calculated by allocating total REC premiums paid (in $) to all kWh of retail electricity sales in Ohio. When calculated in this manner, the average REC value per kWh of electricity sold in Ohio – with or without a carbon policy – is projected to be less than 1/100th of a cent per kWh in 2013, and less than 1/4th of a cent per kWh in 2025.

Wholesale Price Impacts

Wholesale electricity prices consist of two components: energy and capacity. IPM produces marginal energy prices, reflecting the costs of the last unit to be dispatched in each hour to meet load. This marginal energy price reflects the cost of generating electricity, comprising fuel and variable operation and maintenance costs for the most expensive unit in operation in each hour. The marginal capacity price reflects the cost of meeting reserve margin requirements, and reflects the costs of bringing the last MW of capacity onto the system to satisfy the reserve margin requirement. Together these costs reflect the price of firm electricity. These are prices that would be expected in competitive markets. IPM produces these estimates for each year and on a regional basis.

Firm wholesale energy prices also are not dramatically affected by the implementation of an AEPS in Ohio. Most of the advanced energy resources selected by the model to economically comply with an AEPS in Ohio (e.g., wind) have lower variable costs than the generating sources that are displaced. Because these qualifying advanced energy resources have lower variable costs, the model projects lower wholesale energy prices in some hours of the year as a result of an AEPS in Ohio, particularly when surpluses of advanced energy are forecasted due solely to its economic advantages for other compliance purposes (e.g., early forecast years in complying with CAIR, later forecast years if a carbon policy is in place). In no forecast year, with or without carbon policy, do wholesale marginal energy prices increase by more than $0.0011 (0.11 cents) per kWh.

As a result, in the earlier years of the forecast horizon, the implementation of an Ohio AEPS actually tends to reduce forecasted marginal energy prices. In the later years of the forecast horizon, while wholesale electricity prices increase as a result of an Ohio AEPS, the impacts are estimated to remain small (1.1 percent in 2020 and 0.6 percent in 2025) relative to the Reference Case with no AEPS. In the presence of a carbon policy, the wholesale price impacts of the AEPS are also very small.

B. Emission Impacts

An AEPS in Ohio would reduce regional air emissions of already-regulated pollutants: SO_2, NO_x and mercury (see Exhibit 4). However, because these pollutants are currently or proposed to be regulated through national and regional cap and trade programs, little or no net benefits would occur nationally; emission reductions in Ohio would be offset by emissions increases elsewhere, as affected emission sources under these cap-and-trade programs would be able to take advantage of the reduced emissions afforded by the additional advanced energy resources that are spurred by the Ohio AEPS to reduce their compliance requirements and costs elsewhere. While total national emissions of the regulated pollutants would remain unchanged, compliance costs are indicated to decline by a small amount, as the advanced energy resources that qualify for the Ohio AEPS also serve to contribute to compliance with the other environmental regulations due to their low emissions of NO_x, SO_2 and mercury.

The reductions of these pollutants in Ohio due to the assumed AEPS range from less than $1/10^{th}$ of one percent to 1.4 percent, compared to the Reference Case.

Exhibit 4: Potential Air Emission Impacts of AEPS in the Ohio Region						
	AEPS			**Carbon Policy and AEPS**		
Pollutant	**2013**	**2020**	**2025**	**2013**	**2020**	**2025**
Incremental Emission Impacts						
Mercury (lbs)	-14	-61	-34	-25	-17	56
NO_x (Short tons)	-516	-840	-17	-374	-599	1,089
SO_2 (Short tons)	-781	-1,152	424	1,757	-2,238	3,319
Change in Emissions relative to the appropriate reference cases						
Mercury	-0.2%	-1.1%	-0.8%	-0.4%	-0.3%	1.4%
NO_x	-0.2%	-0.4%	- ε %	-0.1%	-0.3%	0.6%
SO_2	-0.1%	-0.2%	0.1%	0.2%	-0.3%	0.6%

Notes: Negative numbers indicate a decline in emissions in the policy case relative to the appropriate reference cases.

The assumed Ohio AEPS is projected to reduce CO_2 emissions both in the Ohio region and at the national level (see Exhibit 5). At the regional level, the forecasted reductions are 0.3 million short tons (0.1% reduction) in 2013 and 4.7 million short tons (1.2% reduction) in 2025; at the national level, they are 0.5 million (0.02%) and 6.2 million (0.2%) short tons of CO_2 in 2013 and 2025, respectively. Reductions are indicated to occur outside Ohio because the availability of new advanced energy resources to meet the Ohio AEPS requirements would free up surplus Ohio generating capacity, thereby enabling additional Ohio electricity exports to displace fossil generation elsewhere.

Even in the presence of a carbon policy, an Ohio AEPS is forecasted to incrementally reduce Ohio air emissions in most of the years. However, the incremental emission reductions due to AEPS are estimated to be smaller in the presence of a carbon policy than without a carbon policy. This is because the carbon policy itself, without an AEPS policy in Ohio, promotes cleaner energy generation, resulting in lower emissions than what would have occurred in the absence of a carbon policy.

Exhibit 5: Potential Changes in CO_2 Emissions Due to Ohio AEPS						
	AEPS[b]			**Carbon Policy and AEPS[b]**		
	2013	**2020**	**2025**	**2013**	**2020**	**2025**
Net CO_2 impacts (1,000 short tons of CO_2)						
Ohio Region[a]	-292	-3,269	-4,724	-520	-1,268	367
Change relative to appropriate	-0.1%	-0.9%	-1.2%	-0.1%	-0.4%	0.1%
U.S.	-543	-5,573	-6,247	-1,750	21	878
Change relative to appropriate	- ε %	-0.2%	-0.2%	-0.1%	ε %	ε %

Notes: (a) Ohio region includes the three Ohio modeling regions. (b) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (c) ε indicates that the values are too small for the number of significant digits shown.

C. Capacity, Generation and Coal Market Impacts

Wind, biomass and landfill gas are among the lowest cost advanced energy resources, and are projected to be among the new resources added in Ohio in the future, both in the Reference Case and in the Policy Case. However, in the Policy Case, significantly more new advanced energy resources, including solar PV, are added to the system. Exhibit 6 presents projected incremental advanced energy resources added in the Policy Case by type for 2013 and 2025. In total, by 2025, over 1 GW of wind resources and nearly 970 MW of biomass resources are added, along with over 600 MW of solar PV to satisfy the solar PV ”set-aside”. In addition to these resources, advanced energy resources added in the Reference Case (nearly 90 MW of wind and about 280 MW of landfill gas, both in 2009) are also available to meet the requirements of the AEPS.

Exhibit 6: Incremental Advanced Energy Capacity and Generation Due to Ohio AEPS (no Carbon Policy)

	2013	2020	2025	2013	2020	2025
		MW			GWh	
Wind	884	960	1,014	2,671	2,933	3,119
Biomass	0	911	968	0	6,621	6,382
Solar PV	11	233	604	21	429	1017
Total	***895***	***2,104***	***2,586***	***2,692***	***9,983***	***10,518***

Notes: (a) Ohio region includes the three Ohio modeling regions. (b) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases.

The advanced energy resources that are forecasted to be built in response to the assumed Ohio AEPS policy displace some amount of new fossil fuel-fired capacity that was projected to have been constructed in the absence of the policy. Electricity generation from new and existing fossil fuel fired units is also indicated to be displaced by the advanced energy resources forecasted to be built to satisfy the AEPS. Because the wind and PV resources generally operate at lower capacity factors than conventional power plants, more megawatts of wind and PV capacity must be constructed for each megawatt of displaced fossil capacity.

Lower levels of coal, natural gas and a small amount of nuclear generation are required in the Policy Case as a result of the increased generation from advanced energy resources, compared to the generation levels in the Reference Case. The amount of displaced fossil generation is estimated to be lower than the amount of qualifying generation from advanced energy resources required by the AEPS, because the increased advanced energy generation allows Ohio to increase exports of low-cost coal resources that have been freed-up.

Reduced coal-fired generation, and hence reduced demand for coal, is forecasted as a result of an Ohio AEPS requirement. However, as shown in Exhibit 7, Ohio's coal production is not significantly affected by the AEPS across the years, with or without a carbon policy in place.[4] This is because coal generation in the Ohio region and consequently the demand for Ohio's coal within and outside of Ohio are not significantly lowered by the Ohio's AEPS.

[4] A national carbon policy is likely to have a negative impact on Ohio coal production, but the incremental impact of an Ohio AEPS in the presence of a national carbon policy is forecasted to be insignificant.

Exhibit 7: Changes in Ohio Coal Production Due to Ohio AEPS

AEPS (No Carbon)	2013	2020	2025
Changes in Ohio coal production due to Ohio's AEPS *(million short tons)*	0	0	0
Percentage of change in Ohio coal production, relative to the no-AEPS Scenario	0%	0%	0%
AEPS and Carbon Policy			
Changes in Ohio coal production due to Ohio's AEPS *(million short tons)*	0	-0.12	0.23
Percentage of change in Ohio coal production, relative to the no-AEPS Scenario	0%	-0.2%	0.3%

Notes: Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases.

Across the board, the impacts of the assumed Ohio AEPS on coal and gas prices are forecasted to be minimal. Average delivered coal prices decline by one-fifth of one percent or less, and natural gas prices fluctuate by less than one-half of one percent (±0.5%) due to the AEPS, across all years with or without a carbon policy in place.

Appendices

Appendix A. Supplementary Study Results

A1. Impacts of Ohio's AEPS in the Absence of a Carbon Policy

New Advanced Energy Capacity and Generation

Table A1.1 Cumulative New Advanced Energy Capacity in the Reference Case

	2009	2011	2013	2016	2020	2025
			(MW)			
Non Solar						
Wind	87	87	87	87	87	87
Biomass	0	0	0	0	0	721
Landfill Gas	282	282	282	282	282	282
Total New non-Solar Advanced Energy Capacity	*369*	*369*	*369*	*369*	*369*	*1,090*
Solar PV						
New Solar PV Capacity	*0*	*0*	*0*	*0*	*0*	*0*
Total New Advanced Energy Capacity	***369***	***369***	***369***	***369***	***369***	***1,090***

Table A1.2 Cumulative New Advanced Energy Capacity in the Policy Case

	2009	2011	2013	2016	2020	2025
			(MW)			
Non Solar						
Wind	971	971	971	1,047	1,047	1,101
Biomass	0	0	0	319	911	1,689
Landfill Gas	282	282	282	282	282	282
Solar Thermal	0	0	0	0	0	0
Total New non-Solar PV Advanced Energy Capacity	*1,253*	*1,253*	*1,253*	*1,648*	*2,240*	*3,072*
Solar PV						
New Solar PV Capacity	*0*	*1*	*11*	*22*	*233*	*604*
Total New Advanced Energy Capacity	***1,253***	***1,254***	***1,264***	***1,670***	***2,473***	***3,676***

Table A1.3 Incremental Advanced Energy Capacity Added in Response to Ohio AEPS

	2009	2011	2013	2016	2020	2025
	(MW)					
Non Solar						
Wind	884	884	884	960	960	1,014
Biomass	0	0	0	319	911	968
Solar PV						
PV	0	1	11	22	233	604
Total Incremental Advanced Energy Capacity	***884***	***885***	***895***	***1,301***	***2,104***	***2,586***

Table A1.4 New Annual Advanced Energy Generation and Compliance with Ohio AEPS

	2009	2011	2013	2016	2020	2025
	(GWh)					
Total AEPS Generation Standard(2)	***0***	***2,738***	***5,201***	***7,864***	***12,559***	***17,807***
Non Solar						
Wind	2,947	2,947	2,947	3,209	3,209	3,395
Biomass	0	0	0	2,317	6,621	11,096
Landfill Gas	2,301	2,301	2,301	2,301	2,301	2,301
Total non-Solar Renewable Generation	*5,248*	*5,248*	*5,248*	*7,825*	*12,130*	*16,790*
Non-Solar Renewable Generation Standard	*0*	*2,736*	*5,181*	*7,825*	*12,130*	*16,790*
Solar PV						
Solar PV Generation	0	2	21	40	429	1,017
Solar PV Generation Standard	*0*	*2*	*21*	*40*	*429*	*1,017*
Total Advanced Energy Generation	***5,248***	***5,250***	***5,269***	***7,867***	***12,560***	***17,809***

Note: Totals may not add up due to rounding.

Table A1.5 Incremental New Advanced Energy Generation in the Policy Case, Relative to the Reference Case

	2009	2011	2013	2016	2020	2025
	(GWh)					
Non Solar						
Wind	2,671	2,671	2,671	2,933	2,933	3,119
Biomass	0	0	0	2,317	6,621	6,382
Landfill Gas	0	0	0	0	0	0
Incremental New non-Solar Renewable Generation	*2,671*	*2,671*	*2,671*	*5,250*	*9,554*	*9,501*
Solar PV						
Incremental New Solar PV Generation	0	2	21	40	429	1,017
Total "Incremental" New Advanced Energy Generation	***2,671***	***2,673***	***2,692***	***5,290***	***9,983***	***10,518***
New incremental advanced energy generation as a percentage of renewable portfolio in the Policy Case (No Carbon)	*51%*	*51%*	*51%*	*67%*	*79%*	*59%*

Displaced New Capacity and Changes in Generation Mix

Table A1.6 Projected Changes in New Fossil Capacity Due to Ohio AEPS

	2011	2013	2016	2020	2025
	(MW)				
New Scrubbed Coal	0	0	-120	-369	-856
New Combined Cycle	0	-19	-43	-107	-158
New Combustion Turbine	0	0	22	22	-39
Total	***0***	***-19***	***-141***	***-454***	***-1,053***

Notes: (1) Positive values indicate capacity additions and negative values indicate capacity displaced in the Policy Case, relative to the Reference Case.

Table A1.7 Changes in Generation and Energy Transmission Due to Ohio AEPS

	2011	2013	2016	2020	2025
			(GWh)		
Generation					
Coal	-1136	-220	-862	-3,304	-5,798
Natural Gas	-48	-67	-260	-549	-460
Oil	0	0	0	0	0
Uranium (Nuclear)	-4	0	0	0	0
Total	*-1,188*	*-287*	*-1,122*	*-3,853*	*-6,258*
Fraction of fossil fuel fired generation displaced for one unit increase in advanced energy generation	44%	11%	42%	73%	66%
Changes in generation as a percentage of fuel-specific total generation in the Reference Case					
Coal	*0%*	*0%*	*0%*	*-1%*	*-1%*
Natural Gas	*-3%*	*-3%*	*-5%*	*-7%*	*-6%*
Transmission			(GWh)		
Changes in net exports of electric power to other regions	1,600	2,500	4,300	6,100	4,300
Changes in net exports of electric power, as a percentage of net exports to other regions in the Reference Case	4%	9%	24%	42%	13%

Notes: Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases.

Displaced Fossil Fuel Consumption

Table A1.8 Changes in Fossil Fuel Consumption Due to Ohio AEPS Policy

Fuel Type	2011	2013	2016	2020	2025
			(TBtu)		
Coal					
Coal Consumption in the Policy Case	3,405	3,406	3,378	3,442	3,647
Coal Consumption in the Reference Case	3,417	3,408	3,386	3,471	3,691
Natural Gas					
Natural Gas Consumption in the Policy Case	16	19	38	57	57
Consumption in the Reference Case	16	20	40	61	60
Displaced coal consumption in the Policy Case, relative to the Reference Case					
Coal	0.4%	0.1%	0.2%	0.8%	1.2%
Natural Gas	3.1%	3.0%	6.0%	6.5%	5.0%

Table A1.9 Changes in Ohio Coal Production Due to Ohio AEPS Policy

	2011	2013	2016	2020	2025
	(million short tons)				
Changes in Ohio coal production due to Ohio AEPS	0	0	-0.57	0	0
Percentage change in Ohio coal production, relative to Reference Case	0%	0%	-1.4%	0%	0%

Notes: Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases.

Changes to the Wholesale Electric Prices

Table A1.10 Annual Wholesale Electricity Price Impacts of Ohio AEPS

	2011	2013	2016	2020	2025
	(cents per kWh)				
Wholesale price impacts of the AEPS per kWh of electricity sold in Ohio (excluding REC value)	-0.04	- ε	0.05	0.11	0.06
Wholesale price impacts of the AEPS, relative to Reference Case wholesale prices	-0.4%	- ε%	0.5%	1.1%	0.6%

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Value of Renewable Energy Credits (REC)

Table A1.11 REC Prices in the AEPS Case

	2011	2013	2016	2020	2025
	(cents/kWh of Eligible Generation)				
Non-solar REC prices	0	0	1.91	1.25	1.31
Solar PV REC prices	17.92	23.34	21.15	19.06	29.57
Average incentive required per kWh of new renewable electricity generation in Ohio	0.01	0.09	2.00	1.86	2.92
Average REC Costs in the Retail Electricity Market under the AEPS	(cents/kWh of Sales)				
REC Value per kWh of electricity sales in Ohio	ε	ε	0.09	0.12	0.24

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Table A1.12 Combined Wholesale and REC Price Impacts of Ohio AEPS

	2011	2013	2016	2020	2025
	(cents per kWh)				
Wholesale (energy plus capacity) electricity price impacts per kWh of electricity sold in Ohio (excluding REC value)	-0.04	- ε	0.05	0.11	0.06
REC value per kWh of electricity sold in Ohio	ε	ε	0.09	0.12	0.24
Combined wholesale price and REC value impacts per kWh of electricity sold in Ohio	-0.04	- ε	0.13	0.22	0.30
Wholesale cost impacts of the AEPS relative to Reference Case wholesale prices	-0.4%	- ε %	1.3%	2.3%	3.0%

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Potential Air Emission Impacts

Table A1.13 Potential Air Emission Impacts of AEPS in Ohio

	2011	2013	2016	2020	2025
Incremental Emission Impacts					
Mercury (lbs)	-100	-14	4	-61	-34
NOx (Short tons)	-3,253	-516	-67	-840	-17
SO2 (Short tons)	-4,180	-781	-2,570	-1,152	424
Change in Emissions relative to the Reference Case					
Mercury	-1.5%	-.2	0.1%	-1.1%	-0.8%
NOx	-1.2%	-.2	ε %	-0.4%	ε %
SO2	-0.6%	-.1	-0.4%	-0.2%	0.1%

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Table A1.14 Potential Changes in CO_2 Emissions due to AEPS

Pollutant	2011	2013	2016	2020	2025
Net CO2 impacts of Ohio AEPS	***(1,000 short tons of CO2)***				
Ohio	-1,309	-292	-906	-3,269	-4,724
U.S.	-839	-543	-2,759	-5,573	-6,247
Change in CO2 Emissions relative to the Reference Case					
Ohio	-0.4%	-0.1%	-0.3%	-0.9%	-1.2%
U.S.	- ε %	- ε %	-0.1%	-0.2%	-0.2%

Notes: (1) Negative numbers indicate a decline relative to the Reference Case. (2) ε is a small positive quantity less than the displayed significant digits.

A2. Impacts of Ohio's AEPS in the Presence of a Carbon Policy

New Advanced Energy Capacity and Generation

Table A2.1 Cumulative New Advanced Energy Capacity in the AEPS-Carbon Scenario

	2009	2011	2013	2016	2020	2025
			(MW)			
Non Solar						
Wind	90	90	90	170	170	270
Biomass	0	20	357	686	2679	6599
Landfill Gas	225	282	282	282	282	282
Total New non-Solar PV Advanced Energy Capacity	*315*	*392*	*729*	*1,138*	*3,131*	*7,151*
Solar PV						
New Solar PV Capacity	*0*	*1*	*11*	*22*	*233*	*604*
Total New Advanced Energy Capacity	***315***	***393***	***740***	***1,160***	***3,364***	***7,755***

Table A2.2 Incremental New Renewable Capacity Additions due to AEPS in the Presence of a Carbon Policy

	2009	2011	2013	2016	2020	2025
			(MW)			
Non Solar						
Wind	0	0	0	80	0	100
Biomass	0	20	357	686	568	149
Landfill Gas	-14	0	0	0	0	0
Total New non-Solar PV Advanced Energy Capacity	*-14*	*20*	*357*	*766*	*568*	*249*
Solar PV						
New Solar PV Capacity	0	0	0	0	0	0
Total New Advanced Energy Capacity	***-14***	***20***	***357***	***766***	***568***	***249***

Notes: These results reflect capacity additions due to the Ohio AEPS over the Reference Case in the presence of a carbon policy.

Table A2.3 Incremental New Advanced Energy Generation in the AEPS-Carbon Scenario

	2009	2011	2013	2016	2020	2025
	(GWh)					
Total AEPS Generation Standard	***-***	***2,738***	***5,201***	***7,864***	***12,559***	***17,807***
Non Solar						
Wind	288	288	288	538	538	754
Biomass	0	149	2,594	4,987	19,478	47,974
Landfill Gas	1,839	2,301	2,301	2,301	2,301	2,301
Solar Thermal	0	0	0	0	0	0
Non-Solar Advanced Energy Generation	*2,127*	*2,736*	*5,181*	*7,825*	*22,317*	*51,029*
Non-Solar PV Advanced Energy Generation Standard	*-*	*2,736*	*5,181*	*7,825*	*12,130*	*16,790*
Solar PV						
Total Solar PV Generation	0	2	21	40	429	1,017
Total Solar PV Generation Standard	*0*	*2*	*21*	*40*	*429*	*1,017*
Total AEPS Advanced Energy Generation)	***2,127***	***2,740***	***5,204***	***7,866***	***22,746***	***52,046***

Notes: These results reflect incremental advanced energy generation due to the AEPS relative to the Reference Case in the presence of a carbon policy. The generation and the generation standard numbers may slightly differ due to rounding.

Displaced Capacity and Changes in Generation Mix

Table A2.4 Potential Changes in Generation Mix Due to Ohio AEPS in the presence of a Carbon Policy

Fuel Type	2011	2013	2016	2020	2025
Changes in Generation as a percentage of fuel-specific Total Generation in the Reference Case					
Coal	ε %	-0.2%	-0.3%	-1.6%	-0.9
Natural Gas	-0.5%	0.3%	-1.3%	0.1%	6.7%
Transmission			**(GWh)**		
Changes in net exports of electric power to other regions	100	2,200	3,200	-600	-1,600
Changes in net exports of electric power, as a percentage of net exports to other regions in the Reference Case	0%	8%	1,067%	-2%	-2%

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Coal Production Impacts

Table A2.5 Impacts of Ohio AEPS on Ohio Coal Production in the Presence of a Carbon Policy

	2011	2013	2016	2020	2025
	(millions of short tons)				
Change in Ohio coal production	0	0	-0.17	-0.12	0.23
% change in Ohio coal production relative to the Reference Case	0%	0%	-0.5%	-0.2%	0. 3%

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases.

Electricity Price Impacts and RECs

Table A2.6 Annual Marginal Wholesale Electricity Price Impacts Due to Ohio AEPS in the Presence of a Carbon Policy

	2011	2013	2016	2020	2025
	(cents per kWh)				
Wholesale (energy plus capacity) electricity price impacts per kWh of electricity sold in Ohio (excluding REC value)	ε	0.01	0.11	-0.01	-0.03
REC value per kWh of electricity sold in Ohio	ε	0.01	0.05	0.04	0.13
Combined wholesale price and REC value impacts per kWh of electricity sold in Ohio	0.01	0.03	0.16	0.02	0.10

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Table A2.7 Annual REC Prices in the AEPS-Carbon Scenario

	2011	2013	2016	2020	2025
Non-Solar AEPS					
Non-solar REC prices ($/MWh)	2.67	4.05	11.32	0	0
Non-solar REC prices (cents/kWh)	0.27	0.41	1.13	0	0
Solar PV AEPS					
Solar PV REC prices ($/MWh)	174.1	227.6	195.4	174.9	278.1
Solar PV REC prices (cents/kWh)	17.4	22.8	19.5	17.5	27.8
REC Value (million U.S. 2003$)					
Total Non-solar	7.3	21.0	88.6	0	0
Total Solar PV	0.4	4.7	7.8	75.0	282.8
Total Ohio Advanced Energy	7.7	25.7	96.4	75.0	282.8
Average REC Value in the Retail Electricity Market (cents/kWh)					
REC Value per kWh of electricity sold in Ohio	ε	0.01	0.05	0.04	0.13

Notes: (1) ε is a small positive quantity less than the displayed significant digits.

Potential Air Emission Impacts

Table A2.8 Potential Changes in Emission Due to Ohio AEPS in the Presence of a Carbon Policy

Pollutant	2011	2013	2016	2020	2025
Incremental Emission Impacts					
Mercury (lbs)	25	25	-52	-17	56
NOx (Short tons)	-93	-374	-1,554	-599	1,089
SO_2 (Short tons)	-370	1575	-584	-2,238	3,319
Change in Emissions relative to the Reference Case					
Mercury	0.4%	-0.4%	-0.9%	-0.3%	1.4%
NOx	ε %	-0.1%	-0.7%	-0.3%	0.6%
SO_2	ε %	0.2%	-0.1%	-0.3%	0.6%

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Table A2.9 Changes in CO_2 Emissions Due to Ohio AEPS in the Presence of a Carbon Policy

Pollutant	2011	2013	2016	2020	2025
Net CO_2 impacts of Ohio AEPS	***(1,000 short tons of CO_2)***				
Ohio	-55	-520	-1,518	-1,263	367
U.S.	-84	-1,750	0	21	878
Change in CO_2 Emissions relative to the CO_2-Reference Case					
Ohio	- ε %	-0.1%	-0.5%	-0.4%	0.1%
U.S.	- ε %	- 0.1%	0%	ε %	ε %

Notes: (1) Negative numbers indicate decreases and positive numbers indicate increases, relative to the appropriate reference cases. (2) ε is a small positive quantity less than the displayed significant digits.

Appendix B. Modeling Framework

Integrated Planning Model® (IPM®)

The analysis underlying this report was performed using the Integrated Planning Model (IPM®), a sophisticated energy modeling system that simulates the deregulated wholesale market for electricity.

ICF's IPM® model has been developed and applied for over 30 years for a wide range of clients in the public and private sector. It has also been used extensively on behalf of utilities, the financial community and developers of generation assets to value assets and other transactions, to determine optimal resource plants, to evaluate environmental compliance strategies for electricity, as well as to generate forward price curves. IPM® is used by the U.S. Environmental Protection Agency (EPA) as well as other government and industry entities for the analysis of wholesale power markets, environmental policies and compliance decisions, most recently in analyzing the Clean Air Rules (including the Clean Air Interstate Rule, the Clean Air Mercury Rule, and the Clean Air Visibility Rule).

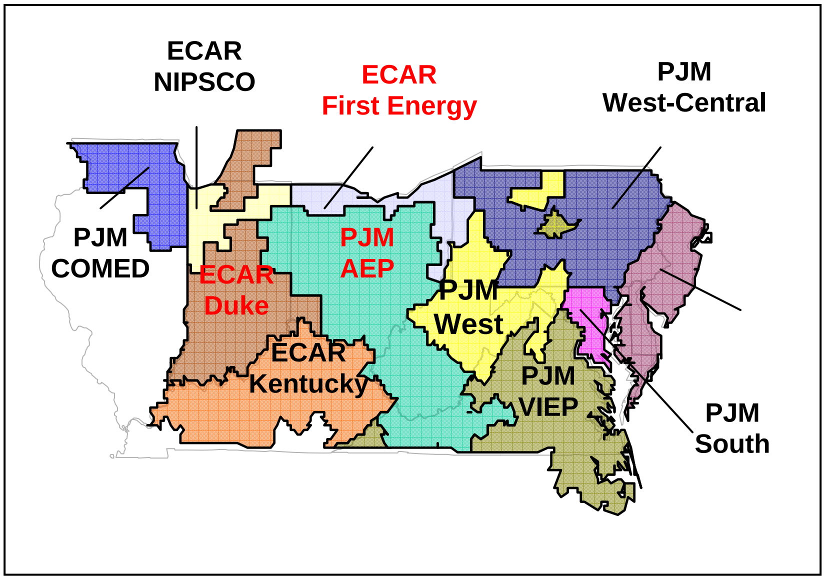
IPM® is a capacity planning and dispatch model for the electric power sector based upon engineering and economic fundamentals. IPM® simulates the operations of every power generation unit in the continental U.S. with regional detail. The model determines the least-cost method of meeting national level energy and peak demand requirements for a specific period of time.

IPM® is a production costing model that uses linear programming techniques to minimize the total, discounted net present value of the costs of meeting electricity demand, recognizing power system constraints, and environmental requirements over the entire planning horizon. In its solution, the model takes into consideration several operating regulatory, market and engineering constraints. These include emission limitations, transmission capabilities, fuel market constraints, regional reserve margin constraints, system operating constraints, and air and other regulatory requirements, including renewable or advanced energy portfolio standards. The objective function represents the summation of all the going-forward costs incurred by the electricity sector in meeting future demand. It does not include embedded (or sunk) costs such as carrying charges associated with existing units or fixed transmission system costs and general and administrative costs.

The assumed Ohio AEPS is explicitly modeled in IPM® as a minimum generation requirement from eligible technologies and resources that must be satisfied. The model also projects the Renewable Energy Credit (REC) prices, or the premium that is required to encourage the development of advanced energy resources that otherwise would not come into the market. The REC price thus represents the additional payment required, in addition to other energy and capacity payments, to generate the return on capital required to finance the investments to bring these resources onto the system. The REC value is determined by the market conditions, the level of demand for qualifying advanced energy resources (the AEPS level), and the characteristics of the eligible resources.

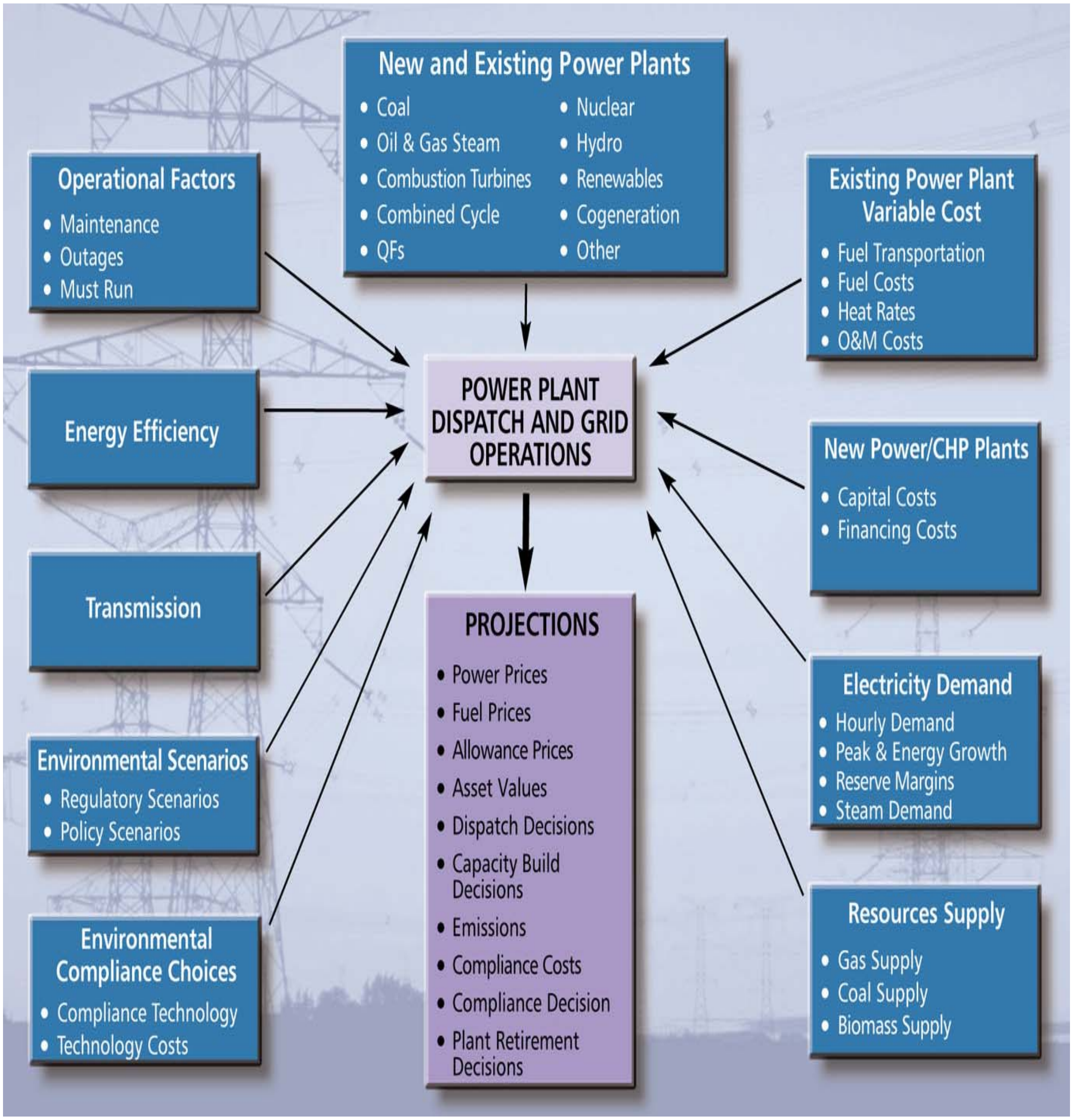
IPM® is a multi-region model. The model regions representing the U.S. power market in this study correspond broadly to regions and sub-regions that constitute the North American Electric Reliability Council (NERC) regions. The regions of particular interests for this study correspond to parts of the NERC region, Reliability First Corporation, comprising the portion of American Electric Power (AEP) service territory within PJM, ECAR service territory of First Energy and Duke Energy in and around the State of Ohio. In this study, Ohio is part of the three regions (see Figure B.1).

Figure B.1: Ohio Modeling Region and Adjoining Areas in IPM



<u>Note:</u> Ohio Modeling Region includes ECAR First Energy, PJM AEP and ECAR Duke.

Figure B.2: Modeling and Data Structure of IPM®



IPM® also takes into consideration the complex nature of emission regulations involving banking, trading and progressive flow control of emission allowances as well as command-and-control emission policies. This study incorporates existing SO_2, NO_x, mercury and CO_2 environmental regulations as per Federal and state regulations, which are implemented in IPM® via system-wide and unit-level emission constraints.

Federal regulations include the Title IV SO_2 Regulations, NO_X Regulations including NO_x SIP Call trading program, Title IV unit specific rate limits and Clean Air Act Reasonable Available Control Technology (RACT) requirements for controlling NOx emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Regions (OTR), and the Clean Air Rules, including the Clean Air Interstate Rule, the Clean Air Mercury Rule and the Clean Air Visibility Rule.

State-specific Environmental Regulations are included for Connecticut, Massachusetts, Missouri, New Hampshire, North Carolina, Texas, Wisconsin, Illinois, Maine, Minnesota, New York and Oregon, among others.

IPM includes fuels such as coal, natural gas, oil, nuclear fuel, and biomass for electric generation. Coal, natural gas and biomass price assumptions are represented via supply curves, whereas oil and nuclear fuel prices are exogenously determined and entered in the model during model set-up as a constant price point that is applicable at all levels of supply.

Model Projections

IPM® generates a range of operating, financial and environmental outputs. Key outputs of the IPM® model include:

- Generation – Generation quantities and dispatch are forecasted by IPM® based on the non-fixed economics of the units, given all constraints and other inputs.
- Capacity Mix – IPM® forecasts total capacity (in terms of MW) by plant type (e.g., combined cycle, combustion turbine, coal, etc.). Total capacity reports reflect existing capacity, new capacity already committed for construction, capacity chosen to be built by the model, and retirements made by the model on the basis of total going-forward economics. In addition, the output includes the level of capacity that is retrofitted with emission controls equipment.
- Capacity prices – Capacity price is one of the two components of the firm electricity price and is expressed in terms of $/kW.
- Wholesale electricity prices – This is expressed in terms of $/MWh, representing the marginal cost of production.
- Production Costs – All production costs derived in IPM® represent wholesale production costs. The model costs represent the “going-forward” costs and do not consider embedded (or sunk) costs such as carrying charges of existing units, or transmission and distribution charges and general and administrative costs. For each region and each run year, the model projects the total production costs such as variable O&M, fixed O&M costs, fuel costs and capital costs.
- Fuel consumption and prices – IPM® projects total fuel consumption by region and price. Prices for fuels such as coal and natural gas are endogenously determined by the model via supply curves – a set of price-quantity relationships that reflect the underlying fundamentals of the market. The model determines the optimal level of supply given demand, generation characteristics, emissions constraints, etc.

- Emissions (NO_x, SO_2, CO_2 and mercury) – IPM® forecasts the level of emissions for NO_x (in terms of thousands of tons), SO_2 (in terms of thousands of tons), CO_2 (in terms of millions of tons) and mercury (in terms of tons).
- Allowance prices – For each emission constraint that is modeled, allowance prices are calculated (as the shadow price of the pollutant constraint) for pollutants such as NO_x, SO_2 and mercury. The allowance prices are expressed either terms of $/Ton or $/lb.
- Retrofits – All existing units are given the option to retrofit with several pollution control technologies such as scrubbers, SCR, SNCR and ACI controls based on the applicability of the technology and the unit characteristics. Two states of retrofit are possible (e.g. Scrubber followed by SCR in a later year). Combinations of options are allowed in each year.

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Appendix C. Modeling Assumptions

This section provides details on the Scenario definitions and the assumptions adopted by The Cleveland Foundation for modeling the hypothetical scenarios of the Ohio AEPS using IPM®.

Overview of the Modeling Assumptions

- Introduction and Goals of the Analysis
- Study Overview
- AEPS and Carbon Policy Scenarios
- Air Emission and Renewable Generation Regulatory Scenarios
- General Assumptions
- Run Year Structure
- Power and Fuel Market Drivers
- Existing Capacity and Operation and Maintenance
- Mothballing, Retirements, and Nuclear Re-licensing and Uprate
- Financial Assumptions
- New Capacity: Conventional and Renewable Generating Technology
- Emission Rates and Pollution Control Technologies

Introduction and Goals of the Analysis

- The Cleveland Foundation has commissioned ICF to evaluate the energy market impacts of implementing an Advanced Energy Portfolio Standard scenario for Ohio.

- The analysis is driven by two key issues: the Assumptions used and the Scenarios examined.

- Both the technical and market assumptions that serve as inputs to the modeling analysis, as well as the policy scenarios evaluated, were developed by and are the sole responsibility of The Cleveland Foundation.

- ICF used the Integrated Planning Model® (IPM®) to analyze these policies based upon the assumptions developed by The Cleveland Foundation.

- ICF's proprietary databases and models, such as CoalDOM® for coal, are directly integrated into IPM®. Changing the assumptions underlying these data and models, while possible, were deemed to be beyond the scope of this project.

- This appendix provides an overview of the technical and market assumptions necessary for this analysis, with examples of data sets that The Cleveland Foundation has adopted for analyzing the impacts of AEPS to Ohio.

Study Overview: Modeling Scenarios & Study Results

- Four Scenarios are modeled for this study using IPM®.
- Two Reference Scenarios are modeled without an AEPS for Ohio, one under a no-carbon policy and one under a hypothetical carbon policy scenario.
- Two Policy Scenarios are modeled with the hypothetical Ohio AEPS, with and without carbon policy scenarios.
- The study results present estimated impacts of AEPS, which are calculated based on the differences between the policy and reference cases, with and without the corresponding carbon policy scenarios.

IPM® Generates Results for Specific Run Years

- Because of the level of detail represented within the national model, the number of IPM® *run years* was limited.
  - A run year is a calendar year chosen to represent a single year or a group of years that face similar electric and fuel market conditions and environmental policies.
- To understand the mid- to long-term impacts of the policies being examined here, the run year structure on this slide was used for this analysis. This structure is held constant throughout all runs in order to allow for direct comparison across scenarios.
- Results are reported for every run year from 2011 through 2025, which will cover the period 2010-2027.
- The run years map to the calendar years as shown below:

Calendar Year	2007	2008	2009	2010-2012	2013-2014	2015-2017	2018-2022	2023-2027	2028-2032
Run Year	2007	2008	2009	2011	2013	2016	2020	2025	2030

Air Regulatory Compliance in IPM®

- The national version of IPM® for the U.S. is specifically designed for simulating the effect of environmental regulations in the electricity sector.
- IPM® incorporates constraints on emissions of NO_X, SO_2, mercury, and CO_2 into its optimization process. Constraints can be specified on the basis of target-emission rates, cap-and-trade policies, emission taxes ($/ton of pollutant emitted) for individual generating units or for groups of units.
- Units subject to environmental regulatory constraints have the following compliance options, which the units can use in any combination.

- **Reduce Operation**. In order to comply with non-command-and-control polices, a unit can limit its operational hours.

- **Fuel Switch**. In the case of SO_2 regulations, coal and oil units can choose to burn more costly low sulfur fuels.

- **Retrofit Pollution Control Technology**. For the three current criteria pollutants (NO_X, SO_2, and mercury), a variety of retrofit technologies are available to reduce emissions. The cost and performance assumptions of all retrofit technologies are detailed in the *Pollution Control Technologies* section of this document.

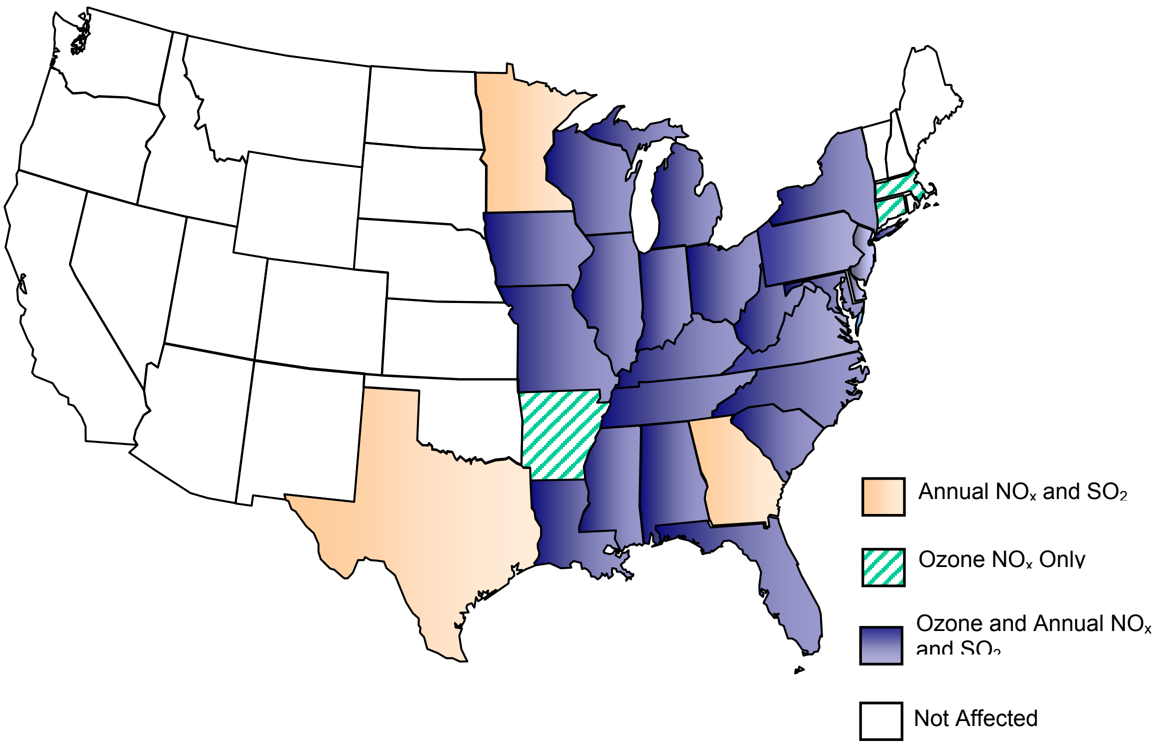
- **Retire**. If a unit cannot cover its operating costs going forward, it is allowed to retire.

Air Regulatory Scenario Assumptions

- For modeling purposes, the following regulatory scenario is assumed for the Reference Scenario:

  - EPA's Title IV SO2 Policy
  - SIP Call NOx Policy
  - EPA's Final Clean Air Interstate Rule (CAIR) for SO_2 and NO_X
  - EPA's Final Clean Air Mercury Rule (CAMR)
  - EPA's Final Clean Air Visibility Rule (CAVR)
  - The Regional Greenhouse Gas Initiative (RGGI)
  - State-specific Air Regulations
  - No National CO_2 regulatory policy was assumed.

CAIR Affected States



State-Specific Air Regulations

State	Notes	Status	NO_X	SO_2	Mercury	Carbon
Connecticut	Trading/facility	Promulgated on 12/28/2000	Non-Ozone Cap @ 0.15 lb/MMBtu in 2002 (Trading)	0.55 lb/MMBtu in 2002 0.33 lb/MMBtu in 2003 (Facility)	0.6lb/TBtu or 90% from input, whichever is least stringent in 2008 (Facility)	RGGI State
Illinois	Trading and Banking Allowed	Part of the State Implementation Plan	Annual Cap @ 0.25 lb/MMBtu in 2003 and 0.15 lb/MMBtu in 2004	NA	Governor Blagojevich proposal for 90% reduction in emissions by 2009; agreements with Ameren and Dynegy phase in requirements. All Ameren units to be controlled by 2012 and all Dynegy units by 2015.	
Maryland	Healthy Air Act impacts 7 largest coal plants: RP Smith, Brandon Shores, CP Crane, Wagner, Chalk Point, Morgantown, and Dickerson	Signed by Governor Ehrlich on April 6, 2006	20,216 tons by 2009 16,667 tons by 2012	48,618 tons by 2010 37,235 tons by 2013	80% from input by 2010 90% from input by 2013	Join RGGI by June 30, 2007
Massachusetts	All policies are facility specific (i.e. No trading)	Promulgated on 5/11/2001	1.5 lb/MWhr by 2004	6 lb/MWhr by 2006 3 lb/MWhr by 2008	85% from input by 10/1/2006; 95% from input by 10/1/2012	1800 lb/MWhr by 2006

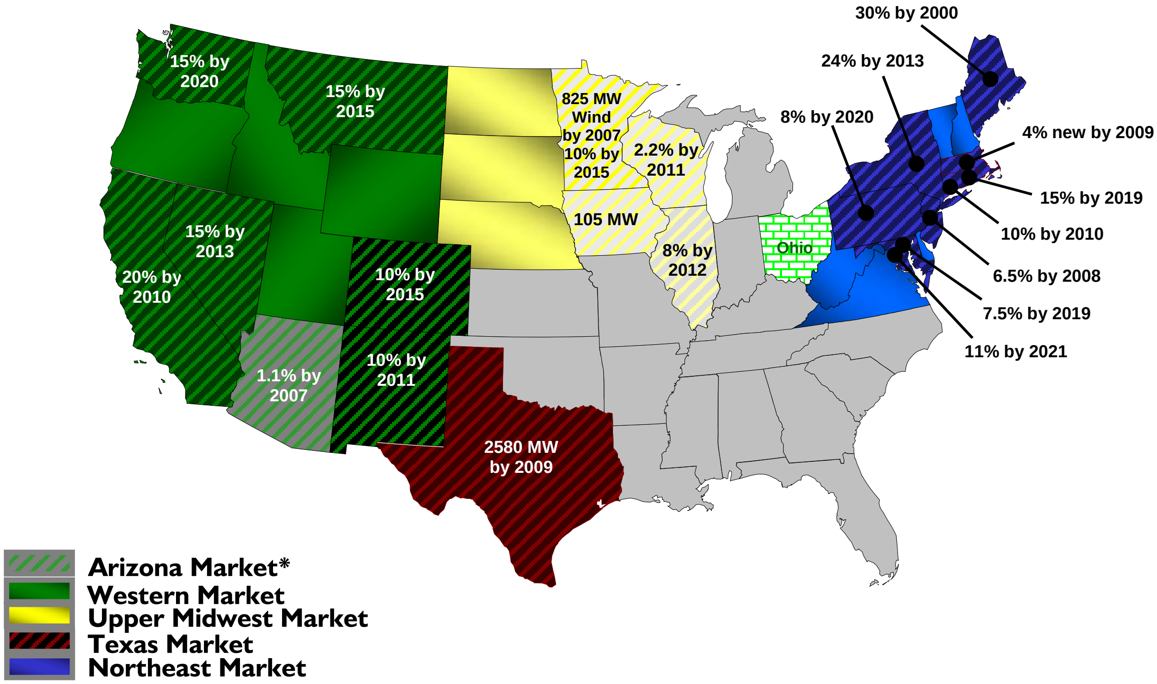
State-Specific Air Regulations (continued)

State	Notes	Status	NO_X	SO_2	Mercury	Carbon
Minnesota	Mercury Emissions Reduction Act of 2006 (HF 37120)	Signed by the Governor on 5/11/2006	NA	NA	90% reduction of annual emissions for existing EGUs GT 250 MW; required by 2009 for dry PM controlled units and 2014 for wet PM controlled units	NA
Missouri	Trading and Banking Allowed	Signed Into Law on 9/30/2000	Annual Cap @ 0.35 lb/MMBtu in certain counties and 0.25 lb/MMBtu in other counties starting in 2003	NA	NA	NA
New Hampshire	Trading and Banking Allowed	Passed House Committee on 11/28/2001	Annual Cap @ 1.5 lb/MWhr in 2006 3,644 tons	Annual Cap @ 3.0 lb/MWhr in 2006 7,289 tons	Merrimack forced to install FGD by 2013 to receive Hg co-benefit (SCR already installed)	5.426 million tons in 2006 to '10; Phase II cap recommended in 2004 RGGI State
New Jersey	MACT	Proposed 12/12/03	NA	NA	90% reduction from coal power plants in 2007	RGGI State
New York	Trading and Banking Allowed	Passed on 3/26/03	Non-Ozone Cap @ 0.15 lb/MMBtu in 2004 3:1 IP* 39,908 tons	25 % below Phase II starting 2005 50% starting 2008 3:1 IP*	NA	RGGI State

State-Specific Air Regulations (continued)

State	Notes	Status	NO_X	SO_2	Mercury	Carbon
North Carolina	In-state Trading Only	Signed Into Law on 6/20/02	56,000 ton annual cap (78% reduction) by 2009	250,000 ton annual cap (49% reduction) by 2009 and a 130,000 ton cap (73% reduction) by 2013	Draft rule adopts EPA model with provision for installation of control technology on all units by specified dates	NA
Texas	Senate Bill 7 and SIP Call Rules	Promulgated on 9/1/1999	**Houston 80% from 1997 by 2007 ***Dallas 45$ from 1997 by 2005 East TX @ ~0.16 lb/MMBtu in 2003	East TX @ 1.38 lb/MMBtu in 2003	EPA model rule	NA
Wisconsin	Standards for 8 WEPCO facilities	Environmental Cooperative Agreement	Annual Cap @ 0.25 lb/MMBtu in 2008 0.15 lb/MMBtu in '13	Annual Cap @ 0.70 lb/MMBtu in 2008 0.45 lb/MMBtu in '13	10% reduction from 1999 levels in 2008 50% reduction from 1999 levels in '13	NA

Regional Renewable Market Configuration



*Arizona may export but not import RECs to/from other states.

- 21 states have passed or are considering renewable portfolio standards (RPS) that require a certain percentage of electric sales within the state to be satisfied by certified renewable generation. The design of each state's RPS varies by the type of renewables allowed, the generation requirements and the geographic scope from which credits for renewable generation can be obtained.

- The map on the previous slide illustrates each state-level RPS and the regional configuration used to capture the impact of renewable energy credit (REC) trading within IPM®.

- This represents a generally more regionalized structure than some states currently allow for, but represents ICF's view that REC markets will tend to expand geographically.
  - States that have a diagonal line represent states that have an existing RPS policy.
  - States that are shaded the same color as an RPS state can generate RECs for use in related state markets.

- RPS programs incentivize generally low variable cost and low- or non-emitting generation and therefore tend to reduce pressure on emissions markets and spot prices, while demanding a premium due to their higher levelized costs. ("higher level costs" or just "higher costs")

- The Reference Scenario does not include the assumed Advanced Energy Portfolio Standard for Ohio.

Hypothetical Carbon Policy Scenario

Carbon Policy	Hypothetical Carbon Policy Scenario for The Cleveland Foundation's Ohio-AEPS Carbon Scenario
Starting Year	2015
Affected Units	All power generation units in U.S. Electric Power Sector > 25 MW
Type of Emission limit	Emission Level; Cap & Trade; Use of offsets from other sectors not allowed.
Emission limit for electric power sector	2015-2019: 2006 level; 2020-2024: 2000-level; 2025-2029: 1997-level; 2030-2035: 1990-level of total Electric power sector emissions. These represent the following reduction requirements, relative to the Reference Scenario projections: 16% in 2016; 26% in 2020; and 38% in 2025.
Electric power sector emission cap* [*million short tons of CO2 (MMTCO2)*]	2015-2019: 2650; 2020-2024: 2500; 2025-2029: 2275; 2030-2032: 1980** These represent reductions of 16% in 2016, 20% in 2020 and 27% in 2025 below the Reference Case Emissions Projections in 2016.

Notes: * These are approximate and only based on CO2 emissions; all other GHGs not included; These were based on the emissions from the entire sector, including from those that have less than 25 MW generating capacity, but their contribution is very small.
** 2032 is the final model year in the version of the IPM used for this analysis.

Electricity Demand and Reserve Margin Assumptions

- The demand forecast reflects the 2006 Annual Energy Outlook (AEO 2006) demand projections, developed by the U.S. Department of Energy's Energy Information Administration.
- For 2007, national energy demand is estimated to be 3.8 million GWh. It is assumed to grow at the average annual rate of approximately 1.8% per year.
- The AEO 2006 regional demand projections are adapted to the IPM® model structure.
- The IPM® model incorporates region-specific reserve margins. In the near term, they are in the range of 15% to 20%, which are representative of NERC's reserve margin requirements.

Natural Gas Demand and Supply

- The equilibrium marginal well-head natural gas prices are determined within IPM® based on the total demand for and supply of natural gas for the contiguous U.S. and based on a supply curve structure.

- Natural gas supply and markets for this analysis are based on AEO 2006. To maintain the endogenous forecasting ability, the AEO reference case natural gas prices are fitted to a supply curve structure.
  - The curves were developed based on analysis using ICF's North American Natural gas Assessment System (NANGAS®) model in conjunction with the electric sector gas demand generated in IPM®.

Biomass and Other Renewables

- Demand for biomass and other renewable generation is determined within IPM®, depending on the respective technology characteristics, air emission and regulatory requirements, renewable resource availability and power market economics.
- The following renewable technology options can be included in IPM®: Biomass, landfill gas, geothermal, wind, solar thermal, and solar photovoltaic.

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- Additional information on biomass and other renewable resources are included later in the "New Capacity" section of this document.

Existing Capacity

- IPM® contains a database of all existing grid-connected generators and boilers in the continental U.S., based on publicly available information from FERC, EIA, EPA, and other public sources.
- In order to limit model size, individual units may be aggregated into model plants based on a strict set of aggregation criteria.
- Existing capacity types include: coal steam, oil and gas steam, combined cycle, combustion turbine, hydro, nuclear, landfill gas, biomass, wind, geothermal, IGCC, and combined heat and power (CHP).
- Existing capacity is given the option to undertake multiple types of pollution control retrofits in order to comply with current and future air regulations. Specific retrofit assumptions are presented later in this document.
- Existing nuclear units may be offered the option to re-license and/or uprate. Assumptions for these options are presented later in this section.
- Existing capacity of hydro, IGCC, CHP and renewable units remain unchanged in the absence of scheduled retirement.

Operation and Maintenance (O&M)

- Generating units require regular operation and maintenance. Costs incurred for O&M purposes comprise a fixed and a variable component.
- Fixed O&M costs ($/kW) are incurred annually, irrespective of the operating hours of the generating units. These costs vary by the type of generating unit (such as a coal steam, oil and gas steam, combined cycle, nuclear, and combustion turbine), the age of the generating unit and the type of the pollution control technology the unit has.
- Variable O&M costs (c/kWh) are incurred in proportion to the operating hours of the generating units. These costs vary both by the type of generating unit and by the load segment (such as peak load and base load) in which the unit operates.
- The IPM® database embeds both the fixed and the variable O&M cost components for the generating units.

Potential Retirements and Mothballing

- In order to properly capture market exit behavior, IPM® incorporates endogenous retirement and mothballing decisions due to economic reasons.
- While retirement refers to permanently removing a generating unit from service, mothballing refers to temporarily removing a generating unit from service. During the mothballed years, the generating unit is not maintained and, therefore, the fixed operating and maintenance costs (that will otherwise be incurred if the unit is in service), are not incurred. The mothballed unit will incur additional costs when it returns to service.
- The mothballing option is provided for all Oil/Gas steam facilities.
- Similarly, retirement option is provided to all existing Coal, Nuclear, and Oil/Gas Steam units in the model.

Nuclear Units Will Have Option to Uprate

- All nuclear units have the option to renew their nuclear licenses at the end of the original 40-year operating period.
- All nuclear units also have the option to retire due to economic reasons from 2007 onwards.
- Existing nuclear units will have the option to invest in a capacity uprate on an economic basis as determined by the model.
- The uprate potential and the associated costs are based on EIA and industry publications.

New Capacity Additions – Firm Build Vs. Potential Build

- There are two types of new capacity additions implemented in IPM®: “Firm Build” and “Potential Build.”

- **Firm Build –** Firm build, short for firmly planned capacity additions, are plants currently under construction or expansion plans at existing sites.

  - From a modeling perspective, firm builds are treated as existing capacity that generally comes online in the next 1-3 years. Since firm build units are considered “done deals” in the model, they incur no capital costs in the optimization process. Their operating costs, however, are treated the same as any other unit.

  - Barring rare exceptions, only those plants that have begun construction as *firm* are included.

- **Potential Build -** IPM® adds capacity necessary to meet net peak demand and reliability/reserve requirements. The mix of new builds is endogenously determined based on the economics of the system and the costs of new capacity.

  - Potential build units are brought online where: (i) they are the least cost option for meeting demand given all costs and constraints over time; and (ii) their capital and operating costs are covered by energy and capacity revenues, assuming pre-specified financial hurdle rates.

New Fossil and Nuclear Cost and Performance Characteristics

- EIA’s AEO 2006 is the basis for the new capacity cost and performance assumptions for non-renewable resources.
  - Cost and performance values are provided for multiple years. These values are reflected in IPM® through the use of vintage-based technology options.

- These costs reflect those for a new unit in an area of average labor, materials and construction costs in the U.S.

- Capital costs include interest during construction based on EIA’s construction schedule. They do not include transmission interconnection adders or regional multipliers.

Potential Build Cost and Performance from EIA AEO 2006

	Combine Cycle	Simple Cycle Gas	Nuclear	Advanced Coal (IGCC)	Supercritical Coal
Construction Lead Times	1	1	6	5	5
2005					
Heat Rate (Btu/kWh)	6,577	8,920			
Total Plant Cost ($/kW)	485	304			
Interconnection Cost ($/kW)	64	64			
TPC + Interconnection + IDC ($/kW)	663	456			
Fixed O&M ($/kW-yr)	10	9			
Variable O&M ($/MWh)	0.70 – 1.28	2.18 – 8.93			
2010					
Heat Rate (Btu/kWh)	6,577	8,920		7,939	8,763
Total Plant Cost ($/kW)	485	304		1,351	1,174
Interconnection Cost ($/kW)	64	64		25	25
TPC + Interconnection + IDC ($/kW)	663	456		1,611	1,303
Fixed O&M ($/kW-yr)	10	9		24	24
Variable O&M ($/MWh)	0.70 – 1.28	2.18 – 8.93		2.00 - 10.17	3.00 - 15.10
2015					
Heat Rate (Btu/kWh)	6,403	8,612	10,400	7,477	8,661
Total Plant Cost ($/kW)	476	295	1,760	1,323	1,158
Interconnection Cost ($/kW)	64	64	100	25	25
TPC + Interconnection + IDC ($/kW)	651	445	2,637	1,638	1,286
Fixed O&M ($/kW-yr)	10	9	60	24	24
Variable O&M ($/MWh)	0.70 – 1.28	2.18 – 8.93	0.44	2.00 - 10.17	3.00 - 15.10
2020					
Heat Rate (Btu/kWh)	6,333	8,550	10,400	7,200	8,600
Total Plant Cost ($/kW)	453	247	1,681	1,278	1,141
Interconnection Cost ($/kW)	64	64	100	25	25
TPC + Interconnection + IDC ($/kW)	624	419	2,526	1,583	1,267
Fixed O&M ($/kW-yr)	10	9	60	24	24
Variable O&M ($/MWh)	0.70 – 1.28	2.18 – 8.93	0.44	2.00 - 10.17	3.00 - 15.10

Regional Cost Adjustments Applied to Potential Build Options

- Regional cost multipliers are applied to the capital costs to reflect regional differences in labor, material and construction costs.
- These multipliers are used that reflect consistent treatment of premiums across the U.S.
- IPM® database embeds these multipliers. Although these multipliers can be changed to reflect specific assumptions, for purposes of this study, however, the multipliers embedded within the IPM® database are used.

Renewable Cost and Performance Assumptions

- The capital cost assumptions for each renewable technology shown below are regionalized using economic multipliers that account for labor and equipment cost differences across the U.S. The capital costs are also adjusted to account for interconnection costs as well as interest during construction.

- Each of the cost and performance assumptions is derived from the assumptions used by DOE/EIA in their 2006 Annual Energy Outlook forecasts. Some of their assumptions have been modified slightly to match IPM®'s modeling structure and regions.

- For the Ohio region, the cost and performance assumptions for wind and solar photovoltaic technologies were developed by The Cleveland Foundation, which consulted with a number of parties familiar with renewable technologies and Ohio's renewable resources in developing these assumptions.

- Landfill gas resource assumptions are based on data provided from the EPA Landfill Methane Outreach Program.

- Wind resource assumptions for non-Ohio regions are based on data in the National Renewable Energy Laboratory's (NREL) WindDS model and are modified to fit the IPM® regional framework.

- Biomass resource assumptions are based on the EPA Base Case 2000 using IPM® (v2.1) documentation. *http://www.epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html#version2002* These assumptions were used in the subsequent model updates through v3.0.

- All of the technologies listed below are considered carbon-neutral and will not contribute emissions toward a carbon cap.

Wind Technology for the Ohio Region

- For this project, both onshore and offshore wind resources are included for Ohio and the associated modeling regions (including PJM-AEP, ECAR-First Energy, and ECAR-Duke).

- The new wind capacity that can be built in "any model run year" is restricted only by the availability of wind resources both for onshore and offshore.

- For other modeling regions, only onshore wind resources are included.

- "Onshore" wind comprises 4 wind resource classes: Class 3, 4, 5 & 6.
  - Each wind resource class has three cost classes: 1, 2, and 3.
  - Cost Class 1 corresponds to the Base Capital Cost, Cost Classes 2 and 3 represent 20% and 50% higher capital costs, respectively, over the capital cost for Cost Class 1.

Ohio's Offshore Wind Technology Assumptions

- "Offshore" wind comprises 2 wind resource classes: Class 5 and Class 6.
  - Each offshore wind resource class has two cost classes: 4 and 5.
  - Cost Classes 4 and 5 for the offshore wind represent 100% and 200% higher capital costs, respectively, over the capital cost for Cost Class 1 for Onshore wind.
  - The first online year for offshore wind to be a viable option is assumed to be 2015.
  - Lead construction time for offshore wind unit is assumed to be 4 years, which is one year more than the typical construction time for onshore wind unit.
  - The fixed O&M costs differ between onshore and offshore wind technology, but they are assumed to be the same for all classes of wind units within these two categories.
  - The average capacity factors / wind generation profiles for offshore wind units are assumed to be the same as those for the onshore wind units, for each wind resource class.

Technology Costs –Wind and Solar PV Power Plant Characteristics for Potential Units in the Ohio Region (2003$)

	Onshore Wind	Offshore Wind	Solar PV - Central Station	Solar PV - Residential
Construction Lead Times (years)	3	4	2	1
Average Unit Size	50 MW		5 MW	2 kW
Generating Capacity Limit	Permitted by Resource Availability		50 MW	None
Online Year	**2010**	**2015**	**2010**	**2010**
Total Plant Cost ($/kW)	1,036	2,072	3,757	6,771
Fixed O&M ($/kW-yr)	27	54	10	10
Variable O&M ($/MWh)	0	0	0	0
Average Capacity Factor	(b)	(b)	21%	18%
Online Year	**2020**	**2020**	**2020**	**2020**
Total Plant Cost ($/kW)	1,033	2,066	3,277	4,512
Fixed O&M ($/kW-yr)	27	27	10	10
Variable O&M ($/MWh)	0	0	0	0
Average Capacity Factor	(b)	(b)	21%	18%

Notes: Average capacity factor for wind varies by regional wind generation profiles and the wind resource availability, by class.
Source: The Cleveland Foundation, December 2006.

Technology Costs – Renewable Power Plant Characteristics for Other Potential Units (2003$)

	Wind: Step 1	Wind: Step 2	Wind: Step 3	Landfill Gas	Solar Thermal	Photovoltaic	Geothermal	Biomass
Construction Lead Times	3	3	3	3	3	2	4	4
2005								
Heat Rate (Btu/kWh)	N/A	N/A	N/A	13,648	N/A	N/A	N/A	
Total Plant Cost ($/kW)	1,049	1,259	1,574	1,443	2,899	4,404	1,966	
Interconnection Cost ($/kW)	82.1	82.1	82.1	54	54	54	60	
TPC + Interconnection Costs + IDC ($/kW)	1,253	1,485	1,834	1,657	3,269	4,766	2,320	
Fixed O&M ($/kW-yr)	27	27	27	101	50	10	105	
Variable O&M ($/MWh)	0.00	0.00	0.00	0.01	0.00	0.00	0.00	
Average Capacity Factor	32%	32%	32%	90%	33%	24%	86%	
2010								
Heat Rate (Btu/kWh)	N/A	N/A	N/A	13,648	N/A	N/A	N/A	8,911
Total Plant Cost ($/kW)	1,036	1,243	1,554	1,424	2,472	3,757	1,700	1,632
Interconnection Cost ($/kW)	82.1	82.1	82.1	54	54	54	60	100
TPC + Interconnection Costs + IDC ($/kW)	1,237	1,467	1,811	1,576	2,736	4,017	1,947	1,963
Fixed O&M ($/kW-yr)	27	27	27	104	50	10	73	52
Variable O&M ($/MWh)	0.00	0.00	0.00	0.01	0.00	0.00	0.00	2.00
Average Capacity Factor	35%	35%	35%	90%	33%	24%	95%	85%
2020								
Heat Rate (Btu/kWh)	N/A	N/A	N/A	13,648	N/A	N/A	N/A	8,911
Total Plant Cost ($/kW)	1,033	1,239	1,549	1,387	2,200	3,277	1,404	1,525
Interconnection Cost ($/kW)	82.1	82.1	82.1	54	54	54	60	100
TPC + Interconnection Costs + IDC ($/kW)	1,234	1,463	1,806	1,535	2,436	3,504	1,608	1,840
Fixed O&M ($/kW-yr)	27	27	27	104	50	10	73	52
Variable O&M ($/MWh)	0.00	0.00	0.00	0.01	0.00	0.00	0.00	2.00
Average Capacity Factor	37%	37%	37%	90%	33%	24%	95%	85%

Source: EIA's AEO 2006 assumptions.

Wind Technology Overnight Capital Costs (2003$/kW): Onshore and Offshore

Wind Class	Wind Resource Class 3	Wind Resource Class 4	Wind Resource Class 5	Wind Resource Class 6
2010 & 2015				
Cost Class 1 (Onshore only)	1,036	1,036	1,036	1,036
Cost Class 2 (Onshore only)	1,243	1,243	1,243	1,243
Cost Class 3 (Onshore only)	1,554	1,554	1,554	1,554
2015				
Cost Class 4 *(Offshore only)*			2,071	2,071
Cost Class 5 *(Offshore only)*			3,107	3,107
2020				
Cost Class 1 (Onshore only)	1,033	1,033	1,033	1,033
Cost Class 2 (Onshore only)	1,239	1,239	1,239	1,239
Cost Class 3 (Onshore only)	1,549	1,549	1,549	1,549
Cost Class 4 *(Offshore only)*			2,066	2,066
Cost Class 5 *(Offshore only)*			3,098	3,098

Source: The Cleveland Foundation, December 2006.

Ohio's Wind Generation

- Wind generation varies by region and by season based on wind resource class and wind generation profile.
- The table below shows the average capacity factor assumed for each wind resource class, by season.

Wind Resource Class	Average Summer CF	Average Winter CF
Wind Class 3	20%	28%
Wind Class 4	28%	38%
Wind Class 5	33%	44%
Wind Class 6	36%	47%

Source: The Cleveland Foundation, December 2006.

Ohio's Wind Resource Potential – Installed Electricity Generating Capacity (MW)

Wind Class	Wind Resource Class 3	Wind Resource Class 4	Wind Resource Class 5	Wind Resource Class 6
Onshore				
Cost Class 1	100	150	20	5
Cost Class 2	1,250	700	50	13
Cost Class 3	650	150	130	33
Offshore				
Cost Class 4			1,250	200
Cost Class 5			1,250	800

Source: The Cleveland Foundation, December 2006.

Ohio's Solar PV

- The potential for central station solar PV construction in Ohio is limited to 250 MW.
- The total new solar PV capacity that can be built in "any given year" is unrestricted.
- The construction lead time for residential solar PV is assumed to be 1 year, which is one-half of the time required to build central station solar PV.

- The fixed and variable O&M costs for residential solar PVs are assumed to be the same as those for central station PVs.

Unit Level Emission Rates in IPM®

- Air emissions arising from electric generating units vary by their type, their combustion thermal efficiency (reflected by their heat rates), their pollution control technology, and the type and the quantity of fuel they consume.

- All else equal, unit level emission rates of SO_2, mercury and CO_2 vary by the sulfur, mercury and carbon contents of the fuel consumed by the unit, respectively. However, NOx emission rates vary by unit type and its characteristics.

Overview of Pollution Control Technologies

- Within the IPM® framework, units affected by air emissions regulations can comply by fuel-switching, buying allowances if the policy is market-based, reducing dispatch, installing emissions control technologies, or shutting down (or retiring).

- IPM® can incorporate the most common existing control technologies, each of which impact the emissions rate for one or more regulated pollutants, SO_2, NOx, mercury, and in some cases CO_2. Emissions rates are calculated by applying emissions reduction factors to the input content of the fuel.

- IPM® has a detailed suite of pollution control retrofits that units can use, in addition to dispatch changes, fuel switching and reliance on allowance markets, to comply with air regulations.

- Announced pollution control retrofit installations are considered “firm” and are therefore, “hardwired” into the analysis.

- Since IPM® will retrofit units as it deems appropriate, given the market and air regulatory environment being analyzed; only those retrofits that are judged to be relatively certain are included in the analysis.

- The following slides give a detailed description of the pollution control technology cost and performance assumptions that are used in this study.

- The assumptions for the pollution control technology options are based on a combination of EIA’s and EPA’s assumptions.

Post-Combustion Retrofit Options for Coal Units

- Coal units are offered the retrofit options listed in the table below. However, no duplicate controls will be offered. For example, a unit with an existing SCR will not receive the option to install a SCR. Furthermore, units will not be able to install two controls from the same category.

- The retrofits listed in the table below can be installed individually or in combination with other retrofits.

NOx Controls	SO2 Controls	Hg Controls
SCR SNCR	Wet FGD	ACI ACI + Fabric Filter SCR + FGD (Bit.)

SCR Cost and Performance Assumptions for Coal Units (2003$)

Unit Size (MW)	300	500	700
Capital ($/kW)	112.8	98.6	89.4
Fixed O&M ($/kW-yr)	1.6	1.3	1.1
Variable O&M (mills/kWh)	1.6	1.6	1.6
NOx Removal	90%	90%	90%

- It is assumed that the combined FGD and SCR controls result in a 90% reduction (from input) in Hg emissions from bituminous coals.

SO_2 Control Assumptions for Coal Units (2003$)

Cost Type / Removal	LSFO Costs (Based on a 500 MW unit)
Capital ($/kW)	236.1
Fixed O&M ($/kW-yr)	9.16
Variable O&M (mills/kWh)	1.08
SO_2 Removal	95%

- SO_2 Control Notes
  - LSFO = Limestone Forced Oxidation, applied to boilers ≥ 100 MW
  - Option assumes a 2.1% capacity and heat rate penalty
  - SCR and scrubber combination is assumed to result in a 90% Hg removal (from input). With the scrubber alone, 34% Hg reduction co-benefit is assumed.

- LSFO
  - Capital = 5,232.8*(1/MW)^0.4986; Fixed O&M = 135.5*(1/MW)^0.4336; Variable O&M = 1.08

- These cost assumptions are based on a unit with 10,000 Btu/kWh heat rate and on the assumptions presented in the Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model.

CO_2 Emission Control Technology

- In the reference case, there is no carbon control technology.
- For purposes of analyzing the carbon policy scenario impacts, CO_2 capture and sequestration technology was included as an optional pollution control technology for new coal plants.
- New coal plants were given an option to take on CO_2 capture and sequestration technology when they are built.