BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)	Case No. 14-1297-EL-SSO

OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY'S MOTION TO TAKE ADMINISTRATIVE NOTICE OF CERTAIN DOCUMENTS

Pursuant to the ruling of the Attorney Examiners at hearing on October 29, 2015, Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, "the Companies") request that the Commission take administrative notice of Companies Exhibits 154 and 155, included as Attachments A and B to this Motion.

At hearing, the Environmental Law and Policy Center ("ELPC") marked as ELPC Exhibits 24, 25, and 26 certain excerpts from the Regulatory Impact Analyses ("RIAs") of the United States Environmental Protection Agency ("EPA") for the Clean Power Plan Final Rule ("CPP"), the Cross-State Air Pollution Rule ("CSAPR"), and the Final Mercury and Air Toxics Standards ("MATS"). Tr. Vol. XXXV at 7309:7-24. The Attorney Examiners took administrative notice of these exhibits, but did so subject to allowing the Companies the opportunity to move to take administrative notice of other excerpts from those RIAs. Tr. Vol.

XXXV at 7482:12-17.[1] Accordingly, the Companies respectfully request that the Commission take administrative notice of: (1) Companies Exhibit 154 which is Chapter 7 of the CSAPR RIA (Attachment A hereto); and (2) Companies Exhibit 155 which is Chapter 3 of the MATS RIA (Attachment B). By taking administrative notice of these documents, the Commission will have a more complete view of the types of analyses undertaken by EPA for those rules and standards.

[1] Specifically, the Attorney Examiner stated "At this time we are going to take administrative notice of ELPC 24, 25, and 26. Subject to if the companies desire to take further administrative notice of other excerpts from those documents, we will entertain that in a motion later." Tr. Vol. XXXV at 7482:12-17.

Date: November 10, 2015

Respectfully submitted,

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ATTORNEYS FOR OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY, AND THE TOLEDO EDISON COMPANY

CERTIFICATE OF SERVICE

I certify that the foregoing was filed electronically through the Docketing Information System of the Public Utilities Commission of Ohio on this 10th day of November, 2015. The PUCO's e-filing system will electronically serve notice of the filing of this document on the following parties:

> Association of Independent Colleges and Universities of Ohio, Buckeye Association Of School Administrators, Buckeye Wind LLC, Citizens Coalition, City Of Akron, City Of Cleveland, Constellation NewEnergy Inc., Council Of Smaller Enterprises, Direct Energy Services LLC, Duke Energy Ohio Inc., Dynegy Inc., Energy Professionals of Ohio, EnerNOC Inc., Environmental Law & Policy Center, Exelon Generation Company, LLC, Hardin Wind LLC, IBEW Local 245, IGS Energy, Industrial Energy Users Of Ohio, Kroger Co., Mid-Atlantic Renewable Energy Coalition, Monitoring Analytics LLC, MSC, Nextera Energy Resources, Northeast Ohio Public Energy Council, Northwest Ohio Aggregation Coalition, Nucor Steel Marion, Inc., Ohio Advanced Energy Economy, Ohio Association Of School Business, Ohio Consumers Counsel, Ohio Energy Group, Inc., Ohio Environmental Counsel, Ohio Hospital Association, Ohio Manufacturers' Association, Ohio Power Company, Ohio Partners For Affordable Energy, Ohio School Boards Association, Ohio Schools Council, PJM Power Providers Group, Power4Schools, Retail Energy Supply Association, Sierra Club, The Cleveland Municipal School District, The Electric Power Supply Association, Wal-Mart Stores East, LP, and Sam's East, Inc.

/s/ David A. Kutik
David A. Kutik

Attachment A

Regulatory Impact Analysis (RIA)
for the final Transport Rule
Docket ID No. EPA-HQ-OAR-2009-0491

Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States

U.S. EPA
Office of Air and Radiation

June 2011

COMPANIES
EXHIBIT 154

TRANSPORT RULE RIA – TABLE OF CONTENTS

Section Page

CHAPTER 7

COST, ECONOMIC, AND ENERGY IMPACTS

This chapter reports the cost, economic, and energy impact analysis performed for the Transport Rule. EPA used the Integrated Planning Model (IPM), developed by ICF Consulting, to conduct its analysis. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for SO_2 and NO_x (as well as other air pollutants) throughout the contiguous United States for the entire power system. Documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm, and updates specific to Transport Rule modeling are available in the document titled: "Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule," available on the website and in the docket.

7.1 Background

Over the last decade, EPA has on several occasions used IPM to consider control options for reducing power-sector SO_2 and NO_x for regional transport. The best known example of one of these occasions is the Clean Air Interstate Rule (CAIR), the regulation that the current rule will replace. , The example of CAIR along with the analysis of the final Transport Rule below provide context and suggest alternative approaches to the Transport Rule (see Keohane 2009, 34–35 and Wagner 2009, 59).

Many EPA analyses with IPM have focused on legislative changes with national programs, such as EPA's IPM analyses of the Clean Air Planning Act (S.843 in 108th Congress), the Clean Power Act (S.150 in 109th Congress), the Clear Skies Act of 2005 (S.131 in 109th Congress), the Clear Skies Act of 2003 (S.485 in 108th Congress), and the Clear Skies Manager's Mark (of S.131). These analyses are available at EPA's website: (www.epa.gov/airmarkets/progsregs/cair/multi.html). EPA's IPM analysis for CAIR is another example of how the model has been used in regulatory analysis of SO_2 and NO_X control strategies, in this case dealing with a regulatory approach focusing on the eastern US: (www.epa.gov/airmarkets/progsregs/epa-ipm/cair/index.html). EPA also analyzed several multi-pollutant reduction scenarios in July 2009 at the request of Senator Tom Carper to illustrate the costs and benefits of multiple levels of SO_2 and NO_X control in the power sector.

In addition, EPA conducted extensive state-by-state analysis of control levels and the associated emissions projections related to upwind pollution that crosses state borders and impacts a downwind state's air quality monitors for the Transport Rule. More details on this analysis can be found in the Significant Contribution and State Emissions Budgets TSD.

As discussed in section 6.5, this rule comes during a period when many new SO_2 and NO_x controls are being installed. Many are needed for compliance with NSR settlements and state rules, while others may have been planned as a result of CAIR. Because CAIR remains in effect until it is replaced, emission reductions continue in the eastern US.

As discussed in section 2.4, the base case in this RIA assumes that CAIR is not in effect, but does take into account emissions reductions associated with the implementation of all federal rules, state rules and statutes, and other binding, enforceable commitments finalized by December 1, 2010, that are applicable the power industry and which govern the installation and operation of SO_2 and NO_x emissions controls in the timeframe covered in the analysis.

To address air quality problems, improve public health and the environment, and to respond to the Court decision in North Carolina v. EPA, the Agency is finalizing the Transport Rule. The Transport Rule requires annual SO_2 and NO_x reductions in 23 states, and also requires ozone season NO_x reductions in 20 States.[53] Many of the Transport Rule states are affected by both the annual SO_2 and NO_x reduction requirements and the ozone season NO_x requirements.

[53] EPA is issuing a supplemental proposal to request comment on requiring ozone-season NO_X reductions in six additional states under the Transport Rule (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin). Reductions that would be required by the supplemental proposal are included in the cost and impacts estimates described in this chapter, and therefore are accounted for in the benefits estimate.

The rule affects roughly 3,700 fossil-fuel-fired units with a nameplate capacity greater than 25 MW located at nearly 1,100 facilities. These sources accounted for roughly 82 percent of nationwide SO_2 emissions and 67 percent of nationwide NO_x emissions in 2010 (see Table 7-1).

Table 7-1. Annual Emissions of SO_2 and NO_x in 2010 and Percentage of Emissions in the Transport Rule Affected Region (tons)

	SO_2	NO_X
Transport Rule Annual NO_X and SO_2 States	4,251,996	1,424,228
Nationwide (Contiguous 48 States)	5,165,954	2,136,612
Emissions of Transport Rule States as Percentage of Nationwide Emissions	82%	67%

Source: EPA emissions data from all reporting units.
Note: Transport Rule annual NO_X and SO_2 states include Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

For SO_2 and annual NO_x, EPA modeled control requirements beginning in 2012 for the 23 eastern states shown in blue and green in Figure 7-1 below. In 16 of those states (shown in green), more stringent SO_2 requirements begin in 2014.[54] For ozone-season NO_x, separate ozone-season requirements were applied to the 26 states shown in green and yellow in Figure 7-1. Many of the Transport Rule states are affected by both the annual SO_2 and NO_x reduction requirements and the ozone-season (May–September) NO_x requirements. Table 7-2 show the emission budgets allotted to each state. For further discussion about the scope and requirements of the Transport Rule, see the Transport Rule preamble or Chapter 2 of this RIA.

[54] These 16 states include: Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin

As previously stated, the emissions, cost, air quality, and benefits analyses done for the Transport Rule are from a modeling scenario that requires annual SO_2 and NO_x reductions in 23 states and ozone season NO_x requirements in 26 states (See Figure 7-1). This modeling differs from the final Transport Rule because it includes ozone season NO_X requirements for six states (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin) that the final Transport Rule does not cover. (As discussed in the preamble to the final rule, EPA is issuing a supplemental proposal to request comment on the inclusion of these six states). Results presented in this chapter reflect inclusion of these six states in the Transport Rule.

Figure 7-1. Transport Rule Covered States

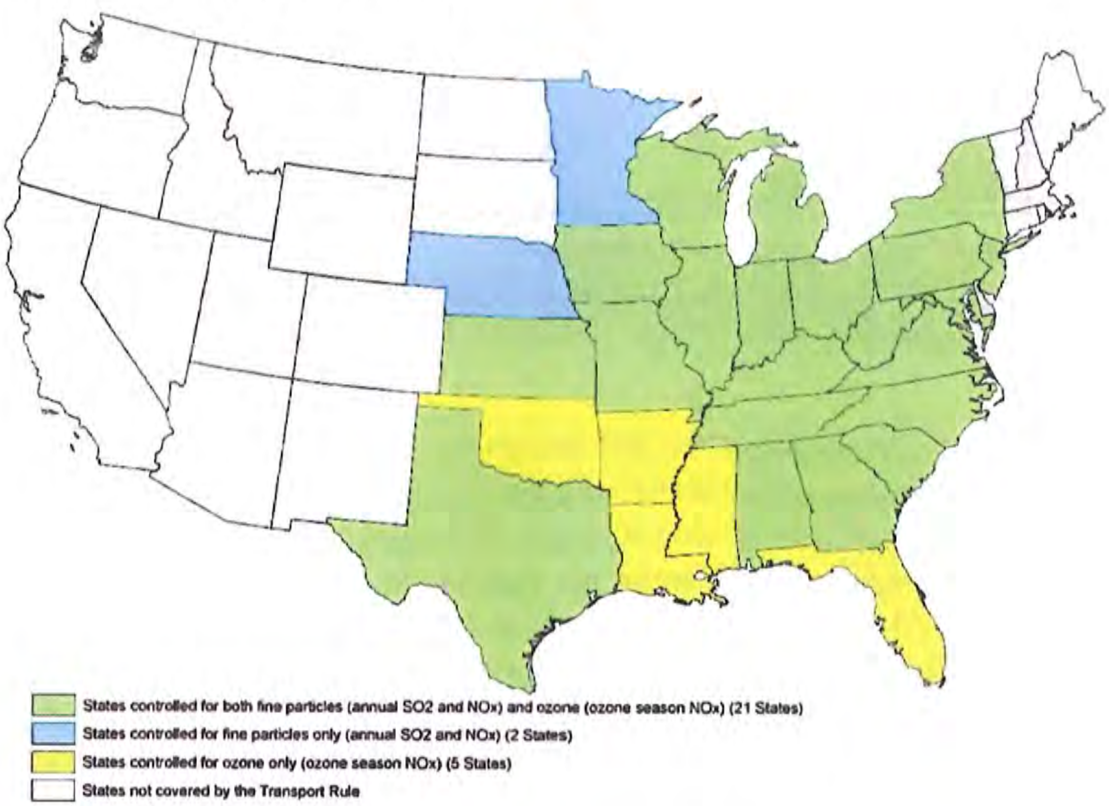


Table 7-2. Transport Rule Annual NO_x and SO_2 and NOx Ozone Season State Emission Budgets (tons)

	SO_2 Annual		NO_X Annual		NO_X Ozone Season	
	2012 and 2013	2014 and Later	2012 and 2013	2014 and Later	2012 and 2013	2014 and Later
Alabama	216,033	213,258	72,691	71,962	31,746	31,499
Arkansas	---	---	---	---	15,037	15,037
Florida	---	---	---	---	27,825	27,825
Georgia	158,527	95,231	62,010	40,540	27,944	18,279
Illinois	234,889	124,123	47,872	47,872	21,208	21,208
Indiana	285,424	161,111	109,726	108,424	46,876	46,175
Iowa	107,085	75,184	38,335	37,498	16,532*	16,207*
Kansas	41,528	41,528	30,714	25,560	13,536*	10,998*
Kentucky	232,662	106,284	85,086	77,238	36,167	32,674
Louisiana	---	---	---	---	13,432	13,432
Maryland	30,120	28,203	16,633	16,574	7,179	7,179
Michigan	229,303	143,995	60,193	57,812	25,752*	24,727*
Minnesota	41,981	41,981	29,572	29,572	---	---
Mississippi	---	---	---	---	10,160	10,160
Missouri	207,466	165,941	52,374	48,717	22,762*	21,073*
Nebraska	65,052	65,052	26,440	26,440	---	---
New Jersey	5,574	5,574	7,266	7,266	3,382	3,382

New York	27,325	18,585	17,543	17,543	8,331	8,331
North Carolina	136,881	57,620	50,587	41,553	22,168	18,455
Ohio	310,230	137,077	92,703	87,493	40,063	37,792
Oklahoma	---	---	---	---	21,835*	21,835*
Pennsylvania	278,651	112,021	119,986	119,194	52,201	51,912
South Carolina	88,620	88,620	32,498	32,498	13,909	13,909
Tennessee	148,150	58,833	35,703	19,337	14,908	8,016
Texas	243,954	243,954	133,595	133,595	63,043	63,043
Virginia	70,820	35,057	33,242	33,242	14,452	14,452
West Virginia	146,174	75,668	59,472	54,582	25,283	23,291
Wisconsin*	79,480	40,126	31,628	30,398	13,704	13,216
Total	3,301,008	2,128,264	609,435	574,107	1,245,869	1,164,910

*Note: as discussed in the preamble to the final rule, EPA is issuing a supplemental proposal to request comment on inclusion of these six states in the Ozone Season program.

Electricity demand is anticipated to grow by roughly 1 percent a year, and total electricity demand is projected to be 4,106 billion kWh by 2014. Table 7-3 shows current electricity generation alongside EPA's base case projections using EPA's IPM modeling. This rule relies on EIA's *Annual Energy Outlook for 2010*'s electric demand forecast for the US and employs a set of EPA assumptions regarding fuel supplies and the performance and cost of electric generation technologies as well as pollution controls. The base case assumption that CAIR is not in effect does have some modest influence on the fossil generation mix in this forecast, because CAIR had increased the costs of coal-fired generation relatively more than it had increased the costs to generation units that burned oil or natural gas.

Table 7-3. 2009 Electricity Net Generation and EPA Base Case Projections for 2012, 2014, 2020 and 2030 for the Contiguous 48 States (Billion kWh)

	Historical	Base Case			
	2009	2012	2014	2020	2030
Coal	1,754	1,958	2,017	2,037	2,071
Oil	29	0.09	0.10	0.14	0.19
Natural Gas	917	721	686	823	1,155
Nuclear	799	812	822	832	811
Hydroelectric	272	281	287	287	286
Non-hydro Renewables	143	233	250	288	328
Other	0	35	45	44	53
Total	**3,914**	**4,041**	**4,107**	**4,311**	**4,704**

Source: 2009 data from EIA Electric Power Annual 2009, Table 1.1 (adjusted to represent the Contiguous 48 States for consistency with projections, which are from the Integrated Planning Model run by EPA, 2011).

As noted above, IPM has been used for evaluating the economic and emission impacts of environmental policies for over a decade. The economic modeling presented in this chapter has been developed for specific analyses of the power sector. Thus, the model has been designed to reflect the industry as accurately as possible. As a result, EPA has used discount rates in IPM that are appropriate for the various types of investments and other costs that the power sector incurs (for example, the primary real discount rate is 5.5 % for pollution control retrofits). The discount rates used in IPM differ from discount rates used in other RIA analyses done for the Transport Rule, particularly the discount rates used in the benefits and macroeconomic analyses that are assumed to be social discount rates. (See Chapters 5 and 8 where social discount rates of 3% and 7% are used.) EPA uses the best available information from utilities, financial institutions, debt rating agencies, and government statistics as the basis for the discount rates used for power sector modeling in IPM. These discount rates have undergone review by the power sector and the Energy Information Administration.

More detail on IPM can be found in the model documentation, which provides additional information on the assumptions discussed here as well as all other assumptions and inputs to the model (http://www.epa.gov/airmarkets/progsregs/epa-ipm). Updates specific to Transport Rule modeling are also in the document titled: "Documentation

Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule."

7.2 Projected SO_2 and NO_x Emissions and Reductions

The Transport Rule achieves substantial emission reductions. EPA projects annual SO_2 emission reductions of 62 percent and annual NO_x emission reductions of 11 percent in the covered region by 2014 relative to the base case. Additionally, EPA projects ozone-season NO_x reductions of 11 percent in the Transport Rule region (see Table 7-4). There is also a small decrease in CO_2 emissions as a result of the Transport Rule.

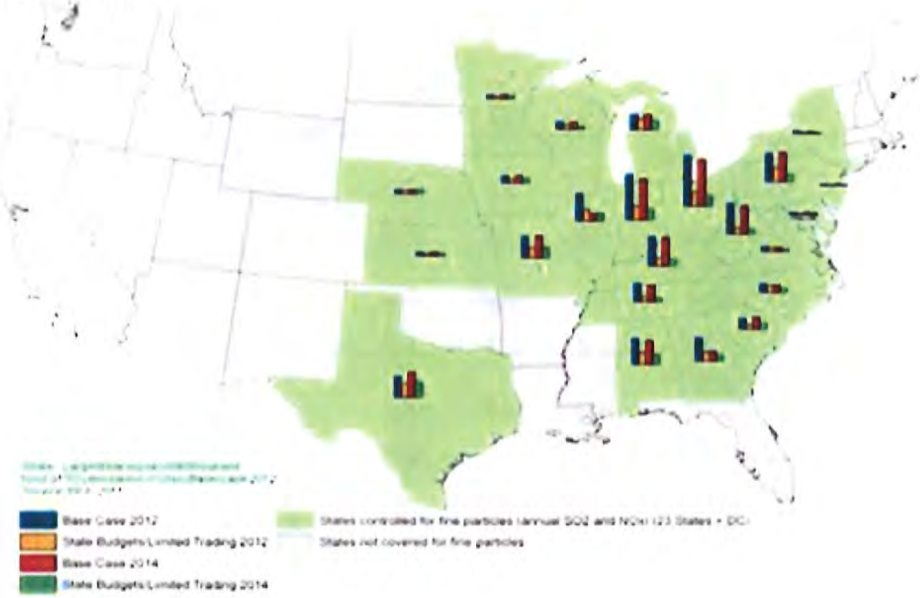
In Figure 7-2 below, the results of EPA modeling of the Transport Rule show that substantial SO_2 emission reductions occur in the Midwest and Mid-Atlantic regions of the country. Because banking of allowances is allowed to encourage early reductions, 2012 SO_2 reductions are greater overall than state budgets alone would require in that year. For many coal-fired electric generation units throughout the region it is economically advantageous to make extra emissions reductions in 2012 through fuel switching to have allowances to later use or sell in 2014 and beyond, when the Transport Rule becomes more stringent and when electric generators will also need to meet higher electric demand. Because of the banking provisions, the relative economics of making pollution reductions below the state assurance levels in 2012 versus making emissions reductions later favor doing more in 2012. Annual NO_x emissions reductions occur across the Transport Rule region (see Figure 7-3), and with the Transport Rule, ozone-season NO_x emission reductions are lower than they would have been with the NO_x SIP Call (base case) (see Figure 7-4).

Table 7-4. Projected Emissions of SO_2, NO_X, and CO_2 with the Base Case (No Further Controls) and with Transport Rule (Million Tons)

		2012				2014			
		Base	TR	Change	% Change	Base	TR	Change	% Change
SO_2 (Annual)	Contiguous 48 States	7.9	3.9	-3.9	-50%	7.2	3.4	-3.8	-53%
	TR States	7.0	3.0	-4.0	-57%	6.2	2.4	-3.9	-62%
NO_X (Annual)	Contiguous 48 States	2.1	2.0	-0.2	-7%	2.1	1.9	-0.2	-9%
	TR States	1.4	1.3	-0.1	-9%	1.4	1.2	-0.2	-11%
NO_X (Summer)	Contiguous 48 States	0.9	0.9	-0.1	-7%	0.9	0.8	-0.1	-9%
	TR States	0.7	0.6	-0.1	-9%	0.7	0.6	-0.1	-11%
CO_2 (Annual)	Contiguous 48 States	2,444	2,431	-12	-1%	2,482	2,454	-28	-1%
	TR States	1,769	1,749	-19	-1%	1,799	1,765	-24	-2%

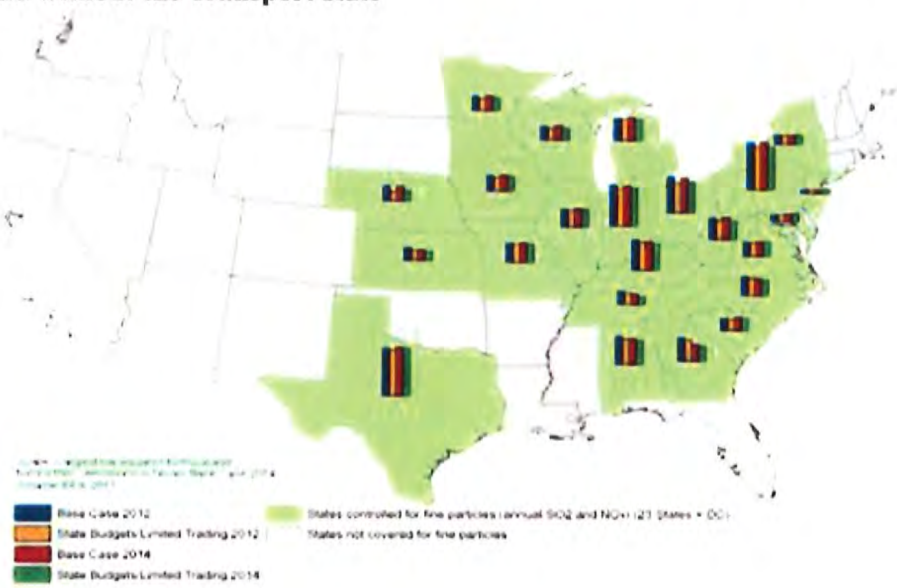
Note: Numbers may not add due to rounding. The emissions data presented here are EPA modeling results and the Transport Rule region includes states modeled for the annual SO_2 and NO_x requirements. "Summer" is from May 1–September 30, which is the ozone season. Base case includes Title IV Acid Rain Program, NO_x SIP Call, and state rules through December 1, 2010.
Source: Integrated Planning Model run by EPA, 2011.

Figure 7-2. SO_2 Emissions from the Power Sector in 2012 and 2014 with and without the Transport Rule



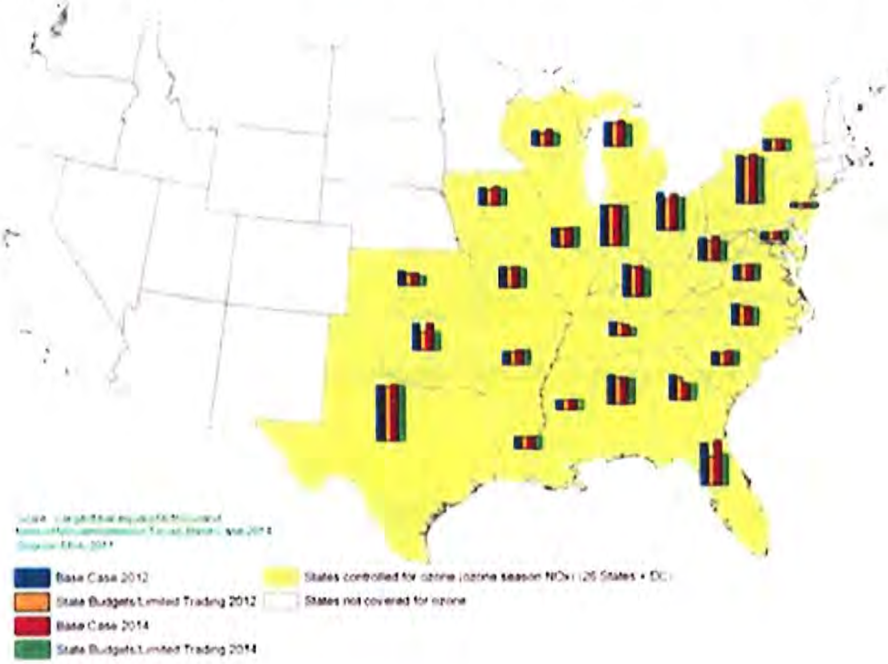
Source: EPA, IPM, 2011.

Figure 7-3. Annual NO_x Emissions from the Power Sector in 2012 and 2014 with and without the Transport Rule



Source: EPA, IPM, 2011.

Figure 7-4. Ozone-season NO_x Emissions from the Power Sector in 2012 and 2014 with and without Transport Rule



Source: EPA, IPM, 2011.

7.3 Overview of Costs and Other Impacts

As shown above in Figure 7-1, the Transport Rule directly affects 23 states in controlling pollution related to fine particles. For ozone, it also affects a distinct but overlapping group of 20[55] states. The states in one or both of these regions constitute most of the fossil-fuel-fired generation and capacity in the contiguous US, especially coal-fired (see Tables 7-5 and 7-6 below).

55 EPA is issuing a supplemental proposal to request comment on requiring ozone-season NO_X reductions in six additional states under the Transport Rule (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin).

Table 7-5. 2010 Fossil-fuel Generation Nationwide and in the Transport Region (Thousand Megawatthours)

	Contiguous US	Transport Rule Fine Particle Area	Transport Rule Ozone Area
Coal-fired	1,829,176	1,405,021	1,510,557
Oil-fired	13,680	5,955	12,080
Natural Gas-fired	894,598	409,534	633,636
Total	**3,954,846**	**2,598,207**	**2,989,910**

Source: EIA Electric Power Monthly with data for December 2010, Tables 1.6B, 1.7.B, 1.8.B, 1.10.B.

Table 7-6. Total Fossil-fuel Capacity Nationwide and in the Transport Region

	Contiguous US	Transport Rule Fine Particle Area	Transport Rule Ozone Area
Pulverized Coal	316	247	266
Combined Cycle	199	97	142
Other Oil/Gas	247	155	196
Total	**998**	**630**	**743**

Source: EPA's NEEDS v4.10.

While most impacts of the Transport Rule affect the covered states themselves, national impacts are important. Because the electric grid is connected irrespective of state boundaries, effects on electrical generation in one state have spillover effects in other states. Likewise, because the Transport Rule states have the vast majority of coal-fired generation, changes in their coal consumption and demand affect coal prices nationwide. In some cases, such as retail electricity prices and the operation of pollution controls, nationwide information would not be as relevant as regional totals. But for most of the following sections, nationwide projections provide a more complete picture of the Transport Rule's impacts.

7.4 Projected Compliance Costs

The power industry's "compliance costs" are the changes in electric power generation costs in the base case and alternative pollution control approaches that are examined in this chapter. In simple terms, these costs are the resource costs of what the power industry will directly expend to comply with EPA's requirements. This is not the "social cost" of the control approaches, which is separately explained and estimated in Chapter 8.

EPA projects that the annual incremental compliance costs of the Transport Rule are \$1.4 billion in 2012 and \$0.8 billion in 2014 (see Table 7-7 below). Another measure of this impact is the change in electricity prices (discussed in section 7.10). Costs generally are higher in 2012 than in 2014 because of reduced compliance flexibility in 2012, which is too soon for sources to retrofit new FGD and SCR that were not already planned.

Table 7-7. Annualized Compliance Cost of the Transport Rule

	2012	2014	2020
Annualized Compliance Cost (billions of 2007\$)	\$1.4	\$0.8	\$0.6

Note: Numbers rounded to the nearest hundred million for annualized cost.
Source: Integrated Planning Model run by EPA, 2011.

For context, the projected annualized compliance costs are a small fraction of the \$320 billion in expenditures EPA projects that the power sector will make in 2015 alone to generate, transmit, and distribute electricity to end-use consumers. For more information, see Chapter 6.

7.5 Projected Approaches to Emissions Reductions

Fossil-fuel-fired electric generating units in the Transport Region are projected to achieve NO_x and SO_2 emissions reductions through a combination of compliance options. These actions include sustained operation of existing controls originally built for CAIR, additional pollution control installations at coal-fired generators, coal switching (including blending of coals), and increased dispatch of more efficient units and lower-emitting generation technologies (e.g., some reduction of coal-fired generation with an increase of generation from natural gas). In addition, there will be some affected sources that find it more economic to retire rather than invest in new pollution control equipment. These facilities are generally amongst the oldest, least efficient power plants and typically run infrequently.

In 2012, a small shift from coal- and oil-fired generation to greater use of natural gas lowers emissions a small amount (see Table 7-11). NO_x emissions reductions largely stem from year-round operation of selective catalytic reduction (SCR) controls that would otherwise operate only during the ozone season (see Table 7-10). Additionally, a modest amount of NO_x reduction stems from new low- NO_x burners installations on older coal-fired units in states that were not in the original CAIR program but are covered in the ozone program of this rule. The Transport Rule's 2012 SO_2 emissions reductions largely result from sustained operation of all existing FGDs (scrubbers) in states controlled for PM, including those scrubbers built originally for CAIR and which may not have reason to operatein the absence of the Transport Rule. Other 2012 SO_2 reductions are achieved by units choosing to burn lower-sulfur coals as the least-cost compliance approach. In 2014, the Transport Rule drives the sector to install 5.9 GW of new FGD and 3 GW of new dry sorbent injection (DSI), which allow for significant additional SO_2 reductions in the Group 1 states.

Table 7-8 below provides a profile of sulfur contents in alternative coal supplies that offer substantial SO_2 reduction opportunities by increased blending or fuel-switching to cleaner grades. The table shows the degree to which uncontrolled coal-fired generation switches from relatively dirtier coals to relatively cleaner coals in response to imposition of the Transport Rule.

Table 7-8. Percent of Generation without SO_2 Controls by Coal Sulfur Content, 2014

	Very Low (<0.8 lb/mmBtu)	Low (0.81-1.2 lbs/mmBtu)	Low-Medium (1.21-1.66 lbs/mmBtu)	High-Medium (1.67-3.34 lb/mmBtu)	High (>3.35 lb/mmBtu)
Base Case	27%	37%	8%	15%	13%
Transport Rule	59%	28%	7%	3%	2%

Source: Integrated Planning Model run by EPA, 2011.

Table 7-9 shows total coal use among both controlled (i.e., operating either FGD or DSI) and uncontrolled EGUs in the states subject to the SO_2 program. The Transport Rule is associated with only a slight reduction (3% in 2014) in total coal use compared to the base case. More importantly, the table reinforces that the rule drives increased overall use of cleaner bituminous and subbituminous coals, especially very low sulfur subbituminous. This trend appears even when, as in this table, coal use at controlled units and very small units are included.

Table 7-9. Coal Use by Sulfur Category in the $PM_{2.5}$ Transport Region for the Base Case and Transport Rule* (million short tons)

		Lignite	Subbituminous			Bituminous				Total
			High sulfur	Low sulfur	Very low sulfur	High sulfur	High-medium sulfur	Low-medium sulfur	Low sulfur	
2012	Base	30	13	145	156	91	211	83	3	732
	TR	25	2	77	255	83	195	74	12	723
2014	Base	37	13	145	154	102	216	71	9	747
	TR	32	2	108	202	88	202	73	18	724

*These coal usage results are for the 23 states covered by the rule in the trading program to reduce SO_2 emissions.
Source: Integrated Planning Model run by EPA, 2011.

EPA does not project additional SO_2 control retrofits in 2012. For SO_2, EPA believes that to meet the 2012/2013 state assurance levels, compliance strategies would at most involve: operation of existing controls year-round, operation of controls that are scheduled to become operational by 2012, switching to a lower sulfur coal, and/or a general optimization of dispatch. EPA projects incremental FGD installations of about 5.9 GW by 2014 (see Table 7-10). These FGD retrofits are primarily wet scrubbers. Additionally, approximately 3 GW of DSI is projected to be installed by 2014. EPA believes that the January 1, 2014 starting date is as expeditious as practicable for sources to install such controls, and that retrofits of this limited extent can be realized in the 30 month interim between signature and the start of 2014. For further discussion, see discussion in section VII.C.2 of the preamble.

Table 7-10. Newly-Constructed Advanced SO_2 Control Retrofits on Coal-fired Generation by Technology Built with the Base Case and with the Transport Rule (GW) in 2014

	Base Case	Transport Rule	Incremental Retrofits
Wet FGD	4.6	10.3	5.7
Dry FGD	3.6	3.8	0.2
DSI	6.8	9.8	3.0

Note: FGD (Flue Gas Desulphurization) and DSI (Dry Sorbent Injection) are advanced SO_2 controls. Source: Integrated Planning Model run by EPA, 2011.

In 2014, the Transport Rule is also projected to result in the operation of an additional 25 GW of flue gas desulfurization (scrubbers) for SO_2 control and the year-round operation of an additional 5 GW of selective catalytic reduction technology (SCR) for NO_x control on existing coal-fired generation capacity (see "Existing Controls Induced to Operate" in Table 7-11). These controls were largely built for compliance with CAIR and are thus assumed not to operate in the base case.

Table 7-11. Coal-fired Capacity Operating Advanced Pollution Controls with the Transport Rule, 2014 (GW)

	Existing Controls Induced to Operate	Newly-Built Controls	Total Operational Controls
FGD	25	6	209
DSI	0	3	10
SCR	5	0	146

Note: FGD (Flue Gas Desulphurization) and DSI (Dry Sorbent Injection) are advanced SO_2 controls. SCR (Selective Catalytic Reduction) is an advanced NO_X control. Source: Integrated Planning Model run by EPA, 2011.

Projected operation of advanced pollution controls accounts for the vast majority of the NO_x reductions, while for SO_2 the reductions from the FGD and DSI controls are also supplemented by the continued and expanded use of relatively cleaner coals at uncontrolled units.

7.6 Projected Allowance Prices

Table 7-12 shows the projected allowance prices for the four trading programs under the Transport Rule in 2012 and 2014. These are the marginal emission reduction costs (i.e., the cost of reducing the last ton of a pollutant subject to the Transport Rule budgets) that EPA projected using the Integrated Planning Model (IPM) to analyze the final rule's remedy, in those states where the variability limits do not bind (in states where the variability limits bind, the marginal cost of emission reductions is higher than the allowance price). Under the trading programs, the marginal emission reduction costs inform the market-clearing price to emit that balances the supply of and demand for allowances under the Transport Rule programs.

The projected allowance prices differ from the cost-effective thresholds that were the original basis of the state budgets because they reflect the ability of the electricity sector to use the trading program flexibilities to achieve the aggregate required cost-effective emission reductions at minimized marginal costs. Most notably, banking allows entities to make emission reductions beyond what is needed in early years (accelerating environmental improvements) and smooth the trajectory of emission reductions in later years to minimize cost.

EPA believes that these projected marginal costs under the Transport Rule programs can inform allowance price discovery as program participants seek cost-effective reductions at individual units and in the compliance marketplace.

Table 7-12. Projected allowance prices for the four Transport Rule programs in 2012 and 2014 (2007$)

	Emission Allowance Prices ($/Ton)	
	2012	**2014**
Annual SO2 Group 1 Trading Program	1,000	1,100
Annual SO2 Group 2 Trading Program	600	700
Annual NOx Trading Program	500	600
Ozone Season NOx Trading Program	1,300	1,500

Note: EPA has provided projections rounded to the nearest hundred dollars because the model's point estimates do not reflect the price-discovery process of real-world markets that do not feature the same perfect information as in IPM.

7.7 Projected Generation Mix

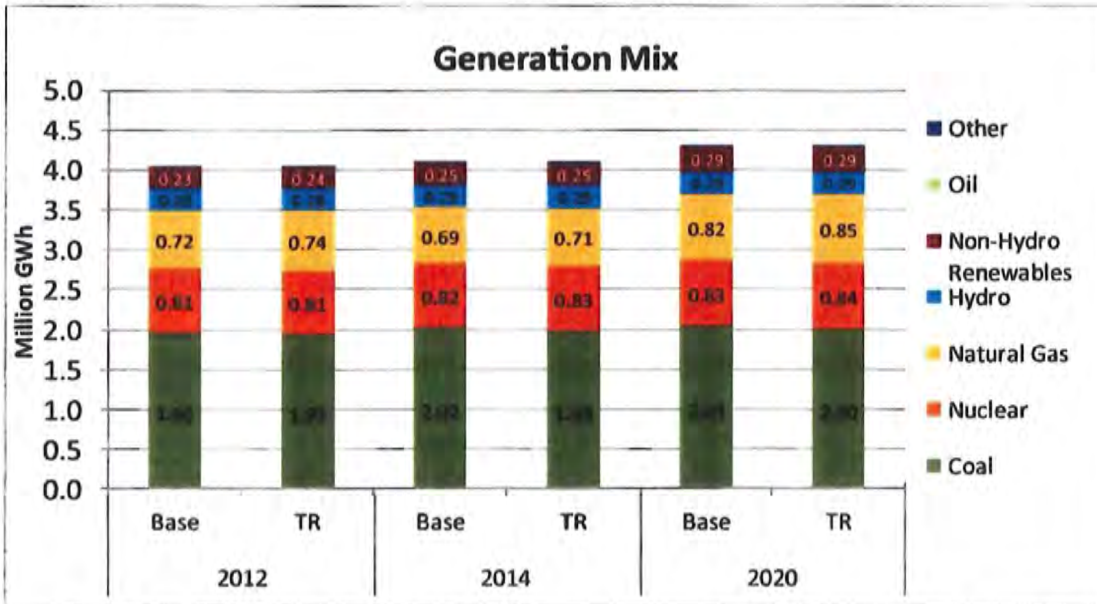
Table 7-13 and Figure 7-5 show the generation mix with the Transport Rule. Coal-fired generation and natural-gas-fired generation are projected to remain relatively unchanged because of the phased-in nature of the Transport Rule, which allows industry the appropriate amount of time to install the necessary pollution controls. Additionally, the operating costs of complying coal-fired units are not so affected as to result in major changes in the electricity generation mix. Both the base case and the Transport Rule case show shifts away from oil and natural gas generation and toward increased coal generation between 2012 and 2014.

Table 7-13. Generation Mix with the Base Case (No Further Controls) and with Transport Rule, Contiguous US (Thousand GWh)

	2009	2012				2014			
	Historical	Base	TR	Change from Base	Percent Change	Base	TR	Change from Base	Percent Change
Coal	1,754	1,958	1,935	-23	-1.2%	2,017	1,978	-39	-1.9%
Oil	29	0.09	0.09	0.00	-2.2%	0.10	0.11	0.01	5.8%
Natural Gas	917	721	739	18	2.5%	686	714	28	4.1%
Nuclear	799	812	812	0	0.0%	822	829	7	0.8%
Hydroelectric	272	281	282	1	0.2%	287	286	-1	-0.4%
Non-hydro Renewables	143	233	239	6	2.7%	250	250	1	0.2%
Other	0	35	35	0.0	0.0%	45	45	0.6	1.3%
Total	**3,914**	**4,041**	**4,043**	**2**	**0.0%**	**4,107**	**4,102**	**-4**	**-0.1%**

Note: Numbers may not add due to rounding.
Source: 2009 data from EIA Electric Power Annual 2009, Table 2.1 and Net Generation by State by Type of Producer by Energy Source (EIA-906); 2012 and 2014 projections are from the Integrated Planning Model run by EPA, 2011.

Figure 7-5. Generation Mix with the Base Case (No Further Controls) and with Transport Rule



Source: Integrated Planning Model run by EPA, 2011.

Relative to the base case, about 4.8 GW of coal-fired capacity is projected to be uneconomic to maintain (less than 2 percent of all coal-fired capacity in the Transport Rule states, or about 1% of all capacity nationally) by 2014. Notably, about 3 GW of capacity would have closed by 2014 in the base case without the Transport Rule (for a total of 7.8 GW of retirement in 2014 due to economic conditions and the Transport Rule) . Uneconomic units, for the most part, are small and infrequently used generating units that are dispersed throughout the states covered in the Transport Rule. In practice, units projected to be uneconomic to maintain may be "mothballed," retired, or kept in service to ensure transmission reliability in certain parts of the grid. EPA modeling is unable to distinguish between these potential outcomes. IPM can only predict that specific generating units are uneconomic to maintain, based on their fuel, operating and fixed costs, and whether they are needed to meet both demand and reliability reserve requirements.

7.8 Projected Capacity Additions

In addition, EPA projects that most future growth in electric demand will be met with new natural gas-fired capacity (see Table 7-14) in both the base and Transport Rule scenarios.

Table 7-14. Total Generation Capacity by 2014 (GW)

	2010	Base	TR	Change
Pulverized Coal	317	312	307	-5
Natural Gas Combined Cycle	201	205	205	0
Other Oil/Gas	253	232	233	0
Non-Hydro Renewables	31	70	70	0
Hydro	99	99	99	0
Nuclear	102	103	104	1
Other	5	81	85	4
Total	1,009	1,103	1,103	0

Source: 2010 data from EPA's NEEDS v4.10. Projections from Integrated Planning Model run by EPA.
Note: "Renewables" include biomass, geothermal, solar, and wind electric generation capacity.

7.9 Projected Coal Production for the Electric Power Sector

Coal production for electricity generation is expected to increase relative to current levels, with or without the Transport Rule (see Table 7-15). Under the Transport Rule, EPA projects coal production for use by the power sector will increase above 2009 levels by 21 million tons in 2012 and by a further 14 million tons in 2014, as opposed to 30 million tons in 2012 and a further 26 million tons in 2014 without the Transport Rule in place.

The Transport Rule will encourage the installation of new controls and operation of existing pollution controls for SO_2 and NO_x removal. Many of these pollution controls can achieve SO_2 removal rates of 95 percent or greater, which allows industry to rely more heavily on local bituminous coal in the eastern and central parts of the country that has a higher sulfur content and is less expensive to transport than western subbituminous coal. Note, for example, the projected increase in Appalachian coal production under the Transport

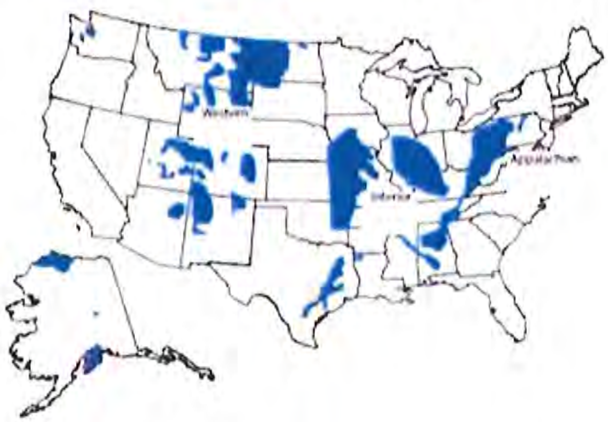
Rule in 2014, which contrasts with the projected 11 million ton decrease over that time in the absence of the rule. Production of low-sulfur western coal also increases as a result of the Transport Rule in both 2012 and 2014, as some units pursue fuel-switching to lower-sulfur coals to achieve emission reductions. Notwithstanding the Transport Rule, coal production in the interior region is still projected to increase more than 60% above 2009 levels by 2014.

Table 7-15. Coal Production for the Electric Power Sector with the Base Case (No Further Controls) and with the Transport Rule (Million Tons)

Supply Area	2009 Historical	2012 Base	2012 TR	2012 Change from Base	2014 Base	2014 TR	2014 Change from Base
Appalachia	246	193	184	-9	182	186	4
Interior	129	209	189	-20	238	210	-27
West	553	544	565	21	554	556	3
Waste Coal	14	14	14	0	14	14	0
Imports	19	31	31	0	30	30	0
Total	961	991	983	-8	1,017	996	-21

Source: Production: U.S. Energy Information Administration (EIA data), Coal Distribution -- Annual (Final), web site http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/a_distributions.html (posted February 18, 2011); Waste Coal: U.S. EIA, Monthly Energy Review, January 2011 Edition, Table 6.1 Coal Overview, web site http://www.eia.doe.gov/emeu/mer/coal.html (posted January 31, 2011). Imports: U.S. Energy Information Administration (EIA) and U.S. Census. All projections from Integrated Planning Model run by EPA, 2011.

Figure 7-6. Total Coal Production by Coal-Producing Region, 2007 (Million Short Tons)



Note: Regional totals do not include refuse recovery
Source: EIA Annual Coal Report, 2007

7.10 Projected Retail Electricity Prices

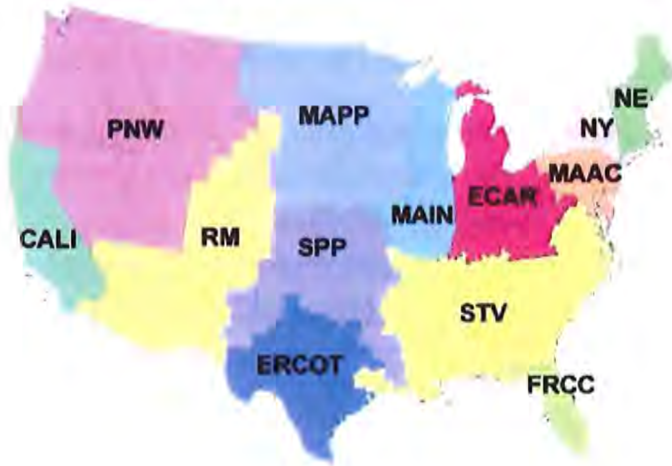
Retail electricity prices for the Transport Rule region are projected to increase a small amount with the Transport Rule (see Table 7-16). Regional retail electricity prices in the eastern half of the country are projected to range from 0.1 to 3 percent higher with the Transport Rule in 2014. By 2014, retail electricity prices in the regions directly affected by the Transport Rule, on average, are projected to be roughly 0.8 percent higher with the Transport Rule.

Table 7-16. Projected Regional Retail Electricity Prices with the Base Case (No Further Controls) and with Transport Rule (2007 cents/kWh)

	Base			Transport Rule			Percent Change		
	2012	2014	2020	2012	2014	2020	2012	2014	2020
ECAR	7.4	7.9	8.1	7.7	8.2	8.3	3.0%	3.1%	2.9%
ERCOT	7.8	8.8	8.7	8.1	8.9	8.8	3.4%	0.3%	1.9%
MAAC	8.4	9.4	10.3	8.7	9.5	10.4	4.0%	1.4%	1.2%
MAIN	7.3	7.9	8.4	7.5	8.1	8.4	2.0%	1.7%	0.9%
MAPP	7.8	8.0	7.9	7.8	8.1	7.9	0.4%	0.8%	0.3%
NY	12.5	13.7	13.3	12.8	13.7	13.4	2.5%	0.4%	0.4%
NE	11.4	12.3	11.8	11.7	12.3	11.9	1.8%	-0.1%	0.6%
FRCC	9.5	10.2	9.7	9.6	10.2	9.8	1.1%	-0.2%	0.4%
STV	7.7	7.9	7.8	7.8	7.9	7.8	0.9%	0.5%	0.4%
SPP	7.4	7.6	7.4	7.4	7.6	7.4	0.8%	0.1%	-0.1%
PNW	6.9	7.1	6.9	6.9	7.1	6.9	0.5%	0.0%	0.0%
RM	8.6	9.1	9.4	8.7	9.2	9.4	0.7%	0.2%	0.3%
CALI	12.7	13.0	12.5	12.9	13.0	12.5	0.8%	0.0%	0.2%
TR Region Average	8.5	9.2	9.2	8.7	9.3	9.3	2.2%	0.8%	1.0%
Contiguous U.S. Average	8.5	9.0	8.9	8.6	9.0	9.0	1.7%	0.8%	0.9%

Source: EPA's Retail Electricity Price Model.

Figure 7-7. Retail Price Model Regions



7.11 Projected Fuel Price Impacts

The impacts of the Transport Rule on coal prices and natural gas prices are shown below in Tables 7-17 and 7-18. Overall, the projected average coal price decrease is related to the small decrease in projected coal demand. Projected gas price changes are directly related to the projected increase in natural gas consumption under the Transport Rule.

IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply of and demand in competitive markets for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is not a forecast of natural gas prices incurred by *end-use consumers* at any particular point in time. The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and even sees major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs; however, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts. IPM assumes these longer-term price arrangements take place "outside of the model" and on top of the "real-time" shorter-term price variation necessary to align supply and demand. Therefore, the model's natural gas price projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the time period 2012 to 2030.

For this analysis, in order to represent a natural gas price evolution that end-use consumers can anticipate under retail rate regulation and/or typical hedging behavior, EPA is displaying the weighted average of IPM's natural gas price projections for the 2012-2030 time horizon (see Table 7-18). In that framework, consumer natural gas price impacts are anticipated to range from 0.2% to 0.3% based on consumer class in response to the Transport Rule.

Table 7-17. Average Minemouth and Delivered Coal Prices with the Base Case and with the Transport Rule (2007$/MMBtu)

		2012			2014		
	2007	Base	TR	Percent Change from Base	Base	TR	Percent Change from Base
Minemouth	1.27	1.35	1.29	-4.3%	1.37	1.35	-1.7%
Delivered	1.76	2.08	2.05	-1.4%	2.12	2.10	-0.9%

Source: Historical data from EIA AEO 2010 Reference Case Table 15 (Coal Supply, Distribution, and Prices); projections from the Integrated Planning Model run by EPA, 2011.

Table 7-18. 2012-2030 Weighted Average Henry Hub and Delivered Natural Gas Prices with the Base Case and with the Transport Rule (2007$/MMBtu)

	Base	TR	Percent Change from Base
Henry Hub	5.32	5.34	0.4%
Delivered - Electric Power	5.60	5.62	0.3%
Delivered - Residential	10.97	10.99	0.2%

Source: Projections from the Integrated Planning Model run by EPA (2011) adjusted to Henry Hub prices using historical data from EIA AEO 2011 reference case to derive residential prices.

7.12 Key Differences in EPA Model Runs for Transport Rule Modeling Geography

As previously stated, the emissions, cost, air quality, and benefits analyses done for the Transport Rule are from a modeling scenario that requires annual SO_2 and NO_x reductions in 23 states and ozone season NO_x requirements in 26 states (See Figure 7-1). This modeling differs from the final Transport Rule because it includes ozone season NO_X requirements for six states (Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin) that the final Transport Rule does not cover. (As discussed in the preamble to the final rule, EPA is issuing a supplemental proposal to request comment on inclusion of these six states).

7.13 Projected Primary PM Emissions from Power Plants

IPM does not endogenously model primary PM emissions from power plants. These emissions are calculated as a function of IPM outputs, emission factors and control configuration. IPM-projected fuel use (heat input) is multiplied by PM emission factors (based in part on the presence of PM-relevant pollution control devices) to determine PM emissions. Primary PM emissions are calculated by adding the filterable PM and condensable PM emissions.

Filterable PM emissions for each unit are based on historical information regarding existing emissions controls and types of fuel burned and ash content of the fuel burned, as well as the projected emission controls (e.g., scrubbers and fabric filters).

Condensable PM emissions are based on plant type, sulfur content of the fuel, and SO_2 and PM control configurations. Although EPA's analysis is based on the best available emission factors, these emission factors do not account for the potential changes in condensable PM emissions due to the installation and operation of SCRs. The formation of additional condensable PM (in the form of SO_3 and H_2SO_4) in units with SCRs depends on a number of factors, including coal sulfur content, combustion conditions and characteristics of the catalyst used in the SCR, and is likely to vary widely from unit to unit. SCRs are generally designed and operated to minimize increases in condensable PM. This limitation means that IPM post-processing is potentially underestimating condensable PM emissions for units with SCRs. In contrast, it is possible that IPM post-processing overestimates condensable PM emissions in a case where the unit is combusting a low-sulfur coal in the presence of a scrubber.

EPA plans to continue improving and updating the PM emission factors and calculation methodologies. For a more complete description of the methodologies used to post-process PM emissions from IPM, see "IPM ORL File Generation Methodology" (March, 2011).

7.14 Analysis Approach and Limitations

EPA's modeling is based on its best judgment for various input assumptions that are uncertain. Assumptions for future fuel prices and electricity demand growth deserve particular attention because of the importance of these two key model inputs to the power sector. As a general matter, the Agency selects the best available information from available engineering studies of air pollution controls and has set up what it believes is the most reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory controls.

The annualized cost estimates of the private compliance costs that are provided in this analysis are meant to show the increase in production (engineering) costs to the power sector of the Transport Rule selected remedy and any alternatives. In simple terms, the private compliance costs that are presented are the annual increase in revenues required for the industry to be as well off after the Transport Rule is implemented as before. To estimate these annualized costs, EPA uses a conventional and widely-accepted approach that is commonplace in economic analysis of power sector costs for estimating engineering costs in annual terms. For estimating annualized costs, EPA has applied a capital recovery factor (CRF) multiplier to capital investments and added that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are EPA's best estimate of the direct private compliance costs of the Transport Rule.

The annualized cost of the Transport Rule, as quantified here, is EPA's best assessment of the cost of implementing the Transport Rule. These costs are generated from rigorous economic modeling of changes in the power sector due to the Transport Rule. This type of analysis using IPM has undergone peer review and federal courts have upheld regulations covering the power sector that have relied on IPM's cost analysis.

The direct private compliance cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. EPA believes that the cost assumptions used for the Transport Rule reflect, as closely as possible, the best information available to the Agency today. The relatively small cost associated with monitoring emissions, reporting, and record keeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to be approximately $26.2 million (see Section 9.3., Paperwork Reduction Act, of this RIA for more information).

Cost estimates for the Transport Rule are based on results from ICF's Integrated

Planning Model. The model minimizes the costs of producing electricity (including abatement costs) while meeting load demand and other constraints (full documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm and in the document titled: "Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule"). The structure of the model assumes that the electric utility industry will be able to meet environmental emission caps at least cost. Montgomery (1972) has shown that this least cost solution corresponds to the equilibrium of an emission permit system. See also Atkinson and Tietenburg (1982), Krupnick et al. (1980), and McGartland and Oates (1985). However, to the extent that transaction and/or search costs, combined with institutional barriers, restrict the ability of utilities to exhaust all the gains from emission trading, costs are underestimated by the model. Utilities in the IPM model also have "perfect foresight." To the extent that utilities misjudge future conditions affecting the economics of pollution control, costs may be understated as well.

The "perfect foresight" of the model is also relevant in the context of the assurance provisions required in the Transport Rule. Because of the sizeable penalties associated with violating assurance provisions, EPA believes it will be economical for units to comply with the provisions. EPA modeled these provisions, which restrict emissions from a state to the budget plus variability limits on a 1-year basis, as state-specific emissions caps set at the budget plus average variability, or state assurance level. The Power Sector Variability Technical Support Document contains further details on these assurance provisions.

Modeling the assurance provisions as caps means that the model must meet the same limit each year, but it also allows the model to optimize with perfect foresight the present and future limits. The model minimizes production costs while meeting required generation and reserve margin, but sources in reality may choose to make greater emission reductions than required in exchange for more certainty about emissions variability. IPM captures the cost associated with making required reductions in each state, but because of its "perfect foresight," the model likely cannot capture the true benefit to sources of having a range of allowed variability.

From another vantage point, this modeling analysis does not take into account the potential for advancements in the capabilities of pollution control technologies for SO_2 and NO_x removal as well as reductions in their costs over time after 2014. Market-based cap and trade regulation serves to promote innovation and the development of new and cheaper technologies. As an example, cost estimates of the Acid Rain SO_2 trading program by Resources for the Future (RFF) and MIT's Center for Energy and Environmental Policy Research (CEEPR) have been as much as 83 percent lower than originally projected by the EPA (see Carlson et al., 2000; Ellerman, 2003). It is important to note that the original analysis for the Acid Rain Program done by EPA also relied on an optimization model like IPM. Ex ante, EPA cost estimates of roughly \$2.7 to \$6.2 billion[56] in 1989 were an overestimate of the costs of the program in part because of the limitation of economic modeling to predict technological improvement of pollution controls and other compliance options such as fuel switching. Ex post estimates of the annual cost of the Acid Rain SO_2 trading program range from \$1.0 to \$1.4 billion. Harrington et al. have examined cost analyses of EPA programs and found a tendency for predicted costs to overstate actual implementation costs in market-based programs (Harrington, Morgenstern, and Nelson, 2000). In recognition of this, EPA's mobile source program uses adjusted engineering cost estimates of pollution control equipment and installation costs to account for this fact, which EPA has not done in this case.[57] The Agency is considering approaches to make this adjustment in the future, or at least to be able to provide a sense of the rough amount by which costs could be overstated in the analysis that has occurred.

EPA's latest update of IPM incorporates state rules or regulations and various NSR settlements adopted through December, 2010. Documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm and in the document titled: " Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule." Any state or settlement action since that time has not been accounted for in our analysis in this chapter.

As configured in this application, IPM does not take into account demand response (i.e., consumer reaction to electricity prices). The increased retail electricity prices shown in Table 7-16 would prompt end users to curtail (to some extent) their use of electricity and encourage them to use substitutes.[58] The response would lessen the demand for electricity,

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56 2010 Phase II cost estimate in \$1995.

57 See regulatory impact analysis for the Tier 2 Regulations for passenger vehicles (1999) and Heavy-Duty Diesel Vehicle Rules (2000).

58 The degree of substitution/curtailment depends on the costs and performance of the goods that substitute for

resulting in electricity price increases slightly lower than IPM predicts, which would also reduce generation and emissions. Because of demand response, certain unquantified negative costs (i.e., savings) result from the reduced resource costs of producing less electricity because of the lower quantity demanded. To some degree, these saved resource costs will offset the additional costs of pollution controls and fuel switching that we would anticipate with the Transport Rule. Although the reduction in electricity use is likely to be small, the cost savings from such a large industry[59] is not insignificant. EIA analysis examining multi-pollutant legislation under consideration in 2003 indicates that the annualized costs of the Transport Rule may be overstated substantially by not considering demand response, depending on the magnitude and coverage of the price increases.[60]

On balance, after consideration of various unquantified costs (and savings that are possible), EPA believes that the annual private compliance costs that we have estimated are more likely to overstate the future annual compliance costs that industry will incur, rather than understate those costs.

Finally, EPA's projected impacts of this final rule do not reflect minor technical corrections to SO2 budgets in three states (KY, MI, and NY). These projections also assumed preliminary variability limits that were smaller than the variability limits finalized in this rule. EPA conducted sensitivity analysis confirming that these differences do not meaningfully alter any of the Agency's findings or conclusions based on the projected cost, benefit, and air quality impacts presented for the final Transport Rule. The results of this sensitivity analysis are presented in Appendix F in the final Transport Rule RIA.

7.15 Significant Energy Impact

The Transport Rule has a significant impact according to *E.O. 13211: Actions that*

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more energy consuming goods, which is reflected in the demand elasticity.

[59] Investor-owned utilities alone accounted for nearly $300 billion in revenue in 2008 (EIA).

[60] See "Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003." Energy Information Administration. September, 2003. EIA modeling indicated that the Clear Skies Act of 2003 (a nationwide cap and trade program for SO_2, NO_X, and mercury), demand response could lower present value costs by as much as 47% below what it would have been without an emission constraint similar to the Transport Rule.

Significantly Affect Energy Supply, Distribution, or Use. Under the provisions of this final rule, EPA projects that approximately 4.8 GW of additional coal-fired generation may be removed from operation by 2014. In practice, however, the units projected to be uneconomic to maintain may be "mothballed," retired, or kept in service to ensure transmission reliability in certain parts of the grid. These units are predominantly small and infrequently-used generating units dispersed throughout the area affected by the rule. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to keep these units operational.

EPA estimates that average retail electricity price could increase in the contiguous U.S. by about 1.7 percent in 2012 and 0.8 percent in 2014. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, EPA projects limited impacts on coal and gas prices. The average delivered coal price decreases by about 1.4 percent in 2012 and 0.9 percent in 2014 relative to the base case as a result of decreased coal demand and shifts in the type of coal demanded. As discussed above in section 7.11, EPA also projects that electric power sector-delivered natural gas price will increase by about 0.3% over the 2012-2030 timeframe and that natural gas use for electricity generation will increase by approximately 200 billion cubic feet (BCF) by 2014. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, under the Transport Rule, EPA projects that coal production for use by the power sector will increase above 2009 levels by 21 million tons in 2012 and a further 14 million tons in 2014, as opposed to 30 million tons in 2012 and a further 26 million tons in 2014 without the Transport Rule in place. The Transport Rule is not projected to impact production of coal for uses outside the power sector (e.g., export, industrial sources), which represent approximately 6% of total coal production in 2009. EPA does not believe that this rule will have any other impacts (e.g., on oil markets) that exceed the significance criteria.

EPA believes that a number of features of the rulemaking serve to reduce its impact on energy supply. First, the trading component of the Transport Rule provides considerable flexibility to the power sector and enables industry to comply with the emission reduction requirements in the most cost-effective manner, thus minimizing overall costs and the ultimate impact on energy supply. Second, the emission budgets for SO_2 are set in two phases, providing adequate time for EGUs to install pollution controls ahead of the second phase. In addition, both the operational flexibility of trading and the ability to bank allowances for future years help industry plan for and ensure reliability in the electrical system.

7.16 References

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Attachment B

United States Environmental Protection Agency

Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards

COMPANIES
EXHIBIT 155

EPA-452/R-11-011
December 2011

Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impacts Division
Research Triangle Park, NC

CONTENTS

CHAPTER 3
COST, ECONOMIC, AND ENERGY IMPACTS

This chapter reports the compliance cost, economic, and energy impact analysis performed for the Mercury and Air Toxics Standards (MATS). EPA used the Integrated Planning Model (IPM), developed by ICF Consulting, to conduct its analysis. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for SO_2, NO_X, Hg, HCl, and other air pollutants throughout the United States for the entire power system. Documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm, and updates specific to the MATS modeling are in the "Documentation Supplement for EPA Base Case v.4.10_MATS – Updates for Final Mercury and Air Toxics Standards (MATS) Rule" (hereafter IPM 4.10 Supplemental Documentation for MATS).

3.1 Background

Over the last decade, EPA has on several occasions used IPM to consider pollution control options for reducing power-sector emissions.[1] Most recently EPA used IPM extensively in the development and analysis of the impacts of the Cross-State Air Pollution Rule (CSAPR).[2] As discussed in Chapter 2, MATS coincides with a period when many new pollution controls are being installed. Many are needed for compliance with NSR settlements and state rules, while others may have been planned in expectation of CAIR and its replacement, the CSAPR.

The emissions scenarios for the RIA reflects the Cross-State Air Pollution Rule (CSAPR) as finalized in July 2011 and the emissions reductions of SO_X, NO_X, directly emitted PM, and CO_2 are consistent with application of federal rules, state rules and statutes, and other binding, enforceable commitments in place by December 2010 for the analysis timeframe.[3]

[1] Many EPA analyses with IPM have focused on legislative proposals with national scope, such as EPA's IPM analyses of the Clean Air Planning Act (S.843 in 108th Congress), the Clean Power Act (S.150 in 109th Congress), the Clear Skies Act of 2005 (S.131 in 109th Congress), the Clear Skies Act of 2003 (S.485 in 108th Congress), and the Clear Skies Manager's Mark (of S.131). These analyses are available at EPA's website: (http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html). EPA also analyzed several multi-pollutant reduction scenarios in July 2009 at the request of Senator Tom Carper to illustrate the costs and benefits of multiple levels of SO_2 and NO_X control in the power sector.

[2] Additionally, IPM has been used to develop the NO_X Budget Trading Program, the Clean Air Interstate Rule programs, the Clean Air Visibility Programs, and other EPA regulatory programs for the last 15 years.

[3] Consistent with the mercury risk deposition modeling for MATS, EPA did not model non-federally enforceable mercury-specific emissions reduction rules in the base case or MATS policy case (see preamble section III.A). Note that this approach does not significantly affect SO_2 and NO_X projections underlying the cost and benefit results presented in this RIA

EPA has made these base case assumptions recognizing that the power sector will install a significant amount of pollution controls in response to several requirements. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the base case is necessary in order to reflect the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case will provide meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions in totality, while isolating the incremental impacts of MATS relative to a base case with other air emission reduction requirements separate from today's action.

The model's base case features an updated Title IV SO_2 allowance bank assumption and incorporates updates related to the Energy Independence and Security Act of 2007. Some modeling assumptions, most notably the projected demand for electricity, are based on the 2010 Annual Energy Outlook from the Energy Information Administration (EIA). In addition, the model includes existing policies affecting emissions from the power sector: the Title IV of the Clean Air Act (the Acid Rain Program); the NO_x SIP Call; various New Source Review (NSR) settlements[4]; and several state rules[5] affecting emissions of SO_2, NO_x, and CO_2 that were finalized through June of 2011. IPM includes state rules that have been finalized and/or approved by a state's legislature or environmental agency, with the exception of non-federal mercury-specific rules. The IPM 4.10 Supplemental Documentation for MATS contains details on all of these other legally binding and enforceable commitments for installation and operation of pollution controls. This chapter focuses on results of EPA's analysis with IPM for the model's 2015 run-year in connection with the compliance date for MATS.

MATS establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the "electric utility steam generating unit" source category, which includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public.

[4] The NSR settlements include agreements between EPA and Southern Indiana Gas and Electric Company (Vectren), Public Service Enterprise Group, Tampa Electric Company, We Energies (WEPCO), Virginia Electric & Power Company (Dominion), Santee Cooper, Minnkota Power Coop, American Electric Power (AEP), East Kentucky Power Cooperative (EKPC), Nevada Power Company, Illinois Power, Mirant, Ohio Edison, Kentucky Utilities, Hoosier Energy, Salt River Project, Westar, Puerto Rico Power Authority, Duke Energy, American Municipal Power, and Dayton Power and Light. These agreements lay out specific NO_x, SO_2, and other emissions controls for the fleets of these major Eastern companies by specified dates. Many of the pollution controls are required between 2010 and 2015.

[5] These include current and future state programs in Alabama, Arizona, California, Colorado, Connecticut, Delaware, Georgia, Illinois, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, New Hampshire, New Jersey, New York, North Carolina, Oregon, Pennsylvania, Tennessee, Texas, Utah, Washington, West Virginia, and Wisconsin the cover certain emissions from the power sector.

Coal-fired electric utility steam generating units include electric utility steam generating units that burn coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels. Examples of supplemental fuels include petroleum coke and tire-derived fuels. The NESHAP establishes standards for HAP emissions from both coal- and oil-fired EGUs and will apply to any existing, new, or reconstructed units located at major or area sources of HAP. Although all HAP are pollutants of interest, those of particular concern are hydrogen fluoride (HF), hydrogen chloride (HCl), dioxins/furans, and HAP metals, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium.

This rule affects any fossil fuel fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility steam generating unit. The rule affects roughly 1,400 EGUs: approximately 1,100 existing coal-fired generating units and 300 oil-fired steam units, should those units combust oil. Of the 600 power plants potentially covered by this rule, about 430 have coal-fired units only, 30 have both coal- and oil- or gas-fired steam units, and 130 have oil- or gas-fired steam units only. Note that only steam electric units combusting coal or oil are covered by this rule.

EPA analyzed for the RIA the input-based (lbs/MMBtu) MATS control requirements shown in Table 3-1. In this analysis, EPA does not model an alternative SO_2 standard. Coal steam units with access to lignite in the modeling are subjected to the "Existing coal-fired unit low Btu virgin coal" standard. For further discussion about the scope and requirements of MATS, see the preamble or Chapter 1 of this RIA.

Table 3-1. Emissions Limitations for Coal-Fired and Solid Oil-Derived Fuel-Fired Electric Utility Steam Generating Units

Subcategory	Filterable Particulate Matter	Hydrogen Chloride	Mercury
Existing coal-fired unit not low Btu virgin coal	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh)	1.2 lb/TBtu (0.020 lb/GWh)
Existing coal-fired unit low Btu virgin coal	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh)	11.0 lb/TBtu (0.20 lb/GWh) 4.0 lb/TBtu[a] (0.040 lb/GWh[a])
Existing - IGCC	0.040 lb/MMBtu (0.40 lb/MWh)	0.00050 lb/MMBtu (0.0050 lb/MWh)	2.5 lb/TBtu (0.030 lb/GWh)
Existing – Solid oil-derived	0.0080 lb/MMBtu (0.090 lb/MWh)	0.0050 lb/MMBtu (0.080 lb/MWh)	0.20 lb/TBtu (0.0020 lb/GWh)
New coal-fired unit not low Btu virgin coal	0.0070 lb/MWh	0.40 lb/GWh	0.00020 lb/GWh
New coal-fired unit low Btu virgin coal	0.0070 lb/MWh	0.40 lb/GWh	0.040 lb/GWh
New – IGCC	0.070 lb/MWh[b] 0.090 lb/MWh[c]	0.0020 lb/MWh[d]	0.0030 lb/GWh[e]
New – Solid oil-derived	0.020 lb/MWh	0.00040 lb/MWh	0.0020 lb/GWh

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input
lb/TBtu = pounds pollutant per trillion British thermal units fuel input
lb/MWh = pounds pollutant per megawatt-hour electric output (gross)
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross)
[a] Beyond-the-floor limit as discussed elsewhere
[b] Duct burners on syngas; based on permit levels in comments received
[c] Duct burners on natural gas; based on permit levels in comments received
[d] Based on best-performing similar source
[e] Based on permit levels in comments received

Table 3-2. Emissions Limitations for Liquid Oil-Fired Electric Utility Steam Generating Units

Subcategory	Filterable PM	Hydrogen Chloride	Hydrogen Fluoride
Existing – Liquid oil-continental	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.010 lb/MWh)	0.00040 lb/MMBtu (0.0040 lb/MWh)
Existing – Liquid oil-non-continental	0.030 lb/MMBtu (0.30 lb/MWh)	0.00020 lb/MMBtu (0.0020 lb/MWh)	0.000060 lb/MMBtu (0.00050 lb/MWh)
New – Liquid oil – continental	0.070 lb/MWh	0.00040 lb/MWh	0.00040 lb/MWh
New – Liquid oil – non-continental	0.20 lb/MWh	0.0020 lb/MWh	0.00050 lb/MWh

EPA used the Integrated Planning Model (IPM) v.4.10 to assess the impacts of the MATS emission limitations for coal-fired electricity generating units (EGU) in the contiguous United States. IPM modeling did not subject oil-fired units to policy criteria.[6] Furthermore, IPM modeling did not include generation outside the contiguous U.S., where EPA is aware of only 2 facilities that would be subject to the coal-fired requirements of the final rule. Given the limited number of potentially impacted facilities, limited availability of input data to inform the modeling, and limited connection to the continental grid, EPA did not model the impacts of the rule beyond the contiguous U.S.

Mercury emissions are modeled as a function of mercury content of the fuel type(s) consumed at each plant in concert with that plant's pollutant control configuration. HCl emissions are projected in a similar fashion using the chlorine content of the fuel(s). For both mercury and HCl, EGUs in the model must emit at or below the final mercury and HCl emission rate standards in order to operate from 2015 onwards. EGUs may change fuels and/or install additional control technology to meet the standard, or they may choose to retire if it is more economic for the power sector to meet electricity demand with other sources of generation. See IPM 4.10 documentation and IPM 4.10 Supplemental Documentation for MATS for more details.

Total PM emissions are calculated exogenously to IPM, using EPA's Source Classification Code (SCC) and control-based emissions factors. SCC is a classification system that describes a generating unit's characteristics.

[6] EPA did not model the impacts of MATS on oil-fired units using IPM. Rather, EPA performed an analysis of impacts on oil-fired units for the final rule. The results are summarized in Appendix 3A.

Instead of emission limitations for the organic HAP, EPA is proposing that if requested, owners or operators of EGUs submit to the delegated authority or EPA, as appropriate, documentation showing that an annual performance test meeting the requirements of the rule was conducted. IPM modeling of the MATS policy assumes compliance with these work practice standards.

Electricity demand is anticipated to grow by roughly 1 percent per year, and total electricity demand is projected to be 4,103 billion kWh by 2015. Table 3-3 shows current electricity generation alongside EPA's base case projection for 2015 generation using IPM. EPA's IPM modeling for this rule relies on EIA's *Annual Energy Outlook for 2010*'s electric demand forecast for the US and employs a set of EPA assumptions regarding fuel supplies and the performance and cost of electric generation technologies as well as pollution controls.[7] The base case includes CSAPR as well as other existing state and federal programs for air emissions control from electric generating units, with the exception of state mercury rules.

[7] Note that projected electricity demand in AEO 2010 is about 2% higher than the AEO 2011 projection in 2015. Since this RIA assumes higher electricity demand in 2015 than is shown in the latest AEO projection, it is possible that the model may be taking compliance actions to meet incremental electricity demand that may not actually occur, and projected compliance costs may therefore be somewhat overstated in this analysis.

Table 3-3. 2009 U.S. Electricity Net Generation and EPA Base Case Projections for 2015-2030 (Billion kWh)

	Historical	Base Case		
	2009	2015	2020	2030
Coal	1,741	1,982	2,002	2,027
Oil	36	0.11	0.13	0.21
Natural Gas	841	710	847	1,185
Nuclear	799	828	837	817
Hydroelectric	267	286	286	286
Non-hydro Renewables	116	252	289	333
Other	10	45	45	55
Total	3,810	**4,103**	**4,307**	**4,702**

Source: 2009 data from AEO Annual Energy Review, Table 8.2c Electricity Net Generation: Electric Power Sector by Plant Type, 1989-2010; Projections from Integrated Planning Model run by EPA, 2011.

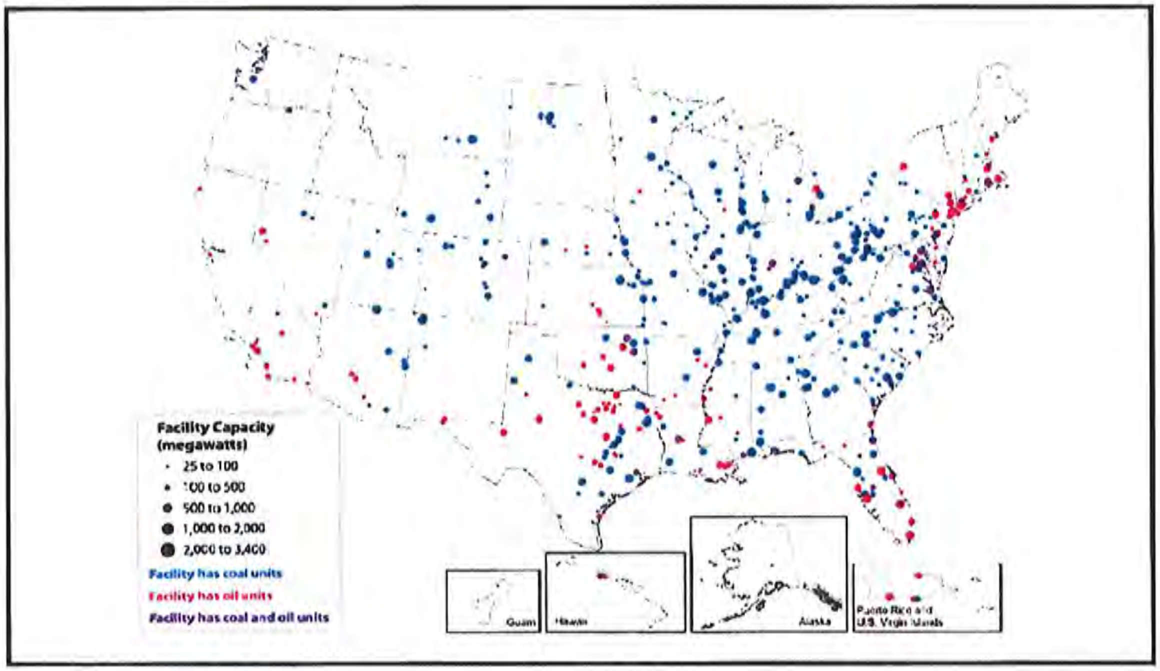

Figure 3-1. Geographic Distribution of Affected Units, by Facility, Size and Fuel Source in 2012

Source/Notes: National Electric Energy Data System (NEEDS 4.10 MATS) (EPA, December 2011) and EPA's Information Collection Request (ICR) for New and Existing Coal- And Oil-Fired Electric Utility Stream Generation Units (2010). This map displays facilities that are included in the NEEDS 4.10 MATS data base and that contain at least one oil-fired steam generating unit or one coal-fired steam generating unit that generates more than 25 megawatts of power. This includes coal-fired units that burn petroleum coke and that turn coal into gas before burning (using integrated gasification combined cycle or IGCC). NEEDS reflects available capacity on-line by the end of 2011; this includes committed new builds and committed retirements of old units. Only coal and oil-fired units are covered by this rule. Some of the oil units displayed on the map are capable of burning oil and/or gas. If a unit burns only gas, it will not be covered in the rule. In areas with a dense concentration of facilities, the facilities on the map may overlap and some may be impossible to see. IPM modeling did not include generation outside the contiguous U.S., where EPA is aware of only two facilities that would be subject to the coal-fired requirements of the final rule. Given the limited number of potentially impacted facilities, limited availability of input data to inform the modeling, and limited connection to the continental grid, EPA did not model the impacts of the rule beyond the contiguous U.S. Facilities outside the contiguous U.S. are displayed based on data from EPA's 2010 ICR for the rule.

As noted above, IPM has been used for evaluating the economic and emission impacts of environmental policies for over two decades. The economic modeling presented in this chapter has been developed for specific analyses of the power sector. Thus, the model has been designed to reflect the industry as accurately as possible. To that end, EPA uses a series of capital charge factors in IPM that embody financial terms for the various types of investments that the power sector considers for meeting future generation and environmental constraints.

The model applies a discount rate of 6.15% for optimizing the sector's decision-making over time. IPM's discount rate, designed to represent a broad range of private-sector decisions for power generation, rates differs from discount rates used in other analyses in this RIA, such as the benefits analysis which each assume alternative social discount rates of 3% and 7%. These discount rates represent social rates of time preference, whereas the discount rate in IPM represents an empirically-informed price of raising capital for the power sector. Like all other assumed price inputs in IPM, EPA uses the best available information from utilities, financial institutions, debt rating agencies, and government statistics as the basis for the capital charge rates and the discount rate used for power sector modeling in IPM.

More detail on IPM can be found in the model documentation, which provides additional information on the assumptions discussed here as well as all other assumptions and inputs to the model (http://www.epa.gov/airmarkets/progsregs/epa-ipm). Updates specific to MATS modeling are also in the IPM 4.10 Supplemental Documentation for MATS.

3.2 Projected Emissions

MATS is anticipated to achieve substantial emissions reductions from the power sector. Since the technologies available to meet the emission reduction requirements of the rule reduce multiple air pollutants, EPA expects the rule to yield a broad array of pollutant reductions from the power sector. The primary pollutants of concern under MATS from the power sector are mercury, acid gases such as hydrogen chloride (HCl), and HAP metals, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium. EPA has extensively analyzed mercury emissions from the power sector, and IPM modeling assesses the mercury contents in all coals and the removal efficiencies of relevant emission control technologies (e.g., ACI). EPA also models emissions and the pollution control technologies associated with HCl (as a surrogate for acid gas emissions). Like SO_2, HCl is removed by both scrubbers and DSI (dry sorbent injection). Projected emissions are based on both control technology and detailed coal supply curves used in the model that reflect the chlorine content of coals, which corresponds with the supply region, coal grade, and sulfur, mercury, and ash content of each coal type. This information is critical for accurately projecting future HCl emissions, and for understanding how the power sector will respond to a policy requiring reductions of multiple HAPs.

Generally, existing pollution control technologies reduce emissions across a range of pollutants. For example, both FGD and SCR can achieve notable reductions in mercury in addition to their primary targets of SO_2 and NO_X reductions. DSI will reduce HCl emissions while also yielding substantial SO_2 emission reductions, but is not assumed in EPA modeling to result in mercury reductions. Since there are many avenues to reduce emissions, and because the power sector is a highly complex and dynamic industry, EPA employs IPM in order to reflect the relevant components of the power sector accurately, while also providing a sophisticated view of how the industry could respond to particular policies to reduce emissions. For more detail on how EPA models emissions from the power sector, including recent updates to include acid gases, see IPM 4.10 Supplemental Documentation for MATS.

Under MATS, EPA projects annual HCl emissions reductions of 88 percent in 2015, Hg emissions reductions of 75 percent in 2015, and $PM_{2.5}$ emissions reductions of 19 percent in 2015 from coal-fired EGUs greater than 25 MW. In addition, EPA projects SO_2 emission reductions of 41 percent, and annual CO_2 reductions of 1 percent from coal-fired EGUs greater than 25 MW by 2015, relative to the base case (see Table 3-4).[8] Mercury emission projections in EPA's base case are affected by the incidental capture in other pollution control technologies (such as FGD and SCR) as described above.

Table 3-4. Projected Emissions of SO_2, NO_X, Mercury, Hydrogen Chloride, PM, and CO_2 with the Base Case and with MATS, 2015

		Million Tons		Mercury (Tons)	Thousand Tons		CO_2 (Million Metric Tonnes)
		SO_2	NO_X		HCl	$PM_{2.5}$	
Base	All EGUs	3.4	1.9	28.7	48.7	277	2,230
	Covered EGUs	3.3	1.7	26.6	45.3	270	1,906
MATS	All EGUs	2.1	1.9	8.8	9.0	227	2,215
	Covered EGUs	1.9	1.7	6.6	5.5	218	1,882

Source: Integrated Planning Model run by EPA, 2011

[8] The CO_2 emissions reported from IPM account for the direct CO_2 emissions from fuel combustion and CO_2 created from chemical reactions in pollution controls to reduced sulfur.

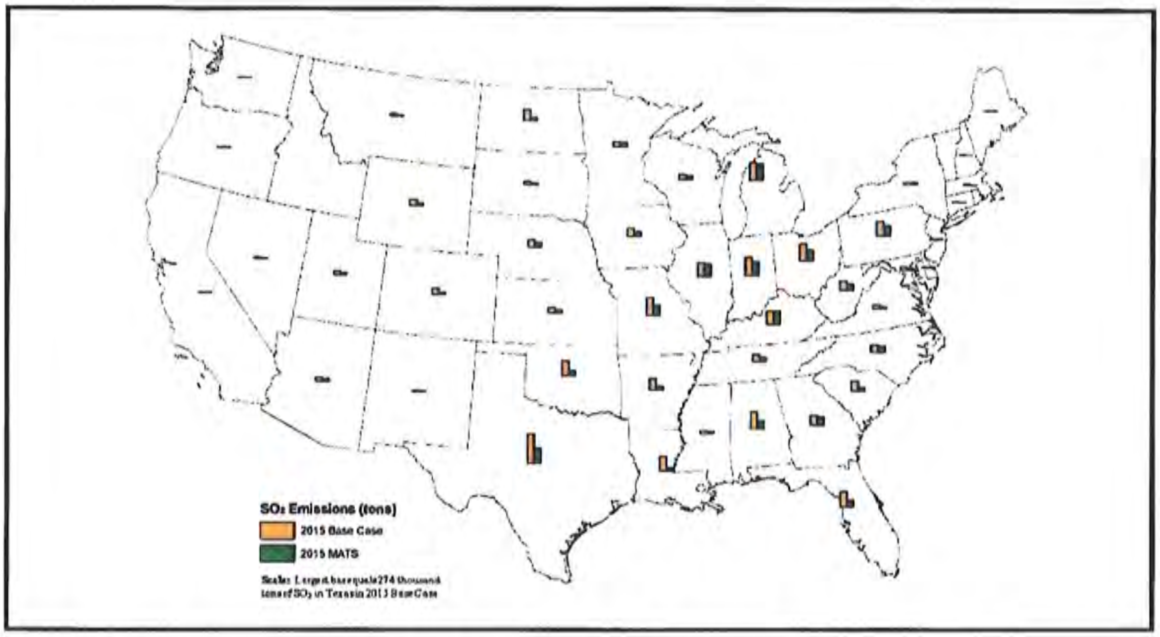

Figure 3-2. SO_2 Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10 base case and control case projections (EPA, February 2011)

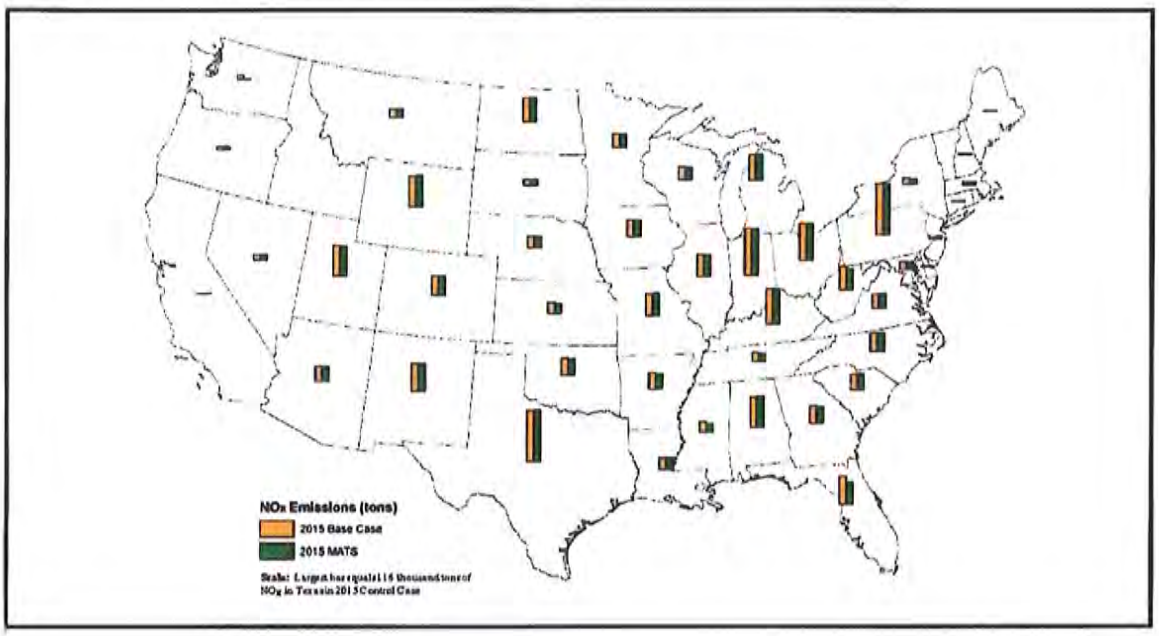

Figure 3-3. NO_X Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10_MATS base case and control case projections (EPA, 2011)

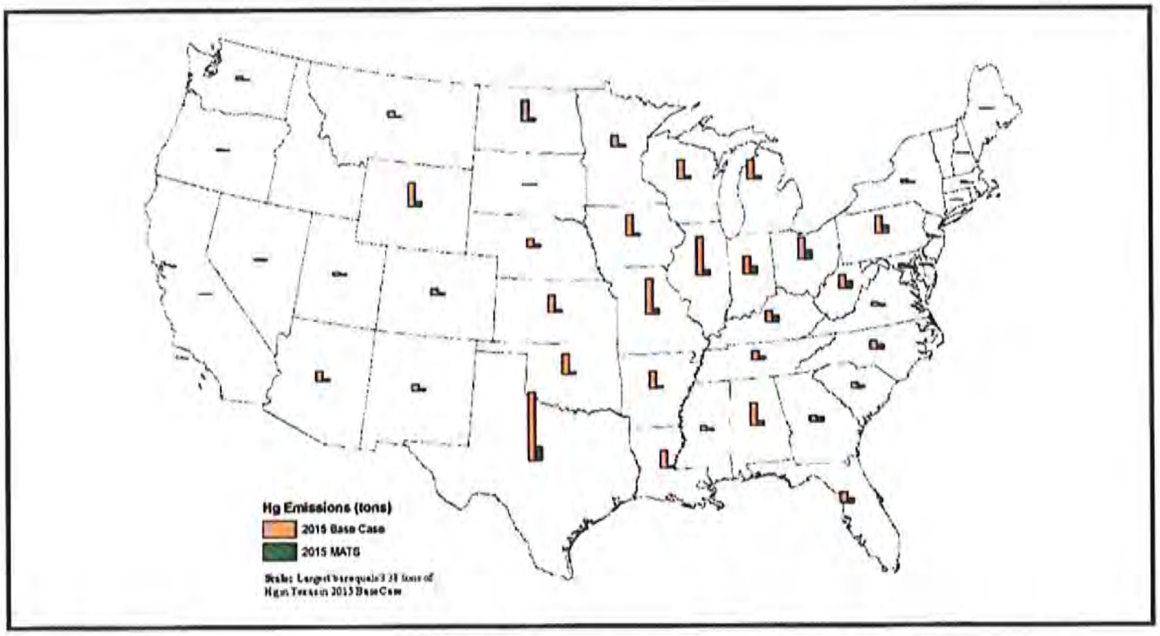

Figure 3-4. Mercury Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10_MATS base case and control case projections (EPA, 2011)

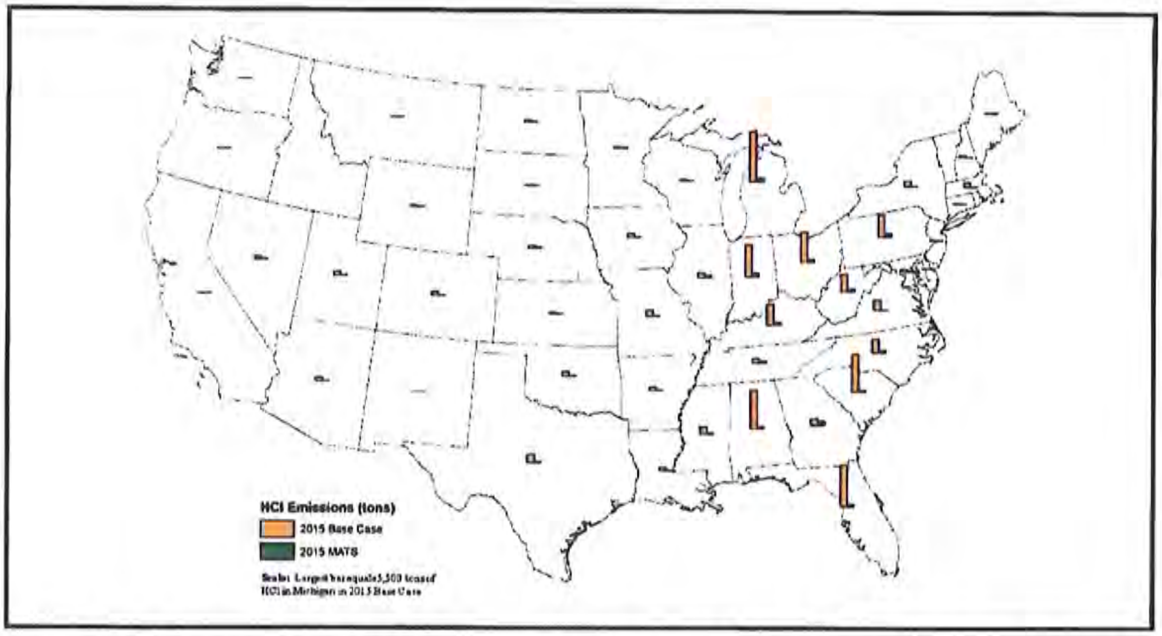

Figure 3-5. Hydrogen Chloride Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10_MATS base case and control case projections (EPA, 2011)

3.3 Projected Compliance Costs

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the final HAP emission standards. In simple terms, these costs are the resource costs of what the power industry will directly expend to comply with EPA's requirements.

EPA projects that the annual incremental compliance cost of MATS is $9.4 billion in 2015 ($2007). The annual incremental cost is the projected additional cost of complying with the final rule in the year analyzed, and includes the amortized cost of capital investment (at 6.15%) and the ongoing costs of operating additional pollution controls, investments in new generating sources, shifts between or amongst various fuels, and other actions associated with compliance. This projected cost does not include the compliance calculated outside of IPM modeling, namely the compliance costs for oil-fired EGUs, and monitoring, reporting, and record-keeping costs. See section 3.14 for further details on these costs. EPA believes that the cost assumptions used for the final rule reflect, as closely as possible, the best information available to the Agency today.

Table 3-5. Annualized Compliance Cost for MATS Requirements on Coal-fired Generation

	2015	2020	2030
Annualized Compliance Cost (billions of 2007$)	$9.4	$8.6	$7.4

Source: Integrated Planning Model run by EPA, 2011.

EPA's projection of $9.4 billion in additional costs in 2015 should be put into context for power sector operations. As shown in section 2.7, the power sector is expected in the base case to expend over $320 billion in 2015 to generate, transmit, and distribute electricity to end-use consumers. Therefore, the projected costs of compliance with MATS amount to less than a 3% increase in the cost to meet electricity demand, while securing public health benefits that are several times more valuable (as described in Chapters 4 and 5).

3.4 Projected Compliance Actions for Emissions Reductions

Fossil fuel-fired electric generating units are projected to achieve HAP emission reductions through a combination of compliance options. These actions include improved operation of existing controls, additional pollution control installations, coal switching (including blending of coals), and generation shifts towards more efficient units and lower-emitting generation technologies (e.g., some reduction of coal-fired generation with an increase of generation from natural gas). In addition, there will be some affected sources that find it uneconomic to invest in new pollution control equipment and will be removed from service. These facilities are generally amongst the oldest and least efficient power plants, and typically run infrequently. In order to ensure that any retirements resulting from MATS do not adversely impact the ability of affected sources and electric utilities from meeting the demand for electricity, EPA has conducted an analysis of the impacts of projected retirements on electric reliability. This analysis is discussed in TSD titled: "Resource Adequacy and Reliability in the IPM Projections for the MATS Rule" which is available in the docket.

The requirements under MATS are largely met through the installation of pollution controls (see Figure 3-6). To a lesser extent, there is a small degree of shifting within and across various ranks and types of coals, and a relatively small shift from coal-fired generation to greater use of natural gas and non-emitting sources of electricity (e.g., hydro and nuclear) (see Table 3-6). The largest share of emissions reductions occur from coal-fired units installing new pollution control devices, such as FGD, ACI, and fabric filters; a smaller share of emission reductions come from fuel shifts and unit retirements. Mercury emission reductions are largely driven by SCR/FGD combinations and ACI installations. HCl emission reductions are largely driven by FGD and DSI installations, which also incidentally provide substantial SO_2 reductions in the policy case. Mercury, $PM_{2.5}$, and HCl emission reductions are also facilitated by the installation of fabric filters, which boost mercury and HCl removal efficiencies of ACI and DSI, respectively.

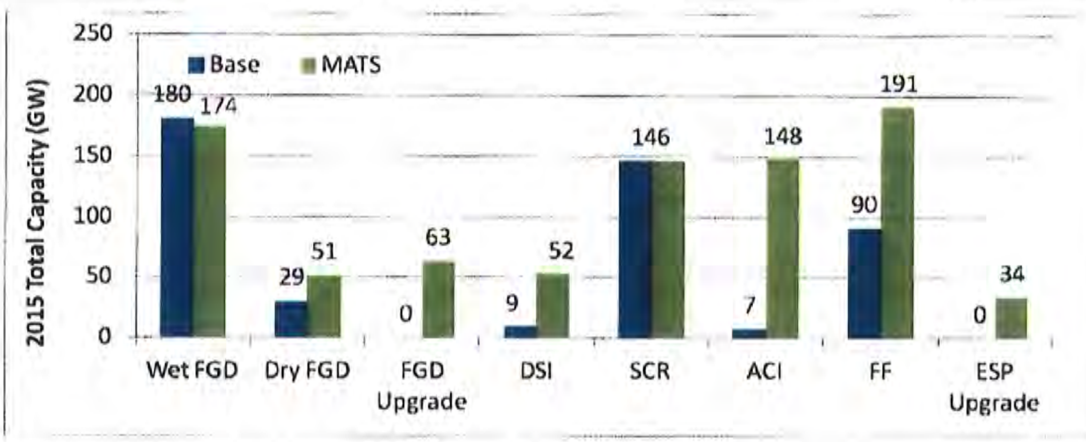

Figure 3-6. Operating Pollution Control Capacity on Coal-fired Capacity (by Technology) with the Base Case and with MATS, 2015 (GW)

Note: The difference between controlled capacity in the base case and under the MATS may not necessarily equal new retrofit construction, since controlled capacity above reflects incremental operation of dispatchable controls in 2015. Additionally, existing ACI installed on those units online before 2008 are not included in the base case to reflect removal of state mercury rules from IPM modeling. For these reasons, and due to rounding, numbers in the text below may not reflect the increments displayed in this figure. See IPM Documentation for more information on dispatchable controls.

Source: Integrated Planning Model run by EPA, 2011.

As shown in Figure 3-6, this analysis projects that by 2015, the final rule will drive the installation of an additional 20 GW of dry FGD (dry scrubbers), 44 GW of DSI, 99 GW of additional ACI, 102 GW of additional fabric filters, 63 GW of scrubber upgrades, and 34 GW of ESP upgrades. Furthermore, the final rule results in a 3 GW decrease in retrofit wet FGD capacity relative to the base, where the SO_2 allowance price under CSAPR provides an incentive for the additional SO_2 reductions achieved by a wet scrubber relative to a dry scrubber.

The difference between operating controlled capacity in the base case and under MATS in Figure 3-6 may not necessarily equal new retrofit construction, since total controlled capacity in the figure reflects incremental operation of existing controls that are projected to operate under MATS but not under the base case. With respect to the increase in operating ACI, some of this increase represents existing ACI capacity on units built before 2008. EPA's modeling does not reflect the presence of state mercury rules, and EPA assumes that ACI controls on units built before 2008 do not operate in the absence of these rules. In the policy case, these controls are projected to operate and the projected compliance cost thus reflects the operating cost of these controls. Since these controls are in existence, EPA does not count their capacity toward new retrofit construction, nor does EPA's compliance costs projection reflect the capital cost of these controls (new retrofit capacity is reported in the previous paragraph).

3.5 Projected Generation Mix

Table 3-6 and Figure 3-7 show the generation mix in the base case and in MATS. In 2015, coal-fired generation is projected to decline slightly and natural-gas-fired generation is projected to increase slightly relative to the base case. Coal-fired generation is projected to increase above 2009 actual levels. 2015 natural gas-fired generation is projected to be lower than 2009, due in large part to the smaller relative difference in delivered natural gas and coal prices in different areas of the country projected in 2015 than occurred in 2009. The vast majority (over 98%) of base case coal capacity is projected to remain in service under MATS. In addition, the operating costs of complying coal-fired units are not so affected as to result in major changes in the electricity generation mix.

Table 3-6. Generation Mix with the Base Case and the MATS, 2015 (Thousand GWh)

	2009	2015			
	Historical	Base Case	Policy Case	Change from Base	Percent Change
Coal	1,741	1,982	1,957	-25	-1.3%
Oil	36	0.11	0.11	0.00	3.6%
Natural Gas	841	710	731	22	3.1%
Nuclear	799	828	831	3	0.4%
Hydroelectric	267	286	288	2	0.8%
Non-hydro Renewables	116	252	250	-1	-0.6%
Other	10	45	45	0.0	0.0%
Total	3,810	**4,103**	**4,104**	**1**	**0.0%**

Note: Numbers may not add due to rounding.

Source: 2009 data from AEO Annual Energy Review, Table 8.2c Electricity Net Generation: Electric Power Sector by Plant Type, 1989-2010; 2015 projections are from the Integrated Planning Model run by EPA, 2011.

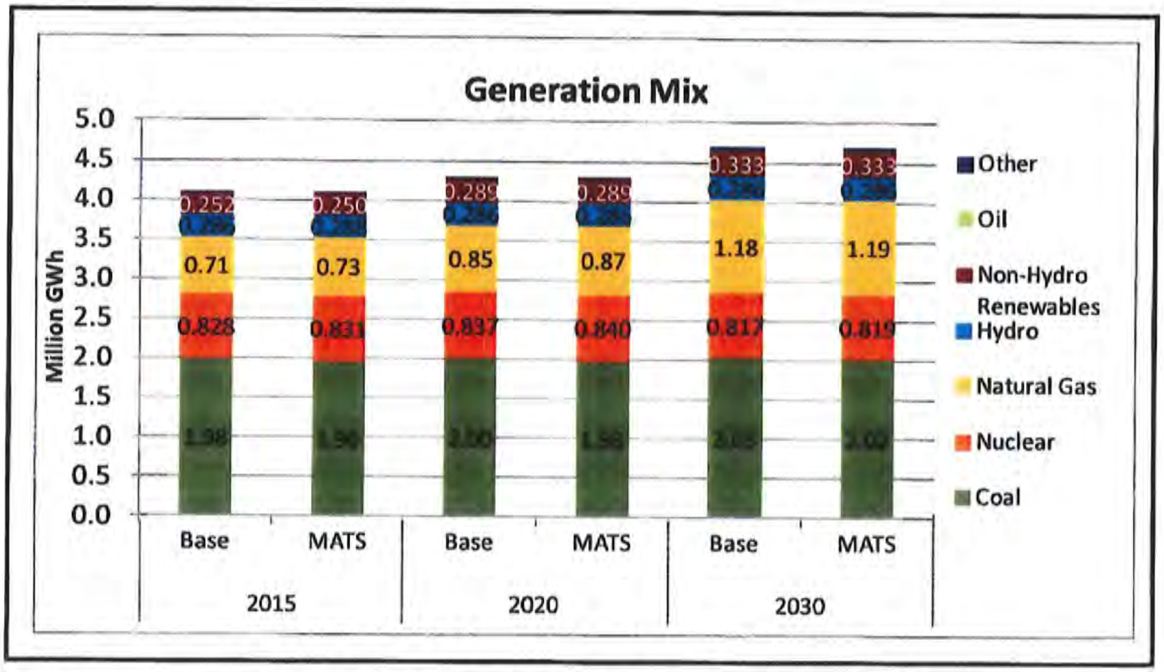

Figure 3-7. Generation Mix with the Base Case and with MATS, 2015-2030
Source: Integrated Planning Model run by EPA, 2011.

3.6 Projected Withdrawals from Service

Relative to the base case, about 4.7 GW (less than 2 percent) of coal-fired capacity is projected to be uneconomic to maintain by 2015. This projection considers various regional factors (e.g., other available capacity and fuel prices) and unit attributes (e.g., efficiency and age). These projected "uneconomic" units, for the most part, are older, smaller, and less frequently used generating units that are dispersed throughout the country (see Table 3-7).

Table 3-7. Characteristics of Covered Operational Coal Units and Additional Coal Units Projected to Withdraw as Uneconomic under MATS, 2015

	Average Age (Years)	Average Capacity	
		MW	Factor in Base
Withdrawn as Uneconomic	52	129	54%
Operational	43	322	71%

Source: Integrated Planning Model run by EPA, 2011.

These results should be considered "potential" closures. There are a variety of local factors that could make plant owners decide to keep one or more units projected to be uneconomic in service. These factors include different costs or demand estimates than what was included in the IPM modeling, and local operating conditions or requirements that are on a smaller scale than that represented in EPA's IPM modeling. To the extent EPA's modeling does not account for plants that continue to operate due to one or more of these local factors, these results could be overestimating the capacity removed from service as a result of this rule.

For the final rule, EPA has examined whether the IPM-projected closures may adversely impact reserve margins and reliability planning. The IPM model is specifically designed to ensure that generation resource availability is maintained in the projected results subject to reserve margins in 32 modeling regions for the contiguous US, which must be preserved either by using existing resources or through the construction of new resources. IPM also addresses reliable delivery of generation resources by limiting the ability to transfer power between regions using the bulk power transmission system. Within each model region, IPM assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region. The IPM model projects available capacity given certain constraints such as reserve margins and transmission capability but does not constitute a detailed reliability analysis. For example, the IPM model does not examine frequency response. For more detail on IPM's electric load modeling and power system operation, please see IPM documentation (http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html) and the TSD on Resource Adequacy and Reliability in the IPM Projections for the MATS Rule.

Total operational capacity is lower in the policy scenario, primarily as a result of additional coal projected to be uneconomic to maintain. Since most regions are projected to have excess capacity above their target reserve margins, most of these withdrawals from service are absorbed by a reduction in excess reserves. Operational capacity changes from the base case in 2015 are shown in Table 3-8.

Table 3-8. Total Generation Capacity by 2015 (GW)

	2010	Base Case	MATS
Pulverized Coal	317	310	305
Natural Gas Combined Cycle	201	206	206
Other Oil/Gas	253	233	233
Non-Hydro Renewables	31	70	70
Hydro	99	99	99
Nuclear	102	104	105
Other	5	4	4
Total	1,009	1,026	1,021

Source: 2010 data from EPA's NEEDS v.4.10_PTox. Projections from Integrated Planning Model run by EPA.
Note: "Non-Hydro Renewables" include biomass, geothermal, solar, and wind electric generation capacity. 2015 capacity reflects plant closures planned to occur prior to 2015.

The policy case analyzed maintains resource adequacy in each region projected to decrease in coal capacity by using excess reserve capacity within the region, reversing base case withdrawals of non-coal capacity, building new capacity, or by importing excess reserve capacity from other regions. Although any closure of a large generation facility will need to be studied to determine potential local reliability concerns, EPA analysis suggests that projected economic withdrawals from service under the final rule could have little to no overall impact on electric reliability. Not only are projected withdrawals under MATS limited in scope, but the existing state of the power sector is also characterized by substantial excess capacity. The weighted average reserve margin at the national level is projected to be approximately 25% in the base case, while the North American Electric Reliability Corporation (NERC) recommends a margin of 15%. EPA projects that MATS would only reduce total operational capacity by less than one percent in 2015.

Moreover, coal units projected to withdraw as uneconomic are distributed throughout the power grid with limited effect at the regional level, such that any potential impacts should not adversely affect reserve margins and should be manageable through the normal industry processes. For example, in the RFC NERC reliability Region, containing coal-fired generating area in Pennsylvania, West Virginia and the Midwest, there is a decrease of less than 2% in the reserve margin in the policy case and a remaining overall reserve margin of over 20%. Furthermore, subregions may share each other's excess reserves to ensure adequate reserve margins within a larger reliability region. EPA's IPM modeling accommodates such transfers of reserves within the assumed limits of reliability of the inter-regional bulk power system. For these reasons, the projected closures of coal plants are not expected to raise broad reliability concerns.

3.7 Projected Capacity Additions

Due in part to a low growth rate anticipated for future electricity demand levels in the latest EIA forecast, EPA analysis indicates that there is sufficient excess capacity through 2015 to compensate for capacity that is retired from service under MATS. In the short-term, most new capacity is projected as a mix of wind and natural gas in response to low fuel prices and other energy policies (such as tax credits and state renewable portfolio standards). In addition, future electricity demand expectations have trended downwards in recent forecasts, reducing the need for new capacity in the 2015 timeframe (see Chapter 2 for more discussion on future electricity demand).

Table 3-9. Total Generation Capacity by 2030 (GW)

	2010	Base Case	MATS	Change
Pulverized Coal	317	308	304	-3.9
Natural Gas Combined Cycle	201	275	278	2.9
Other Oil/Gas	253	235	235	0.6
Non-Hydro Renewables	31	79	79	0.1
Hydro	99	99	99	0.0
Nuclear	102	103	103	0.3
Other	5	4	4	0.0
Total	1,009	1,103	1,102	-0.1

Note: "Non-Hydro Renewables" include biomass, geothermal, solar, and wind electric generation capacity.
Source: 2010 data from EPA's NEEDS v.4.10_PTox. Projections from Integrated Planning Model run by EPA.

3.8 Projected Coal Production for the Electric Power Sector

Coal production for electricity generation under MATS is expected to increase from 2009 levels and decline modestly relative to the base case without the rule. The reductions in emissions from the power sector will be met through the installation and operation of pollution controls for HAP removal. Many available pollution controls achieve emissions removal rates of up to 99 percent (e.g., HCl removal by new scrubbers), which allows industry to rely more heavily on local bituminous coal in the eastern and central parts of the country that has higher contents of HCl and sulfur, and it is less expensive to transport than western subbituminous coal. Overall demand for coal is projected to be reduced as a result of MATS, with a slight reduction in bituminous coal, and more of a reduction in subbituminous coal (see Tables 3-10 and 3-11). The trend reflects the projected reduced demand for lower-sulfur coal under MATS, where nearly all units are operating with a post-combustion emissions control. In this case, because of the additional pollution controls, many of these units no longer find it economic to pay a transportation premium to purchase lower-sulfur subbituminous coals. Instead, EGUs are generally projected to shift consumption towards nearby bituminous coal, which can achieve low emissions when combined with post-combustion emissions controls. This explains the increase from the base case in coal supplied from the Interior region, which is located in relatively close proximity to many coal-fired generators subject to MATS. This continues a trend of increased Interior supply (due to abundant Illinois Basin reserves that are relatively inexpensive to mine) and decreased Central Appalachian supply which is forecasted to occur in the base case from historic levels. The decline in Appalachia is a result of an increase in the relative cost of Central Appalachian extraction due both to rising mining cost (e.g., in 2010 major producers reported mining cost increases up to 15% with this trend continuing into 2011) and shrinking economically recoverable capacity. Growing international demand for Appalachian thermal coal is also contributing to its rising price. The increase in lignite use occurs at units blending subbituminous and lignite coals, and reflects a small shift in blended balance towards a greater use of lignite.

Table 3-10. 2015 Coal Production for the Electric Power Sector with the Base Case and MATS (Million Tons)

Supply Area	2009	2015 Base	2015 MATS	Change in 2015
Appalachia	246	184	172	-6%
Interior	129	216	236	9%
West	553	554	537	-3%
Waste Coal	14	14	13	-5%
Imports		30	30	0%
Total	942	998	989	-1%

Source: Production: U.S. Energy Information Administration (EIA), *Coal Distribution — Annual (Final)*, web site http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/a_distributions.html (posted February 18, 2011); Waste Coal: U.S. EIA, *Monthly Energy Review, January 2011 Edition*, Table 6.1 Coal Overview, web site http://www.eia.doe.gov/emeu/mer/coal.html (posted January 31, 2011). All projections from Integrated Planning Model run by EPA, 2011.

Table 3-11. 2015 Power Sector Coal Use with the Base Case and the MATS, by Coal Rank (TBtu)

Coal Rank	Base	MATS	Change
Bituminous	11,314	11,248	-0.6%
Subbituminous	7,736	7,554	-2%
Lignite	849	895	5%
Total	19,900	19,698	-1%

Source: Integrated Planning Model run by EPA, 2011.

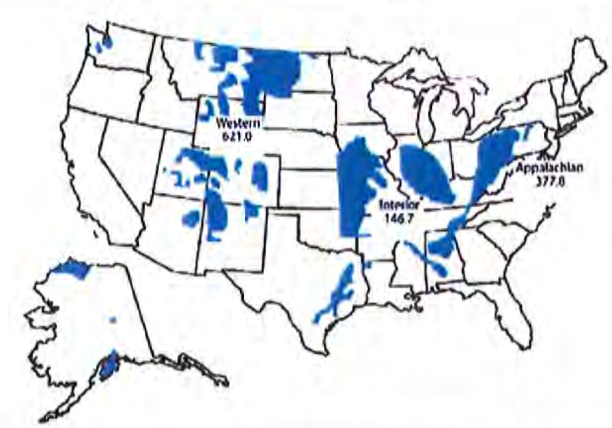

Figure 3-8. Total Coal Production by Coal-Producing Region, 2007 (Million Short Tons)
Note: Regional totals do not include refuse recovery
Source: EIA Annual Coal Report, 2007

3.9 Projected Retail Electricity Prices

EPA's analysis projects a near-term increase in the average retail electricity price of 3.1% in 2015 falling to 2% by 2020 under the final rule in the contiguous U.S. The projected price impacts vary by region and are provided in Table 3-12 (see Figure 3-9 for regional classifications).

Regional retail electricity prices are projected to range from 1 to 6 percent higher with MATS in 2015. The extent of regional retail electricity increases correlates with states that have considerable coal-fired generation in total generation capacity and that coal-fired generation is less well-controlled (such as in the ECAR and SPP regions). Retail electricity prices embody generation, transmission, and distribution costs. IPM modeling projects changes in regional wholesale power prices, capacity payments, and actual costs of compliance in areas that are "cost of service" regions that are combined with EIA regional transmission and distribution costs to complete the retail price picture.

Table 3-12. Projected Contiguous U.S. and Regional Retail Electricity Prices with the Base Case and with the MATS (2007 cents/kWh)

	Base Case			MATS			Percent Change		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
ECAR	8.2	8.2	9.8	8.5	8.5	9.9	4.5%	2.8%	1.0%
ERCOT	8.9	8.8	11.3	9.2	8.8	11.3	3.3%	0.6%	-0.2%
MAAC	9.5	10.4	12.7	9.8	10.4	12.7	2.8%	0.4%	-0.2%
MAIN	8.1	8.4	9.7	8.3	8.6	9.7	2.8%	2.2%	0.2%
MAPP	8.0	7.9	8.5	8.5	8.3	8.8	5.3%	5.6%	3.4%
NY	13.8	13.4	16.6	14.1	13.5	16.6	2.2%	0.7%	-0.1%
NE	12.3	11.8	13.8	12.6	11.9	13.8	2.0%	0.8%	0.0%
FRCC	10.2	9.7	11.0	10.4	9.8	11.0	2.2%	0.9%	0.4%
STV	7.9	7.8	8.4	8.2	8.0	8.6	3.1%	2.4%	1.6%
SPP	7.7	7.4	8.1	8.1	7.8	8.4	6.3%	6.1%	4.6%
PNW	7.1	6.8	7.6	7.3	7.0	7.6	2.7%	2.6%	1.1%
RM	9.2	9.5	11.0	9.4	9.7	11.1	2.3%	1.9%	1.1%
CALI	13.0	12.5	12.7	13.2	12.6	12.7	1.3%	0.7%	0.0%
Contiguous U.S. Average	9.0	9.0	10.2	9.3	9.2	10.3	3.1%	2.0%	0.9%

Source: EPA's Retail Electricity Price Model, 2011.

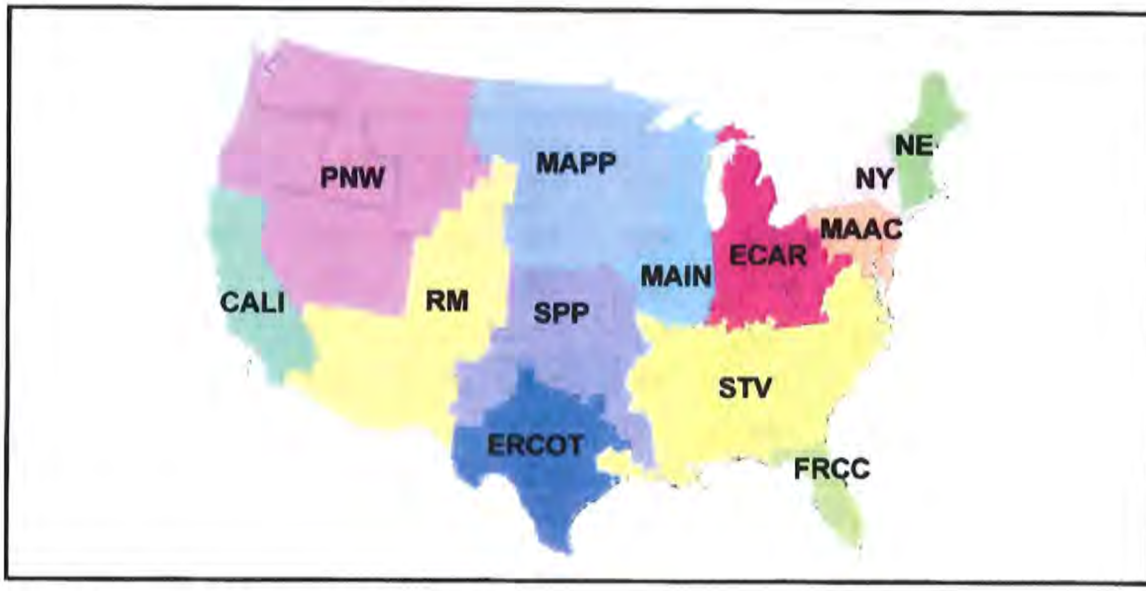

Figure 3-9. Retail Price Model Regions

3.10 Projected Fuel Price Impacts

The impacts of the final Rule on coal and natural gas prices before shipment are shown below in Tables 3-13 and 3-14. Overall, the national average coal price changes are related to changes in demand for a wide variety of coals based upon a number of parameters (e.g., chlorine or mercury content, heat content, proximity to the power plant, etc.), and this national average captures increases and decreases in coal demand and price at the regional level. Generally, total demand for coal decreases slightly under MATS, most notably subbituminous coal, which is by far the least expensive type of coal supplied to the power sector on an MMBtu basis. This is reflected in the projected average minemouth price of coal, which goes up by about 3 percent even though total demand for coal is reduced slightly (1 percent reduction). Notwithstanding the projected "mine-mouth" coal price changes, many units may in fact be realizing overall fuel cost savings by switching to more local coal supplies (which reduces transportation costs) after installing additional pollution control equipment. Gas price changes are directly related the projected increase in natural gas consumption under MATS. This increase in demand is met by producing additional natural gas at some increase in regional costs, resulting over time in a small price increase.

Table 3-13. Average Minemouth and Delivered Coal Prices with the Base Case and with MATS (2007$/MMBtu)

		2015			2030		
	2007	Base Case	MATS	Percent Change from Base	Base Case	MATS	Percent Change from Base
Minemouth	1.27	1.35	1.39	2.8%	1.51	1.56	3.3%
Delivered	1.76	2.11	2.15	1.9%	2.29	2.33	1.7%

Source: Historical data from EIA AEO 2010 Reference Case Table 15 (Coal Supply, Distribution, and Prices); projections from the Integrated Planning Model run by EPA, 2011.

Table 3-14. 2015-2030 Weighted Average Henry Hub (spot) and Delivered Natural Gas Prices with the Base Case and with MATS (2007$/MMBtu)

	Base Case	MATS	Percent Change from Base
Henry Hub	5.29	5.32	0.6%
Delivered - Electric Power	5.56	5.60	0.6%
Delivered - Residential	10.94	10.97	0.3%

Source: Projections from the Integrated Planning Model run by EPA (2011) adjusted to Henry Hub prices using historical data from EIA AEO 2011 reference case to derive residential prices.

IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply of and demand in competitive markets for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is <u>not</u> a forecast of natural gas prices incurred by *end-use consumers* at any particular point in time. The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and even sees major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs; however, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts. IPM assumes these longer-term price arrangements take place "outside of the model" and on top of the "real-time" shorter-term price variation necessary to align supply and demand. Therefore, the model's natural gas price projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the time period 2015 to 2030.

For this analysis, in order to represent a natural gas price evolution that end-use consumers can anticipate under retail rate regulation and/or typical hedging behavior, EPA is displaying the weighted average of IPM's natural gas price projections for the 2015-2030 time horizon (see Table 3-14). In that framework, consumer natural gas price impacts are anticipated to range from 0.3% to 0.6% based on consumer class in response to MATS.

3.11 Key Differences in EPA Model Runs for MATS Modeling

In this analysis, we use the Integrated Planning Model (IPM), which is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector.[9] The length of time required to conduct emissions and photochemical modeling precluded the use of IPM version 4.10_MATS. Thus the air quality modeling for MATS relied on EGU emission projections from an interim IPM platform that was subsequently updated during the rulemaking process for the base case and policy scenario summarized in this chapter. The 2015 base case EGU emissions projections of mercury, hydrogen chloride, SO_2, and PM used in air quality modeling were obtained from an earlier version of IPM, 4.10_FTransport. IPM version 4.10_FTransport reflects all state rules and consent decrees adopted through December 2010. Units with SO_2 or NO_X advanced controls (e.g., scrubber, SCR) that were not required to run for compliance with Title IV, New Source Review (NSR), state settlements, or state-specific rules were allowed in IPM to decide on the basis of economic efficiency whether to operate those controls. Note that this base case includes CSAPR, which was finalized in July 2011. Further details on the EGU emissions inventory used for this proposal can be found in the IPM Documentation.

The results presented in this chapter, from IPM version 4.10_MATS, reflect updates made to the 4.10_FTransport base case. These revisions are fully documented in the IPM 4.10 Supplemental Documentation for MATS and include: updated assumptions regarding the removal of HCl by alkaline fly ash in subbituminous and lignite coals; an update to the fuel-based mercury emission factor for petroleum coke, which was corrected based on re-examination of the 1999 ICR data; updated capital cost for new nuclear capacity and nuclear life extension costs; corrected variable operating and maintenance cost (VOM) for ACI retrofits; adjusted coal rank availability for some units, consistent with EIA From 923 (2008); updated state rules in Washington and Colorado; and numerous unit-level revisions based on comments received through the notice and comment process. Additionally, IPM v.4.10_MATS does not reflect mercury-specific state regulations (see section 1 above).

[9] http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html

3.12 Projected Primary PM Emissions from Power Plants

IPM does not endogenously model primary PM emissions from power plants. These emissions are calculated as a function of IPM outputs, emission factors and control configuration. IPM-projected fuel use (heat input) is multiplied by PM emission factors (based in part on the presence of PM-relevant pollution control devices) to determine PM emissions. Primary PM emissions are calculated by adding the filterable PM and condensable PM emissions.

Filterable PM emissions for each unit are based on historical information regarding existing emissions controls and types of fuel burned and ash content of the fuel burned, as well as the projected emission controls (e.g., scrubbers and fabric filters).

Condensable PM emissions are based on plant type, sulfur content of the fuel, and SO_2/HCl and PM control configurations. Although EPA's analysis is based on the best available emission factors, these emission factors do not account for the potential changes in condensable PM emissions due to the installation and operation of SCRs. The formation of additional condensable PM (in the form of SO_3 and H_2SO_4) in units with SCRs depends on a number of factors, including coal sulfur content, combustion conditions and characteristics of the catalyst used in the SCR, and is likely to vary widely from unit to unit. SCRs are generally designed and operated to minimize increases in condensable PM. This limitation means that IPM post-processing is potentially underestimating condensable PM emissions for units with SCRs. In contrast, it is possible that IPM post-processing overestimates condensable PM emissions in a case where the unit is combusting a low-sulfur coal in the presence of a scrubber.

EPA plans to continue improving and updating the PM emission factors and calculation methodologies. For a more complete description of the methodologies used to post-process PM emissions from IPM, see "IPM ORL File Generation Methodology" (March, 2011).

3.13 Illustrative Dry Sorbent Injection Sensitivity

Several commenters believe that EPA's IPM modeling assumptions regarding the efficacy and cost of DSI are based on too little data and are too optimistic. Some commenters believe that in practice there will be a need for many more FGD scrubbers for MATS compliance than projected by EPA for effective acid gas control, and at a corresponding higher cost. EPA disagrees with these opinions for several reasons (see the response to comments document in the docket) and believes that EPA's modeling assumptions regarding DSI cost and performance are reasonable.

However, to examine the potential impacts of limited DSI availability, EPA analyzed a scenario that limited total DSI capacity to 35 GW in 2015. In this scenario, which reduces the capacity of DSI by 18 GW compared to the primary MATS scenario, an additional 14 GW of coal capacity chooses to install scrubbers, and an additional 1.3 GW of capacity is projected to withdraw from service.

Limiting total DSI capacity to 35 GW results in a $1.2 billion (2007$) increase in annualized compliance costs in 2015. Additionally, SO_2 is further reduced in 2015 by an additional 62,000 tons (a 4.7% increase in SO_2 reductions and 4.5% increase in health benefits).

3.14 Additional Compliance Costs Analyzed for Covered Units

3.14.1 Compliance Cost for Oil-Fired Units.

As discussed in section 3.1, EPA used IPM to assess impacts of the MATS emission limitations for coal-fired EGUs but did not use IPM to assess the impacts for oil-fired units. IPM, with its power system and fuel cost assumptions, predicts many dual fuel units switch to natural gas and oil-fired units will not operate because IPM focuses on least cost operation of the power system. However, despite their apparent economic disadvantages, many of these units have run during many of the past five years (2006-2010). Therefore, EPA conducted a separate analysis to assess the impacts of the MATS emission limitations for oil-fired units.[10] EPA limited this analysis to oil-fired units in the contiguous U.S. Although there are several oil-fired units in states and territories outside the contiguous U.S., the final MATS emission limitations (shown in Table 3-2) for non-continental units will likely allow these units to continue firing residual fuel oil without additional air pollution controls.

For the base case, EPA categorized units by modeled fuels as listed in NEEDS 4.10 (EPA, December 2010) and assigned each unit the least-cost fuel among its available fuels. For units with natural gas curtailment provisions that might require the firing of residual fuel oil, EPA assigned a mixed fuel ratio based on each unit's 2008-2010 weighted average natural gas-to-fuel oil ratio. For the policy case, EPA assessed three compliance options: (1) switching to natural gas where available, (2) switching to distillate fuel oil, and (3) installing an electrostatic precipitator (ESP) capable of 90% particulate removal efficiency. These compliance options address particulate emissions only. However, there might be additional emission reductions that result from changes to oil-fired units' generation due to changes in relative generating costs.

[10] Additional details and methodology for the analysis are presented in appendix 3A.

Between the base case and policy case, 12 units convert from residual fuel oil to distillate fuel oil at a cost of approximately $12 million annually (2007$) to meet the MATS emission limitations for oil-fired units. An additional 11 units, eight of which are subject to natural gas curtailment, that do not have existing ESP particulate pollution controls install an ESP at a cost of approximately $44 million annually (2007$) to achieve the MATS emission limitations for oil-fired units (see Table 3-15). EPA believes the emission impacts from these potential actions will be relatively small when compared to the full impacts of the MATS emission limitations because particulate emissions from oil-fired units are a small fraction of the total particulate emissions from EGUs.

Table 3-15. Cost Impacts of Compliance Actions for Oil-Fired Units

Compliance option	Number of units affected	Capacity of units affected	Annual cost (2007$)
Switch to distillate fuel oil	12	2,675 MW	$12 million
Install ESP for residual fuel oil	11	4,015 MW	$44 million
Total	**23**	**6,690 MW**	**$56 million**

3.14.2 Monitoring, Reporting and Record-keeping Costs

The annual monitoring, reporting, and record-keeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $158 million. This includes 698,907 labor hours per year at a total labor cost of $49 million per year, and total non-labor capital costs of $108 million per year. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and record-keeping. Initial capital expenses to purchase monitoring equipment for affected units are estimated at a cost of $231 million. This includes 504,629 labor hours at a total labor cost of $35 million for planning, selection, purchase, installation, configuration, and certification of the new systems and total non-labor capital costs of $196 million. All burden estimates are in 2007 dollars and represent the most cost effective monitoring approach for affected facilities. See Section 7.3, Paperwork Reduction Act.

3.14.3 Total Costs Projected for Covered Units under MATS

EPA used IPM to analyze the compliance cost, and economic and energy impacts of the MATS rule. IPM estimated the costs for coal-fired electric utility steam generating units that burn coal, coal refuse, or solid-oil derived fuel. EPA did not use IPM, however, estimate compliance costs for most oil/gas steam boilers because IPM projection shows least-cost dispatch in an environment where oil/gas-fired units are primarily selecting natural gas on an economic basis. In the separate analysis summarized above, EPA estimates compliance costs for oil-fired EGUs in a scenario in which these units continue to burn oil as historically observed and thus take compliance measures to remain on oil. This is a reasonable estimate of compliance costs for these units, but does not represent a re-balancing of electricity dispatch where these units combust oil rather than natural gas. Therefore, the summation of IPM-projected compliance costs for least-cost dispatch with the oil-fired compliance costs and the monitoring, reporting, and record-keeping costs is a reasonable approximation of total compliance costs, but does not represent projected compliance costs under an economically efficient dispatch (see Table 3-16).

Table 3-16. Total Costs Projected for Covered Units under MATS, 2015 (billions of 2007$)

	2015
IPM Projection	$9.4
Monitoring/Reporting/Record-keeping	$0.158
Oil-Fired Fleet	$0.056
Total	$9.6

3.15 Limitations of Analysis

EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are in fact uncertain. Assumptions for future fuel supplies and electricity demand growth deserve particular attention because of the importance of these two key model inputs to the power sector. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions.

The IPM-projected annualized cost estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the final rule. To estimate these annualized costs, EPA uses a conventional and widely-accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are EPA's best estimate of the direct private compliance costs of MATS.

The annualized cost of the final rule, as quantified here, is EPA's best assessment of the cost of implementing the rule. These costs are generated from rigorous economic modeling of changes in the power sector due to implementation of MATS. This type of analysis using IPM has undergone peer review, and federal courts have upheld regulations covering the power sector that have relied on IPM's cost analysis.

Cost estimates for MATS are based on results from ICF's Integrated Planning Model. The model minimizes the costs of producing electricity (including abatement costs) while meeting load demand and other constraints (full documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm and in the IPM 4.10 Supplemental Documentation for MATS. IPM assumes "perfect foresight" of market conditions over the time horizon modeled; to the extent that utilities and/or energy regulators misjudge future conditions affecting the economics of pollution control, costs may be understated as well.

In the policy case modeling, EPA exogenously determines that a subset of covered units might require a retrofit fabric filter (also known as a baghouse) retrofit, or might need to upgrade existing ESP control in order to meet the PM standard. EPA's methodology for assigning these controls to EGUs in policy case modeling is based on historic PM emission rates and reported control efficiencies, and is explained in the IPM 4.10 Supplemental Documentation for MATS.

Additionally, this modeling analysis does not take into account the potential for advancements in the capabilities of pollution control technologies as well as reductions in their costs over time. In addition, EPA modeling cannot anticipate in advance the full spectrum of compliance strategies that the power sector may innovate to achieve the required emission reductions under MATS, which would potentially reduce overall compliance costs. Where possible, EPA designs regulations to assure environmental performance while preserving flexibility for affected sources to design their own solutions for compliance. Industry will employ an array of responses, some of which regulators may not fully anticipate and will generally lead to lower costs associated with the rule than modeled in this analysis. For example, unit operators may find opportunities to improve or upgrade existing pollution control equipment without requiring as many new retrofit devices (i.e., meeting the PM standard with an existing ESP without requiring installation of a new fabric filter).

With that in mind, MATS establishes emission rates on key HAPs, and although this analysis projects a specific set of technologies and behaviors as EPA's judgment of least-cost compliance, the power sector is free to adopt alternative technologies and behaviors to achieve the same environmental outcome EPA has deemed in the public interest as laid out in the Clean Air Act. Such regulation serves to promote innovation and the development of new and cheaper technologies. As an example, cost estimates of the Acid Rain SO_2 trading program by Resources for the Future (RFF) and MIT's Center for Energy and Environmental Policy Research (CEEPR) have been as much as 83 percent lower than originally projected by the EPA (see Carlson et al., 2000; Ellerman, 2003). It is important to note that the original analysis for the Acid Rain Program done by EPA also relied on an optimization model like IPM. Ex ante, EPA cost estimates of roughly $2.7 to $6.2 billion[11] in 1989 were an overestimate of the costs of the program in part because of the limitation of economic modeling to perfectly anticipate technological improvement of pollution controls and economic improvement of other compliance options such as fuel switching. Ex post estimates of the annual cost of the Acid Rain SO_2 trading program range from $1.0 to $1.4 billion.

In recognition of this historic pattern of overestimated regulatory cost, EPA's mobile source program uses adjusted engineering cost estimates of pollution control equipment and installation costs.[12] To date, and including this analysis, EPA has not incorporated a similar approach into IPM modeling of EGU compliance with environmental constraints. As a result, this analysis may overstate costs where such cost savings from as-yet untapped improvements to pollution control technologies may occur in the future. Considering the broad and complex suite of generating technologies, fuels, and pollution control strategies available to the power sector, as well as the fundamental role of operating cost in electricity dispatch, it is not possible to apply a single technology-improving "discount" transformation to the cost projections in this analysis. The Agency will consider additional methodologies in the future which may inform the amount by which projected compliance costs could be overstated regarding further technological development in analyses of power sector regulations.

As configured in this application, IPM does not take into account demand response (i.e., consumer reaction to electricity prices). The increased retail electricity prices shown in Table 3-13 would prompt end users to increase investment in energy efficiency and/or curtail (to some extent) their use of electricity and encourage them to use substitutes.[13] Those responses would lessen the demand for electricity, resulting in electricity price increases slightly lower than IPM predicts, which would also reduce generation and emissions. Demand response would yield certain unquantified cost savings from requiring less electricity to meet the quantity demanded. To some degree, these saved resource costs will offset the additional costs

[11] 2010 Phase II cost estimate in $1995.

[12] See regulatory impact analysis for the Tier 2 Regulations for passenger vehicles (1999) and Heavy-Duty Diesel Vehicle Rules (2000).

[13] The degree of substitution/curtailment depends on the costs and performance of the goods that substitute for more energy consuming goods, which is reflected in the demand elasticity.

of pollution controls and fuel switching that EPA anticipates from the final rule, although there could be some increase in social cost resulting from any decrease in electricity consumption. Although the reduction in electricity use is likely to be small, the cost savings from such a large industry[14] are not insignificant. EIA analysis examining multi-pollutant legislation in 2003 indicated that the annualized costs of MATS may be overstated substantially by not considering demand response, depending on the magnitude and coverage of the price increases.[15]

EPA's IPM modeling of MATS reflects the Agency's authority to allow facility-level compliance with the HAP emission standards rather than require each affected unit at a given facility to meet the standards separately. This flexibility would offer important cost savings to facility owners in situations where a subset of affected units at a given facility could be controlled more cost-effectively such that their "overperformance" would compensate for any "underperformance" of the rest of the affected units. EPA's modeling in this analysis required the average emission rate across all affected units at a given facility to meet the standard. This averaging flexibility has the potential to offer further cost savings beyond this analysis if particular units find ways to achieve superior pollution control beyond EPA's assumptions of retrofit technology performance at the modeled costs (which could then reduce the need to control other units at the same facility).

Additionally, EPA has chosen to express most of the control requirements here as engineering performance standards (e.g., lbs/MMBtu of heat input), which provide power plant operators goals to meet as they see fit in choosing coals with various pollutant concentrations and pollutant control technologies that they adopt to meet the requirements. Historically, such an approach encourages industry to engineer cheaper solutions over time to achieve the pollution controls requirements.

EPA's IPM modeling is based on retrofit technology cost assumptions which reflect the best available information on current and foreseeable market conditions for pollution control deployment. In the current economic environment, EPA does not anticipate (and thus this analysis does not reflect) significant near-term price increases in retrofit pollution control supply chains in response to MATS. To the extent that such conditions may develop during the

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[14] Investor-owned utilities alone accounted for nearly $300 billion in revenue in 2008 (EIA).

[15] See "Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003." Energy Information Administration. September, 2003. EIA modeling indicated that the Clear Skies Act of 2003 (a nationwide cap and trade program for SO_2, NO_X, and mercury), demand response could lower present value costs by as much as 47% below what it would have been without an emission constraint similar to the Transport Rule.

sector's installation of pollution control technologies under the final rule, this analysis may understate the cost of compliance.

3.16 Significant Energy Impact

MATS would have a significant impact according to *E.O. 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use*. Under the provisions of this rule, EPA projects that approximately 4.7 GW of coal-fired generation (less than 2 percent of all coal-fired capacity and 0.5% of total generation capacity in 2015) may be removed from operation by 2015. These units are predominantly smaller and less frequently-used generating units dispersed throughout the area affected by the rule. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to keep these units operational.

EPA also projects fuel price increases resulting from MATS. Average retail electricity price are shown to increase in the contiguous U.S. by 3.1 percent in 2015. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, the average delivered coal price increases by less than 2 percent in 2015 as a result of shifts within and across coal types. As discussed above in section 8.10, EPA also projects that electric power sector-delivered natural gas prices will increase by about 0.6% percent over the 2015-2030 timeframe and that natural gas use for electricity generation will increase by less than 200 billion cubic feet (BCF) in 2015. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 10 million tons in 2015 from base case levels, which is about 1 percent of total coal produced for the electric power sector in that year. The EPA does not believe that this rule will have any other impacts (e.g., on oil markets) that exceed the significance criteria.

3.17 References

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APPENDIX 3A

COMPLIANCE COSTS FOR OIL-FIRED ELECTRIC GENERATING UNITS

This appendix highlights the supplemental oil-fired electric generating unit (EGU) compliance cost analysis performed for the Mercury and Air Toxics Standards (MATS). EPA used the Integrated Planning Model (IPM) to assess the cost, economic, and energy impacts of the MATS emission limitations on coal-fired EGUs in the contiguous U.S., but did not use IPM to assess the compliance costs for oil-fired EGUs because IPM focuses on the least cost operation of the power system and, therefore, predicts the oil-fired units will not operate. These oil-fired units, however, do not operate on a purely economic basis. Some oil-fired units may operate as "must run", "black start", or "spinning reserve". In addition, some dual fuel fired units which IPM predicts will fire natural gas may be required to fire fuel oil when subject to mandatory curtailment of natural gas supplies.

When practicable, this supplemental analysis for oil-fired EGUs was based on the data and assumptions used in IPM. Documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm.

3A.1 Methodology and Assumptions

3A.1.1 Base Case

EPA developed the base case for oil-fired units listed in the National Electric Energy Data System (hereafter, NEEDS) (EPA, 2010a). NEEDS lists 302 "oil/gas steam" units greater than 25 MW for which distillate fuel oil and/or residual fuel oil are among the modeled fuels (see Table 3A-1).[16] For each of these units, EPA projected 2015 heat input and apportioned the heat input among the NEEDS modeled fuels. EPA used each unit's average annual heat input from 2006-2010[17] as a proxy for 2015 heat input. For units not subject to mandatory natural gas curtailment, EPA assumed the unit fired the least cost fuel available based on regional IPM fuel cost projections for 2015. For units that may be required to fire fuel oil due to mandatory natural gas curtailment, EPA apportioned the heat input based on the unit's weighted average natural gas and fuel oil apportionment from 2008-2010.[18] EPA used the three most recent years because, as a percentage of total heat input, fuel oil heat input has fallen steadily since 2007 (see Figure 3A-1). With increased availability of natural gas in the New York region from new

[16] One unit, Charles Poletti unit 001 (ORIS 2491), was removed because the unit retired in 2010 (EPA, 2011).

[17] Designated representatives for each of the oil-fired units included in this analysis certify and report hourly heat input and emission data to EPA under 40CFR Part 75.

[18] The units subject to mandatory natural gas curtailment report fuel-apportioned heat input to EPA under 40CFR Part 75 (Appendix D). EPA categorized "diesel" as distillate fuel oil and "oil" and "other oil" as residual fuel oil.

gas supplies and new gas pipelines (FERC, 2011), it is likely this trend will continue even in the absence of the MATS. Therefore, using a longer historical period might significantly overestimate the proportion of heat input derived from fuel oil for these units.

Table 3A-1. Oil-fired EGUs by Fuel Type

NEEDS modeled fuel	Number of units	Capacity (MW)
Distillate fuel oil	10	814
Distillate fuel oil, natural gas	99	19,822
Residual fuel oil	17	5,867
Residual fuel oil, distillate fuel oil	15	1,187
Residual fuel oil, natural gas	149	39,913
Residual fuel oil, distillate fuel oil, natural gas	12	3,706

Source: EPA. 2010. National Electricity Energy Data System (NEEDS 4.10). Available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html.

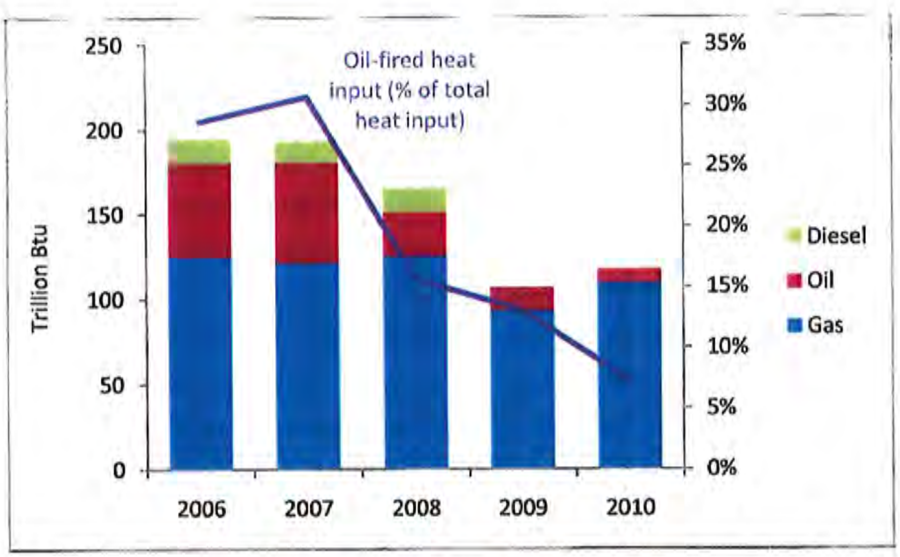

Figure 3A-1. 2006-2010 Heat Input Apportioned by Fuel for Oil-Fired Units Subject to Mandatory Natural Gas Curtailment

Source/Notes: EPA. 2011. Data and Maps. Available at: http://epa.gov/camddataandmaps/

Power companies are responding to fuel prices, natural gas supplies, and other market factors by replacing some oil-gas steam units with new combined cycle plants (Neville, J. 2011). EPA did not, however, factor in the effect of expanded availability of natural gas on the utilization of these oil-fired units. As a result, this analysis likely overestimates the impact of the MATS emission limitations on oil-fired units.

In the base case, natural gas is the least cost fuel for the majority of units (see Table 3A-2). However, 41 units are expected to continue burning some amount of residual fuel oil because the units are subject to mandatory natural gas curtailment or may not have access to natural gas supplies.[19] Of these 41 units, 14 have existing electrostatic precipitator (ESP) particulate pollution controls.

Table 3A-2. Least Cost NEEDS Modeled Fuels for Oil-fired EGUs

NEEDS modeled fuel	Number of units	Capacity (MW)
Distillate fuel oil	19	1,228
Residual fuel oil	23	6,640
Natural gas	242	57,232
Natural gas with mandatory curtailment	18	6,208

3A.1.2 Policy Case

For the policy case, EPA considered three actions to comply with the MATS emission limitations: (1) switching to natural gas where available, (2) switching to distillate fuel oil, and (3) ESP particulate pollution control capable of 90% particulate removal efficiency. EPA modeled the cost of actions 2 and 3 for each unit in the base case. EPA did not model the cost of converting to natural gas because, for units with natural gas as a NEEDS modeled fuel, it was the least cost fuel and therefore the base case fuel for the unit. The cost of switching a unit's heat input to distillate fuel oil was based on the cost of converting operations, including tank, line, and pump cleaning and burner atomizer assembly replacement, and the unit's 2015 projected heat input from residual fuel oil multiplied by the cost difference between residual fuel oil and distillate fuel oil in the region where the unit is located. Conversion costs were annualized using the methodology described in the IPM documentation (EPA, 2010b).

The cost of installing a flat plate-type ESP on oil-fired model units of various sizes was calculated using the methodology outlined in EPA's Cost Manual (EPA, 2002) and adjusted to 2010 values using the Chemical Engineering Plant Cost Index (CEPCI). EPA developed non-linear

[19] To ensure the analysis was not likely to underestimate compliance costs, EPA assumed units that do not include natural gas as a NEEDS modeled fuel do not have access to a natural gas pipeline. The cost of obtaining pipeline access for these units was assumed to be uneconomical and was not modeled in the analysis.

regression power functions similar to those used for costing air pollution controls in IPM. The cost functions are shown in equations (3A.1)-(3A.3).

$$\text{Capital costs} = 243{,}494.4 \text{ X } (\text{MW capacity})^{0.7800} \tag{3A.1}$$

$$\text{Annual fixed costs} = 13{,}883.4 \text{ X } (\text{MW capacity})^{0.7294} \tag{3A.2}$$

$$\text{Annual variable costs} = 8{,}108.6 \text{ X } (\text{MWh generation})^{0.8632} \tag{3A.3}$$

Capital costs were annualized using the capital cost recovery factor used in the IPM documentation (EPA, 2010b). Annual variable costs were calculated using the predicted 2015 generation from residual fuel oil based on the unit's base case 2015 residual fuel oil heat input and the unit's heat rate listed in NEEDS (EPA, 2010a).

3A.1.3 Cost Sensitivities Related to Mandatory Natural Gas Curtailment

There are 18 dual fuel fired units (i.e., units capable of firing both gas and oil) that are subject to mandatory natural gas curtailment. Of these units, six have existing ESP particulate pollution controls installed. For the remaining 12 units, nine fired natural gas for more than 90 percent of their total heat input (see Table 3A-3). Because the MATS emission limits do not apply to units that fire coal or oil for less than 10 percent of total heat input averaged over three years or 15 percent in a single year, EPA analyzed historical oil-fired heat input between 2006 and 2010 at these units and found that four dual fuel fired units subject to mandatory natural gas curtailment did not exceed 15 percent in any single year and averaged less than 10 percent across all three year periods between 2006 and 2010. EPA did not include the cost of control on these units in the summary results. If these four units were to install ESPs, however, the annual compliance cost of the MATS emission limits would increase $13 million (2007$).

As noted in 3A.1.1, natural gas supplies to the region are increasing and operating data for dual fuel fired units subject to mandatory natural gas curtailment indicate that their proportion of heat input from residual oil is declining. There are four units in addition to those described in the paragraph above that exceeded 15 percent oil-fired heat input in 2006 and/or 2007, but between 2008 and 2010 did not exceed 15 percent oil-fired heat input in a single year and averaged below 10 percent across all three years. These units were assigned ESP particulate pollution controls in this analysis. However, if these four dual fuel fired units do not install ESPs, the annual compliance cost of the MATS emission limits would decline $16 million (2007$).

Table 3A-3. Percentage of Total Heat Input Derived from Oil for Oil-Fired Units Subject to Mandatory Natural Gas Curtailment (2008-2010)

Percentage	Number of units
< 1.0%	4
1.0% to 4.9%	1
5.0% to 9.9%	4
10.0% to 15.0%	3

3A.2 Results

For the purpose of estimating the impacts of the MATS emission limitations for oil-fired units, EPA had to make assumptions about the compliance actions oil-fired units will take. Table 3A-4 lists those assumptions based on differences between the base and policy cases. EPA assumed that the least cost compliance option for 12 residual fuel oil-fired units would be converting to distillate fuel oil at an annual cost of approximately $12 million (2007$). An additional 11 units would likely continue to burn residual fuel oil following the installation of an ESP at a cost of approximately $44 million annually (2007$).

Table 3A-4. Costs to Achieve the MATS Emission Limitations for Oil-Fired Units

Unit	Compliance action	Annual cost (2007$)
Cleary Flood, Unit 8	Distillate fuel oil	$ 308,000
Jefferies, Unit 1	Distillate fuel oil	$ 642,000
Jefferies, Unit 2	Distillate fuel oil	$ 673,000
McManus, Unit 1	Distillate fuel oil	$ 391,000
McManus, Unit 2	Distillate fuel oil	$ 512,000
Montville Station, Unit 6	Distillate fuel oil	$ 3,968,000
Possum Point, Unit 5	Distillate fuel oil	$ 119,000
Schuylkill Generating Station, Unit 1	Distillate fuel oil	$ 2,113,000
Vienna Operations, Unit 8	Distillate fuel oil	$ 1,741,000
William F Wyman, Unit 1	Distillate fuel oil	$ 783,000
William F Wyman, Unit 2	Distillate fuel oil	$ 646,000
Yorktown, Unit 3	Distillate fuel oil	$ 119,000
Astoria Generating Station, Unit 30	ESP	$ 4,214,000
Astoria Generating Station, Unit 40	ESP	$ 4,132,000
Astoria Generating Station, Unit 50	ESP	$ 4,202,000
B L England, Unit 3	ESP	$ 2,155,000
East River, Unit 60	ESP	$ 1,844,000
East River, Unit 70	ESP	$ 2,336,000
Herbert A Wagner, Unit 4	ESP	$ 4,352,000
Middletown, Unit 4	ESP	$ 4,391,000
Ravenswood, Unit 10	ESP	$ 3,904,000
Ravenswood, Unit 20	ESP	$ 3,898,000
Ravenswood, Unit 30	ESP	$ 8,322,000

3A.3 References

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