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for the Transport Rule

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Updates to EPA Base Case v3.02 EISA Using the Integrated Planning Model

U.S. Environmental Protection Agency

Office of Air and Radiation

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Updates to EPA Base Case v3.02 EISA Using the Integrated Planning Model

This document describes EPA Base Case v3.02 EISA using the Integrated Planning Model (IPM), the version used to model electric generation for the proposed Transport Rule. It builds on the last major update, EPA Base Case 2006 (v3.0), and a subsequent minor update from 2007 (v3.01).

In the fall of 2006, EPA released Base Case 2006 (v3.0) using IPM, which included extensive updates of IPM's assumptions, inputs, and capabilities. The model was again updated in the summer of 2007 for purposes of climate modeling (v3.01). In preparing these base cases, EPA obtained input from nationally recognized experts in fuels, technology, and power system operation. Power companies provided information on generating resources and emission controls. EPA also obtained input from Regional Planning Organizations, States, and their constituent organizations. Key updates included:

- Coal Supply and Transportation Assumptions
- Natural Gas Assumptions
- Federal and State Emission Regulations and Enforcement Actions
- Cost and Performance of Generating Technologies and Emission Controls
- Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_X) emissions
- Power System Operating Characteristics and Structure
- Electric Generating Unit Inventory
- Modeling Time Horizon and Run Years (2010, 2015, 2020, 2025)
- Carbon capture and storage for potential (new) units
- Biomass co-firing capability for existing coal boilers
- Updated constraints on new nuclear and renewable capacity builds

The detailed assumptions for Base Case 2006 (v3.0), titled "Documentation for EPA Base Case 2006 (v3.0) Using the Integrated Planning Model" (November 2006) can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs. Likewise, documentation on the updates made for v3.01 can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/Documentation%20for%20EPA%27s%20Base%20Case%20v3.01%20Using%20IPM.pdf

Compared to these earlier versions, v3.02 EISA contains updates to several key features of the model:

1. Revised electricity demand (largely driven by the Energy Independence and

Security Act of 2007 (EISA))
2. Updated power technology costs for new units
3. Updated power technology costs for retrofit controls
4. Updated natural gas supply assumptions
5. Updated NSR and state rules (through February 3, 2009)
6. Dispatchable flue gas deposition (FGD) and selective catalytic reduction (SCR) retrofits
7. Updates to the National Electric Energy Data System (NEEDS)
8. Title IV SO_2 allowance bank estimate
9. Updated mapping of model run years
10. Updated financial assumptions

The following document summarizes the key features and changes found in Base Case v3.02 EISA.

Overview of IPM and EPA Modeling Applications[1]

EPA uses the Integrated Planning Model (IPM) to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. Developed by ICF Resources, Inc., and used to support public and private sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting electricity demand, environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon dioxide (CO_2), and mercury (Hg) from the electric power sector and is used extensively by EPA to support regulatory activities. Updates for this version of the model were primarily focused on allowing strong analysis of regional SO_2 and NO_X reductions.

Among the factors that make IPM particularly well suited to model multi-emissions control programs are (1) its ability to capture complex interactions among the electric power, fuel, and environmental markets; (2) its detail-rich representation of emission control options encompassing a broad array of retrofit technologies along with emission reductions through fuel switching, changes in capacity mix and electricity dispatch strategies; (3) its capability to model a variety of environmental regulatory structures such as state and regional cap and trade programs and source specific controls; and its ability to generate the detailed, location-specific emission data required for air quality

[1] See also Appendix I of this document.

modeling. IPM's ability to capture the dynamics of the allowance market (including banking) and its provision of a wide range of emissions reduction options are particularly important for assessing the impact of multi-emissions environmental policies for the power sector.

IPM is a single sector, linear programming model that captures the economic behavior of the power sector. It has been used by itself to analyze many power specific policies including: the Title IV NO_X Program, the NO_X SIP Call and CAIR. The model has also been employed by EPA in conjunction with broader macroeconomic models to help provide deeper resolution of the power sector than is available in most macro-economic models.

1. Electricity Demand

The electric load assumptions in Base Case v3.02 EISA are shown in Table 1 below. These values were derived based on the electricity sales forecast in the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2008 reflecting EISA 2007. The revised growth rate used in the reference case is nearly 1%, compared to a growth rate of 1.5% in past IPM modeling applications.

Table 1. Net Energy for Load in EPA v3.02 EISA Base Case (GWh)

Year	Net Energy For Load (GWh)
2012	4,223,337
2015	4,287,367
2020	4,498,173
2025	4,717,525

2. Potential (New) Unit Costs

Costs for potential units have been updated to incorporate more recent higher-cost market conditions than used in IPMv3.0 and v3.01. EPA uses both EIA and independent analysis to support cost and performance assumptions for new power generating technologies in IPM. The costs used here are generally higher than those reflected in AEO 2008. Tables 2 and 3 below show the cost and performance characteristics of the modeled potential (new) build units.

Table 2. Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in v3.02 EISA Base Case

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle - Bituminous	Integrated Gasification Combined Cycle - Subbituminous	Integrated Gasification Combined Cycle with Carbon Capture-Bituminous	Integrated Gasification Combined Cycle with Carbon Capture - Subbituminous	Supercritical Pulverized Coal - Wet Bituminous	Supercritical Pulverized Coal Dry Sub-Bituminous
Size (MW)	400	230	1350	550	550	380	380	600	600
First Year Available	2013	2012	2020	2015	2015	2015	2015	2015	2015
Lead Time (Years)	3	2	6	4	4	4	4	4	4
Vintage #1 (years covered)	2012 - 2013	2012 - 2013	--	--	--	--	--	--	--
Vintage #2 (years covered)	2014 - 2017	2014 - 2017	--	2014 - 2017	2014 - 2017	2014 - 2017	2014 - 2017	2014 - 2017	2014 - 2017
Vintage #3 (years covered)	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022
Vintage #4 (years covered)	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035
Availability	87%	92%	90%	80%	80%	80%	80%	85%	85%
Vintage #1									
Heat Rate (Btu/kWh)	6,720	10,200	--	--	--	--	--	--	--
Capital (2006$/kW)	800	535							
Fixed O&M (2006$/kW/yr)	9.8	11.6							
Variable O&M (2006$/MWh)	1.32	2.42							
Vintage #2									
Heat Rate (Btu/kWh)	6,720	10,200	--	8,920	9,310	10,510	11,000	9,000	9,170
Capital (2006$/kW)	780	519		1,980	2,310	2,610	3,000	1,800	1,750
Fixed O&M (2006$/kW/yr)	9.8	11.6		35.3	39.5	43.7	48.6	25.7	25.2
Variable O&M (2006$/MWh)	1.32	2.42		6.49	7.17	8.1	9.0	4.97	4.87
Vintage #3									
Heat Rate (Btu/kWh)	6,720	10,200	10,400	8,920	9,310	10,510	11,000	9,000	9,170
Capital (2006$/kW)	765	508	3,000	1,936	2,259	2,553	2,934	1,768	1,719
Fixed O&M (2006$/kW/yr)	9.8	11.6	66.1	35.3	39.5	43.7	48.6	25.7	25.2
Variable O&M (2006$/MWh)	1.32	2.42	0.48	6.49	7.17	8.1	9.0	4.97	4.87
Vintage #4									
Heat Rate (Btu/kWh)	6,720	10,200	10,400	8,920	9,310	10,510	11,000	9,000	9,170
Capital (2006$/kW)	745	490	2,784	1,883	2,197	2,482	2,853	1,739	1,691
Fixed O&M (2006$/kW/yr)	9.8	11.6	66.1	35.3	39.5	43.7	48.6	25.7	25.2
Variable O&M (2006$/MWh)	1.32	2.42	0.48	6.49	7.17	8.1	9.0	4.97	4.87

Note: Capital costs represent overnight capital costs

Table 3. Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in v3.02 EISA Base Case

	Biomass Conventional	Biomass Gasification Combined Cycle	Fuel Cells	Geothermal	Landfill Gas			Solar Photovoltaic	Solar Thermal	Wind
					LGHI	LGLo	LGVLo			
Size (MW)	35	120	10	50	30			5	100	50
First Year Available	2012	2020	2012	2012	2012			2012	2012	2012
Lead Time (Years)	3	4	3	4	3			2	3	3
Vintage #1 (years covered)	2012 - 2013	--	2012 - 2013	2012 - 2035	2012 - 2013	2012 - 2013	2012 - 2013	2012 - 2013	2012 - 2013	2012 - 2013
Vintage #2 (years covered)	2014 - 2017	--	2014 - 2017		2014 - 2017	2014 - 2017	2014 - 2017	2014 - 2017	2014 - 2017	2014 - 2017
Vintage #3 (years covered)	2018 - 2022	2018 - 2022	2018 - 2022		2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022	2018 - 2022
Vintage #4 (years covered)	2023 - 2035	2023 - 2035	2023 - 2035		2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035	2023 - 2035
Availability	85%	80%	87%	87%	90%			90%	90%	95%
Generation Capability	Economic Dispatch		Economic Dispatch	Economic Dispatch	Economic Dispatch			Generation Profile	Generation Profile	Generation Profile
Vintage #1										
Heat Rate (Btu/kWh)	13,500	--	7,930	29,660 - 397,035	13,648	13,648	13,648	0	0	0
Capital (2006$/kW)	3,000		5,374	1,049 - 13,352	1,881	2,370	3,649	4,915	3,004	1,707 - 4,558
Fixed O&M (2006$/kW/yr)	83.0		5.5	147 - 212	111.2	111.2	111.2	11.4	55.2	29.5
Variable O&M (2006$/MWh)	11.30		46.62	0	0.01	0.01	0.01	0	0	0
Vintage #2										
Heat Rate (Btu/kWh)	13,500	--	7,930	--	13,648	13,648	13,648	0	0	0
Capital (2006$/kW)	3,000		5,374		1,881	2,370	3,649	4,915	3,004	1,707 - 4,558
Fixed O&M (2006$/kW/yr)	83.0		5.5		111.2	111.2	111.2	11.4	55.2	29.5
Variable O&M (2006$/MWh)	11.30		46.62		0.01	0.01	0.01	0	0	0
Vintage #3										
Heat Rate (Btu/kWh)	13,500	9,800	7,930	--	13,648	13,648	13,648	0	0	0
Capital (2006$/kW)	2,700	2,600	5,374		1,828	2,304	3,547	4,330	2,523	1,693 - 4,522
Fixed O&M (2006$/kW/yr)	83.0	47.0	5.5		111.2	111.2	111.2	11.4	55.2	29.5
Variable O&M (2006$/MWh)	11.30	8.60	46.62		0.01	0.01	0.01	0	0	0
Vintage #4										
Heat Rate (Btu/kWh)	13,500	9,800	7,930	--	13,648	13,648	13,648	0	0	0
Capital (2006$/kW)	2,700	2,600	5,374		1,828	2,304	3,547	4,330	2,523	1,693 - 4,522
Fixed O&M (2006$/kW/yr)	83.0	47.0	5.5		111.2	111.2	111.2	11.4	55.2	29.5
Variable O&M (2006$/MWh)	11.30	8.60	46.62		0.01	0.01	0.01	0	0	0

Note: Capital costs represent overnight capital costs

3. Pollution Retrofit Costs

The following is a tabular representation of the engineering equations that were used to generate the input costs for NO_X control retrofits in IPM. Specifically, Table 4 and the accompanying notes provide the coefficients, terms and scaling factors of the engineering equations that were used to derive the capital, FOM (fixed operating and maintenance), and VOM (variable operating and maintenance) cost rates used in IPM for NO_X retrofit emission controls. In the notes under Table 4 examples are provided to illustrate how these cost rates would be derived for a 275 MW unit from the values shown in the table.

Table 4. NO_X Control Retrofit Cost Assumptions for Existing Coal-fired Units in v3.02 EISA Base Case (2006$)

Post-Combustion Control Technology	Coefficients			Percent Removal
	Capital ($/kW)	Fixed O&M ($/kW-year)	Variable O&M (mills/kWh)	
SCR[2]	169	0.79	0.71	90%[1]
SCNR[3]	Term1: 29 Term2: 33	Term1: 0.30 Term2: 0.35	0.79	35%
SNCR[4] (Cyclone)	17	0.17	1.55	35%
SNCR[5] (Fluidized Bed)	29	0.31	0.91	50%

Notes:

The "Coefficients" in the table above are multiplied by the terms below to determine costs.

"MW" in the terms below is the unit's capacity in megawatts.

[1] Cannot provide reductions any further beyond 0.06 lbs/mmBtu.

[2] SCR Cost Equations:

SCR Capital Cost ($/kW) = 169 * $(242.72/MW)^{0.27}$

SCR Fixed O&M Cost ($/kW-year) = 0.79 * $(242.72/MW)^{0.27}$

SCR Variable O&M Cost (mills/kWh) = 0.71 $(242.72/MW)^{0.11}$

The cost equations shown above apply up to 600 MW. The cost obtained for a 600 MW unit applies for units larger than 600 MW.

Example for 275 MW unit:

SCR Capital Cost ($/kW) = 169 * $(242.72/275)^{0.27}$ ≈ 163 $/kW

SCR FOM Cost ($/kW-year) = 0.79 * $(242.72/275)^{0.27}$ ≈ 0.76 $/kW-year

SCR VOM Cost (mills/kWh) = 0.71 * $(242.72/275)^{0.11}$ ≈ 0.70 mills/kWh

[3] SNCR Cost Equations:

SNCR Capital Cost ($/kW) = $(29*(200/MW)^{0.577} + 33*(100/MW)^{0.681})/2$

SNCR Fixed O&M Cost ($/kW-year) = $(0.30*(200/MW)^{0.577} + 0.35*(100/MW)^{0.681})/2$

Example for 275 MW unit:

SNCR Capital Cost ($/kW) = $(29 * (200/275)^{0.577} + 33 * (100/275)^{0.681})/2$ ≈ 20 $/kW

SNCR FOM Cost ($/kW-year) = $(0.30 * (200/275)^{0.577} + 0.35 * (100/275)^{0.681})/2$ ≈ 0.21 $/kW-year

SNCR VOM Cost (mills/kWh) = 0.79 mills/kWh

[4] Cyclone Cost Equations:

Coal SNCR—Cyclone Capital Cost ($/kW) = 17 $(300/MW)^{0.577}$

Coal SNCR—Cyclone Fixed O&M Cost ($/kW-year) = 0.17 $(300/MW)^{0.577}$

Example for 275 MW unit:

Capital Cost for Cyclone Coal SNCR ($/kW) = 17 * $(300/275)^{0.577}$ ≈ 18 $/kW

FOM Cost for Cyclone Coal SNCR ($/kW-year) = 0.17 * $(300/275)^{0.577}$ ≈ 0.18 $/kW-year

VOM Cost for Cyclone Coal SNCR (mills/kWh) = 1.55

[5] Fluidized Bed Cost Equations:

SNCR - Fluidized Bed Capital Cost ($/kW) = 29 * $(200/MW)^{0.577}$

SNCR - Fluidized Bed Fixed O&M Cost ($/kW-year) = 0.31 * $(200/MW)^{0.577}$

Example for 275 MW unit:

Fluidized Bed Capital Cost for SNCR ($/kW) = 29 * $(200/275)^{0.577} \approx$ 24 $/kW

Fluidized Bed FOM Cost for SNCR ($/kW-year) = 0.31 * $(200/275)^{0.577} \approx$ 0.26 $/kW-year

Fluidized Bed VOM Cost for SNCR (mills/kWh) = 0.91

Reference

Khan, S. and Srivastava, R. "Updating Performance and Cost of NO_X Control Technologies in the Integrated Planning Model," Mega Symposium, August 30, 2004 - September 2, 2004, Washington, D.C.

For comparison, Table 4.a. provides the same parameters as in Table 4 but from the IPM analysis for the final CAIR. The EPA's modeling for CAIR used IPM Base Case 2004 (v.2.1.9). The information in Table 4.a is taken from Table 5.6 in Chapter 5 in the documentation for v.2.1.9.[2] The CAIR analysis was performed using 1999 dollars and costs in Table 4.a are also presented in 1999 dollars.

Table 4.a NO_X Control Retrofit Cost Assumptions for Existing Coal-fired Units in CAIR v2.1.9 Base Case (1999$)

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percent Gas Use	Percent Removal
SCR[2]	$100	$0.66	0.6	--	90%[1]
SNCR[3] – Term 1	$17.1	$0.25	See Note 3	--	35%
Term 2	$19.5	$0.30	See Note 3	--	35%
SNCR[4] (Cyclone)	$9.9	$0.14	1.31	--	35%

Notes:

[1] Cannot provide reductions any further beyond 0.06 lbs/mmBtu.

[2] SCR Cost Scaling Factor:
SCR Capital and Fixed O&M Costs: $(242.72/MW)^{0.27}$
SCR Variable O&M Costs: $(242.72/MW)^{0.11}$
Scaling factor applies up to 600 MW.

[3] SNCR Cost Scaling Factor:
SNCR Capital and Fixed O&M Costs: $(\text{Term1}*(200/MW)^{0.577} + \text{Term2}*(100/MW)^{0.681})/2$
VO&M = 0.88

[4] Cyclone Cost Scaling Factor:
High NO_x Coal SNCR—Cyclone Capital and Fixed O&M Costs: $(300/MW)^{0.577}$
VO&M = 1.27 for MW $\leq$ 300,
VO&M = 1.27 – ((MW – 300)/100) * 0.015 for MW > 300.

Reference
Khan, S. and Srivastava, R. "Updating Performance and Cost of NO_x Control Technologies in the Integrated Planning Model," Mega Symposium, August 30, 2004 - September 2, 2004, Washington, D.C.

[2] Standalone Documentation for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA 2005 (http://epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html#version2004).

Table 5 on the next page shows the capital, FOM, and VOM cost rates for the two SO_2 emission control retrofit technologies represented in the IPM – Limestone Forced Oxidation (LSFO) scrubbers and Lime Spray Dryer (LSD) – for a representative range of generating units differentiated by their capacities, heat rates, and coals.[3] The engineering equations and related assumptions used to derive the values shown in this table are presented in two papers: James E. Staudt and Sikander R. Khan, "Updating Performance and Cost of SO_2 Control Technologies in the Integrated Planning Model and the Coal Utility Environmental Cost Model," The Mega Symposium, August 28–31, 2006, Baltimore, Maryland, and "SO_2 Control Technology Performance and Cost Study" by Andover Technology Partners, EPA Contract No. 68-W-03-02, April 2006.

[3] LSFO and LSD have removal rates of 95% and 90% respectively, as detailed in Table 5.2 of the v3.0 documentation referenced earlier.

Table 5. Application of SO_2 Control Retrofit Cost Assumptions for Existing Coal-fired Units in v3.02 EISA Base Case (2006$)

Scrubber Type	Capacity (MW)	Heat Rate (Btu/kWh)			Cost
		9,000	10,000	11,000	
Limestone Forced Oxidation (LSFO) Minimum Cutoff: 100 MW Maximum Cutoff: None Assuming 5.0 lbs/MMBtu SO_2 Coal	100	705	708	711	Capital Cost ($/kW)
		20.3	20.3	20.3	Fixed O&M ($/kW-year)
		1.39	1.49	1.60	Variable O&M (mills/kWh)
	300	345	348	351	Capital Cost ($/kW)
		11.7	11.7	11.7	Fixed O&M ($/kW-year)
		1.39	1.49	1.60	Variable O&M (mills/kWh)
	500	259	263	266	Capital Cost ($/kW)
		9.6	9.6	9.6	Fixed O&M ($/kW-year)
		1.39	1.49	1.60	Variable O&M (mills/kWh)
	700	212	215	218	Capital Cost ($/kW)
		8.5	8.5	8.5	Fixed O&M ($/kW-year)
		1.39	1.49	1.60	Variable O&M (mills/kWh)
	1000	179	182	186	Capital Cost ($/kW)
		7.5	7.5	7.5	Fixed O&M ($/kW-year)
		1.39	1.49	1.60	Variable O&M (mills/kWh)
Lime Spray Dryer (LSD) Minimum Cutoff: 100 MW Maximum Cutoff: None Assuming 3.0 lbs/MMBtu SO_2 Coal	100	422	433	443	Capital Cost ($/kW)
		11.7	13.9	12.8	Fixed O&M ($/kW-year)
		2.24	2.56	2.77	Variable O&M (mills/kWh)
	300	224	235	247	Capital Cost ($/kW)
		8.5	8.5	8.5	Fixed O&M ($/kW-year)
		2.24	2.56	2.77	Variable O&M (mills/kWh)
	500	188	198	210	Capital Cost ($/kW)
		6.4	6.4	6.4	Fixed O&M ($/kW-year)
		2.24	2.56	2.77	Variable O&M (mills/kWh)
	700	168	179	191	Capital Cost ($/kW)
		5.3	5.3	5.3	Fixed O&M ($/kW-year)
		2.24	2.56	2.77	Variable O&M (mills/kWh)
	1000	157	170	182	Capital Cost ($/kW)
		4.3	4.3	4.3	Fixed O&M ($/kW-year)
		2.24	2.56	2.77	Variable O&M (mills/kWh)

The values shown above in Tables 4 and 5 incorporate scaling factors to capture cost increases that have occurred since the equations were originally developed. In general, the capital cost increases are consistent with those adopted for potential new units as discussed previously.

Table 6. Post-Combustion NO_X Controls for Oil/Gas Steam Units (2006$) in v3.02 EISA Base Case

Post-Combustion Control Technology	Coefficients		Variable O&M (mills/kWh)	Percent Removal
	Capital ($/kW)	Fixed O&M ($/kW-year)		
SCR[1]	49	1.05	0.12	80%
SNCR[2]	16	0.18	0.53	50%

Notes:
The "Coefficients" in the table above are multiplied by the terms below to determine costs.
"MW" in the terms below is the unit's capacity in megawatts.

[1] SCR Cost Equations:
SCR Capital Cost ($/kW) = 49 * $(200/MW)^{0.35}$
SCR Fixed O&M Cost ($/kW-year) = 1.05 * $(200/MW)^{0.35}$
The cost equations shown above apply up to 500 MW. The cost obtained for a 500 MW unit applies for units larger than 500 MW.
Example for 275 MW unit:
SCR Capital Cost ($/kW) = 49 * $(200/275)^{0.35} \approx$ 44 $/kW
SCR FOM Cost ($/kW-year) = 1.05 * $(200/275)^{0.35} \approx$ 0.94 $/kW-year
SCR VOM Cost (mills/kWh) = 0.12 mills/kWh

[2] SCNR Cost Equations:
SNCR Capital Cost ($/kW) = 16 * $(200/MW)^{0.577}$
SNCR Fixed O&M Cost ($/kW-year) = 0.18 * $(200/MW)^{0.577}$
The cost equations shown above apply up to 500 MW. The cost obtained for a 500 MW unit applies for units larger than 500 MW.
Example for 275 MW unit:
SNCR Capital Cost ($/kW) = 16 * $(200/275)^{0.577} \approx$ 13 $/kW
SNCR FOM Cost ($/kW-year) = 0.18 * $(200/275)^{0.577} \approx$ 0.15 $/kW-year
SNCR VOM Cost (mills/kWh) = 0.53 mills/kWh

Reference:
Cost Estimates for Selected Applications of Nox Control Technologies on Stationary Combustion Boilers, Bechtel Power Corporation for US EPA, June 1997.

For comparison, Table 6.a. provides the same parameters as in Table 6 but from the IPM analysis for the final CAIR. The EPA's modeling for CAIR used IPM Base Case 2004 (v.2.1.9). The information in Table 6.a is taken from Table 5.7 in Chapter 5 in the documentation for v.2.1.9.[4] The CAIR analysis was performed using 1999 dollars and costs in Table 6.a are also presented in 1999 dollars.

[4] Standalone Documentation for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model, EPA 2005 (http://epa.gov/airmarkets/progsregs/epa-ipm/past-modeling.html#version2004).

Table 6.a NO_X Control Retrofit Cost Assumptions for Oil/Gas Steam Units in CAIR v2.1.9 Base Case (1999$)

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW/Yr)	Variable O&M (mills/kWh)	Percent Removal
SCR[1]	28.9	0.89	0.10	80%
SNCR[2]	9.7	0.15	0.45	50%

Notes:
[1] SCR Cost Scaling Factor:
SCR and Gas Reburn Capital Cost and fixed O&M: $(200/MW)^{0.35}$
Scaling factor applies up to 500 MW

[2] SNCR Cost Scaling Factor: :
SNCR Capital Cost and fixed O&M: $(200/MW)^{0.577}$
Scaling factor applies up to 500 MW

Reference
Cost Estimates for Selected Applications of NOx Control Technologies on Stationary Combustion Boilers, Bechtel Power Corporation for US EPA, June 1997.

Table 7. Cost (2006$) of NO_X Combustion Controls for Coal Boilers in Base Case v3.02 EISA

Boiler Type	Technology	Coefficients		Variable O&M (mills/kWh)
		Capital ($/kW)	Fixed O&M ($/kW-year)	
Dry Bottom Wall-Fired	Low NO_X Burner without Overfire Air (LNB without OFA)	29	0.31	0.064
	Low NO_X Burner with Overfire Air (LNB with OFA)	39	0.43	0.085
Tangentially-Fired	Low NO_X Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	15	0.17	0.000
	Low NO_X Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	21	0.22	0.029
	Low NO_X Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	24	0.27	0.029

Notes:
For all of the above combustion controls the following equations are used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in megawatts) of the unit taking on combustion controls:
Capital Cost ($/kW) = X * $(300/MW)^{0.359}$
Fixed O&M Cost ($/kW-year) = X * $(300/MW)^{0.359}$
where "X" is the appropriate coefficient shown in the above table (in $/kW or $/kW-year for Capital or Fixed O&M respectively) and "MW" is the capacity (in megawatts) of the unit taking on combustion controls.
No scaling is applied in calculating the variable operating and maintenance cost (i.e., the Variable O&M values above apply for all sizes).

Example for 275 MW dry bottom wall-fired unit installing LNB with OFA:
Capital Cost ($/kW) = 39 * $(300/275)^{0.359} \approx$ 40 $/kW

Fixed O&M Cost ($/kW-year) = 0.43 * $(300/275)^{0.359} \approx$ 0.44 $/kW-year
Variable O&M Cost (mills/kWh) = 0.085 mills/kWh

4. Updated Natural Gas Supply Projections

The natural gas supply curves are based on the same assessment of available gas resource through the U.S. and Canada as used in ICF's Gas Market Model (GMM) as of late 2007, including resources in Alaska and the Mackenzie Delta area of the Canadian arctic. The Base Case assumes that pipelines will be built to transport gas from these two areas to North American demand markets. The curves assumes a Mackenzie Delta gas pipeline is built in 2015 with a capacity of 1 Bcfd, and an Alaska pipeline is built in 2020 with an initial capacity of 4 Bcfd, which is expanded in 2023 to 6 Bcfd. Together, gas production from Mackenzie Delta and Alaska make up roughly 11 percent of gas supplies by 2030.

The gas supply curves also assume significant growth in North American liquefied natural gas (LNG) imports, based on projected growth in liquefaction capability and taking into account the expect growth in gas demand in other importing countries in Europe and Asia. LNG imports are expected to grow to over 7 Bcfd, or roughly 11 percent of gas supplies by 2030.

See Appendix II for detailed natural gas supply curves.

5. Power Sector Regulatory Environment

The model includes policies affecting 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[5]; and several state rules[6] affecting emissions of SO_2 and NO_X that were finalized through February 3, 2009. IPM includes state rules that have been finalized and/or approved by a state's legislature or environmental agency. Appendixes III and IV show the rules and settlements newly modeled.

The Clean Air Visibility Rule (CAVR) and the Clean Air Mercury Rule (CAMR) were removed from the baseline. On February 8, 2008, the D.C. Circuit Court vacated EPA's

[5] 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, and Kentucky Utilities.

[6] These include current and future state programs in Connecticut, Delaware, Georgia, Illinois, Maine, Maryland, Massachusetts, Minnesota, Missouri, New Hampshire, North Carolina, New Jersey, New York, Oregon, Texas, and Wisconsin.

rule removing power plants from the Clean Air Act list of sources of hazardous air pollutants and at the same time, the Court vacated the CAMR. In June 2005, EPA finalized guidelines for States to use in determining which facilities must install controls and the type of controls the facilities must use to satisfy Best Available Retrofit Technology (BART) requirements to address regional haze (also known as the CAVR). Because of uncertainty regarding the precise measures and requirements States will adopt, the specific CAVR power sector assumptions that were formerly modeled in IPM have been removed.

6. Dispatchable Controls

As detailed in chapter 7 of the proposed Transport Rule Regulatory Impact Analysis, developing the Transport Rule presented a unique regulatory situation to represent in IPM: the possibility of an area moving to less stringent control requirements than were expected previously (e.g., under CAIR). To model this situation, v3.02 EISA decides economically whether to operate certain advanced SO_2 and NO_X emissions controls. In areas transitioning from a more stringent to less stringent regulatory regime (for example, a state affected by CAIR but potentially not affected by the proposed Transport Rule), operators may have economic incentive to bypass or reduce operation of FGD or SCR. At the same time, units built to comply with settlements, state rules, or other past policies would be required to continue to operate regardless of changes to the CAIR program.

In order to represent these decisions accurately within the framework of IPM, v3.02 EISA models this choice as a retrofit option without capital cost. If a particular FGD, SCR, or ACI is dispatchable, it is removed from NEEDS for the purposes of modeling. In its place, the affected model plant receives a special FGD or SCR retrofit option that matches the operating characteristics of the removed control but, unlike a normal retrofit, has zero capital cost. The model will use this retrofit if the control is economical to operate, but it will not use the retrofit if the control is not economical. Hence the model makes the control “dispatchable.”

Base Case v3.02 EISA incorporates a set of rules to determine which EGUs have dispatchable controls. These rules are designed to target controls not affected by continuing mandates to operate, such as those installed for compliance with EPA-administered trading programs like the Acid Rain Programs for SO_2. The rules listed below apply to FGD, SCR, and ACI on coal-fired units.

Note that as in previous IPM modeling, a set of rules applies to all units to determine their NO_X rates. These rules are discussed in detail in Section 3 of the documentation for EPA Base Case 2006 (v3.0): http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/Section-3.pdf. The model can choose whether to install a dispatchable post-combustion NO_X control, but once installed, it is treated the same as any other control under the Section 3 rules in determining a unit's NO_X rate.

Rules for dispatchable scrubbers on coal units

1. If the unit online year is 1990 or later then the scrubber will not be dispatchable. Such units are likely to be new units required to control.
2. If the unit is online before 1990 and if the scrubber is online in 1992 or earlier then the scrubber will not be dispatchable. These scrubbers were most likely built for a reason other than compliance with the Title IV Acid Rain Program.
3. If the unit is online before 1990 and if the scrubber is online in 1993 or later then the scrubber will not be dispatchable if it is mandated by NSR, state settlement or state-specific rule and the scrubber is online by the end of 2011.
4. If the criteria in (1–3) are not met, then scrubbers will be dispatchable.

Rules for dispatchable SCR controls on coal units within the CAIR region but outside the SIP Call region

1. If the unit online year is 1990 or later then the SCR will not be dispatchable. Such units are likely to be new units required to control.
2. If the unit's firing type is cyclone and the SCR is online in 1999 or earlier then the SCR will not be dispatchable. Such a control was most likely installed for compliance with the Title IV NO_X Program or an earlier mandate.
3. If the unit is online before 1990 then the SCR will not be dispatchable if the SCR control is mandated by NSR, state settlement or state-specific rule and the control is online by the end of 2011.
4. If the criteria in (1–3) are not met then SCR controls will be dispatchable.

Rules for dispatchable SCR controls on coal units outside the CAIR region and/or within the SIP Call region

No SCR controls will be dispatchable. (They are still subject to Section 3 rules for determining NO_X rates; see above.)

Rules for dispatchable SNCR controls on coal units

No SNCR controls will be dispatchable.

Rules for dispatchable ACI on coal units

ACI will not be dispatchable if any of the following criteria is met:

a) If the ACI control is mandated by NSR, state settlement or state-specific rule and the control is online by the end of 2011.
b) If the unit is online after 2005 (i.e., those treated as committed by NEEDS).
c) If the unit is in one of the following states with mercury rules: GA; IL; ME; MD; MN; NH; WI.

7. Updates to National Electric Energy Data System (NEEDS)

The National Electric Energy Data System or “NEEDS” database contains the generation unit records used to construct the “model” plants that represent existing and planned/committed units in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units. NEEDS was updated for Base Case v3.02 EISA.

Table 8. Data Sources for NEEDS v3.02 EISA

Data Source[1]	Data Source Documentation
DOE's Form EIA-860 (2005)	DOE's Form EIA-860 is an annual survey of utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), status, prime mover, primary energy source, in-service year, and a generator-level cogenerator flag.
DOE's Form EIA-767 (2005)	DOE's Form EIA-767 is an annual survey, "Steam-Electric Plant Operation and Design Report", that contains data for steam boilers such as fuel quantity and quality; boiler identification, location, status, and design information; and post-combustion NO_X control, FGD scrubber and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The relationship between boilers and generators is also provided. Note that boilers and generators are not necessarily in a one-to-one correspondence.
NERC Electricity Supply and Demand (ES&D) database (2006)	The NERC ES&D is released annually. It contains generator-level information such as summer, winter and nameplate capacity, state, NERC region and sub-region, status, primary fuel and on-line year.
EIA’s Annual Energy Outlook (AEO 2008)	The Energy Information Administration (EIA) Annual Energy Outlook presents annually updated forecasts of energy supply, demand and prices covering a 20-25 year time horizon. The projections are based on results from EIA’s National Energy Modeling System (NEMS). Information from AEO 2008, such as heat rates and renewable builds in response to state renewable portfolio standards (RPS) were used in NEEDS V3.02 EISA.
Global Energy Decisions New Entrants database (August 2007)	Global Energy’s New Entrants database has information on new power plant builds, rerates and retirements. This was used in NEEDS v3.02 EISA for information on planned-committed units.
EPA's Emission Tracking System (ETS 2006)	The Emission Tracking System (ETS) database is updated quarterly and certified annually. It contains boiler-level information such as primary fuel, heat input, SO_2 and NO_X controls, and SO_2, NO_X and CO_2 emissions. NEEDS V3.02 EISA used ETS data for developing emission rate and post-combustion control information.
Utility and RPO (Regional Planning Organizations) Comments	Comments from selected U.S. utilities and RPOs regarding the population in NEEDS as well as unit characteristics were used in NEEDS V3.02 EISA.

[1]Indicated under “Data Source” are the primary issue dates of the indicated data sources that were used. Other vintages of these data sources were also used in instances where data were not available for the indicated issue date or where there were methodological reasons for using other vintages of the data.

Table 9. Rules Used in Populating NEEDS v3.02 EISA

Scope	
Geographic	Excluded units in Alaska or Hawaii
Capacity	Excluded units with reported nameplate, summer and winter capacity of zero
Status	Excluded units on long-term scheduled maintenance or retired (i.e. units with status codes “OS” or “RE” in EIA Forms) Status of boiler(s) and associated generator(s) were taken into account for determining operation status
Planned or Future Units	Included planned units that had broken ground or secured financing and were expected to be online by the end of 2011
Firm/Non-firm Electric Sales	Excluded non-utility onsite generators that do not produce electricity for sale to the grid. Excluded all mobile and distributed generators

Table 10. Hierarchy of Data Sources for Capacity in NEEDS v3.02 EISA

Sources Presented in Hierarchy
Capacity from Utility/Regional Planning Organization(RPO) Comments
2005 EIA 860 Summer Capacity
NERC ES&D 2006 Summer Capacity
2005 EIA 860 Winter Capacity
NERC ES&D 2006 Winter Capacity
2005 EIA 860 Nameplate Capacity

Notes:

1. If a unit’s capacity was shown as zero, it was not included in NEEDS v3.02 EISA.

Table 11. Summary Population (through 2005) in NEEDS v3.02 EISA

Plant Type	Number of Units	Capacity (MW)
Biomass	126	2,124
Coal Steam	1,247	306,062
Combined Cycle	1,493	172,567
Combustion Turbine	5,248	131,366
Fossil Waste	19	581
Geothermal	201	2,194
Hydro	3,724	77,414
IGCC	4	529
Landfill Gas	572	892
Municipal Solid Waste	172	2,054
Non-Fossil Waste	48	530
Nuclear	104	101,099
O/G Steam	698	113,618
Pumped Storage	150	20,864
Solar	18	411
Tires	3	44
Wind	275	8,711
Total	14,102	941,060

Table 12. Data Sources for Unit Configuration in NEEDS v3.02 EISA

Unit Component	Primary Data Source	Secondary Data Source	Tertiary Data Source	Other Sources	Default
Firing Type	Utility/RPO Comments	2005 EIA 767	-	-	-
Bottom Type	Utility/RPO Comments	2005 EIA 767	-	-	Dry
SO_2 Pollution Control	NSR Settlement or Utility/RPO Comments	EPA's Emission Tracking System (ETS) - 2006	2005 EIA 767	See Note[1]	No Control
NO_X Pollution Control	NSR Settlement or Utility/RPO Comments	EPA's Emission Tracking System (ETS) - 2006	2005 EIA 767	See Note[1]	No Control
Particulate Matter Control	NSR Settlement or Utility/RPO Comments	EPA's Emission Tracking System (ETS) - 2006	2005 EIA 767	1999 Hg ICR	-

[1] In addition to the primary, secondary and tertiary data sources listed here, the web sites of generating unit owners and operators were also consulted.

8. Title IV SO_2 Allowance Bank Estimate

The Title IV SO_2 bank going into 2012 was assumed to be 1.6 million allowances. This was based on calculations that assumed increasing overall emissions following the remand of CAIR. Since early 2009, when Base Case v3.02 EISA was completed, SO_2 emissions have instead continued to decline. Even if the Title IV bank does not decline to 1.6 million allowances by 2012, EPA believes there will be little or no resulting effect on the costs and emissions resulting from the Transport Rule or similar policies that do not directly relate to Title IV allowances.

9. Run year mapping

Table 13. Run Years and Analysis Year Mapping Used in the IPM Base Case v3.02 EISA

Run Year	Year Mapping
2012	2012 – 2013
2015	2014 – 2017
2020	2018 – 2022
2025	2023 – 2027

10. Financial Assumptions

Table 14. Capital Charge Rates and Real Discount Rates by Plant Type in Base Case v3.02 EISA

Investment Technology	Capital Charge Rate	Discount Rate
Environmental Retrofits	11.4%	5.5%
Conventional Pulverized Coal	11.2%	5.5%
Advanced Combined Cycle	12.2%	6.1%
Advanced Combustion Turbine	13.0%	6.9%
Nuclear	10.8%	5.5%
Renewable Generation Technologies	12.2%	6.1%

11. Small-unit Retrofit Options Present in Policy Case Model Runs

In the proposed Transport Rule base case (TR_Base_Case), coal-fired EGUs under 100 MW capacity do not have the option of retrofitting FGD or SCR. In model runs other than the Transport Rule base case, coal-fired EGUs greater than 25 MW do have the option of retrofitting FGD and SCR. Because FGD and SCR retrofits to such small units are very costly in any case, EPA believes the absence of that option has little or no effect on emissions or cost results in the base case. A summary of available SO_2 control options, based on an approximate extrapolation from retrofit costs for larger capacity units, appears in Table 15 below.[7] SCR costs for these units follow the same formula described above in Section 3.

Table 15. Application of SO_2 Retrofit Options for Coal-fired Units at 25 MW and below 100 MW Capacity (2006$)

Scrubber Type	Limestone Forced Oxidation (LSFO) Minimum Cutoff: ≥ 25 MW Maximum Cutoff: < 100 MW			Lime Spray Dryer (LSD) Minimum Cutoff: ≥ 25 MW Maximum Cutoff: < 100 MW		
Capacity (MW)	**25**	**50**	**75**	**25**	**50**	**75**
Capital Cost ($/kW)	1,368	934	748	487	396	350
Fixed O&M ($/kW-year)	39.7	28.5	23.4	21.1	16.1	13.8
Variable O&M (mills/kWh)	1.47	1.47	1.47	2.50	2.50	2.50

12. Unit-specific Adjustments Present in Some Model Runs

In the course of deriving budgets for the proposed Transport Rule, some EGUs were noted as demonstrating unusually high emissions rates in model results relative to the emissions rates of the same units in recent data. As a result, the rates of 30 units were constrained in subsequent runs to provide more accurate emissions results for those units. Additionally, 3 units possessed existing controls not accounted for in NEEDS; these were accounted for with removal percentages assumed for their emissions.

These adjustments are present neither in the proposed Transport Rule base case nor in the analysis of significant contribution using the Air Quality Assessment Tool. They are present in runs representing the three remedy options for the proposed Transport Rule and in the A–4 analysis runs conducted for Regulatory Impact Analysis. The units and their rates are listed below in Table 16.

[7] These LSFO and LSD match the characteristics shown in Table 5.2 of the v3.0 documentation referenced earlier, including removal rates of 95% and 90% respectively.

Table 16. Unit-specific Adjustments to Transport Rule Remedy Runs

NEEDS ID	ORIS Code	Plant Name	Unit ID	Pollutant	Emissions Rate Limit (lbs/mmBTU) or Other Modification
568_B_BHB3	568	Bridgeport Station	BHB3	Annual SO_2	0.131
856_B_1	856	E D Edwards	1	Annual SO_2	0.461
856_B_2	856	E D Edwards	2	Annual SO_2	0.457
856_B_3	856	E D Edwards	3	Annual SO_2	0.429
2516_B_1	2516	Northport	1	Annual SO_2	0.132
2516_B_2	2516	Northport	2	Annual SO_2	0.344
2516_B_3	2516	Northport	3	Annual SO_2	0.299
2516_B_4	2516	Northport	4	Annual SO_2	0.244
2517_B_3	2517	Port Jefferson	3	Annual SO_2	0.294
2517_B_4	2517	Port Jefferson	4	Annual SO_2	0.305
3788_B_1	3788	Potomac River	1	Annual SO_2	0.383
3788_B_2	3788	Potomac River	2	Annual SO_2	0.343
3803_B_1	3803	Chesapeake	1	Annual SO_2	0.891
3803_B_2	3803	Chesapeake	2	Annual SO_2	0.885
3803_B_3	3803	Chesapeake	3	Annual SO_2	0.895
3803_B_4	3803	Chesapeake	4	Annual SO_2	0.939
2378_B_1	2378	B L England	1	Annual SO_2	Controls achieve 93% removal
2240_B_8	2240	Lon Wright	8	Annual SO_2	0.651
2277_B_1	2277	Sheldon	1	Annual SO_2	0.590
2277_B_2	2277	Sheldon	2	Annual SO_2	0.567
2291_B_1	2291	North Omaha	1	Annual SO_2	0.754
2291_B_5	2291	North Omaha	5	Annual SO_2	0.721
59_B_1	59	Platte	1	Annual SO_2	0.745
60_B_1	60	Whelan Energy Center	1	Annual SO_2	0.696
6077_B_1	6077	Gerald Gentleman	1	Annual SO_2	0.615
6077_B_2	6077	Gerald Gentleman	2	Annual SO_2	0.601
6096_B_1	6096	Nebraska City	1	Annual SO_2	0.727
8048_B_1	8048	Anclote	1	Annual NO_X	0.183
8048_B_2	8048	Anclote	2	Annual NO_X	0.136
619_B_PRV3	619	Riviera	PRV3	Annual NO_X	0.208
619_B_PRV4	619	Riviera	PRV4	Annual NO_X	0.307
136_B_1	136	Seminole	1	Annual NO_X	Controls achieve 90% removal
136_B_2	136	Seminole	2	Annual NO_X	Controls achieve 90% removal

Still other controls were hardwired in *all* 3.02 EISA modeling, both base and policy cases, to account for additional controls not present in NEEDS 3.02 EISA but nonetheless known to be in operation no later than 2012. These are listed in Table 17 below.

Table 17. Additional Unit-specific Controls in All Transport Rule Runs

NEEDS ID	ORIS Code	Plant Name	Unit ID	Control
6002_B_2	6002	James H Miller Jr	2	Wet Scrubber
6705_B_1	6705	Warrick	1	Wet Scrubber
6705_B_2	6705	Warrick	2	Wet Scrubber
6705_B_3	6705	Warrick	3	Wet Scrubber
6705_B_4	6705	Warrick	4	Wet Scrubber
113_B_3	113	Cholla	3	Wet Scrubber
113_B_4	113	Cholla	4	Wet Scrubber
2850_B_1	2850	J M Stuart	1	Wet Scrubber
2850_B_2	2850	J M Stuart	2	Wet Scrubber
2850_B_3	2850	J M Stuart	3	Wet Scrubber
2850_B_4	2850	J M Stuart	4	Wet Scrubber
983_B_1	983	Clifty Creek	1	Wet Scrubber
983_B_2	983	Clifty Creek	2	Wet Scrubber
983_B_3	983	Clifty Creek	3	Wet Scrubber
983_B_4	983	Clifty Creek	4	Wet Scrubber
983_B_5	983	Clifty Creek	5	Wet Scrubber
983_B_6	983	Clifty Creek	6	Wet Scrubber
994_B_1	994	Petersburg	1	Wet Scrubber
994_B_2	994	Petersburg	2	Wet Scrubber
1082_B_3	1082	Walter Scott Jr. Energy Center	3	Wet Scrubber
6664_B_101	6664	Louisa	101	Wet Scrubber
3788_B_3	3788	Potomac River	3	Wet Scrubber
3788_B_4	3788	Potomac River	4	Wet Scrubber
3788_B_5	3788	Potomac River	5	Wet Scrubber
2823_B_B1	2823	Milton R Young	B1	SCR
2866_B_7	2866	W H Sammis	7	SCR
8069_B_2	8069	Huntington	2	Wet Scrubber
525_B_H1	525	Hayden	H1	Dry Scrubber
525_B_H2	525	Hayden	H2	Dry Scrubber
1001_B_1	1001	Cayuga	1	Wet Scrubber
6113_B_4	6113	Gibson	4	Wet Scrubber
6177_B_U2B	6177	Coronado	U2B	SCR
4941_B_1	4941	Navajo	1	Wet Scrubber
4941_B_2	4941	Navajo	2	Wet Scrubber
4941_B_3	4941	Navajo	3	Wet Scrubber

13. 2012 Feasibility Limits Present in Policy Case Model Runs

Because the 2012 run year represents years within eighteen months of the present, it is unrealistic to expect advanced SO_2 and NO_X post-combustion controls to be operating or new units to be planned and constructed in 2012 in response to a policy change. Therefore, in all runs other than the proposed Transport Rule base case, new builds of all units and retrofits of FGD, SCR, and SNCR are limited to those built in the base case (TR_Base_Case).

Appendix I. Background on the Integrated Planning Model (IPM), Its Uses, and Related Peer Review Activities

EPA uses the Integrated Planning Model (IPM) to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. The model was developed by ICF Resources and IPM® is a registered trademark of ICF Resources, Inc.

IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. The model provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM provides both a broad and detailed analysis of the emission control options available to the power sector (e.g., installation of emission controls, power generation adjustments, fuel use changes, and national, regional/state, and local air emissions changes) along with the economic impacts of these control options in terms of costs, wholesale electricity prices, closures, allowance values, etc..

EPA's application of IPM is a very detailed, data intensive representation of the U.S. power sector. A great deal of effort is expended to ensure that IPM is populated with high quality input data and that its assumptions are based on latest engineering and economic experience. The data and assumptions are fully documented and publicly available on EPA's web site. Use of such a bottom-up model imposes scientific and technical discipline on EPA that serves to improve the decision making process and increase opportunities for broad public & expert review and input.

EPA sponsors periodic independent formal peer review of IPM, covering the model itself and EPA's key modeling input assumptions. Examples include reviews by separate panels of independent experts of the model's coal supply and transportation assumptions, natural gas assumptions, and model formulation.

In addition to formal peer review, the rulemaking process offers opportunities for expert review and comment by operators of the electricity sector that is represented in IPM, stakeholders affected by the policies being modeled, and developers of other models of the U.S. electricity sector. This feedback provides a highly detailed reality check of input assumptions, model representation, and model results. EPA is required to respond to every significant comment submitted. Comments on IPM have been solicited in most of the major air regulations that EPA has promulgated in the last 15 years. Such efforts date back to the extensive review by energy and environmental modeling experts from states, industry and other groups during the 2 years of the OTAG process in 1997-1998 and Science Advisory Board review of IPM as part of the CAAA Section 812 prospective study 1997–1999.

IPM has also been used by states (e.g., for RGGI, WRAP, OTAG), other Federal agencies (e.g., FERC, GAO), environmental groups (including the Clean Air Task Force), and industry (e.g., TVA, SoCAL), all of whom subject the model to their own review procedures.

Appendix II. Natural Gas Supply Curves

The supply curves below specify annual price and volume relationships at the Henry Hub. For each listed step the price applies for all increments of supply greater than the value shown in the preceding step up to and including the supply level indicated in the current step. For example, in 2012 a price of \$4.60 (2006\$) would secure natural gas supplies for the electric sector beyond the 2,752 TBtu provided in the preceding step and up to a level of 2,932 TBtu.

Year	Price (2006$/MMBtu)	Gas Supply to Electric Sector (TBtu)	Non-Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)
2012	4.50	2,752	19,836	22,588
2012	4.60	2,932	19,685	22,617
2012	4.70	3,107	19,538	22,645
2012	4.80	3,278	19,395	22,673
2012	4.90	3,444	19,256	22,700
2012	5.01	3,607	19,120	22,727
2012	5.10	3,765	18,988	22,753
2012	5.20	3,921	18,859	22,779
2012	5.30	4,072	18,733	22,804
2012	5.40	4,220	18,610	22,829
2012	5.49	4,364	18,489	22,853
2012	5.60	4,505	18,372	22,877
2012	5.70	4,643	18,257	22,900
2012	5.80	4,778	18,145	22,923
2012	5.90	4,910	18,036	22,946
2012	6.00	5,040	17,928	22,968
2012	6.10	5,167	17,823	22,990
2012	6.20	5,292	17,720	23,012
2012	6.30	5,413	17,620	23,033
2012	6.40	5,533	17,521	23,054
2012	6.50	5,651	17,424	23,075

Year	Price (2006$/MMBtu)	Gas Supply to Electric Sector (TBtu)	Non-Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)
2012	6.60	5,766	17,329	23,095
2012	6.70	5,879	17,236	23,115
2012	6.80	5,990	17,145	23,135
2012	6.90	6,100	17,055	23,155
2012	7.00	6,207	16,967	23,174
2012	7.10	6,312	16,881	23,193
2012	7.20	6,416	16,796	23,212
2012	7.31	6,518	16,713	23,231
2012	7.40	6,618	16,631	23,249
2012	7.50	6,717	16,550	23,267
2012	7.60	6,814	16,471	23,285
2012	7.70	6,910	16,393	23,303
2012	7.80	7,003	16,317	23,320
2012	7.90	7,096	16,241	23,337
2012	8.00	7,187	16,167	23,354
2012	8.10	7,277	16,094	23,371
2012	8.20	7,365	16,023	23,388
2012	8.30	7,452	15,952	23,404
2012	8.40	7,537	15,883	23,420
2012	8.50	7,622	15,814	23,436
2012	8.60	7,705	15,747	23,452
2012	8.70	7,788	15,680	23,468
2012	8.80	7,869	15,615	23,484
2012	8.90	7,949	15,550	23,499
2012	9.00	8,027	15,487	23,514
2012	9.10	8,105	15,424	23,529
2012	9.20	10,752	35,202	45,954
2015	4.50	2,374	20,321	22,695
2015	4.60	2,559	20,165	22,724
2015	4.70	2,741	20,012	22,753
2015	4.80	2,917	19,864	22,781
2015	4.90	3,089	19,720	22,808
2015	5.01	3,256	19,579	22,835
2015	5.10	3,420	19,442	22,861
2015	5.20	3,579	19,308	22,887
2015	5.30	3,735	19,177	22,912
2015	5.40	3,887	19,050	22,937
2015	5.49	4,037	18,925	22,962
2015	5.60	4,183	18,804	22,986
2015	5.70	4,325	18,685	23,010
2015	5.80	4,465	18,568	23,033
2015	5.90	4,601	18,455	23,056
2015	6.00	4,736	18,343	23,079
2015	6.10	4,867	18,234	23,101
2015	6.20	4,995	18,128	23,123
2015	6.30	5,122	18,023	23,145
2015	6.40	5,245	17,921	23,166
2015	6.50	5,367	17,820	23,187

Year	Price (2006$/MMBtu)	Gas Supply to Electric Sector (TBtu)	Non-Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)
2015	6.60	5,486	17,722	23,208
2015	6.70	5,603	17,626	23,228
2015	6.80	5,717	17,531	23,248
2015	6.90	5,830	17,438	23,268
2015	7.00	5,941	17,347	23,288
2015	7.10	6,050	17,257	23,307
2015	7.20	6,157	17,169	23,326
2015	7.31	6,262	17,083	23,345
2015	7.40	6,366	16,998	23,364
2015	7.50	6,468	16,914	23,382
2015	7.60	6,568	16,832	23,400
2015	7.70	6,666	16,752	23,418
2015	7.80	6,764	16,672	23,436
2015	7.90	6,859	16,594	23,453
2015	8.00	6,952	16,518	23,470
2015	8.10	7,045	16,442	23,487
2015	8.20	7,136	16,368	23,504
2015	8.30	7,227	16,295	23,521
2015	8.40	7,316	16,222	23,538
2015	8.50	7,403	16,151	23,554
2015	8.60	7,489	16,082	23,570
2015	8.70	7,573	16,013	23,586
2015	8.80	7,657	15,945	23,602
2015	8.90	7,740	15,878	23,618
2015	9.00	7,821	15,812	23,633
2015	9.10	7,901	15,747	23,648
2015	9.20	10,007	36,541	46,547
2020	4.50	1,393	21,191	22,584
2020	4.60	1,586	21,027	22,613
2020	4.70	1,775	20,868	22,642
2020	4.80	1,958	20,713	22,670
2020	4.90	2,137	20,562	22,698
2020	5.01	2,311	20,414	22,725
2020	5.10	2,481	20,271	22,752
2020	5.20	2,647	20,131	22,778
2020	5.30	2,809	19,995	22,804
2020	5.40	2,968	19,862	22,829
2020	5.49	3,123	19,731	22,854
2020	5.60	3,274	19,604	22,878
2020	5.70	3,422	19,480	22,902
2020	5.80	3,567	19,359	22,926
2020	5.90	3,709	19,240	22,949
2020	6.00	3,849	19,124	22,972
2020	6.10	3,984	19,010	22,994
2020	6.20	4,118	18,898	23,016
2020	6.30	4,249	18,789	23,038
2020	6.40	4,377	18,682	23,059
2020	6.50	4,503	18,577	23,080

Year	Price (2006$/MMBtu)	Gas Supply to Electric Sector (TBtu)	Non-Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)
2020	6.60	4,627	18,474	23,101
2020	6.70	4,749	18,373	23,122
2020	6.80	4,868	18,274	23,142
2020	6.90	4,985	18,177	23,162
2020	7.00	5,100	18,082	23,182
2020	7.10	5,213	17,988	23,201
2020	7.20	5,324	17,897	23,220
2020	7.31	5,433	17,806	23,239
2020	7.40	5,541	17,718	23,258
2020	7.50	5,646	17,630	23,276
2020	7.60	5,749	17,545	23,294
2020	7.70	5,852	17,460	23,312
2020	7.80	5,953	17,377	23,330
2020	7.90	6,052	17,296	23,348
2020	8.00	6,149	17,216	23,365
2020	8.10	6,245	17,137	23,382
2020	8.20	6,340	17,059	23,399
2020	8.30	6,433	16,983	23,416
2020	8.40	6,526	16,907	23,433
2020	8.50	6,616	16,833	23,449
2020	8.60	6,705	16,760	23,465
2020	8.70	6,793	16,688	23,481
2020	8.80	6,880	16,617	23,497
2020	8.90	6,966	16,547	23,513
2020	9.00	7,051	16,478	23,529
2020	9.10	7,134	16,410	23,544
2020	9.20	9,557	36,896	46,453
2025	4.50	2,585	20,764	23,349
2025	4.60	2,780	20,600	23,380
2025	4.70	2,969	20,441	23,410
2025	4.80	3,153	20,286	23,439
2025	4.90	3,333	20,135	23,468
2025	5.01	3,509	19,987	23,496
2025	5.10	3,680	19,844	23,524
2025	5.20	3,847	19,704	23,551
2025	5.30	4,010	19,568	23,578
2025	5.40	4,170	19,434	23,604
2025	5.49	4,326	19,304	23,630
2025	5.60	4,478	19,177	23,655
2025	5.70	4,627	19,053	23,680
2025	5.80	4,774	18,931	23,705
2025	5.90	4,917	18,812	23,729
2025	6.00	5,057	18,696	23,753
2025	6.10	5,194	18,582	23,776
2025	6.20	5,329	18,471	23,799
2025	6.30	5,461	18,361	23,822
2025	6.40	5,590	18,254	23,844
2025	6.50	5,717	18,149	23,866

Year	Price (2006$/MMBtu)	Gas Supply to Electric Sector (TBtu)	Non-Electric Gas Demand (TBtu)	Total Gas Supply (TBtu)
2025	6.60	5,842	18,046	23,888
2025	6.70	5,964	17,945	23,909
2025	6.80	6,084	17,846	23,930
2025	6.90	6,202	17,749	23,951
2025	7.00	6,318	17,654	23,972
2025	7.10	6,432	17,560	23,992
2025	7.20	6,544	17,468	24,012
2025	7.31	6,654	17,378	24,032
2025	7.40	6,763	17,289	24,052
2025	7.50	6,869	17,202	24,071
2025	7.60	6,974	17,116	24,090
2025	7.70	7,077	17,032	24,109
2025	7.80	7,179	16,949	24,128
2025	7.90	7,279	16,867	24,146
2025	8.00	7,377	16,787	24,164
2025	8.10	7,474	16,708	24,182
2025	8.20	7,570	16,630	24,200
2025	8.30	7,664	16,554	24,218
2025	8.40	7,757	16,478	24,235
2025	8.50	7,848	16,404	24,252
2025	8.60	7,938	16,331	24,269
2025	8.70	8,027	16,259	24,286
2025	8.80	8,115	16,188	24,303
2025	8.90	8,201	16,118	24,319
2025	9.00	8,286	16,049	24,335
2025	9.10	8,370	15,981	24,351
2025	9.20	10,759	37,013	47,772

Appendix III. New Source Review Settlements: Incremental Changes from EPA Base Case v.3.0

Company and Plant	State	Unit	SETTLEMENT ACTIONS											Allowance Retirement	Allowance Restrictions		Notes
			Retire/Repower		SO_2 Control			No_x Control			PM or Mercury Control						
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Kentucky Utilities Company																	
EW Brown Generating Station	Kentucky	Unit 3			Install FGD	97% or 0.100	12/31/10	Install and continuously operate SCR by 12/31/2012, continuously operate low NO_X boiler and OFA.	0.07	12/31/12	Continuously operate ESP	0.03	12/31/10	KU must surrender 53,000 SO_2 allowances of 2008 or earlier vintage by March 1, 2009. All surplus NO_X allowances must be surrendered through 2020.	SO_2 and NO_X allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		Annual SO_2 cap is 31,998 tons through 2010, then 2,300 tons each year thereafter. Annual NO_X cap is 4,072 tons.
American Electric Power																	
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year				NO_X and SO_2 allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	NO_X and SO_2 allowances may not be used to comply with any of the limits imposed by the Consent Decree. The Consent Decree includes a formula for calculating excess NO_X allowances relative to the CAIR Allocations, and restricts the use of some. See par. 74-79 for details. Reducing emissions below the Eastern System-Wide Annual Tonnage Limitations for NO_X and SO_2 earns supercompliance allowances.		
						450,000	2010		96,000	2009							
						450,000	2011		92,500	2010							
						420,000	2012		92,500	2011							
						350,000	2013		85,000	2012							
						340,000	2014		85,000	2013							
						275,000	2015		85,000	2014							
						260,000	2016		75,000	2015							
						235,000	2017		72,000	2016 and thereafter							
						184,000	2018										
						174,000	2019 and thereafter										

Company and Plant	State	Unit	SETTLEMENT ACTIONS: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 Control: Equipment	SO_2 Control: Percent Removal or Rate	SO_2 Control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restrictions: Restriction	Allowance Restrictions: Effective Date	Notes
At least 600MW from various units	West Virginia	Sporn 1 – 4	Retire, retrofit, or re-power	12/31/18													
	Virginia	Clinch River 1 – 3															
	Indiana	Tanners Creek 1 – 3															
	West Virginia	Kammer 1 – 3															
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08							
		Unit 2					12/31/10			01/01/09							
		Unit 3					12/31/09			01/01/08							
Big Sandy	Kentucky	Unit 1			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_X burners		Date of entry							
		Unit 2			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/09							
Cardinal	Ohio	Units 1, 2			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09				
		Unit 3					12/31/12										
Clinch River	Virginia	Units 1 – 3				Annual Cap (tons)	Year	Continuously operate low NO_X burners		Date of entry							
						21,700	2010										
						21,700	2011										
						21,700	2012										
						21,700	2013										
						21,700	2014										
						16,300	2015 onwards										

Company and Plant	State	Unit	SETTLEMENT ACTIONS												Allowance Retirement	Allowance Restrictions		Notes
			Retire/Repower		SO_2 Control			No_x Control			PM or Mercury Control							
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date		Retirement	Restriction	Effective Date	
Conesville	Ohio	Units 1, 2	Retire, retrofit, or re-power	Date of entry														
Conesville	Ohio	Unit 3	Retire, retrofit, or re-power	12/31/12														
Conesville	Ohio	Unit 4			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		12/31/10								
Conesville	Ohio	Units 5, 6			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_X burners		Date of entry								
Gavin	Ohio	Units 1, 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09								
Glen Lyn	Virginia	Units 5, 6			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_X burners		Date of entry								
Kammer	West Virginia	Units 1 – 3				Plant-wide annual cap: 35,000	01/01/12	Continuously operate over-fire air		Date of entry								
Kanawha River	West Virginia	Units 1, 2			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_X burners		Date of entry								
Mitchell	West Virginia	Units 1, 2			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09								
Mountaineer	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/08								
Muskingum River	Ohio	Units 1 – 4	Retire, retrofit, or re-power	12/31/15														
Muskingum River	Ohio	Unit 5			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/08	Continuously operate ESP	0.03	12/31/02					

Company and Plant	State	Unit	SETTLEMENT ACTIONS											Allowance Retirement	Allowance Restrictions		Notes
			Retire/Repower		SO_2 Control			No_x Control			PM or Mercury Control						
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Picway	Ohio	Unit 9						Continuously operate low NO_X burners		Date of entry							
Rockport	Indiana	Unit 1			Install and continuously operate FGD		12/31/17	Install and continuously operate SCR		12/31/17							
		Unit 2					12/31/19			12/31/19							
Sporn	West Virginia	Unit 5	Retire, retrofit, or re-power	12/31/13													
Tanners Creek	Indiana	Units 1 – 3			Burn only coal with no more than 1.2 lb/MMBtu annual average		Date of entry	Continuously operate low NO_X burners		Date of entry							
		Unit 4			Burn only coal with no more than 1.2% sulfur content annual average			Continuously operate over-fire air									
East Kentucky Power Cooperative Inc.																	
Dale Plant	Kentucky	Units 1, 2						Install and continuously operate low NO_X burners by 10/31/2007	0.46	01/01/08				EKPC must surrender 1,000 NO_X allowances immediately under the ARP, and 3,107 under the NO_X SIP Call. EKPC must also surrender 15,311 SO_2 allowances.		Date of entry	
System-wide					System-wide 12-month rolling tonnage limits apply	12-month rolling limit (tons)	Start of 12-month cycle	All units must operate low NO_X boilers	12-month rolling limit (tons)	Start of 12-month cycle	PM control devices must be operated continuously system-wide, ESPs	0.03	1 year from entry date	All surplus SO_2 allowances must be surrendered each year, beginning in 2008.	SO_2 and NO_X allowances may not be used to comply with the Consent Decree. NO_X allowances that would become		By 12/31/2009, EKPC shall choose whether to: 1) install and continuou

Company and Plant	State	Unit	SETTLEMENT ACTIONS											Allowance Retirement	Allowance Restrictions		Notes
			Retire/Repower		SO_2 Control			NO_x Control			PM or Mercury Control						
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
						57,000	10/01/08		11,500	01/01/08	must be optimized within 270 days of entry date, or EKPC may choose to submit a PM Pollution Control Upgrade Analysis.				available as a result of compliance with the Consent Decree may not be sold or traded. SO_2 and NO_X allowances allocated to EKPC must be used within the EKPC system. Allowances made available due to supercompliance may be sold or traded.		sly operate NO_X controls at Cooper 2 by 12/31/2012 and SO2 controls by 6/30/2012 or 2) retire Dale 3 and Dale 4 by 12/31/2012.
						40,000	07/01/11		8,500	01/01/13							
						28,000	01/01/13		8,000	01/01/15							
Spurlock	Kentucky	Unit 1			Install and continuously operate FGD	95% or 0.1	6/30/2011	Continuously operate SCR	0.12 for Unit 1 until 01/01/2013, at which point the unit limit drops to 0.1. Prior to 01/01/2013, the combined average when both units are operating must be no more than 0.1	60 days after entry							
		Unit 2			Install and continuously operate FGD by 10/1/2008	95% or 0.1	1/1/2009	Continuously operate SCR and OFA	0.1 for Unit 2, 0.1 combined average when both units are operating								

Company and Plant	State	Unit	SETTLEMENT ACTIONS: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 Control: Equipment	SO_2 Control: Percent Removal or Rate	SO_2 Control: Effective Date	No_x Control: Equipment	No_x Control: Rate	No_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restrictions: Restriction	Allowance Restrictions: Effective Date	Notes
Dale Plant	Kentucky	Units 3, 4	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012													
Cooper	Kentucky	Unit 2			If EKPC opts to install controls rather than retiring Dale, it must install and continuously operate FGD or equiv. technology	95% or 0.10	12/31/11	If EKPC elects to install controls, it must continuously operate SCR or install equiv. technology	0.08 (or 90% if non-SCR technology is used)	12/31/12							
Nevada Power Company																	
Clark Generating Station	Nevada	Unit 5	Units may only fire natural gas					Increase water injection immediately, then install and operate ultra-low NO_X burners (ULNBs) or equivalent technology. In 2009, Units 5 and 8 may not emit more than 180 tons combined	5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)					Allowances may not be used to comply with the Consent Decree, and no allowances made available due to compliance with the Consent Decree may be traded or sold.		Beginning 1/1/2010, combined NO_X emissions from Units 5,6,7, and 8 must be no more than 360 tons per year.
		Units 6, 7								12/31/09 (ULNB installation), 01/30/10 (1-hour average)							
		Unit 8								12/31/08 (ULNB installation), 01/30/09 (1-hour average)							
PSEG FOSSIL																	
Kearny	New Jersey	Units 7, 8	Retire units	01/01/07										Allowances allocated to Kearny, Hudson, and Mercer may only be used for the operational needs of those units, and all			

Company and Plant	State	Unit	SETTLEMENT ACTIONS												Allowance Retirement	Allowance Restrictions		Notes
			Retire/Repower		SO_2 Control			No_x Control			PM or Mercury Control							
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date		Retirement	Restriction	Effective Date	
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	12/31/10	Install Baghouse (or approved technology)	0.015	12/31/10		surplus allowances must be surrendered. Within 90 days of amended Consent Decree, PSEG must surrender 1,230 NO_X Allowances and 8,568 SO_2 Allowances not already allocated to or generated by the units listed here. Kearny allowances must be surrendered with the shutdown of those units.			
						Annual Cap (tons)	Year		Annual Cap (tons)	Year								
						5,547	2007		3,486	2007								
						5,270	2008		3,486	2008								
						5,270	2009		3,486	2009								
						5,270	2010		3,486	2010								
Mercer	New Jersey	Units 1, 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10					

Notes:

1) This summary table describes incremental changes in New Source Review settlement actions as they are represented in EPA Base Case 3.0 to 3.02 EISA. The settlement actions are simplified for representation in the model. This table is not intended to be a comprehensive description of all elements of the actual settlement agreements.

Appendix IV. State Rules and Requirements

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
California	CA Reclaim Market	NO_X	9.68 MTons annual cap for any source with actual emissions of 4 tons or more in 1990 and thereafter	1994	Since the Reclaim Trading Credits are applicable to entities besides power plants, we approximate by hardwiring the NO_X and SO_2 allowance prices for the calendar year 2006.
		SO_2	4.292 MTons annual cap for any source with actual emissions of 4 tons or more in 1990 and thereafter		
Delaware	Regulation No. 1146: Electric Generating Unit (EGU) Multi-Pollutant Regulation	NO_X	0.125 lbs/MMBtu rate limit of NO_X annually for all coal and residual-oil fired units greater than 25 MW	2009	
		SO_2	0.26 lbs/MMBtu annual rate limit for coal and residual-oil fired units greater than 25 MW		
Georgia	Multipollutant Control for Electric Utility Steam Generating Units	SCR, FGD, and Sorbent Injection Baghouse controls to be installed	The following plants must install controls: Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates	Implementation from 2008 through 2015, depending on plant and control type	
Illinois	Title 35, Part 225, Subpart B: Control of Hg Emissions from Coal Fired Electric Generation Units	NO_X	0.11 lbs/MMBtu annual rate limit and ozone season rate limit for all Dynergy and Ameren coal steam units greater than 25 MW	2012	
		SO_2	0.33 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units greater than 25 MW	2013	
		Hg	90% Hg removal (or emission rate of 0.08 lbs/GWh) for all Ameren coal units greater than 25 MW and 90% Hg removal (or 0.08 lbs/GWh) for all Dynergy coal units greater than 25 MW	2015	
	Title 35 Part 225; Subpart F: Combined Pollutant Standards	NO_X	0.11 lbs/MMBtu annual rate limit and during the ozone season for all Midwest Gen coal steam units	2012	
		SO_2	0.44 lbs/MMBtu annual rate limit in 2013, decreasing annually to 0.11 lbs/MMBtu in 2019 for all Midwest Gen coal steam units	2013	
		Hg	90% Hg removal (or emission rate of 0.08 lbs/GWh) annually for all Midwest Gen coal steam units	2015	Will County unit has a unique restriction of 90% (or 0.08 lbs/GWh) starting in 2016
Maine	Chapter 145 NO_X Control Program	NO_X	0.15 lbs/MMBtu annual rate limit for all fossil fuel units greater than 25 MW built before 1995 with a heat input capacity greater than 750 MMBtu/hr and 0.20 lbs/MMBtu annually for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity greater than 250 MMBtu/hr	2005	
	Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air	Hg	Cap of 100 lbs of Hg annually for any facility including EGUs gradually lowering to 25 lbs in 2010	2005	
Minnesota	Minnesota Hg Emission Reduction Act	Hg	90% removal of Hg content of fuel annually for all coal units greater than 250 MW	2008	
New Hampshire	RSA 125-O: 11-18	Hg	80% reduction of aggregated Hg content of the coal burned at the facilities for Merrimack Units 1 & 2 and Schiller Units 4, 5, & 6	2013	Scrubbers must also be installed at the Merrimack Station units
	ENV-A2900 Multiple pollutant annual budget trading and banking program	CO_2	REMOVED: CO_2 annual cap of 5,426 Mtons for six specific existing steam units owned by PSNH	2007	This constraint was removed as the cap was no longer in effect given RGGI.
Texas	Senate Bill 7 Chapter 101	SO_2	273.95 MTons cap of SO_2 for all grandfathered units built before 1971 in East Texas Region	2003	
		NO_X	Annual cap for all grandfathered units built before 1971 in MTons: 84.48 in East Texas, 18.10 in West Texas, 1.06 in El Paso Region		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	Chapter 117	NO_X	East and Central Texas annual rate limits in lbs/MMBtu for units that came online before 1996: Gas fired units: 0.14 Coal fired units: 0.165 Stationary gas turbines: 0.14	2007	
			Dallas/Fort Worth Area annual rate limit for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system except for CT and CC units online after 1992: 0.033 lbs/MMBtu or 0.50 lbs/MWh output or 0.0033 lbs/MMBtu on system wide heat input weighted average for large utility systems 0.06 lbs/MMBtu for small utility systems		
			Housont/Galveston region annual Cap and Trade (MECT) for all fossil units: 8.46 Mtons		
			Beaumont-Port Arthur region annual rate limits for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system: 0.10 lbs/MMBtu		
Wisconsin	NR 428 Wisconsin Administration Code	NO_X	Annual rate limits in lbs/MMBtu for coal fired boilers greater than 1,000 MMBtu/hr : Wall fired, tangential fired, cyclone fired, and fluidized bed: 2009: 0.15, 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	2009	
			Annual rate limits in lbs/MMBtu for coal fired boilers between 500 and 1,000 MMBtu/hr: Wall fired: 2009: 0.20; 2013 onwards: 0.17 in 2013 Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2009: 0.20; 2013 onwards: 0.15 Fluidized bed: 2009: 0.15; 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18		
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs greater than 50 MW: 0.11 Distillate oil CTs greater than 50 MW: 0.28 Biologically derived fuel CTs greater than 50 MW: 0.15 Natural gas CTs between 25 and 49 MW: 0.19 Distillate oil CTs between 25 and 49 MW: 0.41 Biologically derived fuel CTs between 25 and 49 MW: 0.15		
			Annual rate limits for CCs in lbs/MMBtu: Natural gas CCs greater than 25 MW: 0.04 Distillate oil CCs greater than 25 MW: 0.18 Biologically derived fuel CCs greater than 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19		
	WI Hg rule	Hg	75% reduction of Hg emissions to coal fired units belonging to Alliant Energy, WE Energies, Wisconsin Public Service and Dairyland Power Cooperative	2010	