Figure 3.1. U.S. EPA Base Case 2006 Model Regions

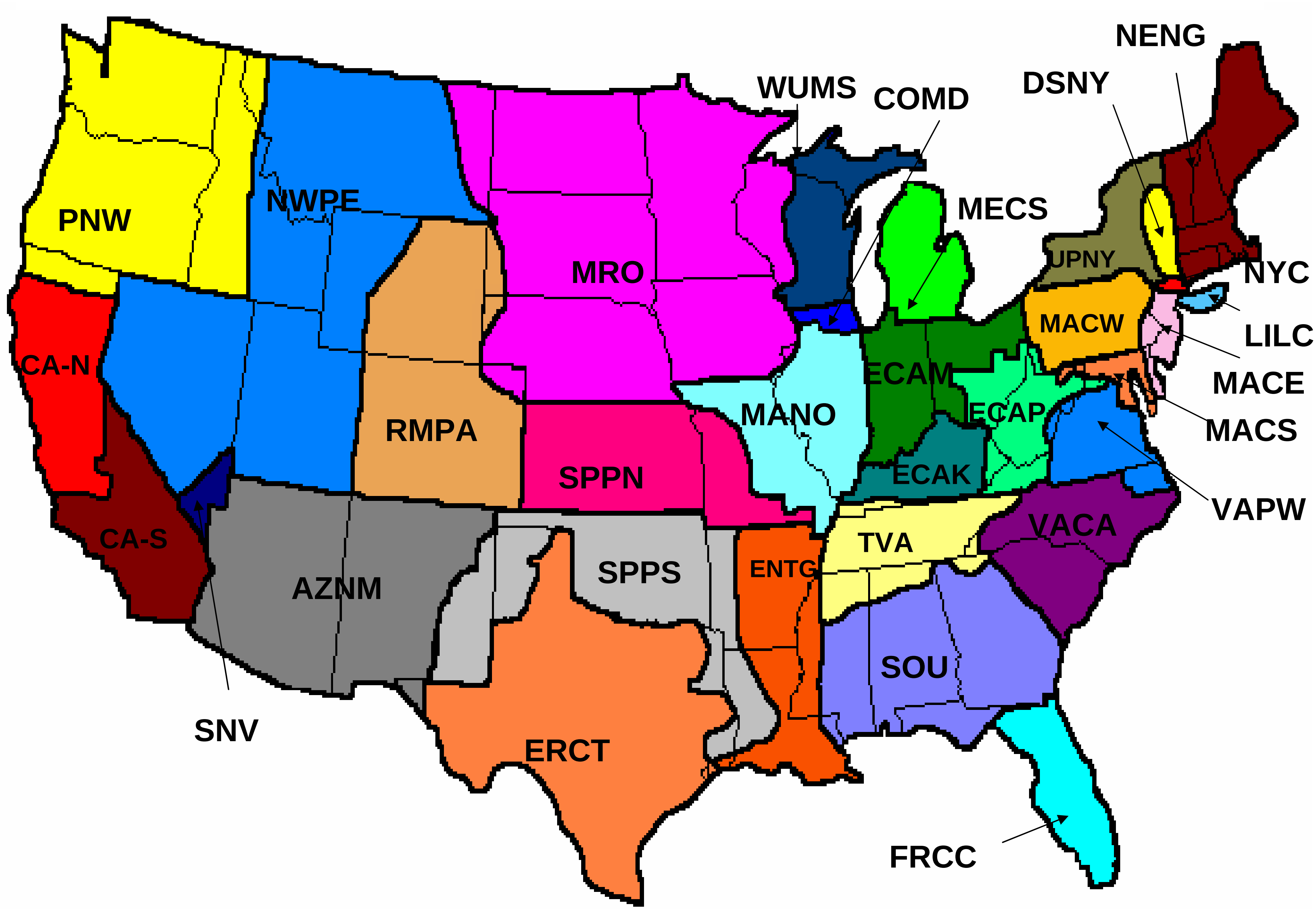

Table 3.1. Mapping of NERC Regions with EPA Base Case 2006 Model Regions

NERC Region	Model Region	Region Description or Reliability Council Name
ECAR	ECAM	East Central Area Reliability Coordination Agreement - MISO
	ECAP	East Central Area Reliability Coordination Agreement - PJM
	ECAK	East Central Area Reliability Coordination Agreement - MISO-KY
	MECS	Michigan Electric Coordination System
ERCOT	ERCT	Electric Reliability Council of Texas
FRCC	FRCC	Florida Reliability Coordinating Council
MAAC	MACE	Mid-Atlantic Area Council - East
	MACS	Mid-Atlantic Area Council - South
	MACW	Mid-Atlantic Area Council - West
MAIN	MANO	Mid-America Interconnected Network - South
	COMD	Commonwealth Edison
	WUMS	Wisconsin-Upper Michigan
MRO	MRO	Midwest Regional Planning Organization
NPCC	DSNY	Downstate New York
NPCC	LILC	Long Island Lighting Company
	NYC	New York City
	UPNY	Upstate New York
	NENG	New England Power Pool
SERC - EES	ENTG	Entergy
SERC - SOCO	SOU	Southern Company
SERC - TVA	TVA	Tennessee Valley Authority
SERC - VACAR	VACA	Virgina-Carolinas
	VAPW	Dominion Virginia Power
SPP	SPPN	Southwest Power Pool - North
	SPPS	Southwest Power Pool - South
WECC - AZNMSNV	AZNM	Western Electricity Coordinating Council - Arizona, New Mexico
	SNV	Western Electricity Coordinating Council - Southern Nevada
WECC - California ISO	CA-N	Western Electricity Coordinating Council - California North
	CA-S	Western Electricity Coordinating Council - California South
WECC - NWPP	PNW	Western Electricity Coordinating Council - Pacific Northwest
	NWPE	Western Electricity Coordinating Council-Northwest Power Pool East
WECC - RMPA	RMPA	Western Electricity Coordinating Council - Rocky Mountain Power Area

Table 3.2. Electric Load Assumptions in EPA Base Case 2006

Year	EPA Base Case 2006 Net Energy for Load
	(Billions of kWh)
2010	4,253
2015	4,582
2020	4,945
2025	5,320

Table 3.3. Baseline Electricity Sales Forecast Used for EPA Base Case 2006

	2010	2015	2020	2025	AAGR
GDP AEO 2005 (Billion $2004)	14,275	16,601	19,239	22,139	2.97%
Electricity Sales Forecast (Billion kWh)					
AEO 2005	4,070	4,430	4,811	5,220	1.67%
EPA Base Case 2006 Assumptions	3,998	4,323	4,661	5,016	1.52%

Table 3.4. National Non-Coincidental Peak Demand

Year	Peak Demand (GW) Winter	Peak Demand (GW) Summer
2010	685	778
2015	736	834
2020	794	900
2025	859	973

Table 3.5. Annual Transmission Capabilities between Model Regions

Region From	Region To	Energy Transfer Capability (MW)	Capacity Transfer Capability (MW)
	ECAM	2,776	1,904
MECS	ECAP	3,900	683
	ECAM	3,365	1,225
	ECAP	1,000	175
	MANO	200	200
ECAK	TVA	1,500	632
	COMD	2,760	1,360
	ECAK	815	270
	ECAP	12,838	7,951
	MACW	3,100	2,274
	MANO	7,078	3,504
ECAM	MECS	4,603	825
	COMD	3,100	3,100
	ECAK	1,000	537
	ECAM	15,041	8,525
	MACS	2,500	350
	MACW	3,900	1,075
	MECS	3,700	1,762
	TVA	1,000	1,000
	VACA	3,002	2,042
ECAP	VAPW	3,080	953
	ENTG	1,001	1,001
ERCT	SPPS	1,574	1,574
	DSNY	1,000	1,000
	LILC	650	521
	MACW	2,000	2,000
MACE	NYC	1,000	1,000
	ECAP	2,500	750
	MACW	3,500	3,000
MACS	VAPW	2,600	2,600
	ECAM	2,208	504
	ECAP	3,300	2,044
	MACE	6,200	5,800
	MACS	5,000	1,350
MACW	UPNY	1,155	1,155
	COMD	1,100	1,100
	ECAK	200	200
	ECAM	6,299	1,848
	ENTG	4,200	2,100
	MRO	405	405
	SPPN	1,300	1,300
MANO	TVA	1,812	1,812
	ECAM	1,620	1,110
	ECAP	4,500	788
	MANO	2,050	2,050
	MRO	825	825
COMD	WUMS	825	825
	COMD	1,125	1,125
WUMS	MRO	270	270

Table 3.5. Annual Transmission Capabilities between Model Regions (Continued)

Region From	Region To	Energy Transfer Capability (MW)	Capacity Transfer Capability (MW)
	COMD	610	610
	ENTG	2,000	2,000
	MANO	320	320
	NWPE	200	200
	RMPA	310	310
	SPPN	2,000	2,000
MRO	WUMS	800	800
	DSNY	700	700
NENG	LILC	431	431
	DSNY	4,550	4,550
	MACW	1,155	1,155
UPSNY	NENG	150	150
	LILC	1,300	1,300
	MACE	2,000	2,000
	NENG	1,120	1,120
	NYC	3,700	3,700
DNSY	UPNY	3,400	3,400
	DSNY	2,000	2,000
	LILC	250	250
NYC	MACE	500	500
	DSNY	530	530
	MACE	650	590
	NENG	431	431
LILC	NYC	420	420
	ENTG	3,745	1,260
	MANO	1,200	1,200
	MRO	600	600
SPPN	SPPS	700	700
	AZNM	420	420
	ENTG	9,030	2,310
	ERCT	820	820
SPPS	SPPN	1,200	1,200
	MANO	910	140
	MRO	150	150
	SOU	2,250	2,250
	SPPN	1,120	140
	SPPS	4,494	735
ENTG	TVA	1,681	1,681
	ENTG	2,950	2,950
	FRCC	3,600	3,600
	TVA	3,742	3,742
SOU	VACA	2,158	2,158
FRCC	SOU	2,000	2,000
	ECAK	2,000	1,073
	ECAP	1,500	263
	ENTG	2,919	2,919
	MANO	1,550	1,550
	SOU	2,258	2,258
TVA	VACA	864	864
	ECAP	4,117	438
	SOU	3,242	3,242
	TVA	3,586	3,586
VACA	VAPW	1,942	1,942
	ECAP	5,460	1,952
	MACS	2,100	2,100
VAPW	VACA	1,849	1,849

Table 3.5. Annual Transmission Capabilities between Model Regions (Continued)

Region From	Region To	Energy Transfer Capability (MW)	Capacity Transfer Capability (MW)
	CA-S	3,700	3,700
	NWPE	150	100
CA-N	PNW	3,675	3,675
	AZNM	3,627	2,428
	CA-N	3,000	2,400
	NWPE	1,400	1,400
	PNW	3,100	3,100
CA-S	SNV	4,688	4,688
	CA-N	4,000	4,000
	CA-S	3,100	3,100
PNW	NWPE	1,505	1,505
	AZNM	690	690
	MRO	310	310
RMPA	NWPE	665	665
	AZNM	820	820
	CA-N	160	120
	CA-S	1,920	1,920
	MRO	150	150
	PNW	2,002	2,002
	RMPA	679	679
NWPE	SNV	300	250
	CA-S	3,627	2,428
	NWPE	850	850
	RMPA	690	690
	SNV	4,634	4,634
AZNM	SPPS	420	420
	AZNM	4,785	4,785
	CA-S	4,688	4,688
SNV	NWPE	300	300

Table 3.6. International Electricity Imports

	2010	2015	2020	2025
Net International Imports (billion kWh)	24.85	24.98	21.45	22.23

Table 3.7. Availability Assumptions in the EPA Base Case 2006

Unit Type	Availability (%)
Biomass	83.0
Coal Steam	80.4 - 85.8
Combined Cycle	84.7
Combustion Turbine	89.7 - 90.7
Gas/Oil Steam	78.2 - 89.4
Geothermal	87.1
IGCC	85.0
Pumped Storage	89.1

Note: Values shown are a range, since they vary by the size of the unit.

Table 3.8. Seasonal Hydro Capacity Factors (%) in the EPA Base Case 2006

IPM Region	Winter Capacity Factor (%)	Summer Capacity Factor (%)	Annual Capacity Factor (%)
AZNM	31.2%	34.8%	32.7%
SNV	21.2%	24.8%	22.7%
CA-N	32.3%	46.3%	38.2%
CA-S	34.2%	45.9%	39.1%
DSNY	57.5%	50.1%	54.4%
ECAM	79.0%	95.3%	85.8%
ECAP	28.3%	26.2%	27.4%
ECAK	43.1%	52.0%	46.8%
ENTG	40.6%	40.4%	40.5%
ERCT	9.9%	19.6%	14.0%
FRCC	39.7%	37.4%	38.7%
MACE	9.0%	10.6%	9.7%
MACS	20.5%	28.0%	23.7%
MACW	42.8%	32.4%	38.5%
MANO	18.6%	24.8%	21.2%
COMD	40.9%	47.3%	43.6%
MRO	35.5%	46.7%	40.2%
MECS	62.6%	59.7%	61.4%
NENG	35.6%	33.4%	34.7%
NWPE	27.4%	44.1%	34.4%
PNW	38.8%	39.4%	39.0%
RMPA	17.5%	33.3%	24.1%
SOU	24.1%	19.3%	22.1%
SPPN	14.3%	19.4%	16.5%
SPPS	23.3%	29.3%	25.8%
TVA	41.7%	38.4%	40.3%
UPNY	56.7%	54.6%	55.8%
VACA	16.0%	14.9%	15.5%
VAPW	20.1%	19.4%	19.8%
WUMS	75.1%	80.6%	77.4%
National Weighted	**26.7%**	**31.4%**	**28.7%**

Table 3.9. Planning Reserve Margins in EPA Base Case 2006

Region Description	Reserve Margin
East Central Area Reliability Coordination Agreement - MISO	15.0%
East Central Area Reliability Coordination Agreement - PJM	15.0%
East Central Area Reliability Coordination Agreement - MISO-KY	15.0%
Michigan Electric Coordination System	15.0%
Electric Reliability Council of Texas	12.5%
Florida Reliability Coordinating Council	15.0%
Mid-Atlantic Area Council - East	16.0%
Mid-Atlantic Area Council - South	16.0%
Mid-Atlantic Area Council - West	16.0%
Mid-America Interconnected Network - South	17.0%
Commonwealth Edison	15.0%
Wisconsin-Upper Michigan	15.0%
Midwest Regional Planning Organization	15.0%
Downstate New York	18.0%
Long Island Lighting Company	18.0%
New York City	18.0%
Upstate New York	18.0%
New England Power Pool	16.0%
Entergy	15.0%
Southern Company	15.0%
Tennessee Valley Authority	13.0%
Virgina-Carolinas	15.0%
Dominion Virginia Power	15.0%
Southwest Power Pool - North	13.6%
Southwest Power Pool - South	13.6%
Western Electricity Coordinating Council - Arizona New Mexico	12.8%
Western Electricity Coordinating Council - Southern Nevada	12.8%
Western Electricity Coordinating Council - California North	15.0%
Western Electricity Coordinating Council - California South	15.0%
Western Electricity Coordinating Council - Pacific Northwest	12.4%
Western Electricity Coordinating Council - Northwest Power Pool East	12.4%
Western Electricity Coordinating Council - Rocky Mountain Power Area	13.5%

Table 3.10. Lower and Upper Limits Applied to Heat Rate Data in NEEDS 2006

	Heat Rate (Btu/kWh)	
	Lower Limit	**Upper Limit**
Coal Steam	8,300	14,500
Oil/Gas Steam	8,300	14,500
Combined Cycle - Natural Gas	5,500	15,000
Combined Cycle - Oil	6,000	15,000
Combustion Turbine - Natural Gas - 80 MW and above	8,700	18,700
Combustion Turbine - Natural Gas < 80 MW	8,700	36,800
Combustion Turbine - Oil and Oil/Gas - 80 MW and above	6,000	25,000
Combustion Turbine - Oil and Oil/Gas < 80 MW	6,000	36,800
IC Engine - Natural Gas	8,700	18,000
IC Engine - Oil and Oil/Gas - 5 MW and above	8,700	20,500
IC Engine - Oil and Oil/Gas < 5 MW	8,700	42,000

Table 3.13. Emission and Removal Rate Assumptions for Potential (New) units in EPA Base Case 2006

Gas	Removal, and Emissions Rates	Conventional Pulverized Coal - Wet Scrubber	Conventional Pulverized Coal - Dry Scrubber	Integrated Gasification Combined Cycle	Advanced Combined Cycle	Advanced Combustion Turbine	Biomass Integrated Gasification Combined Cycle	Geothermal	Landfill Gas
SO_2	Removal / Emissions Rate	95% with a floor of 0.06 lbs/MMBtu	90% with a floor of 0.09 lbs/MMBtu	99%	None	None	0.08 lbs/MMBtu	None	None
NO_x	Emission Rate	0.06 lbs/MMBtu	0.06 lbs/MMBtu	0.066 lbs/MMBtu (2008-2012) and 0.013 lbs/MMBtu (2013-)	0.011 lb/MMBtu	0.08 lb/MMBtu	0.02 lb/MMBtu	None	0.09 lb/MMBtu
Hg	Emission Rate	90%	90%	90%	Natural Gas: .000138 lbs/MMBtu Oil: .483 lbs/MMBtu	Natural Gas: .000138 lbs/MMBtu Oil: .483 lbs/MMBtu	0.57 lbs/MMBtu	3.70	None
CO_2	Emission Rate	202.4 - 216.6 lbs/MMBtu	202.4 - 216.6 lbs/MMBtu	202.4 - 216.6 lbs/MMBtu	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39	None	None	115.258 lbs/MMBtu

Appendix 3-1. NO_x Rate Development in EPA Base Case 2006

In EPA Base Case 2006 and the policy model runs built upon this base case (as in previous EPA base cases) NO_x combustion controls are not represented as retrofit options that the model chooses. Instead, in setting up each model run, the presence or absence of combustion controls is captured in the NO_x rates assigned to existing units. State-of-the-art NO_x combustion controls are assumed to be used in geographical areas that are subject to NO_x control limits that go into effect after 2003. Within the NO_x SIP Call region*, however, no additional combustion controls were assumed, so the controlled base and controlled policy NO_x rates are the same

Each existing fossil-fuel-fired generating unit in the NEEDS 2006 database has four NO_x emission rates associated with it from which the IPM set-up program assigns the rate applicable for each specific model scenario. A "Base Rate" for NO_x is said to apply, if under a particular modeled scenario, a unit is not located in a geographical area affected by NO_x control limits beyond those already reflected in the baseline emission rate data incorporated into NEEDS from the sources described in Steps 2-5 below. A "Policy Rate" for NO_x applies if a unit is located in a geographical area affected by NO_x control limits beyond those reflected in the baseline emission rate data. This results in four NO_x rates being associated with each generating unit:

Mode 1= Uncontrolled Base Rate
Mode 2= Controlled Base Rate
Mode 3= Uncontrolled Policy Rate
Mode 4 = Controlled Policy Rate

There are several things to note about the Modes 1-4 designations. "Controlled" refers to the rates provided by post combustion NO_x controls, i.e., selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), if they are present at the unit. For generating units that do not have post-combustion controls, the controlled rate will be the same as the uncontrolled rate. For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ unless the post-combustion controls are operated year round. In such cases, the "uncontrolled rates" are assigned the "controlled" NO_x emission rate. Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or is in the SIP Call region where current combustion controls are assumed to be retained. Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls that would be installed in response to a NO_x policy. Examples of each of these instances are shown in Table A 3-1:1.

The list below enumerates the procedure that is used to derive the four emission rates. Several aspects of the list are worth noting. (1) In general, winter NO_x rates reported in EPA's Emission Tracking System were used as proxies for the uncontrolled base NO_x rates. (2) If a unit does not report having combustion controls, but has an emission rate below a specific cut-off rate (shown in Table 3-1:2), it is considered to have combustion controls. (3) For units with combustion controls that were not state-of-the-art, emission rates without those combustion controls were back calculated and then policy rates were derived assuming the reductions provided by state-of-the art combustion controls. (4) The NO_x rates achievable by state-of-the-art combustion controls vary by coal rank (bituminous and sub-bituminous) and boiler type. The equations used to derive these rates are shown in Table 3-1:3.

*The SIP Call region includes Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, and West Virginia..

Process Used to Derive Base and Policy NO_x Rates in EPA Base Case 2006

Step 1: Four modes for NO_x rates were defined:

Mode 1= Uncontrolled Base Rate
Mode 2= Controlled Base Rate
Mode 3= Uncontrolled Policy Rate
Mode 4 = Controlled Policy Rate

Step 2: NO_x rates were derived for the summer and winter seasons from the data reported to EPA under Title IV of the Clean Air Act Amendments of 1990 (Acid Rain Program) and NO_x budget program. This data is maintained in EPA's Emission Tracking System (ETS) and, consequently, the resulting values are called ETS emission rates.

Step 3: In general, ETS winter NO_x rates were used as proxies for uncontrolled baseline NO_x rates (Mode 1). For units without ETS winter NO_x rates and without post combustion NO_x controls, ETS summer NO_x rates were used as the Mode 1 NO_x rate when available. For units without ETS winter NO_x rates and with post combustion NO_x controls, ETS summer NO_x rates were used to back calculate their Mode 1 NO_x rate by assuming a removal efficiency of the post combustion NO_x control. For an SCR, the assumed removal efficiency was 80% for a combined cycle, combustion turbine, IC engine or oil/gas steam unit and 90% for a coal steam unit; for an SNCR, the assumed removal efficiency was 50% for a combined cycle, combustion turbine, IC engine or oil/gas steam unit and 35% for a coal steam unit.

Step 4: For non-coal units in NEEDS without ETS NO_x rates, default Mode 1 rates were developed from similar units with ETS rates. This was done by state, plant type, fuel type, post combustion control and size. If state level defaults were not available for certain generating units then national level defaults were used.

Step 5: For coal units without ETS NO_x rates, default Mode 1 rates were developed from similar units with ETS rates. This was done by state, firing, bottom, combustion control, post combustion control and size. If state level defaults were not available for certain boilers then national level defaults by firing, bottom, combustion control, and post combustion control were used.

Step 6: For coal steam units with an SCR, the Mode 2 NO_x rate was calculated by applying a 90% reduction to the Mode 1 NO_x rate as long as this result was higher than the floor rate of 0.06 lb/mmBtu. For coal steam units with an SNCR, the Mode 2 rate was derived by applying a 35% reduction to the Mode 1 rate and no floor rate was used. For oil/gas steam units with an SCR, the Mode 2 rate was calculated by applying a 80% reduction to the Mode 1 rate. For oil/gas steam units with an SNCR, the Mode 2 rate was calculated by applying a 50% reduction to the Mode 1 rate. For combined cycle, combustion turbine, and internal combustion (IC) units, if both summer and winter ETS NO_x rates were available, the Mode 2 rate was calculated as the lesser of the summer ETS NO_x rate and the winter ETS NO_x rate. For units without ETS summer NO_x rates and without post combustion NO_x controls, and if winter ETS NO_x rates were available, the Mode 2 rate equals the winter ETS NO_x rate. For units with a post combustion NO_x control and the winter ETS NO_x rate is lower than 0.04 lb/mmBtu, the Mode 2 rate equals the winter ETS NO_x rate; however, if the winter ETS NO_x rate is higher than 0.04 lb/mmBtu, then the Mode 2 rate is the larger of the floor rate of 0.01 lb/mmBtu and the calculated rate based on the formula: winter ETS NO_x rate * (1 – SCR Removal Efficiency of 80%). If both winter and summer ETS NO_x rates were not available, default Mode 2 rates were developed based on the methodology applied to the development of default Mode 1 rates. In case the default Mode 2 NO_x rates were greater than the default Mode 1 rates, the default Mode 2 NO_x rates were reset to the default Mode 1 rates. For all other units, Mode 2 NO_x rate is equal to the Mode 1 NO_x rate.

Step 7: For boilers that were not listed as having either combustion or post-combustion controls, an additional engineering check was performed to determine if they should be considered to have combustion controls. Their Mode 1 NO_x rate was compared with the cut-off NO_x rate indicative of the presence of combustion controls in similar boilers. If the units Mode 1 NO_x rate was less than or equal to the cut-off rate (in columns 2-4 of Table 3-1:2), then the boiler was assumed to have a NO_x combustion control and the Mode 3 rate was assigned the same value as the Mode 1 rate.

Step 8: The technology configuration for units listed as having combustion controls were checked to see if they reflected the presence of state of the art NO_x controls. If not, calculations were performed to provide a NO_x rate that would result with state of the art combustion controls. The calculations (described in Step 9) were tailored to the specific configuration of controls that were in place. This rate was used as the Mode 3 Uncontrolled Policy NO_x Rate. This step was not applied to units in the SIP Call region since they already had their combustion controls in operation and were unlikely to move to a higher level of control. The step was also not applied to units that had SCR and to units whose Mode 1 rate was lower than the cut-off rate (as described in Step 7). All such boilers that were excluded from this step, were assigned identical Mode 1 and Mode 3 NO_x rates.

Step 9: For wall- and tangentially fired units the following procedure was used to calculate the state-of-the-art combustion control NO_x rates required in Step 8. Based on the specific controls in place, one of several candidate equations (column 4 in Table 3-1:3) was first used to back-calculate the uncontrolled emission rate that would have resulted without the existing controls. (In cases where the applicable equation could not be solved a default removal rate (column 5 in Table 3-1:3) was used to back-calculate the uncontrolled emission rate.) Once the uncontrolled NO_x rate was calculated, a removal efficiency equation for the applicable state of the art NO_x combustion control was applied to derive the Mode 3 policy rate. The specific removal equation used depended on the type of boiler and the predominant coal rank (bituminous or subbituminous) consumed by the unit. (It is one of those shown in bold italic in column 4 of Table 3-1:3)

Step 10: The rate derived in Step 9 was compared to the applicable NO_x rate floor (columns 5-7 of Table 3-1:2) that engineering analysis indicated applied to each burner type. If the rate derived in Step 9 was below the applicable floor rate, the floor rate, not the Step 9 rate, was used as the Mode 3 rate.

Step 11: The removal rates for combustion controls on cell, cyclone, and vertically fired boilers were assumed to be 60%, 50%, and 40% respectively.

Step 12: For coal units, the Mode 4 emission rate was calculated by applying a 90% reduction to the Mode 3 rate of coal units with an SCR as long as this result was higher than the floor rate of .06 lb/mmBtu. For units with SNCR the Mode 4 rate was derived by applying a 35% reduction to the Mode 3 rate. No floor rate was used.

Step 13: For all non coal units, the Mode 3 NO_x rate is equal to the Mode 1 NO_x rate and Mode 4 NO_x rate is equal to Mode 2 NO_x rate.

Table 3-1:1. Examples of Base and Policy NO_x Rates Occurring in EPA Base Case 2006.							
Plant Name	UniqueID	Post-Comb Control	Uncontrolled NO_x Base Rate	Controlled NO_x Base Rate	Uncontrolled NO_x Policy Rate	Controlled NO_x Policy Rate	Explanation
Situation 1: For generating units that do not have post-combustion controls, the controlled and uncontrolled rates will be the same.							
JACK WATSON	2049_B_5	None	0.59	0.59	0.43	0.43	Situation 4 also applies, i.e., unit had LNB and now added OFA so see drop in policy rates.
Situation 2a: For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ							
BIG SANDY	1353_B_BSU2	SCR	0.55	0.06	0.55	0.06	(1) Has SCR so see difference between uncontrolled and controlled rates (2) Situation 3b also applies.
Situation 2b: . . . unless the post-combustion controls are operated year round. In such cases, the "uncontrolled rates" are assigned the "controlled" NO_x rate.							
AZNM_ Coal Steam_AZ	82500_C_001	SCR	0.06	0.06	0.06	0.06	Planned/Committed unit so run SCR year-round
Situation 3a: Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or . . .							
SOUTH OAK CREEK	4041_B_5	None	0.17	0.17	0.17	0.17	Situation1 also applies.
Mayo	6250_B_1A	SCR	0.36	0.06	0.36	0.06	Situation 2a also applies.
Situation 3b: . . . is in the SIP Call region where current combustion controls are assumed to be retained.							
WIDOWS CREEK	50_B_7	SCR	0.42	0.06	0.42	0.06	Situation 2a also applies.
SIBLEY	2094_B_3	None	0.62	0.62	0.62	0.62	(1) Has NO_x combustion control and is in SIP so doesn't get added combustion control. High NO_x rate because it is a cyclone unit (2) Situation 1 also applies.
Situation 4: Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls and would install such controls in response to a NO_x policy.							
Rochester 7	2642_B_1	SNCR	0.58	0.37	0.26	0.17	(1) Drop in uncontrolled policy NO_x rate compared to uncontrolled base rate is due to addition of combustion controls. (Note 0.32 is floor.) (2) Unit has SNCR so Situation #2a also applies and you see a 35% drop between uncontrolled and controlled NO_x rates.

Table A3-1:2. Cutoff and Floor NO_x Rates (lb/mmBtu)

Boiler Type	Cutoff Rate (lbs. per MMBtu) Bit	Sub	Lig	Floor rate (lbs. per MMBtu) Bit	Sub	Lig
Wall-Fired Dry-Bottom	0.43	0.33	0.29	0.32	0.18	0.18
Tangentially-Fired	0.34	0.24	0.22	0.24	0.12	0.17
Cell-Burners	0.43	0.43	0.43	0.32	0.32	0.32
Cyclones	0.62	0.67	0.67	0.47	0.49	0.49
Vertically-Fired	0.57	0.44	0.44	0.49	0.25	0.25

Bit = bituminous, Sub = subbituminous, Lig = lignite

Table A 3-1:3. NO_x Removal Efficiencies for Different Combustion Control Configurations. (State of the art configurations are shown in bold italic.)

Boiler Type	Coal Type	Combustion Control Technology	Fraction of Removal	Default Removal
Dry Bottom Wall-Fired	Bituminous	LNB	0.163 + 0.272* Base NO_x	0.568
		LNB + OFA	***0.313 + 0.272* Base*** $\boldsymbol{NO_x}$	***0.718***
Dry Bottom Wall-Fired	Sub-bituminous/Lignite	LNB	0.135 + 0.541* Base NO_x	0.574
		LNB + OFA	***0.285 + 0.541* Base*** $\boldsymbol{NO_x}$	***0.724***
Tangentially-Fired	Bituminous	LNC1	0.162 + 0.336* Base NO_x	0.42
		LNC2	0.212 + 0.336* Base NO_x	0.47
		LNC3	***0.362 + 0.336* Base*** $\boldsymbol{NO_x}$	***0.62***
Tangentially-Fired	Sub-bituminous/Lignite	LNC1	0.20 + 0.717* Base NO_x	0.563
		LNC2	0.25 + 0.717* Base NO_x	0.613
		LNC3	***0.35 + 0.717* Base*** $\boldsymbol{NO_x}$	***0.713***

LNB = low NO_x burner. OFA = overfire air. LNC = low NO_x control

Appendix 3-2. State Power Sector Regulations Incorporated in EPA Base Case 2006

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Western Region--Arizona, New Mexico, Oregon, Utah, Wyoming	WRAP	SO_2	Cap of 198,900 tons on all fossil > 25 MW	2018	
Connecticut	Executive Order 22	NO_x	Emission rate of 0.15 lb/mmBtu for fossil units > 15 MW	2007	
	Executive Order 19	SO_2	Emission rate of 0.33 lb/mmBtu for fossil units > 15 MW	2007	
	Public Act No. 30-72	Hg	Emission rate of 0.0000006 lb/mmBtu for all coal-fired plants, alternatively can meet a 90% emission reduction	2008	
Illinois	Title 35, Section 217.706	NO_x	Emission rate of 0.25 lb/mmBtu for fossil units > 25 MW. Some units are allowed to average their emissions; others must meet the rate on a facility basis.	2007	
Maine	Chapter 145 NO_x Control Program	NO_x	Emission rate of 0.22 lb/mmBtu for fossil units > 25 MW built before 1995 with a heat input capacity between 250 and 750 mmBtu/hr	2007	
		NO_x	Emission rate of 0.15 lb/mmBtu for fossil units >25MW built before 1995 with a heat input capacity greater than 750 MmBtu/hr	2007	The impacted unit's emissions fall below the cap so no additional emission constraint was included in the model.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Maryland	Healthy Air Act (no out-of-state trading; no inter-company trading; no banking from year-to-year[1])	NO_x	Phase I: Sets unit specific annual caps (totaling 20,216 tons) and ozone season caps (totaling 8,900 tons) Phase II: Sets unit specific annual caps (totaling 16,667 tons) and ozone season caps (totaling 7,337 tons)	2009 2012	
		SO_2	Phase I: Sets unit specific annual caps (totaling 48,618 tons) Phase II: Sets unit specific annual caps (totaling 37,235 tons)	2010 2013	
		Hg	Phase I: 12-month rolling average of minimum 80% removal efficiency Phase II: 12-month rolling average of minimum 90% removal efficiency	2010 2013	
Massachusetts	310 CMR 7.29	NO_x	Emission rate of 1.5 lb/MWh for the 6 grandfathered units in state	2007	
		SO_2	Emission rate of 3.0 lb/MWh for the 6 grandfathered units in state	2007	
		Hg	6 facilities must comply with: 85% reduction or 0.0075 lbs/GWh in 2008; and 90% reduction or 0.0025 lbs/GWh in 2012[2]	2008/2012	
		CO2	Emission rate of 1,800 lb/MWh for the 6 grandfathered units in state	2007	
Minnesota	Agreement between Minnesota Pollution Control Agency and Xcel Energy	NO_x, SO_2, Hg	Specific Xcel Energy plants must repower or install controls	2007-2009	

[1] Brandon Shores (units 1 and 2), C.P. Crane (units 1 and 2), Chalk Point (units 1 and 2), Dickerson (units 1, 2 and 3), H.A. Wagner (units 2 and 3), Morgantown (units 1 and 2), R. Paul Smith (units 3 and 4)

[2] Brayton Point (units 1, 2, 3, 4, IC1, IC2, IC3, and IC4), Mystic (units 4, 5, 6, 7, 307, 308, 309, and 310), NRG Somerset (units 8, J1, and J2), Mount. Tom (unit 1), Canal (units 1 and 2), and Salem Harbor (units 1, 2, 3, and 4).

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	Hg Bill	Hg	Two Xcel Energy and one Minnesota Power plant to have 90% removal efficiency.	2015	
Missouri	Title 10, Div 10, Ch 6.350	NO_x	Units are subject to a county specific emission rate of either 0.18 lbs/mmBtu or 0.25 lbs/mmBtu or 0.35 lbs/mmBtu[3]	2007	
New Hampshire	ENV-A2900	NO_x	Cap of 3,644 tons on all existing fossil steam units	2007	
		SO_2	Cap of 7,289 tons on all existing fossil steam units	2007	
		Hg	Requires installation of scrubbers on Merrimack Station (units 1 and 2) with State-level credits for over- or early-compliance.	July 1, 2013	
		CO2	Cap of 5,425,866 tons on all existing fossil steam units	2007	
	ENV-A3200	NO_x	Seasonal Cap of 2,900 tons on fossil steam units >250 MMBtu/hr and that operated in calendar year 1990	2007	Emission specs reflect information obtained from RPO
New Jersey	Hg MACT Rule	Hg	All coal units will have a removal efficiency of 90%	2007	
New York	Part 237	NO_x	Non-ozone season cap of 39,908 tons on fossil units > 25 MW	2007	
		SO_2	Annual cap of 197,046 tons starting in 2007 and 131,364 tons starting in 2008 on fossil units > 25 MW	2007	
North Carolina	Clean Smokestacks Act	NO_x	Cap of 25,000 tons on coal-fired units belonging to CP&L >25MW	2007	
		NO_x	Cap of 35,000 tons starting in 2007 and 31,000 starting in 2009 on coal-fired units belonging to Duke Energy >25MW	2007	

[3] Missouri counties subject to 0.25 llbs/mmBtu limit: Bollinger, Butler, Cape Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Gasconade, Iron, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Phelps, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Francois, Ste. Genevieve, Scott, Shannon, Stoddard, Warren, Washington and Wayne. Missouri counties subject to 0.18 llbs/mmBtu limit: City of St. Louis, Franklin, Jefferson, St. Louis. Missouri counties subject to 0.35 llbs/mmBtu limit: Buchanan, Jackson, Jasper, Randolph, and any other county not listed.

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
		SO_2	Cap of 100,000 tons on 14 coal-fired units belonging to CP&L >25MW by 2009 and 50,000 tons by 2013 [Title IV allowances allocated to North Carolina units that exceed the State's cap will be retired from the federal program in IPM]	2009	
		SO_2	Cap of 150,000 tons on 14 coal-fired units belonging to Duke Energy >25MW by 2009 and 80,000 tons by 2013 [Title IV allowances allocated to North Carolina units that exceed the State's cap will be retired from the federal program in IPM]	2009	
Pacific Northwest (Washington, Oregon, Idaho)	Washington House Bill 3141	CO2	Requires new fossil units to reduce their CO2 emissions by 20% of a 30 year period, or purchase credits, or pay penalty of $1.60 per metric ton of CO2	2007	Emission limits affecting future potential units have to be modeled at the model region level in IPM, not at the state level. A CO2 emissions charge of $1.60 per metric ton was used to represent both the Washington and Oregon CO2 provisions. While Idaho does not have CO2 limits, the inclusion of the Idaho portion of the PNW model region under this cap is consistent with the governor's Executive Order 2006-25 which calls for no new coal-fired power plants as a way of limiting mercury emissions.
	Oregon Administrative Rules, Chapter 345, Division 24	CO2	Annual emission rate of 675 lb/MWh for new Combustion turbines burning natural gas with a Capacity Factor >75%, and all new non-base load plants (with a CF <=75%) emitting CO2	2007	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Texas	Senate Bill 7	NO_x -East	Annual emission cap of 58,365 tons for all grandfathered fossil > 25MW [all of Texas traversed by or east of Rt 35]	2007	
		NO_x -West	Annual emission cap of 18,028 tons for all grandfathered fossil > 25MW [all of Texas not in East region or El Paso county]	2007	
		NO_x - El Paso	Annual emission cap of 1,058 tons for all grandfathered fossil > 25MW [El Paso county]	2007	
		SO_2 - East	Annual emission cap of 111,183 tons for all grandfathered fossil > 25MW [all of Texas traversed by or east of Rt 35]	2007	
		SO_2 -West	25% reduction from 1997 baseline for all grandfathered fossil > 25MW [all of Texas not in East region or El Paso county]	-	Since the impacted units' emissions fall below the cap no additional emission constraint was included in the model.
		SO_2 - El Paso	25% reduction from 1997 baseline for all grandfathered fossil > 25MW [El Paso county]	-	Since the impacted units' emissions fall below the cap no additional emission constraint was included in the model.
	Ch. 117	NO_x - Houston	Cap of 8,459 tons applied to all fossil units	2007	
		NO_x - Dallas/ Fort Worth	Unit-specific rate limits that can alternatively be met by a system-wide averaging cap of 2,164 tons applied to all fossil units	2007	
		NO_x - East/ Central	Unit-specific rate limits that can alternatively be met by a system-wide averaging cap of 123,528 tons applied to all fossil units	2007	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Wisconsin We Energies (WEPCO) *owns 5 coal and 3 natural gas facilities affected by agreement*	Cooperative agreement between WEPCO and DNR Wisconsin Dept of Natural Resources (PUB-AM-316 2001)	SO_2	System-wide emission limit of 0.70 lb/mmBtu in 2008 and 0.45 lb/mmBtu in 2013 for WEPCO coal plants	2007/2012	
		NO_x	System-wide emission limit of 0.25 lb/mmBtu in 2008 and 0.15 lb/mmBtu in 2013 for WEPCO coal plants Performance standards for NOx emissions for utility and non-utility units.[4]	2007/2012	
		Hg	Planned 10% reduction from 1998-2000 levels by 2007 and 50% reduction by 2012, but no cap approved yet	-	-

[4] Performance standards (NOx) are: 0.28lb/mmBtu for utility boilers; 0.45 lb/mmBtu (cyclone), 0.20lb/mmBtu (fluidized bed), 0.30lb/mmBtu (pulverized coal), 0.10lb/mmBtu (gas-fired), 0.12 (distillate oil), 0.20lb/mmBtu (residual oil) for non-utility boilers; and, 75 ppm (gas) and 110 ppm (oil) for combustion turbines.

Appendix 3-3. New Source Review (NSR) Settlements in EPA Base Case 2006

		Settlement Actions														
		retire/repower		SO2 control			Nox Control			PM or Mercury Control			Allowance retirement	Allowance Restriction		
Company and Plant	Unit	Action	Effective Date	Equipment	Percent removal or rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes
Alabama Power																
James H. Miller	Unit 3			Install and Operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06	With 45 days of settlement entry, APC must retire 7,538 SO2 emission allowances.	APC shall not sell, trade, or otherwise exchange any Plant Miller excess SO2 emission allowances outside of the APC system	1/1/2021	1) Settlement requires 95% removal efficiency for SO2, or 90% in the event that the unit combust a coal with sulfur content greater than 1% by weight. 2) The settlements requires APC to retire $4,900,000 of SO2 emission allowances within 45 days of consent decree entry. 3) EPA assumed a retirement of 7, 538 SO2 allowances based on a current allowance price of $650. 4) The FGD and SCR controls are modeled as emission constraints in EPA Base Case 2006.
	Unit 4			Install and Operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06			1/1/2021	
Minnkota Power Cooperative																
		Beginning 1/01/2006, Minnkota shall not emit more than 31,000 tons of SO2/year, no more than 26,000 tons beginning 2011, no more than 11,500 tons beginning 1/01/2012. If unit 3 is not operational by 12/31/2015, then beginning 1/01/14, the plant wide emission shall not exceed 8,500.														
Milton R. Young	Unit 1			Install and continuously operate FGD	95% if wet FGD, 90% if dry	12/31/11	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate <.36	0.36	12/31/09		0.03 if wet FGD, .015 if dry FGD	71/2012	Plant will surrender 4,346 allowances for each year 2012-2015, 8,693 allowances for years 2016 - 2018, 12,170 allowances for year 2019, and 14,886 allowances/year thereafter if units 1 - 3 are operational by 12/31/2015. If only units 1 and 2 are operational by12/31/2015, the plant shall retire 17,886 units in 2020 and thereafter.	Minnkota shall not sell or trade Nox allowances allocated to Units 1, 2, or 3 that would otherwise be available for sale or trade as a result of the actions taken by the settling defendants to comply with the requirements		1) Settlement requires a 95% removal efficiency for SO2 at Unit 1 if a wet FGD is installed, or 90% if a dry FGD is installed. The FGD for units 1 and 2 and the NOx control for unit 1 are modeled as emission constraints in EPA Base Case 2006, the NOx control for unit 2 is hardwired into EPA base case 2006. 2) Beginning 12/31/2010, unit 2 will achieve a phase II average NOx emission rate established through its NOx BACT determination. Beginning 12/31/2011, unit 1 will achieve a phase II NOx emission rate established by its BACT determination.
	Unit 2			Design, upgrade, and continuously operate FGD	90%	12/31/10	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate <.36	0.36	12/31/07		0.03	Before 2008				
SIGECO																
FB Culley	Unit 1	Repower to natural gas (or retire)	12/31/06										The provision did not specify an amount of SO2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			Settlement requires that unit 1 must either shutdown or repower to natural gas. EPA Base Case 2006 assumes the unit will be retired
	Unit 2			Improve and continuously operate existing FGD (shared by units 2 and 3)	95%	06/30/04										Improved operation of the FGD is hardwired into EPA Base Case 2006
	Unit 3			Improve and continuously operate existing FGD (shared by units 2 and 3)	95%	06/30/04	Operate Existing SCR Continuously	0.1	09/01/03	Install and continuously operate a baghouse	0.015	06/30/07				Improved operation of the FGD, continuous operation of the SCR, and installation of the baghouse are hardwired into EPA Base Case 2006

PSEG FOSSIL																
Bergen	Unit 2	Repower to combined cycle	12/31/02													This action is hardwired into EPA Base Case 2006
Hudson	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/06	Install SCR (or approved tech) and continually operate	0.1	05/01/07	Install Baghouse (or approved technology)	0.015	12/31/06	The provision did not specify an amount of SO2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			The FGD, SCR, and baghouse are hardwired into EPA Base Case 2006. The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case 2006
Mercer	Unit 1			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.13	05/01/06							The SCR is hardwired into EPA Base Case 2006; the FGD is modeled as an individual constraint. The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case 2006.
	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/12	Install SCR (or approved tech) and continually operate	0.13	05/01/06							The SCR is hardwired into EPA Base Case 2006; the FGD is modeled as an individual constraint. The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case 2006.
TECO																
Big Bend	Unit 1			Existing Scrubber (shared by units 1 & 2)	95% (95% or .25)	9/1/2000 (Jan 1, 2013)	Install SCR	0.1	05/01/09				The provision did not specify an amount of SO2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			FGD and SCR are installed on Units 1-4, and hardwired into EPA base case 2006
	Unit 2			Existing Scrubber (shared by units 1 & 2)	95% (95% or .25)	9/1/2000 (Jan 1, 2013)	Install SCR	0.1	05/01/09							
	Unit 3			Existing Scrubber (shared by units 3 & 4)	93% if units 3 & 4 are operating	2000 (Jan 1, 2010)	Install SCR	0.1	05/01/09							
	Unit 4			Existing Scrubber (shared by units 3 & 4)	93% if units 3 & 4 are operating	06/22/05	Install SCR	0.1	07/01/07							
Gannon	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/04													Settlement requires all six coal units to shutdown by 12/31/04. Retirement of coal units and repowering as two natural gas units are built into EPA Base Case 2006. New plant is called Bayside Station
WEPCO																
WEPCO shall comply with the following system wide average NOx emission rates and total NOx tonnage permissible: By 1/1/05 an emission rate of .27 and 31,500 tons, by 1/1/07 an emission rate of .19 and 23,400 tons, and by 1/1/13 an emission rate of .17 and 17, 400 tons. For SO2 emissions, WEPCO will comply with: by 1/1/05 an emission rate of .76 and 86,900 tons, by 1/1/07 an emission rate of .61 and 74,400 tons, by 1/1/08 an emission rate of .45 and 55,400 tons, and by 1/1/13 an emission rate of .32 and 33,300 tons.																
Presque Isle	Units 1-4	Retire or install SO2 and Nox controls	12/31/12	Install and continuously operate FGD (or approved equiv tech)	95% or .1	12/31/12	Install SCR (or approved tech) and continually operate	0.1	12/31/12							WEPCO may elect to retire or install controls at Presque Isle unit 1-4. For EPA Base Case 2006, we imposed the SO2 and NOx limits as individual emission constraints
	Units 5,6						Install and operate low Nox burners		12/31/03							LNBs for units 5 and 6 are hardwired in EPA Base Case 2006
	Units 7,8						Operate existing low NOx burners		12/31/05	Install Baghouse						LNBS for units 7 -9 are hardwired in EPA Base Case 2006. The settlement requires demonstration of full-scale TOXECON, and these units already have ESP in place. In EPA Base Case 2006, ESP and baghouses are hardwired on these units, and mercury emissions modification factor (EMF) for ESP & baghouse combination is applied.
	Unit 9						Operate existing low NOx burners		12/31/06	Install Baghouse						

Pleasant Prairie	1			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/06	Install and continuously operate SCR (or approved tech)	0.1	12/31/06				The provision did not specify an amount of SO2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			(Settlement requires compliance with the specified SO2 & NOx efficiency or limit by one-month after the required installation date shown in this table for Pleasant Prairie units 1 & 2.) In EPA Base Case 2006, FGD and SCR on units 1 & 2 are hardwired.
	2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/07	Install and continuously operate SCR (or approved tech)	0.1	12/31/03							
Oak Creek	Units 5,6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12							For EPA Base Case 2006, we imposed the SO2 and NOx limits as individual emission constraints
	Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12							(Settlement requires compliance with the specified SO2 & NOx efficiency or limit by one-month after the required installation date shown in this table for Oak Creek units 7 & 8.) In EPA Base Case 2006, the required SO2 and NOx controls on these units are modeled as individual emission constraints
	Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12							
Port Washington	Units 1-4	Retire	12/31/04 for units 1 - 3. Unit 4 by entry of consent decree													WEPCO announced plans to retire Port Washington and repower with two natural gas units. Retirement of the four coal units and repowering of the first natural gas unit are hardwired in EPA Base Case 2006
Valley	Boilers 1-4						Operate Existing Low NOx Burner		30 days after entry of consent decree							LNBs on units 1-4 are hardwired in EPA Base Case 2006
VEPCO																
The Total Permissible NOx Emissions (in tons) from VEPCO system are: 104,000 in 2003, 95,000 in 2004, 90,000 in 2005, 83,000 in 2006, 81,000 in 2007, 63,000 in 2008 - 2010, 54,000 in 2011, 50,000 in 2012, and 30,250 each year there after. Beginning 1/1/2013 they will have a system wide emission rate no greater then .15 lb/mmbtu																
Mount Storm	Unit 1 - 3			Construct or improve FGD	95% or .15	01/01/05	Install and continuously operate SCR	0.11	01/01/08				On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO2 allowances.			Units 1-3 have installed FGD and SCR. These controls are built into EPA Base Case 2006
Chesterfield	Unit 4						Install and continuously operate SCR	0.1	01/01/13							SCR on this unit is hardwired in EPA Base Case 2006
	Unit 5			Construct or improve FGD	95% or .13	10/12/12	Install and continuously operate SCR	0.1	01/01/12							SCR on this unit is hardwired in EPA Base Case 2006. The FGD is modeled as an individual emission constraint
	Unit 6			Construct or improve FGD	95% or .13	01/01/10	Install and continuously operate SCR	0.1	01/01/11							SCR and FGD on this unit are hardwired in EPA Base Case 2006
Chesapeake Energy	Units 3,4						Install and continuously operate SCR	0.1	01/01/13							SCR on these units is hardwired in EPA Base Case 2006
Clover	Units 1,2			Improve FGD	95% or .13	09/01/03										FGD on Clover units 1 & 2 are hardwired into EPA Base Case 2006
Possum Point	Units 3,4	Retire and Repower to Natural Gas	05/02/03													This action is hardwired into EPA Base Case 2006
Santee Cooper																
Santee Cooper shall comply with the following system wide averages for NOx emission rates and combined tons for emission of: By 1/01/05 facility shall comply with an emission rate of .3 and 30,000 tons, by 1/1/07 an emission rate of .18 and 25,000 tons, by 1/1/2010 and emission rate of .15 and 20,000 tons. For SO2 emission the company shall comply with system wide averages of: by 1/1/05 an emission rate of .92 and 95,000 tons, by 1/1/07 and emission rate of .75 and 85,000 tons, by 1/1/09 an emission rate of .53 and 70 tons, and by 1/1/11 and emission rate of .5 and 65 tons.																
Cross	Unit 1			Upgrade and continuously operate FGD	95%	06/30/06	Install and continuously operate SCR	0.1	05/31/04							Effective Dates for NOx rate and SO2 efficiency are as shown in the table. SCR and FGD are hardwired into EPA Base Case 2006
	Unit 2			Upgrade and continuously operate FGD	87%	06/30/06	Install and Continuously operate SCR	.11/.1	5/31/04 and 5/31/07							SCR and FGD controls for unit 2 are hardwired into EPA Base Case 2006

Winyah	Unit 1			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	.11/.1	11/30/04 and 11/30/04				The provision did not specify an amount of SO2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			SCR and FGD are hardwired into EPA Base Case 2006
	Unit 2			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.12	11/30/04							SCR and FGD are hardwired into EPA Base Case 2006
	Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/08	Install and continuously operate SCR	.14/.12	11/30/2005 and11/30/08							SCR and FGD are hardwired into EPA Base Case 2006
	Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/07	Install and continuously operate SCR	.13/.12	11/30/05 and 11/30/08							SCR and FGD are hardwired into EPA Base Case 2006
Grainger	Unit 1						Operate Low Nox Burner or more stringent technology		06/25/04							LNBs on units 1 & 2 are hardwired in EPA Base Case 2006
	Unit 2						Operate Low Nox Burner or more stringent technology		05/01/04							
Jeffries	Units 3,4						Operate Low Nox Burner or more stringent technology		06/25/04							LNBs on units 3 & 4 are hardwired in EPA Base Case 2006
OHIO EDISON																
Ohio Edison shall achieve reductions of 2,483 tons NOx between 7/1/05 and 12/31/10 using any combination of: (1)low sulfur coal at Burger Units 4 and 5, (2)operating SCRs currently installed at Mansfield Units 1 through 3 during the months of October through April, and/or (3)emitting fewer tons than the Plant-Wide Annual Cap for NOx required for the Sammis Plant. Ohio Edison must reduce 24,600 tons system-wide of SO2 by 12/31/10.																
	No later than 8/11/05, Ohio Edison shall install and operate low NOx burners on Sammis Units 1,2,4,5,6, and 7 and overfired air on Sammis Units 1,2,3,6, and 7. No later than Dec. 1, 2005, Ohio Edison shall install advanced combustion control optimization with software to minimize NOx emissions from Sammis Units 1 through 5.															
W.H. Sammis Plant	Unit 1			Install Induct Scrubber (or approved equiv control tech)	50% removal or 1.1 lb/mmBTU	12/31/08	Install SNCR (or approved alt tech) & Operate Continuously	0.25	10/31/07							SNCR for each unit are hardwired into EPA Base Case 2006. SO2 controls are modeled as individual emission constraints in EPA Base Case 2006 Plant-wide NOx Annual Caps: 11,371 tons 7/1/05-12/31/05; 21,251 tons 2006; 20,596 tons 2007; 18,903 tons 2008; 17,328 tons 2009-2010; 14,845 tons 2011; 11,863 2012 onward. Sammis Plant-Wide Annual SO2 Caps: 58,000 tons SO2 7/1/05-12/31/05; 116,000 tons 1/1/06-12/31/07; 114,000 tons 1/1/08-12/31/08; 101,500 tons 1/1/09-12/31/10; 29,900 tons 1/1/11 onward. Sammis units 1 through 5 are also subject to the following SO2 Monthly Caps if Ohio Edison installs the improved SO2 control technology (Unit 5's option A): 3,242 tons May, July, and August 2010; 3,137 tons June and September 2010. If Ohio Edison installs the required SO2 technology (Unit 5's option B), the Monthly Caps are: 2,533 tons May, July, and August 2010; 2,451 tons June and September 2010. Regardless of the technology used, Add'l Monthly Caps are: 2,533 tons May, July, and August 2011; 2,451 tons June and September 2011 thereafter.
	Unit 2			Install Induct Scrubber (or approved equiv control tech)	50% removal or 1.1 lb/mmBTU	12/31/08	Operate Existing SNCR Continuously	0.25	02/15/06							
	Unit 3			Install Induct Scrubber (or approved equiv control tech)	50% removal or 1.1 lb/mmBTU	12/31/08	Operate Low NOx burners and overfire air by Dec. 1, 2005; Install SNCR (or approved alt tech) & Operate Continuously by Dec. 31, 2007	0.25	12/01/05; 10/31/07							
	Unit 4			Install Induct Scrubber (or approved equiv control tech)	50% removal or 1.1 lb/mmBTU	06/30/09	Install SNCR (or approved alt tech) & Operate Continuously	0.25	10/31/07							
	Unit 5			Install Flash Dryer Absorber or ECO^2 (or approved equiv control tech) & Operate Continuously	50% removal or 1.1 lb/mmBTU	06/29/09	Install SNCR (or approved alt tech) & Operate Continuously	0.29	03/31/08				Beginning on 1/1/06, Ohio Edison may use, sell or transfer any restricted SO2 only to satisfy the Operational Needs at the Sammis, Burger and Mansfield Plant, or new units within the FirstEnergy			If Ohio Edison cannot install Flash Dryer Absorber due to a lack of permits, this unit's requirements must be passed off to another plant.

	Unit 6			Install FGD[3] (or approved equiv control tech) & Operate Continuously	95% removal or 0.13 lb/mmBTU	06/30/11	Install SNCR (or approved alt tech) & Operate Continuously	"Minimum Extent Practicable"	06/30/05	Operate Existing ESP Continuously	0.03	01/01/10	System that comply with a 96% removal for SO2. For calendar year 2006 through 2017, Ohio Edison may accumulate SO2 allowances for use at the Sammis, Burger, and Mansfield plants, or FirstEnergy units equipped with SO2 Emission Control Standards. Beginning in 2018, Ohio Edison shall surrender unused restricted SO2 allowances.			In addition to SNCR, settlement requires installation of first SCR (or approved alt tech) on either unit 6 or 7 by Dec. 31, 2010; second installation by Dec. 31, 2011. Both SCRs must achieve 90% Design Removal Efficiency by 180 days after installation date. Each SCR must provide a 30-Day Rolling average. NOx Emission Rate of 0.1 lb/mmBtu starting 180 days after installation dates above.
	Unit 7			Install FGD (or approved equiv control tech) & Operate Continuously	95% removal or 0.13 lb/mmBTU	06/30/11	Operate Existing SNCR Continuously	"Minimum Extent Practicable"	08/11/05	Operate Existing ESP Continuously	0.03	01/01/10				
Mansfield Plant	Unit 1			Upgrade Existing FGD	95%	12/31/05										Additional Mansfield Plant-wide SO2 reductions are as follows: 4,000 tons in 2006, 8,000 tons in 2007, and 12,000 tons/yr for every year after. Settlement allows relinquishment of SO2 requirement upon shutdown of unit, after which the SO2 reductions must be made by another plant(s).
	Unit 2			Upgrade Existing FGD	95%	12/31/06										
	Unit 3			Upgrade Existing FGD	95%	10/31/07										
Eastlake	Unit 5						Install Low NOx burners, overfired air and SNCR & Operate Continuously	"Minimize Emissions to the Extent Practicable"	12/31/06							Settlement requires Eastlake Plant to achieve additional reductions of 11,000 tons of NOx per year commencing in calendar year 2007, and no less than 10,000 tons must come from this unit. The extra 1,000 tons may come from this unit or another unit in the region. Upon shutdown of Eastlake, another plant must achieve these reductions.
Burger	Unit 4	Repower with through construction of circulating fluidized bed boilers or other clean coal technologies to maintain at least 95% removal for SO2 or 30-Day Rolling Emission Rate of 0.1 lb/mmBtu.	12/31/10	Install wet FGD or ECO (or approved alt tech)	95%	12/31/10	Install SNCR (or approved alt tech) & Operate Continuously	"Minimize Emissions to the Extent Practicable"	12/31/08							Burger plant must achieve SO2 reductions of 25,000 tons on or before 2011. Between Jan. 1, 2006 and Dec. 31, 2010, Burger plant shall achieve 35,000 tons SO2 reductions in the amount of 7,000/yr on a rolling average. basis through the use of low sulfur coal. Burger plants shall achieve additional NOx reductions of 1,400 tons per year commencing in 2009. In no case shall the reductions be less than 1,300 tons from these units. The extra 100 tons can come from another unit in the region.
	Unit 5		12/31/10	Install wet FGD or ECO (or approved alt tech)	95%	12/31/10	Install SNCR (or approved alt tech) & Operate Continuously	"Minimize Emissions to the Extent Practicable"	12/31/08							
MIRANT[1,6]																
System-wide NOx Emission Annual Caps: 36,500 tons 2004; 33,840 tons 2005; 33,090 tons 2006; 28,920 tons 2007; 22,000 tons 2008; 19,650 tons 2009; 16,000 tons 2010 onward. System-wide NOx Emission Ozone Season Caps: 14,700 tons 2004; 13,340 tons 2005; 12,590 tons 2006; 10,190 tons 2007; 6,150 tons 2008-2009; 5,200 tons 2010 thereafter. Beginning on May 1, 2008, and continuing for each and every Ozone Season thereafter, the Mirant System shall not exceed a System-wide Ozone Season Emission Rate of 0.150 lb/MMBtu NOx.																
Potomac River Plant	Unit 1									Install and continuously operate ACI technology	70% Hg removal	3/31/2007 (or by a date no later than 24 months after the loss of Morgantown plant)				
	Unit 2										70% Hg removal					
	Unit 3						Install Low Nox Burners (or more effective tech) & Operate Continuously		05/01/04		70% Hg removal	12/31/2006 (or by a date no later than 24 months after the loss of Morgantown plant)				Settlement requires installation of Separated Overfire Air tech (or more effective technology) by May 1, 2005. Plant-wide Ozone Season NOx Caps: 1,750 tons 2004; 1,625 tons 2005; 1,600 tons 2006-2009; 1,475 tons 2010 thereafter. Plant-wide annual NOx Caps are 3,700 tons in 2005 and each year there after.
	Unit 4						Install Low Nox Burners (or more effective tech) & Operate Continuously		05/01/04		70% Hg removal					
	Unit 5						Install Low Nox Burners (or more effective tech) & Operate Continuously		05/01/04		70% Hg removal					

Morgantown Plant	Unit 1						Install SCR (or approved alt tech) & Operate Continuously	0.1	05/01/07							
	Unit 2						Install SCR (or approved alt tech) & Operate Continuously	0.1	05/01/08							
Chalk Point	Unit 1			Install and continuously operate FGD (or equivalent technology)	95%	06/01/10							For each year after Mirant commences FGD operation at Chalk Point, Mirant shall surrender the number of SO2 Allowances equal to the amount by which the SO2 Allowances allocated to the Units at the Chalk Point Plant are greater than the total amount of SO2 emissions allowed under this Section XVIII			Mirant must install and operate FGD by 6/1/210 if they were authorized by court to reject ownership interest in Morgantown Plant, or by no later than 36 months after they loose ownership interest of the Morgantown Plant
	Unit 2			Install and continuously operate FGD (or equivalent technology)	95%	06/01/10										
ILLINOIS POWER																
System-wide NOx Emission Annual Caps: 15,000 tons 2005; 14,000 tons 2006; 13,800 tons 2007 onward. System-wide SO2 Emission Annual Caps: 66,300 tons 2005-2006; 65,000 tons 2007;62,000 tons 2008-2010; 57,000 tons																
Baldwin	Unit 1			Install wet or dry FGD (or approved equiv alt tech) & Operate Continuously	0.1	12/31/11	Operate OFA & Existing SCR Continuously	0.1	08/11/05	Install & Continuously Operate Baghouse	0.015	12/31/10	By year end 2008, Dynergy will surrender 12,000 SO2 emission allowances, by year end 2009 it will surrender 18,000, by year end 2010 it will surrender 24,000, any by year end 2011 and each year thereafter it will surrender 30,000 allowances. If the surrendered allowances result in insufficient remaining allowances allocated to the units			
	Unit 2			Install wet or dry FGD (or approved equiv alt tech) & Operate Continuously	0.1	12/31/11	Operate OFA & Existing SCR Continuously	0.1	08/11/05	Install & Continuously Operate Baghouse	0.015	12/31/10				
	Unit 3			Install wet or dry FGD (or approved equiv alt tech) & Operate Continuously	0.1	12/31/11	Operate OFA and/or low NOx burners	0.12 until Dec. 30, 2012; 0.1 from Dec. 31, 2012	08/11/05; 12/31/12	Install & Continuously Operate Baghouse	0.015	12/31/10				
Havana	Unit 6			Install wet or dry FGD (or approved equiv alt tech) & Operate Continuously	1.2 lb/mmBtu until Dec. 30, 2012; 0.1 lb/mmBtu from Dec. 31, 2012 onward	08/11/05; 12/31/12	Operate OFA and/or low NOx burners & Operate Existing SCR Continuously	0.1	08/11/05	Install & Continuously Operate Baghouse, then install ESP or alt PM equip	For Baghouse: .015 lb/MMBtu; For ESP: .03 lb/MMBtu	For Baghouse: 31-Dec-12; For ESP: 31-Dec-05				
Hennepin	Unit 1				1.2	07/27/05	Operate OFA and/or low NOx burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv alt tech) & Continuously Operate ESPs	0.03	12/31/06				Settlement requires first installation of ESP at either unit 1 or 2 on Dec. 31, 2006; and on the other by Dec. 31, 2010.
	Unit 2				1.2	07/27/05	Operate OFA and/or low NOx burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv alt tech) & Continuously Operate ESPs	0.03	12/31/06				

Vermilion	Unit 1			1.2	01/31/07	Operate OFA and/or low NOx burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv alt tech) & Continuously Operate ESPs	0.03	12/31/10	comprising the DMG system, DMG can request to surrender fewer SO2 allowances.			
	Unit 2			1.2	01/31/07	Operate OFA and/or low NOx burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv alt tech) & Continuously Operate ESPs	0.03	12/31/10				
Wood River	Unit 4			1.2	07/27/05	Operate OFA and/or low NOx burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv alt tech) & Continuously Operate ESPs	0.03	12/31/05				Settlement requires first installation of ESP at either unit 4 or 5 on Dec. 31, 2005; and on the other by Dec. 31, 2007.
	Unit 5			1.2	07/27/05	Operate OFA and/or low NOx burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv alt tech) & Continuously Operate ESPs	0.03	12/31/05				

Notes

1) This summary table describes New Source Review settlement actions as they are represented in EPA Base Case 2006. 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.

2) Settlement actions for which the required emission limits will be effective by the time of the first mapped run year (before 1/1/2009) are built into the database of units used in EPA Base Case 2006 ("hardwired"). However, future actions are generally modeled as individual constraints on emission rates in EPA Base Case 2006, allowing the modeled economic situation to dictate whether and when a unit would opt to install controls versus retire.

3) Some control installations that are required by these NSR settlements have already been taken by the affected companies, even if deadlines specified in their settlement haven't occurred yet. Any controls that are already in place are built into EPA Base Case 2006

4) If a settlement agreement requires installation of PM controls, then the controls are shown in this table and reflected in EPA Base Case 2006. If settlement requires optimization or upgrade of existing PM controls, those actions are not included in EPA Base Case 2006.

5) For units for which an FGD is modeled as an emissions constraint in EPA Base Case 2006, EPA used the assumptions on removal efficiencies that are shown in Table 5-2 of this documentation report

6) For units for which an FGD is hardwired in EPA Base Case 2006, unless the type of FGD is specified in the settlement, EPA modeling assumes the most cost effective FGD (wet or dry) and a corresponding 95% removal efficiency for wet and 90% for dry.

7) For units for which an SCR is modeled as an emissions constraint or is hardwired in EPA Base Case 2006, EPA assumed an emissions rate equal to 10% of the unit's uncontrolled rate, with a floor of .06 lb/mmBTU or used the emission limit if provided.

8) The applicable low NOx burner reduction efficiencies are shown in Table A 3-1:3 in the Base Case 2006 documentation materials.

9) EPA included in EPA Base Case 2006 the requirements of the settlements as they existed on October 1, 2006.

10) Some of the NSR settlements require the retirement of SO2 allowances. For Base Case 2006, EPA estimate the amount of allowances to be retired from these settlements and adjusted the total Title IV allowances accordingly.

Appendix 3-4. State Settlements in EPA Base Case 2006

		State Enforcement Actions														
		Retire/repower		SO2 control			Nox Control			PM Control			Mercury Control			
Company and Plant	Unit	Action	Effective Date	Equipment	Percent removal or rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Notes
AES																
If the MPC project is discontinued at Greenridge unit 4 by 12/31/09, unit 4 will be subject to the following SO2 emission caps: 2005 will be 12,125 tons, 2006 will be 11,800 tons, 2007 will be 11,475 tons, 2008 will be 11,150 tons, 2009 will be 10,825 tons. By 12/31/2009, AES shall control, repower, or cease operations at Westover Unit 7. Beginning in 2005, Unit 8 will be subject to the following SO2 emission caps: 2005 is 9500 tons, 2006 is 9250, 2007 is 9000, 2008 is 8750, 2009 is 8500 tons.																
Greenridge	4			Install FGD	90%	9/1/2007	Install SCR	0.15	9/1/2007							1) Except when Greenridge Unit 4 is operating below minimum operating load, it will make good faith efforts to achieve a NOx emission rate of .1 lb/mmBtu. If this level cannot be achieved, the emission limit shall be the level achieved within one year of commencement of operation, no less stringent than .15 lb/mmbtu. 2) Unit 4 will make good faith efforts to achieve a SO2 removal efficiency of 95%. If this removal efficiency cannot be achieved, the emission limit shall be the level achieved by September 1, 2007, but no less stringent than 90% removal efficiency, resulting in a .38 lb/mmBTU permitted limit. The SO2 and NOx controls are hardwired into EPA Base Case 2006.
	3			Install BACT		12/31/2009	Install BACT		12/31/2009							Can Install BACT, repower, or cease operation
Westover	8				90%	12/31/2010	Install SCR	0.15	12/31/2010							1) Except when Westover unit 8 is operating below minimum operating load, it will make good faith efforts to achieve a NOx emission rate of .1lb/mmbtu. If this level cannot be achieved, the emission limit will be the level achieved within 1 year of operation that is no less stringent than .15 mm/btu. 2) Unit 8 will make good faith efforts to achieve a SO2 removal efficiency of 95%. If this level cannot be achieved, a removal efficiency no less than 90% will be used, resulting in a .34 lb/mmbtu permit.
	7			Install BACT		12/31/2009	Install BACT		12/31/2009							Install BACT, repower, or cease operations
Hickling	1			Install BACT		5/1/2007	Install BACT		5/1/2007							Install BACT, repower, or cease operations. EIA Form 860 showed a "O/S" status for this unit, meaning that it had been out of service for at least a year. It was therefore not included in Base Case 2006.
	2			Install BACT		5/1/2007	Install BACT		5/1/2007							Install BACT, repower, or cease operations. EIA Form 860 showed a "O/S" status for this unit, meaning that it had been out of service for at least a year. It was therefore not included in Base Case 2006.
Jennison	1			Install BACT		5/1/2007	Install BACT		5/1/2007							Install BACT, repower, or cease operations. EIA Form 860 showed a "O/S" status for this unit, meaning that it had been out of service for at least a year. It was therefore not included in Base Case 2006.
	2			Install BACT		5/1/2007	Install BACT		5/1/2007							Install BACT, repower, or cease operations. EIA Form 860 showed a "O/S" status for this unit, meaning that it had been out of service for at least a year. It was therefore not included in Base Case 2006.
Niagara Mohawk Power																
NRG shall comply with the below annual tonnage limitations for its Huntley and Dunkirk Stations: 2005 is 59,537 tons of SO2 and 10,777 tons of NOx, 2006 is 34,230 of SO2 and 6772 of NOx, 2007 is 30,859 of SO2 and 6211 of NOx, 2008 is 22,733 tons of SO2 and 6211 tons of NOx, 2009 is 19444 of SO2 and 5388 of NOx, 2010 and 2011 are 19444 of SO2 and 4861 of NOx, 2012 is 16,807 of SO2 and 3,241 of NOx, 2013 and thereafter is 14,169 of SO2 and 3241 of NOx.																
Huntley	63-66	retire	Before 2008													Will be retired, but date is dependent on approval from the Public Service Commission
Public Service Co. of NM																
San Juan	1			state-of-the-art technology	90%	10/31/2008	state-of-the-art technology	0.3	10/31/2008	Operate baghouse and demister technology	0.015	12/31/2009	Design activated carbon injection technology (or		12/31/2009	Unit 3 and 4 controls will be hardwired into EPA Base Case 2006. Unit 1 and 2 controls will be modeled as an emission constraint in EPA Base Case 2006. EPA modeling assumed FGD and SCR as the appropriate state-of-the-art technology.
	2					3/31/2009			3/31/2009			12/31/2009			12/31/2009	
	3					4/30/2008			4/30/2008			4/30/2008			4/30/2008	
	4					10/31/2007			10/31/2007			10/31/2007			10/31/2007	
Public Service Co of Colorado																
Comanche	1			Install and operate FGD	0.1 lb/mmbtu combined average	7/1/2009	Install low-Nox emission controls	0.15 lb/mmbtu combined average	7/1/2009				Install sorbent injection technology		7/1/2009	Comanche units 1 and 2 taken together shall not exceed a .15 heat rate for Nox, nor .10 for SO2. Comanche 1 & 2 will no later than 180 days after initial start-up of control equipment, or by 7/01/09, whichever is earlier. The SO2 and NOx controls are modeled as emission constraints in EPA Base Case 2006.
	2			Install and operate FGD		7/1/2009	Install low-Nox emission controls		7/1/2009				Install sorbent injection technology		7/1/2009	
	3			Install and operate FGD	0.1		Install and operate SCR	0.08		Install and operate a fabric filter dust collection system	0.013		Install sorbent injection technology		Within 180 days of start-up	Control equipment will be incorporated into pre-construction plans, and effective when the plant first comes on line. This unit will be a new unit to come online in 2009.

Appendix 3-5. Constraint on FGD and SCR Capacity Due to Boilermaker Availability in the Period When SO2 and Nox Retrofits Will Occur for the Clean Air Interstate Rule (CAIR)

GW Capacities for the Constraints

FGD	SCR
80	13
70	20.9
60	28.7
50	36.6
40	44.4
30	52.3
20	60.1
10	67.9