United States
Environmental Protection Agency

Air and Radiation
(6204J)

EPA 430-K-11-004
June 2011

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

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

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW (6204J)
Washington, D.C. 20460
(www.epa.gov/airmarkets)

June 2011

Table of Contents

Introduction 1

Universal Comments Resulting in Model Revisions

1 Cogeneration Units 2

2 NO_x Rates 35

3 SO_2 Removal Rates for Flue Gas Desulfurization (FGD) 41

4 Coal Switching − Bituminous to Subbituminous 44

5 Restrictions on coal choice in 2012 46

6 Waste Coal Cost Correction 48

7 Comments Considered but that did not Result in Changes 51

- Oil consumption at dual fired (oil/gas) units
- Capital cost of Flue Gas Desulfurization (FGD) on units whose capacity is less than 100 MW
- Selective Catalytic Reduction (SCR) retrofit costs
- 30 year book life for emission control retrofits
- Must run, black start, and spinning reserve units
- Availability assumptions for existing coal units

Addenda: Notes on various modeling assumptions… 53

- Dry Sorbent Injection (DSI) and Fabric Filter Cost Development
- Variable Operating and Maintenance (VOM) Cost of Dry Sorbent Injection (DSI) Retrofits
- Updated Appendices 3-2 through 3-4
- 2012 Emission Control Retrofits
- Emission Controls in IPM Parsed Files
- Mercury Emission Modification Factor (EMF) for Waste Coal Units
- Carbon dioxide (CO2) Emissions from Chemical Reactions in a Wet Flue Gas Desulfurization (FGD) System for Sulfur Dioxide (SO2) Control

Addendum A ─ Dry Sorbent Injection (DSI) and Fabric Filter Cost Development in EPA Base Case v.4.10_FTransport 55

Addendum B ─ Representation of State Electric Power Emission Regulations (Appendix 3-2), New Source Review (NSR) Settlements (Appendix 3-3), and State Settlements (Appendix 3-4) in EPA Base Case v.4.10_FTransport 67

Introduction

This documentation supplement describes the changes implemented for the Final Transport Rule analysis in EPA's application of the Integrated Planning Model (IPM), the modeling platform used by EPA for U.S. electric power sector analysis. The changes described here resulted from comments received on the Proposed Transport Rule and on the Notice of Data Availability (NODA) for the Proposed Transport Rule, which were announced on September 1, 2010. The NODA included detailed documentation of the version of the model that EPA proposed using in the final rulemaking, a database of generating unit level input data used in the model, model run results, and user guides to input assumptions and model outputs.

Comments received on the modeling platform fell into two basic categories: detailed comments on specific generating units and universal comments affecting broad categories of generating units. Changes resulting from detailed unit level comments (usually pertaining to distinct operating characteristics of specific generating units) are being documented separately as part of the "Transport Rule IPM Assumptions Response To Comments" document. EPA's response to the universal modeling comments and the resulting updates to the modeling platform are presented here in the form of a documentation supplement for the Final Transport Rule.

This documentation supplement is organized by comment topic. The presentation of each comment is divided into two sections. The first section summarizes the comment and EPA's responses. The second section contains a mark-up of the relevant sections of the *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html), indicating the exact modeling changes that resulted from the universal comments. To make it easier to recognize these mark-ups, they appear on a gray background, visually signaling that they are revisions of the previous documentation.

In the discussion below the following terminology is used: "EPA Base Case v.4.10_NODA version"[1] refers to base case released as part of the September 1, 201O NODA. Its assumptions and results were the subject of the public comments received by EPA. "EPA Base Case v.4.10_FTransport" incorporated the changes described below and was used in the modeling for the Final Transport Rule.

It should also be noted that on March 16, 2011, EPA signed a Notice of Proposed Rulemaking for the Mercury and Air Toxics Standards (MATS). For that rulemaking EPA enhanced its power sector modeling platform with capabilities specifically needed for the Proposed MATS (for example the capability to model HCl emissions and controls, a coal-to-gas retrofit option, and updated assumptions for activated carbon injection for mercury control). These capabilities were also incorporated in the modeling for the Final Transport Rule. However, only those features relevant to the Final Transport Rule are documented here. These include provision of dry sorbent injection (DSI), accompanied by a fabric filter, as a retrofit option for SO_2 (and HCl) emission control (documented in Addendum A at the end of this report) and updates of the State Power Sector Regulations and New Source Review (NSR) and State Settlements shown in Appendices 3-2 through 3-4 of the documentation supplement for the Proposed MATS (also found in Addendum B in this report). Appendices 3-2 through 3-4 reflect regulations and settlements that were in force through December 2010. Subsequent to freezing the assumptions for EPA Base Case v.4.10_FTransport, additional NSR settlements with Northern Indiana Public Service Company (www.epa.gov/compliance/resources/cases/civil/caa/nipsco.html, January 13, 2011) and the Tennessee Valley Authority (www.epa.gov/compliance/resources/cases/civil/caa/tvacoal-fired.html, April 14, 2011) were announced. For the TVA settlement EPA Base Case v.4.10_FTransport includes the provisions shown in the Appendix 3-3. Documentation of the full modeling capabilities for the Proposed MATS can be found in a separately issued report entitled *Documentation Supplement for EPA Base Case v.4.10_Ptox – Updates for Proposed Toxics Rule,* which is available for viewing and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf.

---

[1] In *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* the term "draft EPA Base Case v.4.10" was used when referring to what is now called "EPA Base Case v.4.10 NODA version"

1 Cogeneration Units

1.1 Response to the Comments Received

Comment Theme: Comments indicated that the extent of the operation and emissions from units that produce both steam and electricity (i.e., cogeneration units) in EPA Base Case v.4.10_NODA was considerably lower than actual operating experience.

Discussion: In the draft base case which provoked these comments, cogeneration units were assigned the gross heat rates applicable to both the steam and electric portion of their operation. However, dispatch decisions in IPM are only based on the heat rate efficiency of the electric portion of a cogeneration unit. The lower a unit's heat rate, the more efficient is its use of fuel for electricity generation, and the more likely it is to be dispatched. For electrical dispatch purposes, the net heat rate should have been used for cogeneration units. Since the net heat rate can be considerably lower than the gross heat rate, this revision should increase the extent that cogeneration units are operated. At the same time, since emissions from both the electric and steam portions of cogeneration units are covered by the Transport Rule, an emission multiplier should be used to ensure that total emissions are taken into account. The increased operation together with the emissions multiplier should correct the observation of low cogeneration operations and emissions and should address the points raised in the comments.

Response: Based on these comments, a review was made of the representation of cogeneration units in draft EPA Base Case v.4.10. As a result this review, modifications were made so that the representation of cogeneration units would better reflect the extent of their operation and emissions. In particular, the following revisions were made.

(1) In the draft base case, gross heat rates had been assigned to cogeneration units. That is, the heat rates (efficiency) of cogeneration units were calculated by summing the energy content of the fuel consumed for both steam and power generation and then dividing this sum by the electricity generated. Factoring in both the fuel consumed in producing steam and electricity when calculating the gross heat rate made the cogeneration units less efficient for electricity generation than their operating experience indicated. In the base case for the final Transport Rule net heat rates (heat content of fuel consumed for power generation divided by their generation) are assigned to cogeneration units. This will more accurately reflect their electric generation efficiency and make cogeneration units more economic to dispatch.

(2) In conjunction with the use of net heat rates for cogeneration units in the base case for the final Transport Rule, cogeneration units are allowed to dispatch up to the availabilities assumed for the particular generation technology or up to their historic capacity factors (derived by taking the maximum historical capacity factor reported for the unit in EIA Form 860 for years 2006-2010). These limits are intended to prevent dispatch patterns that exceed the reported technical capabilities of these units. In cases where the maximum reported capacity factors is below 15%, a capacity factor of 15% is used as a limit, since historical capacity factor values below 15% are not considered to reflect the generation capability of the unit.

(3) Even though the dispatch of cogeneration units in the Final Transport Rule will be based on their electric power (net) heat rate characteristics, the emissions from both power and steam production will be taken into account, since for cogeneration units the Transport Rule covers the emissions attributable to both electric and steam generation. To capture these total emissions a multiplier (derived by dividing the total fuel consumed for both steam and power by the fuel consumed for power) is applied to the power only emissions.

1.2 Resulting Updates

The following changes to *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* show the updates that were implemented for the Final Transport Rule analysis in EPA Base Case v4.10_FTransport.

3.5.2 Capacity Factor

Add the following paragraph at the end of this section:

To prevent dispatch patterns that exceed their reported technical capabilities, cogeneration units are allowed to dispatch up to the availabilities assumed for the particular generation technology or up to their historic capacity factors (derived by taking the maximum historical capacity factor reported for the unit in EIA Form 860 for years 2006-2010). In cases where the maximum reported capacity factors is below 15%, a capacity factor of 15% is used as a limit, since historical capacity factor values below 15% are not considered to reflect the generation capability of the unit. Appendix 3-10 shows the capacity factor upper bounds for all the existing cogeneration units that are represented in EPA Base Case v.4.10.

3.8 Heat Rate

Add the following paragraph at the end of this section:

For cogeneration units only, the heating value of the fuel combusted for electricity generation is used to derive the heat rate, since dispatch decisions in IPM are only based on the heat rate efficiency of the electric portion of a cogeneration unit. Known as a cogeneration unit's net heat rate, it is calculated by dividing heat content of fuel consumed for power generation by electric generated from this fuel. To capture the total emissions from the cogeneration unit, a multiplier (derived by dividing the total fuel consumed for both steam and power by the fuel consumed for power) is applied to the power only emissions. Appendix 3-10 shows the heat rate and emission multipliers of all the existing cogeneration units that are represented in EPA Base Case v.4.10. For purposes of comparison Appendix 3-10 includes the net heat rate values currently used in modeling and the gross heat rate used prior to correcting the representation as a result of comments received in the September 2010 Notice of Data Availability (NODA). The net heat rates appear in the column labeled "'Post-NODA Heat Rate (Btu/kWh)." The gross heat rates appear in the column labeled "NODA Heat Rate (Btu/kWh)." Since the net heat rate cannot exceed the gross heat rate, instances where the value of the "'Post-NODA Heat Rate (Btu/kWh)" exceeds the value of the "NODA Heat Rate (Btu/kWh)" were caused by a change in the source of the data between the NODA and post-NODA period. Such instances are highlighted and explained in Appendix 3-10.

Add the following appendix at the end of Chapter 3:

Appendix 3-10. Cogeneration Units - Heat Rates (Before and After NODA Comments), Capacity Factor Upper Bounds, and Emission Multipliers

= Higher Post-NODA Heat Rate Due to Higher Reported Value in AEO 2010 than in AEO 2008 (orange)

= Higher Post-NODA Heat Rate Based on NODA Comment (green)

= Higher Post-NODA Heat Rate Based on Net Heat Rate Reported in EIA Form 923 (yellow)

Plant Name	UniqueID_Final	PlantType	Region Name	Capacity (MW)	NODA Heat Rate (Btu/kWh)	Post-NODA Heat Rate (Btu/kWh)	Emissions Multiplier	2012 Capacity Factor Upper Bound Implemented
ACE Cogeneration Facility	10002_B_CFB	Coal Steam	CA-S	101	10921	10526	1.04	89.70
Trigen Colorado Energy	10003_B_BLR1	O/G Steam	RMPA	8.1	11972	8300	1.44	89.51
Trigen Colorado Energy	10003_B_BLR2	O/G Steam	RMPA	8.1	11964	8300	1.44	89.51
Trigen Colorado Energy	10003_B_BLR3	Coal Steam	RMPA	8.1	10331	8300	1.24	86.40
Trigen Colorado Energy	10003_B_BLR4	Coal Steam	RMPA	8.1	10331	8300	1.24	86.40
Trigen Colorado Energy	10003_B_BLR5	Coal Steam	RMPA	8.1	11768	8300	1.42	86.40
Baptist Medical Center	10008_G_CG-3	IC Engine	FRCC	0.50	13298	13199	1.00	89.24
Baptist Medical Center	10008_G_TG-1	Combustion Turbine	FRCC	2.3	15981	15845	1.00	89.24
Baptist Medical Center	10008_G_TG-2	Combustion Turbine	FRCC	2.2	15981	8700	1.82	89.24
Baptist Medical Center	10008_G_TG-3	Combustion Turbine	FRCC	2.7	15981	8700	1.82	89.24
Baptist Medical Center	10008_G_TG-4	Combustion Turbine	FRCC	3.2	12503	8700	1.43	89.24
NRG Energy Center Dover	10030_B_COGEN1	Coal Steam	MACE	16.0	11782	11782	1.00	75.40
Greater Detroit Resource Recovery	10033_B_11	Municipal Solid Waste	MECS	21.2	19338	8300	1.96	52.47
Greater Detroit Resource Recovery	10033_B_12	Municipal Solid Waste	MECS	21.2	19338	8300	1.96	52.47
Greater Detroit Resource Recovery	10033_B_13	Municipal Solid Waste	MECS	21.2	19338	8300	1.96	52.47
Gilroy Power Plant	10034_G_GEN1	Combined Cycle	CA-N	90.0	8330	8373	1.00	84.63
Gilroy Power Plant	10034_G_GEN2	Combined Cycle	CA-N	40.0	8330	8373	1.00	84.63
Logan Generating Plant	10043_B_B01	Coal Steam	MACE	219	9890	9890	1.00	83.80
Central Utilities Plant LAX	10048_G_GEN1	Combustion Turbine	CA-S	4.0	15981	8700	1.82	89.24
Central Utilities Plant LAX	10048_G_GEN2	Combustion Turbine	CA-S	4.0	15981	8700	1.82	89.24
Cogentrix Virginia Leasing Corporation	10071_B_1A	Coal Steam	VAPW	19.2	11354	10888	1.04	74.60
Cogentrix Virginia Leasing Corporation	10071_B_1B	Coal Steam	VAPW	19.2	10331	10320	1.00	74.60
Cogentrix Virginia Leasing Corporation	10071_B_1C	Coal Steam	VAPW	19.2	10331	10320	1.00	74.60

Cogentrix Virginia Leasing Corporation	10071_B_2A	Coal Steam	VAPW	19.2	11353	10888	1.04	74.60
Cogentrix Virginia Leasing Corporation	10071_B_2B	Coal Steam	VAPW	19.2	10331	10320	1.00	74.60
Cogentrix Virginia Leasing Corporation	10071_B_2C	Coal Steam	VAPW	19.2	10331	10320	1.00	74.60
Pedricktown Cogen Plant	10099_G_GEN1	Combined Cycle	MACE	79.2	8350	7916	1.00	84.63
Pedricktown Cogen Plant	10099_G_GEN2	Combined Cycle	MACE	36.5	8350	7916	1.00	84.63
Frito-Lay Cogen Plant	10110_G_GEN1	Combustion Turbine	CA-N	5.1	15981	15845	1.00	89.24
John B Rich Memorial Power Station	10113_B_CFB1	Coal Steam	MACW	40.0	11190	8300	1.35	95.00
John B Rich Memorial Power Station	10113_B_CFB2	Coal Steam	MACW	40.0	10331	8300	1.24	95.00
Harrisburg Facility	10118_B_1	Municipal Solid Waste	MACW	6.9	19338	8300	2.33	88.41
Harrisburg Facility	10118_B_2	Municipal Solid Waste	MACW	6.9	19338	8300	2.33	88.41
Harrisburg Facility	10118_B_3	Municipal Solid Waste	MACW	6.9	19338	8300	2.33	88.41
Indiana University of Pennsylvania	10129_G_GEN1	IC Engine	MACW	6.0	13298	9480	1.39	89.24
Indiana University of Pennsylvania	10129_G_GEN2	IC Engine	MACW	6.0	13298	9480	1.39	89.24
Indiana University of Pennsylvania	10129_G_GEN3	IC Engine	MACW	6.0	13298	9480	1.39	89.24
Indiana University of Pennsylvania	10129_G_GEN4	IC Engine	MACW	6.0	13298	9480	1.39	89.24
Sierra Pacific Lincoln Facility	10144_G_GEN4	Biomass	CA-N	17.2	15517	8300	1.89	83.00
Fresno Cogen Partners	10156_G_GEN2	Combined Cycle	CA-N	6.0	7651	8594	1.09	15.00
Fresno Cogen Partners	10156_G_GEN3	Combined Cycle	CA-N	21.9	7651	8594	1.09	15.00
Fresno Cogen Partners	10156_G_GEN4	Combined Cycle	CA-N	45.0	7651	8594	1.09	15.00
Cardinal Cogen	10168_G_GTG1	Combined Cycle	CA-N	32.5	9939	9738	1.00	84.63
Cardinal Cogen	10168_G_STG1	Combined Cycle	CA-N	9.4	9939	9738	1.00	84.63
Carson Cogeneration	10169_G_GEN1	Combined Cycle	CA-S	41.3	8994	8557	1.01	84.63
Carson Cogeneration	10169_G_GEN2	Combined Cycle	CA-S	8.0	8994	8557	1.01	84.63
Metro Wastewater Reclamation District	10180_G_1	Non-Fossil Waste	RMPA	1.2	14283	8700	1.64	77.35
Metro Wastewater Reclamation District	10180_G_2	Non-Fossil Waste	RMPA	1.2	14283	8700	1.64	77.35
Metro Wastewater Reclamation District	10180_G_3	Non-Fossil Waste	RMPA	1.2	14283	8700	1.64	77.35
Metro Wastewater Reclamation District	10180_G_4	Non-Fossil Waste	RMPA	1.2	14283	8700	1.64	77.35
Metro Wastewater Reclamation District	10180_G_5	Non-Fossil Waste	RMPA	2.5	10000	8700	1.15	77.35
Metro Wastewater Reclamation District	10180_G_6	Non-Fossil Waste	RMPA	2.5	10000	8700	1.15	77.35
Central Utility Plant	10184_G_EG1	IC Engine	ERCT	4.3	13298	13199	1.00	89.24
Central Utility Plant	10184_G_EG2	IC Engine	ERCT	3.2	13298	13199	1.00	89.24
Central Utility Plant	10184_G_TG1	O/G Steam	ERCT	0.23	11425	10036	1.11	89.51
IMC Phosphates Company Uncle Sam	10198_G_GEN1	Non-Fossil Waste	ENTG	10.2	13102	9854	1.30	75.66
IMC Phosphates Company Uncle Sam	10198_G_GEN2	Non-Fossil Waste	ENTG	10.2	13102	9854	1.30	75.66
Hercules Missouri Chemical Works	10207_B_1	Coal Steam	GWAY	5.7	12508	8300	1.49	85.26
Hercules Missouri Chemical Works	10207_B_2	Coal Steam	GWAY	5.7	12508	8300	1.49	85.26
Hercules Missouri Chemical Works	10207_B_3	Coal Steam	GWAY	5.7	12508	8300	1.49	85.26
Snowbird Power Plant	10215_G_1367	IC Engine	NWPE	0.59	13298	8700	1.52	89.24
Snowbird Power Plant	10215_G_1391	IC Engine	NWPE	0.59	13298	8700	1.52	89.24
Snowbird Power Plant	10215_G_1392	IC Engine	NWPE	0.59	13298	8700	1.52	89.24
Alabama River Pulp	10216_B_PB1	Biomass	SOU	22.3	15517	8300	1.89	83.00

Alabama River Pulp	10216_B_RB1	Non-Fossil Waste	SOU	22.3	13102	8300	1.54	55.17
Leaf River Cellulose LLC	10233_B_PB	Biomass	SOU	37.5	15517	8300	1.89	83.00
Leaf River Cellulose LLC	10233_B_RB	Non-Fossil Waste	SOU	12.5	13102	8300	1.54	55.17
King City Power Plant	10294_G_GTG	Combined Cycle	CA-N	73.0	7990	7990	1.00	84.63
King City Power Plant	10294_G_STG	Combined Cycle	CA-N	38.0	7990	7990	1.00	84.63
Bayou Cogen Plant	10298_G_GEN1	Combustion Turbine	ERCT	65.0	15981	8700	1.82	90.81
Bayou Cogen Plant	10298_G_GEN2	Combustion Turbine	ERCT	65.0	15981	8700	1.82	90.81
Bayou Cogen Plant	10298_G_GEN3	Combustion Turbine	ERCT	65.0	15981	8700	1.82	90.81
Bayou Cogen Plant	10298_G_GEN4	Combustion Turbine	ERCT	65.0	15981	8700	1.82	90.81
Bellingham Cogeneration Facility	10307_G_CT1	Combined Cycle	NENG	102	8300	7953	1.04	22.19
Bellingham Cogeneration Facility	10307_G_CT2	Combined Cycle	NENG	102	8300	7953	1.04	22.19
Bellingham Cogeneration Facility	10307_G_ST1	Combined Cycle	NENG	60.0	8300	7953	1.04	22.19
Sayreville Cogeneration Facility	10308_G_CT1	Combined Cycle	MACE	98.0	8650	8200	1.00	84.63
Sayreville Cogeneration Facility	10308_G_CT2	Combined Cycle	MACE	98.0	8650	8200	1.00	84.63
Sayreville Cogeneration Facility	10308_G_ST1	Combined Cycle	MACE	75.0	8650	8200	1.00	84.63
Central Power & Lime	10333_B_1	Coal Steam	FRCC	139	10896	10327	1.06	60.53
Foster Wheeler Martinez	10342_G_TG1	Combined Cycle	CA-N	35.0	8600	8266	1.13	84.63
Foster Wheeler Martinez	10342_G_TG2	Combined Cycle	CA-N	35.0	8600	8266	1.13	84.63
Foster Wheeler Martinez	10342_G_TG3	Combined Cycle	CA-N	33.5	8600	8266	1.13	84.63
Foster Wheeler Mt Carmel Cogen	10343_B_SG-101	Coal Steam	MACW	43.0	12500	11845	1.06	90.10
Charleston Resource Recovery Facility	10344_B_B1	Municipal Solid Waste	VACA	4.8	19338	9587	1.70	89.39
Charleston Resource Recovery Facility	10344_B_B2	Municipal Solid Waste	VACA	4.8	19338	9587	1.70	89.39
Greenleaf 2 Power Plant	10349_G_GEN1	Combustion Turbine	CA-N	49.5	10578	8700	1.22	90.81
Greenleaf 1 Power Plant	10350_G_GEN1	Combined Cycle	CA-N	42.0	8290	6181	1.49	66.10
Greenleaf 1 Power Plant	10350_G_GEN2	Combined Cycle	CA-N	8.0	8290	6181	1.49	66.10
Cogentrix Hopewell	10377_B_1A	Coal Steam	VAPW	18.2	10331	9194	1.12	83.40
Cogentrix Hopewell	10377_B_1B	Coal Steam	VAPW	18.2	11360	9194	1.24	83.40
Cogentrix Hopewell	10377_B_1C	Coal Steam	VAPW	18.2	10331	9194	1.12	83.40
Cogentrix Hopewell	10377_B_2A	Coal Steam	VAPW	18.2	11359	9194	1.24	83.40
Cogentrix Hopewell	10377_B_2B	Coal Steam	VAPW	18.2	10331	9194	1.12	83.40
Cogentrix Hopewell	10377_B_2C	Coal Steam	VAPW	18.2	10331	9194	1.12	83.40
Primary Energy Southport	10378_B_1A	Coal Steam	VACA	17.8	11362	11362	1.00	41.34
Primary Energy Southport	10378_B_1B	Coal Steam	VACA	17.8	10331	10320	1.00	41.34
Primary Energy Southport	10378_B_1C	Coal Steam	VACA	17.8	10331	10320	1.00	41.34
Primary Energy Southport	10378_B_2A	Coal Steam	VACA	17.8	11361	11361	1.00	41.34
Primary Energy Southport	10378_B_2B	Coal Steam	VACA	17.8	10331	10320	1.00	41.34
Primary Energy Southport	10378_B_2C	Coal Steam	VACA	17.8	10331	10320	1.00	41.34
Primary Energy Roxboro	10379_B_1A	Coal Steam	VACA	18.7	11362	11362	1.00	83.00
Primary Energy Roxboro	10379_B_1B	Coal Steam	VACA	18.7	10331	10320	1.00	83.00
Primary Energy Roxboro	10379_B_1C	Coal Steam	VACA	18.7	10331	10320	1.00	83.00
Elizabethtown Power LLC	10380_B_A BLR	Coal Steam		16.0	Not in dB	11113	1.05	41.34

Elizabethtown Power LLC	10380_B_B BLR	Coal Steam		16.0	Not in dB	11113	1.05	41.34
Green Power Kenansville	10381_B_1A	Biomass	VACA	16.2	11564	11498	1.37	83.00
Green Power Kenansville	10381_B_1B	Biomass	VACA	16.2	15517	11498	1.37	83.00
Lumberton	10382_B_UNIT1	Coal Steam		16.0	Not in dB	11247	1.04	15.00
Lumberton	10382_B_UNIT2	Coal Steam		16.0	Not in dB	11247	1.04	15.00
Edgecombe GenCo	10384_B_1A	Coal Steam	VAPW	28.9	11325	11062	1.02	90.00
Edgecombe GenCo	10384_B_1B	Coal Steam	VAPW	28.9	10331	10320	1.00	90.00
Edgecombe GenCo	10384_B_2A	Coal Steam	VAPW	28.9	11325	11062	1.02	90.00
Edgecombe GenCo	10384_B_2B	Coal Steam	VAPW	28.9	10331	10320	1.00	90.00
Little Company of Mary Hospital	10400_G_GEN1	Combustion Turbine	COMD	3.2	15981	8700	1.82	89.24
Laidlaw Energy & Environmental	10403_G_ALLI	Combined Cycle	UPNY	2.6	11860	11860	1.00	84.63
Laidlaw Energy & Environmental	10403_G_CAT3	IC Engine	UPNY	0.40	11100	11100	1.00	89.24
Laidlaw Energy & Environmental	10403_G_CAT4	IC Engine	UPNY	0.40	11100	11100	1.00	89.24
Laidlaw Energy & Environmental	10403_G_WEST	Combined Cycle	UPNY	0.70	11860	11860	1.00	84.63
Kingsburg Cogen	10405_G_GEN1	Combined Cycle	CA-N	22.0	9832	8492	1.00	84.63
Kingsburg Cogen	10405_G_GEN2	Combined Cycle	CA-N	11.8	9832	8492	1.00	84.63
Inland Ontario Mill	10427_G_GEN1	Combustion Turbine	CA-S	34.0	15981	15845	1.00	89.87
Wisconsin Rapids Pulp Mill	10477_B_P1	Coal Steam	WUMS	11.2	10331	8300	1.24	85.26
Wisconsin Rapids Pulp Mill	10477_B_P2	Coal Steam	WUMS	11.2	10331	8300	1.24	85.26
Wisconsin Rapids Pulp Mill	10477_B_P3	O/G Steam	WUMS	11.2	11332	8300	1.39	92.41
Wisconsin Rapids Pulp Mill	10477_B_R1	Non-Fossil Waste	WUMS	11.2	13102	8300	1.54	75.66
Wisconsin Rapids Pulp Mill	10477_B_R2	Non-Fossil Waste	WUMS	11.2	13102	8300	1.54	75.66
Wisconsin Rapids Pulp Mill	10477_B_R3	Non-Fossil Waste	WUMS	11.2	13102	8300	1.54	75.66
Pitchess Cogen Station	10478_G_GEN1	Combined Cycle	CA-S	21.5	10211	6716	1.68	84.63
Pitchess Cogen Station	10478_G_GEN2	Combined Cycle	CA-S	5.7	10211	6716	1.68	84.63
Rumford Cogeneration	10495_B_6	Coal Steam	NENG	42.5	11058	8300	1.33	94.10
Rumford Cogeneration	10495_B_7	Coal Steam	NENG	42.5	10331	8300	1.24	94.10
Kern River Cogeneration	10496_G_GTAG	Combustion Turbine	CA-N	72.0	16509	8700	1.90	90.81
Kern River Cogeneration	10496_G_GTBG	Combustion Turbine	CA-N	72.0	16509	8700	1.90	90.81
Kern River Cogeneration	10496_G_GTCG	Combustion Turbine	CA-N	72.0	16509	8700	1.90	90.81
Kern River Cogeneration	10496_G_GTDG	Combustion Turbine	CA-N	72.0	16509	8700	1.90	90.81
Mid-Set Cogeneration	10501_G_K100	Combustion Turbine	CA-N	36.0	15506	8700	1.78	89.87
San Jose Cogeneration	10548_G_GEN1	Combustion Turbine	CA-N	5.6	15981	11640	1.36	89.24
Chambers Cogeneration LP	10566_B_BOIL1	Coal Steam	MACE	131	10000	10000	1.00	74.80
Chambers Cogeneration LP	10566_B_BOIL2	Coal Steam	MACE	131	10331	10079	1.02	74.80
Algonquin Windsor Locks	10567_G_GTG	Combined Cycle	NENG	26.0	10186	7106	1.30	84.63
Algonquin Windsor Locks	10567_G_STG	Combined Cycle	NENG	12.0	10186	7106	1.30	84.63
Sixth Street	1058_B_2	Coal Steam		13.6	Not in dB	12551	1.00	35.53
Sixth Street	1058_B_3	Coal Steam		13.6	Not in dB	14500	1.00	35.53
Sixth Street	1058_B_4	Coal Steam		13.6	Not in dB	14500	1.00	35.53
Sixth Street	1058_B_5	Coal Steam		13.6	Not in dB	14500	1.00	35.53

BP Wilmington Calciner	10601_G_GEN1	Coal Steam	CA-S	29.0	10331	9854	1.05	85.26
Ebensburg Power	10603_B_031	Coal Steam	MACW	49.5	12500	12500	1.00	95.00
Domtar - Woodland Mill	10613_B_3RB	O/G Steam	NENG	23.0	11844	8300	1.39	86.60
Domtar - Woodland Mill	10613_B_9PB	Biomass	NENG	23.0	15517	8300	1.89	83.00
CH Resources Beaver Falls	10617_G_GEN1	Combined Cycle	UPNY	52.5	8700	8700	1.00	84.63
CH Resources Beaver Falls	10617_G_GEN2	Combined Cycle	UPNY	34.0	8700	8700	1.00	84.63
Civic Center	10623_G_GEN1	Combined Cycle	CA-S	18.5	9939	8577	1.14	84.63
Civic Center	10623_G_GEN2	Combined Cycle	CA-S	1.2	9939	8577	1.14	84.63
Wheelabrator Baltimore Refuse	10629_B_BLR1	Municipal Solid Waste	MACS	20.4	19338	16297	1.00	90.00
Wheelabrator Baltimore Refuse	10629_B_BLR2	Municipal Solid Waste	MACS	20.4	19338	16297	1.00	90.00
Wheelabrator Baltimore Refuse	10629_B_BLR3	Municipal Solid Waste	MACS	20.4	19338	16297	1.00	90.00
Hopewell Cogeneration	10633_G_GT1	Combined Cycle		84.1	Not in dB	8292	1.09	27.40
Hopewell Cogeneration	10633_G_GT2	Combined Cycle		84.1	Not in dB	8292	1.09	27.40
Hopewell Cogeneration	10633_G_GT3	Combined Cycle		84.1	Not in dB	8292	1.09	27.40
Hopewell Cogeneration	10633_G_ST1	Combined Cycle		96.0	Not in dB	8292	1.09	27.40
Corona Cogen	10635_G_GEN1	Combustion Turbine	CA-S	40.0	15727	8700	1.81	89.87
Cambria Cogen	10641_B_B1	Coal Steam	MACW	44.0	11076	12200	1.00	95.00
Cambria Cogen	10641_B_B2	Coal Steam	MACW	44.0	10331	12200	1.00	95.00
Bear Mountain Cogen	10649_G_GEN1	Combustion Turbine	CA-N	46.0	13225	8700	1.52	89.87
Badger Creek Cogen	10650_G_GEN1	Combustion Turbine	CA-N	46.0	13225	8700	1.52	89.87
Burney Forest Products	10652_B_BLR1	Biomass	CA-N	15.5	15517	15716	1.00	83.00
Burney Forest Products	10652_B_BLR2	Biomass	CA-N	15.5	15517	15716	1.00	83.00
Sierra Pacific Sonora	54517_G_GEN2	Biomass	CA-N	5.5	15517	8300	1.89	83.00
AES Deepwater	10670_B_AAB001	Coal Steam	ERCT	140	14500	11801	1.23	85.26
AES Shady Point	10671_B_1A	Coal Steam	SPPS	80.0	10471	10471	1.00	80.90
AES Shady Point	10671_B_1B	Coal Steam	SPPS	80.0	10331	10320	1.00	80.90
AES Shady Point	10671_B_2A	Coal Steam	SPPS	80.0	10469	10469	1.00	80.90
AES Shady Point	10671_B_2B	Coal Steam	SPPS	80.0	10331	10320	1.00	80.90
Cedar Bay Generating LP	10672_B_CBA	Coal Steam	FRCC	83.3	9504	9375	1.01	82.80
Cedar Bay Generating LP	10672_B_CBB	Coal Steam	FRCC	83.3	10331	9375	1.10	82.80
Cedar Bay Generating LP	10672_B_CBC	Coal Steam	FRCC	83.3	10331	9375	1.10	82.80
AES Thames	10675_B_A	Coal Steam	NENG	90.5	10173	9491	1.07	94.10
AES Thames	10675_B_B	Coal Steam	NENG	90.5	10331	9491	1.09	94.10
AES Beaver Valley Partners Beaver Valley	10676_B_2	Coal Steam	RFCP	43.0	11621	10910	1.07	72.07
AES Beaver Valley Partners Beaver Valley	10676_B_3	Coal Steam	RFCP	43.0	12508	10910	1.14	72.07
AES Beaver Valley Partners Beaver Valley	10676_B_4	Coal Steam	RFCP	43.0	12508	10910	1.14	72.07
AES Beaver Valley Partners Beaver Valley	10676_B_5	Coal Steam	RFCP	17.0	12508	10910	1.14	72.07
AES Placerita	10677_G_UNT1	Combined Cycle	CA-S	46.0	9900	9894	1.00	84.63
AES Placerita	10677_G_UNT2	Combined Cycle	CA-S	46.0	9900	9894	1.00	84.63
AES Placerita	10677_G_UNT3	Combined Cycle	CA-S	23.0	9900	9894	1.00	84.63
AES Warrior Run Cogeneration Facility	10678_B_BLR1	Coal Steam	RFCP	180	11177	10577	1.06	92.30

Colorado Power Partners	10682_G_GT1	Combined Cycle	RMPA	25.0	11860	8841	1.34	25.35
Colorado Power Partners	10682_G_GT2	Combined Cycle	RMPA	25.0	11860	8841	1.34	25.35
Colorado Power Partners	10682_G_ST1	Combined Cycle	RMPA	30.0	11860	8841	1.34	25.35
BCP	10683_G_GT3	Combined Cycle	RMPA	32.0	11860	9885	1.00	84.63
BCP	10683_G_ST2	Combined Cycle	RMPA	40.0	11860	9885	1.00	84.63
Argus Cogen Plant	10684_B_BLR25	Coal Steam	CA-S	25.0	10331	8300	1.24	85.26
Argus Cogen Plant	10684_B_BLR26	Coal Steam	CA-S	25.0	10331	8300	1.24	85.26
Westend Facility	10685_G_PINA	Combustion Turbine	CA-S	15.0	15981	8700	1.82	89.24
Rapids Energy Center	10686_B_5	Biomass	MRO	11.2	15517	13179	1.19	83.00
Rapids Energy Center	10686_B_6	Biomass	MRO	11.2	20328	13179	1.54	83.00
Rapids Energy Center	10686_B_7	O/G Steam	MRO	3.5	14500	11511	1.00	92.41
Rapids Energy Center	10686_B_8	O/G Steam	MRO	3.5	11332	11511	1.00	92.41
Jackson County Resource Recovery	10722_G_1	Municipal Solid Waste	MECS	3.0	19338	8300	2.33	52.47
Selkirk Cogen	10725_G_GEN1	Combined Cycle	DSNY	72.6	8861	8109	1.16	63.58
Selkirk Cogen	10725_G_GEN2	Combined Cycle	DSNY	9.2	8861	8109	1.16	63.58
Selkirk Cogen	10725_G_GEN3	Combined Cycle	DSNY	79.7	8861	8109	1.16	63.58
Selkirk Cogen	10725_G_GEN4	Combined Cycle	DSNY	79.7	8861	8109	1.16	63.58
Selkirk Cogen	10725_G_GEN5	Combined Cycle	DSNY	124	8861	8109	1.16	63.58
Masspower	10726_G_GEN1	Combined Cycle	NENG	82.2	8224	8507	1.01	26.13
Masspower	10726_G_GEN2	Combined Cycle	NENG	82.2	8224	8507	1.01	26.13
Prairie Creek	1073_B_1	Coal Steam	MRO	9.1	11595	11595	1.00	52.20
Prairie Creek	1073_B_2	Coal Steam	MRO	10.2	12230	12230	1.00	52.20
Prairie Creek	1073_B_3	Coal Steam	MRO	41.6	11090	11090	1.00	52.20
Prairie Creek	1073_B_4	Coal Steam	MRO	125	10198	10198	1.00	52.20
Clear Lake Cogeneration Ltd	10741_G_G102	Combined Cycle	ERCT	100	10540	5500	1.82	25.04
Clear Lake Cogeneration Ltd	10741_G_G103	Combined Cycle	ERCT	100	10540	5500	1.82	25.04
Clear Lake Cogeneration Ltd	10741_G_G104	Combined Cycle	ERCT	100	10540	5500	1.82	25.04
Clear Lake Cogeneration Ltd	10741_G_S101	Combined Cycle	ERCT	52.0	10540	5500	1.82	25.04
Clear Lake Cogeneration Ltd	10741_G_S102	Combined Cycle	ERCT	14.0	10540	5500	1.82	25.04
Morgantown Energy Facility	10743_B_CFB1	Coal Steam	RFCP	25.0	11298	8693	1.52	85.26
Morgantown Energy Facility	10743_B_CFB2	Coal Steam	RFCP	25.0	10331	8693	1.52	85.26
Midland Cogeneration Venture	10745_G_1G12	IC Engine	MECS	5.2	11585	11585	1.00	89.24
Midland Cogeneration Venture	10745_G_BP15	Combined Cycle	MECS	13.4	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT10	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT11	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT12	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT13	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT14	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT3	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT4	Combined Cycle	MECS	88.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT5	Combined Cycle	MECS	88.0	8974	7289	1.22	37.26

Midland Cogeneration Venture	10745_G_GT6	Combined Cycle	MECS	88.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT7	Combined Cycle	MECS	88.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT8	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_GT9	Combined Cycle	MECS	84.0	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_ST1	Combined Cycle	MECS	410	8974	7289	1.22	37.26
Midland Cogeneration Venture	10745_G_ST2	Combined Cycle	MECS	380	8974	7289	1.22	37.26
Rifle Generating Station	10755_G_GT2	Combined Cycle	RMPA	13.0	11860	10422	1.00	84.63
Rifle Generating Station	10755_G_GT3	Combined Cycle	RMPA	13.0	11860	10422	1.00	84.63
Rifle Generating Station	10755_G_GT4	Combined Cycle	RMPA	21.2	11860	10422	1.00	84.63
Rifle Generating Station	10755_G_ST1	Combined Cycle	RMPA	21.2	11860	10422	1.00	84.63
Las Vegas Cogen LP	10761_G_GEN1	Combined Cycle	SNV	41.0	8289	7701	1.00	84.63
Las Vegas Cogen LP	10761_G_GEN2	Combined Cycle	SNV	9.0	8289	7701	1.00	84.63
Rio Bravo Jasmin	10768_B_CFB	Coal Steam	CA-S	33.0	11568	11445	1.01	92.00
Rio Bravo Poso	10769_B_CFB	Coal Steam	CA-N	33.0	11568	11568	1.00	95.00
Southampton Power Station	10774_B_1	Coal Steam		36.5	Not in dB	11277	1.00	59.87
Southampton Power Station	10774_B_2	Coal Steam		36.5	Not in dB	11277	1.00	90.00
E F Oxnard Energy Facility	10776_G_GTG	Combustion Turbine	CA-S	48.5	15349	8700	1.76	89.87
Seaford Delaware Plant	10793_B_BLR1	O/G Steam	MACE	9.0	14517	8300	1.72	86.60
Seaford Delaware Plant	10793_B_BLR3	O/G Steam	MACE	9.0	14517	8300	1.72	86.60
Seaford Delaware Plant	10793_B_BLR5	O/G Steam	MACE	9.0	12534	8300	1.35	92.41
Lowell Cogen Plant	10802_G_GEN1	Combined Cycle	NENG	18.7	9800	9800	1.00	84.63
Lowell Cogen Plant	10802_G_GEN2	Combined Cycle	NENG	6.3	9800	9800	1.00	84.63
Ogdensburg Power	10803_B_1	Biomass		26.0	Not in dB	8573	1.04	15.00
Ogdensburg Power	10803_G_GEN1	Biomass	UPNY	8.3	8911	Retired		0.00
Ogdensburg Power	10803_G_GEN2	Biomass	UPNY	8.3	8911	Retired		0.00
Ogdensburg Power	10803_G_GEN3	Biomass	UPNY	8.3	8911	8573	1.04	83.00
Kenilworth Energy Facility	10805_G_GEN1	Combined Cycle	MACE	22.5	10700	9867	1.08	76.45
Kenilworth Energy Facility	10805_G_GEN2	Combined Cycle	MACE	4.5	10700	9867	1.08	76.45
Riverside	1081_B_7	Coal Steam	MRO	2.5	12508	12406	1.00	64.00
Riverside	1081_B_8	Coal Steam	MRO	2.5	12508	12406	1.00	64.00
Riverside	1081_B_9	Coal Steam	MRO	130	10720	10720	1.00	64.00
NTC/MCRD Energy Facility	10810_G_GEN1	Combined Cycle	CA-S	21.6	10013	7705	1.23	84.63
NTC/MCRD Energy Facility	10810_G_GEN2	Combined Cycle	CA-S	2.2	10013	7705	1.23	84.63
Naval Station Energy Facility	10811_G_GEN1	Combined Cycle	CA-S	36.7	11520	8143	1.20	82.26
Naval Station Energy Facility	10811_G_GEN2	Combined Cycle	CA-S	9.8	11520	8143	1.20	82.26
Naval Station Energy Facility	10811_G_GEN3	Combined Cycle	CA-S	4.8	11520	8143	1.20	82.26
North Island Energy Facility	10812_G_GEN1	Combined Cycle	CA-S	33.5	9194	6803	1.26	84.17
North Island Energy Facility	10812_G_GEN2	Combined Cycle	CA-S	3.5	9194	6803	1.26	84.17
Ada Cogeneration LP	10819_G_GEN1	Combined Cycle	MECS	23.0	8950	5866	1.55	84.63
Ada Cogeneration LP	10819_G_GEN2	Combined Cycle	MECS	6.4	8950	5866	1.55	84.63
Walter Scott Jr. Energy Center	1082_B_3	Coal Steam	MRO	690	10927	10927	1.00	73.40

Coca Cola Bottling of New York	10829_G_ENG1	IC Engine	DSNY	0.60	12942	Retired		0.00
Coca Cola Bottling of New York	10829_G_ENG2	IC Engine	DSNY	0.60	12942	Retired		0.00
Coca Cola Bottling of New York	10829_G_ENG3	IC Engine	DSNY	0.60	13080	Retired		0.00
Silver Bay Power	10849_B_BLR1	Coal Steam		36.0	Not in dB	9693	1.06	85.26
Silver Bay Power	10849_B_BLR2	Coal Steam		69.0	Not in dB	9693	1.06	85.26
Mojave Cogen	10850_G_GEN1	Combined Cycle	CA-S	40.0	11600	7870	1.25	82.77
Mojave Cogen	10850_G_GEN2	Combined Cycle	CA-S	15.3	11600	7870	1.25	82.77
Biomass One LP	10869_B_NORTH	Biomass	PNW	8.5	15517	12056	1.30	83.00
Biomass One LP	10869_B_SOUTH	Biomass	PNW	14.0	15517	12056	1.30	83.00
Medical Area Total Energy Plant	10883_B_GTHSG1	O/G Steam	NENG	3.1	11332	8300	1.39	92.41
Medical Area Total Energy Plant	10883_B_GTHSG2	O/G Steam	NENG	3.1	11332	8300	1.39	92.41
Medical Area Total Energy Plant	10883_B_HSG1	O/G Steam	NENG	3.1	11332	8300	1.39	92.41
Medical Area Total Energy Plant	10883_B_HSG2	O/G Steam	NENG	3.1	11332	8300	1.39	92.41
Medical Area Total Energy Plant	10883_B_PSG1	O/G Steam	NENG	3.1	11332	8300	1.39	92.41
Medical Area Total Energy Plant	10883_B_PSG2	O/G Steam	NENG	3.1	11332	8300	1.39	92.41
Medical Area Total Energy Plant	10883_B_PSG3	O/G Steam	NENG	3.1	11332	8300	1.39	92.41
Medical Area Total Energy Plant	10883_G_CT1	Combustion Turbine	NENG	12.5	12503	8700	1.43	89.24
Medical Area Total Energy Plant	10883_G_CT2	Combustion Turbine	NENG	12.5	12503	8700	1.43	89.24
Medical Area Total Energy Plant	10883_G_DEG1	IC Engine	NENG	6.0	13988	8700	1.60	89.24
Medical Area Total Energy Plant	10883_G_DEG2	IC Engine	NENG	6.0	13988	8700	1.60	89.24
Medical Area Total Energy Plant	10883_G_DEG3	IC Engine	NENG	6.0	13988	8700	1.60	89.24
Medical Area Total Energy Plant	10883_G_DEG4	IC Engine	NENG	6.0	13988	8700	1.60	89.24
Medical Area Total Energy Plant	10883_G_DEG5	IC Engine	NENG	6.0	13988	8700	1.60	89.24
Medical Area Total Energy Plant	10883_G_DEG6	IC Engine	NENG	6.0	13988	8700	1.60	89.24
Ames Electric Services Power Plant	1122_B_7	Coal Steam	MRO	33.0	12926	12926	1.00	59.00
Ames Electric Services Power Plant	1122_B_8	Coal Steam	MRO	70.0	12926	12926	1.00	59.00
Muscatine Plant #1	1167_B_8	Coal Steam	MRO	35.0	15279	15279	1.00	71.93
Louisiana 1	1391_G_1A	Combined Cycle	ENTG	18.0	10472	5500	1.90	63.33
Louisiana 1	1391_G_2A	Combined Cycle	ENTG	55.0	10472	5500	1.90	63.33
Louisiana 1	1391_G_3A	Combined Cycle	ENTG	55.0	10472	5500	1.90	63.33
Louisiana 1	1391_G_4A	Combined Cycle	ENTG	100	10472	5500	1.90	63.33
Louisiana 1	1391_G_5A	Combined Cycle	ENTG	154	10472	5500	1.90	63.33
R S Nelson	1393_B_1A	Coal Steam	ENTG	107	11041	11041	1.00	85.26
R S Nelson	1393_B_2A	Coal Steam	ENTG	106	11041	11041	1.00	85.26
R S Nelson	1393_B_3	O/G Steam	ENTG	153	10476	10476	1.00	84.42
R S Nelson	1393_B_4	O/G Steam	ENTG	500	10419	10419	1.00	84.42
Kendall Square Station	1595_G_1	Combined Cycle	NENG	15.0	8658	8945	1.16	71.62
Kendall Square Station	1595_G_2	Combined Cycle	NENG	20.0	8658	8945	1.16	71.62
Kendall Square Station	1595_G_3	Combined Cycle	NENG	21.7	8658	8945	1.16	71.62
Kendall Square Station	1595_G_GEN4	Combined Cycle	NENG	180	8658	8945	1.16	71.62
Apache Station	160_G_GT1	Combined Cycle	AZNM	10.0	11855	11071	1.00	84.63

Apache Station	160_G_ST1	Combined Cycle	AZNM	72.0	11855	11071	1.00	84.63
Mistersky	1822_B_5	O/G Steam		163	Not in dB	14500	1.00	89.51
Mistersky	1822_B_6	O/G Steam		163	Not in dB	14500	1.00	92.41
Mistersky	1822_B_7	O/G Steam		163	Not in dB	14500	1.00	89.51
M L Hibbard	1897_B_3	Biomass	MRO	33.3	14500	14500	1.00	83.00
M L Hibbard	1897_B_4	Biomass	MRO	15.3	14500	14500	1.00	83.00
Hibbing	1979_B_1	Coal Steam	MRO	10.2	10331	10320	1.00	40.46
Hibbing	1979_B_2	Coal Steam	MRO	10.2	10331	10320	1.00	40.46
Hibbing	1979_B_3	Coal Steam	MRO	10.2	9906	9906	1.00	40.46
Hibbing	1979_B_wood	Biomass	MRO	20.0	14500	15716	1.00	83.00
New Ulm	2001_B_1	O/G Steam	MRO	3.1	14500	14500	1.00	92.41
New Ulm	2001_B_2	O/G Steam	MRO	3.1	14500	14500	1.00	92.41
New Ulm	2001_B_4	O/G Steam	MRO	16.3	14500	14500	1.00	92.41
Virginia	2018_B_10	O/G Steam	MRO	9.7	11804	11804	1.00	92.41
Virginia	2018_B_7	Coal Steam	MRO	9.7	12245	12245	1.00	38.33
Virginia	2018_B_9	Coal Steam	MRO	9.7	11947	11947	1.00	38.33
Virginia	2018_B_wood	Biomass	MRO	15.0	14500	15716	1.00	83.00
Willmar	2022_B_2	O/G Steam	MRO	3.0	14500	14500	1.00	92.41
Willmar	2022_B_3	Coal Steam	MRO	20.4	12260	12260	1.00	38.07
Chevron Oil	2047_G_1	Combustion Turbine	SOU	15.0	15154	15154	1.00	89.24
Chevron Oil	2047_G_2	Combustion Turbine	SOU	15.0	15154	15154	1.00	89.24
Chevron Oil	2047_G_3	Combustion Turbine	SOU	16.0	15188	15188	1.00	89.24
Chevron Oil	2047_G_4	Combustion Turbine	SOU	16.0	15188	15188	1.00	89.24
Chevron Oil	2047_G_5	Combustion Turbine	SOU	65.0	13160	13160	1.00	90.81
Raton	2468_G_5	Coal Steam	AZNM	6.9	14200	14200	1.00	95.00
East River	2493_B_60	O/G Steam	NYC	134	12215	12830	1.00	83.29
East River	2493_B_70	O/G Steam	NYC	182	12215	11980	1.00	83.29
Ravenswood	2500_G_4	Combined Cycle	NYC	231	7933	15000	1.00	84.63
AES Westover	2526_B_11	Coal Steam	UPNY	21.9	12184	11030	1.10	74.27
AES Westover	2526_B_12	Coal Steam	UPNY	21.9	12508	11030	1.12	74.27
AES Westover	2526_B_13	Coal Steam	UPNY	84.0	11000	11000	1.00	74.27
Hamilton	2917_G_GT2	Combined Cycle	RFCO	12.0	36790	15000	1.00	84.63
Johnsonville	3406_B_1	Coal Steam	TVA	106	11957	11957	1.00	72.87
Johnsonville	3406_B_10	Coal Steam	TVA	141	10649	10649	1.00	72.87
Johnsonville	3406_B_2	Coal Steam	TVA	106	11957	11957	1.00	72.87
Johnsonville	3406_B_3	Coal Steam	TVA	106	11957	11957	1.00	72.87
Johnsonville	3406_B_4	Coal Steam	TVA	106	11957	11957	1.00	72.87
Johnsonville	3406_B_5	Coal Steam	TVA	106	11031	11031	1.00	72.87
Johnsonville	3406_B_6	Coal Steam	TVA	106	11031	11031	1.00	72.87
Johnsonville	3406_B_7	Coal Steam	TVA	141	10649	10649	1.00	72.87
Johnsonville	3406_B_8	Coal Steam	TVA	141	10649	10649	1.00	72.87

Johnsonville	3406_B_9	Coal Steam	TVA	141	10649	10649	1.00	72.87
Valley	4042_B_1	Coal Steam	WUMS	70.0	13428	13428	1.00	61.87
Valley	4042_B_2	Coal Steam	WUMS	70.0	13428	13428	1.00	61.87
Valley	4042_B_3	Coal Steam	WUMS	70.0	13199	13199	1.00	61.87
Valley	4042_B_4	Coal Steam	WUMS	70.0	13199	13199	1.00	61.87
Manitowoc	4125_B_5	Coal Steam	WUMS	1.5	11365	11365	1.00	93.20
Manitowoc	4125_B_6	Coal Steam	WUMS	18.0	11470	11470	1.00	93.20
Manitowoc	4125_B_7	Coal Steam	WUMS	18.0	10331	10320	1.00	93.20
Manitowoc	4125_B_8	Coal Steam	WUMS	20.6	10331	10320	1.00	93.20
Manitowoc	4125_B_9	Coal Steam	WUMS	30.0	10331	10320	1.00	93.20
Menasha	4127_B_5	Coal Steam	WUMS	6.9	10331	8844	1.00	31.67
Menasha	4127_B_B23	Coal Steam		8.50	Not in dB	11844	1.22	24.01
Menasha	4127_B_B24	Coal Steam		14.5	Not in dB	11844	1.22	24.01
Pittsfield Generating LP	50002_G_GEN1	Combined Cycle	NENG	33.8	10808	9095	1.04	15.00
Pittsfield Generating LP	50002_G_GEN2	Combined Cycle	NENG	33.8	10808	9095	1.04	15.00
Pittsfield Generating LP	50002_G_GEN3	Combined Cycle	NENG	33.8	10808	9095	1.04	15.00
Pittsfield Generating LP	50002_G_GEN4	Combined Cycle	NENG	39.6	10808	9095	1.04	15.00
Chalk Cliff Cogen	50003_G_GEN1	Combustion Turbine	CA-N	46.0	13225	8700	1.52	89.87
Linden Cogen Plant	50006_G_GTG1	Combined Cycle	MACE	90.0	9174	6778	1.18	65.22
Linden Cogen Plant	50006_G_GTG2	Combined Cycle	MACE	90.0	9174	6778	1.18	65.22
Linden Cogen Plant	50006_G_GTG3	Combined Cycle	MACE	90.0	9174	6778	1.18	65.22
Linden Cogen Plant	50006_G_GTG4	Combined Cycle	MACE	90.0	9174	6778	1.18	65.22
Linden Cogen Plant	50006_G_GTG5	Combined Cycle	MACE	90.0	9174	6778	1.18	65.22
Linden Cogen Plant	50006_G_GTG6	Combined Cycle	MACE	182	9174	6778	1.18	65.22
Linden Cogen Plant	50006_G_STG1	Combined Cycle	MACE	89.0	9174	6778	1.19	65.22
Linden Cogen Plant	50006_G_STG2	Combined Cycle	MACE	89.0	9174	6778	1.22	65.22
Linden Cogen Plant	50006_G_STG3	Combined Cycle	MACE	89.0	9174	6778	1.46	65.22
Nelson Industrial Steam and Operating Company	50030_B_1A	Coal Steam		107	Not in dB	11041	1.00	85.26
Nelson Industrial Steam and Operating Company	50030_B_2A	Coal Steam		106	Not in dB	11041	1.00	85.26
Kline Township Cogen Facility	50039_B_1	Coal Steam	MACW	50.0	12138	12138	1.00	92.20
Pacific Lumber	50049_B_BLRA	Biomass	CA-N	16.2	15517	15716	1.00	83.00
Pacific Lumber	50049_B_BLRB	Biomass	CA-N	8.7	15517	15716	1.00	83.00
Pacific Lumber	50049_B_BLRC	Biomass	CA-N	8.7	15517	15716	1.00	83.00
Borger Plant	50067_B_1	Fossil Waste	SPPS	16.0	9107	8300	1.10	70.88
Borger Plant	50067_B_2	Fossil Waste	SPPS	16.0	9107	8300	1.10	70.88
Sierra Power	50068_G_WEST	Biomass	CA-S	7.0	15517	14500	1.08	83.00
Marcus Hook Refinery Cogen	50074_G_GEN1	Combustion Turbine	MACE	50.0	10973	8700	1.26	90.81
EQ Waste Energy Services	50077_G_CAT1	Landfill Gas	MECS	0.50	13388	13698	1.00	90.00
EQ Waste Energy Services	50077_G_CAT2	Landfill Gas	MECS	0.30	13388	13698	1.00	90.00
EQ Waste Energy Services	50077_G_CAT3	Landfill Gas	MECS	0.30	13388	13698	1.00	90.00
EQ Waste Energy Services	50077_G_CAT4	Landfill Gas	MECS	0.30	13388	13698	1.00	90.00

Trigen Trenton Energy	50094_G_7213	IC Engine	MACE	3.0	11625	8700	1.34	89.24
Trigen Trenton Energy	50094_G_7214	IC Engine	MACE	3.0	11625	8700	1.34	89.24
Tillotson Rubber	50095_B_EU1	Biomass	NENG	0.70	14594	8300	1.89	83.00
Tillotson Rubber	50095_B_EU2	O/G Steam	NENG	0.60	12364	9210	1.25	86.60
Sierra Pacific Anderson Facility	55049_G_GEN1	Biomass	CA-N	5.0	15517	8300	1.89	83.00
United Cogen	50104_G_G-1	Combined Cycle	CA-N	22.0	9939	9738	1.00	84.63
United Cogen	50104_G_G-2	Combined Cycle	CA-N	7.0	9939	9738	1.00	84.63
Collins Pine Project	10661_B_4	Biomass	CA-N	12.0	15517	8300	1.89	83.00
Sierra Pacific Burney Facility	50110_B_BLR1	Biomass	CA-N	16.3	15517	8300	1.89	83.00
Sierra Pacific Quincy Facility	50112_B_BLR1	Biomass	CA-N	14.4	15517	8300	1.89	83.00
Susanville	50113_G_GEN1	Biomass		11.0	Not in dB	15716	1.00	83.00
Susanville	50113_G_GEN2	Biomass		2.00	Not in dB	15716	1.00	83.00
US Borax	50115_G_GEN1	Combustion Turbine	CA-N	39.0	15981	8700	1.82	89.87
ConocoPhillips Rodeo Refinery	50119_G_GENA	Non-Fossil Waste	CA-N	13.5	13102	8700	1.47	79.92
ConocoPhillips Rodeo Refinery	50119_G_GENB	Non-Fossil Waste	CA-N	13.5	13102	8700	1.47	79.92
ConocoPhillips Rodeo Refinery	50119_G_GENC	Non-Fossil Waste	CA-N	13.5	13102	8700	1.47	79.92
Coalinga Cogeneration	50131_G_K100	Combustion Turbine	CA-N	36.0	15015	8700	1.73	89.87
Sycamore Cogeneration	50134_G_GTAG	Combustion Turbine	CA-S	76.0	16038	8700	1.84	90.81
Sycamore Cogeneration	50134_G_GTBG	Combustion Turbine	CA-S	76.0	16038	8700	1.84	90.81
Sycamore Cogeneration	50134_G_GTCG	Combustion Turbine	CA-S	76.0	16038	8700	1.84	90.81
Sycamore Cogeneration	50134_G_GTDG	Combustion Turbine	CA-S	76.0	16038	8700	1.84	90.81
Snider Industries	50141_G_WGN1	Biomass	SPPS	5.0	15517	8300	1.89	83.00
Union Carbide Seadrift Cogen	50150_G_GE10	Combined Cycle	ERCT	15.0	9489	9335	1.00	84.63
Union Carbide Seadrift Cogen	50150_G_GE11	Combined Cycle	ERCT	35.0	9489	9335	1.00	84.63
Union Carbide Seadrift Cogen	50150_G_GEN5	Combined Cycle	ERCT	15.0	9489	9335	1.00	84.63
Union Carbide Seadrift Cogen	50150_G_GEN6	Combined Cycle	ERCT	35.0	9489	9335	1.00	84.63
Union Carbide Seadrift Cogen	50150_G_GEN7	Combined Cycle	ERCT	6.0	9489	9335	1.00	84.63
Union Carbide Seadrift Cogen	50150_G_GEN8	Combined Cycle	ERCT	35.0	9489	9335	1.00	84.63
Union Carbide Seadrift Cogen	50150_G_GEN9	Combined Cycle	ERCT	15.0	9489	9335	1.00	84.63
Dow St Charles Operations	50152_G_CGN1	Combined Cycle	ENTG	100	8004	8006	1.00	84.63
Dow St Charles Operations	50152_G_CGN2	Combined Cycle	ENTG	100	8004	8006	1.00	84.63
Dow St Charles Operations	50152_G_CSTG	Combined Cycle	ENTG	50.0	8004	8006	1.00	84.63
Dow St Charles Operations	50152_G_CTG	Combined Cycle	ENTG	10.0	8004	8006	1.00	84.63
Dow St Charles Operations	50152_G_STG	Combined Cycle	ENTG	22.0	8004	8006	1.00	84.63
Berry Cogen	50170_G_GEN1	Combustion Turbine	CA-N	35.0	15981	8700	1.82	89.87
Rowan University	50173_G_GEN1	Combustion Turbine	MACE	1.2	12503	12477	1.00	89.24
Watson Cogeneration	50216_G_GN91	Combined Cycle	CA-S	82.0	9939	5500	1.77	70.07
Watson Cogeneration	50216_G_GN92	Combined Cycle	CA-S	82.0	9939	5500	1.77	70.07
Watson Cogeneration	50216_G_GN93	Combined Cycle	CA-S	82.0	9939	5500	1.77	70.07
Watson Cogeneration	50216_G_GN94	Combined Cycle	CA-S	82.0	9939	5500	1.77	70.07
Watson Cogeneration	50216_G_GN95	Combined Cycle	CA-S	35.0	9939	5500	1.77	70.07

Watson Cogeneration	50216_G_GN96	Combined Cycle	CA-S	35.0	9939	5500	1.77	70.07
Texas Petrochemicals	50229_B_TPCBLR	O/G Steam	ERCT	35.0	11332	8300	1.39	92.41
Bucksport Mill	50243_B_5	O/G Steam	NENG	23.3	11844	8300	1.39	89.51
Bucksport Mill	50243_B_6	O/G Steam	NENG	23.3	11332	8300	1.39	89.51
Bucksport Mill	50243_B_7	O/G Steam	NENG	23.3	11332	8300	1.39	89.51
Bucksport Mill	50243_B_8	Biomass	NENG	23.3	15517	8300	1.89	83.00
Bucksport Mill	50243_G_GEN4	Combustion Turbine	NENG	176	12435	9963	1.24	90.81
Archbald Power Station	50279_B_MAIN	Landfill Gas	MACW	20.0	13682	13698	1.00	90.00
Ripon Mill	50299_G_GEN1	Combustion Turbine	CA-N	46.5	15778	8700	1.81	89.87
San Gabriel Facility	50300_G_GEN1	Combustion Turbine	CA-S	39.0	16200	8700	1.86	89.87
Cornell University Central Heat	50368_G_TG1	Coal Steam	UPNY	1	10331	9628	1.07	85.26
Cornell University Central Heat	50368_G_TG2	Coal Steam	UPNY	5.3	10331	9628	1.07	85.26
Paxton Creek Cogeneration	50373_G_GEN1	IC Engine	MACW	6.0	14993	8851	1.69	89.24
Paxton Creek Cogeneration	50373_G_GEN2	IC Engine	MACW	6.0	14993	8851	1.69	89.24
Newark Bay Cogeneration Project	50385_G_GEN1	Combined Cycle	MACE	42.0	8700	8181	1.06	15.23
Newark Bay Cogeneration Project	50385_G_GEN2	Combined Cycle	MACE	42.0	8700	8181	1.06	15.23
Newark Bay Cogeneration Project	50385_G_GEN3	Combined Cycle	MACE	34.0	8700	8181	1.06	15.23
Phillips 66 Carbon Plant	50388_B_K1	Coal Steam	CA-N	10.0	10331	10320	1.00	85.26
Phillips 66 Carbon Plant	50388_B_K2	Coal Steam	CA-N	10.0	10331	10320	1.00	85.26
P H Glatfelter	50397_B_1PB035	Coal Steam	MACW	8.7	10331	8300	1.24	85.26
P H Glatfelter	50397_B_3PB033	Coal Steam	MACW	4.0	12508	8300	1.49	85.26
P H Glatfelter	50397_B_4PB034	Coal Steam	MACW	9.0	10331	8300	1.24	85.26
P H Glatfelter	50397_B_5PB036	Coal Steam	MACW	36.1	10331	8300	1.24	85.26
P H Glatfelter	50397_B_REC037	Non-Fossil Waste	MACW	31.2	13102	8300	1.54	88.41
BP Chemicals Green Lake Plant	50404_G_TG2	Non-Fossil Waste	ERCT	15.0	13102	9854	1.30	89.10
BP Chemicals Green Lake Plant	50404_G_TG3	Non-Fossil Waste	ERCT	23.8	13102	9854	1.30	89.10
Mobile Energy Services LLC	50407_B_7PB	Biomass	SOU	14.4	15517	10510	1.50	83.00
Mobile Energy Services LLC	50407_B_8PB	O/G Steam	SOU	12.5	11425	10538	1.09	92.41
Mobile Energy Services LLC	50407_B_8RB	O/G Steam	SOU	13.2	11425	10538	1.06	92.41
Chester Operations	50410_B_10	Coal Steam	MACE	36.0	10331	8300	1.24	85.26
Olmsted Waste Energy	50413_G_TG2	Municipal Solid Waste	MRO	1.3	19338	11773	1.38	63.34
Olmsted Waste Energy	50413_G_TGI	Municipal Solid Waste	MRO	1.4	19338	11773	1.38	63.34
Bronx Zoo	50427_G_GEN1	IC Engine	NYC	0.50	11600	8700	1.29	89.24
Bronx Zoo	50427_G_GEN2	IC Engine	NYC	0.50	11600	8700	1.29	89.24
Bronx Zoo	50427_G_GEN3	IC Engine	NYC	1.1	11600	8700	1.29	89.24
Bronx Zoo	50427_G_GEN4	IC Engine	NYC	1.5	11600	8700	1.29	89.24
University of Michigan	50431_G_TG1	Combined Cycle	MECS	11.5	6920	5500	1.26	34.14
University of Michigan	50431_G_TG10	Combined Cycle	MECS	3.0	6920	5500	1.26	34.14
University of Michigan	50431_G_TG7	Combined Cycle	MECS	11.5	6920	5500	1.26	34.14
University of Michigan	50431_G_TG8	Combined Cycle	MECS	11.5	6920	5500	1.26	34.14
University of Michigan	50431_G_TG9	Combined Cycle	MECS	3.0	6920	5500	1.26	34.14

S D Warren Westbrook	50447_B_17	O/G Steam	NENG	11.9	11844	9021	1.28	86.60
S D Warren Westbrook	50447_B_18	O/G Steam	NENG	11.9	11844	9021	1.28	86.60
S D Warren Westbrook	50447_B_20	Biomass	NENG	11.9	15517	8300	1.87	64.60
S D Warren Westbrook	50447_B_21	Biomass	NENG	26.9	15517	8300	1.89	83.00
Indeck Silver Springs Energy Center	50449_G_GEN1	Combined Cycle	UPNY	33.7	8890	8270	1.00	84.63
Indeck Silver Springs Energy Center	50449_G_GEN2	Combined Cycle	UPNY	17.2	8890	8270	1.00	84.63
Indeck Oswego Energy Center	50450_G_GEN1	Combined Cycle	UPNY	30.1	9250	8370	1.03	15.00
Indeck Oswego Energy Center	50450_G_GEN2	Combined Cycle	UPNY	16.2	9250	8370	1.03	15.00
Indeck Yerkes Energy Center	50451_G_GEN1	Combined Cycle	UPNY	29.0	9870	9325	1.01	15.00
Indeck Yerkes Energy Center	50451_G_GEN2	Combined Cycle	UPNY	19.4	9870	9325	1.01	15.00
Indeck Corinth Energy Center	50458_G_GEN1	Combined Cycle	DSNY	76.5	8030	7996	1.00	84.63
Indeck Corinth Energy Center	50458_G_GEN2	Combined Cycle	DSNY	55.0	8030	7996	1.00	84.63
Oxnard	50464_G_GEN1	Combustion Turbine	CA-S	21.5	15981	8700	1.82	89.87
Oxnard	50464_G_GEN2	Combustion Turbine	CA-S	45.0	15981	8700	1.82	89.87
American Ref-Fuel of Niagara	50472_B_BLR1	O/G Steam	UPNY	9.0	11332	8300	1.39	92.41
American Ref-Fuel of Niagara	50472_B_BLR2	Biomass	UPNY	9.0	15517	8456	1.86	83.00
American Ref-Fuel of Niagara	50472_B_BLR3	Municipal Solid Waste	UPNY	9.0	19338	8300	1.96	80.91
American Ref-Fuel of Niagara	50472_B_BLR4	Municipal Solid Waste	UPNY	9.0	19338	8300	1.96	80.91
Corpus Christi	50475_G_GEN1	Combustion Turbine	ERCT	33.0	15981	8700	1.82	89.87
Bryant Sugar House	50483_B_B1	Biomass	FRCC	4.4	15517	8300	1.89	83.00
Bryant Sugar House	50483_B_B2	Biomass	FRCC	4.4	15517	8300	1.89	83.00
Bryant Sugar House	50483_B_B3	Biomass	FRCC	4.4	15517	8300	1.89	83.00
Bryant Sugar House	50483_B_B4	Biomass	FRCC	4.4	15517	8300	1.89	83.00
Bryant Sugar House	50483_B_B7	Biomass	FRCC	4.4	15517	8300	1.89	83.00
Bryant Sugar House	50483_B_B8	Biomass	FRCC	4.4	15517	8300	1.89	83.00
PPG Powerhouse C	50489_G_C1	Combined Cycle	ENTG	55.0	9939	9738	1.00	84.63
PPG Powerhouse C	50489_G_C2	Combined Cycle	ENTG	55.0	9939	9738	1.00	84.63
PPG Powerhouse C	50489_G_C3	Combined Cycle	ENTG	52.0	9939	9738	1.00	84.63
PPG Powerhouse C	50489_G_C4	Combined Cycle	ENTG	70.6	9939	9738	1.00	84.63
PPG Powerhouse C	50489_G_C5	Combined Cycle	ENTG	70.6	9939	9738	1.00	84.63
Gas Utilization Facility	50492_G_1	Non-Fossil Waste	CA-S	2.3	13102	8700	1.47	82.98
Gas Utilization Facility	50492_G_2	Non-Fossil Waste	CA-S	2.3	13102	8700	1.47	82.98
Double C	50493_G_DC1	Combustion Turbine	CA-N	23.0	14379	8700	1.65	89.87
Double C	50493_G_DC2	Combustion Turbine	CA-N	23.0	14379	8700	1.65	89.87
Kern Front	50494_G_KF1	Combustion Turbine	CA-N	23.0	15423	8700	1.77	89.87
Kern Front	50494_G_KF2	Combustion Turbine	CA-N	23.0	15423	8700	1.77	89.87
High Sierra	50495_G_HS1	Combustion Turbine	CA-N	23.0	15410	8700	1.77	89.87
High Sierra	50495_G_HS2	Combustion Turbine	CA-N	23.0	15410	8700	1.77	89.87
Bayonne Cogen Plant	50497_G_GTG1	Combined Cycle	MACE	36.0	9300	5634	1.64	15.00
Bayonne Cogen Plant	50497_G_GTG2	Combined Cycle	MACE	36.0	9300	5634	1.64	15.00
Bayonne Cogen Plant	50497_G_GTG3	Combined Cycle	MACE	36.0	9300	5634	1.64	15.00

Bayonne Cogen Plant	50497_G_STG1	Combined Cycle	MACE	62.0	9300	5634	1.64	15.00
Capital District Energy Center	50498_G_GTG	Combined Cycle	NENG	34.3	9200	9545	1.00	84.63
Capital District Energy Center	50498_G_STG	Combined Cycle	NENG	21.0	9200	9545	1.00	84.63
Mosaic Co Mulberry Facility	50510_G_CGN1	Non-Fossil Waste	FRCC	19.5	13102	Retired		0.00
SRI International Cogen Project	50537_G_GEN1	Combustion Turbine	CA-N	5.6	15981	8700	1.82	89.24
Black Hills Ontario Facility	50538_G_GEN1	Combustion Turbine	CA-S	4.5	15981	Retired		0.00
Black Hills Ontario Facility	50538_G_GEN2	Combustion Turbine	CA-S	4.5	15981	Retired		0.00
Rosemary Power Station	50555_G_GEN1	Combined Cycle	VAPW	75.0	8900	9911	1.00	84.63
Rosemary Power Station	50555_G_GEN2	Combined Cycle	VAPW	36.0	8900	9911	1.00	84.63
Rosemary Power Station	50555_G_GEN3	Combined Cycle	VAPW	54.0	8900	9911	1.00	84.63
PowerSmith Cogeneration Project	50558_G_GT01	Combined Cycle	SPPS	67.3	7272	8009	1.08	47.06
PowerSmith Cogeneration Project	50558_G_ST01	Combined Cycle	SPPS	44.1	7272	8009	1.08	47.06
Eagle Point Cogeneration	50561_G_GTG1	Combined Cycle	MACE	75.0	7933	7942	1.00	84.63
Eagle Point Cogeneration	50561_G_GTG2	Combined Cycle	MACE	75.0	7933	7942	1.00	84.63
Eagle Point Cogeneration	50561_G_STG1	Combined Cycle	MACE	45.0	7933	7942	1.00	84.63
McKittrick Cogen	50612_G_GEN1	Combustion Turbine	CA-N	46.0	15073	8700	1.73	89.87
TXU Sweetwater Generating Plant	50615_G_GT01	Combined Cycle	ERCT	32.0	13157	13157	1.00	84.63
TXU Sweetwater Generating Plant	50615_G_GT02	Combined Cycle	ERCT	72.0	13157	13157	1.00	84.63
TXU Sweetwater Generating Plant	50615_G_GT03	Combined Cycle	ERCT	72.0	13157	13157	1.00	84.63
TXU Sweetwater Generating Plant	50615_G_STG1	Combined Cycle	ERCT	64.0	13157	13157	1.00	84.63
Berry Cogen Tanne Hills 18	50622_G_GEN1	Combustion Turbine	CA-N	7.0	15899	8700	1.83	89.24
Berry Cogen Tanne Hills 18	50622_G_GEN2	Combustion Turbine	CA-N	7.0	15899	8700	1.83	89.24
Gaviota Oil Plant	50623_G_GENA	Combustion Turbine	CA-S	3.0	15981	8700	1.82	89.24
Gaviota Oil Plant	50623_G_GENB	Combustion Turbine	CA-S	3.0	15981	8700	1.82	89.24
Gaviota Oil Plant	50623_G_GENC	Combustion Turbine	CA-S	3.0	15981	8700	1.82	89.24
Gaviota Oil Plant	50623_G_GEND	Combustion Turbine	CA-S	3.0	15981	8700	1.82	89.24
ExxonMobil Beaumont Refinery	50625_B_22	Fossil Waste	ENTG	16.7	9107	8300	1.10	23.76
ExxonMobil Beaumont Refinery	50625_B_24	O/G Steam	ENTG	8.3	11425	11177	1.00	92.41
ExxonMobil Beaumont Refinery	50625_B_33	Fossil Waste	ENTG	37.5	9107	8300	1.10	23.76
ExxonMobil Beaumont Refinery	50625_B_34	Fossil Waste	ENTG	37.5	9107	8300	1.10	23.76
ExxonMobil Beaumont Refinery	50625_G_TG23	Combined Cycle	ENTG	38.6	7933	6377	1.25	84.63
ExxonMobil Beaumont Refinery	50625_G_TG24	Combined Cycle	ENTG	32.0	7933	6377	1.25	84.63
ExxonMobil Beaumont Refinery	50625_G_TG41	Combustion Turbine	ENTG	152	12435	8700	1.42	90.81
ExxonMobil Beaumont Refinery	50625_G_TG42	Combustion Turbine	ENTG	152	12435	8700	1.42	90.81
ExxonMobil Beaumont Refinery	50625_G_TG43	Combustion Turbine	ENTG	152	12435	8700	1.42	90.81
Covanta Marion Inc	50630_B_BLR1	Municipal Solid Waste	PNW	5.8	19338	16297	1.00	90.00
Covanta Marion Inc	50630_B_BLR2	Municipal Solid Waste	PNW	5.8	19338	16297	1.00	90.00
Mosaic Co Martlow Facility	50633_G_GEN1	Non-Fossil Waste	FRCC	36.0	13102	9854	1.30	74.23
Mosaic Co Martlow Facility	50633_G_GEN2	Non-Fossil Waste	FRCC	44.0	13102	9854	1.30	74.23
Potlatch Idaho Pulp Paper	50637_B_1PWR	O/G Steam	PNW	1.4	14789	12156	1.17	89.51
Potlatch Idaho Pulp Paper	50637_B_2PWR	O/G Steam	PNW	1.4	14789	12156	1.17	89.51

Potlatch Idaho Pulp Paper	50637_B_4PWR	Biomass	PNW	27.2	15517	12152	1.29	83.00
Potlatch Idaho Pulp Paper	50637_B_4REC	O/G Steam	PNW	1.6	11332	11511	1.00	89.51
Potlatch Idaho Pulp Paper	50637_B_5REC	Non-Fossil Waste	PNW	32.2	13102	12147	1.05	57.86
Sierra Pacific Quincy Facility	50112_B_BLR2	Biomass	CA-N	14.4	15517	8300	1.89	83.00
Covanta Indianapolis Energy	50647_G_GEN1	Municipal Solid Waste	RFCO	5.0	19338	8300	1.96	88.41
Trigen Syracuse Energy	50651_B_1	Coal Steam	UPNY	11.1	10000	8300	1.20	41.00
Trigen Syracuse Energy	50651_B_2	Coal Steam	UPNY	11.1	10331	8300	1.24	41.00
Trigen Syracuse Energy	50651_B_3	Coal Steam	UPNY	11.1	10331	8300	1.24	41.00
Trigen Syracuse Energy	50651_B_4	Coal Steam	UPNY	11.1	10331	8300	1.24	41.00
Trigen Syracuse Energy	50651_B_5	Coal Steam	UPNY	11.1	10331	8300	1.24	41.00
Trigen Syracuse Energy	50651_G_GEN2	Coal Steam	UPNY	11.0	10000	8300	1.20	41.00
Thermo Power & Electric	50676_G_GEN1	Combined Cycle	RMPA	30.0	8650	6245	1.68	20.09
Thermo Power & Electric	50676_G_GEN2	Combined Cycle	RMPA	30.0	8650	6245	1.68	20.09
Thermo Power & Electric	50676_G_GEN3	Combined Cycle	RMPA	8.0	8650	6245	1.68	20.09
KMS Crossroads	50693_G_DG-1	IC Engine	MACE	7.0	10100	10100	1.00	89.24
TCP 272	50707_G_LMA	Combined Cycle	RMPA	31.8	9400	9503	1.00	84.63
TCP 272	50707_G_LMB	Combined Cycle	RMPA	31.8	9400	9503	1.00	84.63
TCP 272	50707_G_LMC	Combined Cycle	RMPA	31.8	9400	9503	1.00	84.63
TCP 272	50707_G_LMD	Combined Cycle	RMPA	31.8	9400	9503	1.00	84.63
TCP 272	50707_G_LME	Combined Cycle	RMPA	31.8	9400	9503	1.00	84.63
TCP 272	50707_G_STA	Combined Cycle	RMPA	52.0	9400	9503	1.00	84.63
TCP 272	50707_G_STB	Combined Cycle	RMPA	52.0	9400	9503	1.00	84.63
Thermo Greeley	50709_G_GEN1	Combustion Turbine	RMPA	37.0	14104	8700	1.62	89.87
BP Naperville Cogeneration Facility	50722_G_GEN1	Combustion Turbine	COMD	7.0	12503	12477	1.00	89.24
Sterling Power Plant	50744_G_GEN1	Combined Cycle	UPNY	38.8	8968	8247	1.03	15.00
Sterling Power Plant	50744_G_GEN2	Combined Cycle	UPNY	16.0	8968	8247	1.03	15.00
Agnews Power Plant	50748_G_GEN1	Combined Cycle	CA-N	23.0	8944	7884	1.08	83.51
Agnews Power Plant	50748_G_GEN2	Combined Cycle	CA-N	7.3	8944	7884	1.08	83.51
Coalinga Cogeneration Facility	50750_G_GEN1	Combustion Turbine	CA-N	3.2	15981	8700	1.82	89.24
Coalinga Cogeneration Facility	50750_G_GEN2	Combustion Turbine	CA-N	3.2	15981	8700	1.82	89.24
Southeast Kern River Cogen	50751_G_GTG1	Combustion Turbine	CA-N	20.5	15981	8700	1.82	89.73
Southeast Kern River Cogen	50751_G_GTG2	Combustion Turbine	CA-N	3.0	15981	8700	1.82	89.73
Southeast Kern River Cogen	50751_G_GTG3	Combustion Turbine	CA-N	3.0	15981	8700	1.82	89.73
Viking Energy of Northumberland	50771_B_B1	Biomass	MACW	16.0	15517	14500	1.08	83.00
EFS Parlin	50799_G_GT1	Combined Cycle	MACE	38.0	10500	7942	1.00	84.63
EFS Parlin	50799_G_GT2	Combined Cycle	MACE	38.0	10500	7942	1.00	84.63
EFS Parlin	50799_G_STG1	Combined Cycle	MACE	25.0	10500	7942	1.00	84.63
EFS Parlin	50799_G_STG2	Combined Cycle	MACE	25.0	10500	7942	1.00	84.63
Stone Container Florence Mill	50806_B_PB1	O/G Steam	VACA	5.6	11844	8300	1.39	89.51
Stone Container Florence Mill	50806_B_PB3	Biomass	VACA	7.6	15517	8300	1.89	83.00
Stone Container Florence Mill	50806_B_PB4	Coal Steam	VACA	74.8	10331	8300	1.24	85.26

Stone Container Florence Mill	50806_B_RBF	O/G Steam	VACA	15.3	11844	8300	1.39	89.51
Stone Container Hopewell Mill	50813_B_CB1	Biomass	VAPW	20.4	15517	8300	1.89	83.00
Stone Container Hopewell Mill	50813_B_RB1	Non-Fossil Waste	VAPW	20.4	13102	8300	1.54	67.40
CoGen Lyondell	50815_G_GEN1	Combined Cycle	ERCT	64.0	9500	9486	1.27	76.54
CoGen Lyondell	50815_G_GEN2	Combined Cycle	ERCT	64.0	9500	9486	1.27	76.54
CoGen Lyondell	50815_G_GEN3	Combined Cycle	ERCT	64.0	9500	9486	1.27	76.54
CoGen Lyondell	50815_G_GEN4	Combined Cycle	ERCT	64.0	9500	9486	1.27	76.54
CoGen Lyondell	50815_G_GEN5	Combined Cycle	ERCT	64.0	9500	9486	1.27	76.54
CoGen Lyondell	50815_G_GEN6	Combined Cycle	ERCT	64.0	9500	9486	1.27	76.54
CoGen Lyondell	50815_G_GEN7	Combined Cycle	ERCT	64.0	9500	9486	1.27	76.54
TES Filer City Station	50835_B_1	Coal Steam	MECS	30.0	11308	11308	1.00	93.30
TES Filer City Station	50835_B_2	Coal Steam	MECS	30.0	10331	10320	1.00	93.30
Southeast Resource Recovery	50837_B_UNIT1	Municipal Solid Waste	CA-S	9.3	19338	16297	1.00	90.00
Southeast Resource Recovery	50837_B_UNIT2	Municipal Solid Waste	CA-S	9.3	19338	16297	1.00	90.00
Southeast Resource Recovery	50837_B_UNIT3	Municipal Solid Waste	CA-S	9.3	19338	16297	1.00	90.00
Weir Cogen Plant	50848_G_GT1	Combustion Turbine	CA-N	3.2	15981	15845	1.00	89.24
PE Berkeley	50849_G_GEN1	Combined Cycle	CA-N	21.0	9939	5500	1.77	84.63
PE Berkeley	50849_G_GEN2	Combined Cycle	CA-N	2.0	9939	5500	1.77	84.63
OLS Energy Chino	50850_G_GEN1	Combined Cycle	CA-S	22.5	8650	7132	1.18	84.63
OLS Energy Chino	50850_G_GEN2	Combined Cycle	CA-S	6.5	8650	7132	1.18	84.63
OLS Energy Camarillo	50851_G_GEN1	Combined Cycle	CA-S	21.5	8580	7828	1.03	84.63
OLS Energy Camarillo	50851_G_GEN2	Combined Cycle	CA-S	6.8	8580	7828	1.03	84.63
RPL Holdings	50852_G_GEN1	Combined Cycle	MACE	51.0	10000	11652	1.00	84.63
RPL Holdings	50852_G_GEN2	Combined Cycle	MACE	13.9	10000	11652	1.00	84.63
Onondaga Cogeneration	50855_G_GEN1	Combined Cycle	UPNY	45.0	9188	Retired		0.00
Onondaga Cogeneration	50855_G_GEN2	Combined Cycle	UPNY	25.0	9188	Retired		0.00
Onondaga Cogeneration	50855_G_GEN3	Combined Cycle	UPNY	23.0	9188	Retired		0.00
Kent County Waste to Energy Facility	50860_B_BLR1	Municipal Solid Waste	MECS	7.9	19338	16297	1.00	90.00
Kent County Waste to Energy Facility	50860_B_BLR2	Municipal Solid Waste	MECS	7.9	19338	16297	1.00	90.00
Sargent Canyon Cogeneration	50864_G_K100	Combustion Turbine	CA-N	30.0	14996	8700	1.72	89.87
Salinas River Cogeneration	50865_G_K100	Combustion Turbine	CA-N	33.0	15001	8700	1.72	89.87
Wheelabrator Sherman Energy Facility	50874_B_19425	Biomass		21.0	Not in dB	15716	1.00	83.00
Wheelabrator Norwalk Energy	50876_G_GEN1	Combined Cycle	CA-S	19.8	9280	7870	1.20	39.95
Wheelabrator Norwalk Energy	50876_G_GEN2	Combined Cycle	CA-S	6.6	9280	7870	1.20	39.95
Wheelabrator Frackville Energy	50879_B_BLR1	Coal Steam	MACW	44.5	11503	9282	1.24	95.00
Wheelabrator Gloucester LP	50885_B_BLR1	Municipal Solid Waste		6.00	Not in dB	16297	1.00	90.00
Wheelabrator Gloucester LP	50885_B_BLR2	Municipal Solid Waste		6.00	Not in dB	16297	1.00	90.00
Northampton Generating Company	50888_B_BLR1	Coal Steam	MACW	112	12174	11336	1.07	89.30
Oswego County Energy Recovery	50907_G_UNT1	Municipal Solid Waste	UPNY	1.7	19338	8300	1.96	80.91
Oswego County Energy Recovery	50907_G_UNT2	Municipal Solid Waste	UPNY	1.7	19338	8300	1.96	80.91
Potlatch Southern Wood Products	50640_B_BLR1	Biomass	ENTG	10.0	15517	8300	1.89	83.00

Yellowstone Energy LP	50931_B_BLR1	Coal Steam	NWPE	27.5	14500	11122	1.30	85.26
Yellowstone Energy LP	50931_B_BLR2	Coal Steam	NWPE	27.5	10331	10320	1.00	85.26
Watsonville Power Plant	50968_G_GEN1	Combined Cycle	CA-N	22.0	11693	7636	1.12	64.66
Watsonville Power Plant	50968_G_GEN2	Combined Cycle	CA-N	6.9	11693	7636	1.12	64.66
Indiantown Cogeneration LP	50976_B_AAB01	Coal Steam	FRCC	330	9200	9200	1.00	74.13
Pryor Power Plant	50991_G_GEN1	Combustion Turbine	SPPS	17.5	12503	Retired		0.00
Pryor Power Plant	50991_G_GEN2	Combustion Turbine	SPPS	17.5	12503	Retired		0.00
Pryor Power Plant	50991_G_GN10	O/G Steam	SPPS	13.0	14789	Retired		0.00
STEC-S LLC	56079_B_North	Biomass	ENTG	2.0	15517	14500	1.08	83.00
North Shore Towers	52052_G_GEN1	IC Engine	NYC	1.1	13298	8700	1.52	89.24
North Shore Towers	52052_G_GEN2	IC Engine	NYC	1.1	13298	8700	1.52	89.24
North Shore Towers	52052_G_GEN3	IC Engine	NYC	1.1	13298	8700	1.52	89.24
North Shore Towers	52052_G_GEN4	IC Engine	NYC	1.1	13298	8700	1.52	89.24
North Shore Towers	52052_G_GEN5	IC Engine	NYC	1.1	13298	8700	1.52	89.24
North Shore Towers	52052_G_GEN6	IC Engine	NYC	1.1	13298	8700	1.52	89.24
Trigen Nassau Energy	52056_G_GT1	Combined Cycle	LILC	43.0	7492	6231	1.55	84.63
Trigen Nassau Energy	52056_G_ST1	Combined Cycle	LILC	12.0	7492	6231	1.55	84.63
Rhodia Dominguez Plant	52064_G_GEN1	O/G Steam	CA-S	3.0	11332	8300	1.39	92.45
Rhodia Houston Plant	52065_G_GEN1	Non-Fossil Waste	ERCT	6.0	13102	8300	1.54	89.10
Rhodia Houston Plant	52065_G_GEN2	Non-Fossil Waste	ERCT	1.5	13102	8300	1.54	89.10
McKittrick Cogen	52076_G_GEN1	Combustion Turbine	CA-N	2.9	15981	8700	1.82	89.24
McKittrick Cogen	52076_G_GEN2	Combustion Turbine	CA-N	2.9	15981	8700	1.82	89.24
McKittrick Cogen	52076_G_GEN3	Combustion Turbine	CA-N	2.9	15981	8700	1.82	89.24
North Midway Cogen	52078_G_GEN7	Combustion Turbine	CA-N	2.9	15981	8700	1.82	89.24
North Midway Cogen	52078_G_GEN8	Combustion Turbine	CA-N	2.9	15981	8700	1.82	89.24
North Midway Cogen	52078_G_GEN9	Combustion Turbine	CA-N	2.9	15981	8700	1.82	89.24
Concord Cogen	52080_G_1605	IC Engine	CA-N	1.5	13298	10526	1.25	89.24
Concord Cogen	52080_G_1606	IC Engine	CA-N	1.5	13298	10526	1.25	89.24
Cymric 31X Cogen	52081_G_TG1	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Cymric 31X Cogen	52081_G_TG2	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Cymric 6Z Cogen	52082_G_TG1	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Cymric 6Z Cogen	52082_G_TG2	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Coalinga 6C Cogen	52083_G_TG1	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Coalinga 6C Cogen	52083_G_TG2	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Taft 26C Cogen	52085_G_TG1	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Taft 26C Cogen	52085_G_TG2	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Taft 26C Cogen	52085_G_TG3	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Taft 26C Cogen	52085_G_TG4	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Coalinga 25D Cogen	52086_G_TG1	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Coalinga 25D Cogen	52086_G_TG2	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Coalinga 25D Cogen	52086_G_TG3	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24

Coalinga 25D Cogen	52086_G_TG4	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Texas City Power Plant	52088_G_GEN1	Combined Cycle	ERCT	139	10299	6319	1.49	42.30
Texas City Power Plant	52088_G_GEN2	Combined Cycle	ERCT	104	10299	6319	1.49	42.30
Texas City Power Plant	52088_G_GEN3	Combined Cycle	ERCT	104	10299	6319	1.49	42.30
Texas City Power Plant	52088_G_GEN4	Combined Cycle	ERCT	104	10299	6319	1.49	42.30
New York Methodist Hospital	52091_G_3A	IC Engine	NYC	0.70	12870	8700	1.48	89.24
New York Methodist Hospital	52091_G_4C	IC Engine	NYC	0.70	12870	8700	1.48	89.24
Oxford Cogeneration Facility	52093_G_GEN1	Combustion Turbine	CA-N	2.4	15981	15845	1.00	89.24
Oxford Cogeneration Facility	52093_G_GEN2	Combustion Turbine	CA-N	2.4	15981	15845	1.00	89.24
Kern River Fee A Cogen	52094_G_GEN1	Combustion Turbine	CA-S	3.2	15981	8700	1.82	89.24
Kern River Fee A Cogen	52094_G_GEN2	Combustion Turbine	CA-S	3.2	15981	8700	1.82	89.24
Kern River Fee C Cogen	52095_G_GEN1	Combustion Turbine	CA-S	3.6	15981	8700	1.82	89.24
Kern River Fee C Cogen	52095_G_GEN2	Combustion Turbine	CA-S	3.2	15981	8700	1.82	89.24
Berry Placerita Cogen	52096_G_GEN1	Combustion Turbine	CA-S	19.6	12503	8700	1.43	89.87
Berry Placerita Cogen	52096_G_GEN2	Combustion Turbine	CA-S	19.6	12503	8700	1.43	89.87
Cymric 36W Cogen	52104_G_GEN1	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Cymric 36W Cogen	52104_G_GEN2	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Cymric 36W Cogen	52104_G_GEN3	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Cymric 36W Cogen	52104_G_GEN4	Combustion Turbine	CA-N	2.7	15981	8700	1.82	89.24
Kern River Eastridge Cogen	52107_G_101A	Combustion Turbine	CA-N	21.0	15981	8700	1.82	89.87
Kern River Eastridge Cogen	52107_G_101B	Combustion Turbine	CA-N	21.0	15981	8700	1.82	89.87
C P Kelco San Diego Plant	52147_G_GEN1	Combustion Turbine	CA-S	8.0	15981	8700	1.82	89.24
C P Kelco San Diego Plant	52147_G_GEN2	Combustion Turbine	CA-S	9.3	15981	8700	1.82	89.24
C P Kelco San Diego Plant	52147_G_GEN3	Combustion Turbine	CA-S	9.3	15981	8700	1.82	89.24
Midway Sunset Cogen	52169_G_A	Combustion Turbine	CA-N	73.0	15981	8700	1.82	90.81
Midway Sunset Cogen	52169_G_B	Combustion Turbine	CA-N	73.0	15981	8700	1.82	90.81
Midway Sunset Cogen	52169_G_C	Combustion Turbine	CA-N	73.0	15981	8700	1.82	90.81
C R Wing Cogen Plant	52176_G_GEN1	Combined Cycle	ERCT	76.0	8982	7718	1.11	31.59
C R Wing Cogen Plant	52176_G_GEN2	Combined Cycle	ERCT	76.0	8982	7718	1.11	31.59
C R Wing Cogen Plant	52176_G_GEN3	Combined Cycle	ERCT	75.0	8982	7718	1.11	31.59
Yuba City Cogen Partners	52186_G_GEN1	Combustion Turbine	CA-N	48.7	15256	8700	1.75	89.87
Delaware City Plant	52193_G_CT1	Fossil Waste	MACE	101	9107	9107	1.00	90.00
Delaware City Plant	52193_G_CT2	Fossil Waste	MACE	92.0	9107	9107	1.00	90.00
Delaware City Plant	52193_G_G1	Fossil Waste	MACE	29.5	9107	9107	1.00	90.00
Delaware City Plant	52193_G_G2	Fossil Waste	MACE	29.5	9107	9107	1.00	90.00
JRW Associates LP	52198_G_GEN1	O/G Steam	CA-N	1.1	11425	11177	1.00	92.45
JRW Associates LP	52198_G_GEN2	O/G Steam	CA-N	1.1	11425	11177	1.00	92.45
JRW Associates LP	52198_G_GEN3	IC Engine	CA-N	1.1	11600	8700	1.29	89.24
JRW Associates LP	52198_G_GEN4	IC Engine	CA-N	1.1	11600	8700	1.29	89.24
JRW Associates LP	52198_G_GEN5	IC Engine	CA-N	1.1	11600	8700	1.29	89.24
JRW Associates LP	52198_G_GEN6	IC Engine	CA-N	1.1	11600	8700	1.29	89.24

JRW Associates LP	52198_G_GEN7	IC Engine	CA-N	1.1	11600	8700	1.29	89.24
JRW Associates LP	52198_G_GEN8	IC Engine	CA-N	1.1	11600	8700	1.29	89.24
Ridgewood/Byron Power Partners	52199_G_GEN1	IC Engine	CA-N	1.1	13776	12672	1.09	89.24
Ridgewood/Byron Power Partners	52199_G_GEN2	IC Engine	CA-N	1.1	13776	12672	1.09	89.24
Ridgewood/Byron Power Partners	52199_G_GEN3	IC Engine	CA-N	1.1	13776	12672	1.09	89.24
Ridgewood/Byron Power Partners	52199_G_GEN4	IC Engine	CA-N	1.1	13776	12672	1.09	89.24
Ridgewood/Byron Power Partners	52199_G_GEN5	IC Engine	CA-N	1.1	13776	12672	1.09	89.24
Sunnyside Cogen Partners	52201_G_GEN1	IC Engine	CA-N	1.1	11303	11303	1.00	89.24
Sunnyside Cogen Partners	52201_G_GEN2	IC Engine	CA-N	1.1	11303	11303	1.00	89.24
Sunnyside Cogen Partners	52201_G_GEN3	IC Engine	CA-N	1.1	11303	11303	1.00	89.24
Sunnyside Cogen Partners	52201_G_GEN4	IC Engine	CA-N	1.1	11303	11303	1.00	89.24
Sunnyside Cogen Partners	52201_G_GEN5	IC Engine	CA-N	1.1	11303	11303	1.00	89.24
Pittsburg Power Plant	54001_G_GEN1	Combustion Turbine	CA-N	16.5	9939	8700	1.14	27.74
Pittsburg Power Plant	54001_G_GEN2	Combustion Turbine	CA-N	22.0	9939	8700	1.14	27.74
Pittsburg Power Plant	54001_G_GEN3	Combustion Turbine	CA-N	22.0	9939	8700	1.14	27.74
Westmoreland Roanoke Valley I	54035_B_BLR1	Coal Steam	VAPW	165	10370	9109	1.14	90.70
Lockport Energy Associates LP	54041_G_GEN1	Combined Cycle	UPNY	45.0	9091	7428	1.16	47.49
Lockport Energy Associates LP	54041_G_GEN2	Combined Cycle	UPNY	45.0	9091	7428	1.16	47.49
Lockport Energy Associates LP	54041_G_GEN3	Combined Cycle	UPNY	45.0	9091	7428	1.16	47.49
Lockport Energy Associates LP	54041_G_GEN4	Combined Cycle	UPNY	75.2	9091	7428	1.16	47.49
Wythe Park Power Petersburg Plant	54045_G_1	Fossil Waste	VAPW	3.0	12320	9316	1.32	6.17
Wythe Park Power 3 Richmond Plant	54047_G_EXIS	IC Engine	VAPW	3.0	12283	9000	1.36	89.24
Pawtucket Power Associates	54056_G_GEN1	Combined Cycle	NENG	36.0	8950	8908	1.00	84.63
Pawtucket Power Associates	54056_G_GEN2	Combined Cycle	NENG	27.0	8950	8908	1.00	84.63
Indeck Olean Energy Center	54076_G_GEN1	Combined Cycle	UPNY	31.9	8740	8626	1.00	84.63
Indeck Olean Energy Center	54076_G_GEN2	Combined Cycle	UPNY	44.6	8740	8626	1.00	84.63
Cogentrix of Richmond	54081_B_1A	Coal Steam	VAPW	26.3	11303	9258	1.22	71.07
Cogentrix of Richmond	54081_B_1B	Coal Steam	VAPW	26.3	10331	9258	1.11	71.07
Cogentrix of Richmond	54081_B_2A	Coal Steam	VAPW	26.3	11303	9258	1.22	71.07
Cogentrix of Richmond	54081_B_2B	Coal Steam	VAPW	26.3	10331	9258	1.11	71.07
Cogentrix of Richmond	54081_B_3A	Coal Steam	VAPW	21.3	11300	9258	1.22	71.07
Cogentrix of Richmond	54081_B_3B	Coal Steam	VAPW	21.3	10331	9258	1.11	71.07
Cogentrix of Richmond	54081_B_4A	Coal Steam	VAPW	21.3	11300	9258	1.22	71.07
Cogentrix of Richmond	54081_B_4B	Coal Steam	VAPW	21.3	10331	9258	1.11	71.07
Kennedy International Airport Cogen	54114_G_GEN1	Combined Cycle	NYC	49.0	10315	8033	1.28	49.51
Kennedy International Airport Cogen	54114_G_GEN2	Combined Cycle	NYC	50.3	10315	8033	1.28	49.51
Kennedy International Airport Cogen	54114_G_GEN3	Combined Cycle	NYC	27.0	10315	8033	1.28	49.51
Fortistar North Tonawanda	54131_G_GEN1	Combined Cycle	UPNY	40.4	7800	7815	1.15	15.00
Fortistar North Tonawanda	54131_G_GEN2	Combined Cycle	UPNY	16.3	7800	7815	1.15	15.00
Fulton Cogeneration Associates	54138_G_GTG	Combustion Turbine	UPNY	42.0	12503	12477	1.00	89.87
Stony Brook Cogen Plant	54149_G_GEN1	Combustion Turbine	LILC	44.5	12082	8700	1.39	89.87

Franklin Heating Station	54224_B_GEN6	Coal Steam	MRO	2.8	10331	10320	1.00	85.26
Franklin Heating Station	54224_B_SG1	O/G Steam	MRO	1	14789	8300	1.72	89.51
Franklin Heating Station	54224_B_SG2	O/G Steam	MRO	1	14789	8300	1.72	89.51
Franklin Heating Station	54224_B_SG3	O/G Steam	MRO	4.1	14789	8300	1.72	89.51
Franklin Heating Station	54224_B_SG4	O/G Steam	MRO	4.1	14789	8300	1.72	89.51
Franklin Heating Station	54224_G_EG1	IC Engine	MRO	2.0	12334	12062	1.00	89.24
Franklin Heating Station	54224_G_EG2	IC Engine	MRO	2.0	12334	12062	1.00	89.24
Franklin Heating Station	54224_G_EG3	IC Engine	MRO	2.0	12334	12062	1.00	89.24
Port of Stockton District Energy Fac	54238_B_N64514	Coal Steam	CA-N	22.0	11465	11465	1.00	69.73
Port of Stockton District Energy Fac	54238_B_N64516	Coal Steam	CA-N	22.0	10331	10320	1.00	69.73
March Point Cogeneration	54268_G_GTG1	Combined Cycle	PNW	39.6	11500	6096	1.82	58.62
March Point Cogeneration	54268_G_GTG2	Combined Cycle	PNW	40.0	11500	6096	1.82	58.62
March Point Cogeneration	54268_G_GTG3	Combined Cycle	PNW	40.6	11500	6096	1.82	58.62
March Point Cogeneration	54268_G_STG1	Combined Cycle	PNW	26.0	11500	6096	1.82	58.62
Saguaro Power	54271_G_CTG1	Combined Cycle	SNV	35.0	9200	9200	1.00	84.63
Saguaro Power	54271_G_CTG2	Combined Cycle	SNV	35.0	9200	9200	1.00	84.63
Saguaro Power	54271_G_STG	Combined Cycle	SNV	22.0	9200	9200	1.00	84.63
Birchwood Power	54304_B_1A	Coal Steam	VAPW	239	10067	9669	1.04	65.54
Goodyear Beaumont Chemical Plant	54321_B_3B101	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_B_3B102	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_B_3B103	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_B_3B104	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_B_3B105	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_B_3B106	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_B_3B107	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_B_3B108	O/G Steam	ENTG	1.6	11425	8300	1.35	92.41
Goodyear Beaumont Chemical Plant	54321_G_2N80	Combustion Turbine	ENTG	4.0	12503	8700	1.43	89.24
Goodyear Beaumont Chemical Plant	54321_G_N802	Combustion Turbine	ENTG	4.0	12503	8700	1.43	89.24
Goodyear Beaumont Chemical Plant	54321_G_N803	Combustion Turbine	ENTG	4.0	12503	8700	1.43	89.24
Goodyear Beaumont Chemical Plant	54321_G_N804	Combustion Turbine	ENTG	4.0	12503	8700	1.43	89.24
Bucknell University	54333_G_G001	Combined Cycle	MACW	4.3	7933	7942	1.00	84.63
Bucknell University	54333_G_G502	Combined Cycle	MACW	0.50	7933	7942	1.00	84.63
Nevada Cogen Associates 2 Black Mountain	54349_G_GTA	Combined Cycle	SNV	21.7	7132	6600	1.36	84.63
Nevada Cogen Associates 2 Black Mountain	54349_G_GTB	Combined Cycle	SNV	21.7	7132	6600	1.36	84.63
Nevada Cogen Associates 2 Black Mountain	54349_G_GTC	Combined Cycle	SNV	21.7	7132	6600	1.36	84.63
Nevada Cogen Associates 2 Black Mountain	54349_G_STM	Combined Cycle	SNV	19.9	7132	6600	1.36	84.63
Nevada Cogen Assoc#1 GarnetVly	54350_G_GTA	Combined Cycle	SNV	21.7	10182	7316	1.22	84.63
Nevada Cogen Assoc#1 GarnetVly	54350_G_GTB	Combined Cycle	SNV	21.7	10182	7316	1.22	84.63
Nevada Cogen Assoc#1 GarnetVly	54350_G_GTC	Combined Cycle	SNV	21.7	10182	7316	1.22	84.63
Nevada Cogen Assoc#1 GarnetVly	54350_G_STM	Combined Cycle	SNV	19.9	10182	7316	1.22	84.63
Orange Cogeneration Facility	54365_G_APC1	Combined Cycle	FRCC	46.4	8999	7380	1.16	40.15

Orange Cogeneration Facility	54365_G_APC2	Combined Cycle	FRCC	46.4	8999	7380	1.16	40.15
Orange Cogeneration Facility	54365_G_APC3	Combined Cycle	FRCC	24.6	8999	7380	1.16	40.15
Oildale Cogen	54371_G_ODC1	Combustion Turbine	CA-N	39.0	16463	8700	1.89	89.87
University of Colorado	54372_G_GT1	Combined Cycle	RMPA	15.0	7933	7164	1.11	15.00
University of Colorado	54372_G_GT2	Combined Cycle	RMPA	15.0	7933	7164	1.11	15.00
University of Colorado	54372_G_ST1	Combined Cycle	RMPA	1	7933	7164	1.11	15.00
Southbridge Energy Center LLC	54373_G_ENG1	IC Engine	NENG	1.3	11600	9106	1.23	89.24
Southbridge Energy Center LLC	54373_G_ENG2	IC Engine	NENG	1.3	11600	9106	1.23	89.24
Southbridge Energy Center LLC	54373_G_ENG3	IC Engine	NENG	1.3	11600	9106	1.23	89.24
Southbridge Energy Center LLC	54373_G_ENG4	IC Engine	NENG	1.3	11600	9106	1.23	89.24
Southbridge Energy Center LLC	54373_G_ENG5	IC Engine	NENG	1.3	11600	9106	1.23	89.24
Capitol Heat and Power	54406_G_1	Coal Steam	WUMS	0.90	10331	8300	1.24	85.26
Capitol Heat and Power	54406_G_2	Coal Steam	WUMS	1	10331	8300	1.24	85.26
DAI Oildale	54410_G_CTG	Combined Cycle	CA-N	22.6	7933	7942	1.00	84.63
DAI Oildale	54410_G_STG	Combined Cycle	CA-N	7.3	7933	7942	1.00	84.63
Lake Cogen Ltd	54423_G_GT1	Combined Cycle	FRCC	41.5	7550	7447	1.14	49.56
Lake Cogen Ltd	54423_G_GT2	Combined Cycle	FRCC	41.5	7550	7447	1.14	49.56
Lake Cogen Ltd	54423_G_ST1	Combined Cycle	FRCC	27.0	7550	7447	1.14	49.56
Pasco Cogen Ltd	54424_G_GT1	Combined Cycle	FRCC	48.8	7701	7784	1.06	43.15
Pasco Cogen Ltd	54424_G_GT2	Combined Cycle	FRCC	48.8	7701	7784	1.06	43.15
Pasco Cogen Ltd	54424_G_ST1	Combined Cycle	FRCC	31.2	7701	7784	1.06	43.15
Project Orange Associates LP	54425_G_GT1	Combustion Turbine	UPNY	48.0	12503	8700	1.43	89.87
Project Orange Associates LP	54425_G_GT2	Combustion Turbine	UPNY	48.0	12503	8700	1.43	89.87
Mulberry Cogeneration Facility	54426_G_GT1	Combined Cycle	FRCC	76.0	8520	8104	1.02	41.67
Mulberry Cogeneration Facility	54426_G_ST1	Combined Cycle	FRCC	37.0	8520	8104	1.02	41.67
Alabama Pine Pulp	54429_B_PB2	Biomass	SOU	32.1	15517	8300	1.89	83.00
Alabama Pine Pulp	54429_B_RB2	Non-Fossil Waste	SOU	32.1	13102	8300	1.54	55.17
Rincon Facility	54445_G_GEN1	Combustion Turbine	CA-S	1.7	12503	Retired		0.00
Welport Lease Project	54447_G_TI	Combustion Turbine	CA-N	4.5	12503	8882	1.40	89.24
Dome Project	54449_G_T1	Combustion Turbine	CA-N	3.3	15981	8700	1.82	89.24
Dome Project	54449_G_T2	Combustion Turbine	CA-N	3.2	15981	8700	1.82	89.24
Orlando Cogen LP	54466_G_GEN1	Combined Cycle	FRCC	120	9960	7882	1.26	84.63
Sumas Power Plant	54476_G_GEN1	Combined Cycle	PNW	87.8	8120	7262	1.14	20.82
Sumas Power Plant	54476_G_GEN2	Combined Cycle	PNW	37.7	8120	7262	1.14	20.82
Oroville Cogeneration LP	54477_G_GEN1	IC Engine	CA-N	1.1	11600	11185	1.00	89.24
Oroville Cogeneration LP	54477_G_GEN2	IC Engine	CA-N	1.1	11600	11185	1.00	89.24
Oroville Cogeneration LP	54477_G_GEN3	IC Engine	CA-N	1.1	11600	11185	1.00	89.24
Oroville Cogeneration LP	54477_G_GEN4	IC Engine	CA-N	1.1	11600	11185	1.00	89.24
Oroville Cogeneration LP	54477_G_GEN5	IC Engine	CA-N	1.1	11600	11185	1.00	89.24
Oroville Cogeneration LP	54477_G_GEN6	IC Engine	CA-N	1.1	11600	11185	1.00	89.24
Oroville Cogeneration LP	54477_G_GEN7	IC Engine	CA-N	1.1	11600	11185	1.00	89.24

STEC-S LLC	56079_B_South	Biomass	ENTG	2.0	15517	14500	1.08	83.00
Formosa Plastics	54518_G_GT1	Combined Cycle	ENTG	33.0	8648	Retired		0.00
Formosa Plastics	54518_G_GT2	Combined Cycle	ENTG	33.0	8648	8582	1.00	84.63
Formosa Plastics	54518_G_GT3	Combined Cycle	ENTG	33.0	8648	8582	1.00	84.63
Formosa Plastics	54518_G_ST1	Combined Cycle	ENTG	8.0	8648	8582	1.00	84.63
Formosa Plastics	54518_G_ST2	Combined Cycle	ENTG	8.0	8648	8582	1.00	84.63
Lyonsdale Biomass LLC	54526_B_00001	Biomass	UPNY	19.0	15517	13201	1.19	83.00
Tenaska Ferndale Cogeneration Station	54537_G_CT1A	Combined Cycle	PNW	88.0	11260	7576	1.10	36.93
Tenaska Ferndale Cogeneration Station	54537_G_CT1B	Combined Cycle	PNW	88.0	11260	7576	1.10	36.93
Tenaska Ferndale Cogeneration Station	54537_G_ST1	Combined Cycle	PNW	95.0	11260	7576	1.10	36.93
Entenmanns Energy Center	54541_G_1	IC Engine	LILC	1.3	12703	8700	1.46	89.24
Entenmanns Energy Center	54541_G_2	IC Engine	LILC	1.3	12703	8700	1.46	89.24
Entenmanns Energy Center	54541_G_3	IC Engine	LILC	1.3	12703	8700	1.46	89.24
Entenmanns Energy Center	54541_G_4	IC Engine	LILC	1.3	12784	8700	1.47	89.24
Sithe Independence Station	54547_G_1	Combined Cycle	UPNY	144	7418	6984	1.12	33.74
Sithe Independence Station	54547_G_2	Combined Cycle	UPNY	144	7418	6984	1.12	33.74
Sithe Independence Station	54547_G_3	Combined Cycle	UPNY	144	7418	6984	1.12	33.74
Sithe Independence Station	54547_G_4	Combined Cycle	UPNY	144	7418	6984	1.12	33.74
Sithe Independence Station	54547_G_5	Combined Cycle	UPNY	204	7418	6984	1.12	33.74
Sithe Independence Station	54547_G_6	Combined Cycle	UPNY	204	7418	6984	1.12	33.74
ExxonMobil Mobile Bay Onshore	54550_G_901	Combined Cycle	SOU	0.90	7933	7942	1.00	84.63
ExxonMobil Mobile Bay Onshore	54550_G_901A	Combined Cycle	SOU	3.4	7933	7942	1.00	84.63
ExxonMobil Mobile Bay Onshore	54550_G_901B	Combined Cycle	SOU	3.4	7933	7942	1.00	84.63
ExxonMobil Mobile Bay Onshore	54550_G_901C	Combined Cycle	SOU	3.4	7933	7942	1.00	84.63
Jefferson Smurfit Santa Clara Mill	54561_G_GT-G	Combined Cycle	CA-N	23.0	9780	5764	1.72	84.63
Jefferson Smurfit Santa Clara Mill	54561_G_ST-G	Combined Cycle	CA-N	3.0	9780	5764	1.72	84.63
North East Cogeneration Plant	54571_G_GEN1	Combined Cycle	MACW	36.5	9163	6747	1.36	15.00
North East Cogeneration Plant	54571_G_GEN2	Combined Cycle	MACW	36.5	9163	6747	1.36	15.00
North East Cogeneration Plant	54571_G_GEN3	Combined Cycle	MACW	8.0	9163	6747	1.36	15.00
Saranac Facility	54574_G_GEN1	Combined Cycle	UPNY	78.0	8616	7399	1.19	84.63
Saranac Facility	54574_G_GEN2	Combined Cycle	UPNY	77.0	8616	7399	1.19	84.63
Saranac Facility	54574_G_GEN3	Combined Cycle	UPNY	85.0	8616	7399	1.19	84.63
Glenns Ferry Cogen Facility	54578_G_1001	Combined Cycle	PNW	10.4	9800	8470	1.00	84.68
Rupert Cogen Project	54579_G_1002	Combined Cycle	NWPE	10.4	9800	6324	1.27	71.01
Batavia Power Plant	54593_G_GEN1	Combined Cycle	UPNY	38.2	8771	7440	1.12	15.00
Batavia Power Plant	54593_G_GEN2	Combined Cycle	UPNY	17.5	8771	7440	1.12	15.00
Mt Poso Cogeneration	54626_B_BL01	Coal Steam	CA-N	52.0	11384	11299	1.19	83.00
Okeelanta Cogeneration	54627_B_A	Biomass	FRCC	25.0	15517	8904	1.77	83.00
Okeelanta Cogeneration	54627_B_B	Biomass	FRCC	25.0	15517	8904	1.77	83.00
Okeelanta Cogeneration	54627_B_C	Biomass	FRCC	25.0	15517	8904	1.77	83.00
Okeelanta Cogeneration	54627_G_GEN2	Biomass	FRCC	74.9	15517	8904	1.53	83.00

St Nicholas Cogen Project	54634_B_1	Coal Steam	MACW	87.9	10931	10931	1.00	95.00
JCO Oxides Olefins Plant	54637_G_GCG1	Combustion Turbine	ENTG	30.5	12503	8700	1.43	89.87
JCO Oxides Olefins Plant	54637_G_GCG2	Combustion Turbine	ENTG	30.5	12503	8700	1.43	89.87
Lakewood Cogen LP	54640_G_GEN1	Combined Cycle	MACE	78.0	8129	8129	1.00	84.63
Lakewood Cogen LP	54640_G_GEN2	Combined Cycle	MACE	78.0	8129	8129	1.00	84.63
Lakewood Cogen LP	54640_G_NA	Combined Cycle	MACE	83.0	8129	8129	1.00	84.63
Auburndale Power Partners	54658_G_CT	Combined Cycle	FRCC	105	8900	8302	1.06	48.82
Auburndale Power Partners	54658_G_ST	Combined Cycle	FRCC	49.6	8900	8302	1.06	48.82
Oyster Creek Unit VIII	54676_G_G81	Combined Cycle	ERCT	73.0	10000	9662	1.02	69.15
Oyster Creek Unit VIII	54676_G_G82	Combined Cycle	ERCT	73.0	10000	9662	1.02	69.15
Oyster Creek Unit VIII	54676_G_G83	Combined Cycle	ERCT	73.0	10000	9662	1.02	69.15
Oyster Creek Unit VIII	54676_G_G84	Combined Cycle	ERCT	160	10000	9662	1.02	69.15
CII Carbon LLC	54677_B_HRB	Coal Steam	ENTG	23.0	10331	10320	1.00	85.26
CII Carbon LLC	54677_G_TG-2	Coal Steam	ENTG	23.0	10331	10320	1.00	85.26
York Cogen Facility	54693_G_GT#1	Combined Cycle	MACW	6.9	9830	9830	1.00	84.63
York Cogen Facility	54693_G_GT#2	Combined Cycle	MACW	6.6	9830	9830	1.00	84.63
York Cogen Facility	54693_G_GT#5	Combined Cycle	MACW	6.9	9830	9830	1.00	84.63
York Cogen Facility	54693_G_GT#6	Combined Cycle	MACW	6.1	9830	9830	1.00	84.63
York Cogen Facility	54693_G_ST#1	Combined Cycle	MACW	7.2	9830	9830	1.00	84.63
York Cogen Facility	54693_G_ST#2	Combined Cycle	MACW	6.9	9830	9830	1.00	84.63
Yuma Cogeneration Associates	54694_G_GEN1	Combined Cycle	AZNM	35.1	8971	7604	1.14	80.86
Yuma Cogeneration Associates	54694_G_GEN2	Combined Cycle	AZNM	17.1	8971	7604	1.14	80.86
Hunterdon Cogen Facility	54707_G_1	Combustion Turbine	MACE	4.1	12503	8700	1.43	89.24
Montclair Cogen Facility	54708_G_1	Combustion Turbine	MACE	3.7	12503	8700	1.43	89.24
Port Neches Plant	54748_G_G1	Combustion Turbine	ENTG	32.0	12503	8700	1.43	89.87
Goal Line LP	54749_G_CTG	Combined Cycle	CA-S	40.0	9182	7724	1.02	74.62
Goal Line LP	54749_G_STG	Combined Cycle	CA-S	9.4	9182	7724	1.02	74.62
Westmoreland Roanoke Valley II	54755_B_BLR2	Coal Steam	VAPW	44.0	11346	9515	1.19	91.60
Hermiston Generating Plant	54761_G_GEN1	Combined Cycle	PNW	80.0	11182	7322	1.00	84.68
Hermiston Generating Plant	54761_G_GEN2	Combined Cycle	PNW	152	11182	7322	1.00	84.68
Hermiston Generating Plant	54761_G_GEN3	Combined Cycle	PNW	80.0	11182	7322	1.00	84.68
Hermiston Generating Plant	54761_G_GEN4	Combined Cycle	PNW	152	11182	7322	1.00	84.68
Boydton Plank Road Cogen Plant	54766_G_GEN1	Fossil Waste	VAPW	3.0	11036	11036	1.00	90.00
Live Oak Cogen	54768_G_GEN1	Combustion Turbine	CA-N	46.0	15065	8700	1.73	89.87
University of Iowa Main Power Plant	54775_B_BLR10	Coal Steam	MRO	4.2	12508	8300	1.49	85.26
University of Iowa Main Power Plant	54775_B_BLR11	Coal Steam	MRO	4.2	12508	8300	1.49	85.26
University of Iowa Main Power Plant	54775_B_BLR7	O/G Steam	MRO	4.2	14789	8300	1.72	92.41
University of Iowa Main Power Plant	54775_B_BLR8	O/G Steam	MRO	4.2	14789	8300	1.72	92.41
University of Iowa Main Power Plant	54775_B_BLR9	O/G Steam	MRO	4.2	14789	8300	1.72	92.41
Grays Ferry Cogeneration	54785_G_GEN1	Combined Cycle	MACE	50.0	9033	5522	1.64	36.96
Grays Ferry Cogeneration	54785_G_GEN2	Combined Cycle	MACE	100	9033	5522	1.64	36.96

Plymouth State College Cogeneration	54803_G_A	IC Engine	NENG	1.2	12334	9448	1.28	89.24
Milagro Cogeneration Plant	54814_G_GENA	Combustion Turbine	AZNM	30.4	16541	8700	1.90	89.87
Milagro Cogeneration Plant	54814_G_GENB	Combustion Turbine	AZNM	30.4	16541	8700	1.90	89.87
Milagro Cogeneration Plant	54814_G_GO1A	Combustion Turbine	AZNM	30.4	16521	8700	1.90	89.87
Milagro Cogeneration Plant	54814_G_GO1B	Combustion Turbine	AZNM	30.4	16541	8700	1.90	89.87
Johnson County	54817_G_GT-1	Combined Cycle	ERCT	163	7060	7859	1.00	84.63
Johnson County	54817_G_ST-1	Fossil Waste	ERCT	104	7859	7859	1.00	90.00
Panda Brandywine LP	54832_G_1	Combined Cycle	MACS	78.6	8330	7612	1.37	32.08
Panda Brandywine LP	54832_G_2	Combined Cycle	MACS	78.6	8330	7612	1.37	32.08
Panda Brandywine LP	54832_G_3	Combined Cycle	MACS	72.8	8330	7612	1.37	32.08
Outagamie County Co-Generation Facility	54842_G_GEN1	Landfill Gas	WUMS	0.80	13682	9273	1.48	67.72
Gordonsville Energy LP	54844_G_GOR1	Combined Cycle	VAPW	71.4	8593	8706	1.00	84.63
Gordonsville Energy LP	54844_G_GOR2	Combined Cycle	VAPW	71.4	8593	8706	1.00	84.63
Gordonsville Energy LP	54844_G_GOR3	Combined Cycle	VAPW	40.6	8593	8706	1.00	84.63
Gordonsville Energy LP	54844_G_GOR4	Combined Cycle	VAPW	40.6	8593	8706	1.00	84.63
Cox Waste to Energy	54850_G_01	Biomass	TVAK	3.0	15517	8300	1.89	83.00
Cox Waste to Energy	54850_G_02	Biomass	TVAK	0.30	15517	8300	1.89	83.00
Brooklyn Navy Yard Cogeneration	54914_G_01	Combined Cycle	NYC	85.0	7477	6759	1.34	84.63
Brooklyn Navy Yard Cogeneration	54914_G_02	Combined Cycle	NYC	85.0	7477	6759	1.34	84.63
Brooklyn Navy Yard Cogeneration	54914_G_03	Combined Cycle	NYC	30.0	7477	6759	1.34	84.63
Brooklyn Navy Yard Cogeneration	54914_G_04	Combined Cycle	NYC	30.0	7477	6759	1.34	84.63
Michigan Power LP	54915_G_G001	Combined Cycle	MECS	58.0	10880	9334	1.01	72.92
Michigan Power LP	54915_G_G101	Combined Cycle	MECS	70.0	10880	9334	1.01	72.92
Sauder Power Plant	54974_G_UNT1	Biomass	RFCO	3.6	18060	18060	1.00	83.00
Sauder Power Plant	54974_G_UNT2	Biomass	RFCO	3.6	18060	18060	1.00	83.00
Fellsway Development LLC	54992_G_CAT1	IC Engine	NENG	0.70	13123	9704	1.34	89.24
Fellsway Development LLC	54992_G_CAT2	IC Engine	NENG	0.80	13123	9704	1.34	89.24
Fellsway Development LLC	54992_G_GT	Combustion Turbine	NENG	0.60	15981	9704	1.63	89.24
Fellsway Development LLC	54992_G_ST	Coal Steam	NENG	0.20	13754	10320	1.00	85.26
SPSA Waste To Energy Power Plant	54998_B_12300	Municipal Solid Waste	VAPW	11.6	19338	12524	1.30	67.40
SPSA Waste To Energy Power Plant	54998_B_12400	Municipal Solid Waste	VAPW	11.6	19338	12524	1.30	67.40
SPSA Waste To Energy Power Plant	54998_B_12500	Municipal Solid Waste	VAPW	11.6	19338	12524	1.30	67.40
SPSA Waste To Energy Power Plant	54998_B_12600	Municipal Solid Waste	VAPW	11.6	19338	12524	1.30	67.40
LSP-Cottage Grove LP	55010_G_CTG1	Combined Cycle	MRO	154	7745	7278	1.08	38.81
LSP-Cottage Grove LP	55010_G_STG1	Combined Cycle	MRO	97.0	7745	7278	1.08	38.81
LSP-Whitewater LP	55011_G_CTG1	Combined Cycle	WUMS	156	7739	6654	1.20	47.91
LSP-Whitewater LP	55011_G_STG1	Combined Cycle	WUMS	97.0	7739	6654	1.20	47.91
Sweeny Cogen Facility	55015_G_1	Combustion Turbine	ERCT	115	11707	11707	1.00	90.81
Sweeny Cogen Facility	55015_G_2	Combustion Turbine	ERCT	115	11707	11707	1.00	90.81
Sweeny Cogen Facility	55015_G_3	Combustion Turbine	ERCT	115	11707	11707	1.00	90.81
Sweeny Cogen Facility	55015_G_4	Combustion Turbine	ERCT	115	11707	11707	1.00	90.81

J & L Electric	55034_G_0001	Biomass	NENG	0.35	15517	15716	1.00	83.00
J & L Electric	55034_G_0002	Biomass	NENG	0.50	15517	15716	1.00	83.00
Mid-Georgia Cogeneration Facility	55040_G_CT1	Combined Cycle	SOU	107	7950	6813	1.14	15.00
Mid-Georgia Cogeneration Facility	55040_G_CT2	Combined Cycle	SOU	107	7950	6813	1.14	15.00
Mid-Georgia Cogeneration Facility	55040_G_ST1	Combined Cycle	SOU	103	7950	6813	1.14	15.00
Cherokee County Cogen	55043_G_GT1	Combined Cycle	VACA	80.0	8000	8663	1.01	22.38
Cherokee County Cogen	55043_G_ST1	Combined Cycle	VACA	35.0	8000	8663	1.01	22.38
Pasadena Cogeneration	55047_G_CTG1	Combined Cycle	ERCT	155	7200	6723	1.14	59.17
Pasadena Cogeneration	55047_G_CTG2	Combined Cycle	ERCT	165	7200	6723	1.14	59.17
Pasadena Cogeneration	55047_G_CTG3	Combined Cycle	ERCT	165	7200	6723	1.14	59.17
Pasadena Cogeneration	55047_G_STG1	Combined Cycle	ERCT	50.0	7200	6723	1.14	59.17
Pasadena Cogeneration	55047_G_STG2	Combined Cycle	ERCT	165	7200	6723	1.14	59.17
Tamarack Energy Partnership	50099_G_GEN1	Biomass	PNW	5.8	15943	14500	1.10	83.00
Georgia Gulf Plaquemine	55051_G_X773	Combustion Turbine	ENTG	80.0	12435	8700	1.42	90.81
Georgia Gulf Plaquemine	55051_G_X774	Combustion Turbine	ENTG	80.0	12435	8700	1.42	90.81
Georgia Gulf Plaquemine	55051_G_X775	Combustion Turbine	ENTG	80.0	12435	8700	1.42	90.81
Black Hawk Station	55064_G_UNT1	Combustion Turbine	SPPS	111	13188	8800	1.50	90.81
Black Hawk Station	55064_G_UNT2	Combustion Turbine	SPPS	111	13200	8800	1.50	90.81
Pine Bluff Energy Center	55075_G_CT01	Combined Cycle	ENTG	150	7274	5500	1.50	77.47
Pine Bluff Energy Center	55075_G_ST01	Combined Cycle	ENTG	48.0	7274	5500	1.50	77.47
Crockett Cogen Project	55084_G_GE1	Combined Cycle	CA-N	247	7500	5919	1.80	41.22
Gregory Power Facility	55086_G_GT1A	Combined Cycle	ERCT	156	7274	5500	1.72	80.75
Gregory Power Facility	55086_G_GT1B	Combined Cycle	ERCT	156	7274	5500	1.72	80.75
Gregory Power Facility	55086_G_STG	Combined Cycle	ERCT	100	7274	5500	1.72	80.75
Dearborn Industrial Generation	55088_G_GT 1	Combined Cycle	MECS	150	7274	5500	1.46	24.62
Dearborn Industrial Generation	55088_G_GT2	Combined Cycle	MECS	150	7274	5500	1.46	24.62
Dearborn Industrial Generation	55088_G_GTP1	Combined Cycle	MECS	150	7274	5500	1.46	24.62
Dearborn Industrial Generation	55088_G_ST1	Combined Cycle	MECS	250	7274	5500	1.46	24.62
Taft Cogeneration Facility	55089_G_CT1	Combined Cycle	ENTG	155	7933	7316	1.04	58.54
Taft Cogeneration Facility	55089_G_CT2	Combined Cycle	ENTG	155	7933	7316	1.04	58.54
Taft Cogeneration Facility	55089_G_CT3	Combined Cycle	ENTG	155	7933	7316	1.04	58.54
Taft Cogeneration Facility	55089_G_ST1	Combined Cycle	ENTG	325	7933	7316	1.04	58.54
Plummer Forest Products	55090_G_GEN1	Biomass	PNW	5.8	16912	10049	1.68	83.00
Miramar Landfill Metro Biosolids Center	55094_G_UNT1	Landfill Gas	CA-S	1.6	11855	12899	1.06	75.52
Miramar Landfill Metro Biosolids Center	55094_G_UNT2	Landfill Gas	CA-S	1.6	11855	12899	1.06	75.52
Miramar Landfill Metro Biosolids Center	55094_G_UNT3	Landfill Gas	CA-S	1.6	11855	12899	1.06	75.52
Miramar Landfill Metro Biosolids Center	55094_G_UNT4	Landfill Gas	CA-S	1.6	11855	12899	1.06	75.52
Portside Energy	55096_G_GT	Combined Cycle	RFCO	34.0	6920	6920	1.00	84.63
Portside Energy	55096_G_ST	Combined Cycle	RFCO	10.0	6920	6920	1.00	84.63
Klamath Cogeneration Plant	55103_G_CT1	Combined Cycle	PNW	150	6920	6794	1.10	73.73
Klamath Cogeneration Plant	55103_G_CT2	Combined Cycle	PNW	150	6920	6794	1.10	73.73

Klamath Cogeneration Plant	55103_G_ST1	Combined Cycle	PNW	170	6920	6794	1.10	73.73
Sabine Cogen	55104_G_SAB1	Combined Cycle	ENTG	37.0	7274	9201	1.00	84.63
Sabine Cogen	55104_G_SAB2	Combined Cycle	ENTG	37.0	7274	9201	1.00	84.63
Sabine Cogen	55104_G_STG	Combined Cycle	ENTG	27.0	7274	9201	1.92	68.22
RS Cogen	55117_G_RS-4	Combined Cycle	ENTG	60.2	7933	7942	1.00	84.63
RS Cogen	55117_G_RS-5	Combined Cycle	ENTG	168	7933	7942	1.00	84.63
RS Cogen	55117_G_RS-6	Combined Cycle	ENTG	168	7933	7942	1.00	84.63
SRW Cogen LP	55120_G_GT1A	Combined Cycle	ENTG	160	7274	7751	1.04	76.43
SRW Cogen LP	55120_G_GT1B	Combined Cycle	ENTG	160	7274	7751	1.04	76.43
SRW Cogen LP	55120_G_ST1A	Combined Cycle	ENTG	100	7274	7751	1.04	76.43
NAFTA Region Olefins Complex Cogen Fac	55122_G_UN1	Combustion Turbine	ENTG	35.0	12503	9934	1.26	89.87
NAFTA Region Olefins Complex Cogen Fac	55122_G_UN2	Combustion Turbine	ENTG	35.0	12503	9934	1.26	89.87
Eastman Cogeneration Facility	55176_G_GEN1	Combined Cycle	SPPS	146	7274	6289	1.48	62.33
Eastman Cogeneration Facility	55176_G_GEN2	Combined Cycle	SPPS	146	7274	6289	1.48	62.33
Eastman Cogeneration Facility	55176_G_GEN3	Combined Cycle	SPPS	110	7274	6289	1.48	62.33
Channelview	55187_G_CHV1	Combined Cycle	ERCT	161	10457	9909	1.00	84.63
Channelview	55187_G_CHV2	Combined Cycle	ERCT	161	10457	9909	1.00	84.63
Channelview	55187_G_CHV3	Combined Cycle	ERCT	161	10457	9909	1.00	84.63
Channelview	55187_G_CHV4	Combined Cycle	ERCT	161	10457	9909	1.00	84.63
Channelview	55187_G_ST1	Combined Cycle	ERCT	135	10457	9909	1.97	76.78
Corpus Christi Energy Center	55206_G_CT1	Combined Cycle		162	Not in dB	7535	1.00	84.63
Corpus Christi Energy Center	55206_G_CT2	Combined Cycle		162	Not in dB	7535	1.00	84.63
Corpus Christi Energy Center	55206_G_ST1	Combined Cycle		159	Not in dB	7535	1.00	84.63
Aera South Belridge Cogen Facility	55216_G_STG1	Combined Cycle	COMD	62.0	10244	5896	1.41	33.26
Aera South Belridge Cogen Facility	55216_G_UNT1	Combined Cycle	COMD	38.0	10244	5896	1.41	33.26
Aera South Belridge Cogen Facility	55216_G_UNT2	Combined Cycle	COMD	38.0	10244	5896	1.41	33.26
Aera South Belridge Cogen Facility	55216_G_UNT3	Combined Cycle	COMD	38.0	10244	5896	1.41	33.26
Los Medanos Energy Center	55217_G_CTG1	Combined Cycle	CA-N	165	6920	6656	1.15	70.00
Los Medanos Energy Center	55217_G_CTG2	Combined Cycle	CA-N	165	6920	6656	1.15	70.00
Los Medanos Energy Center	55217_G_STG3	Combined Cycle	CA-N	237	6920	6656	1.15	70.00
Ina Road Water Pollution Control Fac	55257_G_1	IC Engine	AZNM	0.59	13298	8700	1.52	89.24
Ina Road Water Pollution Control Fac	55257_G_2	IC Engine	AZNM	0.59	13298	8700	1.52	89.24
Ina Road Water Pollution Control Fac	55257_G_3	IC Engine	AZNM	0.59	13298	8700	1.52	89.24
Ina Road Water Pollution Control Fac	55257_G_4	IC Engine	AZNM	0.59	13298	8700	1.52	89.24
Ina Road Water Pollution Control Fac	55257_G_5	IC Engine	AZNM	0.59	13298	8700	1.52	89.24
Ina Road Water Pollution Control Fac	55257_G_6	IC Engine	AZNM	0.59	13298	8700	1.52	89.24
Ina Road Water Pollution Control Fac	55257_G_7	IC Engine	AZNM	0.59	13298	8700	1.52	89.24
Whiting Clean Energy	55259_G_CT1	Combined Cycle	RFCO	167	7113	9051	1.06	26.24
Whiting Clean Energy	55259_G_CT2	Combined Cycle	RFCO	167	7113	9051	1.06	26.24
Whiting Clean Energy	55259_G_ST1	Combined Cycle	RFCO	213	7113	9051	1.06	26.24
Decatur Energy Center	55292_G_CTG1	Combined Cycle	TVA	155	7274	9999	1.00	84.68

Decatur Energy Center	55292_G_CTG2	Combined Cycle	TVA	155	7274	9999	1.00	84.68
Decatur Energy Center	55292_G_CTG3	Combined Cycle	TVA	155	7274	9999	1.00	84.68
Decatur Energy Center	55292_G_STG1	Combined Cycle	TVA	159	7274	9999	1.00	84.68
Morgan Energy Center	55293_G_CTG1	Combined Cycle	TVA	161	7355	7421	1.00	84.68
Morgan Energy Center	55293_G_CTG2	Combined Cycle	TVA	161	7355	7421	1.00	84.68
Morgan Energy Center	55293_G_CTG3	Combined Cycle	TVA	161	7355	7421	1.00	84.68
Morgan Energy Center	55293_G_STG1	Combined Cycle	TVA	266	7355	7421	1.00	84.68
Channel Energy Center	55299_G_CTG1	Combined Cycle	ERCT	185	7200	6016	1.34	40.92
Channel Energy Center	55299_G_CTG2	Combined Cycle	ERCT	185	7200	6016	1.34	40.92
Channel Energy Center	55299_G_ST-1	Combined Cycle	ERCT	215	7200	6016	1.34	40.92
Calvert City	55308_G_GEN1	Combustion Turbine	TVA	23.0	12503	8700	1.43	89.88
Air Products Port Arthur	55309_G_GEN1	Combined Cycle	ENTG	33.2	7274	10719	1.00	84.63
Air Products Port Arthur	55309_G_GEN2	Combined Cycle	ENTG	3.0	7274	10719	1.00	84.63
Ingleside Cogeneration	55313_G_CTG1	Combined Cycle	ERCT	155	7933	8479	1.07	57.25
Ingleside Cogeneration	55313_G_CTG2	Combined Cycle	ERCT	155	7933	8479	1.07	57.25
Ingleside Cogeneration	55313_G_STG	Combined Cycle	ERCT	150	7933	8479	1.07	57.25
Chuck Lenzie Generating Station	55322_G_CTG1	Combined Cycle	SNV	134	7031	7735	1.00	84.63
Chuck Lenzie Generating Station	55322_G_CTG2	Combined Cycle	SNV	168	7031	7735	1.00	84.63
Chuck Lenzie Generating Station	55322_G_ST1	Combined Cycle	SNV	184	7031	7735	1.00	84.63
Baytown Energy Center	55327_G_CTG1	Combined Cycle	ERCT	170	7274	7484	1.00	84.63
Baytown Energy Center	55327_G_CTG2	Combined Cycle	ERCT	170	7274	7484	1.00	84.63
Baytown Energy Center	55327_G_CTG3	Combined Cycle	ERCT	170	7274	7484	1.00	84.63
Baytown Energy Center	55327_G_STG1	Combined Cycle	ERCT	275	7274	7484	1.00	84.63
Columbia Energy Center	55386_G_CT1	Combined Cycle		157	Not in dB	6407	1.73	15.00
Columbia Energy Center	55386_G_CT2	Combined Cycle		157	Not in dB	6407	1.73	15.00
Columbia Energy Center	55386_G_ST1	Combined Cycle		151	Not in dB	6407	1.73	15.00
Carville Energy LLC	55404_G_CTG1	Combined Cycle	ENTG	180	7274	5966	1.36	56.35
Carville Energy LLC	55404_G_CTG2	Combined Cycle	ENTG	180	7274	5966	1.36	56.35
Carville Energy LLC	55404_G_STG	Combined Cycle	ENTG	140	7274	5966	1.36	56.35
Plaquemine Cogeneration Plant	55419_G_G500	Combined Cycle	ENTG	169	7274	6394	1.11	51.42
Plaquemine Cogeneration Plant	55419_G_G600	Combined Cycle	ENTG	169	7274	6394	1.11	51.42
Plaquemine Cogeneration Plant	55419_G_G700	Combined Cycle	ENTG	169	7274	6394	1.11	51.42
Plaquemine Cogeneration Plant	55419_G_G800	Combined Cycle	ENTG	169	7274	6394	1.11	51.42
Plaquemine Cogeneration Plant	55419_G_ST5	Combined Cycle	ENTG	168	7274	6394	1.11	51.42
Deer Park Energy Center	55464_G_CTG1	Combined Cycle	ERCT	155	7274	5712	1.75	76.57
Deer Park Energy Center	55464_G_CTG2	Combined Cycle	ERCT	155	7274	5712	1.75	76.57
Deer Park Energy Center	55464_G_CTG3	Combined Cycle	ERCT	155	7274	5712	1.75	76.57
Deer Park Energy Center	55464_G_CTG4	Combined Cycle	ERCT	155	7274	5712	1.75	76.57
Deer Park Energy Center	55464_G_STG1	Combined Cycle	ERCT	258	7274	5712	1.75	76.57
Green Power 2	55470_G_ST1	Combined Cycle	ERCT	110	7933	5500	1.44	73.01
Green Power 2	55470_G_TR1	Combined Cycle	ERCT	158	7933	5500	1.44	73.01

Green Power 2	55470_G_TR2	Combined Cycle	ERCT	158	7933	5500	1.44	73.01
Green Power 2	55470_G_TR3	Combined Cycle	ERCT	158	7933	5500	1.44	73.01
Blackburn Landfill Co-Generation	55488_G_BB1	Landfill Gas	VACA	1	12328	8700	1.57	67.05
Blackburn Landfill Co-Generation	55488_G_BB2	Landfill Gas	VACA	1	12328	8700	1.57	67.05
Blackburn Landfill Co-Generation	55488_G_BB3	Landfill Gas	VACA	0.90	12328	8700	1.57	67.05
Wilmington Hydrogen Plant	55557_G_T101	O/G Steam	CA-S	23.0	11425	9854	1.13	92.45
Combined Locks Energy Center	55558_G_GEN1	Combined Cycle	WUMS	40.8	7933	6221	1.28	18.89
Combined Locks Energy Center	55558_G_GEN2	Combined Cycle	WUMS	4.3	7933	6221	1.28	18.89
Binghamton Cogen	55600_G_1	Combustion Turbine	UPNY	42.0	10894	9358	1.16	89.87
Mingo Junction Energy Center	55611_B_BOIL1	O/G Steam	RFCO	7.5	11425	8300	1.35	92.41
Mingo Junction Energy Center	55611_B_BOIL2	O/G Steam	RFCO	7.5	11425	8300	1.35	92.41
Mingo Junction Energy Center	55611_B_BOIL3	O/G Steam	RFCO	7.5	11425	8300	1.35	92.41
Mingo Junction Energy Center	55611_B_BOIL4	O/G Steam	RFCO	7.5	11425	8300	1.35	92.41
FPL Energy Marcus Hook LP	55801_G_CT13	Combined Cycle	MACE	162	7274	7274	1.00	84.63
FPL Energy Marcus Hook LP	55801_G_CT1A	Combined Cycle	MACE	162	7274	7274	1.00	84.63
FPL Energy Marcus Hook LP	55801_G_CTIB	Combined Cycle	MACE	160	7274	7274	1.00	84.63
FPL Energy Marcus Hook LP	55801_G_STG	Combined Cycle	MACE	234	7274	7274	1.00	84.63
Desert Power LP	55858_G_GEN7	Coal Steam	NWPE	40.0	9650	Retired		0.00
Co-Gen LLC	50921_G_GEN1	Biomass	PNW	7.0	17974	8566	2.10	83.00
Ashtabula	55990_G_1	Combined Cycle	RFCO	4.4	7274	7083	1.03	73.53
Ashtabula	55990_G_2	Combined Cycle	RFCO	4.4	7274	7083	1.03	73.53
Ashtabula	55990_G_3	Combined Cycle	RFCO	4.4	7274	7083	1.03	73.53
Ashtabula	55990_G_4	Combined Cycle	RFCO	4.4	7274	7083	1.03	73.53
Ashtabula	55990_G_5	Combined Cycle	RFCO	4.4	7274	7083	1.03	73.53
Ashtabula	55990_G_6	Combined Cycle	RFCO	0.69	7274	7083	1.03	73.53
Ashtabula	55990_G_7	Combined Cycle	RFCO	0.69	7274	7083	1.03	73.53
Trigen Revere	55999_G_GEN1	IC Engine	NENG	2.8	10850	9732	1.11	89.24
Trigen Revere	55999_G_GEN2	IC Engine	NENG	2.8	10850	9732	1.11	89.24
WWTP Power Generation Station	56036_G_GEN1	Non-Fossil Waste	CA-N	2.0	14653	14653	1.00	90.00
WWTP Power Generation Station	56036_G_GEN2	Non-Fossil Waste	CA-N	2.0	14653	14653	1.00	90.00
WWTP Power Generation Station	56036_G_GEN3	Non-Fossil Waste	CA-N	2.0	14653	14653	1.00	90.00
Fox Valley Energy Center	56037_G_1	Coal Steam	WUMS	6.5	10331	8300	1.24	85.26
UMCP CHP Plant	56038_G_1	Combined Cycle	MACS	9.4	7933	6534	1.80	84.63
UMCP CHP Plant	56038_G_2	Combined Cycle	MACS	9.4	7933	6534	1.80	84.63
UMCP CHP Plant	56038_G_3	Combined Cycle	MACS	2.0	7933	6534	1.80	84.63
Millennium Hawkins Point	56045_G_1A	Combined Cycle	MACS	1.1	7933	13490	1.09	37.14
Millennium Hawkins Point	56045_G_1B	Combined Cycle	MACS	1.1	7933	13490	1.09	37.14
Millennium Hawkins Point	56045_G_2A	Combined Cycle	MACS	1.1	7933	13490	1.09	37.14
Millennium Hawkins Point	56045_G_2B	Combined Cycle	MACS	1.1	7933	13490	1.09	37.14
Millennium Hawkins Point	56045_G_3A	Combined Cycle	MACS	1.1	7933	13490	1.09	37.14
Millennium Hawkins Point	56045_G_3B	Combined Cycle	MACS	1.1	7933	13490	1.09	37.14

Millennium Hawkins Point	56045_G_ST1	Combined Cycle	MACS	0.50	7933	13490	1.09	37.14
Co-Gen II LLC	50993_G_GEN1	Biomass	PNW	7.0	17139	10285	1.67	83.00
Sierra Pacific Aberdeen	55882_B_BLR1	Biomass	PNW	16.5	15517	8300	1.89	83.00
Middlesex Generating Facility	56119_G_100	Non-Fossil Waste		4.10	Not in dB	7274	1.00	90.00
Middlesex Generating Facility	56119_G_200	Non-Fossil Waste		4.10	Not in dB	7274	1.00	90.00
Middlesex Generating Facility	56119_G_300	Non-Fossil Waste		10.6	Not in dB	7274	1.00	90.00
SP Newsprint- Newberg Cogen	56124_B_10BLR	O/G Steam	PNW	22.3	11332	11511	1.00	92.41
SP Newsprint- Newberg Cogen	56124_G_GT1	Combustion Turbine	PNW	41.6	12503	Retired		0.00
SP Newsprint- Newberg Cogen	56124_G_GT2	Combustion Turbine	PNW	41.6	12503	Retired		0.00
Macon Energy Center	56127_G_1	Combustion Turbine	GWAY	9.1	13301	13301	1.00	89.24
Groveton Paper Board	56140_G_TUR1	Combustion Turbine	NENG	4.0	12678	12477	1.00	89.24
Groveton Paper Board	56140_G_TUR2	Combustion Turbine	NENG	4.0	12678	12477	1.00	89.24
Freeport Energy Center	56152_G_CTG1	Combined Cycle		180	Not in dB	7942	1.00	84.63
Freeport Energy Center	56152_G_STG1	Combined Cycle		80.0	Not in dB	7942	1.00	84.63
Freehold Asbury Park Press	56169_G_UNT1	IC Engine	MACE	1.1	11797	10000	1.18	89.24
Freehold Asbury Park Press	56169_G_UNT2	IC Engine	MACE	1.1	11797	10000	1.18	89.24
Cogeneration 1	56229_G_CT1	Combined Cycle	AZNM	8.3	7933	7942	1.00	84.63
Perham Incinerator	56243_G_1	Municipal Solid Waste	MRO	1.2	19338	16297	1.00	90.00
Shell Chemical	56248_G_101G	Combustion Turbine	ENTG	32.0	12503	10994	1.13	89.87
Shell Chemical	56248_G_201G	Combustion Turbine	ENTG	32.0	12503	10994	1.13	89.87
Trigen St.Louis	56309_G_CT-1	Combined Cycle	GWAY	4.0	11985	5583	2.15	52.35
Trigen St.Louis	56309_G_CT-2	Combined Cycle	GWAY	4.2	11985	5583	2.15	52.35
Trigen St.Louis	56309_G_ST-3	O/G Steam	GWAY	18.0	11425	11177	1.00	92.45
Trigen St.Louis	56309_G_ST-4	Combined Cycle	GWAY	0.77	11985	5583	2.15	52.35
Trigen St.Louis	56309_G_ST-5	Combined Cycle	GWAY	0.81	11985	5583	2.15	52.35
Clearwater Power Plant	56356_G_CT1	Combined Cycle	CA-S	21.0	9100	9368	1.00	84.63
Clearwater Power Plant	56356_G_ST1	Combined Cycle	CA-S	7.0	9100	9368	1.00	84.63
Domain Plant	56373_G_DOMG1	Combustion Turbine	ERCT	5.0	11862	11862	1.00	89.24
Robert Mueller Energy Center	56374_G_CT1	Combustion Turbine	ERCT	3.7	12503	9960	1.00	89.24
Sierra Pacific Burlington Facility	56406_G_GEN1	Biomass	PNW	25.0	15517	12695	1.24	83.00
Tesoro SLC Cogeneration Plant	56509_G_1	Combustion Turbine	NWPE	11.0	12503	8700	1.44	89.24
Tesoro SLC Cogeneration Plant	56509_G_2	Combustion Turbine	NWPE	11.0	12503	8700	1.44	89.24
Edge Moor	593_B_3	Coal Steam	MACE	86.0	13668	12721	1.07	41.53
Edge Moor	593_B_4	Coal Steam	MACE	174	9569	9569	1.00	41.53
Sherburne County	6090_B_1	Coal Steam	MRO	762	10611	10611	1.00	68.27
Sherburne County	6090_B_2	Coal Steam	MRO	752	10452	10452	1.00	68.27
Big Stone	6098_B_1	Coal Steam	MRO	470	11609	11609	1.00	79.70
Warrick	6705_B_1	Coal Steam	RFCO	136	10986	10986	1.00	73.94
Warrick	6705_B_2	Coal Steam	RFCO	136	11017	11002	1.00	73.94
Warrick	6705_B_3	Coal Steam	RFCO	136	11056	11002	1.00	73.94
Warrick	6705_B_4	Coal Steam	RFCO	300	10418	10418	1.00	73.93

Gadsden	7_B_1	Coal Steam	SOU	64.0	12376	12376	1.00	50.27
Gadsden	7_B_2	Coal Steam	SOU	66.0	12846	12846	1.00	50.27
Whitehead	7028_G_K1	IC Engine	NWPE	5.9	14151	14151	1.00	89.24
Whitehead	7028_G_K2	IC Engine	NWPE	6.0	10069	10069	1.00	89.24
Whitehead	7028_G_K3	IC Engine	NWPE	5.9	10069	10069	1.00	89.24
Whitehead	7028_G_K4	IC Engine	NWPE	4.0	10069	10069	1.00	89.24
Whitehead	7028_G_K5	IC Engine	NWPE	2.0	10746	10746	1.00	89.24
Whitehead	7028_G_K6	IC Engine	NWPE	2.1	10746	10746	1.00	89.24
Whitehead	7028_G_K7	IC Engine	NWPE	2.1	10746	10746	1.00	89.24
Brandon Station	7131_G_1	Combustion Turbine	SPPS	20.0	12503	12503	1.00	89.87
Richard Gorsuch	7286_B_1	Coal Steam	RFCO	50.0	11084	11084	1.00	60.67
Richard Gorsuch	7286_B_2	Coal Steam	RFCO	50.0	11084	11084	1.00	60.67
Richard Gorsuch	7286_B_3	Coal Steam	RFCO	50.0	11071	11071	1.00	60.67
Richard Gorsuch	7286_B_4	Coal Steam	RFCO	50.0	11071	11071	1.00	60.67
George Neal South	7343_B_4	Coal Steam	MRO	632	10470	10470	1.00	80.10
University of Florida	7345_G_P1	Combustion Turbine	FRCC	45.0	9249	9249	1.00	89.87
Coyote Springs	7350_G_1	Combined Cycle	PNW	142	7337	7598	1.00	84.68
Coyote Springs	7350_G_2	Combined Cycle	PNW	71.3	7337	7598	1.00	84.68
Indian Trails Cogen 1	7384_B_1	O/G Steam	GWAY	3.3	11425	11177	1.00	92.41
Indian Trails Cogen 1	7384_B_2	O/G Steam	GWAY	3.3	11425	11177	1.00	92.41
Indian Trails Cogen 1	7384_B_3	O/G Steam	GWAY	3.3	11425	11177	1.00	92.41
Carson Ice-Gen Project	7527_G_1	Combined Cycle	CA-N	41.2	11860	8327	1.00	84.63
Carson Ice-Gen Project	7527_G_2	Combined Cycle	CA-N	16.6	11860	8327	1.00	84.63
Milwaukee County	7549_B_1	Coal Steam	WUMS	3.3	11704	11704	1.00	71.80
Milwaukee County	7549_B_2	Coal Steam	WUMS	3.3	10331	10320	1.00	71.80
Milwaukee County	7549_B_3	Coal Steam	WUMS	3.3	10331	10320	1.00	71.80
SCA Cogen 2	7551_G_CCST	Combined Cycle	CA-N	37.6	11094	8469	1.00	84.63
SCA Cogen 2	7551_G_CT1A	Combined Cycle	CA-N	39.6	11094	8469	1.00	84.63
SCA Cogen 2	7551_G_CT1B	Combined Cycle	CA-N	39.6	11094	8469	1.00	84.63
SCA Cogen 2	7551_G_CT1C	Combined Cycle		45.7	Not in dB	8469	1.00	84.63
SPA Cogen 3	7552_G_CCCT	Combined Cycle	CA-N	111	8394	8137	1.00	84.63
SPA Cogen 3	7552_G_CCST	Combined Cycle	CA-N	53.0	8394	8137	1.00	84.63
Everett Cogen	7627_B_14	Biomass	PNW	36.0	15517	11844	1.33	83.00
US DOE Savannah River Site (D Area)	7652_B_D-1	Coal Steam		19.6	Not in dB	10320	1.00	31.67
US DOE Savannah River Site (D Area)	7652_B_D-2	Coal Steam		19.6	Not in dB	10320	1.00	31.67
US DOE Savannah River Site (D Area)	7652_B_D-3	Coal Steam		19.6	Not in dB	10320	1.00	31.67
US DOE Savannah River Site (D Area)	7652_B_D-4	Coal Steam		19.6	Not in dB	10320	1.00	31.67
Washington County Cogeneration Facility	7697_G_1	Combined Cycle	SOU	80.0	7274	9026	1.00	84.63
Washington County Cogeneration Facility	7697_G_2	Combined Cycle	SOU	22.0	7274	9026	1.00	84.63
General Electric Plastic	7698_G_1	Combined Cycle	SOU	85.0	7274	11972	1.00	84.63
General Electric Plastic	7698_G_2	Combined Cycle	SOU	12.0	7274	11972	1.00	84.63

Fairless Hills	7701_B_4	Landfill Gas	MACE	30.0	13682	12789	1.07	47.11
Fairless Hills	7701_B_5	Landfill Gas	MACE	30.0	13682	12789	1.07	47.11
Pea Ridge	7715_G_1	Combustion Turbine	SOU	4.0	14111	14111	1.00	89.24
Pea Ridge	7715_G_2	Combustion Turbine	SOU	4.0	11210	11210	1.00	89.24
Pea Ridge	7715_G_3	Combustion Turbine	SOU	4.0	11210	11210	1.00	89.24
Theodore Cogen Facility	7721_G_1	Combined Cycle	SOU	152	7274	7065	1.00	84.63
Theodore Cogen Facility	7721_G_2	Combined Cycle	SOU	36.0	7274	7065	1.00	84.63
Cogen South	7737_B_B001	Coal Steam	VACA	90.0	10966	10966	1.00	70.87
Encogen	7870_G_CTG1	Combined Cycle	PNW	39.4	11200	9118	1.00	84.68
Encogen	7870_G_CTG2	Combined Cycle	PNW	39.4	11200	9118	1.00	84.68
Encogen	7870_G_CTG3	Combined Cycle	PNW	39.4	11200	9118	1.00	84.68
Encogen	7870_G_STG	Combined Cycle	PNW	51.8	11200	9118	1.00	84.68
West Campus Cogeneration Facility	7991_G_1	Combined Cycle	WUMS	38.0	11985	8367	1.00	84.63
West Campus Cogeneration Facility	7991_G_CT2	Combined Cycle	WUMS	37.2	11985	8367	1.00	84.63
West Campus Cogeneration Facility	7991_G_STG1	Combined Cycle	WUMS	55.0	11985	8367	1.00	84.63
Ware Cogeneration	81542_G_1	Biomass	NENG	4.1	15517	15716	1.00	83.00
Kimberly Clark	82800_G_CC1	Combined Cycle	NENG	17.5	7031	7942	1.00	84.63
Kimberly Clark	82800_G_GT1	Combustion Turbine	NENG	17.5	10664	12477	1.00	89.24
Great River Energy Spiritwood Station	82821_B_1	Coal Steam	MRO	99.0	8763	8937	1.00	85.26
SPPN_KS_Coal steam	82932_C_1	Coal Steam	SPPN	22.0	10820	8937	1.00	85.26
Cabot Holyoke	9864_B_5	O/G Steam		5.80	Not in dB	14500	1.00	89.51
Cabot Holyoke	9864_B_6	O/G Steam		5.80	Not in dB	14500	1.00	89.51
Cabot Holyoke	9864_B_7	O/G Steam		5.80	Not in dB	10817	1.00	89.51
Cabot Holyoke	9864_B_8	O/G Steam		5.80	Not in dB	14500	1.00	89.51

2 NO_x Rates

2.1 Response to the Comments Received

Comment Theme: There were a substantial number of comments indicating that the NO_x rates shown in NEEDS[2] were too low and not achievable.

Discussion: Based on these comments, the decision rules used to derive the NEEDS NO_x rates were reviewed and an out-of-date assumption was found to be causing instances of low NO_x rates. Specifically, the out-of-date decision rule (which was developed at a time when units were subject, at most, to summer season, not annual, NO_x rate limits) designated the winter NO_x rate as the uncontrolled NO_x rate. Applying percent reductions attributable to NO_x post-combustion controls to the winter NO_x rates resulted in unrealistically low controlled NO_x rates for units that in reality operated NO_x controls in the winter.

Response: The previous decision rules were replaced by a more robust procedure for identifying uncontrolled NO_x rates. In addition, a thorough review was made of all the decision rules affecting NO_x rates and, where appropriate, revisions were made. The revised decision rules are shown in the documentation supplement which follows.

In addition, as announced in the Federal Register Notice of Data Availability for the Proposed Transport Rule (FR, vol. 75, no.169, September 1, 2010, 53614-53615) the NO_x rates for fossil-fuel fired units in the final rule are based on 2009 data rather than 2007 NO_x data used in the modeling for the proposed Transport Rule. Reported to EPA by generating units covered under Title IV of the Clean Air Act Amendments of 1990 (Acid Rain Program) and NO_x Budget Program, the updated NO_x rates more accurately reflect the unit level control installations that have occurred at power plants during the past several years.

2.1 Resulting Updates

The following changes to *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* show the updates that were implemented for the Final Transport Rule analysis in EPA Base Case v4.10_FTransport.

In the documentation for EPA Base Case v.4.10_NODA, t*he following replaces the response to question Q4 that had previously appeared in Appendix 3-1 in the NODA documentation.*

[2] The National Electrical Energy Data System (NEEDS) is a database which provides EPA's model of the electric power sector with information on all currently operating and planned-committed electric generating units. An updated version of NEEDS (v.4.10) was part of the September 1, 2010 Notice of Data Availability for the Proposed Transport Rule.

Q4: How are the values of the Mode 1-4 NOx rates derived?
A4: The revised draft of the methodology to develop NO_x rates for coal steam boilers in EPA Base Case v.4.10_FTransport is summarized below.

The procedure employs the following hierarchy of NO_x rate data sources:

1. 2009 ETS
2. EPA 410 NODA Comments
3. 2007 ETS
4. 2005 EIA Form 767
5. Defaults

The existing coal steam boilers in US are categorized into three groups depending on the configuration of NO_x combustion and post-combustion controls

Group 1 - Coal boilers without post combustion NO_x controls
Mode 1 = 2009 ETS Annual Average NO_x Rate
Mode 2 = Mode 1

Mode 3
For coal boilers located in a SIP call NO_x, CAIR ozone/annual NO_x or any NO_x regulated state,
Mode 3 = Mode 1

For coal boilers that are not located in a SIP call NO_x, CAIR ozone/annual NO_x or any NO_x regulated state, follow Steps 1-7

Step 1: Pre-screen units that already have state of art (SOA) combustion controls from units that have non-SOA combustion controls from units that have no combustion controls

Step 2: For units listed as not having combustion controls
Make sure their NO_x rates do not indicate that they really do have SOA control
If Mode 1 > Cut-off (in Table 3-1.2), then Mode 1 = Base NO_x rate. Go to Step 6
If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Mode 3 = Mode 1

Step 3: For units listed as having SOA combustion controls.
Mode 3 = Mode 1.

Step 4: For units listed as not having SOA combustion controls
Make sure their NO_x rates do not indicate that they really do have SOA control

If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Mode 3 = Mode 1
If Mode 1 > Cut-off (in Table 3-1.2), then go to Step 5

Step 5: Determine the unit's Base NO_x rate, i.e., the unit's uncontrolled emission rate without combustion controls, using the appropriate equation (not in boldface italics) in Table 3-1.3 to back calculate their Base NO_x rate. Use the default Base NO_x rate values if back calculations can't be performed. Once the Base NO_x rate is obtained, go to Step 6.

Step 6: Use the appropriate equations (in boldface italics) in Table 3-1.3 to calculate the NO_x rate with SOA combustion controls.

Step 7: Compare the value calculated in Step 6 to the applicable NO_x floor rate in Table 3-1.2.

If the value from Step 6 is ≥ floor, use the Step 6 value as Mode 3. Otherwise, use the floor as the Mode 3 NO_x rate.

Mode 4
Mode 4 = Mode 3

Group 2 - Coal boilers with Dispatchable/Non-Dispatchable SCR

Pre-screen coal boilers with 2009 ETS NO_x rates into the following four operating regimes. A coal boiler is assumed to be operating its SCR when the seasonal NO_x rate is less than 0.2 lbs/MMBtu

Group 2a. Coal boilers with Non-Dispatchable SCR

Group 2a.1 SCR is not operating in both summer and winter seasons

Follow the NO_x rate rules summarized for Group 1 boilers. No state of the art combustion controls are implemented.

Mode 1 = 2009 ETS Annual Average NO_x Rate
Mode 2 = maximum {(1-0.9) * Mode 1, 0.07}
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2a.2 SCR is operating in summer only

Mode 1 = 2009 ETS Winter NO_x Rate
Mode 2 = 2009 ETS Summer NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2a.3 SCR is operating in winter only

Mode 1 = 2009 ETS Summer NO_x Rate
Mode 2 = 2009 ETS Winter NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2a.4 SCR is operating year-round

Mode 1 = if (2007 ETS Winter NO_x Rate > 0.2, 2007 ETS Winter NO_x Rate, 2009 ETS Annual Average NO_x Rate)
Mode 2 = 2009 ETS Annual Average NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2b. Coal boilers with Dispatchable SCR

Group 2b.1 SCR is not operating in both summer and winter seasons

Follow the NO_x rate rules summarized for Group2a.1 boilers.

Group 2b.2 SCR is operating in summer only

Mode 1 = 2009 ETS Winter NO_x Rate
Mode 2 = Mode 1
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2b.3 SCR is operating in winter only

Mode 1 = 2009 ETS Summer NO_x Rate
Mode 2 = Mode 1
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2b.4 SCR is operating year-round

Mode 1 = if (2007 ETS Winter NO_x Rate > 0.2, 2007 ETS Winter NO_x Rate, 2009 ETS Annual Average NO_x Rate)
Mode 2 = Mode 1
Mode 3 = Mode 1
Mode 4 = Mode 2

NOx Rate Development Methodology for Coal Boilers in EPA Base Case v.4.10_FTransport (cont'd)

Group 3 - Coal boilers with SNCR

Step 1: Pre-screen coal boilers with 2009 ETS NO_x rates to verify if they have **not** operated their SNCR in both summer and winter seasons. A coal boiler is assumed to be not operating its SNCR when the NO_x rate is greater than 0.3 lbs/MMBtu in both summer and winter seasons.

Group 3.1 SNCR is not operating in both summer and winter seasons
Follow the NO_x rate rules summarized for Group 1 boilers

Step 2: Pre-screen coal boilers with 2009 ETS NO_x rates into the following three operating regimes. First estimate the implied removal for a coal boiler using the following equation:

*Implied Removal (%) = ((Winter NO_x Rate – Summer NO_x Rate)/ Winter NO_x Rate) * 100*

Second, assign the coal boiler to a specific operating regime based on the following logic.

If Implied Removal > 20% then SNCR is operating in summer season only,
Else if Implied Removal < -20% then SNCR is operating in winter season only,
Else SNCR is operating year-round

Group 3.2 SNCR is operating in summer only
Mode 1 = 2009 ETS Winter NO_x Rate
Mode 2= 2009 ETS Summer NO_x Rate
Mode 3 = same as Group 1 Mode 3

Mode 4 = maximum {(1-0.25) * Mode 3, 0.1} for non FBC units
Mode 4 = maximum {(1-0.50) * Mode 3, 0.08} for FBC units

Note: The (1-.25) and (1-0.5) terms in the equations above represents the NO_x removal efficiencies of SNCR for non FBC and FBC boilers.

Group 3.3 SNCR is operating in winter only
Mode 1 = 2009 ETS Summer NO_x Rate
Mode 2 = 2009 ETS Winter NO_x Rate
Mode 3 = same as Group 3.2 Mode 3
Mode 4 = same as Group 3.2 Mode 4

Group 3.4 SNCR is operating year-round
Mode 1 = if (2007 ETS Winter NO_x Rate > 0.3, 2007 ETS Winter NO_x Rate, 2009 ETS Annual Average NO_x Rate)
Mode 2 = 2009 ETS Annual Average NO_x Rate
Mode 3 = same as Group 3.2 Mode 3
Mode 4 = Mode 3

Table 3-1.1 Examples of Base and Policy NO_x Rates Occurring in EPA Base Case v.4.10_FTransport

Plant Name	Unique ID	Post-Combustion 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.							
Four Corners	2442_B_1	None	0.786	0.786	0.509	0.509	Situation 4 also applies, i.e., unit had LNB and now added OFA so see drop in policy rates.
Situation 2: For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ.							
Big Sandy	1353_B_BSU2	SCR	0.629	0.146	0.629	0.146	(1) Has SCR so see difference between uncontrolled and controlled rates (2) Situation 3b also applies.
Situation 3a: Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or . . .							
Greene County	10_B_2	None	0.363	0.363	0.363	0.363	Situation 1 also applies.
Chalk Point LLC	1571_B_1	SCR	0.485	0.156	0.485	0.156	Situation 2 also applies.
Situation 3b: . . . is in the NO_x Regulated Region[3] where current combustion controls are assumed to be retained.							
Thomas Hill	2168_B_MB3	SCR	0.221	0.102	0.221	0.102	Situation 2 also applies.
Waukegan	883_B_17	None	0.336	0.336	0.336	0.336	(1) Has NO_x combustion control and is in SIP so doesn't get added combustion control. (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.							
Crist	641_B_4	SNCR	0.404	0.404	0.240	0.180	(1) Drop in uncontrolled policy NO_x rate compared to uncontrolled base rate is due to addition of combustion controls. (Note 0.24 is floor.)

[3] NO_x regulated region includes: Alabama, Arkansas, Connecticut, Delaware, District Of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

Table 3-1.2 Cutoff and Floor NO_x Rates (lb/MMBtu) in EPA Base Case v.4.10_FTransport

Boiler Type	Cutoff Rate (lbs/MMBtu)			Floor Rate (lbs/MMBtu)		
	Bituminous	Subbituminous	Lignite	Bituminous	Subbituminous	Lignite
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

Table 3-1.3 NO_x Removal Efficiencies for Different Combustion Control Configurations in EPA Base Case v.4.10_FTransport

(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 NO_x***	***0.718***
Dry Bottom Wall-Fired	Subbituminous /Lignite	LNB	0.135 + 0.541* Base NO_x	0.574
		LNB + OFA	***0.285 + 0.541* Base 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 NO_x***	***0.62***
Tangentially-Fired	Subbituminous /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 NO_x***	***0.713***

Notes:

LNB = Low NO_x Burner
OFA = Overfire Air
LNC = Low NO_x Control

3 SO_2 Removal Rates for Flue Gas Desulfurization (FGD)

Comment Theme: In EPA Base Case v.4.10 the assumed SO_2 removal efficiency for wet and dry FGD on new units and retrofits was 98% and 95% respectively. Comments indicated that the assumption of a 98% SO_2 removal rate for wet FGD on new units and retrofits might be suitable as a short-term performance guarantee but exceeded the long term removal rate that could be achieved under real operating conditions where load following is required. EPA was requested to use the same default wet and dry FGD removal rates as assumed in the previous base case v.3.0.2 EISA , i.e., 95% for wet FGD and 92% for dry FGD.

Discussion: In response to this comment, it was decided to base removal rates for new and retrofit FGD on historical performance data reported in EIA 860 (2008) rather than on the engineering design capabilities of the controls, as was previously used in EPA Base Case v.4.10. This will put the removal rate assumptions for be new and retrofit FGD on the same basis as existing controls.

Response: Default SO_2 removal rates for wet and dry FGD were revised to be based on data reported in EIA 860 (2008). This ensures that they reflect operating removal rates rather than the engineering design removal rates which some commenters asserted could not be maintained under load following conditions.

In particular, for new units and FGD retrofits installed by the model, the assumed SO_2 removal rates will be 96% for wet FGD and 92% for dry FGD. These are the average of the SO_2 removal efficiencies reported in EIA 860 (2008) for dry and wet FGD installed in 2008 or later.

Existing units reporting FGD removal rates in form EIA 860 (2008) will be assigned those rates. However, to reduce the incidence of implausibly high, outlier removal rates, units whose reported EIA Form 860 (2008) SO_2 removal rates are higher than the average of the upper quartile SO_2 removal rates will be assigned the upper quartile average unless the reported EIA 860 rate is confirmed in a submitted comment. One upper quartile removal rate is calculated across all installation years and replaces any reported removal rate that exceeds it no matter what installation year. Existing units not reporting FGD removal rates in form EIA 860 (2008) will be assigned the average of the applicable SO_2 removal rate for a dry or wet FGD as reported in EIA 860 (2008) for the same FGD installation year.

3.2 Resulting Updates

The following changes to *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* show the updates that were implemented for the Final Transport Rule analysis in EPA Base Case v4.10_FTransport.

In Chapter 3 − Power System Operation Assumptions

Change the entries in Table 3-11 as shown in red on the following page.

Table 3-11 Emission and Removal Rate Assumptions for Potential (New) Units in EPA Base Case v.4.10_FTransport

Gas	Controls, Removal, and Emissions Rates	Supercritical Pulverized Coal - Wet Scrubber	Supercritical Pulverized Coal - Dry Scrubber	Integrated Gasification Combined Cycle	Advanced Coal with Carbon Capture	Advanced Combined Cycle	Advanced Combustion Turbine	Biomass Conventional Direct-Fired Boiler	Biomass Gasification Combined Cycle	Geothermal	Landfill Gas
SO_2	Removal / Emissions Rate	~~98%~~ 96%with a floor of 0.06 lbs/MMBtu	~~93%~~ 92% with a floor of ~~0.065~~ 0.08 lbs/MMBtu	99%	99%	None	None	0.08 lbs/MMBtu	0.08 lbs/MMBtu	None	None
NO_x	Emission Rate	0.07 lbs/MMBtu	0.05 lbs/MMBtu	0.013 lbs/MMBtu	0.013 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.36 lbs/MMBtu	0.102 lbs/MMBtu	None	0.09 lbs/MMBtu
Hg	Removal / Emissions Rate	90%	90%	90%	90%	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: .000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	0.57 lbs/MMBtu	0.57 lbs/MMBtu	3.70	None
CO_2	Removal / Emissions Rate	205.2 - 217.3 lbs/MMBtu	205.2 - 217.3 lbs/MMBtu	205.2 - 217.3 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	None	None	None	None
HCl	Removal / Emissions Rate	99% 0.0001 lbs/mmBtu	99% 0.0001 lbs/mmBtu	99% 0.0001 lbs/mmBtu	99% 0.0001 lbs/mmBtu	–	–	–	–	–	–

In Chapter 5 − Emission Control Technologies
Incorporate the changes shown in red below.

5.1 Sulfur Dioxide Control Technologies

Two commercially available Flue Gas Desulfurization (FGD) technology options for removing the SO_2 produced by coal-fired power plants are offered in EPA Base Case v.4.10: Limestone Forced Oxidation (LSFO) — a wet FGD technology — and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO_2 content exceeds 3 lbs SO_2/MMBtu, so this technology is provided only to plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu. In EPA Base Case v.4.10 when a unit retrofits with an LSD SO_2 scrubber, it loses the option of burning BG, BH, and LG coals due to their high sulfur content.

In EPA Base Case v.4.10 the LSFO and LSD SO_2 emission control technologies are available to existing "unscrubbed" units. They are also available to existing "scrubbed" units with reported removal efficiencies of less than fifty percent. Such units are considered to have an injection technology and classified as “unscrubbed” for modeling purposes in the NEEDS database of existing units which is used in setting up the EPA base case. The scrubber retrofit costs for these units are the same as regular unscrubbed units retrofitting with a scrubber. Scrubber efficiencies for existing units were derived from data reported in EIA Form ~~767~~ 860 (2008). In transferring this data for use in EPA Base Case v.4.10 the following changes were made. ~~The maximum removal efficiency was set at 98% for wet scrubbers and 93% for dry scrubber units. Existing units reporting efficiencies above these levels in Form 767 were assigned the maximum removal efficiency in NEEDS v.4.10 indicated in the previous sentence.~~ Units whose reported EIA Form 860 (2008) SO_2 removal rates were higher than the average of the upper quartile SO_2 removal rates were assigned the upper quartile average unless the EIA 860 rate was confirmed in a comment submitted during the Transport Rulemaking . One upper quartile removal rate is calculated across all installation years and replaces any reported removal rate that exceeds it no matter what installation year. Existing units not reporting FGD removal rates in form EIA 860 (2008) were assigned the average of the applicable SO_2 removal rate for a dry or wet FGD as reported in EIA 860 (2008) for the same FGD installation year.

As shown in Table 5-2, existing units that are selected to be retrofitted by the model with scrubbers are given the maximum removal efficiencies of ~~98%~~ 96% for LSFO and ~~93%~~ 92% for LSD. The procedures used to derive the cost of each scrubber type are discussed in detail in the following sections.

Table 5-2 Summary of Retrofit SO_2 Emission Control Performance Assumptions

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal	~~98%~~ 96% with a floor of 0.06 lbs/MMBtu	~~93%~~ 92% with a floor of ~~0.065~~ 0.08 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-4 for examples	Calculated based on characteristics of the unit: See Table 5-4 for examples
Heat Rate Penalty		
Cost (2007$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO_2/MMBtu
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, LD, LE, and LG	BA, BB, BD, BE, SA, SB, SD, LD, and LE

Potential (new) coal-fired units built by the model are also assumed to be constructed with a scrubber achieving a removal efficiency of ~~98%~~ 96% for LSFO and ~~93%~~ 92% for LSD. In EPA Base Case v.4.10 the costs of potential new coal units include the cost of scrubbers.

4 Coal Switching − Bituminous to Subbituminous

4.1 Response to the Comments Received

Comment Theme: In draft EPA Base Case v.410 it was assumed that generating units that had the option to burn both bituminous and subbituminous coal could use any proportion needed of each type of coal. Comments pointed out that there were limitations that prevented unrestricted switching at some existing generating units.

Discussion: Based on these comments, a procedure was developed to capture limitations that prevent unrestricted switching from bituminous to subbituminous coal without incurring additional investment costs. The procedure consisted of the following steps: (1) Determining a level of subbituminous coal consumption indicative of an existing capability to burn 100% subbituminous coal. (2) Developing cost adders, heat rate penalties, and decision rules that would apply to units that don't meet this threshold.

In EPA Base Case v.4.10_FTransport, existing units with a historical record of burning a high percentage of subbituminous (specifically, 90% or more) are assumed to have made investments required for high percentage subbituminous firing. Existing units not meeting the 90% criteria incur a fuel cost adder and heat rate penalty for combusting more than a pre-specified percent of subbituminous. The cost adder is designed to reflect material handling and boiler modification costs. The heat rate penalty reflects the impact of the higher moisture content subbituminous coal on the unit's heat rate. The procedure, which is summarized below, applies only to units that are currently designated to burn both bituminous and subbituminous coal in EPA Base Case v.4.10_FTransport. Historical fuel usage data is used to infer whether units have already made investments allowing them to burn unrestricted amounts of subbituminous coal.

Staff engineering analyses indicated that (a) all boilers that are designated to burn both bituminous and subbituminous coal should be able to burn a limited percentage of subbituminous (i.e., below 20%) without incurring the cost of boiler modifications and fuel handling improvements and (b) while boiler improvements can remove the limitations on the amount of subbituminous coal burned at a unit, they come at a cost ($250/kW) and an associated heat rate penalty (5%).

Consideration was given to allowing units that historically had burned more than 20%, but less than 90% subbituminous coal, to burn up to their historic maximum at no additional cost and only incur the additional cost and heat rate penalty when consuming above their historical maximum percent subbituminous use. However, comments (e.g., the 10/11/10 Dairyland Power Cooperative comment EPA-HQ-OAR-2009-0491-2733.1 on Genoa Unit 1) indicated that during the economic recession of 2007, 2008, and 2009 when electricity demand was lower than normal, units burned higher proportions of subbituminous coal without making the investments that would otherwise have been necessary if their generation had been high enough to trigger a capacity derating. During the recession, units were not generating at high enough levels for capacity deratings to become an issue. Taking this into consideration, EPA took the more conservative approach of assuming that unless the unit historically had burned more than 90% subbituminous coal, it had not previously made the investments needed to burn more than 20% subbituminous coal.

Response: The specifics of the procedure are as follows:

(b) For coal plants that have the option to burn both bituminous and subbituminous coal in EPA Base Case v.4.10_FTransport, those that have burned 90% or more subbituminous coal in 2008, 2009, or first half of 2010 are assumed to have already made the fuel handling and boiler investments needed to burn up to 100% subbituminous coal and would therefore not face any additional costs. In addition, their reported heat rates are assumed to reflect the impact of burning the corresponding proportion of subbituminous coal. EIA Form 423 is used to determine the percent of subbituminous coal burned in 2008, 2009, and first half of 2010.

(c) All other units with the option to burn both bituminous and subbituminous coal in EPA Base Case v.4.10, would have the option to burn
    (i) Less than 20% subbituminous coal without incurring any additional cost or heat rate penalty.

(j) Twenty percent (20%) or more subbituminous coal at a cost of $250/kW and a heat rate penalty of 5% to reflect additional fuel handling and boiler modification costs associated with burning higher proportions of subbituminous coal. The $250/kW cost adder is designed to cover boiler modifications or alternative power purchases in lieu of capacity deratings that would otherwise be associated with burning subbituminous coal with its lower heating value relative to bituminous coal.

4.2 Resulting Updates

The following changes to *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* show the updates that were implemented for the Final Transport Rule analysis in EPA Base Case v4.10_FTransport.

Add the following paragraph between sections 9.3.9 and 9.4.

9.3.10 Coal Switching

Recognizing that boiler modifications and fuel handling enhancements may be required for unrestricted switching from bituminous to subbituminous coal, the following conditions apply in EPA Base Case v.4.10_FTransport to coal plants that have the option to burn both bituminous and subbituminous coal.

Those that have burned 90% or more subbituminous coal in 2008, 2009, and first half of 2010 are assumed to have already made the fuel handling and boiler investments needed to burn up to 100% subbituminous coal and would therefore not face any additional costs. In addition, their reported heat rates are assumed to reflect the impact of burning the corresponding proportion of subbituminous coal. EIA Form 423 is used to determine the percent of subbituminous coal burned in 2008, 2009, and first half of 2010.

All other units with the option to burn both bituminous and subbituminous coal in EPA Base Case v.4.10_FTransport, are subject to the following conditions:

(1) If the unit consumes less than 20% subbituminous coal, no additional cost or heat rate penalty is incurred.

(2) If the unit consumes twenty percent (20%) or more subbituminous coal, it incurs a cost of $250/kW and a heat rate penalty of 5% to reflect additional fuel handling and boiler modification costs associated with burning higher proportions of subbituminous coal. The $250/kW cost adder is designed to cover boiler modifications or alternative power purchases in lieu of capacity deratings that would otherwise be associated with burning subbituminous coal with its lower heating value relative to bituminous coal. The heat rate penalty reflects the impact of the higher moisture content subbituminous coal on the unit's heat rate

5 Restrictions on coal choice in 2012

Comment Theme: Some comments indicated that various factors (including coal contracts and boiler engineering considerations) limited the ability of coal units to change coal grades in the short to medium term and requested that the model reflect these limitations.

Discussion: In draft EPA Base Case v.4.10 generating units are given coal choices consistent with the unit's engineering characteristics, the SO2 emissions limits they face, and the historical record of coals burned at the unit. Once the coal assignments are made, no further restrictions are typically placed on the fuels available to the unit.

Factors limiting changes is near term coal use were considered technically plausible in the first model run year of 2012. Consequently, EPA incorporated such limitations in 2012 in cases where the affected units were explicitly identified, where sufficient documentation and an adequate explanation of the governing factors were provided, where EPA was not aware of data contradicting the claim, and where the inclusion of the limitation might affect modeling results. Beyond 2012, however, EPA's assessment of industry experience suggested that economic considerations would take precedent over short-term restrictions and that the full choice of previously assigned coals should be re-instated for coal units. This would allow the model to make fuel choices based on economic factors reflecting the tendency of these factors to prevail beyond the short term.

Response:
(1) If a comment identified specific units that could not change from a specific coal due to short term constraints and generally met the conditions outlined above, the unit's coal assignment in 2012 would be limited to the coal stipulated in the comment. If not explicitly stipulated in the comment, the coal reported most recently at the plant level in EIA Form 926 would be used. If the information was not reported in EIA Form 926, the unit would be assigned the coal grade which would result in an emission rate closest to the SO2 rate reported for the unit in EPA's Emission Tracking System (ETS) 2009.
(2) If a comment identified by name a group of units (e.g., by company or by plant name) whose coal choices could not change over the short run, the same procedure as described in item #1 was followed, except that it was applied to all units in the group of units.
(3) If a comment did not identify specific units or a specific set of units where coal choices were limited, no change was made.
(4) After 2012, such restrictions no longer apply..

● ●

Changes to be Incorporated in *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model*

Add the following paragraph between new section 9.3.10 and before section 9.4.

9.3.11 Short-term restrictions on coal choice

In draft EPA Base Case v.4.10 generating units are given coal choices consistent with the unit's engineering characteristics, the SO2 emissions limits they face, and the historical record of coals burned at the unit. Once the coal assignments are made, no further restrictions are typically placed on the fuels available to the unit.

However, coal choice was further restricted in the first model run year (2012) in the modeling horizon in situations where information was provided to EPA indicating that short-term factors (like coal contracts and boiler engineering considerations) limited a unit's choice to a particular assigned coal. Beyond the first model run year the full set of assigned coals was restored in keeping with the underlying modeling assumption that economic considerations prevail over short-term restrictions in the longer term.

9.3.11 Short-term restrictions on coal choice and related issues

In draft EPA Base Case v.4.10 generating units are given coal choices consistent with the unit's engineering characteristics, the SO2 emissions limits they face, and the historical record of coals burned at the unit. Once the coal assignments are made, no further restrictions are typically placed on the fuels available to the unit.

However, coal choice was further restricted in the first model run year (2012) in the modeling horizon in situations where information was provided to EPA indicating that short-term factors (like coal contracts and boiler engineering considerations) limited a unit's choice to a particular assigned coal. Beyond the first model run year the full set of assigned coals was restored in keeping with the underlying modeling assumption that economic considerations prevail over short-term restrictions in the longer term.

In conjunction with these changes, limits were imposed in fuel assignments at four Texas coal steam plants to increase consistency with reported fuel use at the plants. The percentage of lignite used in the first model run year (2012) was calibrated so that it would not exceed the historical level reported in 2009, the latest year for available fuel data as reported in EIA Form 923. This limit was increased linearly in model run year 2015 so that by model run year 2020 there would no longer be a limit on lignite use. In other words by model run year 2020, the unit could choose to use up to 100% lignite if the model found that this was economically optimal. The four power plants that were affected by this procedure and the specific applicable limits are shown in the following table:

Plant Name	Plant ORIS ID	Maximum Percent of Heat Input (MMBtu) from Lignite For IPM Run Years Shown		
		2012	2015	2020
Big Brown	3497	≤ 50%	≤ 69%	≤ 100%
Limestone	298	≤ 54%	≤ 71%	≤ 100%
Martin Lake	6146	≤ 69%	≤ 80%	≤ 100%
Monticello	6147	≤ 19%	≤ 50%	≤ 100%

In addition, post-modeling quality assurance checks flagged the 100% subbituminous coal consumption projected at the Martin Lake for 2012 as a discrepancy with the high share of lignite use (74% by weight, 69% on an MMBtu heat content basis) that was reported for 2009 at this lignite mine-mouth plant. To increase short-term modeling consistency with the plant's recent operating history, its 2012 SO_2 emissions were re-calculated using its 2009 reported SO_2 emission rate and its 2012 projected heat input.

Post-modeling quality assurance found a similar discrepancy between the short-term projection and operating history at Gibbons Creek (ORIS 6136) Unit 1 where reported SO_2 emissions at the unit were indicative either of a unit not operating a scrubber or of a scrubber with a very low SO_2 removal efficiency, i.e., producing emission roughly equivalent to the sulfur content of purchased coal as reported in the EIA-923, Since the unit's scrubber had not been designated as "dispatchable" the model was forced to operate it, producing emissions in 2012 and 2014 that were not consistent with the recent operating experience of the unit. To increase short-term modeling consistency with the plant's operating history, its 2012 and 2014 SO_2 emissions were re-calculated to factor out the projected reductions from scrubbing.

6 Waste Coal Cost Correction

6.1 Response to the Comments Received

Comment Theme: Comments were received indicating that the cost of waste coal in draft EPA Base Case v.4.10 was much higher than actually encountered by buyers.

Discussion: Upon investigation it was found that a data entry error had resulted in incorrect waste coal prices. The labeling of the prices in a file obtained by EPA from an outside source had indicated units of 1987 dollars per short ton, which should have been labeled 2008 dollars per short ton.

Response: The dollar year labeling error was corrected and costs were then properly converted to 2007 dollars per short ton. The resulting corrected prices were consistent with those noted in the comment.

6.2 Resulting Updates

The following changes to *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* show the updates that were implemented for the Final Transport Rule analysis in EPA Base Case v4.10_FTransport.

For waste coal entries only (Coal Supply Region: NA; Coal Grade: WC) replace the previous values shown under the "Cost of Production" with the corrected values (highlighted in yellow in the table below)

Appendix 9-4 Coal Supply Curves in EPA Base Case V.4.10

Waste Coal Entries Only

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)		Coal Production (Million Tons/Year)
					Previous	Corrected	
2012	NA	WC	S1	12.35	21.9	12.7	6.6
2012	NA	WC	S2	12.35	22.8	13.3	3.9
2012	NA	WC	S3	12.35	23.9	13.9	2.6
2012	NA	WC	S4	12.35	24.3	14.2	0.9
2012	NA	WC	S5	12.35	24.5	14.3	0.3
2012	NA	WC	S6	12.35	24.6	14.3	0.1
2012	NA	WC	S7	12.35	24.6	14.3	0.1
2012	NA	WC	S8	12.35	24.8	14.4	0.3
2012	NA	WC	S9	12.35	25.4	14.8	0.9
2012	NA	WC	S10	12.35	28.8	16.7	2.6
2012	NA	WC	S11	12.35	41.8	24.3	3.9
2015	NA	WC	S1	12.35	22.0	12.8	7.2
2015	NA	WC	S2	12.35	23.2	13.5	4.2
2015	NA	WC	S3	12.35	24.6	14.3	2.8
2015	NA	WC	S4	12.35	25.2	14.6	0.9
2015	NA	WC	S5	12.35	25.4	14.8	0.3
2015	NA	WC	S6	12.35	25.6	14.9	0.2
2015	NA	WC	S7	12.35	25.7	15.0	0.2
2015	NA	WC	S8	12.35	26.0	15.1	0.3
2015	NA	WC	S9	12.35	27.1	15.8	0.9
2015	NA	WC	S10	12.35	32.9	19.2	2.8
2015	NA	WC	S11	12.35	58.7	34.2	4.2

Appendix 9-4 Coal Supply Curves in EPA Base Case V.4.10 (cont'd)

Waste Coal Entries Only

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)		Coal Production (Million Tons/Year)
					Previous	Corrected	
2020	NA	WC	S1	12.35	22.1	12.9	6.8
2020	NA	WC	S2	12.35	23.1	13.5	4.0
2020	NA	WC	S3	12.35	24.3	14.2	2.7
2020	NA	WC	S4	12.35	24.8	14.4	0.9
2020	NA	WC	S5	12.35	25.0	14.5	0.3
2020	NA	WC	S6	12.35	25.1	14.6	0.1
2020	NA	WC	S7	12.35	25.2	14.7	0.1
2020	NA	WC	S8	12.35	25.4	14.8	0.3
2020	NA	WC	S9	12.35	26.1	15.2	0.9
2020	NA	WC	S10	12.35	30.1	17.5	2.7
2020	NA	WC	S11	12.35	46.1	26.9	4.0
2030	NA	WC	S1	12.35	22.1	12.9	6.6
2030	NA	WC	S2	12.35	23.0	13.4	3.9
2030	NA	WC	S3	12.35	24.2	14.1	2.6
2030	NA	WC	S4	12.35	24.6	14.3	0.9
2030	NA	WC	S5	12.35	24.8	14.4	0.3
2030	NA	WC	S6	12.35	24.9	14.5	0.1
2030	NA	WC	S7	12.35	24.9	14.5	0.1
2030	NA	WC	S8	12.35	25.1	14.6	0.3
2030	NA	WC	S9	12.35	25.7	15.0	0.9
2030	NA	WC	S10	12.35	29.1	16.9	2.6
2030	NA	WC	S11	12.35	42.3	24.6	3.9
2040	NA	WC	S1	12.35	22.2	12.9	6.8
2040	NA	WC	S2	12.35	23.2	13.5	4.0
2040	NA	WC	S3	12.35	24.4	14.2	2.6
2040	NA	WC	S4	12.35	24.9	14.5	0.9
2040	NA	WC	S5	12.35	25.1	14.6	0.3
2040	NA	WC	S6	12.35	25.1	14.6	0.1
2040	NA	WC	S7	12.35	25.2	14.7	0.1
2040	NA	WC	S8	12.35	25.4	14.8	0.3
2040	NA	WC	S9	12.35	26.2	15.2	0.9
2040	NA	WC	S10	12.35	30.1	17.5	2.6
2040	NA	WC	S11	12.35	45.8	26.7	4.0

Appendix 9-4 Coal Supply Curves in EPA Base Case V.4.10 (cont'd)

Waste Coal Entries Only

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)		Coal Production (Million Tons/Year)
					Previous	Corrected	
2050	NA	WC	S1	12.35	22.2	12.9	6.8
2050	NA	WC	S2	12.35	23.2	13.5	4.0
2050	NA	WC	S3	12.35	24.4	14.2	2.6
2050	NA	WC	S4	12.35	24.9	14.5	0.9
2050	NA	WC	S5	12.35	25.1	14.6	0.3
2050	NA	WC	S6	12.35	25.1	14.6	0.1
2050	NA	WC	S7	12.35	25.2	14.7	0.1
2050	NA	WC	S8	12.35	25.4	14.8	0.3
2050	NA	WC	S9	12.35	26.2	15.2	0.9
2050	NA	WC	S10	12.35	30.1	17.5	2.6
2050	NA	WC	S11	12.35	45.8	26.7	4.0

7 Comments Considered but that did not Result in Changes

Oil consumption at dual fired (oil/gas) units
Comment Theme: When compared with recent operating experience, the extent of oil burned by dual fuel generating units in draft EPA Base Case v.4.10 was considerably lower than some commenters thought it should be.
Response: Consideration was given to a number of options for modifying the modeling of oil use at duel fuel units, but it was ultimately decided not to change the previous representation for the following reasons:

(1) The underlying factors that could be causing greater oil consumption were very site specific and the information that would allow modeling such occurrences was not available.
(2) In the absence of site specific information, imposing generic requirements for pre-specified levels of oil consumption was considered to have more drawbacks than the current representation.
(3) Due to their small population, dual fired units are not likely figure significantly in modeling the Transport Rule. Enhanced modeling capability in this regard could be revisited if and when future policies are modeled where oil use by duel fuel units has significant policy implications.

Capital cost of Flue Gas Desulfurization (FGD) on units whose capacity is less than 100 MW
Comment Theme: Some commenters considered the capital cost assumptions in draft EPA Base Case v.4.10 for retrofitting generating units under 100 MW with FGD to be too low. For example, one commenter indicated that the v.4.10 FGD retrofit costs for these units should be multiplied by 4.
Response: The original cost assumptions were retained. Specifically, the FGD capital cost for units below 100 MW is assumed to be the same as those for 100 MW units. While it is recognized that economies of scale would not be realized by units smaller than 100 MW that installed a standard FGD dedicated solely to that unit, prior engineering practice indicates a number of ways that costs will be held at the 100 MW level. Such practices include combining the emissions from multiple smaller units into a larger FGD and thereby achieving economy of scale. Another cost controlling approach for achieving economies of scale that has recently been seen in the marketplace is the development of innovative combinations of controls (e.g., dry sorbent injection, alkali injection, and circulating scrubbers) whose overall cost is lower than the sum of each of the constituent controls taken individually. These options provide a sound technical and economic basis for retaining the current approach of determining the capital cost of FGD for the universe of units less than 100 MW in EPA Base Case v.4.10

Selective Catalytic Reduction (SCR) retrofit costs
Comment Theme: Assumed SCR retrofit costs are too low in EPA Base Case v.4.10
Response: The SCR and FGD cost assumptions in EPA Base Case v.4.10 were updated in the summer of 2010 based on substantial engineering analyses and market assessments by an independent engineering firm. (This is documented on EPA web site at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf and www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52A.pdf.) In response to the comments received on SCR costs, EPA reviewed the cost assumptions and concluded not to modify them at this time. Although site specific conditions (which may the basis for the comments) can result in higher costs, the assumptions developed for EPA Base Case v.4.10 were deemed to be current, to have a strong economic and engineering basis, and to be applicable across the fleet of U.S. generating units.

30 year book life for emission control retrofits
Comment Theme: The 30 year book life assumed for retrofits in v.4.10 is too long. Many retrofits are on smaller and older units where an additional 20-30 year of life is not likely.
Response: For several reasons, the 30 year book life assumption for emission control retrofits was retained. First, as described in section 4.2.8 and Table 4-10 of *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* (www.epa.gov/airmarkets/progsregs/epa-

ipm/docs/v410/Chapter4.pdf), existing units in EPA Base Case v.4.10 incur a life extension cost if they remain in operation past their current expected lifespan. (For existing coal units this occurs when they pass age 40.) The assumption of a 30-year book life for retrofits is consistent with these life extension provisions which allow existing units to stay in operation throughout the 2012-2050 modeling time horizon, rather than forcing them retire upon reaching a pre-specified expected lifespan. The 30-year book life is in line with the 30-year design life typically specified in purchase agreements to ensure the quality of materials and cyclic fatigue life of power boilers, turbines and associated emission control systems. It is also well within the service life of such equipment which extends far beyond 30 years when generally accepted maintenance practices are followed.

Must run, black start, and spinning reserve units

Comment Theme: The model retires units that some commenters identified as being prevented from retiring for reliability purposes

Response: There are several reasons for retaining the current approach that does not attempt to account for "must run" units and does not prevent such units from retiring. First, for competitive business reasons, a comprehensive listing of must-run units is not available from either public or private sources. Limiting the "must run" designation only to those units identified in comments would introduce inconsistency across the universe of units. Second, there is no technically sound approach for defining the extent of operation of a "must run" unit. Finally, there is no technical basis for defining the period over which the "must run" designation would last. This is a particularly important issue in view of the long modeling time horizon (2012 to 2050) in EPA Base Case v.4.10.

Availability assumptions for existing coal units

Comment Theme: The availability assumption for coal units in EPA Base Case v.4.10 should not be based on historical capacity factor data from the Energy Information Administration's *Annual Energy Outlook* 2010 (AEO 2010 but on availabilities in NERC GADS as was done in previous EPA base cases (including v.3.0.2 EISA)

Response: Rather than using NERC GADS availabilities, EPA Base Case v.4.10 adopts an approach similar to AEO 2010 of using historical capacity factors to define the availabilities of existing coal units. The change was a result of analysis that showed that for a large portion of the coal fleet, actual capacity factors for existing coal units fell below the availabilities in NERC GADS. It is also based on an assessment that indicated that the system-level availabilities that are found in NERC GADS were not entirely comparable to the plant level availabilities required for IPM. Comparing previous base case projections to historical data showed tendencies to over-project coal consumption and under-project gas consumption as a result of the use of the GADS availabilities. Consequently, v.4.10 adopts the approach used in AEO 2010 and other modeling efforts which tie availability assumptions for existing coal units to historical capacity factors (plus a growth assumption for capacity factors below 75% and an upper cut off of 95% to reflect an assumed 5% force outage rate). The historical capacity factors used to derive the availability assumptions in EPA Base Case v.4.10 were obtained from AEO 2010.

Addenda − Notes on various modeling assumptions

Though not necessarily responses to comments received on the Transport Rule or NODA, the following features of EPA Base Case v.4.10_FTransport are annotated below for purposes of documentation.

1. **Dry Sorbent Injection (DSI) and Fabric Filter Cost Development** Section 5.5.3.2 and Appendix 5-4 on dry sorbent injection and section 5.5.4 and Appendix 5-5 on fabric filter cost development are incorporated below from the *Documentation Supplement for EPA Base Case v.4.10_Ptox – Updates for Proposed Toxics Rule*. Minor changes have been made to the text to highlight aspects particularly relevant to the Final Transport Rule, i.e., the use of DSI in combination a fabric filter as a retrofit option for SO_2 control.

2. **Variable Operating and Maintenance (VOM) Cost of Dry Sorbent Injection (DSI) Retrofits:** In modeling the Final Transport Rule (i.e., in EPA Base Case v.4.10_FTransport), DSI is provided as a retrofit for units burning coals with an SO_2 content of less than 2 lbs/mmBtu and is assumed to be retrofit in conjunction with a fabric filter. When retrofit on units with a pre-existing fabric filter, it is assumed that no ESP is present and that the DSI is installed upstream of the FF. Consequently, the fly ash that is caught in the fabric filter will be contaminated by the sorbent and not marketable. Since the entire combined fly ash, reaction products, and unreacted sorbent mass will have to be disposed, the full DSI capital, FOM, and VOM costs are incurred. In contrast, when DSI is retrofit on units with no pre-existing fabric filter, it is assumed that the DSI will be installed after the ESP (which, in the absence of a FF, will be present for PM control) and upstream of the FF which is installed in conjunction with the DSI. Since the upstream ESP will capture the fly ash before it arrives at the DSI, it will not be contaminated by the sorbent and can be sold rather than disposed. (Note: No credit for fly ash sales is taken into account in IPM.) Only the reaction products and unreacted sorbent which is caught in the FF will need to be landfilled. Since the waste disposal cost only applies to the sorbent, there is a 35% reduction in VOM. In this situation the reduced VOM and standard capital and FOM costs are incurred for the DSI retrofit plus the capital, FOM, and VOM costs for the associated FF.

3. **Updated Appendices 3-2 through 3-4:** These appendices, which are included below, show the state power sector air emissions regulations (Appendix 3-2), NSR settlements (Appendix 3-3) and state settlements (Appendix 3-4) that are represented in EPA Base Case v.4.10_FTransport.

4. **2012 Emission Control Retrofits:** In EPA's modeling for the Final Transport Rule, emission controls in response to the Transport Rule are not allowed to be occur in 2012, the first model run year, because of insufficient lead time to install flue gas desulfurization (FGD) for SO2 and selective catalytic reduction (SCR) for NO_x control by 2012. However, in order not to overstate the emission levels without the Transport Rule, emission controls are allowed to occur in 2012 in response to non-Transport Rule legal requirements that were in place in 2010 or earlier. While the specific controls that the model builds and operates (or partially operates) may not correspond to those actually installed as part of a source's compliance strategy, they should capture valid levels of emission reductions that can be expected to be achieved in complying with binding non-Transport Rule agreements or regulations. This dual approach to 2012 retrofits is implemented by allowing the model to install emission control retrofits in 2012 in the base case (which does not include Transport Rule but does include binding non-Transport Rule legal requirements). Any 2012 retrofits occurring in the base case are then carried over into the "Remedy" policy case (which includes the Final Transport Rule emission requirements), but the model is not allowed to install any additional 2012 emission controls (which would come in response to the Transport Rule requirements).

5. **Emission Controls in IPM Parsed Files:** Users are sometimes unclear about the origins of the advanced post-combustion emission controls (e.g., FGD or SCR) that appear in the "parsed files" for

an IPM model run. These controls originate in one of four possible sources. (1) Most existing controls are the same as those found in the National Electric Energy Data System (NEEDS), the database of existing and planned/committed units which serves as the starting point for setting up EPA's base and policy cases using IPM. For the Final Transport Rule existing controls are those present in 2011 or earlier. (2) A small number of existing emission controls appear in parsed files, but are not found in NEEDS. They are controls that became known after the NEEDS database was "frozen" for purposes of setting up a family of model runs. Rather than appearing in NEEDS, they are represented directly in IPM as emission control retrofit options available from the start of the modeling time horizon. They can either be forced to operate through the imposition of modeling constraints (in which case they are termed "non-dispatchable" controls) or be left for the model to determine endogenously whether emission policies require them to operate (in which case they are termed "dispatchable" controls). (3) Some generating units have either (a) an existing legal requirement, such as a consent decree or state rule requiring the installation of a control by a particular date post 2011, or (b) have publically announced or submitted comment noting the installation and/or beginning of construction of a control for post 2011 start-up. In instances where the control is expected in the future, but not present by 2011 or earlier, the control is represented directly in IPM as a retrofit option which is either forced by a modeling constraint to be installed and operate (non-dispatchable controls) or left for the model to determine whether they need to operate (dispatchable controls). These controls appear in the model run year corresponding to the year they are expected to operate (typically 2012 or 2015) both in IPM outputs and parsed files. They do not appear in NEEDS (since they were not present prior to 2012). (4) The remaining emission controls found in parsed files are those that the model builds as part of the optimal (most cost effective) solution in response to all the requirements faced by the electric power system represented in the model.

6. **Mercury Emission Modification Factor (EMF) for Waste Coal Units:** In EPA Base Case v.4.10_FTransport (as in the base case for the proposed Mercury and Air Toxics Standards Rule - EPA Base Case v.4.10_PTox), all waste coal units are assumed to have a mercury EMF of 0.02.

7. **Carbon dioxide (CO_2) Emissions from Chemical Reactions in a Wet Flue Gas Desulfurization (FGD) System for Sulfur Dioxide (SO_2) Control:** In EPA applications of IPM the chemical reactions in a limestone forced oxidation (LSFO) system (also known as a wet FGD or wet scrubber) are assumed to cause CO_2 increases according to the following equation:

$$\text{CO}_2 \text{ increase in \% of total CO}_2 \text{ from fuel} = 0.35 \times \text{SO}_2 \text{ emission rate of the fuel (in lb/MMBtu)} - 0.02$$

For example, for coal with an SO_2 emission factor of 4.3 lb/MMBtu, the increase in CO_2 is 1.485%. In contrast to LSFO, there is no representation of direct emissions of CO_2 or other greenhouse gases from the other control technologies in IPM. These include limestone spray dryers (LSD) for SO_2 control, dry sorbent injection (DSI) for SO_2 and hydrogen chloride (HCl) control, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) for NO_x control, and activated carbon injection (ACI) for mercury control.

Addendum A ─ Dry Sorbent Injection (DSI) and Fabric Filter Cost Development in EPA Base Case v.4.10_FTransport

Note: The numbering of the sections and tables in this addendum is the same as found in the *Documentation Supplement for EPA Base Case v.4.10_Ptox – Updates for Proposed Toxics Rule*, where this material originally appeared.

Table 5-21 Summary of Retrofit SO_2 (and HCl) Emission Control Performance Assumptions in v4.10_FTransport

Performance Assumptions	Limestone Forced Oxidation (LSFO)		Lime Spray Dryer (LSD)		Dry Sorbent Injection (DSI)[1]	
	SO_2	**HCl**	**SO_2**	**HCl**	**SO_2**	**HCl**
Percent Removal	96% with a floor of 0.06 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	92% with a floor of 0.065 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	**With fabric filter:** 70% --- **With an electrostatic percipitator[2]:** 50%	**With fabric filter:** 90% with a floor of 0.0001 lbs/MMBtu --- **With an electrostatic percipitator[2]:** 60% with a floor of 0.0001 lbs/MMBtu
Capacity Penalty	-1.65%		-0.70%		-0.65%	
Heat Rate Penalty	1.68%		0.71%		0.65%	
Cost (2007$)	See Table 5-3 and 5-4		See Table 5-3 and 5-4		See Tables D and E	
Applicability	Units ≥ 25 MW		Units ≥ 25 MW		Units ≥ 25 MW	
Sulfur Content Applicability			Coals ≤ 2.0% Sulfur by Weight		Coals ≤ 2.0 lb/mmBtu of SO_2	
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, LD, LE, and LG		BA, BB, BD, BE, SA, SB, SD, LD, LE, and LG		BA, BB, BD, SA, SB, SD, and LD	

Notes

1. The cost and performance values shown in this table apply to existing units with pre-existing fabric filters or electrostatic precipitators. Units with neither ESP nor FF are assumed to have to install a fabric filter in order to qualify for the DSI retrofit.
2. The option to retrofit DSI on existing units with ESP was not offered in the runs performed for the current rulemaking.

5.5.3.2 Dry Sorbent Injection

EPA Base Case v4.10_FTransport includes dry sorbent injection (DSI) as a retrofit option for achieving (in combination with a particulate control device) SO_2 (and HCl) removal. With DSI a dry sorbent is injected into the flue gas duct where it reacts with the SO_2 and HCl in the flue gas to form a compound, which is then captured in a downstream fabric filter or electrostatic precipitator (ESP) and disposed of as waste. (A sorbent is a material that takes up another substance by either adsorption on its surface or absorption internally or in solution. A sorbent may also chemically react with another substance.) The sorbent assumed in the cost and performance characterization discussed in this section is trona, a sodium-rich material with major underground deposits found in Sweetwater County, Wyoming. Trona is typically delivered with an average particle size of 30 μm diameter, but can be reduced to about 15 μm through onsite in-line milling to increase its surface area and capture capability.

Removal rate assumptions: The removal rate assumptions for DSI are summarized in Table 5-21. The assumptions shown in the last two columns of Table 5-21 were derived from assessments by EPA engineering staff in consultation with Sargent & Lundy. As indicated in this table, the assumed SO2 removal rate for DSI + ESP is 50% and for DSI + fabric filter is 70%. The assumed HCl removal rate is 60% for DSI + ESP and 90% for DSI + fabric filter. (This is noted in the next-to-the-last column in Table 5-21.) Although the option to retrofit DSI on existing units with ESP is shown in Table 5-21 it was not offered in the runs performed for the current rulemaking.

Methodology for Obtaining DSI Control Costs: The engineering firm of Sargent & Lundy, whose analyses were used to update the cost of SO_2 and post-combustion NO_x controls in EPA Base Case , v4.10, performed similar engineering assessments of the cost of DSI retrofits with two alternative, associated particulate control devices, i.e., ESP and fabric filter (also called a "baghouse"). Their analysis of DSI noted that the cost drivers of DSI are quite different from those of wet or dry FGD. Whereas plant size and coal sulfur rates are key underlying determinants of FGD cost, sorbent feed rate and fly ash waste handling are the main drivers of the capital cost of DSI with plant size and coal sulfur rates playing a secondary role.

Sorbent feed rate determines the amount of sorbent required and the size and extensiveness of the DSI installation. The sorbent feed rate needed to achieve a specified percent SO_2 or HCl removal[4] is firstly a function of the flue gas SO_2 rate (which, in turn, is a function of the sulfur content of the coal burned, expressed in lbs of SO_2/mmBtu), the unit's size and heat rate, and the sorbent particle size (which determines whether in-line milling is needed). The sorbent feed rate is also a function of the residence time of the sorbent in the flue gas stream and the extent of mixing and penetration of the sorbent in the flue gas. Residence time, penetration, and mixing are largely dependent on the type of particulate control device use (electrostatic precipitator or fabric filter).

In EPA Base Case v4.10_FTransport the DSI sorbent feed rate and variable O&M costs are based on assumptions that a fabric filter and in-line trona milling are used, and that the SO2 removal rate is 60%. The corresponding HCl removal effect is assumed to be 90%, based on information from Solvay Chemicals (H. Davidson, *Dry Sorbent Injection for Multi-pollutant Control Case Study*, CIBO IECT VIII, August 2010).

The cost of fly ash waste handling, the other key contributor to DSI cost, is a function of the type of particulate capture device and the flue gas SO_2 rate (which, as noted above, is itself a function of the

[4] For purposes of engineering calculations the percent removal is often translated into a corresponding "Normalized Stoichiometric Ratio" (NSR) associated with a particular percent removal, where the NSR is defined as

$$NSR = \left(\frac{moles\ of\ sobent\ inject}{moles\ of\ SO2\ in\ flue\ gas}\right) \Big/ (theoretical\ moles\ of\ sorbent\ required)$$

sulfur content of the coal and the unit's size and heat rate). Fly ash waste handling costs are also a function of the ash content and the higher heating value (HHV) of the coal. The governing variables of the key capital cost components of DSI are presented in Table 5-22.

Table 5-22. Capital Cost Components and Their Governing Variables for HCl Removal with DSI.

Module	Retrofit Difficulty (1 = average)	Particulate Capture Type (ESP or Baghouse)	Sorbent Particle Size Require-ment (milled or unmilled)	Heat Rate (Btu/ kWh)	SO2 Rate of coal (lb/ MMBtu)	Ash Content of Coal (percent)	Higher Heating Value (HHV) of Coal (Btu/lb)	Unit Size (MW)
Sorbent Feed Handling	X		X	X	X			X
Fly Ash Waste Handling	X	X		X		X	X	X

Once the key variables for the two DSI modules are identified, they are used to derive costs for each base module component. These costs are then summed to obtain total bare module costs. The base installed cost for DSI includes

- All equipment
- Installation
- Buildings
- Foundations
- Electrical
- Average retrofit difficulty
- In-line milling equipment is assumed to be included

This total is increased by 15% to account for additional engineering and construction management costs, labor premiums, and contractor profits and fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC), the CECC subtotal is increased by 5% to account for owner's home office costs, i.e., owner's engineering, management, and procurement costs. Since DSI installations are expected to be completed in less than a year, no Allowance for Funds used During Construction (AFUDC) is provided for DSI. The cost resulting from these calculations is the capital cost factor (expressed in $/kW) that is used in EPA Base Case v4.10_FTransport.

Variable Operating and Maintenance Costs (VOM): These are the costs incurred in running an emission control device. They are proportional to the electrical energy produced and are expressed in units of $ per MWh. For DSI, Sargent & Lundy identified three components of VOM: (a) costs for sorbent usage, (b) costs associated with waste production and disposal, (c) cost of additional power required to run the DSI control (often called the "parasitic load"). For DSI, sorbent usage is a function of the "Normalized Stoichiometric Ratio" and SO_2 feed rate. As noted above the feed rate is a function of the SO_2 rate of the coal and the unit's size and heat rate.

Total waste production involves the production of both reacted and unreacted sorbent and fly ash.

Sorbent waste is a function of the sorbent feed rate with an adjustment for excess sorbent feed. Use of DSI makes the fly ash unsalable, which means that any fly ash produced must be landfilled along with the reacted and unreacted sorbent waste. Typical ash contents for each fuel are used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for the total waste stream for the VOM analysis.

For purposes of modeling, the total VOM includes the first two component costs noted in the previous paragraph, i.e., the costs for sorbent usage and the costs associated with waste production and disposal,. The last component – cost of additional power – is factored into IPM, not in the VOM value, but through a capacity and heat rate penalty as described in the next paragraph.

Capacity and Heat Rate Penalty: The amount of electrical power required to operate the DSI is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 0.65% of the unit's electrical generation is needed to operate DSI, the generating unit's capacity is reduced by 0.65%. This is the "capacity penalty." At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the DSI device), the unit's heat rate is scaled up such that a comparable reduction (0.65% in the previous example) in the new higher heat rate yields the original heat rate. The factor used to scale up the original heat rate is called "heat rate penalty." It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency). As was the case for FGD in EPA Base Case v4.10, specific DSI heat rate and capacity penalties are calculated for each installation. For DSI the installation specific calculations take into account the additional power required by air blowers for the injection system, drying equipment for the transport air, and in-line milling equipment, if required.

Fixed Operating and Maintenance Costs (FOM): These are the annual costs of maintaining an emission control. They represent expenses incurred regardless of the extent to which the emission control system is run. They are expressed in units of $ per kW per year. In calculating FOM Sargent & Lundy took into account labor and materials costs associated with operations, maintenance, and administrative functions. The following assumptions were made:

- FOM for operations is based on the number of operators needed which is a function of the size (i.e., MW capacity) of the generating unit. In general for DSI two (2) additional operators are assumed to be needed.

- FOM for maintenance is a direct function of the DSI capital cost.

- FOM for administration is a function of the FOM for operations and maintenance.

Table 5-23 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalties of a DSI retrofit for an illustrative and representative set of generating units with the capacities and heat rates indicated.

Illustration worksheets of the detailed calculations performed to obtain the capital, VOM, and FOM costs for an example DSI appear in Appendix 5-4. The worksheets were developed by Sargent & Lundy[5].

[5]These worksheets were extracted from Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies: Complete Dry Sorbent Injection Cost Development Methodology* (Project 12301-007), May 2010. The complete report is available for review and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/.

Table 5-23. Illustrative Dry Sorbent Injection (DSI) Costs for Representative Sizes and Heat Rates Under Assumptions in EPA Base Case v4.10_FTransport

Control Type	**Heat Rate (Btu/ kWh)**	**SO2 Rate (lb/ MMBtu)**	**Capacity Penalty (%)**	**Heat Rate Penalty (%)**	**Variable O&M (mills/ kWh)**	**Capacity (MW)**									
						100		**300**		**500**		**700**		**1000**	
						Capital Cost ($/kW)	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**
DSI - FF	9,000	2.0	0.64	0.65	6.05	122	2.25	55	0.87	38	0.57	30	0.43	28	0.36
Assuming Bituminous Coal	10,000	2.0	0.71	0.72	6.72	125	2.28	57	0.89	40	0.58	31	0.43	31	0.38
	11,000	2.0	0.79	0.79	7.40	129	2.30	59	0.90	41	0.59	34	0.46	34	0.41
DSI - ESP	9,000	2.0	1.08	1.10	11.23	141	2.41	64	0.94	47	0.64	47	0.57	47	0.52
Assuming Bituminous Coal	10,000	2.0	1.20	1.22	12.47	145	2.44	66	0.96	52	0.68	52	0.61	52	0.56
	11,000	2.0	1.32	1.34	13.72	149	2.48	68	0.98	58	0.73	58	0.65	58	0.60

5.5.4 Fabric Filter (Baghouse) Cost Development

Fabric filters are not endogenously modeled as a separate retrofit option in EPA Base Case v4.10_FTransport, but are accounted for as a cost adder when installed in conjunction with DSI. In EPA Base Case v4.10_FTransport, an existing or new fabric filter particulate control device is a pre-condition for installing a DSI retrofit. Any unit that is retrofit by the model with DSI and does not have an existing fabric filter incurs the cost of installing a fabric filter. This cost is added to the DSI costs discussed in section 5.5.3.2. This section describes the methodology used by Sargent & Lundy to derive the cost of a fabric filter.

The engineering cost analysis is based on a pulse-jet fabric filter which collects particulate matter on a fabric bag and uses air pulses to dislodge the particulate from the bag surface and collect it in hoppers for removal via an ash handling system to a silo. This is a mature technology that has been operating commercially for more than 25 years. “Baghouse” and “fabric filters” are used interchangeably to refer to such installations.

<u>Capital Cost</u>: Two governing variables are used to derive the bare module capital cost of a fabric filter. The first of these is the “air-to-cloth” (A/C) ratio. The major driver of fabric filter capital cost, the A/C ratio is defined as the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater the area of the cloth required and the higher the cost for a given volumetric flow.

The other determinant of capital cost is the flue gas volumetric flow rate (in ACFM) which is a function of the type of coal burned and the unit’s size and heat rate.

The capital cost for fabric filters include:

- Duct work modifications,
- Foundations,
- Structural steel,
- Induced draft (ID) fan modifications or new booster fans, and
- Electrical modifications.

After the bare installed total capital cost is calculated, it is increased by 20% to account for additional engineering and construction management costs, labor premiums, and contractor profits and fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC), the CECC subtotal is increased by 5% to account for owner’s home office costs, i.e., owner’s engineering, management, and procurement costs, and by another 6% to account for Allowance for Funds used During Construction (AFUDC) which is premised on a 2-year project duration.

The cost resulting from these calculations is the capital cost factor (expressed in $/kW). Fabric filter capital costs are implemented in EPA Base Case v4.10_FTransport as an FOM adder. Plants that install fabric filters incur a total FOM charge which includes the true FOM associated with the fabric filter plus a capital cost FOM Adder derived by multiplying the capital cost by a capital charge rate of 11.3%, i.e.,

Total FOM = True FOM + Capital Cost FOM Adder

where the FOM Adder = Capital Cost X Capital Charge Rate = Capital Cost X 11.3%

In EPA Base Case v4.10_FTransport the capital cost of a fabric filter is based on the use of a “polishing” fabric filter designed with A/C=6.0. This basis results in a capital cost that is at least 10% less than the cost of a design with A/C=4.0, and assumes that the existing ESP remains in place and active.

Variable Operating and Maintenance Costs (VOM): For fabric filters the VOM is strictly a function of the costs of the fabric filter bag and cage translated in a $/MWhr cost based on the filter and bag replacement cycle for a specified A/C ratio. For units whose A/C ratio = 6.0, the replacement cycle for the bag is 3 years and the cage is 9 years, whereas for units whose A/C ratio = 4.0, the bag and cage replacement cycles are 5 and 10 years respectively.

Capacity and Heat Rate Penalty: Conceptually, the capacity and heat rate penalties for fabric filters represent the amount of electrical power required to operate the baghouse and are calculated by the same procedure used when calculating the capacity and heat rate penalty for DSI as described in section 5.5.3.2. The resulting capacity and heat rate penalties are both 0.6%.

However, since fabric filters were not endogenously modeled as a retrofit option, but simply added to the DSI costs for generating units that do not have an existing baghouse, the capacity and heat rate penalties described here were not factored into the representation of fabric filters in EPA Base Case v4.10_FTransport.

Fixed Operating and Maintenance Costs (FOM): Sargent & Lundy's engineering analysis indicated that no additional operations staff would be required for a baghouse. Consequently the FOM strictly includes two components:

- FOM for maintenance is a direct function of the DSI capital cost.
- FOM for administration is a function of the FOM for operations (which is zero) and maintenance.

Table 5-24 presents the capital, VOM, and FOM costs for fabric filters as represented in EPA Base Case v4.10_FTransport for an illustrative set of generating units with a representative range of capacities and heat rates.

Worksheets illustrating the detailed calculations performed to obtain the capital, VOM, and FOM costs for two example fabric filters (A/C Ratio = 4.0 and A/C Ratio = 6.0) appear in Appendix 5-5. The worksheets were developed by Sargent & Lundy[6].

[6] These worksheets were extracted from Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology* (Project 12301-009), October 2010. The complete report is available for review and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/.

Table 5-24. Illustrative Fabric Filter (Baghouse) Costs for Representative Sizes and Heat Rates Under Assumptions in EPA Base Case v4.10_FTransport

Coal Type	Heat Rate (Btu/ kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/ kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
Bituminous	9,000	0.60	0.60	0.15	188	0.8	153	0.6	139	0.6	130	0.6	122	0.5
	10,000				205	0.9	167	0.7	151	0.6	141	0.6	132	0.6
	11,000				221	0.9	180	0.8	163	0.7	153	0.6	143	0.6

Notes on Implementation

1. Plant specific fabric filter capital costs shown in this table are implemented in EPA Base Case v4.10_FTransport as an FOM adder. Plants that install fabric filters incur a total FOM charge which includes the true FOM component shown in the above table plus a capital cost FOM Adder derived by multiplying the capital cost in the table above by a capital charge rate 11.3%, i.e.,

Total FOM = True FOM + Capital Cost FOM Adder

where the FOM Adder = Capital Cost X Capital Charge Rate = Capital Cost X 11.3%.

Plants that install fabric filters also incur the additional VOM costs shown in the above table.

2. Since the fabric filter costs were not endogenously modeled as a retrofit option, the capacity and heat rate penalties shown in the above table were not represented in the model.

Appendix 5-4 Example Cost Calculation Worksheet for Dry Sorbent Injection (DSI) for HCl (and SO_2) Emissions Control in EPA Base Case v4.10_FTransport

Complete Dry Sorbent Injection Cost Development Methodology – Final

Table 1. Example Complete Cost Estimate for a DSI System

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H		50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.93	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.07	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A **Should be used for model input.**
Trona Cost	R	($/ton)	145	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	Labor cost including all benefits

Costs are all based on 2010 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	$	16,615,000	Base DSI module includes all equipment from unloading to injection
BM ($/KW) =		33	Base module cost per kW
Total Project Cost			
A1 = 5% of BM	$	831,000	Engineering and Construction Management costs
A2 = 5% of BM	$	831,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	831,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**19,108,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**38**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	955,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**20,063,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**40**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**20,063,000**	Total project cost
TPC ($/kW) =		**40**	Total project cost per kW

Complete Dry Sorbent Injection Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<-- User Input
Retrofit Factor	B		1	<-- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<-- User Input
SO2 Rate	D	(lb/MMBtu)	2	<-- User Input
Type of Coal	E		Bituminous	<-- User Input
Particulate Capture	F		ESP	<-- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H		50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.07	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A **Should be used for model input.**
Trona Cost	R	($/ton)	145	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	Labor cost including all benefits

Costs are all based on 2010 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (1 additional operator)*2080*U/(A*1000)	$	0.25	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.33	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.59**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = M*R/A	$	4.74	Variable O&M costs for trona reagent
VOMW ($/MWh) = (N+P)*S/A	$	3.18	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste
VOMP ($/MWh) = Q*T*10	$	-	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**7.92**	

Appendix 5-5 Example Cost Calculation Worksheets for Fabric Filters (A/C Ratio = 4.0 and A/C Ratio = 6.0) in EPA Base Case v4.10_FTransport

Table 1. Example Complete Cost Estimate for a 4.0 A/C Baghouse Installation (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
Type of Coal	D		Bituminous	<--- User Input
Baghouse Air-to-Cloth Ratio	E		4.0 A/C Ratio	<--- User Input
Heat Input	F	(Btu/hr)	4.75E+09	= A*C*1000
Flue Gas Rate	G	(acfm)	2,068,502	Downstream of an air preheater For Bituminous Coal = A*C*0.435 For PRB Coal = A*C*0.400 For Lignite Coal = A*C*0.362
Aux Power	**H**	**(%)**	**0.60**	0.6 default value **Should be used for model input.**
Aux Power Cost	J	($/kWh)	0.06	
Bag Cost	K	($/bag)	80	
Cage Cost	L	($/cage)	30	
Operating Labor Rate	M	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = if(E = 6.0 Air-to-Cloth then 422, E = 4.0 Air-to-Cloth then 476)*B*G^0.81	$	62,128,000	Base module for an additional baghouse including: ID or booster fans, piping, ductwork, etc...
BM ($/KW) =		124	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	6,213,000	Engineering and Construction Management costs
A2 = 5% of BM	$	3,106,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	3,106,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3	$	**74,553,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**149**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	3,728,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1	$	4,697,000	AFUDC for baghouse: 6% for a 2 year engineering and construction cycle
TPC ($) = CECC + B1 + B2 + C1 + C2	$	**82,978,000**	Total project cost
TPC ($/kW) =		**166**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (0 additional operators)*2080*M/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.005/(B*A*1000)	$	0.62	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	$	**0.63**	Total Fixed O&M costs
Variable O&M Cost			
VOMB ($/MWh) = if(E = 6.0 Air-to-Cloth then 0.004, E = 4.0 Air-to-Cloth then 0.005)*(K/3+L/9)	$	0.15	Variable O&M costs for bags and cages.
VOM ($/MWh) = VOMB	$	**0.15**	

Table 2. Example Complete Cost Estimate for a 6.0 A/C Baghouse Installation (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
Type of Coal	D		Bituminous	<--- User Input
Baghouse Air-to-Cloth Ratio	E		6.0 A/C Ratio	<--- User Input
Heat Input	F	(Btu/hr)	4.75E+09	= A*C*1000
Flue Gas Rate	G	(acfm)	2,068,502	Downstream of an air preheater For Bituminous Coal = A*C*0.435 For PRB Coal = A*C*0.400 For Lignite Coal = A*C*0.362
Aux Power	**H**	**(%)**	**0.60**	0.6 default value **Should be used for model input.**
Aux Power Cost	J	($/kWh)	0.06	
Bag Cost	K	($/bag)	80	
Cage Cost	L	($/cage)	30	
Operating Labor Rate	M	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = if(E = 6.0 Air-to-Cloth then 422, E = 4.0 Air-to-Cloth then 476)*B*G^0.81	$	55,080,000	Base module for an additional baghouse including: ID or booster fans, piping, ductwork, etc...
BM ($/KW) =		110	Base module cost per kW
Total Project Cost			
A1 = 10% of BM	$	5,508,000	Engineering and Construction Management costs
A2 = 5% of BM	$	2,754,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	2,754,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3	$	**66,096,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**132**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	3,305,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1	$	4,164,000	AFUDC for baghouse: 6% for a 2 year engineering and construction cycle
TPC ($) = CECC + B1 + B2 + C1 + C2	$	**73,565,000**	Total project cost
TPC ($/kW) =		**147**	Total project cost per kW
Fixed O&M Cost			
FOMO ($/kW yr) = (0 additional operators)*2080*M/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.005/(B*A*1000)	$	0.55	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	$	**0.56**	Total Fixed O&M costs
Variable O&M Cost			
VOMB ($/MWh) = if(E = 6.0 Air-to-Cloth then 0.004, E = 4.0 Air-to-Cloth then 0.005)*(K/3+L/9)	$	0.12	Variable O&M costs for bags and cages.
VOM ($/MWh) = VOMB	$	**0.12**	

Addendum B ─ Representation of State Electric Power Emission Regulations (Appendix 3-2), New Source Review (NSR) Settlements (Appendix 3-3), and State Settlements (Appendix 3-4) in EPA Base Case v.4.10_FTransport

Note: The numbering of the appendices in this addendum is the same as found in the *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model*, where an earlier version of these appendices previously appeared.

Appendices 3-2 (State Regulations), 3-3 (NSR Settlements), and 3-4 (State Settlements)

The tables of State Power Sector Regulations (Appendix 3-2), New Source Review Settlements (Appendix 3-3), and State Settlements (Appendix 3-4) were updated to reflect changes that had occurred since the provisions had been incorporated in EPA Base Case v4.10. The updated tables are included below.
****

Appendix 3-2 State Power Sector Regulations included in EPA Base Case v4.10_FTransport

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
Alabama	Alabama Administrative Code Chapter 335-3-8	NO_x	0.02 lbs/MMBtu annual PPMDV for combined cycle EGUs which commenced operation after April 1, 2003	2003
Arizona	Title 18, Chapter 2, Article 7	Hg	90% removal of Hg content of fuel or 0.0087 lb/GWH-hr annual reduction for all non-cogen coal units > 25 MW	2017
California	CA Reclaim Market	NO_x	9.68 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)	1994
		SO_2	4.292 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)	
Colorado	40 C.F.R. Part 60	Hg	2012 & 2013: 80% reduction of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for Pawnee Station 1 and Rawhide Station 101 2014 through 2016: 80% reduction of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for all coal units > 25 MW 2017 onwards: 90% reduction of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal units > 25 MW	2012
Connecticut	Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) 22a-174-22	NO_x	0.15 lbs/MMBtu rate limit in the winter season for all fossil units > 15 MW	2003
	Executive Order 19, RCSA 22a-198 & Connecticut General Statues (CGS) 22a-198	SO_2	0.33 lbs/MMBtu annual rate limit for all Title IV sources > 15 MW 0.55 lbs/MMBtu annual rate limit for all non-Title IV sources > 15 MW	
	Public Act No. 03-72 & RCSA 22a-198	Hg	90% removal of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal-fired units	2008
Delaware	Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions	NO_x	0.19 lbs/MMBtu ozone season PPMDV for stationary, liquid fuel fired CT EGUs >1 MW 0.39 lbs/MMBtu ozone season PPMDV for stationary, gas fuel fired CT EGUs >1 MW	2009
	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 > 25 MW	2009
		SO_2	0.26 lbs/MMBtu annual rate limit for coal and residual-oil fired units > 25 MW	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
		Hg	2012: 80% removal of Hg content of fuel or 0.0174 lb/GW-hr annual reduction for all coal units > 25 MW 2013 onwards: 90% removal of Hg content of fuel or 0.0087 lb/GW-hr annual reduction for all coal units > 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, Section 217.706	NO_x	0.25 lbs/MMBtu summer season rate limit for all fossil units > 25 MW	2004
	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 > 25 MW	2012
		SO_2	2013 & 2014: 0.33 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW 2015 onwards: 0.25 lbs/MMBtu annual rate limit for all Dynergy and Ameren coal steam units > 25 MW	2013
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GW-hr annual reduction for all Ameren and Dynergy coal units > 25 MW	2015
	Title 35 Part 225; Subpart F: Combined Pollutant Standards	NO_x	0.11 lbs/MMBtu ozone season and annual rate limit for all specified 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 specified Midwest Gen coal steam units	2013
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GWh annual reduction for all specified Midwest Gen coal steam units	2015
Kansas	NO_x Emission Reduction Rule, K.A.R. 28-19-713a.	NO_x	0.20 lbs/MMBtu annual rate limit for Quindaro Unit 2 and 0.26 lbs/MMBtu annual rate limit for Nearman Unit 1.	2012
Louisiana	Title 33 Part III - Chapter 22, Control of Emissions of Nitrogen Oxides	SO_2	1.2 lbs/MMBtu ozone season PPMDV for all single point sources that emit or have the potential to emit 5 tons or more of SO2 into the atmosphere	2005
	Title 33 Part III - Chapter 15, Emission Standards for Sulfur Dioxide	NO_x	Various annual rate limits depending on plant and fuel type for facilities within the Baton Rouge Nonattainment Area that collectively have the potential to emit 25 tons or more per year of NO_x or facilities within the Region of Influence that collectively have the potential to emit 50 tons or more per year of NO_x	2005
Maine	Chapter 145 NO_x Control Program	NO_x	0.22 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity < 750 MMBtu/hr 0.15 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity > 750 MMBtu/hr 0.20 lbs/MMBtu annual rate limit for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity > 250 MMBtu/hr	2005
	Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air	Hg	25 lbs annual cap for any facility including EGUs	2010

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
Maryland	Maryland Healthy Air Act	NO_x	3.6 MTons summer cap and 8.3 MTons annual cap for Mirant coal units 0.5 MTons summer cap and 1.4 MTons annual cap for Allegheny coal units 3.6 MTons summer cap and 8.03 MTons annual cap for Constellation coal units.	2009
		SO_2	2009 through 2012: 23.4 MTons annual cap for Constellation coal units, 24.2 MTons annual cap for Mirant Coal units, and 4.6 MTons annual cap for Allegheny coal units. 2013 onwards: 17.9 MTons annual cap for Constellation coal units, 18.5 MTons annual cap for Mirant Coal units, and 4.6 MTons annual cap for Allegheny coal units.	
		Hg	2010 through 2012: 80% removal of Hg content of fuel for Mirant, Allegheny, and Constellation coal steam units 2013 onwards: 90% removal of Hg content of fuel for Mirant, Allegheny, and Constellation coal steam units	
Massachusetts	310 CMR 7.29	NO_x	1.5 lbs/MWh annual GPS for Bayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	2006
		SO_2	3.0 lbs/MWh annual GPS for Bayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	
		Hg	2012: 85% removal of Hg content of fuel or 0.00000625 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor 2013 onwards: 95% removal of Hg content of fuel or 0.00000250 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Somerset Station, Mount Tom, Canal, and Salem Harbor	
Michigan	Part 15. Emission Limitations and Prohibitions - Mercury	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2015
Minnesota	Minnesota Hg Emission Reduction Act	Hg	90% removal of Hg content of fuel annually for all coal units > 250 MW	2008
Missouri	10 CSR 10-6.350	NO_x	0.25 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: 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 0.18 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW the following counties: City of St. Louis, Franklin, Jefferson, and St. Louis 0.35 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Buchanan, Jackson, Jasper, Randolph, and any other county not listed	2004
Montana	Montana Mercury Rule Adopted 10/16/06	Hg	0.90 lbs/TBtu annual rate limit for all non-lignite coal units 1.50 lbs/TBtu annual rate limit for all lignite coal units	2010
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	2012

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
	ENV-A2900 Multiple pollutant annual budget trading and banking program	NO_x	2.90 MTons summer cap for all fossil steam units > 250 MMBtu/hr operated at any time in 1990 and all new units > 15 MW 3.64 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6	2007
		SO_2	7.29 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6	
New Jersey	N.J.A.C. 7:27-27.5, 27.6, 27.7, and 27.8	Hg	90% removal of Hg content of fuel annually for all coal-fired units 95% removal of Hg content of fuel annually for all MSW incinerator units	2007
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 1	NO_x	2009 - 2012 annual rate limits in lbs/MMBtu for the following technologies: Coal Boilers (Wet Bottom) - 1.0 for tangential and wall-fired, 0.60 for cyclone-fired Coal Boilers (Dry Bottom) - 0.38 for tangential, 0.45 for wall-fired, 0.55 for cyclone-fired Oil and/or Gas or Gas only: 0.20 for tangential, 0.28 for wall-fired, 0.43 for cyclone-fired 2013 & 2014 annual rate limits in lbs/MWh for the following technologies: All Coal Boilers: 1.50 for all Oil and/or Gas: 2.0 for tangential, 2.80 for wall-fired, 4.30 for cyclone-fired Gas only: 2.0 for tangential and wall-fired, 4.30 for cyclone-fired 2015 onward annual rate limits in lbs/MWh for the following technologies: All Coal Boilers: 1.50 for all Oil and/or Gas: 2.0 for fuel heavier than No. 2 fuel oil, 1.0 for No. 2 and lighter fuel oil Gas only: 1.0 for all	2009
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 4	NO_x	2.2 lbs/MWh annual GPS for gas-burning simple cycle combustion turbine units 3.0 lbs/MWh annual GPS for oil-burning simple cycle combustion turbine units 1.3 lbs/MWh annual GPS for gas-burning combined cycle CT or regenerative cycle CT units 2.0 lbs/MWh annual GPS for oil-burning combined cycle CT or regenerative cycle CT units	2007
New York	Part 237	NO_x	39.91 MTons non-ozone season cap for fossil fuel units > 25 MW	2004
	Part 238	SO_2	131.36 MTons annual cap for fossil fuel units > 25 MW	2005
	Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units	Hg	786 lbs annual cap through 2014 for all coal fired boiler or CT units >25 MW after Nov. 15, 1990. 0.60 lbs/TBtu annual rate limit for all coal units > 25 MW developed after Nov.15 1990	2010
North Carolina	NC Clean Smokestacks Act: Statute 143-215.107D	NO_x	25 MTons annual cap for Progress Energy coal plants > 25 MW and 31 MTons annual cap for Duke Energy coal plants > 25 MW	2007
		SO_2	2012: 100 MTons annual cap for Progress Energy coal plants > 25 MW and 150 MTons annual cap for Duke Energy coal plants > 25 MW 2013 onwards: 50 MTons annual cap for Progress Energy coal plants > 25 MW and 80 MTons annual cap for Duke Energy coal plants > 25 MW	2009
Oregon	Oregon Administrative Rules, Chapter 345, Division 24	CO_2	675 lbs/MWh annual rate limit for new combustion turbines burning natural gas with a CF >75% and all new non-base load plants (with a CE <= 75%) emitting CO_2	1997

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
	Oregon Utility Mercury Rule - Existing Units	Hg	90% removal of Hg content of fuel reduction or 0.6 lbs/TBtu limitation for all existing coal units >25 MW	2012
	Oregon Utility Mercury Rule - Potential Units	Hg	25 lbs rate limit for all potential coal units > 25 MW	2009
Pacific Northwest	Washington State House Bill 3141	CO_2	\$1.45/Mton cost (2004\$) for all new fossil-fuel power plant	2004
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	
	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	
			Houston/Galveston region annual Cap and Trade (MECT) for all fossil units: 17.57 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	
Utah	R307-424 Permits: Mercury Requirements for Electric Generating Units	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2013
Wisconsin	NR 428 Wisconsin Administration Code	NO_x	Annual rate limits in lbs/MMBtu for coal fired boilers > 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	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs > 50 MW: 0.11 Distillate oil CTs > 50 MW: 0.28 Biologically derived fuel CTs > 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 > 25 MW: 0.04 Distillate oil CCs > 25 MW: 0.18 Biologically derived fuel CCs > 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19	
	Chapter NR 446. Control of Mercury Emissions	Hg	2012 through 2014: 40% reduction in total Hg emissions for all coal-fired units in electric utilities with annual Hg emissions > 100 lbs 2015 onwards: 90% removal of Hg content of fuel or 0.0080 lbs/GW-hr reduction in coal fired EGUs > 150 MW 80% removal of Hg content of fuel or 0.0080 lbs/GW-hr reduction in coal fired EGUs > 25 MW	2010

Notes:

Updates to the EPA Base Case v4.10_FTransport from EPA Base Case 4.10 include the following:

1) An update of the modeling of SO_2 rate limits in Connecticut

2) An update of the modeling of the effective dates of various controls on units in Georgia

3) Addition of two Kansas State Law unit-specific constraints

4) An update of the modeling of NO_x rate limits in Louisiana

5) An update of the modeling of the NO_x annual and summer caps and SO_2 annual cap in Maryland

6) An update of the modeling of the NO_x rate limits in New Jersey

Appendix 3-3 New Source Review (NSR) Settlements in EPA Base Case v.4.10_FTransport (05-16-11)

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Alabama Power																	
James H. Miller	Alabama	Units 3 & 4			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06	Within 45 days of settlement entry, APC must retire 7,538 SO_2 emission allowances.	APC shall not sell, trade, or otherwise exchange any Plant Miller excess SO_2 emission allowances outside of the APC system	1/1/21	http://www.epa.gov/compliance/resources/cases/civil/caa/alabamapower.html
Minnkota Power Cooperative																	
Beginning 1/01/2006, Minnkota shall not emit more than 31,000 tons of SO_2/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 1/01/2014, the plant wide emission shall not exceed 8,500																	
Milton R. Young	Minnesota	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		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 NO_x 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		http://www.epa.gov/compliance/resources/cases/civil/caa/minnkota.html
		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	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/06										The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			http://www.epa.gov/compliance/resources/cases/civil/caa/sigecofb.html
		Unit 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04										
		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				
PSEG FOSSIL																	
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/02										The provision			

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			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	12/31/06	Install SCR (or approved tech) and continually operate	0.1	05/01/07	Install Baghouse (or approved technology)	0.015	12/31/06	did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			http://www.epa.gov/compliance/resources/cases/civil/caa/pseglIc.html
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	0.13	05/01/06							
TECO																	
Big Bend	Florida	Units 1 & 2			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	05/01/09				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			http://www.epa.gov/compliance/resources/cases/civil/caa/teco.html
		Unit 3			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	2000 (01/01/10)	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	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/04													
WEPCO																	
WEPCO shall comply with the following system wide average NO_x emission rates and total NO_x tonnage permissible: by 1/1/2005 an emission rate of 0.27 and 31,500 tons, by 1/1/2007 an emission rate of 0.19 and 23,400 tons, and by 1/1/2013 an emission rate of 0.17 and 17, 400 tons. For SO_2 emissions, WEPCO will comply with: by 1/1/2005 an emission rate of 0.76 and 86,900 tons, by 1/1/2007 an emission rate of 0.61 and 74,400 tons, by 1/1/2008 an emission rate of 0.45 and 55,400 tons, and by 1/1/2013 an emission rate of 0.32 and 33,300 tons.																	http://www.epa.gov/compliance/resources/cases/civil/caa/wepco.html
Presque Isle	Wisconsin	Units 1 – 4	Retire or install SO_2 and NO_x controls	12/31/12	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/12	Install SCR (or approved tech) and continually operate	0.1	12/31/12							
		Units 5 & 6						Install and operate low NO_x burners		12/31/03							
		Units 7 & 8						Operate existing low NO_x burners		12/31/05	Install Baghouse						
		Unit 9						Operate existing low NO_x burners		12/31/06	Install Baghouse						
Pleasant Prairie	Wisconsin	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 SO_2 allowances to be surrendered. It only provided			
		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							

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 Restriction: Restriction	Effective Date	Reference
Oak Creek	Wisconsin	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				that excess allowances resulting from compliance with NSR settlement provisions must be retired.			
		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							
		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	Wisconsin	Units 1 – 4	Retire	12/31/04 for Units 1 – 3. Unit 4 by entry of consent decree													
Valley	Wisconsin	Boilers 1 – 4						Operate existing low NO_x burner		30 days after entry of consent decree							
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 0.15 lb/mmBtu.																	
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	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 SO_2 allowances.			http://www.epa.gov/compliance/resources/cases/civil/caa/vepco.html
Chesterfield	Virginia	Unit 4						Install and continuously operate SCR	0.1	01/01/13							
		Unit 5			Construct or improve FGD	95% or 0.13	10/12/12	Install and continuously operate SCR	0.1	01/01/12							
		Unit 6			Construct or improve FGD	95% or 0.13	01/01/10	Install and continuously operate SCR	0.1	01/01/11							
Chesapeake Energy	Virginia	Units 3 & 4						Install and continuously operate SCR	0.1	01/01/13							
Clover	Virginia	Units 1 & 2			Improve FGD	95% or 0.13	09/01/03										
Possum Point	Virginia	Units 3 & 4	Retire and repower to natural gas	05/02/03													
Santee Cooper																	
Santee Cooper shall comply with the following system wide averages for NO_x emission rates and combined tons for emission of: by 1/01/2005 facility shall comply with an emission rate of 0.3 and 30,000 tons, by 1/1/2007 an emission rate of 0.18 and 25,000 tons, by 1/1/2010 and emission rate of 0.15 and 20,000 tons. For SO_2 emission the company shall comply with system wide averages of: by 1/1/2005 an emission rate of 0.92 and 95,000 tons, by 1/1/2007 and emission rate of 0.75 and 85,000 tons, by 1/1/2009 an emission rate of 0.53 and 70 tons, and by 1/1/2011 and emission rate of 0.5 and 65 tons.																	
Cross	South Carolina	Unit 1			Upgrade and continuously operate FGD	95%	06/30/06	Install and continuously operate SCR	0.1	05/31/04				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided			http://www.epa.gov/compliance/resources/cases/civil/caa/santeecooper.html
		Unit 2			Upgrade and continuously operate FGD	87%	06/30/06	Install and Continuously operate SCR	0.11/0.1	05/31/04 and 05/31/07							
Winyah	South Carolina	Unit 1			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.11/0.1	11/30/04 and 11/30/04							
		Unit 2			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.12	11/30/04							
		Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/08	Install and continuously operate SCR	0.14/0.12	11/30/2005 and 11/30/08							

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
		Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/07	Install and continuously operate SCR	0.13/0.12	11/30/05 and 11/30/08				only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			
Grainger	South Carolina	Unit 1						Operate low NO_x burner or more stringent technology		06/25/04							
		Unit 2						Operate low NO_x burner or more stringent technology		05/01/04							
Jeffries	South Carolina	Units 3, 4						Operate low NO_x burner or more stringent technology		06/25/04							
Ohio Edison																	
Ohio Edison shall achieve reductions of 2,483 tons NO_x between 7/1/2005 and 12/31/2010 using any combination of: 1) low sulfur coal at Burger Units 4 and 5, 2) operating SCRs currently installed at Mansfield Units 1– 3 during the months of October through April, and/or 3) emitting fewer tons than the Plant-Wide Annual Cap for NO_x required for the Sammis Plant. Ohio Edison must reduce 24,600 tons system-wide of SO_2 by 12/31/2010.																	
No later than 8/11/2005, Ohio Edison shall install and operate low NO_x burners on Sammis Units 1 - 7 and overfired air on Sammis Units 1,2,3,6, and 7. No later than 12/1/2005, Ohio Edison shall install advanced combustion control optimization with software to minimize NO_x emissions from Sammis Units 1 – 5.																	
W.H. Sammis Plant	Ohio	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				Beginning on 1/1/2006, Ohio Edison may use, sell or transfer any restricted SO_2 only to satisfy the Operational Needs at the Sammis, Burger and Mansfield Plant, or new units within the FirstEnergy System that comply with a 96% removal for SO_2. For calendar year 2006 through			http://www.epa.gov/compliance/resources/cases/civil/caa/ohioedison.html
		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 NO_x burners and overfire air by 12/1/05; install SNCR (or approved alt. tech) & operate continuously by 12/31/07	0.25	12/01/05 and 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							

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 Restriction: Restriction	Effective Date	Reference
		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	2006 through 2017, Ohio Edison may accumulate SO_2 allowances for use at the Sammis, Burger, and Mansfield plants, or FirstEnergy units equipped with SO_2 Emission Control Standards. Beginning in 2018, Ohio Edison shall surrender unused restricted SO_2 allowances.			
		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	Pennsylvania	Unit 1			Upgrade existing FGD	95%	12/31/05										
		Unit 2			Upgrade existing FGD	95%	12/31/06										
		Unit 3			Upgrade existing FGD	95%	10/31/07										
Eastlake	Ohio	Unit 5						Install low NO_x burners, over-fired air and SNCR & operate continuously	"Minimize Emissions to the Extent Practicable"	12/31/06							
Burger	Ohio	Unit 4	Repower with at least 80% biomass fuel, up to 20% low sulfur coal.	12/31/11													
		Unit 5		12/31/11													
Mirantl[1,6]																	
System-wide NO_x 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 NO_x 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 5/1/2008, 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 NO_x.																	
Potomac River Plant	Virginia	Unit 1															http://www.epa.gov/compliance/resources/cases/civil/caa/mirant.html
		Unit 2															
		Unit 3						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04							
		Unit 4						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04							
		Unit 5						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04							

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Morgantown Plant	Maryland	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	Maryland	Unit 1			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10							For each year after Mirant commences FGD operation at Chalk Point, Mirant shall surrender the number of SO_2 Allowances equal to the amount by which the SO_2 Allowances allocated to the Units at the Chalk Point Plant are greater than the total amount of SO_2 emissions allowed under this Section XVIII.			
		Unit 2			Install and continuously operate FGD (or equiv. 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 2011; 49,500 tons 2012; 29,000 tons 2013 onward.																	http://www.epa.gov/compliance/resources/cases/civil/caa/illinoispower.html
Baldwin	Illinois	Units 1 & 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	By year end 2008, Dynergy will surrender 12,000 SO_2 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			
		Unit 3			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA and/or low NO_x burners	0.12 until 12/30/12; 0.1 from 12/31/12	08/11/05 and 12/31/12	Install & continuously operate Baghouse	0.015	12/31/10				
Havana	Illinois	Unit 6			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	1.2 lb/mmBtu until 12/30/2012; 0.1 lb/mmBtu from 12/31/2012 onward	08/11/05 and 12/31/12	Operate OFA and/or low NO_x burners & operate existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse, then install ESP or alt. PM equip	For Bag-house: 0.015 lb/mmBtu; For ESP: 0.03 lb/mmBtu	For Baghouse: 12/31/12; For ESP: 12/31/05				
Note: Havana Unit 6 in the Illinois Power NSR settlement refers to the affected electric generator. The provisions shown here as applying to Havana Unit 6 are represented in IPM as applying to Havana Unit 9, which is the boiler that powers generator unit #6.																	

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Hennepin	Illinois	Unit 1				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06	the surrendered allowances result in insufficient remaining allowances allocated to the units comprising the DMG system, DMG can request to surrender fewer SO_2 allowances.			
		Unit 2				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06				
Vermilion	Illinois	Units 1 & 2				1.2	01/31/07	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10				
Wood River	Illinois	Units 4 & 5				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05				
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.		http://www.epa.gov/compliance/resources/cases/civil/caa/kucompany.html
Salt River Project Agricultural Improvement and Power District (SRP)																	
Coronado Generating Station	Arizona	Unit 1 or Unit 2			Immediately begin continuous operation of existing FGDs on both units, install new FGD.	95% or 0.08	New FGD installed by 1/1/2012	Install and continuously operate low NO_x burner and SCR	0.32 prior to SCR installation, 0.080 after	LNB by 06/01/2009, SCR by 06/01/2014	Optimization and continuous operation of existing ESPs.	0.03	Optimization begins immediately, rate limit begins 01/01/12 (date of new FGD installation)	Beginning in 2012, all surplus SO_2 allowances for both Coronado and Springerville Unit 4 must be surrendered through 2020. The allowances limited by this condition may, however, be used for compliance at a prospective future plant using BACT and otherwise specified in par. 54 of the consent decree.	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.		http://www.epa.gov/compliance/resources/cases/civil/caa/srp.html
		Unit 1 or Unit 2			Install new FGD	95% or 0.08	01/01/13	Install and continuously operate low NO_x burner	0.32	06/01/11			Optimization begins immediately, rate limit begins 01/01/13 (date of new FGD installation)				
American Electric Power																	
						Annual Cap (tons)	Year		Annual Cap (tons)	Year					NO_x and SO_2		

Company and Plant	State	Unit	Settlement Actions: Retire/Repower		Settlement Actions: SO_2 control			Settlement Actions: NO_x Control			Settlement Actions: PM or Mercury Control			Settlement Actions: Allowance Retirement	Settlement Actions: Allowance Restriction		Reference
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Eastern System-Wide						450,000	2010		96,000	2009				NO_x and SO_2 allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	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.		http://www.epa.gov/compliance/resources/cases/civil/caa/americanelectricpower1007.html
						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										
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			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		01/01/09							
		Unit 3			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		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							

Company and Plant	State	Unit	Settlement Actions: Retire/Repower		SO$_2$ control			NO$_x$ Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		Reference
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Cardinal	Ohio	Unit 1			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 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			Install and continuously operate FGD		12/31/12	Install and continuously operate SCR		01/01/09							
Clinch River	Virginia	Units 1 – 3				Plant-wide annual cap: 21,700 tons from 2010 to 2014, then 16,300 after 1/1/2015	2010 – 2014, 2015 and thereafter	Continuously operate low NO$_x$ burners		Date of entry							
Conesville	Ohio	Unit 1	Retire, retrofit, or re-power	Date of entry													
		Unit 2	Retire, retrofit, or re-power	Date of entry													
		Unit 3	Retire, retrofit, or re-power	12/31/12													
		Unit 4			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		12/31/10							
		Unit 5			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO$_x$ burners		Date of entry							
		Unit 6			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO$_x$ burners		Date of entry							
Gavin	Ohio	Unit 1			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09							
		Unit 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09							
Glen Lyn	Virginia	Units 1 – 3															
		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	01/01/10	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	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09							
		Unit 2			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09							

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
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													
		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				
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			Install and continuously operate FGD		12/31/19	Install and continuously operate SCR		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		Date of entry	Continuously operate over-fire air		Date of entry							
East Kentucky Power Cooperative Inc.																	
By 12/31/2009, EKPC shall choose whether to: 1) install and continuously operate NO_x controls at Cooper 2 by 12/31/2012 and SO_2 controls by 6/30/2012 or 2) retire Dale 3 and Dale 4 by 12/31/2012.																	
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 must be optimized within 270 days of entry date, or EKPC may choose to submit a PM Pollution Control Upgrade Analysis.	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 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		http://www.epa.gov/compliance/resources/cases/civil/caa/nevadapower.html
						57,000	10/01/08		11,500	01/01/08							
						40,000	07/01/11		8,500	01/01/13							

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 Restriction: Restriction	Effective Date	Reference
						28,000	01/01/13		8,000	01/01/15					EKPC system. Allowances made available due to supercompliance may be sold or traded.		
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	60 days after entry							
Dale Plant	Kentucky	Unit 1						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	http://www.epa.gov/compliance/resources/cases/civil/caa/eastkentuckypower-dale0907.html
		Unit 2						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08							
		Unit 3	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012													
		Unit 4															
		Unit 1															

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 Restriction: Restriction	Effective Date	Reference
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		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																	
Beginning 1/1/2010, combined NO_x emissions from Units 5,6,7, and 8 must be no more than 360 tons per year.																	
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.		http://www.epa.gov/compliance/resources/cases/civil/caa/nevadapower.html
		Unit 6							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)							
		Unit 7							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)							
		Unit 8							5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)							
Dayton Power & Light																	
Non-EPA Settlement of 10/23/2008																	
Stuart Generating Station	Ohio	Station-wide			Complete installation of FGDs on each unit.	96% or 0.10	07/31/09	Owners may not purchase any new catalyst with SO_2 to SO_3 conversion rate greater than 0.5%	0.17 station-wide	30 days after entry		0.030 lb per unit	07/31/09		NO_x and SO_2 allowances may not be used to comply with the monthly rates specified in the Consent Decree.		Courtlink document provided by EPA in email
									0.17 station-wide	60 days after entry date							
						82% including data from periods of malfunctions	7/31/09 through 7/30/11	Install control technology on one unit	0.10 on any single unit	12/31/12		Install rigid-type electro-des in each unit's ESP	12/31/15				
						82% including data from periods of malfunctions	after 7/31/11		0.15 station-wide	07/01/12							
									0.10 station-wide	12/31/14							
PSEG FOSSIL, Amended Consent Decree of November 2006																	
Kearny	New Jersey	Unit 7	Retire unit	01/01/07										Allowances allocated to Kearny, Hudson, and			http://www.epa.gov/compliance/resources/decrees/amended/psegfossil-amended-cd.pdf
		Unit 8	Retire unit	01/01/07													

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 Restriction: Restriction	Effective Date	Reference
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	Mercer may only be used for the operational needs of those units, and all 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				
Westar Energy																	
Jeffrey Energy Center	Kansas	All units			Units 1, 2, and 3 have a total annual limit of 6,600 tons of SO2 and an annual rate limit of 0.07 lbs/MMBtu starting 2012 Units 1, 2, and 3 must all install FGDs by 2011 and operate them continuously. FGDs must maintain a 30-Day Rolling Average Unit Removal Efficiency for SO2 of at least 97% or a 30-Day Rolling Average Unit Emission Rate for SO2 of no greater than 0.070 lb/MMBtu.			Units 1-3 must continuously operate Low NOx Combustion Systems by 2012 and achieve and maintain a 30-Day Rolling Average Unit Emission Rate for NOx of no greater than 0.180 lb/MMBtu. One of the three units must install an SCR by 2015 and operate it continuously to maintain a 30-Day Rolling Average Unit Emission Rate for NOx of no greater than 0.080 lb/MMBtu. By 2013 Westar shall elect to either (a) install a second SCR on one of the other JEC Units by 2017 or (b) meet a 0.100 lb/MMBtu Plant-Wide 12-Month Rolling Average Emission Rate and 9.6 MTons annual cap for NOx by 2015			Units 1, 2, and 3 must operate each ESP and FGD system continuously by 2011 and maintain a 0.030 lb/MMBtu PM Emissions Rate. Units 1 and 2's ESPs must be rebuilt by 2014 in order to meet a 0.030 lb/MMBtu PM Emissions Rate						
Duke Energy																	
Gallagher	Indiana	Units 1 & 3	Retire or repower as natural gas	1/1/2012													
		Units 2 & 4			Install Dry sorbent injection technology	80%	1/1/2012										
American Municipal Power																	
Gorsuch Station	Ohio	Units 2 & 3	Elected to Retire Dec 15, 2010 (must retire by Dec 31, 2012)														http://amppartners.org/newsroom/amp-to-retire-gorsuch-generating-station/
		Units 1 & 4															

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Hoosier Energy Rural Electric Cooperative																	
Ratts	Indiana	Units 1 & 2						Install & continually operate SNCRS	0.25	12/31/2011	Continuously operate ESP						
Merom	Indiana	Unit 1			Continusly run current FGD for 90% removal and update FGD for 98% removal by 2012	98%	2012	Continuously operate existing SCRs	0.12		Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/12			Annually surrender any NOx and SO2 allowances that Hoosier does not need in order to meet its regulatory obligations			http://www.epa.gov/compliance/resources/cases/civil/caa/hoosier.html
Merom	Indiana	Unit 2			Continusly run current FGD for 90% removal and update FGD for 98% removal by 2014	98%	2014				Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/13						
Tennessee Valley Authority																	
Allen Steam Plant	Tennessee	Units 1 - 3			Install FGD		12/31/2015	Operate SCR		In NEEDS							
Bull Run	Tennessee	Unit 1			Operate Wet FGD		In NEEDS	Operate SCR		In NEEDS							
Colbert	Alabama	Units 1 - 4			Install FGD		6/30/2016	Install SCR		6/30/2016							
Colbert	Alabama	Unit 5			Install FGD		12/31/2015	Operate SCR		In NEEDS							
Cumberland	Tennessee	Units 1 & 2			Operate Wet FGD		In NEEDS	Operate SCR		In NEEDS							
Gallatin	Tennessee	Units 1 - 4			Install FGD		12/31/2017	Install SCR		12/31/2017							
John Sevier	Tennessee	Units 1 & 2	Retire	12/31/2012													
John Sevier	Tennessee	Units 3 & 4			Install FGD		12/31/2015	Install SCR		12/31/2015							
Johnsonville	Tennessee	Units 1 - 4	Retire	12/31/2017													
Johnsonville	Tennessee	Units 5 - 8	Retire	12/31/2018													
Johnsonville	Tennessee	Units 9 & 10	Retire	12/31/2019													
Kingston	Kentucky	Units 1 - 9			Operate Wet FGD		In NEEDS	Operate SCR		In NEEDS							
Paradise	Kentucky	Units 1 & 2			Upgrade FGD	93%	12/31/2012	Operate SCR		In NEEDS							
Paradise	Kentucky	Unit 3			Operate Wet FGD		In NEEDS	Operate SCR		In NEEDS							
Shawnee	Kentucky	Units 1 & 4			Install FGD		12/31/2017	Install SCR		12/31/2017							
Widows Creek	Alabama	Units 1 & 2	Retire	7/31/2013													
Widows Creek	Alabama	Units 3 & 4	Retire	7/31/2014													
Widows Creek	Alabama	Units 5 & 6	Retire	7/31/2015													
Widows Creek	Alabama	Units 7 & 8			Operate Wet FGD		In NEEDS	Operate SCR		In NEEDS							

Notes:

1) Updates to the EPA Base Case 4.10_FTransport from EPA Base Case 4.10 include the additions of the American Municipal Power settlement, the Hoosier Energy Rural Electric Cooperative settlement, a modification to the control requirements on the Mercer plant under the PSEG Fossil settlement, and an update to the SO_2 emission modeling on Jeffrey Energy Center as part of the Westar settlement.

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

3) Settlement actions for which the required emission limits will be effective by the time of the first mapped run year (before 1/1/2012) are built into the database of units used in EPA Base Case ("hardwired"). However, future actions are generally modeled as individual constraints on emission rates in EPA Base Case, allowing the modeled economic situation to dictate whether and when a unit would opt to install controls versus retire.

4) 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

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

6) For units for which an FGD is modeled as an emissions constraint in EPA Base Case, EPA used the assumptions on removal efficiencies that are shown in the latest emission control technologies documentation

7) For units for which an FGD is hardwired in EPA Base Case, 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.

8) For units for which an SCR is modeled as an emissions constraint or is hardwired in EPA Base Case, 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.

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

10) EPA included in EPA Base Case the requirements of the settlements as they existed on January 1, 2011.

11) Some of the NSR settlements require the retirement of SO2 allowances. For the Base Case, 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 v4.10_FTransport

Company and Plant	State	Unit	State Enforcement Actions													
			Retire/Repower		SO_2 control			NO_x Control			PM Control			Mercury Control		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date
AES																
Greenidge	New York	Unit 4			Install FGD	90%	09/01/07	Install SCR	0.15	09/01/07						
		Unit 3			Install BACT		12/31/09	Install BACT		12/31/09						
Westover	New York	Unit 8				90%	12/31/10	Install SCR	0.15	12/31/10						
		Unit 7			Install BACT		12/31/09	Install BACT		12/31/09						
Hickling	New York	Units 1 & 2			Install BACT		05/01/07	Install BACT		05/01/07						
Jennison	New York	Units 1 & 2			Install BACT		05/01/07	Install BACT		05/01/07						
Niagara Mohawk Power																
NRG shall comply with the below annual tonnage limitations for its Huntley and Dunkirk Stations: 2005 is 59,537 tons of SO_2 and 10,777 tons of NO_x, 2006 is 34,230 of SO_2 and 6,772 of NO_x, 2007 is 30,859 of SO_2 and 6,211 of NO_x, 2008 is 22,733 tons of SO_2																
Huntley	New York	Units 63 – 66	Retire	Before 2008												
Public Service Co. of NM																
San Juan	New Mexico	Unit 1			State-of-the-art technology	90%	10/31/08	State-of-the-art technology	0.3	10/31/08	Operate Baghouse and demister technology	0.015	12/31/09	Design activated carbon injection technology (or comparable tech)		12/31/09
		Unit 2					03/31/09			03/31/09			12/31/09			12/31/09
		Unit 3					04/30/08			04/30/08			04/30/08			04/30/08
		Unit 4					10/31/07			10/31/07			10/31/07			10/31/07
Public Service Co of Colorado																
Comanche	Colorado	Units 1 & 2			Install and operate FGD	0.1 lb/mmBtu combined average	07/01/09	Install low-NO_x emission controls	0.15 lb/mmBtu combined average	07/01/09				Install sorbent injection technology		07/01/09
		Unit 3			Install and operate FGD	0.1 lb/mmBtu		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
Rochester Gas & Electric																
Russell Plant	New York	Units 1 – 4	Retire all units													
Mirant New York																
Lovett Plant	New York	Unit 1	Retire	05/07/07												
		Unit 2	Retire	04/30/08												

Note: The TVA settlement with North Carolina was removed from this table to reflect the July 26, 2010 ruling by the U.S. Court of Appeals, Fourth Circuit Court reversing the settlement.