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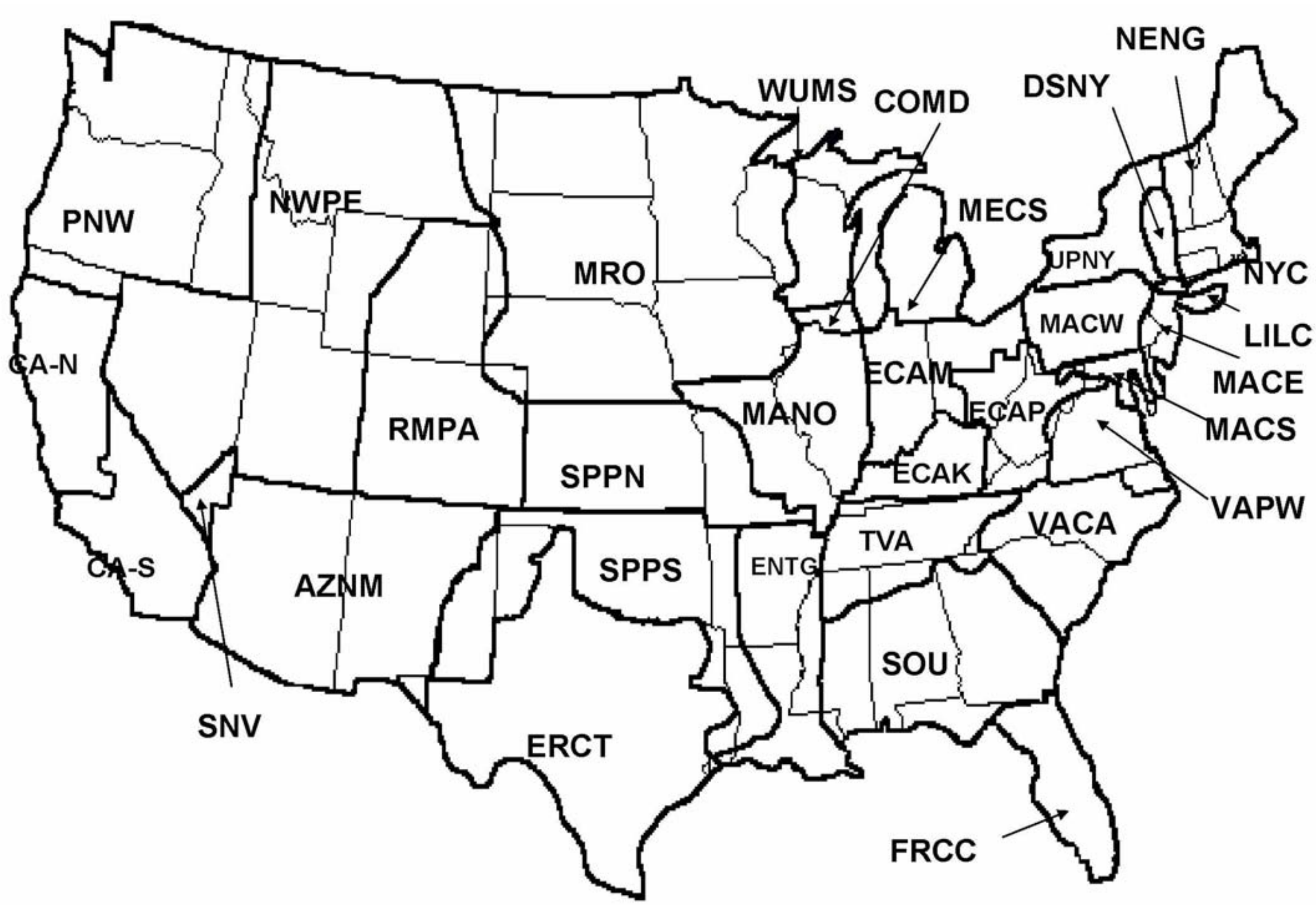
Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model



Background: The Integrated Planning Model (IPM) is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least- cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X) , carbon dioxide (CO_2), and mercury (Hg) from the electric power sector. IPM is used by the U.S. Environmental Protection Agency (EPA) to project the impact of emissions policies on the electric power sector in the 48 contiguous states and the District of Columbia. The assumptions underlying EPA's Base Case and associated policy cases were incorporated in IPM under EPA direction by ICF Resources, Inc. IPM was developed by ICF and is used in support of its public and private sector clients. IPM® is a registered trademark of ICF Resources, Inc.

Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model

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Summary Table of Base Case 2006 Updates

The documentation for EPA Base Case 2006 consists of this summary table and a series of detailed tables, figures, exhibits, and reports which provide specific in-depth background information on all key assumptions in Base Case 2006. The Summary Table below lists all documentation elements. Notes are included in the table for selected items, where the information in the item is not self-explanatory or where additional information appeared to be useful. To facilitate cross-referencing, the ID of the corresponding Base Case 2004 table or figure is retained here for Base Case 2006. The ID appears in the first column of the following table. A break in the table and figure numbering sequence indicates that there is no equivalent Base Case 2006 table or figure. New Base Case 2006 tables and figures that have no Base Case 2004 equivalent are given a unique ID. The Base Case 2004 tables and figures can be found in "Standalone Documentation for EPA Base Case 2004 (V.2.1.9) Using the Integrated Planning Model," September 2005 (EPA 430-R-05-011), which can be viewed and downloaded at www.epa.gov/airmarkets/epa-ipm.

ID	Title	Notes
Overview		
Figure 1.1	Modeling and Data Structure for EPA Base Case 2006, v.3.0	
Table 1.1	Plant Types in EPA Base Case 2006	Fluidized Bed Combustion is now separately reported in model outputs for easier post-run analysis.
Table 1.2	Emission Control Technologies in EPA Base Case 2006	(a) Two retrofit scrubber technologies for SO2 removal are now represented in the model: Limestone Forced Oxidation (LSFO) and Lime Spray Dryer (LSD). Based on engineering and economic assessments, Magnesium Enhanced Lime (MEL) is no longer provided as an SO2 retrofit option. The cost and performance characteristics of LSFO and LSD were completely updated to reflect recent experience. (See Tables 5.2 and 5.3.) (b) Separate cost and performance characteristics were added for Selective Non-Catalytic Reduction for NOx control on fluidized bed combustion units (See Table 5.6) (c) Existing units with SNCR can be retrofit with SCR in Base Case 2006 with the SCR replacing the SNCR.
Modeling Framework		
Figure 2.1	Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve	
Figure 2.2	Stylized Depiction of Load Duration Curve Used in EPA Base Case 2006	There are six, instead of five, segments in the Base Case 2006 load duration curves. Since there are separate summer and winter load curves, this results in a total of 12 load segments per run year. The addition of a super peak segment allows IPM to better capture the "peakiness" of load and to reduce incidences of plants having zero generation.

ID	Title	Notes
Figure 2.3	Stylized Dispatch Order	
Appendix 2-1	Load Duration Curves Used in Base Case 2006	This appendix contains the data comprising the winter and summer load curves for each model region represented in EPA Base Case 2006. Graphs of each region's summer and winter load duration curve are also included. Load shapes were updated based on FERC Form 714 data.
Note: The PDF file for Section 2 includes graphs of the 62 winter and summer load duration curves used in EPA Base Case 2006 along with all the data plotted in these curves. In addition, for the convenience of users requiring direct access to the load duration curve data, a spreadsheet file of Appendix 2-1 is provided for viewing and downloading. This file contains the data only, not the graphs.		
Power System Operations Assumptions		
Figure 3.1	Base Case 2006 Model Regions (map)	To better capture the operation of the electricity grid, transmission bottlenecks, and the administrative changes involving regional transmission organization (RTOs) and independent system operators (ISOs), Base Case 2006 includes 32 model regions compared to the 26 regions in the previous base case. Changes include disaggregating ECAO (East Central Area Reliability Coordination Agreement - South) region into three regions (ECAM, ECAP, ECAK), AZNM (Arizona New Mexico) into two regions (AZNM and SNV), California (CALI) into two regions (CA-N and CA-S), Virginia-Carolina (VACA) into two regions (VACA and VAPW), and Mid-America Interconnected Network - South (MANO) into two regions (MANO and COMD). Besides adding these new regions, boundaries of some regions were adjusted to reflect current realities.
Table 3.1	Mapping of NERC Regions with EPA Base Case 2006 Model Regions	
Table 3.2	Electric Load Assumptions in EPA Base Case 2006	The electric load assumptions in Base Case 2006 are shown in Table 3.2. The starting point for deriving the values in this table is the electricity sales forecast in the U.S. Energy Information Administration's Annual Energy Outlook. EPA adjusts AEO electricity sales forecasts to account for reductions in electricity consumption due to a series of voluntary programs which are not fully reflected in the AEO reference case projections. Such programs include EPA's Energy Star and the U.S. Department of Energy's "Best Practices" activities. Factoring in these energy savings results in an average annual electricity growth rate of 1.52% over the 2010-2025 time horizon covered in Base Case 2006. Table 3.3 summarizes these results and for comparison purposes shows the electricity sales (in billion kWh) projected for the run years used in the Base Case 2006 together with the AEO electricity sales and gross domestic product (GDP) projections for these years. The net energy for load values shown in Table 3.2 were calculated by multiplying the electricity sales in Table 3.3 by the ratio of net energy for load to total sales as found in AEO.
Table 3.3	Baseline Electricity Sales Forecast Used for EPA Base Case 2006, v.3.0	
Table 3.4	National Non-Coincidental Peak Demand	Base Case 2006 has separate regional winter and summer peak demand values, as derived from each region's seasonal load duration curve (found in Appendix 2-1). Peak projections were estimated based on AEO 2006 load factors and the estimated energy projections shown in Table 3.2. Table 3.4 illustrates the national sum of each region's winter and summer peak

ID	Title	Notes
		demand. Because each region's seasonal peak demand need not occur at the same time, the national peak demand is defined as non-coincidental.
Table 3.5	Annual Transmission Capabilities between Model Regions	Table 3.5 shows the firm (capacity) and non-firm (energy) Total Transfer Capabilities (TTC) between model regions. TTC is a metric that represents the capability of the power system to import or export power from one region to another. The purpose of TTC analysis is to identify the sub-markets created by key commercially significant constraints. Firm TTCs specify the maximum firm energy and capacity transfer capability between sub-regions while non-firm TTCs specify the maximum firm energy and capacity transfer capability between sub-regions plus incremental curtailable non firm energy transfer capability. As a general principle, non-firm TTCs are determined under the assumption of no transmission contingency (N-0) and they represent the absolute maximum transfer capability. Since there is no guarantee that these maximum TTC are attainable in all hours, non-firm TTCs are not used as limits for capacity transfers. In contrast, firm TTCs reflect conservative estimates of transfer capability because they are determined based on the contingency loss of a single (N-1) transmission facility. Therefore under normal system conditions, the firm TTC limits should be available for commercial energy and capacity transactions. In the previous base case summer and winter transmission capabilities were shown in Table 3.5. For Base Case 2006, most of the transmission links were based on ICF's expert opinion and these tend to be the same for both winter and summer. Thus, in order to be consistent, identical winter and summer capabilities were modeled for transmission capabilities from all other sources as well. However, seasonal (summer and winter) energy and capacity transfers are captured in the base case 2006. The transmission link capabilities shown in Table 3.5 were updated based on public data obtained from NERC 2004 Summer Assessment, "2005 IRM Study, Summer Ratings (NYSRC - NYCA Installed Capacity Requirement for the Period May 2005 through April 2006)", WECC Information Summary, July 2004, and WECC 2003 Path Rating Catalog. Where public data were not available, the energy and capacity transfer capabilities shown in the table are based on ICF's expert view.
Table 3.6	International Electricity Imports	Table 3.6 summarizes the assumption on net electricity imports into the U.S. from Canada and Mexico. It is based on Annual Energy Outlook 2006.
Table 3.7	Availability Assumptions in the EPA Base Case 2006	Power plant "availability" is the percentage of time that a generating unit is available to provide electricity to the grid. Availability takes into account both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit's available hours adjusted for derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an

ID	Title	Notes
		upper bound on generation to meet demand. Table 3.7 summarizes the availability assumptions used in EPA Base Case 2006. They are based on data from North American Electric Reliability Council's Generating Availability Data System (NERC GADS) for 2003-04 and AEO 2006. In Base Case 2006 availabilities for specific types of units were further differentiated based on unit size.
Table 3.8	Seasonal Hydro Capacity Factors (%) in the EPA Base Case 2006	Since generation from hydro units is constrained by resource limitations, IPM uses capacity factors, not availabilities, to define the upper bound on the generation obtainable from these units. The capacity factor is the percentage of the maximum possible power generated by the unit. The seasonal capacity factor assumptions for hydro facilities shown in Table 3.8 were updated based on 2000-2004 EIA Form 906 data.
Table 3.9	Planning Reserve Margins in EPA Base Case 2006	A reserve margin is a measure of the electric power system's generating capability above the amount required to meet the net internal demand (peak load) requirement. In IPM reserve margins are used to depict the reliability standards that are in effect in each NERC region. In Base Case 2006 individual reserve margins for each IPM region are derived from the following sources. a. NERC: 2004 Long Term Reliability Assessment (ERCT, FRCC, MANO, WUMS, MRO, DSNY, LILC, NYC, UPNY, SPPN, SPPS regions) b. WECC - Information Summary, July 2004, (for IPM regions: AZNM, SNV, CA-N, CA-S, PNW, NWPE and RMPA) c. "PJM ISO - Installed Reserve Margin Study, For Market Integration Zones, August 2004", (for IPM regions: MACE, MACW, MACS and COMD) d. RGGI Analysis (for NENG), e. TVA Reservoir Operations Study - Final EIS" (for TVA region) f. ICF (for remaining regions)
Table 3.10	Lower and Upper Limits Applied to Heat Rate Data in NEEDS 2006	Heat rates describe the efficiency of a generating unit, expressed as BTUs per KWh. Base Case 2006 heat rates were derived from AEO 2006 values. As in EPA's previous base case, the reported heat rates were screened to ensure that they were within the engineering capabilities of the generating unit types. EPA's engineering analysis to establish upper and lower heat rate cut-off values was further refined for Base Case 2006 with separate cut-off values being developed for two size categories (less than 80 MW and 80 MW up) and two types (natural gas and oil-oil/gas) of combustion turbines, two size categories (less than 5 MW and 5 MW up) of oil and oil/gas IC engines as well as for natural gas IC engines of any size. The resulting upper and lower heat rate limits are shown in Table 3.10. If the reported heat rate for one of the listed types of units was below the applicable lower limit or above the upper limit, the cut-off value was substituted for the reported value. The resulting heat rates can be found in the latest version of NEEDS 2006, a database of all existing and committed units that are represented in Base Case 2006.

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Table 3.13	Emission and Removal Rate Assumptions for Potential (New) units in EPA Base Case 2006	Base Case 2006 provides two configurations of potential (new) pulverized coal units: those with wet flue gas desulfurization systems (i.e., limestone force oxidation), and those with dry flue gas desulfurization systems (i.e., lime spray dryers). The 90% mercury removal rates for these configurations is premised on wet FGD plants having SCR and burning bituminous coal and on dry FGD plants using activated carbon injection for mercury removal.
Appendix 3-1	Appendix 3-1. NOx Rate Development in EPA Base Case 2006	
Appendix 3-2	State Power Sector Regulations Included in EPA Base Case 2006	A comprehensive update of state regulations affecting emissions from the U.S. power sector was performed for Base Case 2006. It included comments from states and Regional Planning Organizations.
Appendix 3-3	New Source Review (NSR) Settlements in EPA Base Case 2006	Base Case 2006 includes a comprehensive update of NSR settlements.
Appendix 3-4.	State Settlements in EPA Base Case 2006	Base Case 2006 includes state enforcement settlements affecting emissions from the power sector.
Appendix 3-5	Constraint on FGD and SCR Capacity Due to Boilermaker Availability in the Period When SO_2 and NO_x Retrofits Will Occur for the Clean Air Interstate Rule (CAIR)	The table and graph in this appendix show the constraint on the combined capacity of FGD and SCR retrofits in model run year 2010 that is included in Base Case 2006 to capture limitations on boilermaker availability during the installation period for CAIR. This constraint was developed on the assumptions of (a) a 14% contingency factor for possible additional labor needs due to unforeseen events, (b) availability of 29,000 boilermakers during the 2007-2009 period, based on 2006 estimates obtained from the International Brotherhood of Boilermakers, and (c) initiation of boilermaker activity on CAIR retrofits in February 2007, eleven months following the signing of the CAIR Federal Implementation Plan (FIP). The constraint accounts for boilermakers who will be needed to work on new units and on emission controls previously announced but not yet constructed.
Generating Resources		
Table 4.1	Data Sources for NEEDS 2006	
Table 4.2	Rules Used in Populating NEEDS 2006	
Table 4.3	Summary Population (through 2004) in NEEDS 2006	
Table 4.4	Hierarchy of Data Sources for	

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	Capacity in NEEDS 2006	
Table 4.5	Capacity-Parsing Algorithm for Steam Units in NEEDS 2006	
Table 4.6	Data Sources for Unit Configuration in NEEDS 2006.	
Table 4.7	Aggregation Profile of Model Plants as Provided at Set Up of EPA Base Case 2006	
Table 4.8	VOM Assumptions (2004$) in EPA Base Case 2006	Cost and performance assumptions were updated based on Annual Energy Outlook 2006. The variable operating and maintenance costs for fossil-fired units are shown as a range, because a segmental VOM methodology is employed in Base Case 2006: VOM changes based on the segment of the load duration curve in which a unit is operating.
Table 4.9	FOM Assumptions Used in EPA Base Case 2006	
Table 4.10	Summary of Planned-Committed Units in EPA Base Case 2006	
Table 4.11	Planned-Committed Units by Model Region in EPA Base Case 2006	
Table 4.12	Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies	
Table 4.13	Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Fossil Technologies in EPA Base Case 2006	Cost and performance assumptions were updated based on Annual Energy Outlook 2006. The variable operating and maintenance costs for fossil-fired units are shown as a range, because a segmental VOM methodology is employed in Base Case 2006: VOM changes based on the segment of the load duration curve in which a unit is operating.
Table 4.14	Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity	
Table 4.15	Terrain Cost Adjustment Factors for New Wind Plants	
Table 4.16	Regional Interconnection Costs for	

ID	Title	Notes
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Table 4.17	Potential Geothermal Capacity and Cost Characteristics per Model Region	
Table 4.18	Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case 2006	
Table 4.19	Regional Assumptions on Potential Geothermal Electric Capacity	
Table 4.20	Regional Assumptions on Potential Electric Capacity from New Landfill Gas Units (MW)	
Table 4.21	Reserve Margin Contribution and Average Capacity Factor by Wind Class and Model Region	
Table 4.22	Reserve Margin Contribution and Average Capacity Factor by Model Region	
Table 4.23	Average Regional Nuclear Capacity Factors in EPA Base Case 2006	
Table 4.24	Cost and Performance Assumptions for Repowering Options in EPA Base Case 2006	
Appendix 4-1	Representative Wind Generation Profiles in EPA Base Case 2006	
Appendix 4-2	Representative Solar Generation Profiles in EPA Base Case 2006	
Appendix 4-3	Existing Nuclear Units in NEEDS 2006	
Appendix 4-4	VOM and FOM Cost Assumptions for Existing Nuclear Units	
Appendix 4-5	Nuclear Upratings and Scheduled Retirements (MW) as Incorporated	

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	in EPA Base Case 2006 from AEO 2006	
Emission Control Technologies		
Table 5.1	Summary of Emission Control Technology Retrofit Options in EPA Base Case 2006	
Table 5.2	Summary of SO2 Retrofit Emission Control Performance Assumptions	Emission rate floors are included in Base Case 2006 for flue gas desulfurization (FGD) retrofits of existing units. They are the same as shown in table 3.13 for new potential units. The capacity penalty and heat rate derating assumptions for LSFO and LSD scrubber systems were also updated.
Table 5.3	Illustrative Scrubber Costs (2004$) for Representative MW and Heat Rates under the Assumptions in EPA Base Case 2006	Two types of flue gas desulfurization (FGD) systems are included in Base Case 2006: limestone forced oxidation (LSFO) and lime spray dryer (LSD). An improved procedure for deriving the capital costs for these systems was used for Base Case 2006. Details of the procedure, including cost equations, are presented in a recently published technical paper by James E. Staudt and Sikander R. Khan, "Updating Performance and Cost of SO_2 Control Technologies in the Integrated Planning Model and the Coal Utility Environmental Cost Model," The Mega Symposium, August 28-31, 2006, Baltimore, Maryland. Operating and maintenance costs were revised based on consumable costs reported in"SO2 Control Technology Performance and Cost Study" by Andover Technology Partners, EPA Contract No. 68-W-03-02, April 2006.
Table 5.4	Cost (2004$) of NOx Combustion Controls for Coal Boilers (300 MW Size)	
Table 5.5	Summary of Retrofit NOx Emission Control Performance Assumptions	In Base Case 2006 Selective Non-Catalytic Reduction is provided as a retrofit option for Fluidized Bed Combustion units with performance and cost characteristics appropriate for that type of unit.
Table 5.6	Post-Combustion NOx Controls for Coal Plants (2004$)	
Table 5.7	Post-Combustion NOx Controls for Oil/Gas Steam Units (2004$)	
Table 5.8	Mercury Emission Factors in the EPA Base Case 2006	As a result of a complete update of coal supply assumptions in Base Case 2006 and the redefining and enhancing of coal sulfur grades, the clusters used to characterize the mercury content of coal and their associated mercury values differ from the previous base case.
Table 5.9	Assumptions on Mercury Concentrations in Non-Coal Fuel in	

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Table 5.10	Mercury Emission Modification Factors Used in EPA Base Case 2006	
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Table 6.1	Run Years and Analysis Year Mapping Used in the EPA Base Case 2006	
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Table 7.1	Risk Profile Assumptions for	

ID	Title	Notes
	Different Classes of New Units	
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Table 8.1	Coal Supply Regions in EPA Base Case 2006	
Figure 8.1	Map of the Coal Supply Regions in EPA Base Case 2006	
Table 8.2	Coal Demand Regions in EPA Base Case 2006	
Table 8.3	Average Mine-Mouth Coal Prices (2004$/ton) in the EPA Base Case 2006	
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Table 8.6	Example of Coal Assignments made in EPA Base Case 2006	
Table 8.7	SO2 Emission Factors of Coal Used in EPA Base Case 2006	
Table 8.8	Carbon Dioxide Emission Factors of Coal in EPA Base Case 2006	
Table 8.9	Mercury Emission Factors of Coal in EPA Base Case 2006	
Table 8.10	Natural Gas Transportation Differentials for EPA Base Case 2006 (2004 Cents/MMBtu)	
Table 8.11	Seasonal Natural Gas Price Adders in EPA Base Case 2006 (2004 cents/MMBtu)	
Table 8.12	US Wellhead and National Average	

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	Delivered Natural Gas Prices in the EPA Base Case 2006 (2004$/MMBtu)	
Table 8.13	Fuel Oil Prices in EPA Base Case 2006	Fuel oil prices were updated based on Annual Energy Outlook 2006 with differentiated prices in 13 model regions.
Table 8.14	Sulfur Dioxide (SO2) Emission Factors of Fuel Oils in EPA Base Case 2006	
Appendix 8-2	Technical Background Paper on the Development of Natural Gas Supply Curves for EPA Base Case 2006	This paper describes the structure and assumptions of the North American Natural Gas Analysis System (NANGAS), the model used to develop the natural gas supply curves for EPA Base Case 2006. Section 3 of the paper summarizes enhancements, revisions, and updates of NANGAS that were made in preparation for generating the natural gas supply curves to be used in EPA Base Case 2006
Appendix 8-3	Natural Gas Supply Curves for EPA Base Case 2006	For Base Case 2006 ICF International updated a number of key assumptions in their North American Natural Gas Analysis System (NANGAS), which produces the natural gas supply curves used in IPM. The updates included bringing existing well decline rates in line with recent production experience, developing a three period representation of LNG pricing, refining near term demand elasticities for the residential and commercial sectors, and updating basis differentials.
Appendix 8-4	Biomass Supply Curves in EPA Base Case 2006	
Appendix 8-5	Coal Supply Curves in EPA Base Case 2006	EPA assembled a team of fuels experts from Hill and Associates, PA Consulting, Hellerworx, Pace Global Energy Services, and ICF International to develop new coal supply curves and a transportation cost matrix for EPA Base Case 2006. The data and graphs in these appendices are the result of this effort.
Appendix 8-6	Coal Transportation Matrix for EPA Base Case 2006	

Note: The PDF file for Section 8 includes graphs of the 95 coal supply curves used in EPA Base Case 2006 along with all the data for the Base Case 2006 natural gas supply curves (Appendix 8-3), biomass supply curves (Appendix 8-4), coal supply curves (Appendix 8-5), and coal transportation matrix (Appendix 8-6). In addition, for the convenience of users requiring direct access to the data, spreadsheet files for Appendix 8-3 through Appendix 8-6 are provided for viewing and downloading. These files contain the data only, not the graphs.