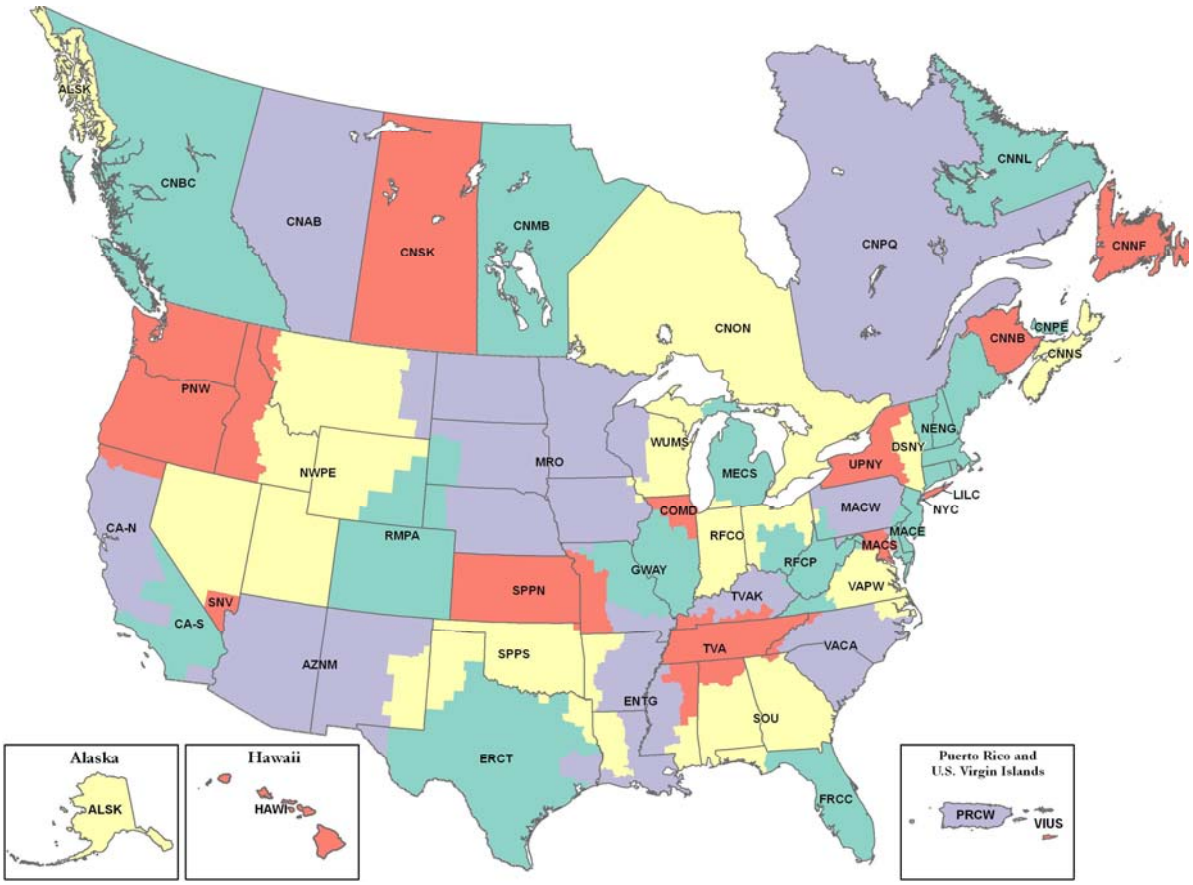
United States
Environmental Protection
Agency

Air and
Radiation
(6204J)

EPA #430R10010
August 2010

Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model



Cover: EPA Base Case v.4.10 and associated policy cases are used by the U.S. Environmental Protection Agency to project the impact of emissions policies on the electric power sector in the 48 contiguous states and the District of Columbia in the lower continental U.S. Representation of the electric power sector in Canada, Alaska, Hawaii, Puerto Rico, and U.S. Virgin Islands is also included for purposes of integrated projections. The map appearing on the cover shows the 32 model regions used to characterize the operation of the U.S. electric power system in the lower continental U.S., 11 model regions in Canada, and the 4 self-contained model regions in Alaska, Hawaii, Puerto Rico, and U.S. Virgin Islands. EPA Base Case v.4.10 was developed by EPA's Clean Air Markets Division with technical support from ICF International, Inc. The IPM modeling platform is a product of ICF International, Inc and is used in support of its public and private sector clients. IPM® is a registered trademark of ICF Resources, L.L.C.

Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model

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

August 2010

Acknowledgment

This document was prepared by U.S. EPA's Clean Air Markets Division, Office of Air and Radiation. ICF Services Company, L.L.C. provided technical support under EPA Contract EP-W-08-018.

TABLE OF CONTENTS

1 INTRODUCTION 1-1

2 MODELING FRAMEWORK 2-1

2.1 IPM OVERVIEW 2-1
2.1.1 Purpose and Capabilities 2-1
2.1.2 Applications 2-2

2.2 MODEL STRUCTURE AND FORMULATION 2-2
2.2.1 Objective Function 2-2
2.2.2 Decision Variables 2-3
2.2.3 Constraints 2-4

2.3 KEY METHODOLOGICAL FEATURES OF IPM 2-4
2.3.1 Model Plants 2-4
2.3.2 Model Run Years 2-6
2.3.3 Cost Accounting 2-6
2.3.4 Modeling Wholesale Electric Markets 2-6
2.3.5 Load Duration Curves (LDC) 2-7
2.3.6 Dispatch Modeling 2-9
2.3.7 Reliability Modeling 2-9
2.3.8 Fuel Modeling 2-10
2.3.9 Transmission Modeling 2-10
2.3.10 Perfect Competition and Perfect Foresight 2-10
2.3.11 Air Regulatory Modeling 2-10

2.4 HARDWARE AND PROGRAMMING FEATURES 2-11
2.4.1 Data Parameters for Model Inputs 2-11
2.4.2 Model Outputs 2-12
Appendix 2-1 Load Duration Curves Used in EPA Base Case v.4.10 2-1

3 POWER SYSTEM OPERATION ASSUMPTIONS 3-1

3.1 MODEL REGIONS 3-1

3.2 ELECTRIC LOAD MODELING 3-1
3.2.1 Demand Elasticity 3-4
3.2.2 Net Internal Demand (Peak Demand) 3-4
3.2.3 Regional Load Shapes 3-5

3.3 TRANSMISSION 3-5
3.3.1 Inter-regional Transmission Capability 3-5
3.3.2 Joint Transmission Capacity and Energy Limits 3-9
3.3.3 Transmission Link Wheeling Charge 3-10
3.3.4 Transmission Losses 3-11

3.4 INTERNATIONAL IMPORTS 3-11

3.5 CAPACITY, GENERATION, AND DISPATCH 3-11
3.5.1 Availability 3-11
3.5.2 Capacity Factor 3-12
3.5.3 Turndown 3-13

3.6 RESERVE MARGINS 3-13

3.7 POWER PLANT LIFETIMES 3-15

3.8 HEAT RATES 3-17

3.9 EXISTING ENVIRONMENTAL REGULATIONS 3-17
3.9.1 SO_2 Regulations 3-17
3.9.2 NO_x Regulations 3-18
3.9.3 CO_2 Regulations and Renewable Portfolio Standards 3-20
3.9.4 State Specific Environmental Regulations 3-20
3.9.5 New Source Review (NSR) Settlements 3-20
3.9.6 Emission Assumptions for Potential (New) Units 3-20
3.10 CAPACITY DEPLOYMENT CONSTRAINTS 3-21
Appendix 3-1 NO_x Rate Development in EPA Base Case v.4.10 ..... 3-1.1
Appendix 3-2 State Power Sector Regulations included in EPA Base Case v.4.10 ..... 3-2.1
Appendix 3-3 New Source Review (NSR) Settlements in EPA Base Case v.4.10 ..... 3-3.1
Appendix 3-4 State Settlements in EPA Base Case v.4.10 ..... 3-4.1
Appendix 3-5 Citizen Settlements in EPA Base Case v.4.10 ..... 3-5.1
Appendix 3-6 Renewable Portfolio Standards in EPA Base Case v.4.10 ..... 3-6.1
Appendix 3-7 Capacity Deployment Limits for Advanced Coal with CCS and New Nuclear in EPA Base Case v.4.10 ..... 3-7.1
Appendix 3-8 Nuclear Capacity Deployment Constraint in EPA Base Case v.4.10 ..... 3-8.1
Appendix 3-9 Complete Availability Assumptions in EPA Base Case v.4.10 ..... 3-9.1
4 GENERATING RESOURCES 4-1
4.1 NATIONAL ELECTRIC ENERGY DATA SYSTEM (NEEDS) 4-1
4.2 EXISTING UNITS 4-1
4.2.1 Population of Existing Units 4-1
4.2.2 Capacity 4-4
4.2.3 Plant Location 4-5
4.2.4 Online Year 4-5
4.2.5 Unit Configuration 4-5
4.2.6 Model Plant Aggregation 4-5
4.2.7 Cost and Performance Characteristics of Existing Units 4-9
4.2.8 Life Extension Costs for existing units 4-10
4.3 PLANNED-COMMITTED UNITS 4-13
4.3.1 Population and Model Plant Aggregation 4-13
4.3.2 Capacity 4-17
4.3.3 State and Model Region 4-17
4.3.4 Online and Retirement Year 4-18
4.3.5 Unit Configuration and Cost-and-Performance 4-18
4.4 POTENTIAL UNITS 4-18
4.4.1 Methodology Used to Derive the Cost and Performance Characteristics of Conventional Potential Units 4-18
4.4.2 Cost and Performance for Potential Conventional Units 4-19
4.4.3 Short-Term Capital Cost Adder 4-21
4.4.4 Regional Cost Adjustment 4-21
4.4.5 Cost and Performance for Potential Renewable Generating and Non-4-Conventional Technologies 4-25
4.5 NUCLEAR UNITS 4-44
4.5.1 Existing Nuclear Units 4-44
4.5.2 Potential Nuclear Units 4-45
Appendix 4-1 Representative Wind Generation Profiles in EPA Base Case v.4.10 ..... 4-1.1
Appendix 4-2 Representative Solar Generation Profiles in EPA Base v.4.10 ..... 4-2.1
Appendix 4-3 Characteristics of Existing Nuclear Units 4-3.1
5 EMISSION CONTROL TECHNOLOGIES 5-1

5.1 SULFUR DIOXIDE CONTROL TECHNOLOGIES 5-1
5.1.1 Methodology for Obtaining SO_2 Controls Costs 5-2
5.2 NITROGEN OXIDES CONTROL TECHNOLOGY 5-7
5.2.1 Combustion Controls 5-7
5.2.2 Post-combustion Controls 5-8
5.2.3 Methodology for Obtaining SCR Costs for Coal Units 5-9
5.2.4 Methodology for Obtaining SCR Costs for Oil/Gas Steam units 5-12
5.2.5 Methodology for Obtaining SNCR Costs 5-12
5.2.6 SO_2 and NO_x Controls for Units with Capacities from 25 MW to 100 MW (25 M ≤ capacity < 100 MW) 5-13
5.3 BIOMASS CO-FIRING 5-14
5.4 MERCURY CONTROL TECHNOLOGIES 5-15
5.4.1 Mercury Content of Fuels 5-16
5.4.2 Mercury Emission Modification Factors 5-17
5.4.3 Mercury Control Capabilities 5-18
Appendix 5-1 Example Cost Calculation Worksheets for SO_2 Control Technologies in EPA Base Case v.4.10 5-1
Appendix 5-2 Example Cost Calculation Worksheets for NO_x Post-Combustion Control Technologies in EPA Base Case v.4.10 5-1
6 CO_2 CAPTURE, TRANSPORT, AND STORAGE 6-1
6.1 CO_2 CAPTURE 6-1
6.2 CO_2 STORAGE 6-2
6.3 CO_2 TRANSPORT 6-5
Appendix 6-1 CO_2 Storage Cost Curves in EPA Base Case 4.10 ..... 6-1.1
Appendix 6-2 CO_2 Transportation Matrix in EPA Base Case v.4.10 ..... 6-2.1
7 SET-UP PARAMETERS AND RULES 7-1
7.1 RUN YEAR MAPPING 7-1
7.2 RETROFIT ASSIGNMENTS 7-1
7.3 TRADING AND BANKING 7-3
7.4 POST-2030 MODELING ASSUMPTIONS AND CAPABILITIES 7-4
8 FINANCIAL ASSUMPTIONS 8-1
8.1 SUMMARY OF KEY FINANCIAL PARAMETERS 8-1
8.1.1 Capital Charge Rate, Book Life, and Discount Rate for Capital Expenditures 8-1
8.1.2 ARRA Production and Investment Tax Credit (PTC and ITC) for Renewables 8-2
8.1.3 Discount Rate for Non-Capital Expenditures 8-3
8.1.4 Inter-temporal Allowance Price Calculation 8-3
8.1.5 Nominal and Real Dollars 8-3
8.2 DEVELOPMENT OF THE FINANCIAL ASSUMPTIONS FOR EPA BASE CASE V.4.10 8-3
8.2.1 Introduction 8-3
8.2.2 Method for Deriving Discount Rate and Capital Charge Rate in EPA Base Case v 4.10 8-4
8.2.3 Calculation of the Hybrid Capital Charge Rates 8-7
8.2.4 Development of Merchant Financing Parameters 8-8
8.2.5 Development of Utility Financing Parameters 8-10
8.2.6 Development of Other Parameters 8-10
9 COAL 9-1

9.1 COAL MARKET REPRESENTATION IN EPA BASE CASE V.4.10 9-1
9.1.1 Coal Supply Regions 9-2
9.1.2 Coal Demand Regions 9-3
9.1.3 Coal Quality Characteristics 9-9
9.1.4 Emission Factors 9-10
9.1.5 Coal Grade Assignments 9-15
9.2 COAL SUPPLY CURVES 9-16
9.2.1 Nature of Supply Curves Developed for EPA Base Case v.4.10 9-16
9.2.2 Procedure Employed in Determining Mining Costs 9-17
9.2.3 Supply Curve Development 9-20
9.2.4 Data Sources Used to Build the Curves 9-21
9.2.5 Procedure Used In Determining Mine Productivity 9-22
9.2.6 Procedure to Determine Total Recoverable Reserves by Region and Type 9-22
9.2.7 New Mine Assumptions 9-23
9.2.8 Other Notable Procedures 9-23
9.2.9 Region Specific Assumptions and Outlooks 9-23
9.2.10 Explanation of Coal Supply Curve Extensions to 2040 9-25
9.3 COAL TRANSPORTATION 9-25
9.3.1 Coal Transportation Matrix Overview 9-26
9.3.2 Calculation of Supply/Demand Region Distances 9-26
9.3.3 Overview of Rail Rates 9-27
9.3.4 Truck rates 9-30
9.3.5 Barge and Lake Vessel Rates 9-30
9.3.6 Transportation Rates for Imported Coal 9-31
9.3.7 Other Transportation Costs 9-32
9.3.8 Long-Term Escalation of Transportation Rates 9-32
9.3.9 Market Drivers Moving Forward 9-34
9.3.10 Other Considerations 9-36
9.4 COAL EXPORTS, IMPORTS, AND NON-ELECTRIC SECTORS DEMAND 9-36
Appendix 9-1. Illustrative Example of Wood Mackenzie Costing Procedure Used in Developing EPA's Coal Supply Curves 9-1.1
Appendix 9-2 New Mines Included in 2040 Curves 9-2.1
Appendix 9-3 Coal Transportation Matrix in EPA Base Case v.4.10 ..... 9-3.1
Appendix 9-4 Coal Supply Curves in EPA Base Case v.4.10 ..... 9-4.1
10 NATURAL GAS 10-1
10.1 OVERVIEW OF IPM'S NATURAL GAS MODULE 10-1
10.2 KEY COMPONENTS OF THE NEW IPM NATURAL GAS MODULE 10-4
10.2.1 Note on the Modeling Time Horizon and Pre- and Post-2030 Input Assumptions 10-6
10.3 RESOURCE CHARACTERIZATION AND ECONOMIC EVALUATION 10-7
10.3.1 Resource and Reserves Assessment 10-8
10.3.2 Frontier Resources (Alaska and Mackenzie Delta) 10-10
10.3.3 Use of the HSM resource and reserves data in EPA Base Case using IPM v.4.10 Natural Gas Module 10-12
10.3.4 Undiscovered Resource Appreciation 10-13
10.4 EXPLORATION, DEVELOPMENT, AND PRODUCTION COSTS AND CONSTRAINTS 10-14
10.4.1 Exploration and Development Cost 10-14
10.4.2 Resource Discovery and Drilling Constraints 10-17
10.4.3 Reserves-to-Production (R/P) Ratio 10-19
10.4.4 Variable Costs, Natural Gas Liquid Share, and Crude Oil Share 10-19
10.4.5 Lease and Plant Gas Use 10-20

10.5 LIQUEFIED NATURAL GAS (LNG) IMPORTS 10-20
10.5.1 Liquefaction Facilities and LNG Supply 10-20
10.5.2 Regasification Facilities 10-21
10.5.3 LNG Regasification Capacity Expansions 10-22
10.6 END USE DEMAND 10-23
10.6.1 Step 1: Developing Sector Specific Econometric Models of Non-Power Sector Demand 10-23
10.6.2 Step 2: Use projections based on the GMM econometric models to produce monthly gas demand curves by sector and demand node 10-25
10.6.3 Step 3: Develop non-electric sector natural gas demand curves that correspond to the seasons and segments in the load duration curves used in IPM 10-25
10.7 PIPELINE NETWORK 10-27
10.7.1 Network Structure 10-27
10.7.2 Pipeline Transportation Costs 10-28
10.7.3 Pipeline Capacity Expansion Logic 10-29
10.8 GAS STORAGE 10-30
10.8.1 Storage Capacity and Injection/Withdrawal Constraints 10-33
10.8.2 Variable Cost and Fuel Use 10-33
10.8.3 Storage Capacity Expansion Logic 10-34
10.9 FUEL PRICES 10-35
10.9.1 Crude Oil and Natural Gas Liquids Prices 10-35
10.9.2 Natural Gas Prices 10-36
10.10 OUTPUTS AND PROXY NATURAL GAS SUPPLY CURVES 10-36
10.10.1 Outputs from the New IPM Natural Gas Module 10-36
10.10.2 Proxy Natural Gas Supply Curves 10-36
Appendix 10-1 EPA Base Case v.4.10 with AEO Gas Resource Assumptions 10-1.1
11 OTHER FUELS AND FUEL EMISSION FACTOR ASSUMPTIONS 11-1
11.1 FUEL OIL 11-1
11.2 BIOMASS 11-2
11.3 NUCLEAR FUEL 11-3
11.4 WASTE FUELS 11-3
11.5 FUEL EMISSION FACTORS 11-5
Appendix 11-1 Biomass Supply Curve in EPA Base Case v.4.0 11-1

LIST OF TABLES

Table 1-1 Plant Types in EPA Base Case v.4.10 1-2
Table 1-2 Emission Control Technologies in EPA Base Case v.4.10 1-3
Table 1-3 Key Updates in the EPA Base Case v.4.10 1-4
Table 3-1 Mapping of NERC Regions and NEMS Regions with EPA Base Case v.4.10 Model Regions 3-3
Table 3-2 Electric Load Assumptions in EPA Base Case v.4.10 3-4
Table 3-3 National Non-Coincidental Net Internal Demand 3-5
Table 3-4 Annual Transmission Capabilities of U.S. Model Regions in EPA Base Case v.4.10 3-6
Table 3-5 Annual Joint Capacity and Energy Limits to Transmission Capabilities Between Model Regions in EPA Base Case v.4.10 3-9
Table 3-6 International Electricity Imports in EPA Base Case v.4.10 3-11
Table 3-7 Availability Assumptions in the EPA Base Case v.4.10 3-12
Table 3-8 Seasonal Hydro Capacity Factors (%) in the EPA Base Case v.4.10 3-12
Table 3-9 Planning Reserve Margins in EPA Base Case v.4.10 3-14
Table 3-10 Lower and Upper Limits Applied to Heat Rate Data in NEEDS v.4.10 3-17
Table 3-11 Emission and Removal Rate Assumptions for Potential (New) Units in EPA Base Case v.4.10 3-23
Table 4-1 Data Sources for NEEDS v.4.10 for EPA Base Case v.4.10 4-2
Table 4-2 Rules Used in Populating NEEDS v.4.10 for EPA Base Case v.4.10 4-3
Table 4-3 Summary Population (through 2006) of Existing Units in NEEDSv.4.10 for EPA Base Case v.4.10 4-3
Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS v.4.10 4-4
Table 4-5 Capacity-Parsing Algorithm for Steam Units in NEEDS v.4.10 4-4
Table 4-6 Data Sources for Unit Configuration in NEEDS v.4.10 for EPA Base Case v.4.10 4-6
Table 4-7 Aggregation Profile of Model Plants as Provided at Set Up of EPA Base Case v.4.10 4-7
Table 4-8 VOM Assumptions (2007$) in EPA Base Case v.4.10 4-9
Table 4-9 FOM Assumptions Used in EPA Base Case v.4.10 4-11
Table 4-10 Life Extension Cost Assumptions Used in EPA Base Case v.4.10 4-13
Table 4-11 Summary of Planned-Committed Units in NEEDS v.4.10 for EPA Base Case v.4.10 4-14
Table 4-12 Planned-Committed Units by Model Region in NEEDS v.4.10 for EPA Base Case v.4.10 4-14
Table 4-13 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Base Case v4.10 4-20
Table 4-14 Short-Term Capital Cost Adders for New Power Plants in EPA Base Case v.4.10 (2007$) 4-23
Table 4-15 Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies in EPA Base Case v.4.10 4-25
Table 4-16 Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in EPA Base Case v4.10 4-27
Table 4-17 Onshore Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.4.10 4-29
Table 4-18 Offshore Shallow Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.4.10 4-32

Table 4-19 Offshore Deep Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.4.10 4-34
Table 4-20 Onshore Reserve Margin Contribution an Average Capacity Factor by Wind Class and Model Region 4-37
Table 4-21 Offshore Shallow Reserve Margin Contribution an Average Capacity Factor by Wind Class and Model Region 4-37
Table 4-22 Offshore Deep Reserve Margin Contribution an Average Capacity Factor by Wind Class and Model Region 4-38
Table 4-23 Capital Cost Adjustment Factors for New Wind Plants in Base Case v.4.10 4-39
Table 4-24 Example Calculations Of Wind Generation Potential, Reserve Margin Contribution, And Capital Cost For Onshore Wind In CA-N At Wind Class 7, Cost Class 2 4-40
Table 4-25 Solar Reserve Margin Contribution and Average Capacity Factor by Model Region 4-41
Table 4-26 Regional Assumptions on Potential Geothermal Electric Capacity 4-42
Table 4-27 Potential Geothermal Capacity and Cost Characteristics by Model Region 4-42
Table 4-28 Regional Assumptions on Potential Electric Capacity from New Landfill Gas Units (MW) 4-43
Table 4-29 Nuclear Upratings (MW) as Incorporated in EPA Base Case v.4.10 from AEO 2010 4-45
Table 5-1 Summary of Emission Control Technology Retrofit Options in EPA Base Case v.4.10 5-1
Table 5-2 Summary of Retrofit SO_2 Emission Control Performance Assumptions 5-2
Table 5-3 Capital Cost Modules and Their Governing Variables for SO_2 and NO_x Emission Controls 5-3
Table 5-4 Illustrative Scrubber Costs (2007$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.4.10 5-6
Table 5-5 Cost (2007$) of NO_x Combustion Controls for Coal Boilers (300 MW Size) 5-7
Table 5-6 Incremental Combustion NO_x Controls in EPA Base Case v.4.10 5-8
Table 5-7 Summary of Retrofit NO_x Emission Control Performance Assumptions 5-8
Table 5-8 Illustrative Post Combustion NO_X Controls for Coal Plants Costs (2007$) for Representative Sizes and Heat Rates under the Assu Assumptions in EPA Base Case v.4.10 5-11
Table 5-9 Post-Combustion NO_X Controls for Oil/Gas Steam Units in EPA Base Case v.4.10 5-12
Table 5-10 Biomass Cofiring for Coal Plants 5-15
Table 5-11 Mercury Clusters and Mercury Content of Coal by IPM Coal Types 5-17
Table 5-12 Assumptions on Mercury Concentration in Non-Coal Fuel in EPA Base Case v.4.10 5-17
Table 5-13 Mercury Emission Modification Factors Used in EPA Base Case v.4.10 5-19
Table 5-14 Definition of Acronyms for Existing Controls 5-26
Table 5-15 Key to Burner Type Designations in Table 5-13 5-26
Table 5-16 Illustrative Activated Carbon Injection Costs (2007$) for Representative Sizes under the Assumptions in EPA Base Case v.4.10 5-28
Table 5-17 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Base Case v.4.10 5-29
Table 6-1 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Pulverized Coal Plants 6-1

Table 6-2 CO_2 Transport Cost Calculation Example – MACS to Louisiana Onshore 6-5
Table 7-1 Run Years and Analysis Year Mapping Used in the EPA Base Case v.4.10 7-1
Table 7-2 First Stage Retrofit Assignment Scheme in EPA Base Case v.4.10..... 7-2
Table 7-3 Second Stage Retrofit Assignment Scheme in EPA Base Case v.4.10 7-3
Table 7-4 Trading and Banking Rules in EPA Base Case v.4.10 7-4
Table 7-5 Post-2030 Assumptions in EPA Base Case v.4.10..... 7-5
Table 8-1 U.S. Discount Rates and Capital Charge Rates in EPA Base Case v4.10..... 8-2
Table 8-2 Capital Structure Assumptions for EPA Base Case v4.10..... 8-6
Table 8-3 Debt Rates for EPA Base Case v4.10 8-8
Table 8-4 Book Life, Debt Life and Depreciation Schedules for EPA Base Case v. 4.10..... 8-11
Table 9-1 Coal Supply Regions in EPA Base Case..... 9-2
Table 9-2 Coal Demand Regions in EPA Base Case 9-3
Table 9-3 Coal Rank Heat Content Ranges..... 9-10
Table 9-4 Coal Grade SO_2 Content Ranges 9-10
Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade 9-11
Table 9-6 SO_2 Emission Factors of Coal Used in EPA Base Case v.4.10..... 9-13
Table 9-7 Mercury Emission Factors of Coal Used in EPA Base Case v.4.10 9-14
Table 9-8 Ash Emission Factors of Coal Used in EPA Base Case v.4.10 9-14
Table 9-9 CO_2 Emission Factors of Coal Used in EPA Base Case v.4.10..... 9-15
Table 9-10 Example of Coal Assignments Made in EPA Base Case 9-16
Table 9-11 Basin-Level Groupings Used in Preparing v.4.0 Coal Supply Curves 9-17
Table 9-12 Rail Competition Definitions..... 9-28
Table 9-13 Assumed Eastern Rail Rates (2007 mills/ton-mile)..... 9-29
Table 9-14 Assumed Midwestern Rail Rates (2007 mills/ton-mile)..... 9-29
Table 9-15 Assumed Non-PRB Western Rail Rates (2007 mills/ton-mile) 9-30
Table 9-16 Assumed PRB Western Rail Rates (2007 mills/ton-mile) 9-30
Table 9-17 Assumed Truck Rates (2007 Real Dollars)..... 9-30
Table 9-18 Assumed Barge Rates (2007 Real Dollars) 9-31
Table 9-19 Assumed Transportation Rates for Imported Coal (2007 Real Dollars)..... 9-31
Table 9-20 Assumed Other Transportation Rates (2007 Real Dollars)..... 9-32
Table 9-21 EIA AEO Diesel Fuel Forecast, 2012-2030 (2007 Real Dollars) 9-34
Table 9-22 ABARE Forecast of Iron Ore Prices..... 9-35
Table 9-23 Assumed Production Growth Rates..... 9-36
Table 9-24 Coal Exports..... 9-37
Table 9-25 Residential, Commercial, and Industrial Demand..... 9-38
Table 9-26 Coal Import Limits 9-38
Table 10-1 List of Nodes 10-5
Table 10-2 List of Gas Supply Regions..... 10-1
Table 10-3 List of Key Pipelines..... 10-3
Table 10-4 U.S. and Canada Natural Gas Resources and Reserves..... 10-10
Table 10-5 Exploration and Development Assumptions for EPA Base Case v.4.10 10-17
Table 10-6 North American LNG Regasification Facilities 10-21
Table 10-7 Summer and Winter Load Segments in EPA Base Case v.4.10 10-26
Table 10-8 List of Storage Nodes..... 10-31
Table 10-9 Storage Capacity and Injection/Withdrawal Rates (EOY 2010)..... 10-33

Table 10-10 Base Year 2011 Average Levelized Storage Capital Cost..... 10-35
Table 10-11 Proxy Natural Gas Supply Curves for EPA Base Case v.4.10..... 10-37
Table 10-12 Glossary of Natural Gas Terms Used in Documentation 10-38
Table 11-1 Fuel Oil Prices by NEMS Region in EPA Base Case v.4.10..... 11-1
Table 11-2 Non-Electric Biomass Demand by NEMS Region in EPA Base Case v.4.10 11-2
Table 11-3 Waste Fuels in NEEDS, v.4.10 and EPA Base Case v.4.10 11-4
Table 11-4 Fuel Emission Factor Assumptions in EPA Base Case v.4.10 11-5

LIST OF FIGURES

Figure 1-1 Modeling and Data Structures in EPA Base Case v.4.10 1-4
Figure 2-1 Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve in EPA Base Case v.4.10 2-7
Figure 2-2 Stylized Depiction of Load Duration Curve Used in EPA Base Case v.4.10 2-8
Figure 2-3 Stylized Dispatch Order in EPA Base Case v.4.10 2-9
Figure 3-1 EPA Base Case v.4.10 Model Regions 3-2
Figure 3-2 Scheduled Retirements of Existing Nuclear Capacity Under 60-Year Life Assumption 3-15
Figure 9-1 Map of the Coal Supply Regions in EPA Base Case v.4.10 9-3
Figure 9-2 Cluster Mapping Example --- BG Coal 9-15
Figure 9-3 Cost Calculations Included When Developing Coal Supply Curves (based on a Powder River Basin Mine Supply Curve Example) 9-18
Figure 9-4 Illustration of Preliminary Step in Developing a Cumulative Coal Supply Curve 9-20
Figure 9-5 Illustration of Final Step in Developing a Cumulative Coal Supply Curve 9-21
Figure 9-6 Example Coal Supply Curve in Stepped Format 9-21
Figure 9-7 Calculation of Multi-Mode Transportation Costs (Example) 9-26
Figure 9-8 Coal Demand Region with Multiple Coal Supply Regions 9-27
Figure 9-9 Rail Cost Indices Performance (2Q2003-2Q2008) 9-33
Figure 9-10 Long-Run Marginal Cost Breakdown by Transportation Mode 9-34
Figure 10-1 Modeling and Data Structure in EPA Base Case v.4.10. 10-2
Figure 10-2 Natural Gas Module in EPA Base Case v.4.10. 10-3
Figure 10-3 Gas Transmission Network Map 10-5
Figure 10-4 Gas Supply Regions Map 10-8
Figure 10-5 Gas Demand Regions Map 10-3
Figure 10-6 Natural Gas Storage Facility Node Map 10-7
Figure 10-7 Resource Cost Curves at the End of Year 2010 10-13
Figure 10-8 Exploration & Development and Production Processes and Costs to Bring Undiscovered Resource into Reserves and Production 10-14
Figure 10-9 E&D and Production Technology Improvement Factor 10-15
Figure 10-10 Incremental E&D Cost (EOY 2010) by Percentage of Resource Found 10-15
Figure 10-11 Drilling Rig Speed Constraint 10-19
Figure 10-12 North American LNG Supply Curves 10-21
Figure 10-13 North American LNG Regasification Facilities Map 10-22
Figure 10-14 Examples of Firm Demand Curves by Electric Load Segment 10-26
Figure 10-15 Examples of Interruptible Demand Curves by Electric Load Segment 10-27
Figure 10-16 New England Pipeline Corridors in 2020 10-28
Figure 10-17 Example Pipeline Discount Curve 10-29
Figure 10-18 Pipeline Cost Growth Factor 10-29
Figure 10-19 Storage Cost Growth Factor 10-34
Figure 10-20 Example Maximum Storage Capacity Expansion 10-34
Figure 10-21 Crude Oil and NGL Prices 10-36

1 Introduction

This document describes the nature, structure, and capabilities of the Integrated Planning Model (IPM) and the assumptions underlying the base case (designated EPA Base Case v.4.10) that was developed by the U.S. Environmental Protection Agency (EPA) with technical support from ICF Consulting, Inc. 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 while 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.

Base cases, like EPA Base Case v.4.10, serve as the starting point against which policy scenarios are compared. It is a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2010. (Chapter 3 contains a detailed discussion of the environmental regulations included in EPA Base Case v.4.10.) Regulations, mandated under the Clean Air Act Amendments of 1990 (CAAA), but whose provisions either have not yet been finalized or will expire due to Court action, were not included in the base case. These include.

- *Ozone and Particulate Matter (PM) Standards*: EPA Base Case v.4.10 does not include the provisions of the Clean Air Interstate Rule (CAIR), a Federal regulatory measure for achieving the National Ambient Air Quality Standards (NAAQS) for ozone (8-hour standard of 0.08 ppm) and fine particles (24-hour average of 65 µg/m3 or less and annual mean of 15 µg/m3 for particles of diameter 2.5 micrometers or less, i.e., PM 2.5). Originally issued on March 10, 2005, CAIR was remanded back to EPA by the U.S. Court of Appeals for the District of Columbia Circuit in December 2008 and EPA was required to correct legal flaws in the regulations that had been cited in a ruling by the Court in July 2008. Until EPA's work was completed, CAIR was temporarily reinstated. However, although CAIR's provisions were still in effect when EPA Base Case v.4.10 was released, it is not included in the base case to allow EPA Base Case v.4.10 to be used to analyze the regulations proposed to replace CAIR.
- *EPA Base Case v.4.10* includes ozone and particulate matter standards to the extent that some of the state regulations included in EPA Base Case v.4.10 contain measures to bring non-attainment areas into attainment. A summary of these state regulations can be found in Appendix 3-2 below. Apart from these state regulations, individual permits issued by states in response to ozone and PM standards are only captured (a) to the extent that they are reflected in the NO_X rates reported to EPA under Title IV and the NO_X Budget Program which are incorporated in the base case and (b) to the extent that SO_2 permit limits are used in the base case to define the choice of coal sulfur grades that are available to specific power plants.

- *Regional Haze*: On July 1, 1999, EPA issued Regional Haze Regulations to meet the national goal for visibility established in Section 169A of the CAAA, which calls for "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas [156 national parks and wilderness areas], which impairment results from manmade air pollution." The regulations required states to submit revised State Implementation Plans (SIPs) that include (1) goals for improving visibility in Class I areas on the 20% worst days and allowing no degradation on the 20% best days and (2) assessments and plans for achieving Best Available Retrofit Technology (BART) emission targets for sources placed in operation between 1962-1977. The revised SIPs were to be submitted between 2004-2006 for areas designated as "attainment" and "unclassified" and between 2006-2008 for "nonattainment" areas. They are represented in EPA Base Case v.4.10 to the extent that SO_2 permit limits derived from the SIPs are used in the base case to define the choice of coal sulfur grades that are available to specific power plants. As discussed in chapter 3, however, the base case includes the sulfur dioxide emission cap (144.7 MTons for all affected fossil fired generating units larger than 25 MW), adopted by the Western Regional Air Partnership states of Arizona,

New Mexico, Oregon, Utah, and Wyoming in response to Section 309 of the federal Regional Haze Rule.

In effect, EPA Base Case v.4.10 offers a projection of the electric sector assuming that the only future environmental regulations are those that were in place at the time the base case was finalized and that have a high likelihood of remaining in force. This simplifying assumption ensures that the base case is policy neutral with respect to prospective, future environmental policies. Table 1-1 lists the types of plants included in the EPA Base Case v.4.10. Table 1-2 lists the emission control technologies available for meeting emission limits in EPA Base Case v.4.10.

Table 1-1 Plant Types in EPA Base Case v.4.10

Fossil Fuel Fired
Coal Steam
Oil/Gas Steam
Combustion Turbine
Combined-Cycle Combustion Turbine
Integrated Gasification Combined-Cycle (IGCC) Coal
Advanced Coal with Carbon Capture
Fluidized Bed Combustion
Non-Fossil Fuel Fired
Nuclear
Renewables and Non-Conventional Technologies
Hydropower
Pumped Storage
Biomass IGCC
Onshore Wind
Offshore Shallow Wind
Offshore Deep Wind
Fuel Cells
Solar Photovoltaics
Solar Thermal
Geothermal
Landfill Gas
Other[1]

Note:

[1] Includes fossil and non-fossil waste plants

Table 1-2 Emission Control Technologies in EPA Base Case v.4.10

Sulfur Dioxide (SO_2)	Nitrogen Oxides (NO_x)
Limestone Forced Oxidation (LSFO) Lime Spray Dryer (LSD)	Combustion controls Selective catalytic reduction (SCR) Selective non-catalytic reduction (SNCR)
Mercury (Hg)	**Carbon Dioxide (CO_2)**
Combinations of SO_2, NO_x, and particulate control technologies Activated Carbon Injection	Carbon Capture and Sequestration

Notes:
1. Though not listed in Table 1-2, biomass co-firing, which is offered as a fuel option in EPA Base Case v.4.10, is also used as a CO_2 emission control option. See section 5.3 in Chapter 5 for a description of the implementation of biomass co-firing in EPA Base Case v.4.10.
2. Fuel switching between coal types and to natural gas is also a compliance option for reducing emissions in EPA Base Case v.4.10

Figure 1-1 provides a schematic of the components of the modeling and data structure used for EPA Base Case v.4.10. This report devotes a separate chapter to all the key components shown in Figure 1-1. Chapter 2 provides an overview of IPM's modeling framework (sometimes referred to as the "IPM Engine"), highlighting the mathematical structure, notable features of the model, programming elements, and model inputs and outputs. The remaining chapters are devoted to different aspects of EPA Base Case v.4.10. Chapter 3 covers the power system operating characteristics captured in EPA Base Case v.4.10. Chapter 4 explores the characterization of electric generation resources. Emission control technologies (chapter 5) and carbon capture, transport and storage (chapter 6) are then presented. Chapter 7 describes certain set-up rules and parameters employed in EPA Base Case v.4.10. Chapter 8 summarizes the base case financial assumptions. The last three chapters discuss the representation and assumptions for fuels in the base case. Coal is covered in chapter 9, natural gas in chapter 10, and other fuels (i.e., fuel oil, biomass, nuclear fuel, and waste fuels) in chapter 11 (along with fuel emission factors).

Figure 1-1 Modeling and Data Structures in EPA Base Case v.4.10

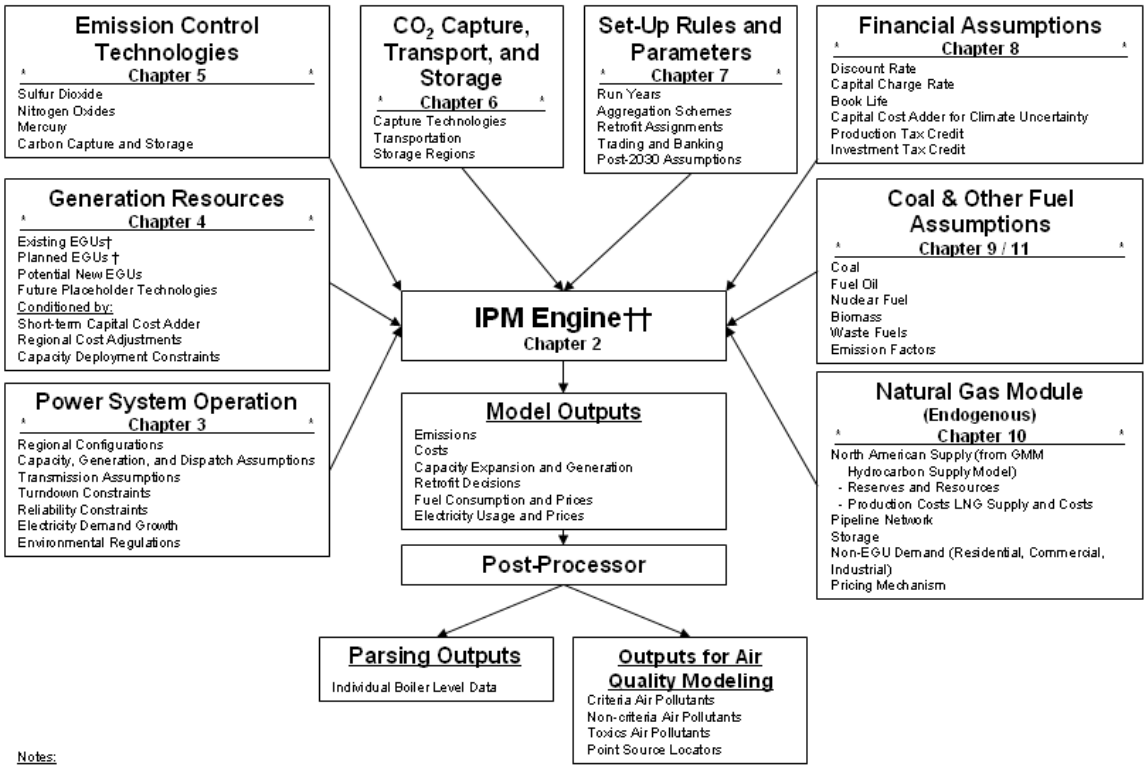


Table 1-3 lists key updates included in EPA Base Case v.4.10 listed in the order they appear in this documentation report. Noted by asterisks in the second column are updates that were "non-routine" in the sense that they constituted new modeling capabilities or notable extensions beyond the capabilities provided in previous EPA base cases or significant reviews of important assumptions. The updates that are not starred represent more routine updates. Equal in importance to the non-routine updates, the routine updates typically require substantial effort and great discipline to maintain. They are critical to the technical credibility of a detailed, bottom-up, data driven model like IPM.

Table 1-3 Key Updates in the EPA Base Case v.4.10

Description	Non-Routine (*)	For More Information
Modeling Framework		
Use of six-segment load duration curves (2012-2030) to enable differentiation of peak and super-peak generating unit dispatch		§2.3.5 - 2.3.6
Power System Operation		
Model region update and inclusion of Canada, Alaska, Hawaii, Puerto Rico, and U.S. Virgin Islands	*	§3.1
Updates based on recent data from EIA, NERC, FERC, etc.		(multiple)
Capacity deployment constraints (for new advanced coal with carbon capture, carbon capture retrofits, and new nuclear)	*	§3.10 App. 3-07 - 3-08

Description	Non-Routine (*)	For More Information
Updated inventory of state emission regulations		App.3-02
Updated inventories of NSR, state, and citizen settlements		App. 3-03 - 3-05
Nuclear retirement at age 60	*	§3.7
Generating Resources		
Updates to NEEDS, the database of existing and planned-committed units and their emission control configurations		§4.1- 4.3
Providing life extension cost option to allow existing units to continue operation over the extended 2012-2050 modeling time horizon in the new base case		§4.2.8
Updated cost and performance characteristics for potential (new) conventional and nuclear generating units, based on comparative cost analyses	*	§4.4.1 - 4.4.2
Adding biomass gasification combined cycle and offshore (shallow and deep) wind as potential (new) renewable generating options	*	§4.4.5
Expanding wind resource base to include 5 wind classes (3-7) by adding new wind classes 3 and 7 using data provided by NREL	*	§4.4.5
Emission Control Technologies		
Complete update of cost and performance assumptions for SO_2 and NO_x emission controls based on engineering studies by Sargent and Lundy	*	§5.1 - 5.2
Inclusion of cost and performance assumptions for SO_2 and NO_x emission controls for units with capacities ranging from 25-100MW	*	§5.2.6
Updated cost and performance assumptions for biomass co-firing by coal units		§5.3
Carbon Capture, Transport and Storage		
Update of the cost and performance characteristics used to represent carbon capture retrofits and new generating units with carbon capture		§6.1
CO_2 transport and storage represented through state level transportation matrix and regional storage cost curves rather than a single cost adder	*	§6.2 - 6.3
Set-Up Parameters and Rules		
Expanded modeling time horizon out to 2050 with six model run years (2012, 2015, 2020, 2030, 2040, 2050)	*	§7.1 and 7.4
Five generic placeholder future generation technologies for later use in comparative scenario analyses		§7.4
Financial assumptions		
Update of discount and capital charge rate assumptions based on a new hybrid capital cost model of utility and merchant finance structures		§8.1.1 and 8.2
Capital cost adder for climate change uncertainty		§8.1.1

Description	Non-Routine (*)	For More Information
Incorporation of latest legislation based tax credits for renewables and nuclear generation		§8.1.1 - 8.1.2
Coal		
Complete update of coal supply curves and transportation matrix	*	§9
Natural Gas		
Development of IPM natural gas module providing completely endogenous comprehensive modeling of North American natural gas system	*	§10
Major revision of unconventional gas resource base, particularly view of shale gas resources	*	§10.3
Base case variant with natural gas resource assumptions similar to AEO 2010		Appendix 10.1
Other Fuels		
Update of biomass supply curves and price assumptions for fuel oil, nuclear fuel and waste fuel	*	§11

2 Modeling Framework

ICF International developed the Integrated Planning Model (IPM) to support analysis of the electric sector. The EPA, in addition to other state air regulatory agencies, utilities, and public and private sector clients, has used IPM extensively for various air regulatory analyses, market studies, strategy planning, and economic impact assessments.

The first section of this chapter provides a brief overview of the model's purpose, capabilities, and applications. The following sections are devoted to describing the IPM model's structure and formulation, key methodological characteristics, and programming features, including its handling of model inputs and outputs. Readers may find some overlap between sections. For example, transmission decision variables and constraints are covered in section 2.2's discussion of model structure and formulation, and transmission modeling is covered as a key methodological feature in section 2.3.9. The different perspectives of each section are designed to provide readers with information that is complementary rather than repetitive.

2.1 IPM Overview

IPM is a well-established model of the electric power sector designed to help government and industry analyze a wide range of issues related to this sector. The model represents economic activities in key components of energy markets – fuel markets, emission markets, and electricity markets. Since the model captures the linkages in electricity markets, it is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

2.1.1 Purpose and Capabilities

IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting energy and peak demand requirements over a specified period. In its solution, the model considers a number of key operating or regulatory constraints (e.g. emission limits, transmission capabilities, renewable generation requirements, fuel market constraints) that are placed on the power, emissions, and fuel markets. In particular, the model is well-suited to consider complex treatment of emission regulations involving trading, banking, and special provisions affecting emission allowances (like bonus allowances and progressive flow control), as well as traditional command-and-control emission policies.

IPM represents power markets through model regions that are geographical entities with distinct characteristics. While they are more numerous (for purposes of picking up local transmission behavior and bottlenecks), the model regions representing the U.S. power market in EPA Base Case v.4.10 are largely consistent with the regions and sub-regions constituting the North American Electric Reliability Council (NERC) regions and with the organizational structures of the Regional Transmission Organizations (RTOs) and Independent System Operators, which handle dispatch on most of the U.S. grid. IPM models the electric demand, generation, transmission, and distribution within each region as well as the inter-regional transmission grid. All existing utility power generation units, including renewable resources, are modeled, as well as independent power producers and cogeneration facilities that sell electricity to the grid.

IPM provides a detailed representation of new and existing resource options, including fossil generating options (coal steam, gas-fired simple cycle combustion turbines, combined cycles, and oil/gas steam), nuclear generating options, and renewable and non-conventional (e.g., fuel cells) resources. Renewable resource options include wind, landfill gas, geothermal, solar thermal, solar photovoltaic and biomass.

IPM can incorporate a detailed representation of fuel markets and can endogenously forecast fuel prices for coal, natural gas, and biomass by balancing fuel demand and supply for electric

generation. The model also includes detailed fuel quality parameters to estimate emissions from electric generation.

IPM provides estimates of air emission changes, regional wholesale energy and capacity prices, incremental electric power system costs, changes in fuel use, and capacity and dispatch projections.

2.1.2 Applications

IPM's structure, formulation and set-up make it very adaptable and flexible. The necessary level of data, modeling capabilities exercised, and computational requirements can be tailored to the particular strategies and policy options being analyzed. This adaptability has made IPM suitable for a variety of applications. These include:

Air Regulatory Assessment: Since IPM contains extensive air regulatory modeling features, state and federal air regulatory agencies have used the model extensively in support of air regulatory assessment.

Integrated Resource Planning: IPM can be used to perform least-cost planning studies that simultaneously optimize demand-side options (load management and conservation), renewable options and traditional supply-side options.

Strategic Planning: IPM can be used to assess the costs and risks associated with alternative utility and consumer resource planning strategies as characterized by the portfolio of options included in the input data base.

Options Assessment: IPM allows industry and regulatory planners to "screen" alternative resource options and option combinations based upon their relative costs and contributions to meeting customer demands.

Cost and Price Estimation: IPM produces realistic estimates of energy prices, capacity prices, fuel prices, and allowance prices. Industry and regulatory agencies have used these cost reports for due diligence, planning, litigation and economic impact assessment.

2.2 Model Structure and Formulation

IPM employs a linear programming structure that is particularly well-suited for analysis of the electric sector to help decision makers plan system capacity and model the dispatch of electricity from individual units or plants. The model consists of three key structural components:

- A linear "objective function,"
- A series of "decision variables," and
- A set of linear "constraints".
- The sections below describe the objective function, key decision variables, and constraints included in IPM for EPA Base Case v.4.10.

2.2.1 Objective Function

IPM's objective function is to minimize the total, discounted net present value, of the costs of meeting demand, power operation constraints, and environmental regulations over the entire planning horizon. The objective function represents the summation of all the costs incurred by the electricity sector. The total resulting cost is expressed as the net present value of all the component costs. These costs, which the linear programming formulation attempts to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. Many of these cost components are captured in the objective function by multiplying the decision variables by a cost coefficient. Cost escalation factors are used in the objective function to reflect changes in cost over time. The applicable discount rates

are applied to derive the net present value for the entire planning horizon from the costs obtained for all years in the planning horizon.

2.2.2 Decision Variables

Decision variables represent the values which the IPM model is "solving for," given the cost-minimizing objective function described in section 2.2.1 and the set of electric system constraints detailed in section 2.2.3. The decision variables values are the model's "outputs" and represent the optimal least-cost solution for meeting the assumed constraints. Key decision variables represented in IPM are described in detail below.

Generation Dispatch Decision Variables: IPM includes decision variables representing the generation from each model power plant[1]. For each model plant, a separate generation decision variable is defined for each possible combination of fuel, season, model run year, and segment of the seasonal load duration curve applicable to the model plant. (See section 2.3.5 below for a discussion of load duration curves.) In the objective function, each plant's generation decision variable is multiplied by the relevant heat rate and fuel price (differentiated by the appropriate step of the fuel supply curve) to obtain a fuel cost. It is also multiplied by the applicable variable operation and maintenance (VOM) cost rate to obtain the VOM cost for the plant.

Capacity Decision Variables: IPM includes decision variables representing the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. In the objective function, the decision variables representing existing capacity and capacity additions are multiplied by the relevant fixed operation and maintenance (FOM) cost rates to obtain the total FOM cost for a plant. The capacity addition decision variables are also multiplied by the investment cost and capital charge rates to obtain the capital cost associated with the capacity addition.

Transmission Decision Variables: IPM includes decision variables representing the electricity transmission along each transmission link between model regions in each run year. In the objective function, these variables are multiplied by variable transmission cost rates to obtain the total cost of transmission across each link.

Emission Allowance Decision Variables: For emission policies where allowance trading applies, IPM includes decision variables representing the total number of emission allowances for a given model run year that are bought and sold in that or subsequent run years. In the objective function, these year-differentiated allowance decision variables are multiplied by the market price for allowances prevailing in each run year. This formulation allows IPM to capture the inter-temporal trading and banking of allowances.

Fuel Decision Variables: For each type of fuel and each model run year, IPM defines decision variables representing the quantity of fuel delivered from each fuel supply region to model plants in each demand region. Coal decision variables are further differentiated according to coal rank (bituminous, sub-bituminous, and lignite), sulfur grade (see section 1 and Table 9-4), and mercury content (see sections 5.4.1and 1 and Table 9-7). These fuel quality decision variables do not appear in the IPM objective function, but in constraints which define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant.

---

[1]Model plants are aggregate representations of real life electric generating units. They are used by IPM to model the electric power sector. For a discussion of model plants in EPA Base Case v.4.10, see section 4.2.6.

2.2.3 Constraints

Model constraints are implemented in IPM to accurately reflect the characteristics of and the conditions faced by the electric sector. Among the key constraints included in EPA Base Case v.4.10 are:

Reserve Margin Constraints: Regional reserve margin constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year. If existing plus planned capacity is not enough to satisfy the annual regional reserve margin requirement, the model will "build" the required level of new capacity.

Demand Constraints: The model categorizes regional annual electricity demand into seasonal load segments which are used to form summer (May 1 - September 30) and winter (October 1 - April 30) load duration curves (LDC). The seasonal load segments when taken together represent all the hourly electricity load levels that must be satisfied in a region in the particular season for a particular model run year. As such, the LDC defines the minimum amount of generation required to meet the region's electrical demand during the specific season. These requirements are incorporated in the model's demand constraints.

Capacity Factor Constraints: These constraints specify how much electricity each plant can generate (a maximum generation level), given its capacity and seasonal availability.

Turn Down/Area Protection Constraints: The model uses these constraints to take into account the cycling capabilities of the units, i.e., whether or not they can be shut down at night or on weekends, or whether they must operate at all times, or at least at some minimum capacity level. These constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base load units.

Emissions Constraints: IPM can consider an array of emissions constraints for SO_2, NO_X, mercury, and CO_2. Emission constraints can be implemented on a plant-by-plant, regional, or system-wide basis. The constraints can be defined in terms of a total tonnage cap (e.g., tons of SO_2) or a maximum emission rate (e.g., lb/MMBtu of NO_X). The scope, timing, and definition of the emission constraints depend on the required analysis.

Transmission Constraints: IPM can simultaneously model any number of regions linked by transmission lines. The constraints define either a maximum capacity on each link, or a maximum level of transmission on two or more links (joint limits) to different regions.

Fuel Supply Constraints: These constraints define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant. A separate constraint is defined for each model plant.

2.3 Key Methodological Features of IPM

IPM is a flexible modeling tool for obtaining short- and long-term projections of production activity in the electric generation sector. The projections obtained using IPM are not statements of what will happen but what might happen given the assumptions and methodologies used. Chapters 3-11 contain detailed discussions of the cost and performance assumptions specific to the EPA Base Case v.4.10. This section provides an overview of the essential methodological and structural features of IPM, that extend beyond the assumptions that are specific to EPA Base Case v.4.10.

2.3.1 Model Plants

Model plants are a central structural component that IPM uses in three ways: (1) to represent aggregations of existing generating units, (2) to represent retrofit and retirement options that are available to existing units, and (3) to represent potential (new) units that the model can build.

Existing Units: Theoretically, there is no predefined limit on the number of units that can be included in IPM. However, to keep model size and solution time within acceptable limits, EPA utilizes model plants to represent aggregations of actual individual generating units. The aggregation algorithm groups units with similar characteristics into model plants with a combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Model plants are defined to maximize the accuracy of the model's cost and emissions estimates by capturing variations in key features of those units that are critical in the base case and anticipated policy case runs. For EPA Base Case v.4.10, IPM employed an aggregation algorithm which allowed 15,023 actual existing electric generating units to be represented by 4,738 model plants. Section 4.2.6 describes the aggregation procedure used in the EPA Base Case v.4.10.

Retrofit and Retirement Options: IPM also utilizes model plants to represent the retrofit and retirement options that are available to existing units. EPA Base Case v.4.10 provides existing model plants with the option to retire early and with a wide range of options for retrofitting with emission control equipment. (See Chapters 5 and section 7.2 in Chapter 7 for a detailed discussion of the options that are included in the EPA Base Case v.4.10.)

The options available to each model plant are pre-defined at the model's set-up. The retrofit and retirement options are themselves represented in IPM by model plants, which, if actuated in the course of a model run, take on all or a portion of the capacity initially assigned to a model plant which represents existing generating units. EPA Base Case v.4.10 model plants that represent potential (new) units are not given the option to take on a retrofit or retire. In setting up IPM, parent-child-grandchild relationships are pre-defined between each existing model plant (parent) and the specific retrofit and retirement model plants (children and grandchildren) that may replace the parent model plant during the course of a model run. The "child" and "grandchild" model-plants are inactive in IPM unless the model finds it economical to engage one of the options provided, e.g., retrofit with particular emission controls or retire early.

Theoretically, there are no limits on the number of "child," "grandchild," and even "great-grandchild" model plants (i.e., retrofit and retirement options) that can be associated with each existing model plant. However, model size and computational considerations dictate that the number of successive retrofits be limited. In EPA Base Case v.4.10, a maximum of two stages of retrofit options are provided (child and grandchild, but not great-grandchild). For example, an existing model plant may be retrofit with a limestone forced oxidation (LSFO) SO_2 scrubber and with a selective catalytic reduction (SCR) control for NO_X in one model run year (stage 1) and with an activated carbon injection (ACI) for mercury control in the same or subsequent run year (stage 2). However, if it exercises this succession of retrofit options, no further retrofit or retirement options are possible beyond the second stage.

Potential (New) Units: IPM also uses model plants to represent new generation capacity that may be built during a model run. All the model plants representing new capacity are pre-defined at set-up, differentiated by type of technology, regional location, and years available. When it is economically advantageous to do so, IPM "builds" one or more of these predefined model plants by raising its generation capacity from zero during the course of a model run. In determining whether it is economically advantageous to "build" new plants, IPM takes into account cost differentials between technologies, expected technology cost improvements (by differentiating costs based on a plant's vintage, i.e., build year) and regional variations in capital costs that are expected to occur over time.

Since EPA Base Case v.4.10 results are presented at the model plant level, EPA has developed a post-processor "parsing" tool designed to translate results at the model plant level into generating unit-specific results. The parsing tool produces unit-specific emissions, fuel use, pollution control retrofit and capacity projections based on model plant results. Another post-processing activity involves deriving inputs for air quality modeling from IPM outputs. This entails using emission factors to derive the levels of pollutants needed in EPA's air quality models from emissions and

other parameters generated by IPM. It also involves using decision rules to assign point source locators to these emissions. (See Figure 1-1 for a graphical representation of the relationship of the post-processing tools to the overall IPM structure.)

2.3.2 Model Run Years

Another important structural feature of IPM is the use of model run years to represent the full planning horizon being modeled. Mapping each year in the planning horizon into a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. Although IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. (See section 2.3.3 below for further details.)

Often models like IPM include a final model run year that is not included in the analysis of results. This technique reduces the likelihood that modeling results in the last represented year will be skewed due to the modeling artifact of having to specify an end point in the planning horizon, whereas, in reality, economic decisions are likely to persist beyond that end point. Due to the number of model run years required by EPA for analytical purposes (six in the 2012-2050 time period) and a greatly expanded suite of modeling capabilities, such an approach could not be used in EPA Base Case v.4.10. It would have increased model size too much. However boundary distortions are only a potential factor in 2050, the last modeled year. In addition, any tendency toward end-year distortions should be reduced by the longer modeling time horizon of this base case and by the relatively large number of calendar years (9) that are mapped into model run year 2050 (see Table 7-1). Nevertheless, the possibility of residual boundary effects is something to bear in mind when interpreting model results for 2050.

2.3.3 Cost Accounting

As noted earlier in the chapter, IPM is a dynamic linear programming model that finds the least cost investment and electricity dispatch strategy for meeting electric demand subject to resource availability and other operating and environmental constraints. The cost components that IPM takes into account in deriving an optimal solution include the costs of investing in new capacity options, the cost of installing and operating pollution control technology, fuel costs, and the operation and maintenance costs associated with unit operations.

Several cost accounting assumptions are built into IPM's objective function that ensures a technically sound and unbiased treatment of the cost of all investment options offered in the model. These features include:

All costs in IPM's single multi-year objective function are discounted to a base year. Since the model solves for all run years simultaneously, discounting to a common base year ensures that IPM properly captures complex inter-temporal cost relationships.

Capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.

The cost components appearing in IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in the individual model run years. This permits the model to capture more accurately the escalation of the cost components over time.

2.3.4 Modeling Wholesale Electric Markets

Another important methodological feature worth noting about IPM is that it is designed to depict production activity in deregulated wholesale electric markets, not in retail markets. The model captures transmission costs and losses between IPM model regions. It is not designed to capture

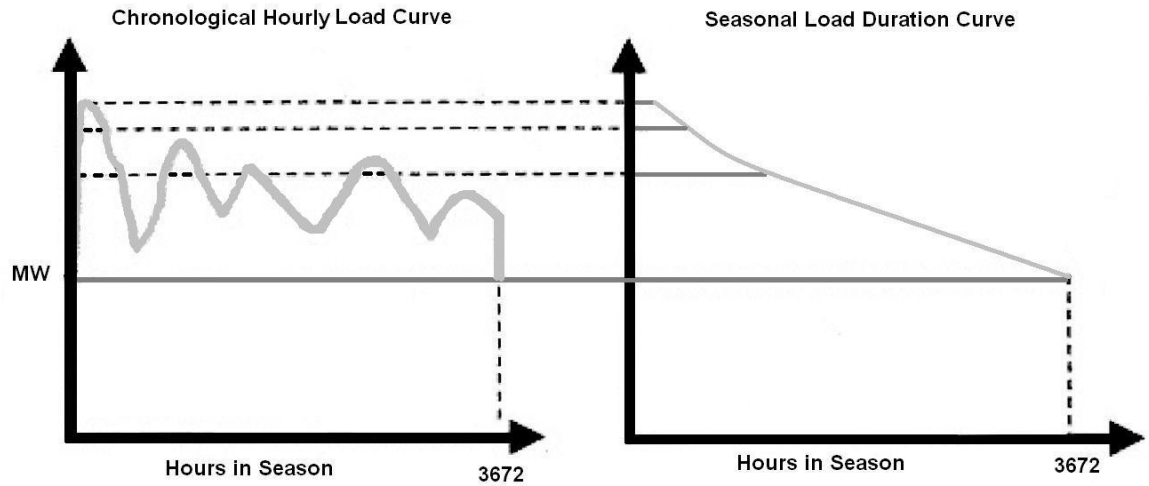
retail distribution costs. However, the model implicitly includes distribution losses since net energy for load,[2] rather than delivered sales,[3] is used to represent electric demand in the model. Additionally, the production costs calculated by IPM are the wholesale production costs. In reporting costs, the model does not include embedded costs, such as carrying charges of existing units that may be part of the retail cost.

2.3.5 Load Duration Curves (LDC)

IPM uses Load Duration Curves (LDCs) to provide realism to the dispatching of electric generating units. Unlike a chronological electric load curve, which is simply an hourly record of electric demand, the LDCs are created by rearranging the hourly chronological electric load data from the highest to lowest (MW) value. For modeling tractability a 6-step piecewise linear representation of the LDC is used in EPA applications of IPM.

IPM can include any number of separate LDCs for any number of user defined seasons. A season can be a single month or several months. For example, EPA Base Case v.4.10 contains two seasons: summer (May 1 – September 30) and winter (October 1– April 30). Separate summer and winter LDCs are created for each of IPM's model regions. Figure 2-1 below presents side-by-side graphs of a hypothetical chronological hourly load curve and a corresponding load duration curve for a season consisting of 3,672 hours.

Figure 2-1 Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve in EPA Base Case v.4.10



National electric demand growth assumptions (from AEO for EPA Base Case v.4.10) and NERC's forecasts of peak and energy demand in each region are used to derive future seasonal load duration curves for each IPM run year in each IPM region from the historical data. The results of this process are individualized seasonal LDCs that capture the unique hourly electric demand profile of each region. The LDCs change over time to reflect projected future variations in electricity consumption patterns.

Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 2-2. EPA Base Case v.4.10 uses six load segments in its seasonal LDCs

---

[2]Net energy for load is the electrical energy requirements of an electrical system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes distribution losses.

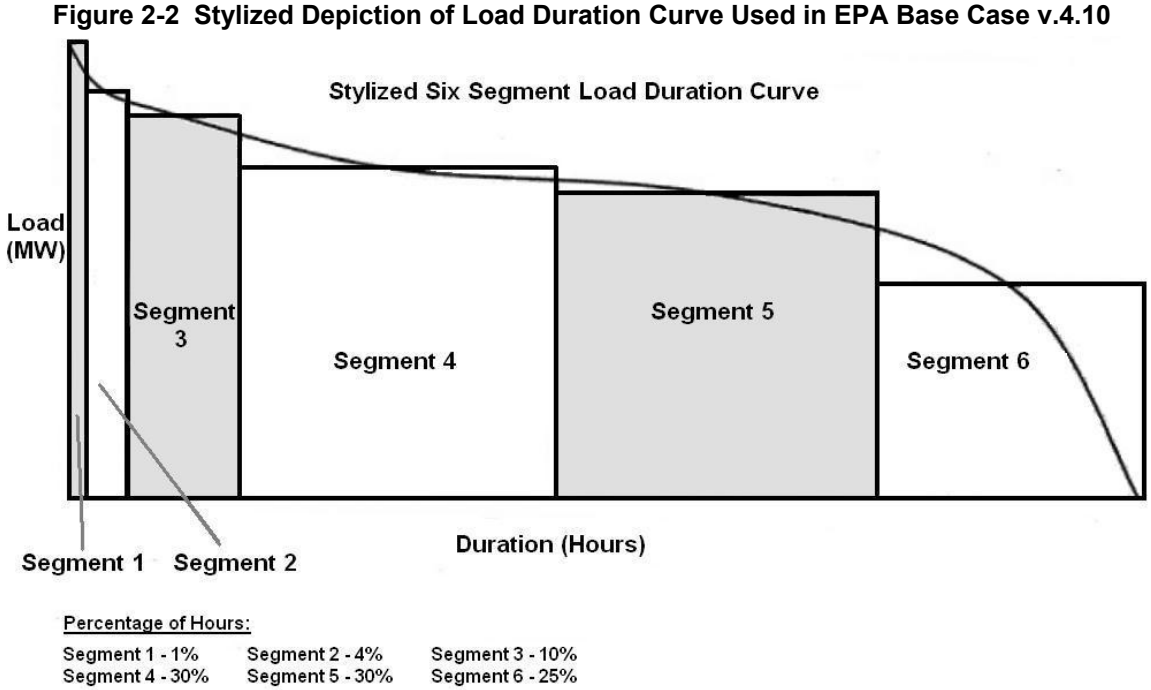
[3]Delivered sales is the electrical energy delivered under a sales agreement. It does not include distribution losses.

for model run years 2012-2030 and 4 load segments in its LDCs for model run years 2040 and 2050. The reduced number of load segments in the later years was adopted out of model size considerations and a view that having a finer grained representation of dispatch was less important that far into the future. Figure 2-3 illustrates and the following text describes the 6-segment LDCs used in the base case's earlier years. Length of time and system demand are the two parameters which define each segment of the load duration curve. The load segment represents the amount of time (along the x-axis) and the capacity that the electric dispatch mix must be producing (represented along the y-axis) to meet system load. Segment 1 in Figure 2-3 generally contains one percent of the hours in the period (i.e., "season") but represents the highest load demand value. IPM has the flexibility to model any number of load segments; however the greater the number of segments, the greater the computational time required to reach a solution. The LDC shows all the hourly electricity load levels that must be satisfied in a region in a particular season of a particular model run year. Segment 1 (the "super peak" load segment with 1% of all the hours in the season) and Segment 2 (the "peak" load segment with 4% of all the hours in the season) represent all the hours when load is at the highest demand levels. Segments 2 through 6 represent hourly loads at progressively lower levels of demand. Plants are dispatched to meet this load based on economic considerations and operating constraints. The most cost effective plants are assigned to meet load in all 6 segments of the load duration curve. This is discussed in greater detail in section 2.3.6 below.

Use of seasonal LDCs rather than annual LDCs allows IPM to capture seasonal differences in the level and patterns of customer demand for electricity. For example, in most regions air conditioner cycling only impacts customer demand patterns during the summer season. The use of seasonal LDCs also allows IPM to capture seasonal variations in the generation resources available to respond to the customer demand depicted in an LDC. For example, power exchanges between utility systems may be seasonal in nature. Some air regulations affecting power plants are also seasonal in nature. This can impact the type of generating resources that are dispatched during a particular season. Further, because of maintenance scheduling for individual generating units, the capacity and utilization for these supply resources also vary between seasons.

Appendix 2-1 contains data and graphs of the 2012 summer and winter load duration curves in each of the 32 model regions in the lower continental U.S. for EPA Base Case v.4.10.

Figure 2-2 Stylized Depiction of Load Duration Curve Used in EPA Base Case v.4.10

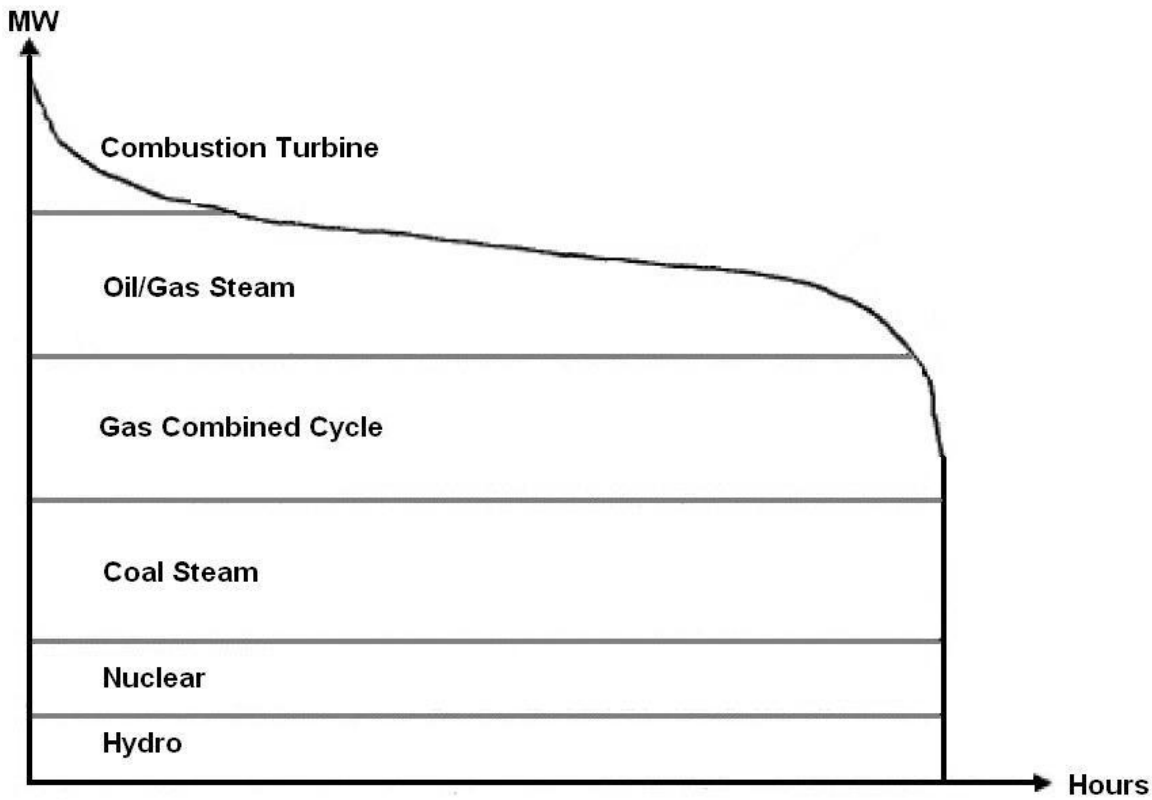


2.3.6 Dispatch Modeling

In IPM, the dispatching of electricity is based on the variable cost of generation. In the absence of any operating constraints, units with the lowest variable cost generate first. The marginal generating unit, i.e., the power plant that generates the last unit of electricity, sets the energy price. Physical operating constraints also influence the dispatch order. For example, IPM uses turndown constraints to prevent base load units from cycling, i.e., switching on and off. Turndown constraints often override the dispatch order that would result based purely on the variable cost of generation. Variable costs in combination with turndown constraints enable IPM to dispatch generation resources in a technically realistic fashion.

Figure 2-3 below depicts a highly stylized dispatch order based on the variable cost of generation of the resource options included in the EPA Base Case v.4.10. In Figure 2-3 a hypothetical load duration curve is subdivided according to the type of generation resource that responds to the load requirements represented in the curve. Notice that the generation resources with the lowest operating cost (i.e., hydro and nuclear) respond first to the demand represented in the LDC and so are at the bottom of "dispatch stack." They are dispatched for the maximum possible number of hours represented in the LDC because of their low operating costs. Generation resources with the highest operating cost (i.e., peaking turbines) are at the top of the "dispatch stack," since they are dispatched last and for the minimum possible number of hours.

Figure 2-3 Stylized Dispatch Order in EPA Base Case v.4.10



2.3.7 Reliability Modeling

Another methodological feature of IPM is its modeling of reliability through reserve margin requirements, which specify the amount of installed capacity that must be in excess of peak power demand. IPM includes regional reserve margin requirements for each run year. Section 3.6 contains a discussion of the reserve margin assumptions in EPA Base Case v.4.10.

2.3.8 Fuel Modeling

Another key methodological feature of IPM is its capability to model the full range of fuels used for electric power generation. The cost, supply, and (if applicable) quality of each fuel included in the model are defined during model set-up. Fuel price and supply are represented in EPA Base Case v.4.10 in one of three alternative ways: (1) through an embedded modeling capability that dynamically balances supply and demand to arrive at fuel prices (natural gas), (2) through a set of supply curves (coal and biomass) or (3) through an exogenous price stream (fuel oil and nuclear fuel). With the first and second approaches, the model endogenously determines the price for that fuel by balancing the supply and demand. IPM uses the fuel quality information (e.g., the sulfur or mercury content of different types of coal from different supply regions) to determine the emissions resulting from the combustion of that fuel.

The EPA Base Case v.4.10 includes coal, natural gas, fuel oil, nuclear fuel, biomass, and fossil and non-fossil waste as fuels for electric generation. The specific base case assumptions for these fuels are examined in chapters 9-11.

2.3.9 Transmission Modeling

IPM includes a detailed representation of existing transmission capabilities between model regions along with options for building new transmission lines. The maximum transmission capabilities between regions are specified in IPM's transmission constraints. Additions to transmission lines are represented by decision variables defined for each eligible link and model run year. In IPM's objective function, the decision variables representing transmission additions are multiplied by new transmission line investment cost and capital charge rates to obtain the capital cost associated with the transmission addition. Due to extensive unresolved policy issues and long-term uncertainty surrounding the building of new transmission lines in the U.S., EPA Base Case v.4.10 does not exercise IPM's capability to model the building of new transmission lines. The specific transmission assumptions in EPA Base Case v.4.10 are described in section 3.3.

2.3.10 Perfect Competition and Perfect Foresight

Two key methodological features of IPM are its assumptions of perfect competition and perfect foresight. The former means that IPM models production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. The model does not explicitly capture any market imperfections such as market power, transaction costs, informational asymmetry or uncertainty. However, if desired, appropriately designed sensitivity analyses or redefined model parameters can be used to gauge the impact of market imperfections on the wholesale electric markets. Since the retail electric market is not modeled in IPM, there are no assumptions about the extent or timing of retail deregulation.

IPM's assumption of perfect foresight implies that economic agents know precisely the nature and timing of the constraints that will be imposed in future years. For example, under IPM there is complete foreknowledge of the levels, timing, and regulatory design of emission limits that will be imposed over the entire modeling time horizon. In making decisions, agents optimize based on this foreknowledge. However, by performing an iterative series of runs, in which new emission limits are successively added in subsequent model run years, imperfect foresight can be incorporated in IPM's projections.

2.3.11 Air Regulatory Modeling

One of the most notable features of IPM is its detailed and flexible modeling of air regulations. Treatment of air regulations is endogenous in IPM. That is, by providing a comprehensive representation of compliance options, IPM enables environmental decisions to be made within the model based on least cost considerations, rather than exogenously imposing environmental choices on model results. For example, unlike other models that enter allowance prices as an exogenous input during model set-up, IPM obtains allowance prices as an output of the endogenous optimization process of finding the least cost compliance options in response to air

regulations. (In linear programming terminology, they are the "shadow prices" of the respective emission constraints — a standard output produced in solving a linear programming problem.) IPM can capture a wide variety of regulatory program designs including cap-and-trade, command-and-control and renewable portfolio standards. IPM's representation of cap-and-trade programs can include allowance banking, trading, borrowing, bonus allowance mechanisms, progressive flow controls or emission taxes. Air regulations can be tailored to specific geographical regions and can be restricted to specific seasons. Many of these regulatory modeling capabilities are exploited in EPA Base Case v.4.10.

2.4 Hardware and Programming Features

IPM produces model files in standard MPS linear programming format. IPM runs on most PC-platforms. Its hardware requirements are highly dependent on the size of a particular model run. For example, with almost 7.3 million decision variables and 1.2 million constraints, EPA Base Case v.4.10 is run on a 64 bit Windows Enterprise Server 2008 platform with four Intel Xeon 2.93 GHz dual core processors and 32 GB of RAM. Due to the size of the EPA base case, a commercial grade solver is required. (Benchmarking tests performed by EPA's National Environmental Scientific Computing Center using research grade solvers yielded unacceptable results.) For current EPA applications of IPM, the FICO Xpress Optimization Suite 7 linear programming solvers are used.

Two data processors -- a front-end and the post-processing tool -- support the model. The front-end creates the necessary input files used in IPM, while the post-processing tool maps IPM model-plant level outputs to individual generating units (a process called "parsing," see section 2.3.1) and creates input files in ORL (one record line) format as needed by EPA's air quality models.

Before it can be run, the model requires an extensive set of input parameters. These are discussed in Section 2.4.1 below. Results of model runs are presented in a series of detailed reports. These are described in Section 2.4.2 below.

2.4.1 Data Parameters for Model Inputs

IPM requires input parameters that characterize the US electric system, economic outlook, fuel supply and air regulatory framework. Chapters 3-11 contain detailed discussions of the values assigned to these parameters in EPA Base Case v.4.10. This section simply lists the key input parameters required by IPM:

<u>Electric System</u>

Existing Utility Generating Resources

- Plant Capacities
- Heat Rates
- Maintenance Schedule
- Forced Outage Rate
- Minimum Generation Requirements (Turn Down Constraint)
- Fuels Used
- Fixed and Variable O&M Costs
- Emissions Limits or Emission Rates for NO_x, SO_2, CO_2, Mercury
- Existing Pollution Control Equipment and Retrofit Options
- Output Profile for Non-Dispatchable Resources

New Generating Resources

- Cost and Operating Characteristics
- Performance Characteristics
- Limitations on Availability

Other System Requirements
- Inter-regional Transmission Capabilities
- Reserve Margin Requirements for Reliability
- Area Protection
- System Specific Generation Requirements
- Regional Specification

Economic Outlook
Electric Demand
- Firm Regional Electric Demand
- Load Curves

Financial Outlook
- Capital Charge Rate
- Discount Rate

Fuel Supply
Fuel Supply Curves for Coal, Natural Gas, and Biomass
Fuel Price
Fuel Quality
Transportation Costs for Coal, Natural Gas, and Biomass

Air Regulatory Outlook
Air Regulations for NO_x, SO_2, CO_2, Mercury
Other Air Regulations

2.4.2 Model Outputs

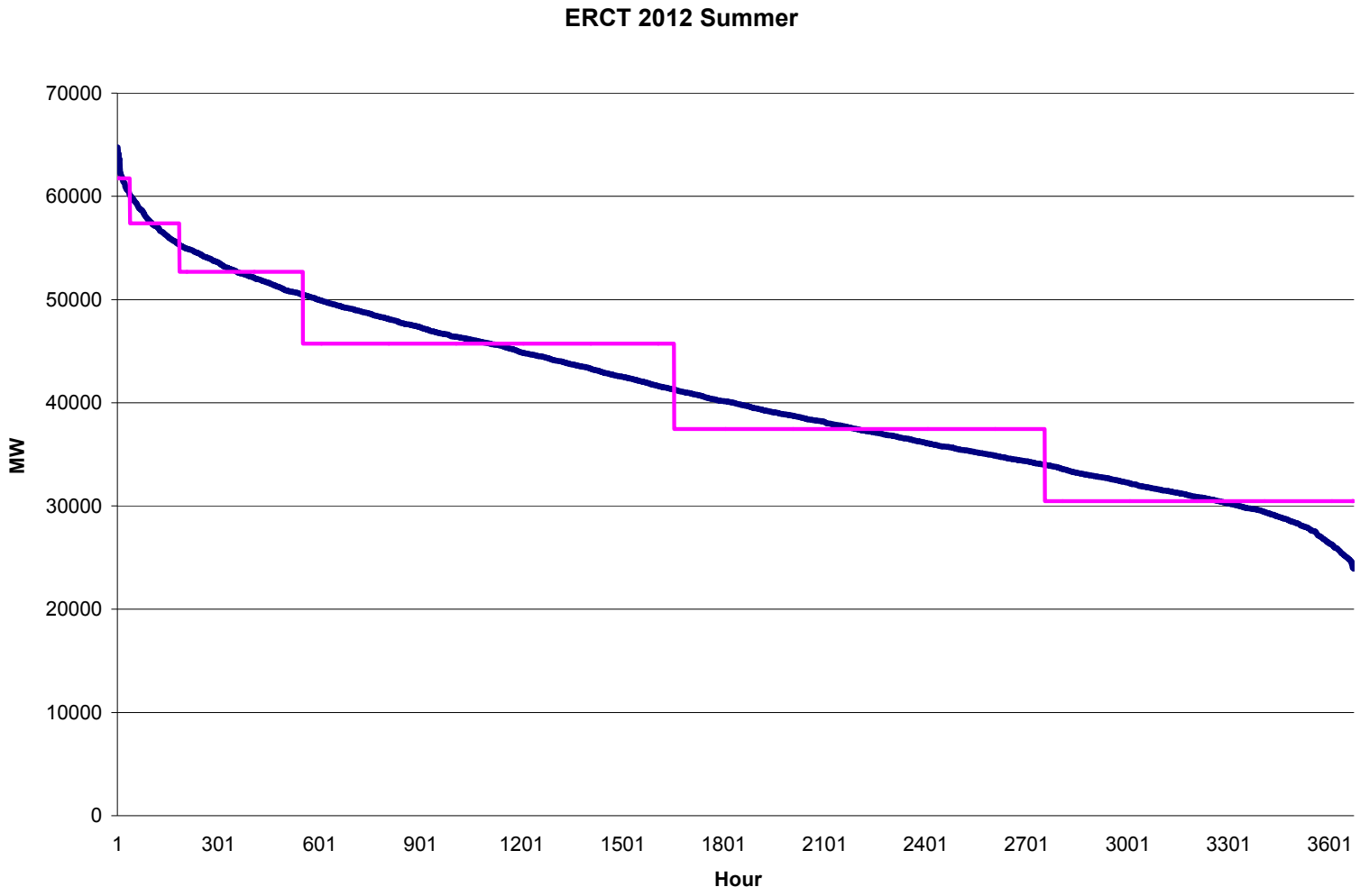
IPM produces a variety of output reports. These range from extremely detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion. Since the entire model solution is stored, IPM can generate additional detailed reports from the stored solution as needed. Standard IPM reports cover the following topics:

- Generation
- Capacity mix (by plant type and presence or absence of emission controls)
- Capacity additions and retirements
- Capacity and energy prices
- Power production costs (capital VOM, FOM and fuel costs)
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and biomass
- Emissions (NO_X, SO_2, CO_2, and Hg)
- Emission allowance prices

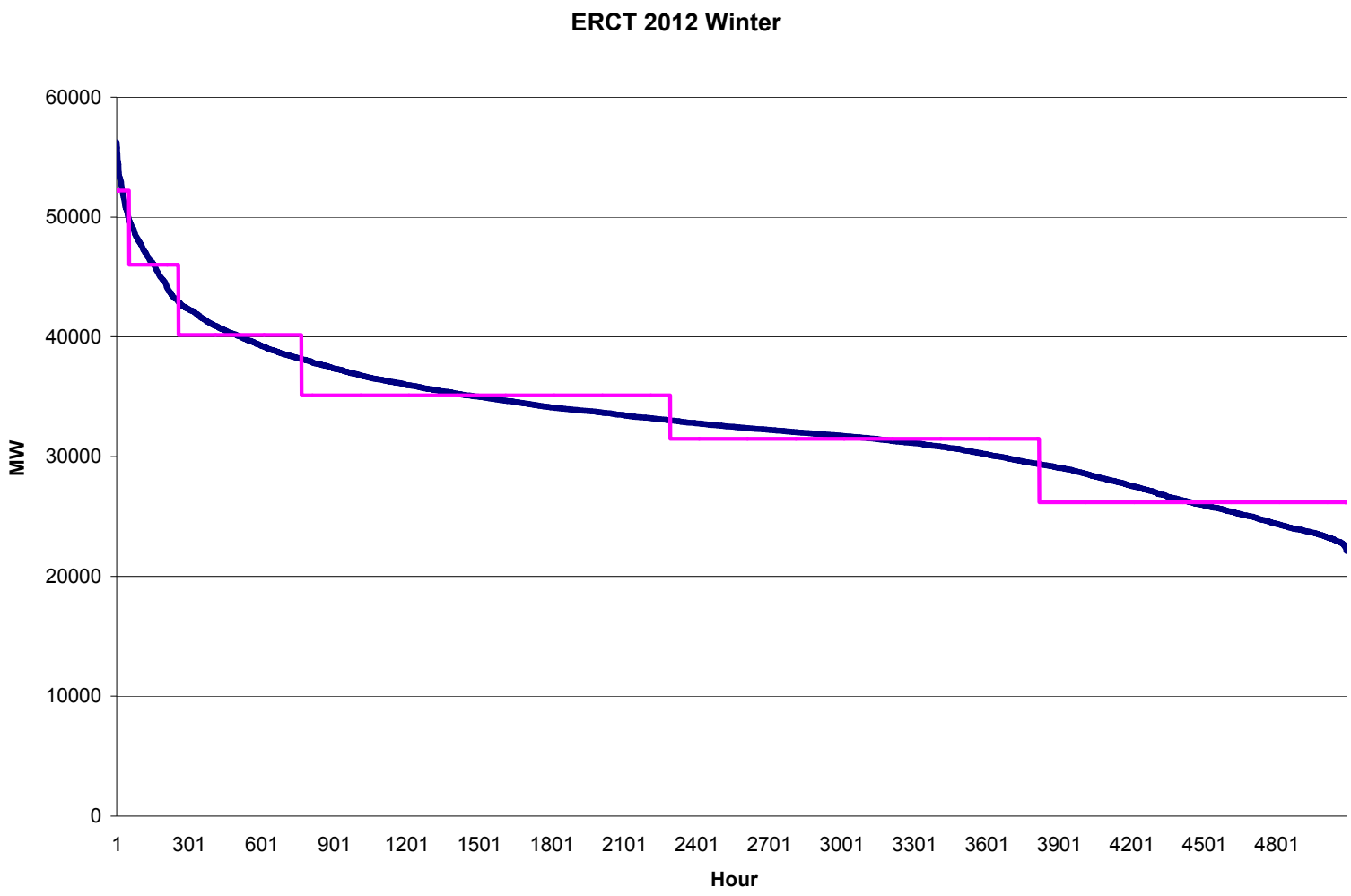
Appendix 2-1 Load Duration Curves Used in EPA Base Case v.4.10

This is a small exerpt of the data and graphs in Appendix 2-1. The complete data set in spreadsheet format and complete set of graphs can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.htm

Month	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Hours	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Day Hours	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	1	2
AZNM	11,182	10,866	10,659	10,628	10,724	10,969	11,250	11,306	11,553	11,707	11,533	11,294	10,977	10,643	10,367	10,304	10,515	11,676	12,475	12,511	12,414	12,076	11,547	10,898	10,467	10,332
CA-N	11,127	11,196	11,477	11,976	12,082	12,262	12,645	12,877	12,812	12,615	12,457	12,274	12,418	13,410	15,256	15,213	14,885	14,386	13,566	12,501	11,793	11,242	10,899	10,829	10,943	11,443
CA-S	15,323	14,636	14,234	14,056	14,129	14,347	14,275	14,448	14,940	15,427	15,690	15,785	15,713	15,619	15,598	15,599	16,951	19,009	19,111	18,803	18,261	17,322	16,040	14,941	14,260	13,937
COMD	10,119	9,763	9,444	9,264	9,140	9,137	9,220	9,419	9,414	9,489	9,698	9,908	10,016	10,032	10,048	9,987	9,965	10,552	11,448	11,495	11,428	11,295	11,037	10,545	10,025	9,654
DSNY	2,861	2,708	2,597	2,526	2,497	2,519	2,575	2,638	2,758	2,936	3,107	3,229	3,291	3,286	3,256	3,282	3,454	3,711	3,710	3,611	3,489	3,283	2,999	2,718	2,520	2,421
ENTG	14,747	14,695	14,588	14,491	14,478	14,554	14,924	15,411	15,669	16,072	16,337	16,392	16,108	15,654	15,183	14,898	14,956	15,495	16,581	17,184	17,320	17,205	16,942	16,309	15,539	15,586
ERCT	29,987	29,796	29,710	29,857	30,395	31,487	32,637	33,019	33,024	33,208	32,996	32,351	31,188	30,011	28,906	28,277	28,409	30,699	34,030	34,697	35,016	34,568	33,283	31,783	30,789	30,379
FRCC	19,757	18,688	17,471	16,766	16,412	16,476	16,780	17,054	18,787	21,128	23,288	24,514	25,262	25,431	25,229	25,051	24,845	25,636	26,465	25,716	24,569	23,236	21,474	19,419	17,658	16,542
GWAY	9,016	8,918	8,852	8,782	8,857	8,995	9,200	9,298	9,475	9,781	10,000	10,019	9,874	9,718	9,546	9,509	9,863	10,775	10,895	10,860	10,778	10,558	10,140	9,725	9,516	9,436
LILC	2,189	2,080	1,991	1,937	1,910	1,909	1,927	1,949	1,995	2,085	2,192	2,276	2,325	2,342	2,348	2,369	2,485	2,615	2,607	2,568	2,517	2,416	2,256	2,085	1,959	1,892
MACE	14,997	14,408	13,928	13,663	13,575	13,629	13,818	14,003	14,204	14,781	15,363	15,771	16,002	16,044	16,064	16,133	16,702	17,567	17,540	17,324	17,013	16,389	15,520	14,538	13,919	13,590
MACS	6,474	6,267	6,056	5,908	5,885	5,961	6,070	6,114	6,194	6,458	6,742	6,963	7,051	7,022	6,934	6,938	7,038	7,519	7,543	7,500	7,355	7,149	6,793	6,456	6,198	6,060
MACW	6,418	6,000	5,606	5,463	5,441	5,552	5,719	5,905	6,206	6,713	7,208	7,495	7,516	7,418	7,246	7,254	7,591	8,267	8,286	8,185	8,036	7,644	6,976	6,300	5,973	5,745
MECS	9,332	9,063	8,867	8,732	8,683	8,758	8,882	9,032	9,078	9,272	9,582	9,829	9,938	9,946	9,912	9,955	10,149	10,693	10,910	10,846	10,765	10,575	10,231	9,833	9,553	9,342
MRO	20,437	19,616	19,012	18,599	18,593	18,901	19,603	20,370	20,737	21,386	21,798	21,936	21,733	21,288	20,761	20,829	21,990	25,094	26,505	26,416	25,724	24,612	23,102	21,442	20,074	19,395
NENG	12,380	11,716	11,272	11,035	11,020	11,181	11,502	11,867	12,438	13,283	14,097	14,625	14,769	14,685	14,545	14,670	15,597	16,268	16,043	15,595	14,985	14,039	12,816	11,738	11,053	10,664
NWPE	6,242	6,086	6,018	5,990	6,027	6,149	6,296	6,431	6,605	6,759	6,818	6,815	6,762	6,673	6,621	6,652	7,010	7,390	7,370	7,273	7,145	6,845	6,423	6,066	5,943	5,852
NYC	4,838	4,645	4,449	4,295	4,237	4,238	4,315	4,376	4,477	4,671	4,889	5,058	5,175	5,246	5,304	5,354	5,507	5,687	5,664	5,593	5,500	5,358	5,110	4,772	4,463	4,269
PNW	19,729	19,289	19,068	19,035	19,342	19,827	20,403	20,925	21,531	22,174	22,697	22,843	22,768	22,505	22,248	22,334	23,178	23,768	23,545	23,064	22,354	21,360	20,104	18,906	18,185	17,856
RFCO	17,029	16,735	16,335	16,166	16,167	16,397	16,785	17,214	17,480	17,852	18,625	19,267	19,642	19,673	19,682	19,755	20,141	21,036	21,358	21,162	20,915	20,370	19,687	18,920	18,246	17,890
RFCP	21,425	20,589	19,799	19,483	19,512	19,932	20,607	21,420	22,257	23,435	24,540	25,256	26,276	26,255	26,253	26,421	27,018	28,753	29,207	29,066	28,838	27,913	26,515	24,912	23,868	23,330
RMPA	5,995	5,904	5,914	6,068	6,205	6,281	6,484	6,718	6,783	6,736	6,613	6,641	6,568	6,599	7,137	8,185	8,384	8,247	8,069	7,693	6,966	6,355	5,998	5,773	5,681	5,732
SNV	2,666	2,637	2,609	2,601	2,602	2,621	2,595	2,515	2,486	2,488	2,494	2,491	2,477	2,446	2,432	2,439	2,576	2,786	2,805	2,788	2,762	2,712	2,648	2,559	2,500	2,465



Appendix 2-1.2


ERCT 2012 Winter
60000
50000
40000
30000
20000
10000
0
MW
1
301
601
901
1201
1501
1801
2101
2401
2701
3001
3301
3601
3901
4201
4501
4801
Hour

3 Power System Operation Assumptions

This section describes the assumptions pertaining to the North American electric power system as represented in EPA Base Case v.4.10.

3.1 Model Regions

EPA Base Case v.4.10 models the US power sector in the contiguous 48 states and the District of Columbia and the Canadian power sector in the 10 provinces (with Newfoundland and Labrador represented as two regions on the electricity network even though politically they constitute a single province[4]) as an integrated network. Alaska, Hawaii, Puerto Rico, and US Virgin Islands are represented in Base Case v.4.10 as separate entities with their own self contained electricity grids.

There are 32 IPM model regions covering the US 48 states and District of Columbia. The IPM model regions are approximately consistent with the configuration of the 8 NERC regions, being disaggregations of North American Reliability Council (NERC) control areas. An attempt has been made to have the US IPM model regions reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs). Further disaggregation into 32 model regions allows a more accurate characterization of the operation of the US power markets by providing the ability to represent transmission bottlenecks within the 8 NERC regions and across RTOs and ISOs.

Disaggregations that were made in the most recent previous IPM base case were retained in Base Case 2010. Notable disaggregations include

- NERC region RFC (Reliability First Corporation) includes three portions of former NERC regions — the non-Kentucky part of ECAR, MAAC, and a portion of MAIN. The remaining portion of MAIN has been renamed COMD. ECAR has been disaggregated into RFCO, MECS, and RFCP and MAAC has been disaggregated into MACE, MACS, and MACW.

- NERC subregion WECC-AZ-NM-SNV has been disaggregated into AZNM and SNV

- NERC subregion WECC-California ISO has been disaggregated into CA-N and CA-S

- NERC Region SERC has been disaggregated into 7 IPM regions (ENTG, SOU, VACA, VAPW, TVA, TVAK (formerly ECAK), and GWAY (formerly a portion of MANO).

Several region boundaries were adjusted to reflect recent organizational changes. There were also several name changes: MANO to GWAY, ECAM to RFCO, ECAP to RFCP, and ECAK to TVAK.

The 11 Canadian model regions are defined strictly along provincial political boundaries.

Figure 3-1 contains a map showing all the EPA Base Case 2010 model regions. Table 3-1 defines the abbreviated region names appearing on the map and gives an approximate crosswalk between the IPM model regions, the NERC regions, and regions used in the Energy Information Administration's (EIA's) National Energy Model System (NEMS) which is the basis for EIA's Annual Energy Outlook (AEO) reports.

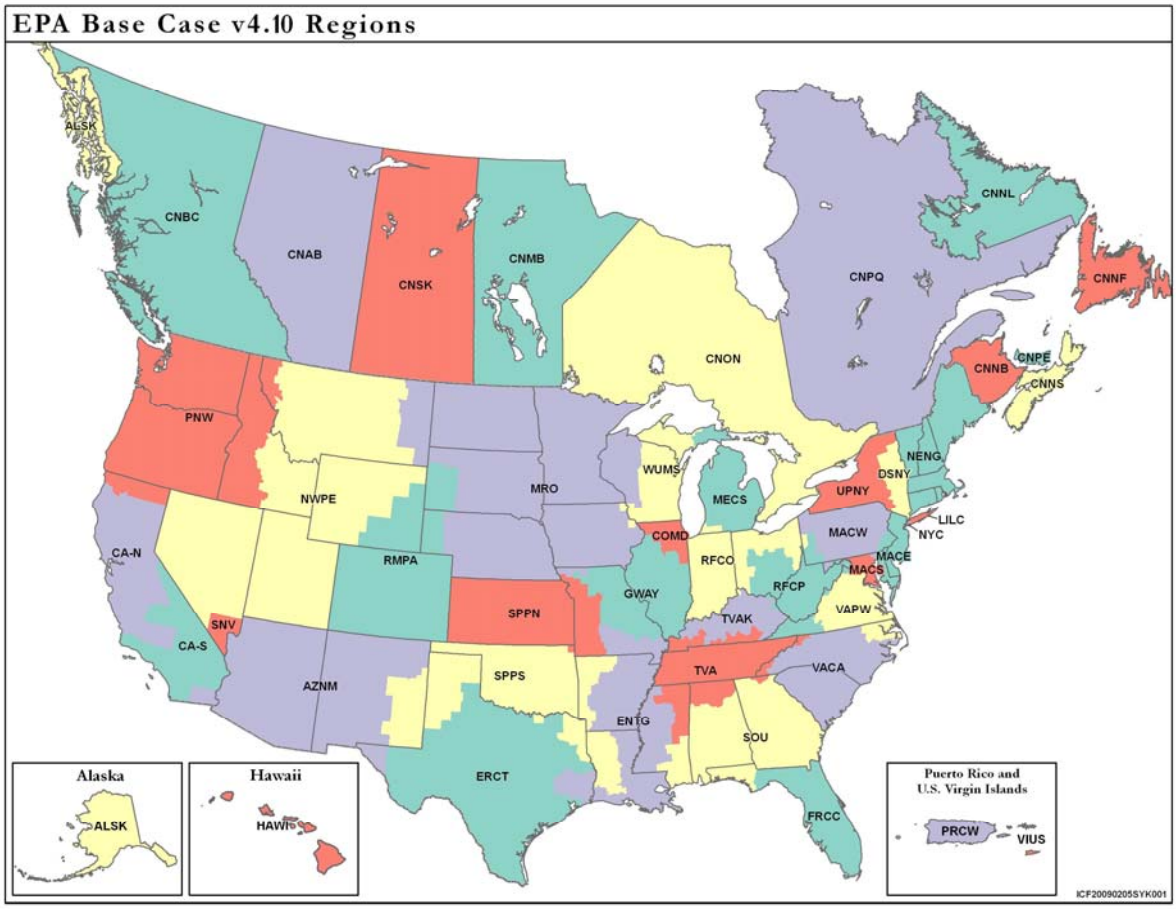
3.2 Electric Load Modeling

Net energy for load and net internal demand are inputs to IPM that together are used to represent the grid-demand for electricity. Net energy for load is the projected annual electric grid-demand, prior to accounting for intra-regional transmission and distribution losses. Net internal demand

[4]This results in a total of 11 Candian model regions being represented in EPA Base Case v.4.10

(peak demand) is the maximum hourly demand within a given year after removing interruptible demand. Table 3-2 shows the electric demand assumptions (expressed as net energy for load) used in EPA Base Case v.4.10. It is based on the net energy for load in AEO 2010[5].

Figure 3-1 EPA Base Case v.4.10 Model Regions



For purposes of documentation, Table 3-2 presents the national net energy for load. However, EPA Base Case v.4.10 models regional breakdowns of net energy for load. The regional net energy for load is derived from the national net energy for load based on the regional demand distribution in NERC electric demand forecasts. Model regions that represent subregions of a NERC region are apportioned their net energy for load based on the regional load shapes, which are developed by aggregating load for control areas within each model region.

[5]The electricity demand in EPA Base Case v.4.10 for the U.S. lower 48 states and the District of Columbia is obtained by summing the "Total Net Energy for Load" for the NEMS Electric Market Module regions as reported in the "Electric Power Projections for Electricity Market Module Regions -- Electricity and Renewable Fuel Tables 72-84" at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.

Table 3-1 Mapping of NERC Regions and NEMS Regions with EPA Base Case v.4.10 Model Regions

NERC Region	NEMS Region	Model Region	Model Region Description
TRE	ERCOT	ERCT	Texas Regional Entity
FRCC	FL	FRCC	Florida Reliability Coordinating Council
MRO	MAPP	MRO	Midwest Regional Planning Organization
	MAIN	WUMS	Wisconsin-Upper Michigan
NPCC	NE	NENG	New England Power Pool
	NY	DSNY	Downstate New York
		LILC	Long Island Company
		NYC	New York City
		UPNY	Upstate New York
RFC	ECAR	RFCO	Reliability First Corporation - MISO
		MECS	Michigan Electric Coordination System
		RFCP	Reliability First Corporation - PJM
	MAAC	MACE	Legacy Mid-Atlantic Area Council - East
		MACS	Legacy Mid-Atlantic Area Council - South
		MACW	Legacy Mid-Atlantic Area Council - West
	MAIN	COMD	Commonwealth Edison
SERC	MAIN	GWAY	Gateway
	ECAR	TVAK	Tennessee Valley Authority - MISO-KY
	STV	SOU	Southern Company
		TVA	Tennessee Valley Authority
		ENTG	Entergy
		VACA	Virginia-Carolinas
		VAPW	Dominion Virginia Power
SPP	SPP	SPPN	Southwest Power Pool - North
		SPPS	Southwest Power Pool - South
WECC-AZ-NM-SNV	RA	AZNM	Western Electricity Coordinating Council - Arizona, New Mexico
		SNV	Western Electricity Coordinating Council - Southern Nevada
WECC-California ISO	CNV	CA-N	Western Electricity Coordinating Council - California North
		CA-S	Western Electricity Coordinating Council - California South
WECC-NWPP	NWP	PNW	Western Electricity Coordinating Council - Pacific Northwest
		NWPE	Western Electricity Coordinating Council - Northwest Power Pool East
WECC-RMPA	RA	RMPA	Western Electricity Coordinating Council - Rocky Mountain Power Area
Canada		CNAB	Alberta
		CNBC	British Columbia
		CNMB	Manitoba
		CNNB	New Brunswick
		CNNF	Newfoundland
		CNNL	Labrador
		CNNS	Nova Scotia
		CNON	Ontario

NERC Region	NEMS Region	Model Region	Model Region Description
		CNPE	Prince Edward Island
		CNPQ	Quebec
		CNSK	Saskatchewan
Other		ALSK	Alaska
		HAWI	Hawaii
		VIUS	U.S. Virgin Islands
		PRCW	Puerto Rico

Table 3-2 Electric Load Assumptions in EPA Base Case v.4.10

Year	Net Energy for Load (Billions of kWh)
2012	4,043
2015	4,086
2020	4,302
2030	4,703
2040	5,113
2050	5,568

Note:
This data is an aggregation of the model-region-specific net energy loads used in the EPA Base Case v.4.10.

3.2.1 Demand Elasticity

EPA Base Case v.4.10 has the capability to model the impact of the price of power on electricity demand. However, this capability is typically only exercised for sensitivity analyses where different price elasticities of demand are specified for purposes of comparative analysis. The default base case assumption is that the electricity demand shown in Table 3-2 is not affected by price and must be met, i.e., the price elasticity of demand is zero[6].

3.2.2 Net Internal Demand (Peak Demand)

EPA Base Case v.4.10 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 2010 load factors and the estimated energy demand projections shown in Table 3-2. Table 3-3 ("National Non-Coincidental Net Internal Demand") illustrates the national sum of each region's winter and summer peak demand. Because each region's seasonal peak demand need not occur at the same time, the national peak demand is defined as non-coincidental.

[6]Occasionally, e.g., when performing modeling of climate policies, the demand assumptions shown in Table 3-2 will be replaced with projections of demand from economy-wide computable general equilibrium (CGE) models which themselves take into account demand elasticity. However, even in such cases the IPM demand elasticity capabilities will not be utilized and the resulting IPM runs will be considered "policy" rather than "base case" runs.

Table 3-3 National Non-Coincidental Net Internal Demand

Year	Peak Demand (GW)	
	Winter	Summer
2012	646	758
2015	655	771
2020	693	816
2030	768	908
2040	843	1,001
2050	929	1,105

Note:
This data is an aggregation of the model-region-specific peak demand loads used in the EPA Base Case v.4.10.

3.2.3 Regional Load Shapes

EPA uses year 2007 as the meteorological year in its air-quality modeling. In order for EPA Base Case v.4.10 to be consistent, the year 2007 was selected as the "normal weather year"[7] for all IPM regions. The proximity of the 2007 cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) to the long-term average cumulative annual HHDs and CDDs over the period 1971 to 2000 was estimated and found to be reasonable close. The 2007 chronological hourly load data were assembled by aggregating individual utility load curves taken from Federal Energy Regulatory Commission Form 714 data.

3.3 Transmission

The United States and Canada can be broken down into several power markets that are interconnected by a transmission grid. As discussed earlier, EPA Base Case 4.10 characterizes the U.S. lower 48 states, the District of Columbia, and Canada into 43 different power market regions by means of 32 model regions in the U.S. and 11 in Canada. EPA Base Case 4.10 includes explicit assumptions regarding the transmission grid connecting these modeled power markets. This section details the assumptions about the transfer capabilities, wheeling costs and inter-regional transmission used in EPA Base Case 4.10.

3.3.1 Inter-regional Transmission Capability

Table 3-4[8] shows the firm and non-firm Total Transfer Capabilities (TTCs) between model regions. TTC is a metric that represents the capability of the power system to import or export power reliably from one region to another. The purpose of TTC analysis is to identify the sub-markets created by key commercially significant constraints. Firm TTCs, also called Capacity TTCs, specify the maximum power that can be transferred reliably, even after the contingency loss of a single transmission system element such as a transmission line or a transformer (N-1). Firm TTCs provide a high level of reliability and are therefore used for capacity transfers. Non-firm TTCs, also called Energy TTCs, represent the maximum power that can be transferred reliably when all facilities are under normal operation (N-0). They specify the sum of the maximum firm transfer capability between sub-regions *plus* incremental curtailable non-firm transfer capability. Non-firm TTCs are used for energy transfers since they provide a lower level of reliability than

[7]The term "normal weather year" refers to a representative year whose weather is closest to the long-term (e.g., 35 year) average weather. The selection of a "normal weather year" can be made, for example, by comparing the cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) in a candidate year to the long-term average. For any individual day, heating degree days indicate how far the average temperature fell below 65 degrees F; cooling degree days indicate how far the temperature averaged above 65 degrees F. Cumulative annual heating and cooling degree days are the sum of all the HDDs and CDDs, respectively, in a given year.

[8]In the column headers in Table 3-4 the term "Energy (MW)" is equivalent to non-firm TTCs and the term "Capacity (MW)" is equivalent to firm TTCs.

Firm TTCs, and transactions using Non-firm TTCs can be curtailed under emergency or contingency conditions.

Table 3-4 Annual Transmission Capabilities of U.S. Model Regions in EPA Base Case v.4.10

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
AZNM	CA-S	3,627	2,428	2.9
	NWPE	300	300	--
	RMPA	690	690	--
	SNV	4,634	4,634	--
	SPPS	400	400	2.9
CA-N	CA-S	3,700	3,700	--
	NWPE	150	100	2.9
	PNW	3,675	3,675	2.9
CA-S	AZNM	3,627	2,428	2.9
	CA-N	3,000	2,400	--
	NWPE	1,400	1,400	2.9
	PNW	3,100	3,100	2.9
	SNV	4,688	4,688	2.9
COMD	GWAY	2,050	2,050	2.9
	MRO	825	825	2.9
	RFCO	1,620	1,110	2.9
	RFCP	4,500	788	--
	WUMS	825	825	2.9
DSNY	LILC	1,290	1,290	--
	MACE	2,000	2,000	2.9
	NENG	1,120	1,120	2.9
	NYC	3,700	3,700	--
	UPNY	3,400	3,400	--
ENTG	GWAY	910	140	2.9
	MRO	150	150	2.9
	SOU	2,250	2,250	2.9
	SPPN	1,120	140	2.9
	SPPS	4,494	735	2.9
	TVA	1,681	1,681	2.9
ERCT	ENTG	1,001	1,001	2.9
	SPPS	979	979	2.9
FRCC	SOU	2,000	2,000	2.9
GWAY	COMD	1,100	1,100	2.9
	ENTG	2,804	2,100	2.9
	MRO	405	405	--
	RFCO	6,299	1,848	--
	SPPN	285	285	2.9
	TVA	1,812	1,812	2.9
	TVAK	200	200	2.9
LILC	DSNY	530	530	--
	MACE	650	590	2.9
	NENG	616	616	2.9

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
	NYC	420	420	--
MACE	DSNY	500	500	2.9
	LILC	650	521	2.9
	MACW	2,000	2,000	--
	NYC	1,200	600	2.9
MACS	MACW	3,500	3,000	--
	RFCP	2,500	750	--
	VAPW	2,600	2,600	--
MACW	MACE	6,200	5,800	--
	MACS	5,000	1,350	--
	RFCO	2,208	504	2.9
	RFCP	3,300	2,044	--
	UPNY	1,085	1,085	2.9
MECS	CNON	1,968	1,968	2.9
	RFCO	2,776	1,904	--
	RFCP	3,900	683	2.9
MRO	COMD	610	610	2.9
	CNON	100	100	2.9
	CNSK	165	165	2.9
	ENTG	2,000	2,000	2.9
	GWAY	320	320	--
	NWPE	200	200	2.9
	RMPA	310	310	2.9
	SPPN	1,494	1,494	2.9
	WUMS	800	800	--
NENG	CNNB	1,000	1,000	2.9
	CNPQ	803	803	2.9
	DSNY	980	980	2.9
	LILC	616	473	2.9
NWPE	AZNM	265	265	--
	CA-N	160	120	2.9
	CA-S	1,920	1,920	2.9
	MRO	150	150	2.9
	PNW	2,002	2,002	--
	RMPA	749	749	--
	SNV	300	250	--
NYC	DSNY	1,999	1,999	--
	LILC	175	175	--
PNW	CA-N	4,000	4,000	2.9
	CA-S	3,100	3,100	2.9
	CNBC	2,000	1,000	2.9
	NWPE	1,505	1,505	--
RFCO	COMD	2,760	1,360	2.9
	GWAY	7,078	3,504	--
	MACW	3,100	2,274	2.9
	MECS	4,603	825	--

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
	RFCP	12,908	7,951	2.9
	TVAK	815	270	2.9
RFCP	COMD	3,100	3,100	--
	MACS	2,500	350	--
	MACW	3,900	1,075	--
	MECS	3,700	1,762	2.9
	RFCO	15,041	8,525	2.9
	TVA	1,000	1,000	2.9
	TVAK	1,000	537	2.9
	VACA	3,002	2,042	2.9
	VAPW	3,080	953	--
RMPA	AZNM	690	690	--
	MRO	310	310	2.9
	NWPE	735	735	--
SNV	AZNM	4,785	4,785	--
	CA-S	4,688	4,688	2.9
	NWPE	300	300	--
SOU	ENTG	2,950	2,950	2.9
	FRCC	3,600	3,600	2.9
	TVA	3,742	3,742	2.9
	VACA	1,358	1,358	2.9
SPPN	ENTG	3,745	1,260	2.9
	GWAY	1,200	1,200	2.9
	MRO	600	600	2.9
	SPPS	700	700	--
SPPS	AZNM	400	400	2.9
	ENTG	9,030	2,310	2.9
	ERCT	650	650	2.9
	SPPN	1,200	1,200	--
TVA	ENTG	2,919	2,919	2.9
	GWAY	1,550	1,550	2.9
	RFCP	1,500	263	2.9
	SOU	2,258	2,258	2.9
	TVAK	2,000	1,073	--
	VACA	664	664	2.9
TVAK	GWAY	200	200	2.9
	RFCO	3,365	1,225	2.9
	RFCP	1,000	175	2.9
	TVA	1,500	632	--
UPNY	CNON	2,000	1,325	2.9
	CNPQ	1,000	1,000	2.9
	DSNY	4,550	4,550	--
	MACW	735	735	2.9
	NENG	150	150	2.9
VACA	RFCP	4,117	438	2.9
	SOU	3,242	3,242	2.9
	TVA	3,586	3,586	2.9

From	To	Energy (MW)	Capacity (MW)	Wheeling Charge (mills/kWh)
	VAPW	1,942	1,942	2.9
VAPW	MACS	2,100	2,100	--
	RFCP	5,460	1,952	--
	VACA	1,849	1,849	2.9
WUMS	COMD	1,125	1,125	2.9
	MRO	270	270	--

The amount of energy and capacity transferred on a given transmission link is modeled on a seasonal (summer and winter) basis for all run years in the EPA Base Case 4.10. All of the modeled transmission links have the same Total Transfer Capabilities for both the winter and summer seasons, which means that the maximum firm and non-firm TTCs for each link is the same for both winter and summer. Wherever available, the maximum values for firm and non-firm TTCs were obtained from public sources. Where public sources were not available, the maximum values for firm and non-firm TTCs are based on ICF's expert view.

It should be noted that each transmission link between model regions shown in Table 3-4 represents a one-directional flow of power on that link. This implies that the maximum amount of flow of power possible from region A to region B may be more or less than the maximum amount of flow of power possible from region B to region A.

3.3.2 Joint Transmission Capacity and Energy Limits

Table 3-5 shows the annual joint limits to the transmission capabilities between model regions, which are identical for the firm (capacity) and non-firm (energy) transfers. The joint limits were developed from the 2004 NERC Summer Assessment and 2004 NERC Winter Assessment. A joint limit represents the maximum simultaneous firm or non-firm power transfer capability of a group of interfaces. It restricts the amount of firm or non-firm transfers between one model region (or group of model regions) and a different group of model regions). For example, the New England model region is connected to multiple model regions contained in the state of New York, with each link between New England and a New York model region described by its own TTCs. However, there is a maximum limit on the total amount of transfers that the New England region may transfer to the whole of New York, which is represented by the annual joint capacity limit between the New England model region and the relevant New York model regions.

Table 3-5 Annual Joint Capacity and Energy Limits to Transmission Capabilities Between Model Regions in EPA Base Case v.4.10

Region Connections	Transmission Path	Joint Constraint Limit
ECAR to MAAC	RFCO to MACW RFCP to MACS RFCP to MACW	1,385
ECAR to MAIN	RFCO to COMD RFCP to COMD RFCO to GWAY TVAK to GWAY	2,593
ECAR to TVA	TVAK to TVA RFCP to TVA	3,561
ECAR to VACAR	RFCP to VACA RFCP to VAPW	2,022
ENTG to SPP	ENTG to SPPN ENTG to SPPS	338

Region Connections	Transmission Path	Joint Constraint Limit
LILC to NYC & DSNY	LILC to DSNY LILC to NYC	530
MAAC to ECAR	MACS to RFCP MACW to RFCO MACW to RFCP	4,715
MAAC to NPCC	MACE to DSNY MACE to LILC MACE to NYC MACW to UPNY	1,708
MAIN to ECAR	COMD to RFCO COMD to RFCP GWAY to TVAK GWAY to RFCO	3,649
MAIN to MAPP	COMD to MRO GWAY to MRO WUMS to MRO	962
MAPP to MAIN	MRO to COMD MRO to GWAY MRO to WUMS	1,238
MAPP to WECC	MRO to NWPE MRO to RMPA	710
NENG to NY	NENG to DSNY NENG to UPNY NENG to LILC	1,550
NPCC to MAAC	DSNY to MACE LILC to MACE NYC to MACE UPNY to MACW	2,353
NY to NENG	DSNY to NENG LILC to NENG UPNY to NENG	1,750
NYC & DSNY to LILC	DSNY to LILC NYC to LILC	1,465
SPP to ENTG	SPPN to ENTG SPPS to ENTG	1,362
TVA to ECAR	TVA to TVAK TVA to RFCP	1,226
VACAR to ECAR	VACA to RFCP VAPW to RFCP	4,278
WECC to MAPP	NWPE to MRO RMPA to MRO	660

Note:
Source: 2004 NERC Summer Assessment, 2004 NERC Winter Assessment

3.3.3 Transmission Link Wheeling Charge

Transmission wheeling charge is the cost of transferring electric power from one region to another using the transmission link. The EPA Base Case 4.10 assumes a wheeling charge of 2.9 mills per kWh for electricity transmission between IPM model regions that fall within different market

regions, such as transmission between Northern California and the Pacific Northwest. However, the wheeling charge is not applied to transmission between model regions that are within the same market region, such as transmission between Northern California (model region CA-N) and Southern California (model region CA-S). The wheeling charge applied between IPM model regions can be found in Table 3-4.

3.3.4 Transmission Losses

The EPA Base Case 4.10 assumes a two percent inter-regional transmission loss of energy transferred, in line with EIA's Annual Energy Outlook (AEO) 2010.

3.4 International Imports

The U.S. electric power system is connected with the transmission grids in Canada and Mexico and the three countries actively trade in electricity. The Canadian power market is endogenously modeled in EPA Base Case v.4.10 but Mexico is not. International electric trading between the U.S. and Mexico is represented by an assumption of net imports based on information from AEO 2010. Table 3-6 summarizes the assumptions on net imports into the US from Mexico.

Table 3-6 International Electricity Imports in EPA Base Case v.4.10

	2012	2015	2020	2030	2040	2050
Net Imports from Mexico (billions kWh)	1.57	1.57	1.11	0.89	0.89	0.89

Notes:
Imports & exports transactions from Canada are endogenously modeled in IPM.
Source: AEO 2010

3.5 Capacity, Generation, and Dispatch

While the capacity of existing units is an exogenous input into IPM, the dispatch of those units is an endogenous decision that the model makes. The capacity of existing generating units included in EPA Base Case v.4.10 can be found in the National Electrical Energy Data System (NEEDS v.4.10), a database which provides IPM with information on all currently operating and planned-committed electric generating units. NEEDS v.4.10 is discussed in full in Chapter 4.

A unit's generation over a period of time is defined by its dispatch pattern over that duration of time. IPM determines the optimal economic dispatch profile given the operating and physical constraints imposed on the unit. In EPA Base Case v.4.10 unit specific operational and physical constraints are generally represented through availability and turndown constraints. However, for some unit types, capacity factors are used to capture the resource or other physical constraints on generation. The two cases are discussed in more detail in the following sections.

3.5.1 Availability

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 upper bound on generation to meet demand. Table 3-7 summarizes the availability assumptions used in EPA Base Case v.4.10. They are based on data from North American Electric Reliability Council's Generating Availability Data System (NERC GADS) 2001 to 2005 and AEO 2010. Appendix 3-9 shows the availability assumptions for all generating units in EPA Base Case v.4.10.

Table 3-7 Availability Assumptions in the EPA Base Case v.4.10

Unit Type	Annual Availability (%)
Biomass	83
Coal Steam	32 - 95
Combined Cycle	85
Combustion Turbine	89 - 91
Gas/Oil Steam	78 - 92
Geothermal	87
IGCC	85
Pumped Storage	90
Solar	90
Wind	95

Notes:
Values shown are a range of all of the values modeled within the EPA Base Case v.4.10.
Availabilities of coal steam units are based on historical capacity factors.

In the EPA Base Case v.4.10, separate seasonal (summer and winter) availabilities are defined. For the fossil and nuclear unit types shown in Table 3-7, summer and winter availabilities differ only in that no planned maintenance is assumed to be conducted during the on-peak summer (June, July and August) months. Characterizing the availability of hydro, solar and wind technologies is more complicated due to the seasonal and locational variations of the resources. The procedures used to represent seasonal variations in hydro are presented in section 3.5.2 and of wind and solar in section 4.4.5.

3.5.2 Capacity Factor

Generation from certain types of units is constrained by resource limitations. These technologies include hydro, wind and solar. For such technologies, IPM uses capacity factors or generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factor is the percentage of the maximum possible power generated by the unit. For example, a photovoltaic solar unit would have a capacity factor of 27% if the usable sunlight were only available that percent of the time. For such units, explicit capacity factors or generation profiles mimic the resource availability. The seasonal capacity factor assumptions for hydro facilities contained in Table 3-8 were derived from EIA Form 906 from 2002 through 2006 data. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in section 4.4.5 and Appendices 4-1 and 4-2.

Table 3-8 Seasonal Hydro Capacity Factors (%) in the EPA Base Case v.4.10

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
AZNM	27.4%	32.2%	29.4%
CA-N	36.7%	50.1%	42.3%
CA-S	38.7%	50.4%	43.6%
COMD	40.6%	45.5%	42.6%
DSNY	57.8%	50.2%	54.6%
ENTG	35.4%	32.5%	34.2%
ERCT	13.5%	19.6%	16.1%
FRCC	48.4%	47.4%	48.0%
GWAY	19.2%	22.5%	20.6%
MACE	30.9%	29.2%	30.2%
MACS	14.8%	18.7%	16.4%
MACW	47.5%	33.7%	42.3%
MECS	54.1%	56.9%	55.3%

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
MRO	31.8%	43.7%	36.8%
NENG	44.9%	41.1%	43.3%
NWPE	28.7%	47.6%	36.6%
PNW	40.6%	44.0%	42.0%
RFCO	66.0%	89.2%	75.6%
RFCP	32.7%	30.9%	31.9%
RMPA	18.0%	31.5%	23.7%
SNV	18.0%	23.3%	20.2%
SOU	25.3%	22.1%	24.0%
SPPN	16.5%	17.8%	17.0%
SPPS	21.2%	27.2%	23.7%
TVA	43.2%	37.1%	40.7%
TVAK	32.4%	38.6%	35.0%
UPNY	66.8%	63.1%	65.2%
VACA	23.7%	22.8%	23.3%
VAPW	22.8%	19.0%	21.2%
WUMS	52.6%	57.3%	54.6%

Note:
Annual capacity factor is provided for information purposes only. It is not directly used in modeling.

Capacity factors are also used to define the upper bound on generation obtainable from nuclear units. This rests on the assumption that nuclear units will dispatch to their availability, and, consequently, capacity factors and availabilities are equivalent. The capacity factors (and, consequently, the availabilities) of existing nuclear units in EPA Base Case v.4.10 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA Base Case v.4.10 is contained in Section 4.5.

3.5.3 Turndown

Turndown assumptions in EPA Base Case v.4.10 are used to prevent coal and oil/gas steam units from operating strictly as peaking units, which would be inconsistent with their operating capabilities. Specifically, the turndown constraints in EPA Base Case v.4.10 require coal steam units to dispatch no less than 50% of the unit capacity in the five base- and mid-load segments of the load duration curve in order to dispatch 100% of the unit in the peak load segment of the LDC. Oil/gas steam units are required to dispatch no less than 25% of the unit capacity in the five base- and mid-load segments of the LDC in order to dispatch 100% of the unit capacity in the peak load segment of the LDC. These turndown constraints were developed by ICF International through detailed assessments of the historical experience and operating characteristics of the existing fleet of coal steam and oil/gas steam units' capacities.

3.6 Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the difference between total dependable capacity and annual system peak load divided by annual system peak load. It is expressed in percent. In practice, each NERC region has a reserve margin requirement, or comparable reliability standard, which is designed to encourage electric suppliers in the region to build beyond their peak requirements to ensure the reliability of the electric generation system within the region.

In IPM reserve margins are used to depict the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived either directly or indirectly

from NERC's electric reliability reports. They are based on reliability standards such as loss of load expectation (LOLE), which is defined as the expected number of days in a specified period in which the daily peak load will exceed the available capacity. EPA Base Case v.4.10 reserve margin assumptions are shown in Table 3-9.

Table 3-9 Planning Reserve Margins in EPA Base Case v.4.10

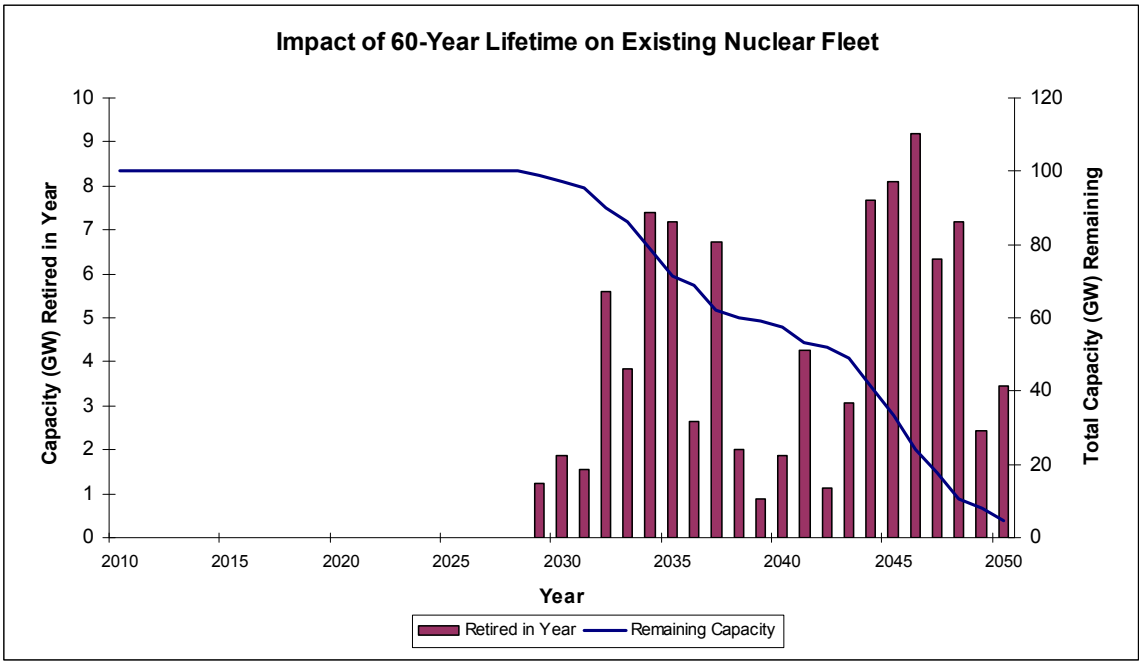
Model Region	Reserve Margin
AZNM	15.7%
CA-N	16.7%
CA-S	16.7%
CNAB	12.8%
CNBC	12.8%
CNMB	15.0%
CNNB	20.0%
CNNF	20.0%
CNNL	20.0%
CNNS	20.0%
CNON	18.3%
CNPE	20.0%
CNPQ	10.0%
CNSK	15.0%
COMD	15.0%
DSNY	16.5%
ENTG	15.0%
ERCT	12.5%
FRCC	15.0%
GWAY	15.0%
LILC	16.5%
MACE	15.0%
MACS	15.0%
MACW	15.0%
MECS	15.0%
MRO	15.0%
NENG	16.0%
NWPE	10.8%
NYC	16.5%
PNW	10.8%
RFCO	15.0%
RFCP	15.0%
RMPA	14.3%
SNV	15.7%
SOU	15.0%
SPPN	13.6%
SPPS	13.6%
TVA	12.0%
TVAK	15.0%
UPNY	16.5%
VACA	15.0%
VAPW	15.0%
WUMS	16.0%

3.7 Power Plant Lifetimes

EPA Base Case v.4.10 does not include any pre-specified assumptions about power plant lifetimes, except for nuclear units. All conventional fossil units (i.e., coal, oil/gas steam, combustion turbines, and combined cycle) and nuclear units can be retired during a model run for economic reasons. Other types of units are not provided an economic retirement option.

Nuclear Retirement at Age 60: Existing nuclear units are forced to retire in EPA Base Case v.4.10 at the completion of age 60. Today's nuclear fleet totals more than 100 GW. A 60-year lifetime reduces the current fleet to under 5 GW in 2050. This is illustrated in Figure 3-2. For a complete listing of the existing nuclear units represented in EPA Base Case v.4.10, including their online year and other characteristics, see Appendix 4-3.

Figure 3-2 Scheduled Retirements of Existing Nuclear Capacity Under 60-Year Life Assumption



The 60-year lifetime assumption is based on several factors. At the time that this base case was prepared there were many instances of the U.S. Nuclear Regulatory Commission (NRC) granting license extensions of 20 years beyond the initial 40 year operating licenses authorized by the NRC for commercial nuclear power plants under the Atomic Energy Act of 1954. At the time of the release of EPA Base Case v.4.10, the NRC had granted license renewals to 50 operating reactors allowing them to operate for 60 years with fifteen additional applications under review and the owners of 21 other units announcing their intention to file for 20-year license extensions. All of these applications would allow the units to operate to age 60.

At the same time, there were no units in the U.S. nuclear fleet licensed to operate past age 60[9]. In keeping with the practice of the EPA base case representing legal provisions that are on the books or immediately pending, a conservative approach was adopted of reflecting the current maximum licensing period of 60 years for the nuclear units in EPA Base Case v.4.10.

Another factor in the decision to implement the 60-year nuclear life assumption is the degree of uncertainty surrounding nuclear life extensions past age 60. As noted in EIA's review of the 60 year nuclear life question, uncertainties include:

- The absence, to date, of publicly available plans and cost estimates for potential major capital expenditures involved with extensions to age 80 such as the replacement of reactor vessels, containment structures, or buried piping and cables.
- Possible future additional regulatory requirements which could result in expensive upgrades at nuclear power plants and figure into life extension decisions. Among those mentioned in EIA's review was a rule that was recently the subject of the Supreme Court case Entergy Corp v. Riverkeeper10, which focused on whether or not the EPA could conduct cost-benefit analyses to determine whether a plant needed to replace open-cycle cooling water systems with closed-cycle systems.

The assumption of nuclear retirements at age 60 in EPA Base Case v.4.10 contrasts to a certain degree with the assumption made in AEO 2010. Due to AEO 2010's shorter time horizon compared to the EPA base case (i.e., 2035 compared to 2050), EIA did not have to explicitly adopt an 80 year nuclear life assumption (as would have been necessary in EPA Base Case v.4.10), only that "the operating lives of existing nuclear power plants would be extended at least through 2035.[11]" The basis for the decision appears to be that "The nuclear industry has expressed strong interest in continuing the operation of existing nuclear facilities, and no particular technical issues have been identified that would impede their continued operation.[12]"

Although the adopted assumptions differ in EPA Base Case v.4.10 and AEO 2010, there is agreement on the importance of performing side cases using the alternative assumptions. In the case of EPA Base Case v.4.10 this will mean performing sensitivity analysis runs with an 80 nuclear lifetime assumption.

---

[9] The Energy Information Administration has an excellent review and summary of the issues involved in the 60 year nuclear life question. Although EPA's base case does not adopt the same assumption as AEO 2010, the text in this section relied heavily on the EIA review. With respect to the status of applications for renewals beyond age 60, the EIA review notes the following: "In December 2009, the Oyster Creek Generating Station in Lacey Township, New Jersey, became the first nuclear power plant in the United States to begin its 40th year of operation. With Oyster Creek and other nuclear plants of similar vintage just beginning to enter their first period of license renewal, it probably will be at least 5 to 10 years before there is any clear indication as to whether plant operators will be likely to seek further extensions of their plants' operating lives." The EIA review also observes ". . . the NRC and the nuclear power industry are preparing applications for license renewals that would allow continued operation beyond 60 years, the first of which is scheduled to be submitted by 2013. In February 2008, DOE and the NRC hosted a joint workshop titled "Life Beyond 60," with a broad group of nuclear industry stakeholders meeting to discuss this issue. The workshop's summary report outlined many of the technical research needs that participants agreed were important to extending the life of the existing fleet of U.S. nuclear plants." Energy Information Administration (EIA), U.S. Department of Energy, "U.S. nuclear power plants: Continued life or replacement after 60?" *Annual Energy Outlook 2010 with Projections to 2035* (DOE/EIA-0383(2010)), May 11, 2010, www.eia.doe.gov/oiaf/aeo/nuclear_power.html.

[10] Supreme Court of the United States, "Entergy Corp. v. Riverkeeper, Inc., et al.," No. 07-588 (October Term, 2008 www.supremecourtus.gov/opinions/ 08pdf/07-588.pdf.

[11] EIA, op.cit.

[12] EIA, ibid.

3.8 Heat Rates

Heat rates, expressed in BTUs per KWh. are a metric of the efficiency of a generating unit. As in previous versions of NEEDS, it is assumed in NEEDS v.4.10 that heat rates of existing units will remain constant over time. This assumption reflects two offsetting factors: (1) plant efficiencies tend to degrade over time and (2) increased maintenance and component replacement work to maintain or improve plant efficiency.

The heat rates in EPA Base Case v.4.10 are based on values from AEO 2008. These values were screened and adjusted using a procedure developed by EPA to ensure that the heat rates used in EPA Base Case v.4.10 are within the engineering capabilities of the generating unit types. Based on engineering analysis, the upper and lower heat rate limits shown in Table 3-10 were applied to coal steam, oil/gas steam, combined cycle, combustion turbine, and internal combustion engines. If the reported heat rate for such a unit was below the applicable lower limit or above the upper limit, the limit was substituted for the reported value.

Table 3-10 Lower and Upper Limits Applied to Heat Rate Data in NEEDS v.4.10

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

3.9 Existing Environmental Regulations

This section describes the existing federal, regional, and state SO_2, NO_x, mercury, and CO_2 emissions regulations that are represented in the EPA Base Case v.4.10. The first three subsections discuss national and regional regulations. The next two subsections describe state level environmental regulations and a variety of legal settlements. The last subsection presents emission assumptions for potential units.

Note on Clean Air Interstate Rule (CAIR): In December 2008 the U.S. Court of Appeals for the District of Columbia Circuit remanded CAIR to EPA to correct legal flaws in the proposed regulations as cited in the Court's July 2008 ruling. Until EPA's work was completed, CAIR, which includes a cap-and-trade system for SO_2 and NO_x emissions, was temporarily reinstated. However, although CAIR's provisions were still in effect when EPA Base Case v.4.10 was released, it is not included in the base case to allow EPA Base Case v.4.10 to be used to analyze the regulations proposed to replace CAIR.

3.9.1 SO_2 Regulations

Unit-level Regulatory SO_2 Emission Rates and Coal Assignments: Before discussing the national and regional regulations affecting SO_2, it is important to note that unit-level SO_2 regulations arising out of State Implementation Plan (SIP) requirements, which are not only state specific but also county specific, are captured at model set-up in the coal choices given to coal fired existing units in EPA Base Case v.4.10. The SIP requirements define "regulatory SO_2

emission rates." Since SO_2 emissions are dependent on the sulfur content of the fuel used, the regulatory SO_2 emission rates are used in IPM to define fuel capabilities.

For instance, a unit with a regulatory SO_2 emission rate of 3.0 lbs/MMBtu would be provided only with those combinations of fuel choices and SO_2 emission control options that would allow the unit to achieve an out-of-stack rate of 3.0 lbs/MMBtu or less. If the unit finds it economical, it may elect to burn a fuel that would achieve a lower SO_2 rate than its specified regulatory emission limit. In EPA Base Case v.4.10 there are 6 different sulfur grades of bituminous coal, 3 different grades of sub-bituminous coal, 3 different grades of lignite, and 1 sulfur grade of residual fuel oil. There are 2 different SO_2 scrubber options for coal units. Further discussion of fuel types and sulfur content is contained in Chapter 9. Further discussion of SO_2 control technologies is contained in Chapter 5.

National and Regional SO_2 Regulations: The national program affecting SO_2 emissions in EPA Base Case v.4.10 is the SO_2 allowance trading program established under Title IV of the Clean Air Act Amendments (CAAA) of 1990, which set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. The program, which became fully operational in year 2000, affects all SO_2 emitting electric generating units greater than 25 MWs. The program provides trading and banking of allowances over time across all affected electric generation sources.

The annual SO_2 caps over the modeling time horizon in EPA Base Case v.4.10 reflect the provisions in Title IV. Since EPA Base Case v.4.10 uses year 2012 as the first analysis year, a projection of allowance banking behavior through the end of 2011 and specification of the available 2012 allowances are needed to initialize the modeling. EPA developed the projection of the banked allowances (11 million) going into 2012. Calculating the available 2012 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2012 SO_2 cap of 8.95 million tons. The surrenders totaled 270.6 thousand tons in allowances, leaving 8.679 million of 2012 allowances remaining. Table 7-4 shows the initial bank and 2012 allowance specification along with the SO_2 caps for the entire modeling time horizon. Specifics of the allowance surrender requirements under state regulations and NSR settlements can be found in Appendices 3-2 and 3-3.

EPA Base Case v.4.10 also includes a representation of the Western Regional Air Partnership (WRAP) Program, a regional initiative involving Arizona, New Mexico, Oregon, Utah, Wyoming directed toward addressing visibility issues in the Grand Canyon and affecting SO_2 emissions starting in 2018. The WRAP specifications for SO_2 are presented in Table 7-4.

3.9.2 NO_x Regulations

Much like SO_2 regulations, existing NO_x regulations are represented in EPA Base Case v.4.10 through a combination of system level NO_x programs and generation unit-level NO_x limits.

The system level NO_x regulation represented in EPA Base Case v.4.10 is the NO_x SIP Call trading program. This trading program affects all fossil units in 20 northeastern states[13] and the District of Columbia. The program is only in effect during the ozone season (May - September). The program includes state-specific NO_x budgets. However, since the program allows for trading among units in different states, the total annual NO_X SIP Call budget of 527,580 tons is used in EPA Base Case v.4.10, rather than the state-specific budgets. The specifications for the SIP Call are presented in Table 7-4.

[13]The states included in the SIP Call program are Alabama, Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, and West Virginia.

The representation of unit-level NO_x limits includes Title IV unit specific rate limits and Clean Air Act Reasonable Available Control Technology (RACT) requirements for controlling NO_x emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Region[14] (OTR). Both of these limits are captured in the specific NO_x emission rates assigned to each unit represented in the base case. Unlike SO_2 emission rates, NO_x emission rates are assumed not to vary with fuel, but are dependent on the combustion properties of the generating unit. Under the EPA Base Case v.4.10 the NO_x emission rate of a unit can only change if the unit is retrofitted with NO_x pollution control equipment.

NO_x Rates in NEEDS, v.4.10 Database: The NO_x rates in the current base case were derived, wherever possible, directly from actual monitored NO_x emission rate data reported to EPA under the Acid Rain and NO_x Budget Program in 2007. The emission rates themselves reflect the impact of the applicable NO_x regulations. For coal-fired units, NO_X rates were used in combination with detailed engineering assessments of NO_X combustion control performance to prepare a set of four possible starting NO_x rates to assign to a unit depending on the specific policy affecting that unit in a model run.

The reason for having four NO_x rates in NEEDS is to allow all possible modeling scenarios involving NO_x controls to be set up. The four NO_x rates are designated as Mode 1–4, and are designed to include all the NO_x rates possible for a unit with its current configuration of NO_x combustion and post-combustion controls. The four NO_x rates are:

- **Mode 1:** Applies to units not covered by a NO_X control policy. Specifically, this is the NO_X rate with post-combustion controls shut off. For units without post-combustion controls, it's their uncontrolled NO_X rate.
- **Mode 2:** A unit, which has post-combustion controls, runs them, but a unit without post-combustion controls operates as usual.
- **Mode 3:** Applies to the off-season NO_X rate for units affected by a seasonal NO_X policy. For units with post-combustion controls, this is the NO_X rate with post-combustion controls shut off. For units without post-combustion controls, it's the NO_X rate with state-of-the-art combustion controls operating. (Exception: In the SIP Call region current combustion controls are assumed to be retained.)
- **Mode 4:** NO_X rate applicable under a NO_X policy. For SCR units, it's the NO_X rate with the SCR operating. For SNCR units, it's the NO_X rate with SNCR operating plus state-of-the-art combustion controls operating if required to attain rate limits. For units without post-combustion controls, it's the NO_X rate with state-of-the-art combustion controls operating. (Exception: In the SIP Call region current combustion controls are assumed to be retained.)

The program that sets up a new model run uses a series of algorithms (decision rules) to determine which of the four NO_X rates is selected:

- A unit covered under an annual NO_X emission limit is assigned the Mode 4 NO_X rate (winter and summer seasons).
- A unit covered by a summer season NO_X emission limit, but not an annual NO_X limit, is assigned the Mode 4 NO_X rate in the summer season but the Mode 3 NO_X rate in the winter season.
- A unit covered by a mercury emission limit and not by a NO_X emission limit is assigned the Mode 2 NO_X rate in both winter and summer seasons. (Note: In the case of mercury limits, Mode 2 applies since it implies operation of an SCR or SNCR. This equipment, in combination with SO_2 and particulate controls, offers as a co-benefit the reduction and capture

[14] The OTR consists of the following states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, District of Columbia, and northern Virginia.

of mercury. See Chapter 5 in the v.4.10 documentation for a discussion of the calculation mercury emission modification factors (EMF).)

- A unit not covered by either an annual or a summer NO_X limit nor mercury control requirements is assigned the Mode 1 NO_X rate in both winter and summer seasons.

The Mode 1-4 NO_x rates for each generating unit are included in the NEEDS, v.4.10 database, described in Chapter 4. Appendix 3-1 and accompanying Tables 3-1.1, 3-1.2, and 3-1.3 give further information on the procedures employed to derive the four NO_X rate modes and give specific examples of generating units that fit each of the Mode 1-4 specifications.

Additional NO_X rate assumptions include default NO_X rates of 0.25 lbs/MMBtu for existing biomass units and 0.09 lbs/MMBtu for existing landfill gas units.

3.9.3 CO_2 Regulations and Renewable Portfolio Standards

The Regional Greenhouse Gas Initiative (RGGI) is a year-round CO_2 cap and trade program affecting fossil fired electric power plants 25 MW or larger in Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, Vermont, Rhode Island, Massachusetts, and Maryland. Table 7-4 shows the specifications for RGGI that are implemented in EPA Base Case v.4.10.

Renewable Portfolio Standards (RPS) generally refer to various state-level policies that require the addition of renewable generation to meet a specified share of state-wide generation In EPA Base Case v.4.10 the state RPS requirements are represented at a regional level utilizing the aggregate regional representation of RPS requirements that is implemented in AEO 2010[15] as shown in Appendix 3-6. This appendix shows the RPS requirements that apply to the NEMS (National Energy Modeling System) regions used in AEO. The RPS requirement for a particular NEMS region applies to all IPM regions that are predominantly contained in that NEMS region.

3.9.4 State Specific Environmental Regulations

EPA Base Case v.4.10 represents laws and regulations in 25 states affecting emissions from the electricity sector. The laws and regulations had to either be on the books or expected to come into force. Appendix 3-2 summarizes the provisions of state laws and regulations that are represented in EPA Base Case 4.10.

3.9.5 New Source Review (NSR) Settlements

The New Source Review, (NSR) settlements refer to legal agreements with companies resulting from the permitting process under the CAAA which requires industry to undergo an EPA pre-construction review of proposed environmental controls either on new facilities or as modifications to existing facilities where there would result a “significant increase” in a regulated pollutant. EPA Base Case v.4.10 includes NSR settlements with 20 electric power companies. A summary of the units affected and how the settlements were modeled can be found in Appendix 3-3.

Seven state settlements and five citizen settlements are also represented in EPA Base Case v.4.10. These are summarized in Appendices 3-4 and 3-5 respectively.

3.9.6 Emission Assumptions for Potential (New) Units

Emissions from existing and planned/committed units vary from installation to installation based on the performance of the generating unit and the emissions regulations that are in place. In contrast, there are no location-specific variations in the emission and removal rate capabilities of potential new units. In IPM, potential new units are modeled as additional capacity and generation that may come on line in each model region. Across all model regions the emission and removal

---

[15]Energy Information Administration, U.S. Department of Energy, *Assumptions to Annual Energy Outlook 2010: Renewable Fuels Module* (DOE/EIA-0554(2010)), April 9, 2010, Table 13.4 “Aggregate Regional RPS Requirements, www.eia.doe.gov/oiaf/aeo/assumption/renewable.html and www.eia.doe.gov/oiaf/aeo/assumption/pdf/renewable_tbls.pdf

rate capabilities of potential new units are the same. It should be noted that, new coal units cannot be built in the CA-N, CA-S, NYC, LILC, or NENG model regions due to particularly stringent state emission limits placed on fossil fired units. The specific assumptions regarding the emission and removal rates of potential new units in EPA Base Case v.4.10 are presented in Table 3-11. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-11 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units see Chapter 4.

3.10 Capacity Deployment Constraints

Due to its extended time horizon and the policies that EPA Base Case v.4.10 is expected to be used to analyze, capacity deployment constraints for the more capital intensive generation technologies and retrofits (new nuclear, advanced coal with carbon capture, and carbon capture retrofits) were incorporated into the base case. The deployment constraints are intended to capture factors that are likely to place an upper bound on the amount of these technologies that can be built in any given model run year over the modeling time horizon. Such limiting factors include:

- production capacity limitations (including the number of engineering and construction (E/C) firms capable of executing large power projects in the U.S., the number of large projects each such firm can handle, and the number of multi-billion dollar projects a firm can take on in parallel),
- general limitations in the domestic infrastructure for heavy manufacturing,
- financial limitations (number of projects that can obtain financing simultaneously at an acceptable level of risk),
- workforce limitations (limitations in the skilled engineering and construction labor force, replacement challenges caused by an aging workforce, on the one hand, and inadequate training infrastructure for new entrants, on the other).

The capacity deployment constraints are based on assessments by EPA power sector engineering staff of historical trends and projections of capability going forward. Conceptually, the procedure used to develop these constraints consisted of the following steps:

1. Start by estimating the maximum number of E/C firms that will be available over the time horizon.
2. Estimate the maximum number of a particular type of generating unit (e.g., 600 MW advanced coal plant with carbon capture) that a single E/C firm can complete in the first 5-year period (2015-2020).
3. Multiply the number of E/C firms estimated in Step 1 by the number of units per firm found in Step 2 to obtain the maximum number of these generating units that can be completed in the first period.
4. Determine if there will be competition from other competing technologies for the same productive capacity and labor force used for the technology analyzed in steps 2 and 3. If not, go to Step 7. If so, go to Step 5.
5. Establish an equivalency table showing how much capacity could be built if the effort required to build 1 MW of the type of technology analyzed in steps 2 and 3 were instead used to build another type of generating technology (e.g., 1600 MW nuclear plant).
6. Based on these calculations build a production possibility frontier showing the maximum mix of the two generating technologies that can be added in the first 5-year period.
7. Over the subsequent five year periods assume that the E/C firms have increased capabilities relative to the previous five year period. Represent the increased capability by a capability multiplier. For example, it might be assumed that each succeeding 5-year period the E/C firms can design and build 1.4 as much as in the immediately preceding 5-year period. Multiply the capacity deployment limit(s) from the preceding period by the capability multiplier to derive the capacity deployment limit for the subsequent period.

8. If necessary, prevent sudden spikes in capacity in later periods when there has been little or no build up in preceding periods by tying the amount of capacity that can be built in a given period to the amount of capacity built in preceding periods.

Appendix 3-07 shows the joint capacity deployment constraint on advanced coal with carbon capture and storage (CCS) and new nuclear. Appendix 3-08 shows the capacity deployment constraint on new nuclear in itself. The bar graph in Appendix 3-08 illustrates how building capacity in earlier years increases the maximum capacity that can be built over the entire modeling time horizon.

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

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% with a floor of 0.06 lbs/MMBtu	93% with a floor of 0.065 lbs/MMBtu	99%	99%	None	None	0.08 lbs/MMBtu	0.08 lbs/MMBtu	None	None
NO_x	Emission Rate	0.06 lbs/MMBtu	0.06 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

Appendix 3-1 NO_x Rate Development in EPA Base Case v.4.10

The following questions (Q) and answers (A) are intended to provide further background on the four NO_X rates found in the NEEDS, v.4.10 database.

Q1: Why are four NO_X rates included in NEEDS?

A1: The four NO_X rates in NEEDS represent a menu of all the NO_X rates applicable to a specific generating unit with only its current configuration of NO_x combustion and post-combustion controls under all the conceivable policies involving NO_x controls that might be modeled in the future. By defining this menu up front for every generating unit, the program that sets up an IPM run can follow a set of decision rules to select the rate(s) appropriate for the unit in the particular policy being modeled consistent with the unit's existing set of combustion and post-combustion NO_x controls.

Q2: What operational states do the four NO_x rates represent?

A2: Before answering this question, let's name the four NO_x rates that are in NEEDS:

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

The operational states associated with each of the four NO_x rates are shown in the second and third columns in the table below.

Q3: What NO_x policies in a model run result in the assignment of each of the NO_x rates?

A3: The policies causing each rate to be assigned are shown in the last column in the table below.

Interpreting the Mode 1 – 4 NO_x Rates in NEEDS

Name	Operational State of NO_x Controls		NO_x Policies Causing This Rate To be Assigned
Mode 1 = Uncontrolled Base Rate	Units with post combustion NO_x controls: Do they operate the controls?	No	If the unit is not covered by any NO_x limit in the run, pre-assign this as its NO_x rate
	Units without post-combustion controls: Do they upgrade to state-off-the-art combustion controls?	No	
Mode 2 = Controlled Base Rate	Units with post combustion NO_x controls: Do they operate the controls?	Yes	If the unit is covered by a mercury policy, pre-assign this as its NO_x rate Explanation: Post-combustion NO_x controls figure in mercury reduction but NO_x combustion controls do not, so the operational state (in column 2) fits the requirements of the policy
	Units without post-combustion controls: Do they upgrade to state-off-the-art combustion controls?	No	
Mode 3 = Uncontrolled Policy Rate	Units with post combustion NO_x controls: Do they operate the controls?	No	If the unit is covered by a summer NO_x limit pre-assign this as its winter NO_x rate.
	Units without post-combustion controls: Do they upgrade to state-off-	Yes	

Name	Operational State of NO_x Controls		NO_x Policies Causing This Rate To be Assigned
	the-art combustion controls?		
Mode 4 = Controlled Policy Rate	Units with post combustion NO_x controls: Do they operate the controls?	Yes	If the unit is covered by a summer NO_x limit pre-assign this as its summer NO_x rate.
	Units without post-combustion controls: Do they upgrade to state-off-the-art combustion controls?	Yes	If the unit is covered by an annual NO_x limit, pre-assign this as its winter and summer NO_x rates.

Q4: How are the values of the Mode 1-4 NO_x rates derived?

A4: We start with the emission data reported to EPA for a specific year under Title IV of the Clean Air Act Amendments of 1990 (Acid Rain Program) and NO_x Budget Program. Using this data, NO_x rates are derived for the summer and winter seasons.

Calculations can get complex, so we'll illustrate it here for coal units only and with the assumption that the data were absolutely complete and consistent with what engineering theory tells us its values should be. Otherwise, we apply additional screens. Explaining them is beyond the scope of this illustration. Basically, here's how the values would be derived:

Mode 1
For all coal units Mode 1 = Winter NO_x rate

Mode 2
For coal units without NO_x post-combustion controls
Mode 2 = Mode 1 rate

For coal units with NO_x post-combustion controls,

Min{max[Mode 1 NO_x rate * (1-removal efficiency), floor rate], ETS Summer NO_x rate}

Where
For an SCR,
Removal efficiency = 90%
Floor rate = 0.06 lb/MMBtu;
For an SNCR,
Removal efficiency = 35%
No floor rate is applicable

Mode 3
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

For coal units without post-combustion NO_x controls

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 rate. Go to Step 3
If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Go to Step 5 using the Mode 1 rate as the provisional SOA NO_x rate.

For coal listed with combustion controls
If Mode 1 > Cut-off (in Table 3-1.2), then unit has non-SOA combustion controls.
Go to Step 2

If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Go to Step 5 using the Mode 1 rate as the provisional SOA NO_x rate.

For coal units with post-combustion NO_x controls

For coal units with SCR
Mode 1 = Mode 3

For coal units with SNCR
If Mode 1 ≤ Cut-off (in Table 3-1.2), then the unit has SOA control and
Mode 1 = Mode 3
If Mode 1 > Cut-off (in Table 3-1.2), then unit has non-SOA combustion controls.
Go to Step 2

Step 2: For units with non-SOA combustion controls, determine their 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 3.

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

Step 4: Compare the value calculated in Step 3 to the applicable NO_x floor rate in Table 3-1:2.

For units with post-combustion controls
If the value from Step 3 is ≥ floor, use the Step 3 value as Mode 3 NO_x rate. Otherwise, use the floor as the Mode 3 NO_x rate.

For units without post-combustion controls
If the value from Step 3 is ≥ floor, use the Step 3 value as the provisional SOA NO_x rate.
Otherwise, use the floor as their provisional SOA NO_x rate.
Go to Step 5.

Step 5: For units without post combustion controls compare the provisional SOA NO_x rate obtained in previous steps to their Summer NO_x rate.
If Summer NO_x rate < provisional SOA NO_x rate, then Mode 3 = summer NO_x rate.
If Summer NO_x rate ≥ provisional SOA NO_x rate, then
Mode 3 = provisional SOA NO_x rate.

Mode 4

For units without post-combustion controls
Mode 4 = Mode 3

For units with SCR post-combustion controls
Mode 4 = Mode 2

For units with SNCR post-combustion controls
Mode 4 = minimum {(1-.35) * Mode 3, Summer NO_x rate}

Note: The (1-.35) term in the equation above represents the 35% NO_x removal efficiency of SNCR.

Q5: Is there anything else that might be useful to understand about the Mode 1 – 4 NO_x rates.

A5: There are several things to note about the Modes 1-4 designations. “Controlled” refers to the rates provided by post combustion NO_x controls, i.e., selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), if they are present at the unit. For generating units that do not have post-combustion controls, the controlled rate will be the same as the uncontrolled rate. For generating units that do have post-combustion controls, the controlled and uncontrolled rates will differ. Base and Policy NO_x rates will be same if the unit has state-of-the-art NO_x combustion controls or is in the SIP Call region where current combustion controls are assumed to be retained. Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls that would be installed in response to a NO_x policy. Examples of each of these instances are shown in Table 3-1.1.

Other things worth noting are:
(a) In general, winter NO_x rates reported in EPA’s Emission Tracking System were used as proxies for the uncontrolled base NO_x rates.
(b) If a unit does not report having combustion controls, but has an emission rate below a specific cut-off rate (shown in Table 3-1.2), it is considered to have combustion controls.
(c) For units with combustion controls that were not state-of-the-art, emission rates without those combustion controls were back-calculated and then policy rates were derived assuming the reductions provided by state-of-the art combustion controls.
(d) The NO_x rates achievable by state-of-the-art combustion controls vary by coal rank (bituminous and sub-bituminous) and boiler type. The equations used to derive these rates are shown in Table 3-1.3.

Q6: What are examples of the Mode 1-4 NO_x for some actual operating generating units?

A6: Table 3-1.1 gives the Mode 1-4 NO_x rates for real generating units. They are meant to illustrate a range of situations that can arise.

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

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	0.809	0.809	0.524	0.524	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	0.638	0.064	0.638	0.064	(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	0.316	0.316	0.316	0.316	Situation 1 also applies.
Roxboro	2712_B_1	SCR	0.900	0.084	0.900	0.084	Situation 2 also applies.
Situation 3b: . . . is in the SIP Call region where current combustion controls are assumed to be retained.							
Thomas Hill	2168_B_MB3	SCR	0.223	0.060	0.223	0.060	Situation 2 also applies.
Waukegan	883_B_17	None	0.710	0.710	0.710	0.710	(1) Has NO_x combustion control and is in SIP so doesn't get added combustion control. High NO_x rate because it is a cyclone unit (2) Situation 1 also applies.
Situation 4: Base and policy rates will differ if a unit does not currently have state-of-the-art combustion controls and would install such controls in response to a NO_x policy.							
Clay Boswell	1893_B_4	SNCR	0.231	0.150	0.152	0.099	(1) Drop in uncontrolled policy NO_x rate compared to uncontrolled base rate is due to addition of combustion controls. (Note 0.32 is floor.) (2) Unit has SNCR so Situation #2a also applies and you see a 35% drop between uncontrolled and controlled NO_x rates.

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

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

(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

Appendix 3-2 State Power Sector Regulations included in EPA Base Case v.4.10

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 annual rate limit 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 fossil units > 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
Louisiana	Title 33 Part II - Chapter 22, Control of Nitrogen Oxides	NO_x	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 SO_2 into the atmosphere	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	7.3 MTons summer cap and 16.7 MTons annual cap for 15 specific existing coal steam units	2009
		SO_2	2009 through 2012: 48.6 MTons annual cap for 15 specific existing coal steam units 2013 onwards: 37.2 MTons annual cap for 15 specific existing coal steam units	
		Hg	2010 through 2012: 80% removal of Hg content of fuel for 15 specific existing coal steam units 2013 onwards: 90% removal of Hg content of fuel for 15 specific existing 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

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
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
	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	Annual rate limits in lbs/MMBtu for the following technologies: 1.0 for tangential and wall-fired wet-bottom coal boilers serving an EGU 0.60 for cyclone-fired wet-bottom coal boilers serving an EGU 0.38 for tangential dry-bottom coal boilers serving an EGU 0.45 for wall-fired dry-bottom coal boilers serving an EGU 0.55 for cyclone-fired dry-bottom coal boilers serving an EGU 0.20 for tangential oil and/or gas boilers serving an EGU 0.28 for wall-fired oil and/or gas boilers serving an EGU 0.43 for cyclone-fired oil and/or gas boilers serving an EGU	2007
	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 >25MW 2013 onwards: 50 MTons annual cap for Progress Energy coal plants > 25 MW and 80	2009

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
			MTons annual cap for Duke Energy coal plants > 25 MW	
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
	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

State/ Region	Bill	Emission Type	Emission Specifications	Implementation Status
			Annual rate limits in lbs/MMBtu for coal fired boilers between 500 and 1,000 MMBtu/hr: Wall fired: 2009: 0.20; 2013 onwards: 0.17 in 2013 Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2009: 0.20; 2013 onwards: 0.15 Fluidized bed: 2009: 0.15; 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs > 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

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

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%	12/31/2011	Operate existing SCR continuously	0.1	5/1/2008		0.03	12/31/2006	With 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	1/1/2021	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	12/31/2011	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/2009		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%	12/31/2010	Install and continuously operate over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/2007		0.03	Before 2008				
SIGECO																	
FB Culley	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/2006										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

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 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	6/30/2004										
		Unit 3			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	6/30/2004	Operate Existing SCR Continuously	0.1	9/1/2003	Install and continuously operate a Baghouse	0.015	6/30/2007				
PSEG FOSSIL																	
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/2002										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/psegllc.html
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/2006	Install SCR (or approved tech) and continually operate	0.1	5/1/2007	Install Baghouse (or approved technology)	0.015	12/31/2006				
Mercer	New Jersey	Units 1 & 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/2010	Install SCR (or approved tech) and continually operate	0.13	5/1/2006							
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	5/1/2009				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting			http://www.epa.gov/compliance/resources/cases/civil/caa/teco.html
		Unit 3			Existing Scrubber	93% if Units 3 & 4	2000	Install SCR	0.1	5/1/2009							

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	
					(shared by Units 3 & 4)	are operating	(01/01/10)							from compliance with NSR settlement provisions must be retired.			
		Unit 4			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	6/22/2005	Install SCR	0.1	7/1/2007							
Gannon	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/2004													
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	12/31/2012	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/2012	Install SCR (or approved tech) and continually operate	0.1	12/31/2012				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.			
		Units 5 & 6						Install and operate low NO_x burners		12/31/2003							
		Units 7 & 8						Operate existing low NO_x burners		12/31/2005	Install Baghouse						
		Unit 9						Operate existing low NO_x burners		12/31/2006	Install Baghouse						
Pleasant Prairie	Wisconsin	1			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2006	Install and continuously operate SCR (or approved tech)	0.1	12/31/2006							
		2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2007	Install and continuously operate SCR (or approved tech)	0.1	12/31/2003							

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	
Oak Creek	Wisconsin	Units 5 & 6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2012	Install and continuously operate SCR (or approved tech)	0.1	12/31/2012							
		Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2012	Install and continuously operate SCR (or approved tech)	0.1	12/31/2012							
		Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/2012	Install and continuously operate SCR (or approved tech)	0.1	12/31/2012							
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 NO_x 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.																	http://www.epa.gov/compliance/resources/cases/civil/caa/vepco.html
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	1/1/2005	Install and continuously operate SCR	0.11	1/1/2008				On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO_2 allowances.			
Chesterfield	Virginia	Unit 4						Install and continuously operate SCR	0.1	1/1/2013							
		Unit 5			Construct or improve FGD	95% or 0.13	10/12/2012	Install and continuously operate SCR	0.1	1/1/2012							
		Unit 6			Construct or improve FGD	95% or 0.13	1/1/2010	Install and continuously operate SCR	0.1	1/1/2011							
Chesapeake Energy	Virginia	Units 3 & 4						Install and continuously operate SCR	0.1	1/1/2013							

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	
Clover	Virginia	Units 1 & 2			Improve FGD	95% or 0.13	9/1/2003										
Possum Point	Virginia	Units 3 & 4	Retire and repower to natural gas	5/2/2003													
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.																http://www.epa.gov/compliance/resources/cases/civil/caa/santeecooper.html
Cross	South Carolina	Unit 1			Upgrade and continuously operate FGD	95%	6/30/2006	Install and continuously operate SCR	0.1	5/31/2004				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.			
		Unit 2			Upgrade and continuously operate FGD	87%	6/30/2006	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%	12/31/2008	Install and continuously operate SCR	0.11/0.1	11/30/04 and 11/30/04							
		Unit 2			Install and continuously operate FGD	95%	12/31/2008	Install and continuously operate SCR	0.12	11/30/2004							
		Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/2008	Install and continuously operate SCR	0.14/0.12	11/30/2005 and 11/30/08							
		Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/2007	Install and continuously operate SCR	0.13/0.12	11/30/05 and 11/30/08							
Grainger	South Carolina	Unit 1						Operate low NO_x burner or more stringent technology		6/25/2004							
		Unit 2						Operate low NO_x burner or more stringent technology		5/1/2004							

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	
Jeffries	South Carolina	Units 3, 4						Operate low NO_x burner or more stringent technology		6/25/2004							
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.																	http://www.epa.gov/compliance/resources/cases/civil/caa/ohioedison.html
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	12/31/2008	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/2007		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 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 2		Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/MMBtu	12/31/2008	Operate existing SNCR continuously	0.25	2/15/2006								
		Unit 3		Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/MMBtu	12/31/2008	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	12/1/2005 and 10/31/2007								
		Unit 4		Install Induct Scrubber (or	50% removal or 1.1 lb/MMBtu	6/30/2009	Install SNCR (or approved	0.25	10/31/2007								

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	
					approved equiv. control tech)			alt. tech) & operate continuously									
		Unit 5			Install Flash Dryer Absorber or ECO[2] (or approved equiv. control tech) & operate continuously	50% removal or 1.1 lb/MMBtu	6/29/2009	Install SNCR (or approved alt. tech) & Operate Continuously	0.29	3/31/2008							
		Unit 6			Install FGD[3] (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lb/MMBtu	6/30/2011	Install SNCR (or approved alt. tech) & operate continuously	"Minimum Extent Practicable"	6/30/2005	Operate Existing ESP Continuously	0.03	1/1/2010				
		Unit 7			Install FGD (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lb/MMBtu	6/30/2011	Operate existing SNCR Continuously	"Minimum Extent Practicable"	8/11/2005	Operate Existing ESP Continuously	0.03	1/1/2010				
Mansfield Plant	Pennsylvania	Unit 1			Upgrade existing FGD	95%	12/31/2005										
		Unit 2			Upgrade existing FGD	95%	12/31/2006										

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 3			Upgrade existing FGD	95%	10/31/2007										
Eastlake	Ohio	Unit 5						Install low NO_x burners, over-fired air and SNCR & operate continuously	"Minimize Emissions to the Extent Practicable"	12/31/2006							
Burger	Ohio	Unit 4	Repower with at least 80% biomass fuel, up to 20% low sulfur coal.	12/31/2011													
		Unit 5		12/31/2011													
Mirant[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.																http://www.epa.gov/compliance/resources/cases/civil/caa/mirant.html
Potomac River Plant	Virginia	Unit 1															
		Unit 2															
		Unit 3						Install low NO_x burners (or more effective tech) & operate continuously		5/1/2004							
		Unit 4						Install low NO_x burners (or more effective tech) & operate continuously		5/1/2004							
		Unit 5						Install low NO_x burners (or more effective tech) & operate continuously		5/1/2004							

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	5/1/2007							
		Unit 2						Install SCR (or approved alt. tech) & operate continuously	0.1	5/1/2008							
Chalk Point	Maryland	Unit 1			Install and continuously operate FGD (or equiv. technology)	95%	6/1/2010							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%	6/1/2010										
Illinois Power																	
System-wide NO_x Emission Annual Caps: 15,000 tons 2005; 14,000 tons 2006; 13,800 tons 2007 onward. System-wide SO_2 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	12/31/2011	Operate OFA & existing SCR continuously	0.1	8/11/2005	Install & continuously operate Baghouse	0.015	12/31/2010	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 the			
		Unit 3			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/2011	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	12/31/2010				

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	
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	8/11/2005 and 12/31/2012	Operate OFA and/or low NO_x burners & operate existing SCR continuously	0.1	8/11/2005	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	surrendered allowances result in insufficient remaining allowances allocated to the units comprising the DMG system, DMG can request to surrender fewer SO_2 allowances.			
Hennepin	Illinois	Unit 1				1.2	7/27/2005	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	8/11/2005	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/2006				
		Unit 2				1.2	7/27/2005	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	8/11/2005	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/2006				
Vermilion	Illinois	Units 1 & 2				1.2	1/31/2007	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	8/11/2005	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/2010				
Wood River	Illinois	Units 4 & 5				1.2	7/27/2005	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	8/11/2005	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/2005				
Kentucky Utilities Company																	
EW Brown Generating Station	Kentucky	Unit 3			Install FGD	97% or 0.100	12/31/2010	Install and continuously operate SCR by 12/31/2012, continuously operate low NO_x boiler and OFA.	0.07	12/31/2012	Continuously operate ESP	0.03	12/31/2010	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)																	

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	
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	1/1/2013	Install and continuously operate low NO_x burner	0.32	6/1/2011			Optimization begins immediately, rate limit begins 01/01/13 (date of new FGD installation)				
American Electric Power																	
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year				NO_x and SO_2 allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	NO_x and SO_2 allowances may not be used to comply with any of the limits imposed by the Consent Decree. The Consent Decree includes a formula for calculating excess NO_x allowances relative to the CAIR Allocations, and restricts the use of some. See par. 74-79 for details. Reducing emissions below the Eastern System-Wide Annual Tonnage Limitations for NO_x and SO_2 earns super compliance allowances.		http://www.epa.gov/compliance/resources/cases/civil/caa/americanelectricpower1007.html
						450,000	2010		96,000	2009							
						450,000	2011		92,500	2010							
						420,000	2012		92,500	2011							
						350,000	2013		85,000	2012							
						340,000	2014		85,000	2013							
						275,000	2015		85,000	2014							
						260,000	2016		75,000	2015							
						235,000	2017		72,000	2016 and thereafter							
						184,000	2018										
						174,000	2019 and thereafter										
At least 600MW from various units	West Virginia	Sporn	Retire, retrofit, or re-power	12/31/2018													
		1 – 4															
	Virginia	Clinch River															
		1 – 3															
	Indiana	Tanners Creek															

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	
		1 – 3															
	West Virginia	Kammer															
		1 – 3															
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/2009	Install and continuously operate SCR		1/1/2008							
		Unit 2			Install and continuously operate FGD		12/31/2010	Install and continuously operate SCR		1/1/2009							
		Unit 3			Install and continuously operate FGD		12/31/2009	Install and continuously operate SCR		1/1/2008							
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		12/31/2015	Install and continuously operate SCR		1/1/2009							
Cardinal	Ohio	Unit 1			Install and continuously operate FGD		12/31/2008	Install and continuously operate SCR		1/1/2009	Continuously operate ESP	0.03	12/31/2009				
		Unit 2			Install and continuously operate FGD		12/31/2008	Install and continuously operate SCR		1/1/2009	Continuously operate ESP	0.03	12/31/2009				
		Unit 3			Install and continuously operate FGD		12/31/2012	Install and continuously operate SCR		1/1/2009							
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													

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 3	Retire, retrofit, or re-power	12/31/2012													
		Unit 4			Install and continuously operate FGD		12/31/2010	Install and continuously operate SCR		12/31/2010							
		Unit 5			Upgrade existing FGD	95%	12/31/2009	Continuously operate low NO_x burners		Date of entry							
		Unit 6			Upgrade existing FGD	95%	12/31/2009	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		1/1/2009							
		Unit 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		1/1/2009							
Glen Lyn	Virginia	Units 5, 6			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							
Kammer	West Virginia	Units 1 – 3				Plant-wide annual cap: 35,000	1/1/2010	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		12/31/2007	Install and continuously operate SCR		1/1/2009							
		Unit 2			Install and continuously operate FGD		12/31/2007	Install and continuously operate SCR		1/1/2009							
Mountaineer	West Virginia	Unit 1			Install and continuously operate FGD		12/31/2007	Install and continuously operate SCR		1/1/2008							
Muskingum River	Ohio	Units 1 – 4	Retire, retrofit, or re-power	12/31/2015													

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 5			Install and continuously operate FGD		12/31/2015	Install and continuously operate SCR		1/1/2008	Continuously operate ESP	0.03	12/31/2002				-
Picway	Ohio	Unit 9						Continuously operate low NO_x burners		Date of entry							-
Rockport	Indiana	Unit 1			Install and continuously operate FGD		12/31/2017	Install and continuously operate SCR		12/31/2017							-
		Unit 2			Install and continuously operate FGD		12/31/2019	Install and continuously operate SCR		12/31/2019							-
Sporn	West Virginia	Unit 5	Retire, retrofit, or re-power	12/31/2013													-
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) 57,000 40,000 28,000	Start of 12-month cycle 10/1/2008 7/1/2011 1/1/2013	All units must operate low NO_x boilers	12-month rolling limit (tons) 11,500 8,500 8,000	Start of 12-month cycle 1/1/2008 1/1/2013 1/1/2015	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 EKPC system. Allowances made available due to super compliance may be sold or traded.		http://www.epa.gov/compliance/resources/cases/civil/caa/nevadapower.html

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	
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	1/1/2008				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	1/1/2008							
		Unit 3	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012													
		Unit 4															
Cooper	Kentucky	Unit 1															

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 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)	12/31/2012							
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	7/31/2009	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	7/31/2009		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							

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	
						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	12/31/2012		Install rigid-type electro-des in each unit's ESP	12/31/2015				
						82% including data from periods of malfunctions	after 7/31/11		0.15 station-wide	7/1/2012							
									0.10 station-wide	12/31/2014							
PSEG FOSSIL, Amended Consent Decree of November 2006																	
Kearny	New Jersey	Unit 7	Retire unit	1/1/2007										Allowances allocated to Kearny, Hudson, and 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.		http://www.epa.gov/compliance/resources/decrees/amended/psegfossil-amended-cd.pdf
		Unit 8	Retire unit	1/1/2007													
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/2010	Install SCR (or approved tech) and continually operate	0.1	12/31/2010	Install Baghouse (or approved technology)	0.015	12/31/2010				
						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							

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	
Mercer	New Jersey	Units 1 & 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/2010	Install SCR (or approved tech) and continually operate	0.1	1/1/2007	Install Baghouse (or approved technology)	0.015	12/31/2010				
Westar Energy																	
Jeffrey Energy Center	Kansas	All units			Units 1, 2, and 3 have a total annual limit of 6,600 tons of SO_2 starting 2011			Units 1-3 must continuously operate Low NO_x Combustion Systems by 2012 and achieve and maintain a 30-Day Rolling Average Unit Emission Rate for NO_x of no greater than 0.180 lb/MMBtu.			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, 2, and 3 must all install FGDs by 2011 and operate them continuously.			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 NO_x of no greater than 0.080 lb/MMBtu.			Units 1 and 2's ESPs must be rebuilt by 2014 in order to meet a 0.030 lb/MMBtu PM Emissions Rate						
					FGDs must maintain a 30-Day Rolling Average Unit Removal Efficiency for SO_2 of at least 97% or a 30-Day Rolling Average Unit Emission Rate for SO_2 of no greater than 0.070 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 for NO_x by 2015									
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										

Notes:

1) This summary table describes New Source Review settlement actions as they are represented in EPA Base Case v.4.10. The settlement actions are simplified for representation in the model. This table is not intended to be a comprehensive description of all elements of the actual settlement agreements.

2) Settlement actions for which the required emission limits will be effective by the time of the first mapped run year (before 1/1/2012) are built into the database of units used in EPA Base Case v.4.10 ("hardwired"). However, future actions are generally modeled as individual constraints on emission rates in EPA Base Case v.4.10 allowing the modeled economic situation to dictate whether and when a unit would opt to install controls versus retire.

3) Some control installations that are required by these NSR settlements have already been taken by the affected companies, even if deadlines specified in their settlement haven't occurred yet. Any controls that are already in place are built into EPA Base Case v.4.10

4) If a settlement agreement requires installation of PM controls, then the controls are shown in this table and reflected in EPA Base Case v.4.10. If settlement requires optimization or upgrade of existing PM controls, those actions are not included in EPA Base Case v.4.10.

5) For units for which an FGD is modeled as an emissions constraint in EPA Base Case v.4.10, EPA used the assumptions on removal efficiencies that are shown in Table 5-4 of this documentation report.

6) For units for which an FGD is hardwired in EPA Base Case v.4.10, unless the type of FGD is specified in the settlement, EPA modeling assumes the most cost effective FGD (wet or dry) and a corresponding 98% removal efficiency for wet and 93% for dry.

7) For units for which an SCR is modeled as an emissions constraint or is hardwired in EPA Base Case v.4.10, EPA assumed an emissions rate equal to 10% of the unit's uncontrolled rate, with a floor of .06 lb/MMBtu or used the emission limit if provided.

8) The applicable low NO_x burner reduction efficiencies are shown in Table A 3-1:3 in the Base Case v.4.10 documentation materials.

9) EPA included in EPA Base Case v.4.10 the requirements of the settlements as they existed at the second quarter of 2010.

10) Some of the NSR settlements require the retirement of SO_2 allowances. For EPA Base Case v.4.10, EPA estimates 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 v.4.10

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%	9/1/2007	Install SCR	0.15	9/1/2007						
		Unit 3			Install BACT		12/31/2009	Install BACT		12/31/2009						
Westover	New York	Unit 8				90%	12/31/2010	Install SCR	0.15	12/31/2010						
		Unit 7			Install BACT		12/31/2009	Install BACT		12/31/2009						
Hickling	New York	Units 1 & 2			Install BACT		5/1/2007	Install BACT		5/1/2007						
Jennison	New York	Units 1 & 2			Install BACT		5/1/2007	Install BACT		5/1/2007						
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%	10/31/2008	State-of-the-art technology	0.3	10/31/2008	Operate Baghouse and demister technology	0.02	12/31/2009	Design activated carbon injection technology (or comparable tech)		12/31/2009
		Unit 2					3/31/2009			3/31/2009			12/31/2009			12/31/2009
		Unit 3					4/30/2008			4/30/2008			4/30/2008			4/30/2008
		Unit 4					10/31/2007			10/31/2007			10/31/2007			10/31/2007
Public Service Co of Colorado																
Comanche	Colorado	Units 1 & 2			Install and operate FGD	0.1 lb/MMBtu combined average	7/1/2009	Install low-NO_x emission controls	0.15 lb/MMBtu combined average	7/1/2009				Install sorbent injection technology		7/1/2009
		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	0.01		Install sorbent injection technology		Within 180 days of start-up

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
TVA																
Bull Run	Tennessee	Unit 1			Complete FGD installation	0.15 lb/MMBtu, 4,431 TPY	FGD already active as of date of entry		0.08 lb/MMBtu, 2,295 TPY							
John Sevier	Tennessee	Unit 1			Install FGD	0.15 lb/MMBtu, 1,023 TPY	27 months from date of entry	Install SCR	0.05 lb/MMBtu, 372 TPY	21 months from date of entry						
		Unit 2				0.15 lb/MMBtu, 1,028 TPY			0.05 lb/MMBtu, 374 TPY							
		Unit 3				0.15 lb/MMBtu, 1,081 TPY			0.05 lb/MMBtu, 389 TPY							
		Unit 4				0.15 lb/MMBtu, 1,000 TPY			0.05 lb/MMBtu, 360 TPY							
Kingston	Tennessee	Unit 1			Install FGD	0.15 lb/MMBtu, 794 TPY	27 months from date of entry	Operate existing SCR	0.06 lb/MMBtu, 323 TPY							
		Unit 2				0.15 lb/MMBtu, 785 TPY			0.06 lb/MMBtu, 320 TPY							
		Unit 3				0.15 lb/MMBtu, 822 TPY			0.06 lb/MMBtu, 335 TPY							
		Unit 4				0.15 lb/MMBtu, 800 TPY			0.06 lb/MMBtu, 326 TPY							
		Unit 5				0.15 lb/MMBtu, 1,021 TPY			0.06 lb/MMBtu, 416 TPY							
		Unit 6				0.15 lb/MMBtu, 1,095 TPY			0.05 lb/MMBtu, 365 TPY							
		Unit 7				0.15 lb/MMBtu, 1,040 TPY			0.05 lb/MMBtu, 347 TPY							
		Unit 8				0.15 lb/MMBtu, 1,048 TPY			0.05 lb/MMBtu, 349 TPY							
		Unit 9				0.15 lb/MMBtu, 1,012 TPY			0.05 lb/MMBtu, 337 TPY							

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
Widows Creek	Alabama	Unit 1			Install FGD	0.15 lb/MMBtu, 569 TPY	27 months from date of entry	Install SCR	0.06 lb/MMBtu, 246 TPY	21 months from date of entry						
		Unit 2				0.15 lb/MMBtu, 608 TPY			0.06 lb/MMBtu, 263 TPY							
		Unit 3				0.15 lb/MMBtu, 663 TPY			0.06 lb/MMBtu, 287 TPY							
		Unit 4				0.15 lb/MMBtu, 602 TPY			0.06 lb/MMBtu, 261 TPY							
		Unit 5				0.15 lb/MMBtu, 640 TPY			0.06 lb/MMBtu, 277 TPY							
		Unit 6				0.15 lb/MMBtu, 626 TPY			0.06 lb/MMBtu, 271 TPY							
		Unit 7				0.56 lb/MMBtu, 8950 TPY			0.06 lb/MMBtu, 892 TPY							
		Unit 8				0.30 lb/MMBtu, 4,508 TPY			0.06 lb/MMBtu, 860 TPY							
Rochester Gas & Electric																
Russell Plant	New York	Units 1 – 4	Retire all units													
Mirant New York																
Lovett Plant	New York	Unit 1	Retire	5/7/2007												
		Unit 2	Retire	4/30/2008												

Appendix 3-5 Citizen Settlements in EPA Base Case v.4.10

Company and Plant	State	Unit	Citizen Suits Provided by DOJ										
			Retire/Repower		SO_2 control			NO_x Control			PM Control		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date
SWEPCO (AEP)													
Welsh	Texas	Units 1-3									Install and operate CEMs		12/31/2010
Allegheny Energy													
Hatfield's Ferry	Pennsylvania	Units 1 - 3			Install and operate wet FGD		6/30/2010				Install and operate sulfur trioxide injection systems, improve ESP performance	0.1 lb/MMBtu in 2006, then 0.075 lbs per hour (filterable) and 0.1 lb/MMBtu for particles less than ten microns in 2010	2006 and 6/30/2010
Wisconsin Public Service Corp													
Pulliam	Wisconsin	Units 3 & 4	Retire	12/31/2007									
University of Wisconsin													
Charter Street Heating Plant	Wisconsin		Repower to burn 100% biomass	12/31/2012									

Company and Plant	State	Unit	Citizen Suits Provided by DOJ										
			Retire/Repower		SO_2 control			NO_x Control			PM Control		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date
Tucson Electric Power													
Springerville Plant	Arizona	Units 1 & 2			Dry FGD, 85% reduction required	0.27 lb/MMBtu	12/31/2006	SCR, LNB	0.22 lb/MMBtu	12/31/2006	Baghouse	0.03 lb/MMBtu	1/1/2006
		Unit 3											
		Future Unit 4				Four-unit cap of 10,662 tons per year once units 3 and 4 are operational			Four-unit cap of 8,940 tons per year once units 3 and 4 are operational				

Appendix 3-6 Renewable Portfolio Standards in EPA Base Case v.4.10

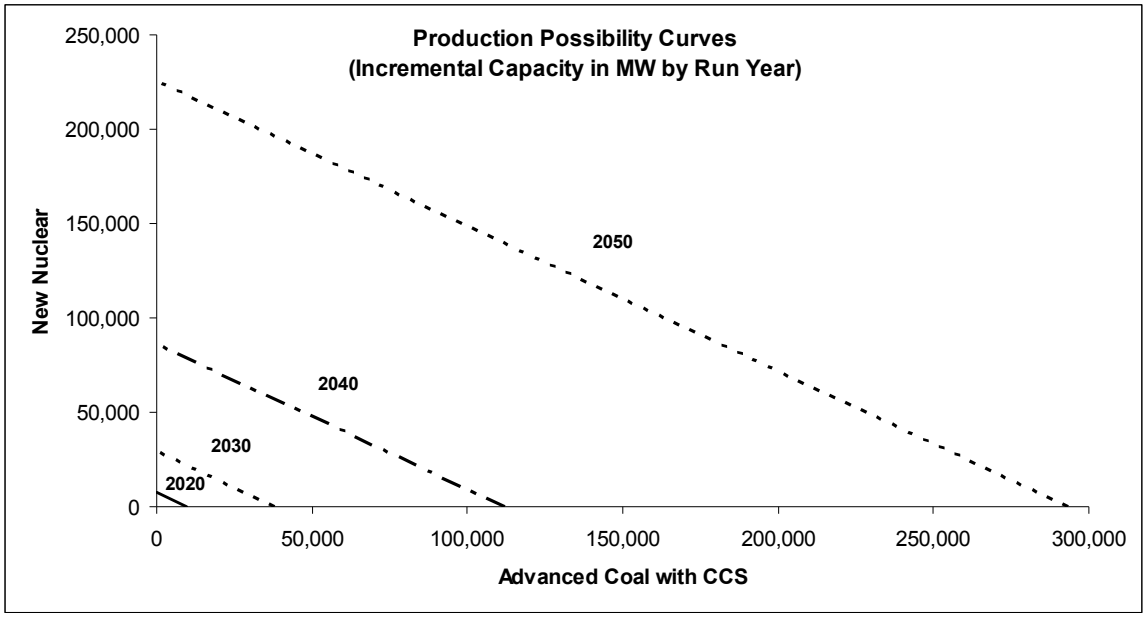
NEMS Region	IPM Regions Covered	Units	2012	2015	2020	2030	2035 - 2050
CNV	CA-N and CA-S	%	15.7%	17.3%	20.0%	20.0%	20.0%
ECAR	MECS, RFCO, RFCP, and TVAK	%	0.8%	3.0%	4.5%	5.7%	5.7%
ERCOT	ERCT	%	3.9%	5.0%	5.0%	5.0%	5.0%
MAAC	MACE, MACS, and MACW	%	7.4%	10.1%	14.8%	15.4%	15.4%
MAIN	COMD, GWAY, and WUMS	%	5.6%	8.9%	13.2%	17.5%	17.5%
MAPP	MRO	%	3.7%	4.6%	6.1%	7.2%	7.2%
NE	NENG	%	7.4%	9.6%	13.4%	13.8%	13.8%
NWP	NWPE and PNW	%	4.6%	7.3%	12.4%	13.7%	13.7%
NY	DSNY, LILC, NYC, and UPNY	GWh	4,838	5,233	5,097	5,236	5,369
RA	AZNM, RMPA, and SNV	%	3.0%	4.2%	6.0%	6.9%	6.9%
SPP	SPPN and SPPS	%	1.9%	1.9%	3.8%	3.8%	3.8%
STV	ENTG, SOU, TVA, VACA, and VAPW	%	0.5%	0.9%	1.7%	1.9%	1.9%

Notes:
The Renewable Portfolio Standard percentages are applied to modeled electricity sale projections.
The actual renewable portfolio standard targets in GWh are implemented exactly as shown in the model.

Appendix 3-7 Capacity Deployment Limits for Advanced Coal with CCS and New Nuclear in EPA Base Case v.4.10

Run Year	Advanced Coal with CCS (MW)	New Nuclear (MW)
2012	0	0
2015	2,000	0
2020	9,750	7,500
2030	38,220	29,400
2040	112,367	86,436
2050	293,652	225,886

Note:
The 2020 through 2050 limits for Advanced Coal with CCS and New Nuclear technologies are a joint constraint, with the maximum amount of possible development for each technology shown by run year. If the maximum amount of one technology is developed in a given run year, zero MW of the other may be developed. See the production possibility chart below.



Appendix 3-8 Nuclear Capacity Deployment Constraint in EPA Base Case v.4.10

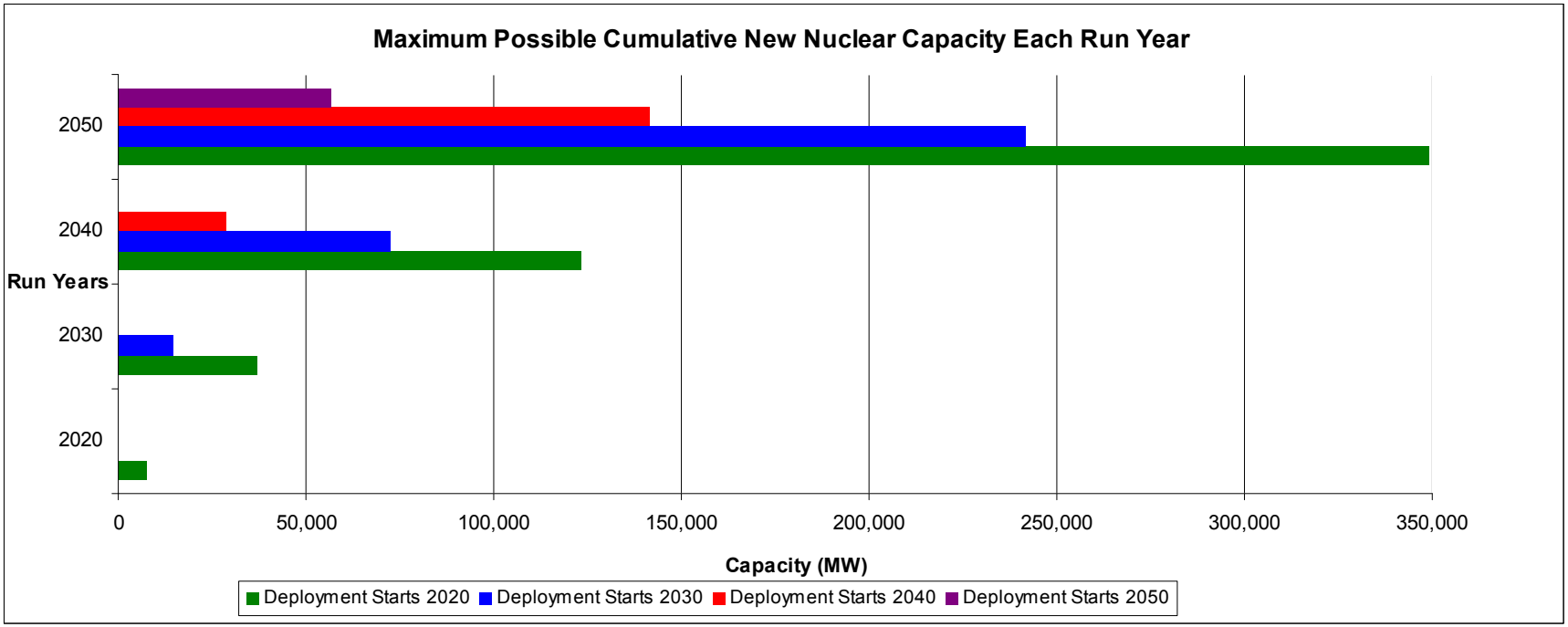
Run Year	Base New Nuclear Capacity	Base New Nuclear Capacity Deployment Equation	*Possible* Additional New Nuclear Capacity Deployment Equation[1]	Maximum Annual Incremental New Nuclear Capacity Deployment Allowed Equation
2020	7,500	7,500	0	7,500
2030	14,700	1.96 * *2020_Base_Capacity*	+ 1.96 * *2020_Incremental_Capacity*	= 1.96 * (*2020_Base_Capacity* + *2020_Incremental_Capacity*)
2040	28,812	1.96 * *2030_Base_Capacity*	+ 1.96 * *2030_Incremental_Capacity*	= 1.96 * (*2030_Base_Capacity* + *2030_Incremental_Capacity*)
2050	56,472	1.96 * *2040_Base_Capacity*	+ 1.96 * *2040_Incremental_Capacity*	= 1.96 * (*2040_Base_Capacity* + *2040_Incremental_Capacity*)

Run Year	Maximum Possible New Nuclear Capacity Deployment Allowed							
	Deployment Starts 2020		Deployment Starts 2030		Deployment Starts 2040		Deployment Starts 2050	
	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2020	7,500	7,500	0	0	0	0	0	0
2030	29,400	36,900	14,700	14,700	0	0	0	0
2040	86,436	123,336	57,624	72,324	28,812	28,812	0	0
2050	225,886	349,222	169,415	241,739	112,943	141,755	56,472	56,472

Notes:

No nuclear deployment is allowed before 2020

[1]Addtional new nuclear capacity deployment is *only* possible if nuclear capacity has been built in the previous run year.


Maximum Possible Cumulative New Nuclear Capacity Each Run Year
Run Years
2050
2040
2030
2020
0
50,000
100,000
150,000
200,000
250,000
300,000
350,000
Capacity (MW)
Deployment Starts 2020
Deployment Starts 2030
Deployment Starts 2040
Deployment Starts 2050

Appendix 3-9 Complete Availability Assumptions in EPA Base Case v.4.10

This is a small exerpt of the data in Appendix 3-9. The complete data set in spreadsheet format can be downloaded via the link found at
www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html
Please see Table 3-7 for summary data

Unit ID	Plant Name	Plant Type	Winter Availability	Summer Availability	Annual Availability
55522_G_CT1	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT10	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT2	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT3	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT4	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT5	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT6	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT7	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT8	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT9	Sundance	Combustion Turbine	89.2	90.8	89.9
55257_G_1	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_2	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_3	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_4	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_5	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_6	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_7	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
82755_C_1	AZNM_AZ_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
6088_G_5	North Loop	Combustion Turbine	89.2	90.8	89.9
118_G_GE1	Saguaro	Combustion Turbine	89.8	92.2	90.8
124_G_GT2	Demoss Petrie	Combustion Turbine	89.8	92.2	90.8
82757_C_1	AZNM_CA_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
2468_G_6	Raton	Combustion Turbine	88.4	90.4	89.2
82759_C_1	AZNM_NM_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
54814_G_GENA	Milagro Cogeneration Plant	Combustion Turbine	89.2	90.8	89.9

4 Generating Resources

"Existing", "planned-committed", and "potential" are the three general types of generating units modeled in EPA Base Case v.4.10. Units that are currently operational in the electric industry are termed as "existing" units. Units that are not currently operating but are firmly anticipated to be operational in the future, and have either broken ground (initiated construction) or secured financing are termed "planned-committed". "Potential" units refer to new generating options used in IPM for capacity expansion projections of the electric industry. Existing and planned-committed units are entered as exogenous inputs to the model, whereas potential units are endogenous to the model in the sense that the model determines the location and size of all the potential units that end up in the final solution for a specific model run.

This chapter is organized into the following five sections:

(1) Section 4.1 provides background information on the National Electric Energy Data System (NEEDS), the database which serves as the repository for information on existing and planned-committed units which are modeled in the EPA Base Case v.4.10,
(2) Section 4.2 provides detailed information on existing non-nuclear generating units modeled in EPA Base Case v.4.10,
(3) Section 4.3 provides detailed information pertaining to planned-committed units which are assumed in EPA Base Case v.4.10,
(4) Section 4.4 provides detailed information pertaining to the IPM assumptions for potential plants, and
(5) Section 4.5 describes the handling of existing and potential nuclear units in EPA Base Case v.4.10

4.1 National Electric Energy Data System (NEEDS)

EPA Base Case v.4.10 uses the NEEDS database as its source for data on all existing and planned-committed units. Table 4-1 below summarizes the resources used in developing data on existing units in NEEDS v.4.10. The data sources for planned-committed units in NEEDS are discussed below in Section 4.3. The population of existing units in NEEDS v4.10 represents generating units that were in operation through the end of 2006. The population of planned-committed includes any units online or scheduled to come online from 2007 to the end of 2011 (with two exceptions listed in the note under Table 4-2 below).

4.2 Existing Units

EPA Base Case v.4.10 models existing units based on information contained in NEEDS. The sections below describe the procedures followed in determining the population of units in NEEDS, as well as each unit's capacity, location, and configuration. Details are also given on the model plant aggregation scheme and the cost and performance characteristics associated with the existing non-nuclear units represented in EPA Base Case v.4.10.

4.2.1 Population of Existing Units

The population of existing units was taken primarily from EIA 860 (2006) and EIA 767 (2005). A number of rules were used to screen the various data sources. These rules helped to ensure data consistency, but also made the population data adaptable for use in IPM. Table 4-2 below summarizes the rules used in populating the NEEDS v.4.10 database.

Table 4-1 Data Sources for NEEDS v.4.10 for EPA Base Case v.4.10

Data Source[1]	Data Source Documentation
DOE's Form EIA-860	DOE's Form EIA-860 is an annual survey of utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), status, prime mover, primary energy source and in-service year. NEEDS v.4.10 uses EIA Form 860 (2006) data as one of the primary data inputs.
DOE's Form EIA-767	DOE's Form EIA-767 is an annual survey, "Steam-Electric Plant Operation and Design Report", that contains data for utility nuclear and fossil fuel steam boilers such as fuel quantity and quality; boiler identification, location, status, and design information; and post-combustion NO_X control, FGD scrubber and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The relationship between boilers and generators is also provided, along with generator-level generation and nameplate capacity. Note that boilers and generators are not necessarily in a one-to-one correspondence. NEEDS v.4.10 uses EIA Form 767 (2005) data as one of the primary data inputs.
NERC Electricity Supply and Demand (ES&D) database	The NERC ES&D is released annually. It contains generator-level information such as summer, winter and nameplate capacity, state, NERC region and sub-region, status, primary fuel and on-line year. NEEDS v.4.10 uses NERC ES&D (2006) data as one of the primary data inputs.
DOE's Annual Energy Outlook (AEO)	The Energy Information Administration (EIA) Annual Energy Outlook presents annually updated forecasts of energy supply, demand and prices covering a 20-25 year time horizon. The projections are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO such as heat rates, planned committed units, nuclear unit capacities and uprates were used in NEEDS v.4.10.
Global Energy Decisions New Entrants database	Global Energy's New Entrants database has information on new power plant builds, rerates and retirements. Information on committed units is based on November 2009 dataset.
EPA's Emission Tracking System (ETS 2007)	The Emission Tracking System (ETS) database is updated quarterly. It contains boiler-level information such as primary fuel, heat input, SO_2 and NO_X controls, and SO_2 and NO_X emissions.
Utility and RPO (Regional Planning Organizations) Comments	Comments from selected U.S. utilities and RPOs regarding the population in NEEDS as well as unit characteristics were used in NEEDS v.4.10.

Note:
[1] Shown in Table 4-1 are the primary issue dates of the indicated data sources that were used. Other vintages of these data sources were also used in instances where date were not available for the indicated issued date or where there were methodological reasons for using other vintages of the data.

Table 4-2 Rules Used in Populating NEEDS v.4.10 for EPA Base Case v.4.10

Scope	Rule
Capacity	Excluded units with reported nameplate, summer and winter capacity of zero
Status	Excluded units that were out of service for two or three consecutive years (i.e., generators with status codes “OS” in the latest three reporting years and boilers with status codes “OS” in the latest two reporting years) and units that were no longer in service and not expected to be returned to service (i.e., generators or boilers with status codes of "RE"). Status of boiler(s) and associated generator(s) were taken into account for determining operation status
Planned or Committed Units	Included planned units that had broken ground or secured financing and were expected to be online by the end of 2011; one biomass and one nuclear unit that are scheduled to come online after 2011 were also included
Firm/Non-firm Electric Sales	Excluded non-utility onsite generators that do not produce electricity for sale to the grid. Excluded all mobile and distributed generators

Note:
[1]The biomass unit is Mitchell, unit 3, and the nuclear unit is Watts Bar Nuclear Plant, unit 2.

As with previous versions of the database, NEEDS v.4.10 includes steam units at the boiler level and non-steam units at the generator level. A unit in NEEDS v.4.10, therefore, refers to a boiler in the case of a steam unit and a generator in the case of a non-steam unit. Table 4-3 provides a summary of the population and capacity of the existing units included in NEEDS v.4.10 through 2006. EIA Form 860 (2006) and Form 767 (2005) is the starting point and largest component of the existing unit population in NEEDS v.4.10 but the final population of existing units is supplemented based on information from other sources, including comments from utilities, submissions to EPA's Emission Tracking System, Annual Energy Outlook, and reported capacity in Global Energy’s New Entrants database.

Table 4-3 Summary Population (through 2006) of Existing Units in NEEDSv.4.10 for EPA Base Case v.4.10

Plant Type	Number of Units	Capacity (MW)
Biomass	134	2,286
Coal Steam	1,235	305,451
Combined Cycle	1,532	179,557
Combustion Turbine	5,386	132,293
Fossil Waste	20	610
Geothermal	196	2,264
Hydro	3,754	77,713
IGCC	4	529
Landfill Gas	698	1,068
Municipal Solid Waste	176	2,098
Non-Fossil Waste	45	516
Nuclear	104	101,099
O/G Steam	682	112,371
Pumped Storage	150	20,940
Solar	19	412
Tires	3	44
Wind	330	11,637
Grand Total	**14,468**	**950,889**

4.2.2 Capacity

The NEEDS unit capacity values implemented in EPA Base Case v.4.10 reflect net summer dependable capacity[16], to the extent possible. Table 4-4 summarizes the hierarchy of primary data sources used in compiling capacity data for NEEDS v.4.10.

Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS v.4.10

Sources Presented in Hierarchy
Capacity from Utility Comments
2006 EIA 860 Summer Capacity
NERC ES&D 2006 Summer Capacity
2006 EIA 860 Winter Capacity
NERC ES&D 2006 Winter Capacity
2006 EIA 860 Nameplate Capacity

Notes:
Presented in hierarchical order that applies.
If capacity is zero, unit is not included.

As noted earlier, for steam units NEEDS v.4.10 includes boiler level data, while for non-steam units NEEDS v.4.10 contains generator level data. Capacity data in EIA and NERC data sources are generator specific and not boiler specific. Therefore, it was necessary to develop an algorithm for parsing generator level capacity to the boiler level for steam producing units.

The capacity-parsing algorithm used for steam units in NEEDS v.4.10 took into account boiler-generator mapping. Fossil steam and nuclear steam electric units have boilers attached to generators that produce electricity. There are generally four types of links between boilers and generators: one boiler to one generator, one boiler to many generators, many boilers to one generator and many boilers to many generators.

The capacity-parsing algorithm used for steam units in NEEDS utilized steam flow data with the boiler-generator mapping. Under EIA 767, steam units report the maximum steam flow from the boiler to the generator. There is, however, no further data on the steam flow of each boiler-generator link. Instead, EIA 767 contains only the maximum steam flow for each boiler. Table 4-5 summarizes the algorithm used for parsing capacity with data on maximum steam flow and boiler-generator mapping. In Table 4-5 MFB_i refers to the maximum steam flow of boiler *i* and MW_{Gj} refers to the capacity of generator *j*. The algorithm uses the available data to derive the capacity of a boiler, referred to as MW_{Bj} in Table 4-5.

Table 4-5 Capacity-Parsing Algorithm for Steam Units in NEEDS v.4.10

	Type of Boiler-Generator Links			
For Boiler B_1 to B_N linked to Generators G_1 to G_N	One-to-One	One-to-Many	Many-to-One	Many-to-Many
	$MW_{Bi} = MW_{Gj}$	$MW_{Bi} = \Sigma_j MW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma_i MF_{Bi}) * MW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma_i MF_{Bi}) * \Sigma_j MW_{Gj}$

Notes:
MF_{Bi} = maximum steam flow of boiler *i*
MW_{Gj} = electric generation capacity of generator *j*

[16]As used here, net summer dependable capacity is the net capability of a generating unit in megawatts (MW) for daily planning and operation purposes during the summer peak season, after accounting for station or auxiliary services.

Since EPA Base Case v.4.10 uses net energy for load as demand, NEEDS v.4.10 only includes generators that sell the majority of their power to the electric grid in order to be consistent with demand. The generators that should be in NEEDS v.4.10. by this qualification are determined from the 2005 EIA Form 906 non-utility source and disposition data set.

4.2.3 Plant Location

NEEDS v.4.10 uses state, county and model region data to represent the physical location of each plant.

State and County
NEEDS v.4.10 used the state and county data in EIA 860 (2006)

Model Region
For each unit the associated model region was derived based on NERC regions and sub-regions reported in NERC ES&D 2006 for that unit. For units with no NERC sub-region data, NERC region and state were used to derive associated model regions. For units with no NERC region data, state and county were used to derive associated model regions. Table 3-1 in Chapter 3 provides a summary of the mapping between NERC regions and EPA Base Case v.4.10 model regions.

4.2.4 Online Year

The EPA Base Case v.4.10 uses online year to capture when the unit entered service. NEEDS includes online years for all units in the database. In NEEDS v.4.10, online years for boilers, utility and non-utility generators were primarily derived from reported in-service dates in EIA 767 2005 and EIA 860 2006 respectively.

EPA Base Case v.4.10 does not include any assumption about the retirement year for generating units, except for existing nuclear units which must retire when they reach age 60. (See section 3.7 for a discussion of the nuclear lifetime assumption.) EPA Base Case v.4.10 does, however, provide economic retirement options to coal, oil and gas steam, combined cycle, combustion turbines, and nuclear units. This means that the model may elect to retire these units if it is economical to do so. In IPM, an early retired plant ceases to incur FOM and VOM costs. However, retired units do meet capital cost obligations for retrofits if the model projected a retrofit on the unit prior to retirement.

4.2.5 Unit Configuration

Unit configuration refers to the physical specification of a unit's design. Unit configuration in EPA Base Case v.4.10 drives model plant aggregation, modeling of pollution control options and mercury emission modification factors. NEEDS v.4.10 contains information on the firing and bottom type of coal steam boilers in the database. Great effort was taken to see that the inventory of existing and committed controls represented in EPA Base Case v.4.10 was comprehensive and as up-to-date as possible. The hierarchy of data sources used is shown in Table 4-6.

4.2.6 Model Plant Aggregation

While IPM is comprehensive in representing all the units contained in NEEDS, an aggregation scheme is used to combine existing units with similar characteristics into "model plants". The aggregation scheme serves to reduce the size of the model and makes the model manageable while capturing the essential characteristics of the generating units. The EPA Base Case v.4.10 aggregation scheme is designed so that each model plant only represents generating units from a single state. This design makes it possible to obtain state-level results directly from IPM outputs. In addition, the aggregation scheme supports modeling plant-level emission limits on fossil generation

The "model plant" aggregation scheme encompasses a variety of different classification categories including location, size, technology, heat rate, fuel choices, unit configuration, SO_2

emission rates and environmental regulations among others. Units are aggregated together only if they match on all the different categories specified for the aggregation. The 10 major categories used for the aggregation scheme in EPA Base Case v.4.10 are the following:

(1) Model Region
(2) Unit Technology Type
(3) Fuel Demand Region
(4) Applicable Environmental Regulations
(5) State
(6) Unit Configuration
(7) Emission Rates
(8) Heat Rates
(9) Fuel
(10) Size

Table 4-6 Data Sources for Unit Configuration in NEEDS v.4.10 for EPA Base Case v.4.10

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

Note:
In addition to the primary, secondary and tertiary data sources listed here, the following sources were consulted and emission controls were updated when corroborating information could be found: McILVAINE Utility Upgrade Database, ICAC (Institute of Clean Air Companies), and web sites of generating unit owners and operators.

Table 4-7 provides a crosswalk between actual plants and the aggregated "model plants" used in the EPA Base Case v.4.10. For each plant type, the table shows the number of real plants and the number of model plants representing these real plants in EPA Base Case v.4.10.[17]

[17]For readers interested in the intricacies of Table 4-7, here are several observations: (1) Depending on its capacity and fuel types combusted, an existing coal steam model plant may be provided with multiple scrubber and ACI retrofit options. As a result the total number of model plants representing scrubber and ACI retrofits may exceed the total number of model plants representing existing coal steam units. (See chapter 5 for a detailed description of the sulfur dioxide (scrubber) and mercury (ACI) retrofit options.) (2) The "Number of IPM Model Plants" shown for many of the "Plant Types" in the "Retrofits" block in Table 4-7 exceeds the "Number of IPM Model Plants" shown for "Plant Type" "Coal Steam" in the block labeled "Existing and Planned/Committed Units", because a particular retrofit "Plant Type" can include multiple technology options and multiple timing options (e.g., Technology A in Stage 1 + Technology B in Stage 2, the reverse timing, or both technologies simultaneously in Stage 1). (3) Since only a subset of coal plants is eligible for certain retrofits, many of the "Plant Types" in the "Retrofits" block that represent only a single retrofit technology (e.g., "Retrofit Coal with Selective Noncatalytic Reduction (SNCR)") have a "Number of of IPM Model Plants" that is a smaller than

Table 4-7 Aggregation Profile of Model Plants as Provided at Set Up of EPA Base Case v.4.10

Existing and Planned/Committed Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass	161	71
Coal Steam	1,267	913
Combined Cycle	1,627	610
Combustion Turbine	5,474	2,225
Fossil_Other	21	14
Fuel Cell	4	4
Geothermal	211	8
Hydro	3,771	99
Import	2	2
Integrated Gas Combined Cycle	6	5
Landfill Gas	747	59
Non Fossil_Other[1]	241	73
Nuclear[2]	105	105
Oil/Gas Steam	685	435
Pumped Storage	151	21
Solar	92	37
Wind	458	57
Total	**15,023**	**4,738**

New Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
New Biomass	--	64
New Coal with Carbon Capture	--	754
New Combined Cycle	--	32
New Combustion Turbine	--	32
New Fuel Cell	--	32
New Future Technology	--	160
New Geothermal	--	26
New IGCC	--	58
New Landfill Gas	--	96
New Nuclear	--	64
New Offshore Wind	--	690
New Onshore Wind	--	600
New SPC-DryFGD_SCR_ACI		27
New SPC-WetFGD_SCR	--	27
New Solar Thermal	--	55
New Solar PV	--	32

the "Number of IPM Model Plants" shown for "Plant Type" "Coal Steam". (4) The total number of model plants representing different types of new units often exceeds the 32 model regions and the specific totals vary from technology to technology for several reasons. First, some technologies have multiple vintages, which must be represented by separate model plants in each IPM region. Second, some technologies are not available in particular regions (e.g., geothermal is geographically restricted to certain regions, conventional pulverized coal is not provided as an option in CA-N).

Total	--	**2,749**

Retrofits		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Retrofit Coal with Activated Carbon Injection (ACI)	--	427
Retrofit Coal with ACI + SCR	--	1,076
Retrofit Coal with ACI + SCR + Scrubber	--	1,575
Retrofit Coal with ACI + SCR + Scrubber + CCS	--	1,708
Retrofit Coal with ACI + SNCR + Scrubber	--	357
Retrofit Coal with ACI + SNCR	--	447
Retrofit Coal with ACI + SNCR + Scrubber + CCS	--	161
Retrofit Coal with ACI + Scrubber	--	1,570
Retrofit Coal with ACI + Scrubber + CCS	--	1,372
Retrofit Coal with Selective Catalytic Reduction (SCR)	--	360
Retrofit Coal with SCR + Scrubber	--	2,281
Retrofit Coal with SCR + Scrubber + CCS	--	2,065
Retrofit Coal with Selective Noncatalytic Reduction (SNCR)	--	141
Retrofit Coal with SNCR + Scrubber	--	544
Retrofit Coal with SNCR + Scrubber + CCS	--	112
Retrofit Coal with Scrubber	--	587
Retrofit Coal with Scrubber + CCS	--	1,078
Retrofit Coal with CCS	--	14
Retrofit Oil Gas with SCR	--	281
Total	--	**16,156**

Early Retirements		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
CC Early Retirement	--	610
Coal Early Retirement	--	6,178
CT Early Retirement	--	2,225
IGCC Early Retirement	--	5
Nuke Early Retirement	--	105
O/G Early Retirement	--	435
Total	--	**9,558**

Grand Total (Existing and Planned/Committed + New + Retrofits + Early Retirements): 33,201

Notes:

[1]Non Fossil_Other includes units whose fuel is municipal solid waste, tires, and other non-fossil waste.

[2]The 105 nuclear units include 104 currently operating units plus Watts Bar Nuclear Plant, Unit 2, which is scheduled to come online in 2014. All are listed in Appendix 4-3.

4.2.7 Cost and Performance Characteristics of Existing Units

In EPA Base Case v.4.10 heat rates, emission rates, variable operation and maintenance cost (VOM) and fixed operation and maintenance costs (FOM) are used to characterize the cost and performance of all existing units in NEEDS v.4.10. For existing units, only the cost of maintaining (FOM) and running (VOM) the unit are modeled. Embedded costs, such as carrying capital charges, are not modeled. The section below contains a discussion of the cost and performance assumptions for existing units used in the EPA Base Case v.4.10.

Variable Operating and Maintenance Cost (VOM)

VOM represents the non-fuel cost variable associated with producing a unit of electricity. If the generating unit contains pollution control equipment, VOM includes the cost of operating the control equipment. Table 4-8 below summarizes VOM assumptions used in EPA Base Case v.4.10. The values shown in this table were obtained using a procedure developed jointly by EPA's power sector engineering staff and ICF.

Table 4-8 VOM Assumptions (2007$) in EPA Base Case v.4.10

Capacity Type	SO_2 Control	Hg Control	NO_x Control	Variable O&M Range (mills/kWh)
Combined Cycle	--	--	No NO_x	2.63 - 7.67
			SCR	2.75 - 7.79
Coal Steam	Scrubbed - Dry	No Hg	No NO_x	3.66 - 5.05
			SCR	4.34 - 5.73
			SNCR	4.73 - 6.12
		ACI	No NO_x	4.62 - 6.02
			SCR	5.30 - 6.69
			SNCR	5.70 - 7.09
	Scrubbed - Wet	No Hg	No NO_x	2.48 - 3.87
			SCR	3.16 - 4.55
			SNCR	3.55 - 4.94
		ACI	No NO_x	3.44 - 4.83
			SCR	4.12 - 5.51
			SNCR	4.51 - 5.91
	Unscrubbed	No Hg	No NO_x	0.90 - 2.29
			SCR	1.58 - 2.97
			SNCR	1.97 - 3.37
		ACI	No NO_x	1.87 - 3.26
			SCR	2.54 - 3.94
			SNCR	2.94 - 4.33
Conventional Hydroelectric	--	--	--	6.66
Combined Turbine	--	No Hg	No NO_x	2.60 - 9.59
			SCR	2.73 - 9.71
Fuel Cell	--	--	--	9.7
Geothermal	--	--	--	8.3
IGCC	--	--	--	0 - 4.72
MSW/Landfill Gas	--	--	--	8.79

Capacity Type	SO_2 Control	Hg Control	NO_x Control	Variable O&M Range (mills/kWh)
Oil/Gas Steam	Scrubbed - Wet	No Hg	No NO_x	0.94 - 5.07
			SNCR	1.49 - 5.62
	Unscrubbed	No Hg	No NO_x	0.94 - 5.07
			SCR	1.06 - 5.19
			SNCR	1.49 - 5.62
Pumped Storage	--	--	--	8.37
Solar Photovoltaic	--	--	--	2.09
Solar Thermal	--	--	--	2.78
Wind	--	--	--	3.18
Wood/Biomass	--	--	--	6.98

Fixed Operation and Maintenance Cost (FOM)
FOM represents the annual fixed cost of maintaining a unit. FOM costs are incurred independent of achieved generation levels and signify the fixed cost of operating and maintaining the unit for generation. Table 4-9 summarizes the FOM assumptions used in EPA Base Case v.4.10. Note that FOM varies by the age of the unit. The values appearing in this table include the cost of maintaining any associated pollution control equipment. The values in Table 4-9 are based on FERC (Federal Energy Regulatory Commission) Form 1 data.

Heat Rates
Heat Rates describe the efficiency of the unit expressed as BTUs per kWh. The treatment of heat rates in EPA Base Case v.4.10 is discussed in Section 3.8.

Lifetimes
Unit lifetime assumptions in EPA Base Case v.4.10 are detailed in Sections 3.7 and 4.2.8.

SO_2 Rates
Section 3.9.1 contains a detailed discussion of SO_2 rates for existing units.

NO_x Rates
Section 3.9.2 contains a detailed discussion of NO_x rates for existing units.

Mercury Emission Modification Factors (EMF)
Mercury EMF refers to the ratio of mercury emissions (mercury outlet) to the mercury content of the fuel (mercury inlet). Section 5.4.2 contains a detailed discussion of the EMF assumptions in EPA Base Case v.4.10.

4.2.8 Life Extension Costs for existing units

The usable modeling time horizon in previous EPA Base Cases typically extended out only as far as 2030 and covered a period of roughly 20-25 years. In contrast, the modeling time horizon in EPA Base Case 4.10 extends to 2050 covers a period of almost 40 years. Due to this longer time horizon, provision had to be made in EPA Base Case v.4.10 for investments (beyond the routine maintenance of the power plant) that would be required to extend the life of existing units over this longer time horizon. The life extension costs for units with retirement options are summarized in Table 4-10 below. These costs were based on a review of FERC Form 1 data regarding annual capital expenditures over the last 10 – 15 years of the power plan.

Table 4-9 FOM Assumptions Used in EPA Base Case v.4.10

Prime Mover Type	Primary Fuel	SO_2 Control	Hg Control	NO_x Control	Age of Unit	FOM (2007$ /kW-Yr)
Combined Cycle	Oil & Gas	--	--	--	All Years	12.6
Conventional Hydroelectric	Water	--	--	--	All Years	14.3
Fuel Cell	Natural Gas	--	--	--	All Years	18.3
Gas Turbine	Oil & Gas	--	--	--	>30 years	8.8
					20-30 years	8.5
					0-20 years	3.7
Geothermal	Earth	--	--	--	All Years	21.6
IGCC	Coal	--	--	--	All Years	118.4
MSW/Landfill Gas	Landfill Gas	--	--	--	All Years	23.6
Nuclear	Nuclear	--	--	--	All Years	100.5
Pumped Storage	Water	--	--	--	All Years	18.3
Solar Photovoltaic	Sun	--	--	--	All Years	17.1
Solar Thermal	Sun	--	--	--	All Years	22.6
Steam Turbine	Coal	Scrubbed - Dry	No Hg	No NO_x	0 to 20 Years	42.2
					20 to 30 Years	44.2
					30 to 40 Years	55.1
					Greater than 40 Years	60.8
				SCR	0 to 20 Years	42.9
					20 to 30 Years	44.9
					30 to 40 Years	55.7
					Greater than 40 Years	61.4
				SNCR	0 to 20 Years	42.5
					20 to 30 Years	44.5
					30 to 40 Years	55.3
					Greater than 40 Years	61.1
			ACI	No NO_x	0 to 20 Years	42.4
					20 to 30 Years	44.4
					30 to 40 Years	55.2
					Greater than 40 Years	60.9
				SCR	0 to 20 Years	43.0
					20 to 30 Years	45.0
					30 to 40 Years	55.9
					Greater than 40 Years	61.6
				SNCR	0 to 20 Years	42.6
					20 to 30 Years	44.6
					30 to 40 Years	55.5
					Greater than 40 Years	61.2
		Scrubbed - Wet	No Hg	No NO_x	0 to 20 Years	43.2
					20 to 30 Years	45.2
					30 to 40 Years	56.0
					Greater than 40 Years	61.8
				SCR	0 to 20 Years	43.8
					20 to 30 Years	45.8

Prime Mover Type	Primary Fuel	SO_2 Control	Hg Control	NO_x Control	Age of Unit	FOM (2007$ /kW-Yr)
					30 to 40 Years	56.7
					Greater than 40 Years	62.4
				SNCR	0 to 20 Years	43.5
					20 to 30 Years	45.5
					30 to 40 Years	56.3
					Greater than 40 Years	62.0
			ACI	No NO_x	0 to 20 Years	43.3
					20 to 30 Years	45.3
					30 to 40 Years	56.2
					Greater than 40 Years	61.9
				SCR	0 to 20 Years	44.0
					20 to 30 Years	46.0
					30 to 40 Years	56.8
					Greater than 40 Years	62.6
				SNCR	0 to 20 Years	43.6
					20 to 30 Years	45.6
					30 to 40 Years	56.5
					Greater than 40 Years	62.2
		Unscrubbed	No Hg	No NO_x	0 to 20 Years	32.9
					20 to 30 Years	34.9
					30 to 40 Years	45.8
					Greater than 40 Years	51.5
				SCR	0 to 20 Years	33.6
					20 to 30 Years	35.6
					30 to 40 Years	46.4
					Greater than 40 Years	52.2
				SNCR	0 to 20 Years	33.2
					20 to 30 Years	35.2
					30 to 40 Years	46.1
					Greater than 40 Years	51.8
			ACI	No NO_x	0 to 20 Years	33.1
					20 to 30 Years	35.1
					30 to 40 Years	45.9
					Greater than 40 Years	51.7
				SCR	0 to 20 Years	33.7
					20 to 30 Years	35.7
					30 to 40 Years	46.6
					Greater than 40 Years	52.3
				SNCR	0 to 20 Years	33.3
					20 to 30 Years	35.3
					30 to 40 Years	46.2
					Greater than 40 Years	51.9
	Oil & Gas	--	--	No NO_x	0 to 20 Years	18.4
					20 to 30 Years	21.0
					30 to 40 Years	22.3
					Greater than 40 Years	28.4
				SCR	0 to 20 Years	19.3

Prime Mover Type	Primary Fuel	SO_2 Control	Hg Control	NO_x Control	Age of Unit	FOM (2007$ /kW-Yr)
					20 to 30 Years	21.9
					30 to 40 Years	23.2
					Greater than 40 Years	29.3
				SNCR	0 to 20 Years	18.6
					20 to 30 Years	21.2
					30 to 40 Years	22.5
					Greater than 40 Years	28.6
Wind	Wind	--	--	--	All Years	18.3
Wood/Biomass	Biomass	--	--	--	All Years	20.1

Table 4-10 Life Extension Cost Assumptions Used in EPA Base Case v.4.10

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost as Proportion of New Unit Capital Cost (%)	Capital Cost of New Unit (2007$/kW)	Life Extension Cost (2007$/kW)
Coal Steam	40	7.0	2,918	204
Combined Cycle	30	9.3	976	91
Combustion Turbine & IC Engine	30	4.2	698	30
Oil/Gas Steam	40	3.4	2,699	91
IGCC	40	7.4	3,265	242
Nuclear	40	9.0	4,621	416

Note:
Life extension expenditures double the lifespan of the unit.

4.3 Planned-Committed Units

EPA Base Case v.4.10 includes all planned-committed units that are likely to come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before 2012.

4.3.1 Population and Model Plant Aggregation

Like existing units, planned-committed units are contained in NEEDS. A comprehensive update of planned-committed units contained in NEEDS was performed for EPA Base Case v.4.10 using the information sources listed in Table 4-1 . Table 4-11 summarizes the extent of inventory of planned-committed units in EPA Base Case v.4.10 indicating its generating capacity by unit types.

Due to data confidentiality restrictions, NEEDS v.4.10 does not list the planned-committed units on a unit by unit basis. Rather, all units having similar technologies and located within the same model region are aggregated together as one record. Table 4-12 gives a breakdown of planned-committed units by IPM region, unit type, number of units, and capacity included in EPA Base Case v.4.10.

Table 4-11 Summary of Planned-Committed Units in NEEDS v.4.10 for EPA Base Case v.4.10

Type	Capacity (MW)	Year Range Described
Renewables/Non-conventional		
Biomass	495	2007 - 2012
Fuel Cell	3	2011
Geothermal	302	2007 - 2011
Hydro	91	2007 - 2011
Landfill Gas	279	2007 - 2011
Municipal Solid Waste	35	2007 - 2011
Non-Fossil Waste	235	2011
Pumped Storage	40	2011
Solar	687	2007 - 2011
Wind	26,295	2007 - 2011
Subtotal	28,462	
Fossil/Conventional		
Coal Steam	17,055	2007 - 2011
Combined Cycle	25,088	2007 - 2011
Combustion Turbine	9,648	2007 - 2011
Fossil Waste	274	2011
IGCC	1,230	2009 - 2011
Nuclear	1,180	2014
O/G Steam	115	2008 - 2011
Subtotal	54,590	
Grand Total	83,052	

Table 4-12 Planned-Committed Units by Model Region in NEEDS v.4.10 for EPA Base Case v.4.10

IPM Region	Plant Type	Capacity (MW)
AZNM	Biomass	24
	Coal Steam	400
	Combined Cycle	94
	Combustion Turbine	593
	Geothermal	95
	Solar	20
	Wind	130
CA-N	Combined Cycle	1,279
	Combustion Turbine	603
	Fuel Cell	1
	Geothermal	25
	Landfill Gas	17
	Solar	249
	Wind	2,533
CA-S	Biomass	2
	Combined Cycle	1,293
	Combustion Turbine	454
	Fuel Cell	2
	Hydro	5
	Landfill Gas	8

IPM Region	Plant Type	Capacity (MW)
	Pumped Storage	40
	Solar	255
	Wind	112
COMD	Combined Cycle	573
	Landfill Gas	6
	Wind	282
DSNY	Combined Cycle	635
ENTG	Biomass	14
	Coal Steam	665
	Combined Cycle	1,336
ERCT	Biomass	50
	Coal Steam	3,250
	Combined Cycle	3,266
	Combustion Turbine	639
	Fossil Waste	274
	Landfill Gas	16
	Non-Fossil Waste	10
	Solar	3
	Wind	7,669
FRCC	Combined Cycle	6,365
	Combustion Turbine	1,191
	Landfill Gas	21
	Municipal Solid Waste	16
GWAY	Coal Steam	1,800
	Landfill Gas	5
	Wind	1,177
LILC	Combined Cycle	350
MACE	Combustion Turbine	105
	Landfill Gas	27
	O/G Steam	9
	Solar	7
MACS	Combustion Turbine	30
	Landfill Gas	5
	O/G Steam	100
MACW	Biomass	30
	Landfill Gas	22
	Municipal Solid Waste	14
	Wind	480
	Landfill Gas	10
	Wind	480
MRO	Biomass	107
	Coal Steam	1,782
	Combined Cycle	1,204
	Combustion Turbine	878
	Hydro	11
	Landfill Gas	7
	Municipal Solid Waste	5

IPM Region	Plant Type	Capacity (MW)
	Non-Fossil Waste	25
	Wind	4,598
NENG	Biomass	44
	Combined Cycle	987
	Combustion Turbine	301
	Hydro	16
	Landfill Gas	11
	O/G Steam	6
	Solar	1
	Wind	650
NWPE	Biomass	1
	Coal Steam	1,112
	Combined Cycle	1,062
	Geothermal	182
	Hydro	12
	Solar	2
	Wind	266
NYC	Combustion Turbine	1
PNW	Biomass	31
	Combined Cycle	1,262
	Combustion Turbine	175
	Hydro	19
	Landfill Gas	10
	Non-Fossil Waste	58
	Solar	2
	Wind	2,584
RFCO	Combined Cycle	720
	IGCC	1,230
	Landfill Gas	26
	Non-Fossil Waste	3
	Wind	554
RFCP	Coal Steam	695
	Combined Cycle	580
	Landfill Gas	5
	Non-Fossil Waste	80
	Wind	264
RMPA	Coal Steam	768
	Combustion Turbine	658
	Hydro	9
	Landfill Gas	6
	Solar	15
	Wind	1,362
SNV	Combustion Turbine	720
	Solar	112
	Wind	189
SOU	Biomass	116
	Combined Cycle	1,237

IPM Region	Plant Type	Capacity (MW)
	Non-Fossil Waste	18
SPPN	Coal Steam	1,172
	Combustion Turbine	845
	Wind	651
SPPS	Coal Steam	660
	Combined Cycle	1,080
	Combustion Turbine	939
	Non-Fossil Waste	35
	Solar	8
	Wind	943
	Nuclear	1,180
	Wind	111
TVAK	Coal Steam	1,018
	Combustion Turbine	200
	Landfill Gas	5
UPNY	Biomass	25
	Hydro	13
	Landfill Gas	14
	Non-Fossil Waste	7
	Wind	826
VACA	Coal Steam	1,980
	Combustion Turbine	779
	Hydro	6
	Landfill Gas	18
	Solar	12
	Wind	38
VAPW	Combined Cycle	1,190
	Combustion Turbine	537
	Landfill Gas	31
	Solar	1
WUMS	Biomass	50
	Coal Steam	1,753
	Combined Cycle	575
	Landfill Gas	8
	Wind	396

Note:
Any unit that has an online year of 2007- 2011 was considered a Planned and Committed Unit

4.3.2 Capacity

The capacity of planned-committed units in NEEDS v.4.10 was obtained from the information sources reported above in Table 4-1 .

4.3.3 State and Model Region

State location data for the planned-committed units in NEEDS v.4.10 came from the information sources noted in Section 4.3.1. The state information was then used to assign planned-committed units to their respective model regions.

4.3.4 Online and Retirement Year

As noted above, planned-committed units included in NEEDS v.4.10 are only those units which are likely to come on-line before 2012. All planned-committed units were given a default online year of end of 2011 since this is the first analysis year in EPA Base Case v.4.10. The assumptions in EPA Base Case v.4.10 do not include a lifetime for planned-committed units.

4.3.5 Unit Configuration and Cost-and-Performance

All planned-committed units in NEEDS v.4.10 assume the cost, performance, and unit configuration characteristics of potential units that are available in 2012. A detailed description of potential unit assumptions is provided below in Section 4.4.

4.4 Potential Units

The EPA Base Case v.4.10 includes options for developing a variety of potential units that may be "built" at a future date in response to electricity demand and the constraints represented in the model. Defined by region, technology, and the year available, potential units with an initial capacity of 0 MW are inputs into IPM. When the model is run, the capacity of certain potential units is raised from zero to meet demand and other system and operating constraints. This results in the model's projection of new capacity.

In Table 4-7 the block labeled "New Units" gives a breakdown of the type and number of potential units provided in EPA Base Case v.4.10. The following sections describe the cost and performance assumptions for the potential units represented in the EPA Base Case v.4.10.

4.4.1 Methodology Used to Derive the Cost and Performance Characteristics of Conventional Potential Units

Cost and performance assumptions for potential units in previous EPA base cases were based primarily on data from the latest available Annual Energy Outlook (AEO) published by the U.S. Department of Energy's Energy Information Administration. However, an unprecedented run up in the costs of new generating units over the preceding 5 years prompted EPA to analyze other references in addition to the AEO for Base Case v.4.10. The cost escalation which was particularly noticeable for base load electric generating units, was generally attributed to international competition and, was increasingly seen as permanent. That is, there was a growing consensus that costs were not going to settle back to pre-2010 levels.

With this in mind, the power sector engineering staff in EPA's Clean Air Markets Division performed comparative cost analyses based on reports and discussions with government agencies, national technical laboratories, industry, academia, and various non-governmental organizations. The key sources reviewed included:

- U.S. Energy Information Administration: *Annual Energy Outlook 2008, 2009, 2010*[18]
- National Energy Technology Laboratory, Fossil Energy Power Plant Desk Reference (Bituminous Coal)[19]

---

[18] U.S. Department of Energy, Energy Information Administration, Assumptions to the Annual Energy Outlook 2008: Electric Market Module, DOE/EIA-0554(2008), June 2008. www.eia.doe.gov/oiaf/archive/aeo08/assumption/electricity.html
U.S. Department of Energy, Energy Information Administration, Assumptions to the Annual Energy Outlook 2009: Electric Market Module, DOE/EIA-0554(2009), March 2009. www.eia.doe.gov/oiaf/archive/aeo09/assumption/electricity.html
U.S. Department of Energy, Energy Information Administration, Assumptions to the Annual Energy Outlook 2010: Electric Market Module, #:DOE/EIA-0554(2010), April 2010. www.eia.doe.gov/oiaf/aeo/assumption/electricity.html.

[19] U.S. Department of Energy, National Energy Technology Laboratory, *Fossil Energy Power Plant Desk Reference, Bituminous Coal and Natural Gas to Electricity Summary Sheets* DOE/NETL-

- U.S. Environmental Protection Agency, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies[20]
- EPRI (Electric Power Research Institute): "Economic Assessment of Advanced Coal-Based Power Plants with CO_2 Capture"[21]
- Harvard University: "Realistic Costs of Carbon Capture"[22]
- Massachusetts Institute of Technology: "Update on the Cost of Nuclear Power"[23]
- Union of Concerned Scientists: Climate 2030 - A National Blueprint for a Clean Energy Economy[24]

4.4.2 Cost and Performance for Potential Conventional Units

The comparative analyses described in the preceding section resulted in the cost and performance characteristics shown in Table 4-13. They are based on EPA's engineering assessments. As seen in Table 4-13, EPA Base Case v.4.10 includes cost and performance characteristics for the following potential technologies: supercritical pulverized coal, advanced combined cycle, advanced combustion turbines, integrated gasification combined cycle (IGCC), advanced coal with carbon capture capabilities, and nuclear units. The cost and performance assumptions are based on the size (i.e., electrical generating capacity in MW) indicated in the table. However, the total new capacity that is added in a given model run for these technologies is not restricted to these capacity levels.

This table includes several components of cost. The total installed cost of developing and building a new plant is captured through the capital cost. It includes expenditures on pollution control equipment that new units are assumed to install to satisfy air regulatory requirements. The capital costs shown in Table 4-13 are typically referred to as "overnight" capital costs. They include engineering, procurement, construction, startup, and owner's costs (for such items as land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licenses, etc). The capital costs in Table 4-13 do not include interest during construction (IDC). IDC is added to the capital costs shown in Table 4-13 during the set-up of a run. Calculation of IDC is based on the construction profile and the discount rate. Details on the discount rates used in the EPA Base Case v.4.10 are discussed in Chapter 8 under financial assumptions.

2007/1282, May 2007. http://www.netl.doe.gov/energy-analyses/pubs/Cost%20and%20Performance%20Baseline-012908.pdf

[20]U.S. EPA, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies. EPA-430/R-06/2006, July 2006.

[21]Booras, G., *Economic Assessment of Advanced Coal-Based Power Plants with CO2 Capture*, a presentation at EPRI (Electric Power Research Institute) MIT Carbon Sequestration Forum IC, September 16, 2008.

[22]Al-Juaied, M and A Whitmore, ""Realistic Costs of Carbon Capture" Harvard Kennedy School. Belfer Center Discussion Paper 2009-08, July 2009. http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

[23]Du, Y., J.E. Parsons (2009). Update on the cost of nuclear power. MIT Center for Energy and Environmental Policy Research (CEEPR) Working Paper 09-004, May 2009. http://web.mit.edu/ceepr/www/publications/workingpapers/2009-004.pdf

[24]Cleetus R., S. Clemmer, and D. Friedman, *Climate 2030 - A National Blueprint for a Clean Energy Economy,* Union of Concerned Scientists, May 2009. http://www.ucsusa.org/global_warming/solutions/big_picture_solutions/climate-2030-blueprint.html#Download_the_Climate_2030_Blueprint_repo

Table 4-13 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Base Case v4.10

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle – Bituminous	Integrated Gasification Combined Cycle – Subbituminous	Advanced Coal with Carbon Capture-Bituminous[1]	Advanced Coal with Carbon Capture – Subbituminous[1]	Supercritical Pulverized Coal - Wet Bituminous	Supercritical Pulverized Coal - Dry Sub-Bituminous
Size (MW)	560	170	1350	600	600	500	500	600	600
First Year Available	2015	2012	2017	2013	2013	2015	2015	2013	2013
Lead Time (Years)	3	2	6	4	4	4	4	4	4
Vintage #1 (years covered)	2012 - 2054	2012 - 2054	2012 - 2054	2012 - 2054	2012 - 2054	2012 - 2054	2015 - 2054	2012 - 2054	2012 - 2054
Availability	87%	92%	90%	85%	85%	85%	85%	85%	85%
Vintage #1									
Heat Rate (Btu/kWh)	6,810	10,720	10,400	8,424	8,062	10,149	9,713	8,874	8,937
Capital[2] (2007$/kW)	976	698	4,621	3,265	3,310	4,720	4,785	2,918	3,008
Fixed O&M (2007$/kW/yr)	14.4	12.3	92.4	47.9	48.2	60.5	61.0	28.9	28.6
Variable O&M (2007$/MWh)	2.57	3.59	0.77	1.32	1.15	1.67	1.46	3.43	2.27

Notes:

[1]For The term "Advanced Coal with Carbon Capture" is used here and in the output files for EPA Base Case v.4.10 to represent a variety of technologies that are expected to provide carbon capture capabilities. These include both supercritical steam generators with carbon capture and integrated gasification combined cycle (IGCC) with carbon capture. Although IGCC with carbon capture was used to define the cost and performance parameters that are implemented in EPA Base Case v.4.10, projections of "Advanced Coal with Carbon Capture" in EPA Base Case v.4.10 are not limited to this technology.

[2]Capital cost represents overnight capital cost.

Table 4-13 also shows fixed operating and maintenance (FOM) and variable operating and maintenance (VOM) components of cost. FOM is the annual cost of maintaining a generating unit. It represents expenses incurred regardless of the extent that the unit is run. It is expressed in units of $ per kW per year. VOM represents the costs incurred in running an electric generating unit. It is proportional to the electrical energy produced and is expressed in units of $ per MWh.

In addition to the three components of cost, Table 4-13 indicates the first year available, lead time, vintage periods, heat rate, and availability for each type of unit. Lead time represents the construction time needed for a unit to come online. Vintage periods are used to capture the cost and performance improvements resulting from technological advancement and learning-by-doing. Mature technologies and technologies whose first year available is not at the start of the modeling time horizon may have only one vintage period, whereas newer technologies may have several vintage periods. Heat rate indicates the efficiency of the unit and is expressed in units of energy consumed (Btus) per unit of electricity generated (kWh). Availability indicates the percentage of time that a generating unit is available to provide electricity to the grid once it has come on line. Availability takes into account estimates of the time consumed by planned maintenance and forced outages. The emission characteristics of the potential units are not presented in Table 4-13, but can be found in Table 3-11.

4.4.3 Short-Term Capital Cost Adder

Besides the capital costs shown in Table 4-13 and Table 4-16 EPA Base Case v.4.10 includes a short-term capital cost adder that kicks in if the new capacity in a specific model run year exceeds certain upper bounds. This is meant to reflect the added cost incurred due to short-term competition for scarce labor and materials. Table 4-14 shows the cost adders for each type of potential unit for model run years through 2030. The adder is not imposed after 2030 on the premise that by then market adjustments will have eliminated the short term scarcity experienced in earlier years.

Here's how these short-term adders work in Base Case v.4.10: The column labeled "Step 1" in Table 4-14 indicates the total amount of capacity of a particular plant type that can be built in a given model run year without incurring a cost adder. However, if the Step 1 upper bound is exceeded, then either the Step 2 or Step 3 cost adder is incurred. Above the Step 1 upper bound, the Step 2 cost adder applies until the cumulative capacity exceeds the Step 1 + Step 2 upper bound. Beyond that point, the Step 3 capital cost adder applies. For example, the Step 1 upper bound in 2012 for coal steam potential units is 25,301 MW. If no more than this total new coal steam capacity is built in 2012, only the capital cost shown in Table 4-13 is incurred. Between 25,301 and 42,168 MW (the sum of the Step 1 and Step 2 upper bounds, i.e., 25,301 MW + 16, 867 MW = 42,168 MW), the Step 2 cost adder of $967/MW applies. For all the new coal capacity built in that model run year (not just the increment of new capacity above the Step 1 upper bound of 25,301 MW), this extra cost is added to the capital cost shown in Table 4-13. If the total new coal steam capacity exceeds the Step 1 + Step 2 upper bound of 42,168 MW, then the Step 3 capacity adder of $2,500/MW is incurred. To determine if the upper bounds for plant type "Coal Steam" in Table 4-14 have been reached, one must sum the capacities added in a model run year for plant types Supercritical Pulverized Coal - Wet Bituminous and Supercritical Pulverized Coal - Dry Bituminous. The upper bound for "Coal Steam" applies to the sum of the capacity added in the model run year for these two plant types.

The short-term capital cost adders shown in Table 4-14 were derived from AEO assumptions.

4.4.4 Regional Cost Adjustment

The capital costs reported in Table 4-14 are generic. Before EPA implements these capital cost values they are converted to region-specific costs. This is done through the application of regional adjustment factors which capture regional differences in labor, material, and construction costs. The regional adjustment factors used in EPA Base Case v.4.10 are shown in Table 4-15. They were developed from AEO and are applied to both conventional technologies shown in Table 4-13 and to the renewable and non-conventional technologies shown in Table 4-16 below.

Table 4-14 Short-Term Capital Cost Adders for New Power Plants in EPA Base Case v.4.10 (2007$)

ID Number	Plant Type		2012			2015			2020			2030		
			Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
1	Biomass	Upper Bound (MW)	600	400	--	1,800	1,200	--	3,000	2,000	--	6,000	4,000	--
		Adder ($/kW)	--	1,410	3,646	--	1,410	3,646	--	1,410	3,646	--	1,410	3,646
2	Coal Steam	Upper Bound (MW)	8,434	5,622	--	25,301	16,867	--	42,168	28,112	--	84,336	56,224	--
		Adder ($/kW)	--	967	2,500	--	967	2,500	--	967	2,500	--	967	2,500
3	Combined Cycle	Upper Bound (MW)	46,469	30,979	--	139,406	92,937	--	232,344	154,896	--	464,687	309,791	--
		Adder ($/kW)	--	310	801	--	310	801	--	310	801	--	310	801
4	Combustion Turbine	Upper Bound (MW)	24,098	16,066	--	72,295	48,197	--	120,492	80,328	--	240,984	160,656	--
		Adder ($/kW)	--	213	551	--	213	551	--	213	551	--	213	551
5	Fuel Cell	Upper Bound (MW)	600	400	--	1,800	1,200	--	3,000	2,000	--	6,000	4,000	--
		Adder ($/kW)	--	1,987	5,138	--	1,987	5,138	--	1,987	5,138	--	1,987	5,138
6	Geothermal	Upper Bound (MW)	315	210	--	946	630	--	1,576	1,051	--	3,152	2,102	--
		Adder ($/kW)	--	1,981	5,123	--	1,981	5,123	--	1,981	5,123	--	1,981	5,123
7	IGCC and Advanced Coal with Carbon Capture	Upper Bound (MW)	2,400	1,600	--	7,200	4,800	--	12,000	8,000	--	24,000	16,000	--
		Adder ($/kW)	--	1,072	2,774	--	1,072	2,774	--	1,072	2,774	--	1,072	2,774
8	Landfill Gas	Upper Bound (MW)	600	400	--	1,800	1,200	--	3,000	2,000	--	6,000	4,000	--
		Adder ($/kW)	--	1,135	2,936	--	1,135	2,936	--	1,135	2,936	--	1,135	2,936
9	Nuclear	Upper Bound (MW)	11,230	7,487	--	33,690	22,460	--	56,151	37,434	--	112,301	74,867	--
		Adder ($/kW)	--	1,579	4,083	--	1,579	4,083	--	1,579	4,083	--	1,579	4,083
10	Solar Thermal	Upper Bound (MW)	106	70	--	317	211	--	528	352	--	1,056	704	--
		Adder ($/kW)	--	1,608	4,158	--	1,608	4,158	--	1,608	4,158	--	1,608	4,158
11	Solar PV	Upper Bound (MW)	54	36	--	54	36	--	90	60	--	180	120	--
		Adder ($/kW)	--	1,733	4,483	--	1,733	4,483	--	1,733	4,483	--	1,733	4,483

ID Number	Plant Type		2012			2015			2020			2030		
			Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
12	Onshore Wind	Upper Bound (MW)	23,000	19,670	--	29,505	19,670	--	49,174	32,783	--	98,348	65,566	--
		Adder ($/kW)	--	646	1,672	--	646	1,672	--	646	1,672	--	646	1,672
13	Offshore Wind	Upper Bound (MW)	600	400	--	1,800	1,200	--	3,000	2,000	--	6,000	4,000	--
		Adder ($/kW)	--	1,304	3,373	--	1,304	3,373	--	1,304	3,373	--	1,304	3,373

Note:
The term “Advanced Coal with Carbon Capture” is used here and in the output files for EPA Base Case v.4.10 to represent a variety of technologies that are expected to provide carbon capture capabilities. These include both supercritical steam generators with carbon capture and integrated gasification combined cycle (IGCC) with carbon capture. Although IGCC with carbon capture was used to define the cost and performance parameters that are implemented in EPA Base Case v.4.10 and shown in Table 4-13, projections of “Advanced Coal with Carbon Capture” in EPA Base Case v.4.10 are not limited to this technology.

Table 4-15 Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies in EPA Base Case v.4.10

Model Region	Region Description or Reliability Council Name	Regional Factor
AZNM	Western Electricity Coordinating Council - Arizona, New Mexico	1.003
CA-N	Western Electricity Coordinating Council - California North	1.058
CA-S	Western Electricity Coordinating Council - California South	1.058
COMD	Commonwealth Edison	1.004
DSNY	Downstate New York	1.043
ENTG	Entergy	0.960
ERCT	Texas Regional Entity	0.986
FRCC	Florida Reliability Coordinating Council	0.961
GWAY	Gateway	1.004
LILC	Long Island Company	1.879
MACE	Legacy Mid-Atlantic Area Council - East	0.996
MACS	Legacy Mid-Atlantic Area Council - South	0.996
MACW	Legacy Mid-Atlantic Area Council - West	0.996
MECS	Michigan Electric Coordination System	1.004
MRO	Midwest Regional Planning Organization	1.004
NENG	New England Power Pool	1.145
NWPE	Western Electricity Coordinating Council - Northwest Power Pool East	1.026
NYC	New York City	1.989
PNW	Western Electricity Coordinating Council - Pacific Northwest	1.026
RFCO	Reliability First Corporation - MISO	1.004
RFCP	Reliability First Corporation - PJM	1.004
RMPA	Western Electricity Coordinating Council - Rocky Mountain Power Area	1.003
SNV	Western Electricity Coordinating Council - Southern Nevada	1.003
SOU	Southern Company	0.960
SPPN	Southwest Power Pool - North	0.997
SPPS	Southwest Power Pool - South	0.997
TVA	Tennessee Valley Authority	0.960
TVAK	Tennessee Valley Authority - MISO-KY	1.004
UPNY	Upstate New York	1.043
VACA	Virginia-Carolinas	0.960
VAPW	Dominion Virginia Power	0.960
WUMS	Wisconsin-Upper Michigan	1.004

4.4.5 Cost and Performance for Potential Renewable Generating and Non-Conventional Technologies

The renewable and non-conventional generating technologies included as potential units in the EPA Base Case v.4.10 are conventional biomass boilers, biomass gasification combined cycle (BGCC), onshore and offshore wind (shallow and deep), geothermal, fuel cells, solar photovoltaic, solar thermal, and landfill gas. Table 4-16 summarizes the cost and performance assumptions in EPA Base Case v.4.10 for these potential units. Except for biomass, the parameters shown in Table 4-16 are based on AEO 2009. The size (MW) presented in Table 4-16 represents the capacity on which unit cost estimates were developed and does not indicate the total potential capacity that the model can build of a given technology. Due to the distinctive nature of generation from renewable resources, some of the values shown in Table 4-16 are averages or ranges that are discussed in further detailed in the following subsections. Also discussed below are additional types of data from sources other than AEO 2009 that play a role in the representation of these types of generation in EPA Base Case v.4.10.

Table 4-16 Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in EPA Base Case v4.10

	Biomass Conventional Boiler[1]	Biomass Gasification Combined Cycle[1]	Fuel Cells	Geothermal	Landfill Gas			Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind
					LGHI	LGLo	LGVLo				
Size (MW)	35	120	10	50	30			5	100	50	50
First Year Available	2013	2019	2013	2014	2013			2012	2013	2013	2013
Lead Time (Years)	3	4	3	4	3			2	3	3	3
Vintage #1 (years covered)	2012 - 2054	2020 - 2054	2012 - 2054	2012 - 2054	2012 - 2019	2012 - 2019	2012 - 2019	2012 - 2019	2012 - 2019	2012 - 2019	2012 - 2019
Vintage #2 (years covered)					2020 - 2029	2020 - 2029	2020 - 2029	2020 - 2029	2020 - 2029	2020 - 2029	2020 - 2029
Vintage #3 (years covered)					2030 - 2054	2030 - 2054	2030 - 2054	2030 - 2054	2030 - 2054	2030 - 2054	2030 - 2054
Availability	85%	85%	87%	87%	90%			90%	90%	95%	95%
Generation Capability	Economic Dispatch							Generation Profile			
Vintage #1											
Heat Rate (Btu/kWh)	13,500	-	7,930	29,655 - 397,035	13,648	13,648	13,648	0	0	0	0
Capital (2007$/kW)[2]	4,698	-	6,259	1,624 - 20,674	2,596	3,270	5,035	5,765	5,156	1,954	3,852 - 5,085
Fixed O&M (2007$/kW/yr)	85.2	-	5.7	151 - 219	114.3	114.3	114.3	11.7	56.8	30.3	89.5
Variable O&M (2007$/MWh)	11.60	-	47.92	0.00	0.01	0.01	0.01	0	0	0.00	0.00
Vintage #2											
Heat Rate (Btu/kWh)	-	9,800	-	-	13,648	13,648	13,648	0	0	0	0
Capital (2007$/kW)[2]	-	4,071	-	-	2,505	3,156	4,859	5,350	4,641	1,912	3,621 - 4,780
Fixed O&M (2007$/kW/yr)	-	48.3	-	-	114.3	114.3	114.3	11.7	56.8	30.3	89.5
Variable O&M (2007$/MWh)	-	8.83	-	-	0.01	0.01	0.01	0	0	0.00	0.00
Vintage #3											
Heat Rate (Btu/kWh)	-	-	-	-	13,648	13,648	13,648	0	0	0	0
Capital (2007$/kW)[2]	-	-	-	-	2,019	2,544	3,916	3,777	4,383	1,580	2,809 - 3,708
Fixed O&M (2007$/kW/yr)	-	-	-	-	114.3	114.3	114.3	11.7	56.8	30.3	89.5
Variable O&M (2007$/MWh)	-	-	-	-	0.01	0.01	0.01	0	0	0.00	0.00

Note:
[1] The biomass generating technologies shown in this table represent new capacity designed to burn biomass only. Assumptions for biomass co-firing at existing coal plants can be found in Table 5-14.
[2]Capital cost represents overnight capital cost.

It should be noted that the short term capital cost adder in Table 4-14 and the regional cost adjustment factors in Table 4-15 apply to the renewable and non-conventional generation technologies as they did to the conventional generation technologies

Biomass Electricity Generation
Two biomass generation technologies with separate vintage periods are offered as new (potential) units in EPA Base Case v.4.10. Conventional direct fired biomass boilers are offered in vintage period 1, i.e., 2012-2019. Based on engineering and market analysis that indicated that biomass gas combined cycle (BGCC) units will become commercially available by 2020, BGCC with its much more favorable heat rate and cost characteristics is provided as a potential unit from 2020 onward. Prepared by EPA's power sector engineering staff, the cost and performance characteristics of these two technology options are shown in Table 4-16.

Wind Generation
Previous EPA base cases only represented onshore wind generation. In addition to onshore wind, EPA Base Case v.4.10 includes offshore-shallow and offshore-deep wind generation. The following sections describe four key aspects of the representation of wind generation: wind quality and resource potential, generation profiles, reserve margin contribution, and capital cost calculation.

Wind Quality and Resource Potential: Wind resources are conventionally categorized into wind quality classes, ranging from class 1 (designated to be the least productive and reliable class for wind generation) to class 7 (designated to be the most productive and reliable class for wind generation). Areas designated as wind class 3 or higher are generally suitable for commercial wind turbine applications. Whereas previous EPA base cases only included wind classes 4, 5, and 6, EPA Base Case v.4.10 also includes class 3 and 7.

EPA worked with the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), on a complete update of the wind resource assumptions for use in EPA Base Case v.4.10. The result is a complete representation of the potential onshore, offshore (shallow and deep) wind generating capacity (in MW) broken into four cost classes (described in greater detail below) in each IPM model region. Table 4-17, Table 4-18 , and Table 4-19 present the onshore, offshore shallow, and offshore deep wind resource assumptions that are used in EPA Base Case v.4.10.

Table 4-17 Onshore Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.4.10

IPM Region	Wind Class	Cost Class			
		1	2	3	4
AZNM	3	707	1,714	44	125,761
	4	42	329	27	33,741
	5	6	2,028	1,612	2,355
	6	214	447	264	512
	7	4	106	144	166
CA-N	3	1,269	--	--	8,646
	4	560	1,069	1,476	1,539
	5	79	631	746	765
	6	286	--	795	740
	7	12	352	--	399
CA-S	3	1,689	--	--	18,014
	4	1,323	1,460	1,402	2,536
	5	380	614	653	831
	6	118	--	435	540
	7	46	--	231	233
COMD	3	2	--	--	62,549
	4	19	260	--	312
DSNY	3	98	599	297	500
	4	64	--	--	268
	5	--	60	--	89
	6	--	--	30	29
	7	--	--	--	29
ENTG	3	1	1	--	2
	5	--	20	--	30
ERCT	3	3,230	--	1,198	321,950
	4	9,912	32,701	2,796	51,392
	5	396	1,415	899	1,484
	6	207	--	512	582
	7	5	--	--	20
GWAY	3	10	--	--	275,467
	4	--	621	580	922
LILC	3	--	--	872	567
	4	--	128	--	194
MACE	3	384	--	925	1,264
	4	9	--	--	163
	5	--	--	--	2
MACS	3	8	--	--	57
	4	2	5	--	10
	5	--	--	--	3
MACW	3	700	1,054	1,747	2,412
	4	182	--	636	477
	5	71	--	200	161
	6	--	26	--	46

IPM Region	Wind Class	Cost Class			
		1	2	3	4
MECS	3	3,571	--	--	35,633
	4	--	--	467	259
	5	--	11	--	12
MRO	3	17	--	--	2,021,548
	4	7	103	163,083	1,010,547
	5	2,052	22,146	68,431	156,014
	6	1,310	1,985	1,380	4,489
NENG	3	1,768	--	--	9,127
	4	737	1,128	--	1,968
	5	364	442	--	969
	6	28	356	471	438
	7	147	--	--	478
NWPE	3	1,913	--	--	630,559
	4	1,891	6,167	7,657	236,910
	5	353	1,058	3,600	50,582
	6	122	1,239	3,823	17,728
	7	205	1,517	755	1,755
PNW	3	216	902	354	74,323
	4	69	322	208	15,515
	5	11	86	122	3,483
	6	34	87	99	1,463
	7	18	116	79	190
RFCO	3	12,199	22,865	8,334	28,239
	4	--	--	--	64
RFCP	3	196	289	4,841	2,976
	4	82	354	--	466
	5	44	--	169	159
	6	41	--	148	96
	7	2	24	--	53
RMPA	3	1,327	--	--	409,831
	4	3,222	4,769	8,447	216,430
	5	2,546	7,038	15,851	58,990
	6	3,149	8,000	11,388	14,741
	7	619	6,188	2,151	6,748
SNV	3	--	--	--	2,707
	4	--	--	--	234
	5	9	--	--	39
	6	1	--	--	11
SOU	3	1	--	2	2
SPPN	3	1	--	--	454,442
	4	1,933	9,618	37,341	163,483
	5	--	--	--	839

IPM Region	Wind Class	Cost Class			
		1	2	3	4
SPPS	3	109	--	69	452,934
	4	2,945	11,388	44,398	349,741
	5	2,660	13,184	--	21,167
	6	3	105	111	170
	7	--	--	--	34
TVA	3	204	--	--	637
	4	--	121	166	155
	5	19	--	56	62
	6	3	--	19	16
	7	--	5	--	12
TVAK	3	4	--	--	220
	4	2	--	17	15
	5	--	--	--	5
	6	--	--	1	--
UPNY	3	--	2,822	3,346	3,675
	4	--	403	--	555
	5	--	95	--	114
	6	--	--	35	25
VACA	3	92	272	--	879
	4	33	60	--	124
	5	8	--	39	44
	6	4	--	30	27
	7	--	7	--	18
VAPW	3	--	261	--	352
	4	13	40	--	100
	5	5	--	34	35
	6	5	--	29	33
	7	--	11	--	17
WUMS	3	371	--	--	130,624
	4	57	49	64	84
	5	--	--	--	41

Table 4-18 Offshore Shallow Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.4.10

IPM Region	Wind Class	Cost Class		
		1	2	4
CA-N	3	497	995	995
	4	281	561	561
	5	43	86	86
	6	29	59	59
	7	1	3	3
CA-S	3	280	560	560
	4	139	277	277
	5	139	278	278
	6	114	228	228
	7	1	3	3
COMD	3	393	785	785
	4	981	1,963	1,963
DSNY	3	11	22	22
ENTG	3	43,021	86,041	86,041
	4	695	1,390	1,390
ERCT	3	14,372	28,745	28,745
	4	15,191	30,382	30,382
	5	4,457	8,915	8,915
FRCC	3	43,305	86,610	86,610
	4	6,120	12,240	12,240
LILC	3	693	1,385	1,385
	4	1,610	3,220	3,220
	5	1,851	3,703	3,703
	6	530	1,060	1,060
MACE	3	2,745	5,490	5,490
	4	8,161	16,323	16,323
	5	8,838	17,676	17,676
	6	5,123	10,246	10,246
MACS	3	1,066	2,132	2,132
	4	187	374	374
MACW	3	160	319	319
	4	136	271	271
	5	1,320	2,640	2,640
	6	5	11	11
MECS	3	2,349	4,699	4,699
	4	3,850	7,701	7,701
	5	5,451	10,903	10,903
	6	1,886	3,771	3,771
	7	6	13	13
MRO	3	399	798	798
	4	952	1,904	1,904
	5	348	696	696
	6	1	3	3

IPM Region	Wind Class	Cost Class		
		1	2	4
NENG	3	2,326	4,652	4,652
	4	3,134	6,269	6,269
	5	2,989	5,978	5,978
	6	6,157	12,314	12,314
	7	334	667	667
NYC	3	99	198	198
	4	253	506	506
	5	3	5	5
PNW	3	716	1,432	1,432
	4	1,651	3,303	3,303
	5	1,310	2,620	2,620
	6	204	407	407
	7	112	224	224
RFCO	3	686	1,371	1,371
	4	2,298	4,595	4,595
	5	5,664	11,328	11,328
	6	1,963	3,925	3,925
SOU	3	8,466	16,933	16,933
	4	4,903	9,806	9,806
	5	311	621	621
UPNY	3	884	1,768	1,768
	4	859	1,718	1,718
	5	659	1,318	1,318
VACA	3	6,229	12,458	12,458
	4	12,064	24,129	24,129
	5	13,709	27,418	27,418
	6	3,209	6,419	6,419
VAPW	3	1,990	3,981	3,981
	4	3,422	6,843	6,843
	5	3,886	7,772	7,772
	6	3,660	7,321	7,321
WUMS	3	2,272	4,544	4,544
	4	2,902	5,805	5,805
	5	1,832	3,664	3,664
	6	680	1,360	1,360

Table 4-19 Offshore Deep Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.4.10

IPM Region	Wind Class	Cost Class		
		1	2	4
CA-N	3	4,039	8,077	8,077
	4	25,846	51,693	51,693
	5	9,947	19,894	19,894
	6	21,282	42,565	42,565
	7	19,318	38,636	38,636
CA-S	3	10,721	21,441	21,441
	4	9,247	18,494	18,494
	5	14,402	28,805	28,805
	6	10,140	20,280	20,280
	7	169	339	339
COMD	4	1,028	2,055	2,055
	5	1,100	2,200	2,200
	6	950	1,900	1,900
ENTG	3	13,473	26,945	26,945
	4	10,730	21,461	21,461
ERCT	4	10,501	21,003	21,003
	5	6,548	13,096	13,096
FRCC	3	28,019	56,037	56,037
	4	53,858	107,715	107,715
	5	1,109	2,219	2,219
LILC	4	501	1,002	1,002
	5	431	861	861
	6	15,589	31,178	31,178
	7	5	10	10
MACE	3	11	22	22
	4	140	280	280
	5	1,049	2,099	2,099
	6	22,490	44,979	44,979
MACS	4	7	14	14
MACW	4	29	58	58
	5	557	1,114	1,114
MECS	3	220	439	439
	4	701	1,403	1,403
	5	7,710	15,420	15,420
	6	33,394	66,787	66,787
	7	45	90	90
MRO	3	354	707	707
	4	4,882	9,765	9,765
	5	3,283	6,566	6,566
	6	1,535	3,070	3,070
NENG	3	144	287	287
	4	1,754	3,508	3,508
	5	3,683	7,366	7,366
	6	59,338	118,676	118,676
	7	1,762	3,524	3,524

IPM Region	Wind Class	Cost Class		
		1	2	4
NYC	4	58	116	116
PNW	3	241	482	482
	4	813	1,625	1,625
	5	12,502	25,005	25,005
	6	34,795	69,589	69,589
	7	25,739	51,477	51,477
RFCO	4	9	19	19
	5	1,162	2,323	2,323
	6	507	1,014	1,014
SOU	3	8,765	17,529	17,529
	4	15,055	30,109	30,109
	5	2,169	4,339	4,339
UPNY	3	50	100	100
	4	1,506	3,011	3,011
	5	5,993	11,986	11,986
	6	465	930	930
VACA	4	2	3	3
	5	6,536	13,073	13,073
	6	23,687	47,373	47,373
VAPW	5	151	302	302
	6	16,150	32,300	32,300
WUMS	3	395	790	790
	4	3,533	7,066	7,066
	5	8,073	16,145	16,145
	6	39,059	78,119	78,119

Generation Profiles: Unlike other renewable generation technologies, which dispatch on an economic basis subject to their availability constraint, wind and solar technologies can only be dispatched when the wind blows and the sun shines. To represent intermittent renewable generating sources like wind and solar, EPA Base Case v.4.10 uses generation profiles which specify hourly generation patterns for a representative day in winter and summer. Each eligible model region is provided with a distinct set of winter and summer generation profiles for wind, solar thermal, and solar photovoltaic plants.

For Hour1 through Hour 24 the generation profile indicates the amount of generation (kWh) per MW of available capacity. The wind generation profiles were prepared with data from NREL. This provided the separate winter and summer generation profiles for wind classes 3-7 for onshore and offshore (shallow and deep) generation in each IPM region. (As an illustrative example Appendix 4-1 shows the generation profile for onshore wind in model region CA-N.) In IPM the seasonal average "kWh of generation per MW" (shown in the last row of the example in Appendix 4-1) is used to derive the generation from a particular wind class in a specific model region.

To obtain the seasonal generation for the units in a particular wind class in a specific region, one must multiply the installed capacity by the capacity factor (which represents the ratio of actual productivity in a time period to the theoretical maximum in the period). Capacity factor is the average "kWh of generation per MW" from the applicable generation profile multiplied by the number of days in the time period (i.e., summer or winter) to obtain the level of generation. The capacity factors for wind generation that are used in EPA Base Case v.4.10 were obtained from AEO 2010 and are shown in Table 4-20, Table 4-21, and. Table 4-22

Reserve Margin Contribution (also referred to as capacity credit): EPA Base Case v.4.10 uses reserve margins, discussed in detail in Section 3.6, to model reliability. Each region has a reserve margin requirement which is used to determine the total capacity needed to reliably meet peak demand. The ability of a unit to assist a region in meeting its reliability requirements is modeled through the unit's contribution to reserve margin. If the unit has 100 percent contribution towards reserve margin, then the entire capacity of the unit is counted towards meeting the region's reserve margin requirement. However, if any unit has less than a 100 percent contribution towards reserve margin, then only the designated share of the unit's capacity counts towards the reserve margin requirement.

All units except those that depend on intermittent resources have 100% contributions toward reserve margin. This means that all renewable resource technologies except wind and solar, have 100 percent contribution towards reserve margin in the EPA Base Case v.4.10. (Note Hydro, not considered a renewable technology, also has less than a 100% reserve margin contribution.)

Reserve margin contribution ratios are based on AEO 2010. Table 4-20, Table 4-21, and Table 4-22 present the reserve margin contributions apportioned to new wind plants in the EPA Base Case v.4.10 as derived from AEO 2010. The tables show the onshore and offshore (shallow and deep) reserve margins for each wind class in each model region.

Table 4-20 Onshore Reserve Margin Contribution an Average Capacity Factor by Wind Class and Model Region

IPM Model Region	Wind Class				
	3	4	5	6	7
AZNM	22%	24%	29%	34%	37%
CA-N	14%	16%	19%	22%	24%
CA-S	14%	16%	19%	22%	24%
COMD	18%	20%	--	--	--
DSNY	18%	20%	24%	28%	30%
ENTG	26%	--	35%	--	--
ERCT	19%	21%	25%	29%	32%
GWAY	18%	20%	--	--	--
LILC	18%	20%	--	--	--
MACE	18%	20%	24%	--	--
MACS	18%	20%	24%	--	--
MACW	18%	20%	24%	28%	--
MECS	22%	25%	30%	--	--
MRO	19%	21%	26%	30%	--
NENG	15%	16%	20%	23%	25%
NWPE	25%	28%	33%	39%	42%
PNW	25%	28%	33%	39%	42%
RFCO	22%	25%	--	--	--
RFCP	22%	25%	30%	35%	38%
RMPA	22%	24%	29%	34%	37%
SNV	22%	24%	29%	34%	--
SOU	26%	--	--	--	--
SPPN	24%	27%	33%	--	--
SPPS	24%	27%	33%	38%	42%
TVA	26%	29%	35%	41%	44%
TVAK	22%	25%	30%	35%	--
UPNY	18%	20%	24%	28%	--
VACA	26%	29%	35%	41%	44%
VAPW	26%	29%	35%	41%	44%
WUMS	18%	20%	24%	--	--
Average Annual Capacity Factor	29%	33%	39%	46%	50%

Table 4-21 Offshore Shallow Reserve Margin Contribution an Average Capacity Factor by Wind Class and Model Region

IPM Model Region	Wind Class				
	3	4	5	6	7
CA-N	15%	17%	20%	24%	25%
CA-S	15%	17%	20%	24%	25%
COMD	19%	21%	--	--	--
DSNY	19%	--	--	--	--
ENTG	27%	30%	--	--	--
ERCT	20%	22%	26%	--	--
FRCC	19%	21%	--	--	--
LILC	19%	21%	25%	29%	--

IPM Model Region	Wind Class				
	3	4	5	6	7
MACE	19%	21%	25%	30%	--
MACS	19%	21%	--	--	--
MACW	19%	21%	25%	30%	--
MECS	23%	26%	31%	37%	39%
MRO	20%	22%	27%	32%	--
NENG	15%	17%	21%	24%	26%
NYC	19%	21%	25%	--	--
PNW	26%	29%	35%	41%	44%
RFCO	23%	26%	31%	37%	--
SOU	27%	30%	36%	--	--
UPNY	19%	21%	25%	--	--
VACA	27%	30%	36%	43%	--
VAPW	27%	30%	36%	43%	--
WUMS	19%	21%	25%	30%	--
Average Annual Capacity Factor	31%	34%	41%	48%	52%

Table 4-22 Offshore Deep Reserve Margin Contribution an Average Capacity Factor by Wind Class and Model Region

IPM Model Region	Wind Class				
	3	4	5	6	7
CA-N	15%	17%	20%	24%	26%
CA-S	15%	17%	20%	24%	26%
COMD	--	21%	26%	30%	--
ENTG	27%	30%	--	--	--
ERCT	--	22%	26%	--	--
FRCC	18%	21%	25%	--	--
LILC	--	21%	25%	30%	32%
MACE	19%	21%	25%	30%	--
MACS	--	21%	--	--	--
MACW	--	21%	25%	--	--
MECS	23%	26%	31%	37%	40%
MRO	20%	23%	27%	32%	--
NENG	15%	17%	21%	24%	26%
NYC	--	21%	--	--	--
PNW	26%	29%	35%	41%	45%
RFCO	--	26%	31%	37%	--
SOU	27%	30%	36%	--	--
UPNY	19%	21%	25%	30%	--
VACA	--	30%	36%	43%	--
VAPW	--	--	36%	43%	--
WUMS	19%	21%	26%	30%	--
Average Annual Capacity Factor	31%	35%	41%	49%	53%

Capital cost calculation: EPA Base Case v.4.10 uses multipliers similar to the LT (long term) multipliers from the Energy Information Administration's NEMS model[25] to capture differences in the capital cost of new wind capacity caused by such factors as distance from existing transmission, terrain variability, slope and other causes of resource degradation, site accessibility challenges, population proximity, competing land uses, aesthetics, and environmental factors. Four cost classes are used in EPA Base Case v.4.10 with class 1 having the lowest cost adjustment factor (1) and class 4 having the highest adjustment factor (ranging from 2.48 to 2.67 depending on the model region and whether the wind resource is onshore, offshore shallow or offshore deep), as shown in Table 4-23. To the obtain the capital cost for a particular new wind model plant, the base capital costs shown in Table 4-16 are multiplied by the cost adjustment factor for the wind cost class applicable to the new plant.

Table 4-23 Capital Cost Adjustment Factors for New Wind Plants in Base Case v.4.10

	Cost Class			
	1	**2**	**3**	**4**
Onshore	1	1.2	1.5	2.5[1]
Offshore Deep Water	1	1.35	--	2.5
Offshore Shallow Water	1	1.35	--	2.5

Note:
[1]The Cost Adjustment Factor for Cost Class 4 Onshore is 2.5 for the majority of regions. Exceptions are as follows:
ERCT has a Cost Adjustment Factor for Cost Class 4 Onshore of 2.62
AZNM, RMPA, and SNV have a Cost Adjustment Factor for Cost Class 4 Onshore of 2.66
NWPE, PNW, SPPN, SPPS, and MRO have a Cost Adjustment Factor for Cost Class 4 Onshore of 2.67

Many factors figure in whether the model determines that adding wind capacity yields the greatest incremental improvement in the system-wide (least cost) solution available to the model at a particular point in the solution process. These factors include trade-offs between such items as the cost, capacity factor, reserve margin contribution, and dispatch capabilities and constraints on the new wind capacity relative to other choices. However, to perform its trade-off computations, the model requires the values described above.

As an illustrative example, Table 4-24 shows the calculations that would be performed to derive the potential electric generation, reserve margin contribution, and cost of new (potential) onshore capacity in wind class 7, cost class 2 in the CA-N model region in run year 2020.

[25]Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power, Report to EIA from Princeton Energy Resources International, LLC. May 2007.

Table 4-24 Example Calculations Of Wind Generation Potential, Reserve Margin Contribution, And Capital Cost For Onshore Wind In CA-N At Wind Class 7, Cost Class 2

Required Data

Table 4-17	Potential wind capacity (*C*) =	352 MW
Appendix 4-1	Winter average generation (G_W) per available MW per hour =	559 kWh/MW
Appendix 4-1	Summer average generation (G_S) per available MW per hour =	422 kWh/MW
	Hours in Winter (H_W) season (October – April) =	5,088 hours
	Hours in Summer (H_S)season (May – September) =	3,672 hours
Table 4-20	Reserve Margin Contribution (*RM*) CA-N, Wind Class 7 =	24 percent
Table 4-16	Capital Cost (Cap_{2020}) in vintage range for year 2020 =	$1,912/kW
Table 4-23	Capital Cost Adjustment Factor ($CAF_{ON,C2}$) for onshore cost class 2 =	1.2
Table 4-15	Regional Factor (RF)	1.058

Calculations

$$\begin{aligned} Generation\ Potential &= C \times G_W \times H_w + C \times G_S \times H_s \\ &= 352\,MW \times 559\,kWh/MW \times 5088\,hours + \\ &\quad 352\,MW \times 422\,kWh/MW \times 3672\,hours \\ &= 1{,}546\,GWh \end{aligned}$$

$$\begin{aligned} \text{Reserve Margin Contribution} &= RM \times C \\ &= 24\% \times 352\,MW \\ &= 84\,MW \end{aligned}$$

$$\begin{aligned} Capital\ Cost &= \text{Cap}_{2020} \times \text{CAF}_{\text{ON,C2}} \times RF \times C \\ &= \$1{,}912/\text{MW} \times 1.2 \times 1.058 \times 352\,MW \\ &= \$854\,million\ dollars \end{aligned}$$

Solar Generation

Solar Resource Potential: No explicit constraint limit is placed on solar electric capacity in EPA Base Case v.4.10. However, since solar thermal is only feasible in areas with sufficient direct isolation, EPA Base Case v.4.10 includes the assumption that new solar thermal plants can only be built west of the Mississippi River. Solar photovoltaic is not limited to specific parts of the country.

Generation profiles: Like wind, solar is an intermittent renewal technology. Since it can only be dispatched when the sun shines, not on a strictly economic basis, it is represented in EPA Base Case v.4.10 with generation profiles which specify hourly generation patterns for typical winter and summer days in each eligible region. The generation profiles were prepared with data from AEO 2010, which provided separate winter and summer generation profiles for solar thermal and photovoltaic in each eligible IPM region. As an illustrative example, Appendix 4-2 shows the solar thermal and solar photovoltaic winter and summer generation profiles in model region AZNM.

Reserve margin contribution: The procedure described above for calculating the reserve margin contributions for wind generation was also used for solar generation. Table 4-25 presents the winter and summer average capacity factors (CFs) and reserve margin contributions by model

region for new solar thermal and photovoltaic units in EPA Base Case v.4.10. The region-specific summer and winter capacity factors included in this table are metrics that provide a shorthand depiction of the hourly specific generation profiles for each region. They are based on AEO 2010 data. The assumptions in EPA Base Case v.4.10 for capacity factors and reserve margin contributions for existing units are also based on AEO 2010.

Table 4-25 Solar Reserve Margin Contribution and Average Capacity Factor by Model Region

Model Region	Solar Thermal			Solar Photovoltaic		
	Winter Average Capacity Factor	Summer Average Capacity Factor	Reserve Margin Contribution	Winter Average Capacity Factor	Summer Average Capacity Factor	Reserve Margin Contribution
AZNM	30%	42%	43%	25%	28%	28%
CA-N	32%	51%	53%	23%	28%	28%
CA-S	32%	51%	53%	23%	28%	28%
COMD				19%	23%	24%
DSNY				17%	22%	22%
ENTG				21%	23%	23%
ERCT	26%	35%	36%	22%	24%	25%
FRCC				23%	23%	23%
GWAY				19%	23%	24%
LILC				17%	22%	22%
MACE				18%	22%	23%
MACS				18%	22%	23%
MACW				18%	22%	23%
MECS				17%	23%	23%
MRO	18%	34%	36%	20%	23%	24%
NENG				19%	22%	23%
NWPE	23%	41%	18%	18%	25%	16%
NYC				17%	22%	22%
PNW	23%	41%	18%	18%	25%	16%
RFCO				17%	23%	23%
RFCP				17%	23%	23%
RMPA	30%	42%	43%	25%	28%	28%
SNV	30%	42%	43%	25%	28%	28%
SOU				21%	23%	23%
SPPN	22%	35%	37%	22%	24%	25%
SPPS	22%	35%	37%	22%	24%	25%
TVA				21%	23%	23%
TVAK				17%	23%	23%
UPNY				17%	22%	22%
VACA				21%	23%	23%
VAPW				21%	23%	23%
WUMS				19%	23%	24%

Geothermal Generation

Geothermal Resource Potential: Six model regions in EPA Base Case v.4.10 have geothermal potential. The potential capacity in each of these regions is shown in Table 4-26. The values are based on AEO 2010 data.

Table 4-26 Regional Assumptions on Potential Geothermal Electric Capacity

IPM Model Region	Capacity (MW)
AZNM	2,216
CA-N	662
CA-S	124
NWPE	4,555
PNW	1,336
RMPA	70
Grand Total	**8,963**

Note:
This data is a summary of the geothermal data used in EPA Base Case v.4.10

Cost Calculation: EPA Base Case v.4.10 does not contain a single capital cost, but multiple geographically-dependent capital costs for geothermal generation. The assumptions for geothermal were developed using AEO 2010 cost and performance estimates for 88 known sites. Both dual flash and binary cycle technologies[26] were represented. In EPA Base Case v.4.10 the 88 sites were collapsed into 26 different options based on geographic location and cost and performance characteristics of geothermal sites in each of the six eligible IPM regions where geothermal generation opportunities exist. Table 4-27 shows the potential geothermal capacity and cost characteristics for applicable model regions.

Table 4-27 Potential Geothermal Capacity and Cost Characteristics by Model Region

IPM Region	Capacity (MW)	Capital Cost (2007$)	FO&M (2007$/kW-yr)
AZNM	1,404	4,002	185.1
	196	4,675	206.8
	316	5,650	201.1
	294	7,744	192.2
	6	9,199	218.8
CA-N	575	1,624	185.1
	7	2,873	185.1
	80	4,214	206.2
CA-S	71	4,957	185.1
	48	5,679	185.1
	5	6,817	185.1

[26]In dual flash systems, high temperature water (above 400°F) is sprayed into a tank held at a much lower pressure than the fluid. This causes some of the fluid to "flash," i.e., rapidly vaporize to steam. The steam is used to drive a turbine, which, in turn, drives a generator. In the binary cycle technology, moderate temperature water (less than 400°F) vaporizes a secondary, working fluid which drives a turbine and generator. Due to its use of more plentiful, lower temperature geothermal fluids, these systems tend to be most cost effective and are expected to be the most prevalent future geothermal technology.

IPM Region	Capacity (MW)	Capital Cost (2007$)	FO&M (2007$/kW-yr)
NWPE	9	6,255	164.1
	24	8,337	164.1
	103	9,776	168.6
	1,165	11,465	179.6
	3,001	20,674	181.7
	137	4,523	185.1
	67	5,380	183.0
	12	3,428	218.8
	28	4,594	185.1
	9	8,210	185.1
PNW	268	3,890	151.5
	36	4,782	151.5
	420	5,211	156.3
	612	5,625	190.3
RMPA	70	5,820	185.1

Landfill Gas Electricity Generation

Landfill Gas Resource Potential: Estimates of potential electric capacity from landfill gas are based on the AEO 2010 inventory. EPA Base Case v.4.10 represents 3 categories of potential landfill gas units; “hi”, “low”, and “very low”. The categories refer to the amount and rate of methane production from the existing landfill site. Table 4-28 summarizes potential electric capacity from landfill gas used in EPA Base Case v.4.10.

There are several things to note about Table 4-28. Since the potential electric capacity from new landfill gas units is based on AEO 2009, the limits listed in Table 4-28 apply to the NEMS (National Energy Modeling System) regions indicated in column 1. In EPA Base Case v.4.10 the sum of the new landfill gas electric capacity in the corresponding IPM regions shown in column 2 cannot exceed the limits shown in columns 3-5. As noted earlier, the capacity limits for three categories of potential landfill gas units are distinguished in this table based on the rate of methane production at three categories of landfill sites: LGHI = high rate of landfill gas production, LGLo = low rate of landfill gas production, and LGLVo = very low rate of landfill gas production. The values shown in Table 4-28 represent an upper bound on the amount of new landfill capacity that can be added in each of the indicated model regions for each of the three landfill categories.

The cost and performance assumptions for adding new capacity in each of the three landfill categories are presented in Table 4-16.

Table 4-28 Regional Assumptions on Potential Electric Capacity from New Landfill Gas Units (MW)

NEMS Region	IPM Region	Class		
		LGHI	LGLo	LGLVo
ECAR	RFCO, MECS, RFCP, TVAK	72	30	539
ERCOT	ERCT	12	26	316
MAAC	MACE, MACS, MACW	93	22	311
MAIN	WUMS, COMD, GWAY	83	92	495
MAPP	MRO	43	22	150
NY	DSNY, LILC, NYC, UPNY	54	27	142
NE	NENG	62	6	51
FL	FRCC	14	26	158

NEMS Region	IPM Region	Class		
		LGHI	LGLo	LGLVo
STV	SOU, TVA, ENG, VACA, VAPW	68	22	447
SPP	SPPN, SPPS	5	-	185
NWP	PNW, NWPE	27	58	185
RA	AZNM, SNV, RMPA	-	-	91
CNV	NA-N, CA-S	131	250	749
US		664	581	3,819

4.5 Nuclear Units

4.5.1 Existing Nuclear Units

Population, Plant Location, and Unit Configuration: To provide maximum granularity in forecasting the behavior of existing nuclear units, all 105 nuclear units in EPA Base Case v.4.10 are represented by separate model plants. As noted in Table 4-7 the 105 nuclear units include 104 currently operating units plus Watts Bar Nuclear Plant, Unit 2, which is scheduled to come online in 2014. All are listed in Appendix 4-3. The population characteristics, plant location, and unit configuration data in NEEDS, v.4.10 were obtained primarily from EIA Form 860 and AEO 2010.

Capacity: Nuclear units are baseload power plants with high fixed (capital and fixed O&M) costs and low variable (fuel and variable O&M) costs. Due to their low VOM and fuel costs, nuclear units are run to the maximum extent possible, i.e., up to their availability. Consequently, a nuclear unit's capacity factor is equivalent to its availability. Thus, EPA Base Case v.4.10 uses capacity factor assumptions to define the upper bound on generation from nuclear units. Nuclear capacity factor assumptions in EPA Base Case v.4.10 are based on an Annual Energy Outlook projection algorithm. The nuclear capacity factor projection algorithm is described below:

- For each reactor, the capacity factor over time is dependent on the age of the reactor.
- Capacity factors increase initially due to learning, and decrease in the later years due to aging.
- For individual reactors, vintage classifications (older and newer) are used.
- For the older vintage (start before 1982) nuclear power plants, the performance peaks at 25 years:
  - Before 25 years: Performance increases by 0.5 percentage point per year;
  - 25-60 years: Performance remains flat; and
- • For the newer vintage (start in or after 1982) nuclear power plants, the performance peaks at 30 years:
  - Before 30 years: Performance increases by 0.7 percentage points per year;
  - 30-60 years: Performance remains flat; and
- The maximum capacity factor is assumed to be 90 percent. That is, any given reactor is not allowed to grow to a capacity factor higher than 90 percent. However, if a unit began with a capacity factor above 90 percent, it is allowed to retain that capacity factor. Given historical capacity factors above 90 percent, the projected capacity factors range from 89 percent to 93 percent.

Cost and Performance: Unlike non-nuclear existing conventional units discussed in section 4.2.7, emission rates are not needed for nuclear units, since there are no SO_2, NO_X, CO_2, or mercury emissions from nuclear units.

As with other generating resources, EPA Base Case v.4.10 uses variable operation and maintenance (VOM) costs and fixed operation and maintenance (FOM) costs to characterize the cost of operating nuclear units. The heat rate, FOM, and VOM values from AEO 2010, which were used to characterize the cost and performance of existing nuclear units in EPA Base Case v.4.10 are shown in Appendix 4-03.

EPA Base Case v.4.10 also uses the nuclear capacity uprates from AEO 2010. These are shown in Table 4-29.

4.5.2 Potential Nuclear Units

The cost and performance assumptions for nuclear potential units that the model has the option to build in EPA Base Case v.4.10 are shown in Table 4-13 above. The cost assumptions were updated as part of the comparative analysis performed by EPA's power sector engineering staff. That update is described above in section 4.4.1.

Table 4-29 Nuclear Upratings (MW) as Incorporated in EPA Base Case v.4.10 from AEO 2010

Name	Plant ID	Unit ID	Year	Change in MWs
Arkansas Nuclear One	8055	1	2016	50.0
Arkansas Nuclear One	8055	2	2016	59.0
Brunswick	6014	1	2014	56.3
Brunswick	6014	2	2014	56.2
Byron Generating Station	6023	1	2019	116.4
Byron Generating Station	6023	2	2019	11.4
Catawba	6036	1	2016	67.7
Catawba	6036	2	2016	67.7
Duane Arnold	1060	1	2015	34.8
Fermi	1729	2	2016	67.0
Grand Gulf	6072	1	2015	76.7
Harris	6015	1	2017	54.0
Joseph M Farley	6001	1	2017	51.0
Joseph M Farley	6001	2	2017	52.0
Limerick	6105	1	2018	113.4
Limerick	6105	2	2018	113.4
McGuire	6038	1	2014	110.0
McGuire	6038	2	2014	110.0
Oconee	3265	1	2017	51.0
Oconee	3265	2	2017	51.0
Oconee	3265	3	2017	51.0
Peach Bottom	3166	2	2014	66.7
Peach Bottom	3166	3	2014	66.7
Perry	6020	1	2016	74.0
PSEG Salem Generation	2410	1	2015	70.4
PSEG Salem Generation	2410	2	2015	67.8
Quad Cities Generation	880	1	2013	52.0
Quad Cities Generation	880	2	2013	52.0
Sequoyah	6152	1	2013	69.0
Sequoyah	6152	2	2013	68.0
South Texas Project	6251	1	2013	76.8
South Texas Project	6251	2	2013	76.8
Surry	3806	1	2015	47.9
Surry	3806	2	2015	47.9
V C Summer	6127	1	2015	58.0
Waterford 3	4270	3	2016	69.1
Wolf Creek Generation	210	1	2017	70.0
Watts Bar Nuclear Plant	7722	2	2014	1,180

Appendix 4-1 Representative Wind Generation Profiles in EPA Base Case v.4.10

Illustrative Hourly Wind Generation Profile (kWh of Generation per MW of Electricity)

Winter Hour	Wind Class				
	3	4	5	6	7
01	268	361	492	504	635
02	268	359	488	503	633
03	269	355	483	498	629
04	263	345	464	483	613
05	253	326	430	454	580
06	243	310	396	424	544
07	236	297	374	402	518
08	233	291	372	395	514
09	230	282	371	391	511
10	227	276	372	389	510
11	225	276	374	391	510
12	226	280	376	394	508
13	226	283	376	396	505
14	228	287	381	400	507
15	227	288	385	402	511
16	228	289	390	404	517
17	231	289	394	406	524
18	240	296	405	415	538
19	250	309	423	433	558
20	259	325	444	453	580
21	267	339	464	473	601
22	271	350	479	488	618
23	271	357	488	498	629
24	268	360	491	502	633
Winter Average	**246**	**314**	**421**	**437**	**559**

Summer Hour	Wind Class				
	3	4	5	6	7
01	380	410	456	591	555
02	374	402	444	583	546
03	366	391	422	566	523
04	350	368	387	535	479
05	326	334	337	489	413
06	299	295	286	433	344
07	282	261	250	389	295
08	292	256	248	384	293
09	320	270	269	408	316
10	348	296	298	442	348
11	368	320	320	466	368
12	381	340	331	480	373
13	388	354	334	484	370
14	393	365	341	489	372
15	393	372	350	496	383
16	390	371	361	501	398
17	384	358	369	501	414
18	377	340	371	496	421
19	375	331	378	496	431
20	374	335	386	500	440
21	378	354	402	518	464
22	382	381	424	546	498
23	384	401	444	572	529
24	382	409	455	586	547
Summer Average	**362**	**346**	**361**	**498**	**422**

Notes:

Based on Onshore Wind in Model Region CA-N.

This is an example of the wind data used in EPA Base Case v.4.10

Appendix 4-2 Representative Solar Generation Profiles in EPA Base v.4.10

Illustrative Hourly Solar Generation Profile (kWh of Generation per MW of Electricity)

Winter Hour	Solar Thermal	Solar Photovoltaic
01	3	0
02	3	0
03	3	0
04	3	0
05	3	0
06	181	29
07	181	29
08	601	660
09	601	660
10	601	660
11	601	660
12	601	660
13	601	660
14	601	660
15	601	660
16	601	660
17	601	660
18	601	660
19	181	29
20	181	29
21	181	29
22	181	29
23	181	29
24	181	29
Winter Average	**336**	**312**

Summer Hour	Solar Thermal	Solar Photovoltaic
01	9	0
02	9	0
03	9	0
04	9	0
05	9	0
06	284	13
07	284	13
08	720	610
09	720	610
10	720	610
11	720	610
12	720	610
13	720	610
14	720	610
15	720	610
16	720	610
17	720	610
18	720	610
19	284	13
20	284	13
21	284	13
22	284	13
23	284	13
24	284	13
Summer Average	**426**	**284**

Notes:

Based on model region AZNM.

This is an example of the solar data used in EPA Base Case v.4.10

Appendix 4-3 Characteristics of Existing Nuclear Units

Region	State	Plant Name	ORIS Code_Unit Id	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2007$ /kW-yr)	VOM (2007 mills/kWh)
AZNM	Arizona	Palo Verde	6008_1	1986	1,311	10,427	117.2	0.50
		Palo Verde	6008_2	1986	1,352	10,427	117.2	0.55
		Palo Verde	6008_3	1988	1,283	10,427	117.2	0.52
CA-N	California	Diablo Canyon	6099_1	1985	1,122	10,427	132.1	0.71
		Diablo Canyon	6099_2	1986	1,118	10,427	132.1	0.70
CA-S	California	San Onofre	360_2	1983	1,070	10,427	208.6	1.00
		San Onofre	360_3	1984	1,080	10,427	208.6	1.05
COMD	Illinois	Braidwood Generation Station	6022_1	1988	1,178	10,427	129.7	0.57
		Braidwood Generation Station	6022_2	1988	1,152	10,427	129.7	0.59
		Byron Generating Station	6023_1	1985	1,164	10,427	126.4	0.57
		Byron Generating Station	6023_2	1987	1,136	10,427	126.4	0.56
		LaSalle Generating Station	6026_1	1984	1,118	10,427	157.9	0.75
		LaSalle Generating Station	6026_2	1984	1,120	10,427	157.9	0.76
		Dresden Generating Station	869_2	1970	867	10,427	203.6	0.89
		Dresden Generating Station	869_3	1971	867	10,427	203.6	0.95
		Quad Cities Generating Station	880_1	1972	867	10,427	177.3	0.83
		Quad Cities Generating Station	880_2	1972	867	10,427	177.3	0.83
DSNY	New York	Indian Point 2	2497_2	1973	1,020	10,427	227.3	1.40
		Indian Point 3	8907_3	1976	1,025	10,427	199.2	0.96
ENTG	Arkansas	Arkansas Nuclear One	8055_1	1974	836	10,427	152.6	0.63
		Arkansas Nuclear One	8055_2	1980	988	10,427	152.6	0.65
	Louisiana	Waterford 3	4270_3	1985	1,152	10,427	162.7	0.61
		River Bend	6462_1	1986	967	10,427	193.7	1.03
	Mississippi	Grand Gulf	6072_1	1985	1,266	10,427	134.8	0.54

Region	State	Plant Name	ORIS Code_Unit Id	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2007$ /kW-yr)	VOM (2007 mills/kWh)
ERCT	Texas	Comanche Peak	6145_1	1990	1,202	10,240	120.0	0.61
		Comanche Peak	6145_2	1993	1,202	10,317	120.0	0.63
		South Texas Project	6251_1	1988	1,280	10,427	121.6	0.59
		South Texas Project	6251_2	1989	1,280	10,427	121.6	0.58
FRCC	Florida	St Lucie	6045_1	1976	839	10,427	142.3	0.64
		St Lucie	6045_2	1983	714	10,427	142.3	0.71
		Turkey Point	621_3	1972	693	10,427	146.8	0.67
		Turkey Point	621_4	1973	693	10,427	146.8	0.66
		Crystal River	628_3	1977	851	10,427	181.5	0.81
GWAY	Illinois	Clinton Power Station	204_1	1987	1,043	10,427	200.1	0.97
	Missouri	Callaway	6153_1	1984	1,190	10,427	139.7	0.74
MACE	New Jersey	PSEG Salem Generating Station	2410_1	1977	1,174	10,427	159.9	0.77
		PSEG Salem Generating Station	2410_2	1981	1,130	10,427	159.9	0.79
		Oyster Creek	2388_1	1969	619	10,427	255.1	1.17
		PSEG Hope Creek Generating Station	6118_1	1986	1,196	10,427	147.5	0.84
	Pennsylvania	Limerick	6105_1	1986	1,134	10,427	127.6	0.55
		Limerick	6105_2	1990	1,134	10,427	127.6	0.54
MACS	Maryland	Calvert Cliffs Nuclear Power Plant	6011_1	1975	885	10,427	155.2	0.75
		Calvert Cliffs Nuclear Power Plant	6011_2	1977	874	10,427	155.2	0.72
MACW	Pennsylvania	Peach Bottom	3166_2	1974	1,112	10,427	172.7	0.81
		Peach Bottom	3166_3	1974	1,112	10,427	172.7	0.80
		PPL Susquehanna	6103_1	1983	1,283	10,427	172.1	0.89
		PPL Susquehanna	6103_2	1985	1,288	10,427	172.1	0.88
		Three Mile Island	8011_1	1974	786	10,427	170.9	0.82
MECS	Michigan	Fermi	1729_2	1988	1,122	10,427	155.9	0.80
		Palisades	1715_1	1972	778	10,427	197.2	1.14

Region	State	Plant Name	ORIS Code_Unit Id	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2007$ /kW-yr)	VOM (2007 mills/kWh)
MRO	Iowa	Duane Arnold	1060_1	1975	581	10,427	208.4	1.11
	Minnesota	Monticello	1922_1	1971	646	10,427	187.8	1.02
		Prairie Island	1925_1	1974	551	10,427	162.3	0.82
		Prairie Island	1925_2	1974	545	10,427	162.3	0.83
	Nebraska	Fort Calhoun	2289_1	1973	478	10,427	219.4	1.19
		Cooper	8036_1	1974	767	10,427	223.6	1.29
NENG	Connecticut	Millstone	566_2	1975	882	10,427	205.4	1.10
		Millstone	566_3	1986	1,236	10,427	192.2	1.02
	Massachusetts	Pilgrim Nuclear Power Station	1590_1	1972	685	10,427	241.6	1.06
	New Hampshire	Seabrook	6115_1	1990	1,244	10,427	178.7	0.94
	Vermont	Vermont Yankee	3751_1	1972	620	10,427	203.8	1.06
PNW	Washington	Columbia Generating Station	371_2	1984	1,131	10,427	152.1	0.73
RFCO	Michigan	Donald C Cook	6000_1	1975	1,029	10,942	174.9	1.05
		Donald C Cook	6000_2	1978	1,077	10,848	174.9	1.08
	Ohio	Perry	6020_1	1987	1,231	11,000	160.1	0.80
		Davis Besse	6149_1	1977	887	11,000	158.1	0.90
RFCP	Pennsylvania	Beaver Valley	6040_1	1976	887	10,962	190.3	0.96
		Beaver Valley	6040_2	1987	887	10,946	190.3	0.90
SOU	Alabama	Joseph M Farley	6001_1	1977	851	11,794	138.5	0.71
		Joseph M Farley	6001_2	1981	860	11,650	138.5	0.68
	Georgia	Edwin I Hatch	6051_1	1975	876	10,427	146.9	0.77
		Edwin I Hatch	6051_2	1979	883	10,427	146.9	0.78
		Vogtle	649_1	1987	1,172	10,427	145.6	0.66
		Vogtle	649_2	1989	1,169	10,427	145.6	0.65
SPPN	Kansas	Wolf Creek Generating Station	210_1	1985	1,166	10,427	137.7	0.71

Region	State	Plant Name	ORIS Code_Unit Id	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2007$ /kW-yr)	VOM (2007 mills/kWh)
TVA	Alabama	Browns Ferry	46_1	1974	1,225	10,550	99.9	0.40
		Browns Ferry	46_2	1975	1,286	10,215	99.9	0.42
		Browns Ferry	46_3	1977	1,337	10,215	99.9	0.40
	Tennessee	Sequoyah	6152_1	1981	1,150	10,123	115.4	0.48
		Sequoyah	6152_2	1982	1,127	10,202	115.4	0.45
		Watts Bar Nuclear Plant	7722_1	1996	1,121	10,266	139.1	0.64
		Watts Bar Nuclear Plant	7722_2	2014	1,180	10,266	92.4	0.49
UPNY	New York	Nine Mile Point Nuclear Station	2589_1	1969	621	10,427	193.5	0.98
		Nine Mile Point Nuclear Station	2589_2	1969	1,311	10,427	188.9	0.97
		James A Fitzpatrick	6110_1	1976	852	10,427	203.0	0.90
		R. E. Ginna Nuclear Power Plant	6122_1	1970	498	10,427	205.8	0.92
VACA	North Carolina	Brunswick	6014_1	1977	938	10,318	110.6	0.46
		Brunswick	6014_2	1975	937	10,397	110.6	0.46
		Harris	6015_1	1987	900	10,982	131.3	0.60
		McGuire	6038_1	1981	1,100	10,427	119.6	0.48
		McGuire	6038_2	1984	1,100	10,427	119.6	0.50
	South Carolina	H B Robinson	3251_2	1971	710	10,697	119.8	0.59
		Oconee	3265_1	1973	846	10,427	139.6	0.73
		Oconee	3265_2	1974	846	10,427	139.6	0.65
		Oconee	3265_3	1974	846	10,427	139.6	0.72
		Catawba	6036_1	1985	1,129	10,427	134.0	0.64
		Catawba	6036_2	1986	1,129	10,427	134.0	0.64
		V C Summer	6127_1	1984	966	10,427	143.5	0.80
VAPW	Virginia	Surry	3806_1	1972	799	10,427	120.7	0.58
		Surry	3806_2	1973	799	10,427	120.7	0.57
		North Anna	6168_1	1978	940	10,427	98.7	0.47
		North Anna	6168_2	1980	925	10,427	98.7	0.50

Region	State	Plant Name	ORIS Code_Unit Id	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2007$ /kW-yr)	VOM (2007 mills/kWh)
WUMS	Wisconsin	Point Beach	4046_1	1970	599	10,427	202.3	0.97
		Point Beach	4046_2	1972	601	10,427	202.3	1.00
		Kewaunee	8024_1	1974	556	10,427	151.5	0.85

5 Emission Control Technologies

EPA Base Case v.4.10 includes a major update of emission control technology assumptions. For this base case EPA contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission controls. In addition to the work by Sargent and Lundy, Base Case v.4.10 includes two Activated Carbon Injections (ACI) options (Standard and Modified) for mercury (Hg) control[27]. Capture and storage options for carbon dioxide (CO_2) have also been added in the new base case.

These emission control options are listed in Table 5-1. They are available in EPA Base Case v.4.10 for meeting existing and potential federal, regional, and state emission limits. It is important to note that, besides the emission control options shown in Table 5-1 and described in this chapter, EPA Base Case v.4.10 offers other compliance options for meeting emission limits. These include fuel switching, adjustments in the dispatching of electric generating units, and the option to retire a unit.

Table 5-1 Summary of Emission Control Technology Retrofit Options in EPA Base Case v.4.10

SO_2 Control Technology Options	NO_X Control Technology Options	Hg Control Technology Options	CO_2 Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Standard Activated Carbon Injection (SPAC-ACI) System	CO_2 Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	Modified Activated Carbon Injection (MPAC-ACI) System	
	Combustion Controls	SO_2 and NO_X Control Technology Removal Cobenefits	

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 3lb 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 Casev.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

[27]The mercury emission controls options and assumptions in EPA Base Case v.4.10 do not reflect mercury control updates that are currently under way at EPA in support of the Utility MACT initiative and do not make use of data collected under EPA’s 2010 Information Collection Request (ICR).

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. 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.

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% for LSFO and 93% 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% with a floor of 0.06 lbs/MMBtu	93% with a floor of 0.065 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% for LSFO and 93% for LSD. In EPA Base Case v.4.10 the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO_2 Controls Costs

The Sargent and Lundy update of SO_2 and NO_x control costs is notable on several counts. First, it brought costs up to levels seen in the marketplace in 2009. Incorporating these costs into EPA's base case carries an implicit assumption, not universally accepted, that the run up in costs seen over the preceding 5 years and largely attributed to international competition, is permanent and will not settle back to pre-2009 levels. Second, a revised methodology, based on Sargent and Lundy's expert experience, was used to build up the capital, fixed and variable operating and maintenance components of cost. That methodology, which employed an engineering build up of each component of cost, is described here and in the following sections. Detailed example cost calculation spreadsheets for both SO_2 and NO_x controls are included in Appendices 5-1 and 5-2 respectively. The Sargent and Lundy reports in which these spreadsheets appeared can be downloaded via links to the Appendices 5-1A, 5-1B, 5-2A, and 5-2B links found at www.epa.gov/airmarkets/progsregs/epaipm/BaseCasev410.html.

Capital Costs: In building up capital costs three separate cost modules were included for LSD and four for LSFO: absorber island, reagent preparation, waste handling (LSFO only), and everything else (also called "balance of plant") with the latter constituting the largest cost module, consisting of fans, new wet chimney, piping, ductwork, minor waste water treatment, and other costs required for treatment. For each of the four modules the cost of foundations, buildings, electrical equipment, installation, minor, physical and chemical wastewater treatment, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. The major variables affecting capital cost are unit size and the SO_2 content of the fuel with the latter having the greatest impact on the reagent and waste handling facilities. In addition, heat rate affects the amount of flue gas produced and consequently the size of each of the modules. The quantity of flue gas is also a function of coal rank since different coals have different typical heating values.

Table 5-3 Capital Cost Modules and Their Governing Variables for SO_2 and NO_x Emission Controls

Module	Retrofit Difficulty (1 = average)	Coal Rank Factor (Bi_t = 1, PRB = 1.05, Lignite = 1.07)	Heat Rate (Btu/kWh)	SO_2 Rate (lb/MMBtu)	NO_x Rate (lb/MMBtu)[5]	Unit Size (MW)
SO_2 Emission Controls – Wet FGD and SDA FGD						
Absorber Island	X	X	X	X		X
Reagent Preparation	X		X	X		X
Waste Handling	X		X	X		X
Balance of Plant[1]	X	X	X			X
NO_x Emission Controls – SCR and SNCR						
SCR/SNCR Island[2]	X	X	X		X[3]	X
Reagent Preparation[3]					X	
Air Heater Modification[4]	X	X	X	X		X
Balance of Plant[5] – SCR	X	X	X			X
Balance of Plant[1] – SNCR					X	X

Notes:
[1]"Balance of plant" costs include such cost items as ID and booster fans, new wet chimneys, piping, ductwork, minor waste water treatment, auxiliary power modifications, and other electrical and site upgrades.
[2]The SCR island module includes the cost of inlet ductwork, reactor, and bypass. The SNCR island module includes cost of injectors, blowers, distributed control system (DCS), and reagent system.
[3]Only applies to SCR.
[4]On generating units that burn bituminous coal whose SO_2 and content exceeds 3 lbs/MMBtu, air heater modifications used to control SO_3 are needed in conjunction with the operation of SCR and SNCR.
[5]For SCR, the NO_x rate is frequently expressed through the calculated NO_x removal efficiency.

Once the key variables that figure in the cost of the four modules are identified, they are used to derive costs for each base module in equations developed by Sargent and Lundy based on their experience with multiple engineering projects. The base module costs are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction 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. The resulting sum is then increased by another 10% to build in an Allowance for Funds used During Construction (AFUDC) over the 3-year engineering and construction cycle. The resulting value, expressed in $/kW, is the capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): These are the costs incurred in running the emission control device. They are proportional to the electrical energy produced and are expressed in units of $ per MWh. For FGD, Sargent and Lundy identified four components of VOM: (a) costs for reagent usage, (b) costs for waste generation, (c) make up water costs, and (d) cost of additional power required to run the control (often called the "parasitic load"). For a given coal rank and a pre-specified SO_2 removal efficiency, each of these components of VOM cost is a function of the generating unit's heat rate (Btu/kWh) and the sulfur content (lb SO_2/MMBtu) of the coal (also referred to as the SO_2 feed rate). For purposes of modeling, the total VOM includes the first three of these component costs. 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. Due to the differences in the removal processes, the per MWh cost for waste handling, makeup water, and auxiliary power tend to be higher for LSFO while reagent usage cost and total VOM (excluding parasitic load) are higher for LSD.

Capacity and Heat Rate Penalty: The amount of electrical power required to operate the FGD device is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 1.6% of the unit's electrical generation is needed to operate the scrubber, the generating unit's capacity is reduced by 1.6%. 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 FGD device), the unit's heat rate is scaled up such that a comparable reduction (1.6% in the previous example) in the new higher heat rate yields the original heat rate[28]. 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). Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

Fixed Operating and Maintenance Costs (FOM): These are the annual costs of maintaining a unit. 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 and Lundy took into account labor and materials costs associated with operations, maintenance, and administrative functions. The following assumptions were made:

---

[28] Mathematically, the relationship of the heat rate and capacity penalties (both expressed as positive percentage values) can be represented as follows:

$$\text{Heat Rate Penalty} = \left(\frac{1}{\left(1 - \frac{\text{Capacity Penalty}}{100}\right)} - 1 \right) \times 100$$

- 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 and the type of FGD control. For LSFO 12 additional operators were assumed to be required for a 500 MW or smaller installation and 16 for a unit larger than 500 MW. For LSD 8 additional operators were assumed to be needed.
- FOM for maintenance is a direct function of the FGD capital cost
- FOM for administration is a function of the FOM for operations and maintenance.

Table 5-4 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalty for the two SO_2 emission control technologies (LSFO and LSD) included in EPA Base Case v.4.10 for an illustrative set of generating units with a representative range of capacities and heat rates.

Table 5-4 Illustrative Scrubber Costs (2007$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.4.10

Scrubber 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)
LSFO														
Minimum Cutoff: ≥ 25 MW	9,000	-1.5	1.53	1.66	747	22.5	547	10.5	473	7.8	430	7.2	388	5.9
Maximum Cutoff: None	10,000	-1.67	1.7	1.84	783	22.8	573	10.8	496	8.0	451	7.4	407	6.1
Assuming 3 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.84	1.87	2.03	817	23.2	598	11.0	517	8.2	470	7.6	425	6.3
LSD														
Minimum Cutoff: ≥ 25 MW	9,000	-1.18	1.2	2.13	641	16.4	469	8.1	406	6.1	385	5.3	385	4.9
Maximum Cutoff: None	10,000	-1.32	1.33	2.36	670	16.7	491	8.3	424	6.3	403	5.5	403	5.1
Assuming 2 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.45	1.47	2.60	698	17.0	511	8.5	442	6.5	420	5.7	420	5.2

5.2 Nitrogen Oxides Control Technology

The EPA Base Case v.4.10 includes two categories of NO_x reduction technologies: combustion and post-combustion controls. Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls operate downstream of the combustion process and remove NO_x emissions from the flue gas. All the specific combustion and post-combustion technologies included in EPA Base Case v.4.10 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The EPA Base Case v.4.10 representation of combustion controls uses equations that are tailored to the boiler type, coal type, and combustion controls already in place and allow appropriate additional combustion controls to be exogenously applied to generating units based on the NO_x emission limits they face. Characterizations of the emission reductions provided by combustion controls are presented in Table 3-1.3 in Appendix 3-1. The EPA Base Case v.4.10 cost assumptions for NO_x Combustion Controls are summarized in Table 5-5. Table 5-6 provides a mapping of existing coal unit configurations and incremental combustion controls applied in EPA Base Case v.4.10 to achieve state-of-the-art combustion control configuration.

Table 5-5 Cost (2007$) of NO_x Combustion Controls for Coal Boilers (300 MW Size)

Boiler Type	Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
Dry Bottom Wall-Fired	Low NO_x Burner without Overfire Air (LNB without OFA)	45	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	61	0.4	0.09
Tangentially-Fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	24	0.2	0.00
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	33	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	38	0.3	0.03
Vertically-Fired	NO_x Combustion Control	29	0.2	0.06

Scaling Factor

The following scaling factor is used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in MW) of the unit taking on combustion controls. No scaling factor is applied in calculating the variable operating and maintenance cost.

LNB without OFA & LNB with OFA = ($ for *X* MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.359}$

LNC1, LNC2 and LNC3 = ($ for *X* MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.359}$

Vertically-Fired = ($ for *X* MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.553}$

where

($ for 300 MW Unit) is the value obtained using the factors shown in the above table and *X* is the capacity (in MW) of the unit taking on combustion controls.

Table 5-6 Incremental Combustion NO_x Controls in EPA Base Case v.4.10

Boiler Type	Existing NO_x Combustion Control	Incremental Combustional Control
Cell	LNB	OFA
	NGR	LNB AND OFA
Cyclone	--	OFA
Stoker/SPR	--	OFA
Tangential	--	LNC3
	LA	LNC3
	LNB	CONVERSION FROM LNC1 TO LNC3
	LNB + OFA	CONVERSION FROM LNC1 TO LNC3
	LNC1	CONVERSION FROM LNC1 TO LNC3
	LNC2	CONVERSION FROM LNC2 TO LNC3
	OFA	LNC1
	ROFA	LNB
Vertical	--	NO_x Combustion Control - Vertically Fired Units
Wall	--	LNB AND OFA
	LA	LNB AND OFA
	LNB	OFA
	LNF	OFA
	OFA	LNB

5.2.2 Post-combustion Controls

The EPA Base Case v.4.10 includes two post-combustion retrofit control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.4.10 oil/gas steam units are eligible for SCR only. NO_x reduction in an SCR system takes place by injecting ammonia (NH_3) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N2) and water H_2O abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In SNCR a nitrogenous reducing agent (reagent), typically ammonia or urea, is injected into, and mixed with, hot flue gas where it reacts with the NO_x in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater NO_x reductions than SNCR. However, SCR costs are higher.

Table 5-7 summarizes the performance and applicability assumptions in EPA Base Case v.4.10 for each NO_x post-combustion control technology and provides a cross reference to information on cost assumptions.

Table 5-7 Summary of Retrofit NO_x Emission Control Performance Assumptions

Control Performance Assumptions	Selective Catalytic Reduction (SCR)		Selective Non-Catalytic Reduction (SNCR)
Unit Type	Coal	Oil/Gas	Coal
Percent Removal	90% down to 0.06 lb/MMBtu	80%	Pulverized Coal: 35% Fluidized Bed: 50%
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Units ≥ 25 MW
Costs (2007$)	See Table 5-8	See Table 5-9	See Table 5-8

Potential (new) coal-fired, combined cycle, and IGCC units are modeled to be constructed with SCR systems and designed to have emission rates ranging between 0.01 and 0.06 lb NO_x/MMBtu. EPA Base Case v.4.10 cost assumptions for these units include the cost of SCR

5.2.3 Methodology for Obtaining SCR Costs for Coal Units

As with the update of SO_2 control costs, Sargent and Lundy employed an engineering build-up of the capital, fixed and variable operating and maintenance components of cost to update post-combustion NO_x control costs. This section describes the approach used for SCR. The next section treats SNCR. Detailed example cost calculation spreadsheets for both technologies can be found in Appendix 5-2.

For cost calculation purposes the Sargent and Lundy methodology calculates plant specific NO_x removal efficiencies, i.e., the percent difference between the uncontrolled NO_x rate[29] for a model plant and the cost calculation floor NO_x rate corresponding to the predominant coal rank used at the plant (0.07 lb/MMBtu for bituminous and 0.05 lb/MMBtu for subbitumionus and lignite coals). For example, a plant that burns subbitumionus coal with an uncontrolled NO_x rate of 0.1667 lb/MMBtu, and a cost calculation floor NO_x rate of 0.05 lb/MMBtu would have a removal efficiency of 70%, i.e., (0.1667 – 0.05)/0.1667 = 0.1167/0.1667 = .70. The NO_x removal efficiency so obtained figures in the capital, VOM, and FOM components of SCR cost.

Capital Costs: In building up SCR capital costs, four separate cost modules were included: SCR island (e.g., inlet ductwork, reactor, and bypass), reagent preparation, air pre-heater modification, and balance of plan (e.g., ID or booster fans, piping, and auxiliary power modification). Air pre-heater modification cost only applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater, where SO_3 control is necessary. Otherwise, there is no air pre-heat cost. For each of the four modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. All four capital cost modules, except reagent preparation, are functions of retrofit difficulty, coal rank, heat rate, and unit size. NO_x rate (expressed via the NO_x removal efficiency) affects the SCR and reagent preparation cost modules. Not shown in Table 5-3, heat input (in Btu/hr) also impacts reagent preparation costs. As noted above, the SO_2 rate becomes a factor in SCR cost for plants that combust bituminous coal with 3 lbs SO_2/MMBtu or greater, where air pre-heater modifications are needed for SO_3 control.

As with FGD capital costs, the base module costs for SCR are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction 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. Whereas the resulting sum is then increased by another 10% for FGD, for SCR it is increased by 6% to factor in an Allowance for Funds used During Construction (AFUDC) over the 2-year engineering and construction cycle (in contrast to the 3-year cycle assumed for FGD). The resulting value, expressed in $/MW, is the capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): For SCR Sargent and Lundy identified four components of VOM: (a) costs for the urea reagent, (b) costs of catalyst replacement and disposal, (c) cost of required steam, and (d) cost of additional power required to run the control

[29] More precisely, the uncontrolled NO_X rate for a model plant in EPA Base Case v.4.10 is the capacity weighted average of the Mode 1 NO_X rates of the generating units comprising the model plant. The meaning of "Mode 1 NO_X rate" is discussed in section 3.9.2 and Appendix 3-1 ("NO_X Rate Development in EPA Base Case v.4.10).

(i.e., the "parasitic load"). As was the case for FGD, 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 earlier. Of the first three of these component costs, reagent cost and catalyst replacement are predominant while steam cost is much lower in magnitude. NO_x rates and heat rates are key determinates of reagent and steam costs, while NO_x rate (via removal efficiency), capacity factor, and coal rank are key drivers of catalyst replacement costs.

Capacity and Heat Rate Penalty:
Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

Fixed Operating and Maintenance Costs (FOM): For SCR the following assumptions were made:

- FOM for operations is based on the assumption that one additional operator working half-time is required.
- FOM for maintenance is assumed to $193,585 (in 2007$) for generating units less than 500 MW and $290,377 (in 2007$) for generating units 500 MW or greater
- There was assumed to be no FOM for administration for SCR.

Table 5-8 presents the SCR and SNCR capital, VOM, and FOM costs and capacity and heat rate penalties for an illustrative set of coal generating units with a representative range of capacities, heat rates, and NO_x removal efficiencies. The illustrations include and identify plants that do and do not burn bituminous coal with 3 lbs SO_2/MMBtu or greater.

Table 5-8 Illustrative Post Combustion NO_X Controls for Coal Plants Costs (2007$) for Representative Sizes and Heat Rates under the Assu Assumptions in EPA Base Case v.4.10

Control 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)
SCR Minimum Cutoff: ≥ 25 MW	9,000	-0.54	0.54	1.15	221	2.5	177	0.8	163	0.7	155	0.5	147	0.4
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.56	0.56	1.24	240	2.5	193	0.8	178	0.7	169	0.5	162	0.4
NO_x rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu	11,000	-0.58	0.59	1.33	258	2.5	209	0.8	193	0.7	184	0.5	176	0.4
SNCR - Non-FBC Minimum Cutoff: ≥ 25 MW	9,000			0.88	45	1	Size Not Modeled							
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	47	1								
NO_x rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu	11,000			1.08	48	1								
SNCR - Fluidized Bed Minimum Cutoff: ≥ 25 MW	9,000			0.88	34	0.9	18	0.4	14	0.2	11	0.2	9	0.1
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	35	0.9	19	0.4	14	0.2	12	0.2	10	0.1
NO_x rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu	11,000			1.08	36	0.9	19	0.4	14	0.2	12	0.2	10	0.1

Note:

If a coal plant burns bituminous coal with a SO_2 content above 3.0 lb/MMBtu then the capital costs will increase due to the required air preheater modification. For example, a 100 MW coal boiler with an SCR burning bituminous coal at a heat rate of 11,000 Btu/kWh and an SO_2 rate of 4.0 lb/MMBtu will have a capital cost of 296 $/kW, a 36 $/kW increase in capital costs from an identical boiler burning coal with an SO_2 rate of 2.0 lb/MMBtu.

5.2.4 Methodology for Obtaining SCR Costs for Oil/Gas Steam units

The cost calculations for SCR described in section 5.2.3 apply to coal units. For SCR on oil/gas steam units the cost calculation procedure employed in EPA's most recent previous base case was used. However, capital costs were scaled up by 2.13 to account for increases in the component costs that had occurred since the assumptions were incorporated in that base case. All costs were expressed in constant 2007$ for consistency with the dollar year cost basis used throughout EPA Base Case v4.10. Table 5-9 shows that resulting capital, FOM, and VOM cost assumptions for SCR on oil/gas steam units. The scaling factor for capital and fixed operating and maintenance costs, described in footnote 1, applies to all size units from 25 MW and up.

Table 5-9 Post-Combustion NO_X Controls for Oil/Gas Steam Units in EPA Base Case v.4.10

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	Percent Removal
SCR[1]	75	1.08	0.12	80%

Notes:

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

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

This data is used in the generation of EPA Base Case v.4.0

[1] SCR Cost Equations:

SCR Capital Cost and Fixed O&M: $(200/MW)^{0.35}$

The scaling factors shown above apply up to 500 MW. The cost obtained for a 500 MW unit applies for units larger than 500 MW.

Example for 275 MW unit:

SCR Capital Cost ($/kW) = $75 * (200/275)^{0.35} \approx 67$ $/kW

SCR FOM Cost ($/kW-yr) = $1.08 * (200/275)^{0.35} \approx 0.97$ $/kW-yr

SCR VOM Cost (mills/kWh) = 0.12 mills/kWh

Reference:

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

5.2.5 Methodology for Obtaining SNCR Costs

In the Sargent and Lundy cost update for SNCR a generic NO_X removal efficiency of 25% is assumed. However, the capital, fixed and variable operating and maintenance costs of SNCR on circulating fluidized bed (CFB) units are distinguished from the corresponding costs for other boiler types (e.g. cyclone, and wall fired).

Capital Costs: Due to the absence of a catalyst and, with it, the elimination of the need for more extensive reagent preparation, the Sargent and Lundy engineering build up of SNCR capital costs includes three rather than four separate cost modules: SNCR (injectors, blowers, distributive control system, reagent system), air pre-heater modification, and balance of plan (e.g., ID or booster fans, piping, and auxiliary power modification). For CFB units, the SNCR and balance of plan module costs are 75% of what they are on other boiler types. The air pre-heater modification cost module is the same as for SCR and there is no cost difference between CFB and other boiler types. As with SCR the air heater modification cost only applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater, where SO_3 control is necessary. Otherwise, there is no air pre-heat cost. For each of the three modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. Unit size affects all three modules. Retrofit difficulty, coal rank, and heat rate impact the SNCR and air heater modification modules. The SO_2 rate impacts the air pre-heater modification module. NO_X rate

(expressed via the NO_X removal efficiency) and heat input (not shown in Table 5-3) affect the balance of plan module.

The base module costs for SNCR are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction 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 SNCR projects are typically completed in less than a year, there is no Allowance for Funds used During Construction (AFUDC) in the SNCR capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): Sargent and Lundy identified two components of VOM for SNCR: (a) cost for the urea reagent and (b) the cost of dilution water. The magnitude of the reagent cost predominates the VOM with the cost of dilution water at times near zero. There is no capacity or heat rate penalty associated with SNCR since the only impact on power are compressed air or blower required for urea injection and the reagent supply system.

Capacity and Heat Rate Penalty:
Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SNCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

Fixed Operating and Maintenance Costs (FOM): The assumptions for FOM for operations and for administration are the same for SNCR as for SCR, i.e.,

- FOM for operations is based on the assumption that one additional operator working half-time is required.
- There was assumed to be no FOM for administration for SCR.

FOM for maintenance materials and labor was assumed to be a direct function of base module cost, specifically, 1.2% of those costs divided by the capacity of the generating unit expressed in kilowatts.

Detailed example cost calculation spreadsheets for SNCR can be found in Appendix 5-2.

5.2.6 SO_2 and NO_x Controls for Units with Capacities from 25 MW to 100 MW (25 M ≤ capacity < 100 MW)

In EPA Base Case v.4.10 coal units with capacities between 25 MW and 100 MW are offered the same SO_2 and NO_x emission control options as larger units. However, for purposes of modeling, the costs of controls for these units are assumed to be equivalent to that of a 100 MW unit. This assumption is based on several considerations. First, to achieve economies of scale, several units in this size range are likely to be ducted to share a single common control, so the 100 MW cost equivalency assumption, though generic, would be technically plausible. Second, single units in this size range that are not grouped to achieve economies of scale are likely to have the option of hybrid multi-pollutant controls currently under development.[30] These hybrid controls achieve cost economies by combining SO_2, NO_X and particulate controls into a single control unit. Singly, the costs of the individual control would be higher for units below 100 MW than for a 100 MW unit,

[30] See, for example, the Greenidge Multi-Pollutant Control Project, which was part of the U.S. Department of Energy, National Energy Technology Lab's Power Plant Improvement Initiative. A joint effort of CONSOL Energy Inc. AES Greenidge LLC, and Babcock Power Environmental, Inc., information on the project can be found at *www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/bib_greenidge.html*.

but when combined in the Multi-Pollutant Technologies (MPTs) their costs would be roughly equivalent to the cost of individual controls on a 100 MW unit. While MPTs are not explicitly represented in EPA Base Case v.4.10, single units in the 25-100 MW range that take on combinations of SO_2 and NO_X controls in a model run can be thought of as being retrofit with an MPT.

Illustrative scrubber, SCR, and SNCR costs for 25-100 MW coal units with a range heats rates can be found by referring to the 100 MW "Capital Costs ($/kW)" and "Fixed O&M" columns in Table 5-4 and Table 5-8. The Variable O&M cost component, which applies to units regardless of size, can be found in the fifth column in these tables.

5.3 Biomass Co-firing

Under most climate policies currently being discussed, biomass is treated as "carbon neutral," i.e., a zero contributor of CO_2 to the atmosphere. The reasoning is that the CO_2 emitted in the combustion of biomass will be reabsorbed via photosynthesis in plants grown to replace the biomass that was combusted. Consequently, if a power plant can co-fire biomass and thereby replace a portion of fossil fuel, it reduces its CO_2 emissions by approximately the same proportion, although combustion efficiency losses may somewhat diminish the proportion of CO_2 reduction. Roughly speaking, by co-firing enough biomass to produce 10% of a coal plant's power output, a co-fired plant can realize close to an effective 10% reduction in CO_2 emitted.

Biomass co-firing is provided as a fuel choice for all coal-fired power plants in EPA Base Case v.4.10. However, logistics and boiler engineering considerations place limits on the extent of biomass that can be fired. The logistic considerations arise because it is only economic to transport biomass a limited distance from where it is grown. In addition, the extent of storage that can be devoted at a power plant to this relatively low density fuel is another limiting factor. Boiler efficiency and other engineering considerations, largely due to the relatively higher moisture content and lower heat content of biomass compared to fossil fuel, also plays a role in limiting the level of co-firing.

In EPA Base Case v.4.10 the limit on biomass co-firing is expressed as the percentage of the facility level power output that is produced from biomass. Based on analysis by EPA's power sector engineering staff, a maximum of 10% of the facility level power output (not to exceed 50 MW) can be fired by biomass. In EPA Base Case v.4.10 "facility level" is defined as the set of generating units which share the same ORIS code[31] in NEEDS v.4.10.

The capital and FOM costs associated with biomass co-firing are summarized in Table 5-10. Developed by EPA's power sector engineering staff[32], they are on the same cost basis as the

---

[31] The ORIS plant locator code is a unique identifying number (originally assigned by the Office of Regulatory Information Systems from which the acronym derived). The ORIS code is given to power plants by EIA and remains unchanged under ownership changes.

[32] Among the studies consulted in developing these costs were:

(a) Briggs, J. and J. M. Adams, *Biomass Combustion Options for Steam Generation*, Presented at Power-Gen 97, Dallas, TX, December 9 – 11, 1997.
(b) Grusha, J and S. Woldehanna, K. McCarthy, and G. Heinz, *Long Term Results from the First US Low NOx Conversion of a Tangential Lignite Fired Unit*, presented at 24th International Technical Conference on Coal & Fuel Systems, Clearwater, FL., March 8 – 11, 1999.

(c) EPRI, *Biomass Cofiring: Field Test Results: Summary of Results of the Bailly and Seward Demonstrations*, Palo Alto, CA, supported by U.S. Department of Energy Division of Energy Efficiency and Renewable Energy, Washington D.C.; U.S. Department of Energy Division Federal Energy Technology Center, Pittsburgh PA; Northern Indiana Public Service Company, Merrillville, IN; and GPU Generation, Inc., Johnstown, PA: 1999. TR-113903.
(d) Laux S., J. Grusha, and D. Tillman, Co-firing of Biomass and Opportunity Fuels in Low NOx

costs shown in Table 4-16 which resulted from EPA's comparative analysis of electricity sector costs as described in Chapter 4.

Table 5-10 Biomass Cofiring for Coal Plants

Size of Biomass Unit (MW)	5	10	15	20	25	30	35	40	45	50
Capital Cost (2007$/kW From Biomass)	488	411	371	345	327	312	300	290	282	275
Fixed O&M (2007$/kW-yr)	24.2	16.2	11.7	9.4	8.0	11.1	9.9	8.9	8.1	7.5

The capital and FOM costs were implemented by ICF in EPA Base Case v.4.10 as a $/MMBtu biomass fuel cost adder. The procedure followed to implement this was first to represent the discrete costs shown in Table 5-10 as continuous exponential cost functions showing the FOM and capital costs for all size coal generating units between 0 and 50 MW in size. Then, for every coal generating unit represented in EPA Base Case 4.10, the annual payment to capital for the biomass co-firing capability was derived by multiplying the total capital cost obtained from the capital cost exponential function by an 11% capital charge rate. (This is the capital charge rate for environmental retrofits found in Table 8-1 and discussed in Chapter 8.) The resulting value was added to the annual FOM cost obtained from the FOM exponential function to obtain the total annual cost for the biomass co-firing for each generating unit.

Then, the annual amount of fuel (in MMBtus) required for each generating unit was derived by multiplying the size of a unit (in MW) by its heat rate (in Btu/kWh) by its capacity factor (in percent) by 8,760 hours (i.e., the number of hours in a year). Dividing the resulting value by 1000 yielded the annual fuel required by the generating unit in MMBtus. Dividing this number into the previously calculated total annual cost for biomass co-firing resulted in the cost of biomass co-firing per MMBtu of biomass combusted. This was represented in IPM as a fuel cost adder incurred when a coal units co-fires biomass.

5.4 Mercury Control Technologies

As previously noted, the mercury emission controls options and assumptions in EPA Base Case v.4.10 do not reflect mercury control updates that are currently under way at EPA in support of the Utility MACT initiative and do not make use of data collected under EPA's 2010 Information Collection Request (ICR). The following discussion is based on EPA's earlier work on mercury controls.

For any power plant, mercury emissions depend on the mercury content of the fuel used, the combustion and physical characteristics of the unit, and the emission control technologies deployed. In the absence of emission policies that would require the installation of mercury emission controls, mercury emission reductions below the mercury content of the fuel are strictly due to characteristics of the combustion process and incidental removal resulting from non-mercury control technologies, i.e., the SO_2, NO_X, and particulate controls. While the base case itself does not include any federal mercury control policies, it does include some State mercury reduction requirements. IPM has the capability to model mercury controls that might be installed in response to such State mercury control policies. These same controls come into play in model runs that analyze possible federal mercury policies relative to the base case. The technology specifically designated for mercury control in such policy runs is Activated Carbon Injection (ACI) downstream of the combustion process.

Burners, PowerGen 2000 - Orlando, FL, www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.
Tillman, D. A., *Cofiring Biomass for Greenhouse Gas Mitigation*, presented at Power-Gen 99, New Orleans, LA, November 30 – December 1, 1999.
(e) Tillman, D. A. and P. Hus, *Blending Opportunity Fuels with Coal for Efficiency and Environmental Benefit*, presented at 25th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 6 – 9, 2000

The following discussion is divided into three parts. Sections 5.4.1 and 5.4.2 treat the two factors that figure into the unregulated mercury emissions resulting under EPA Base Case v.4.10. Section 5.4.1 discusses how mercury content of fuel is modeled in EPA Base Case v.4.10. Section 5.4.2 looks at the procedure used in the base case to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.4.3 explains the mercury emission control options that are available under EPA Base Case v.4.10. A major focus is on the cost and performance features of Activated Carbon Injection. Each section indicates the data sources and methodology used.

5.4.1 Mercury Content of Fuels

Coal: The assumptions in EPA Base Case v.4.10 on the mercury content of coal (and the majority of emission modification factors discussed below in Section 5.4.2) are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR).[33] A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit . . . with a capacity greater than 25 megawatts electric [MWe]), as well as accurate information on the total amount of coal burned by each such unit," and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations.

The ICR second component resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content and other characteristics of coal burned at coal-fired utility units greater than 25 MW. To make this data usable in EPA Base Case v.4.10, these data points were first grouped by IPM coal types and IPM coal supply regions. (IPM coal types divide bituminous, sub-bituminous, and lignite coal into different grades based on sulfur content. See Table 5-11.) Next, a clustering analysis was performed on the data using the SAS statistical software package. Clustering analysis places objects into groups or clusters, such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. First, the number of clusters of mercury concentrations for each IPM coal type was determined based on the range of mercury and SO_2 concentrations for that coal type. Each coal type used one, two or three clusters. To the greatest extent possible the total number of clusters for each coal type was limited to keep the model size and run time within feasible limits. Second, the clustering procedure was used to group each coal type within each IPM coal supply region into the previously determined number of clusters and show the resulting mercury concentration for each cluster. The average of each cluster is the mercury content of coal finally used in EPA Base Case v.4.10 for estimating mercury emissions. IPM input files retain the mapping between different coal type-supply region combinations and the mercury clusters. Table 5-11 below provides a summary by coal type of the number of clusters and their mercury concentrations.

[33]Data from the ICR can be found at http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html.

Table 5-11 Mercury Clusters and Mercury Content of Coal by IPM Coal Types

Coal Type by Sulfur Grade	Mercury Emission Factors by Coal Sulfur Grades (lbs/TBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Easter Bituminous (BA)	3.19	4.37	--
Low Sulfur Western Bituminous (BB)	1.82	4.86	--
Low Medium Sulfur Bituminous (BD)	5.38	8.94	21.67
Medium Sulfur Bituminous (BE)	19.53	8.42	--
High Sulfur Bituminous (BG)	7.10	20.04	14.31
High Sulfur Bituminous (BH)	7.38	13.93	34.71
Low Sulfur Subbituminous (SA)	4.24	5.61	--
Low Sulfur Subbituminous (SB)	6.44	--	--
Low Medium Sulfur Subbituminous (SD)	4.43	--	--
Low Medium Sulfur Lignite (LD)	7.51	12.00	--
Medium Sulfur Lignite (LE)	13.55	7.81	--
High Sulfur Lignite (LG)	14.88	--	--

Oil, natural gas, and waste fuels: The EPA Base Case v.4.10 also includes assumptions on the mercury content for oil, gas and waste fuels, which were based on data derived from previous EPA analysis of mercury emissions from power plants.[34] Table 5-12 provides a summary of the assumptions on the mercury content for oil, gas and waste fuels included in EPA Base Case v.4.10.

Table 5-12 Assumptions on Mercury Concentration in Non-Coal Fuel in EPA Base Case v.4.10

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00[1]
Petroleum Coke	23.18
Biomass	0.57
Municipal Solid Waste	71.85
Geothermal Resource	2.97 - 3.7

Note:
[1]The values appearing in this table are rounded to two decimal places. The zero value shown for natural gas is based on an EPA study that found a mercury content of 0.00014 lbs/TBtu. Values for geothermal resources represent a range.

5.4.2 Mercury Emission Modification Factors

Emission Modification Factors (EMFs) represent the mercury reductions attributable to the specific burner type and configuration of SO_2, NO_X, and particulate matter control devices at an electric generating unit. An EMF is the ratio of outlet mercury concentration to inlet mercury concentration, and depends on the unit's burner type, particulate control device, post-combustion NO_X control and SO_2 scrubber control. In other words, the mercury reduction achieved (relative to

[34]"Analysis of Emission Reduction Options for the Electric Power Industry," Office of Air and Radiation, US EPA, March 1999.

the inlet) during combustion and flue-gas treatment process is (1-EMF). The EMF varies by the type of coal (bituminous, sub-bituminous, and lignite) used during the combustion process.

Deriving EMFs involves obtaining mercury inlet data by coal sampling and mercury emission data by stack testing at a representation set of coal units. As noted above, EPA's EMFs were initially based on 1999 mercury ICR emission test data. More recent testing conducted by the EPA, DOE, and industry participants[35] has provided a better understanding of mercury emissions from electric generating units and mercury capture in pollution control devices. Overall the 1999 ICR data revealed higher levels of mercury capture for bituminous coal-fired plants than for subbitumionus and lignite coal-fired plants, and significant capture of ionic Hg in wet-FGD scrubbers. Additional mercury testing indicates that for bituminous coals, SCR systems have the ability to convert elemental Hg into ionic Hg and thus allow easier capture in a downstream wet-FGD scrubber. This improved understanding of mercury capture with SCRs was incorporated in EPA Base Case v.4.10 mercury EMFs for unit configurations with SCR and wet scrubbers.

Table 5-13 below provides a summary of EMFs used in EPA Base Case v.4.10. Table 5-14 provides definitions of acronyms for existing controls that appear in Table 5-13. Table 5-15 provides a key to the burner type designations appearing in Table 5-13.

5.4.3 Mercury Control Capabilities

EPA Base Case v.4.10 offers two options for meeting mercury reduction requirements: (1) combinations of SO_2, NO_X, and particulate controls which deliver mercury reductions as a co-benefit and (2) Activated Carbon Injection (ACI), a retrofit option specifically designed for mercury control. These two options are discussed below.

[35] For a detailed summary of emissions test data see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, February 2005. This report can be found at www.epa.gov/ttnatw01/utility/hgwhitepaperfinal.pdf .

Table 5-13 Mercury Emission Modification Factors Used in EPA Base Case v.4.10

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Cyclone	Cold Side ESP	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.58
Cyclone	Fabric Filter	SNCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	None	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	None	0.11	0.27	1
Cyclone	Hot Side ESP	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	SCR	None	0.9	1	1
Cyclone	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP	SCR	Dry FGD	0.9	1	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Cyclone	Hot Side ESP	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	None	None	0.9	1	1
Cyclone	Hot Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Hot Side ESP + FGC	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP + FGC	SCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	None	0.9	1	1
Cyclone	No Control	SNCR	None	1	1	1
Cyclone	No Control	SNCR	Wet FGD	0.45	0.6	1
Cyclone	No Control	SNCR	Dry FGD	1	1	1
Cyclone	No Control	SCR	None	1	1	1
Cyclone	No Control	SCR	Wet FGD	0.1	0.7	1
Cyclone	No Control	SCR	Dry FGD	1	1	1
Cyclone	No Control	None	Wet FGD	0.45	0.6	1
Cyclone	No Control	None	Dry FGD	1	1	1
Cyclone	No Control	None	None	1	1	1
Cyclone	PM Scrubber	None	None	0.8	1	1
FBC	Cold Side ESP	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP + FGC	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP + FGC	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Wet FGD	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	SCR	None	0.05	0.43	0.43

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
FBC	Fabric Filter	SCR	Wet FGD	0.05	0.27	0.43
FBC	Fabric Filter	SCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	Wet FGD	0.1	0.43	0.43
FBC	Fabric Filter	None	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	None	0.05	0.43	0.43
FBC	Hot Side ESP	SNCR	None	1	1	1
FBC	Hot Side ESP	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	None	1	1	1
FBC	No Control	SNCR	None	1	1	1
FBC	No Control	SNCR	Wet FGD	1	1	1
FBC	No Control	SNCR	Dry FGD	0.45	0.45	1
FBC	No Control	SCR	None	1	1	1
FBC	No Control	SCR	Wet FGD	0.1	0.7	1
FBC	No Control	SCR	Dry FGD	0.45	0.45	1
FBC	No Control	None	Wet FGD	1	1	1
FBC	No Control	None	Dry FGD	0.45	0.45	1
FBC	No Control	None	None	1	1	1
PC	Cold Side ESP	SNCR	None	0.64	0.97	1
PC	Cold Side ESP	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	SCR	None	0.64	0.97	1
PC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	None	None	0.64	0.97	1
PC	Cold Side ESP + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	None	None	0.2	0.75	1
PC	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
PC	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	None	None	0.64	0.97	1
PC	Cold Side ESP + FGC + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	None	None	0.2	0.75	1
PC	Fabric Filter	SNCR	None	0.11	0.27	1
PC	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
PC	Fabric Filter	SNCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	SCR	None	0.11	0.27	1
PC	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	None	Dry FGD	0.05	0.75	1
PC	Fabric Filter	None	None	0.11	0.27	1
PC	Hot Side ESP	SNCR	None	0.9	0.9	1
PC	Hot Side ESP	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP	SNCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	SCR	None	0.9	0.9	1
PC	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	None	None	0.9	0.94	1
PC	Hot Side ESP + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	None	None	0.11	0.27	1
PC	Hot Side ESP + FGC	SNCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP + FGC	SNCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	SCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP + FGC	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	None	None	0.9	0.94	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
PC	Hot Side ESP + FGC + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
PC	No Control	SNCR	None	1	1	1
PC	No Control	SNCR	Wet FGD	0.58	0.7	1
PC	No Control	SNCR	Dry FGD	0.6	0.85	1
PC	No Control	SCR	None	1	1	1
PC	No Control	SCR	Wet FGD	0.1	0.7	1
PC	No Control	SCR	Dry FGD	0.6	0.85	1
PC	No Control	None	Wet FGD	0.58	0.7	1
PC	No Control	None	Dry FGD	0.6	0.85	1
PC	No Control	None	None	1	1	1
PC	PM Scrubber	SNCR	None	0.9	0.91	1
PC	PM Scrubber	SCR	None	0.9	1	1
PC	PM Scrubber	None	None	0.9	0.91	1
Stoker	Cold Side ESP	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP + FGC	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP + FGC	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP + FGC	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	None	0.65	0.97	1
Stoker	Fabric Filter	SNCR	None	0.11	0.27	1
Stoker	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Stoker	Fabric Filter	SNCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	SCR	None	0.11	0.27	1
Stoker	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	SCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	None	Dry FGD	0.1	0.75	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Stoker	Fabric Filter	None	None	0.11	0.27	1
Stoker	Hot Side ESP	SNCR	None	1	1	1
Stoker	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	SCR	None	1	1	1
Stoker	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	None	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	SCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	None	1	1	1
Stoker	No Control	SNCR	None	1	1	1
Stoker	No Control	SNCR	Wet FGD	0.58	1	1
Stoker	No Control	SNCR	Dry FGD	1	1	1
Stoker	No Control	SCR	None	1	1	1
Stoker	No Control	SCR	Wet FGD	0.1	0.7	1
Stoker	No Control	SCR	Dry FGD	1	1	1
Stoker	No Control	None	Wet FGD	0.58	1	1
Stoker	No Control	None	Dry FGD	1	1	1
Stoker	No Control	None	None	1	1	1
Stoker	PM Scrubber	None	None	1	1	1
Other	Cold Side ESP	SNCR	None	0.64	0.97	1
Other	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	SCR	None	0.64	0.97	1
Other	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	None	0.64	0.97	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Other	Fabric Filter	SNCR	None	0.45	0.75	1
Other	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Other	Fabric Filter	SNCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	SCR	None	0.11	0.27	1
Other	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	SCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	None	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	None	0.11	0.27	1
Other	Hot Side ESP	SNCR	None	1	1	1
Other	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP	SCR	None	1	1	1
Other	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP	SCR	Dry FGD	1	1	1
Other	Hot Side ESP	None	Wet FGD	0.58	1	1
Other	Hot Side ESP	None	Dry FGD	1	1	1
Other	Hot Side ESP	None	None	1	1	1
Other	Hot Side ESP + FF	None	None	0.11	0.27	1
Other	Hot Side ESP + FGC	SNCR	None	1	1	1
Other	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	SCR	None	1	1	1
Other	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	None	1	1	1
Other	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
Other	No Control	SNCR	None	1	1	1
Other	No Control	SNCR	Wet FGD	0.58	0.7	1
Other	No Control	SNCR	Dry FGD	1	1	1
Other	No Control	SCR	None	1	1	1
Other	No Control	SCR	Wet FGD	0.1	0.7	1
Other	No Control	SCR	Dry FGD	1	1	1
Other	No Control	None	Wet FGD	0.58	0.7	1
Other	No Control	None	Dry FGD	1	1	1
Other	No Control	None	None	1	1	1
Other	PM Scrubber	None	None	0.9	0.91	1

Table 5-14 Definition of Acronyms for Existing Controls

Acronym	Description
ESP	Electro Static Precipitator - Cold Side
HESP	Electro Static Precipitator - Hot Side
ESP/O	Electro Static Precipitator - Other
FF	Fabric Filter
FGD	Flue Gas Desulfurization - Wet
DS	Flue Gas Desulfurization - Dry
SCR	Selective Catalytic Reduction
PMSCRUB	Particulate Matter Scrubber

Table 5-15 Key to Burner Type Designations in Table 5-13

"PC" refers to conventional pulverized coal boilers. Typical configurations include wall-fired and tangentially fired boilers (also called T-fired boilers). In wall-fired boilers the burner's coal and air nozzles are mounted on a single wall or opposing walls. In tangentially fired boilers the burner's coal and air nozzles are mounted in each corner of the boiler.

"Cyclone" refers to cyclone boilers where air and crushed coal are injected tangentially into the boiler through a "cyclone burner" and "cyclone barrel" which create a swirling motion allowing smaller coal particles to be burned in suspension and larger coal particles to be captured on the cyclone barrel wall where they are burned in molten slag.

"Stoker" refers to stoker boilers where lump coal is fed continuously onto a moving grate or chain which moves the coal into the combustion zone in which air is drawn through the grate and ignition takes place. The carbon gradually burns off, leaving ash which drops off at the end into a receptacle, from which it is removed for disposal.

"FBC" refers to "fluidized bed combustion" where solid fuels are suspended on upward-blowing jets of air, resulting in a turbulent mixing of gas and solids and a tumbling action which provides especially effective chemical reactions and heat transfer during the combustion process.

"Other" refers to miscellaneous burner types including cell burners and arch- , roof- , and vertically-fired burner configurations.

Mercury Control through SO_2 and NO_X Retrofits
In EPA Base Case v.4.10, units that install SO_2, NO_X, and particulate controls, reduce mercury emissions as a byproduct of these retrofits. Section 5.4.2 described how EMFs are used in the base case to capture the unregulated mercury emissions depending on the rank of coal burned, the generating unit's combustion characteristics, and the specific configuration of SO_2, NO_X, and particulate controls (i.e., hot and cold-side electrostatic precipitators (ESPs), fabric filters (also called "baghouses") and particulate matter (PM) scrubbers). These same EMFs would be available in mercury policy runs to characterize the mercury reductions that can be achieved by retrofitting a unit with SCR, SNCR, SO_2 scrubbers and particulate controls. The absence of a federal mercury emission reduction policy means that these controls appear in the base case in response to SO_2, NO_X, or particulate limits or state-level mercury emission requirements. However, in future model runs where mercury limits are present these same SO_2 and NO_X controls could be deliberately installed for mercury control if they provide the least cost option for meeting mercury policy limits.

Activated Carbon Injection (ACI)
The technology specifically designated for mercury control is Activated Carbon Injection (ACI) downstream of the combustion process in coal fired units. A comprehensive ACI update, which will incorporate the latest field experience through 2010, is being prepared by Sargent and Lundy (the same engineering firm that developed the SO_2 and NO_X control assumptions used in EPA Base Case v.4.10). It will be incorporated in a future EPA base case. The ACI assumptions in the current base case release are the result of a 2007 internal EPA engineering study.

Based on this study, it is assume that 90% removal from the level of mercury in the coal is achievable with the application of one of three alternative ACI configurations: Standard Powered Activated Carbon (SPAC), Modified Powered Activated Carbon (MPAC), or SPAC in combination with a fabric filter. The MPAC option exploits the discovery that by converting elemental mercury to oxidized mercury, halogens (like chlorine, iodine, and bromine) can make activated carbon more effective in capturing the mercury at the high temperatures found in industrial processes like power generation. In the MPAC system, a small amount of bromine is chemically bonded to the powdered carbon which is then injected into the flue gas stream either upstream of both the particulate control device (ESP or fabric filter) and the air pre-heater (APH), between the APH and the particulate control device, or downstream of both the pre-existing APH and particulate control devices but ahead of a new dedicated pulsed-jet fabric filter. (The latter is known as the TOXECON™ approach, an air pollution control process patented by EPRI.)

Table 5-16 presents the capital, FOM, and VOM costs as well as the capacity and heat rate penalty for the five Hg emission control technologies included in EPA Base Case v.4.10 for an illustrative set of generating units with a representative range of capacities.

Table 5-16 Illustrative Activated Carbon Injection Costs (2007$) for Representative Sizes under the Assumptions in EPA Base Case v.4.10

Control Type	Capacity Penalty (%)	Heat Rate Penalty (%)	Capacity (MW)											
			100			300			500			700		
			Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M cost (mills/kWh)
MPAC_Baghouse Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	3	0.1	0.16	2	0.05	0.17	2	0.04	0.17	2	0.03	0.16
MPAC_CESP Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	8	0.1	0.57	6	0.1	0.61	5	0.1	0.61	5	0.1	0.59
SPAC_Baghouse Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	5	0.1	0.22	4	0.1	0.23	3	0.1	0.23	3	0.1	0.23
SPAC_ESP Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	27	0.5	2.29	21	0.3	2.46	18	0.3	2.44	17	0.3	2.39
SPAC_ESP+Toxecon Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	269	4.3	2.44	202	2.5	2.61	176	2.1	2.59	161	2.0	2.54

The applicable ACI option depends on the coal type burned, its SO_2 content, the boiler and particulate control type and, in some instances, consideration of whether an SO_2 scrubber (FGD) system or SCR NO_x post-combustion control are present. Table 5-17 shows the ACI assignment scheme used in EPA Base Case v.4.10 to achieve 90% mercury removal.

Table 5-17 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Base Case v.4.10

Applicability of Activated Carbon Injection

Coal Type	SO_2 in Coal (lb/MMBtu)	Boiler Type	Particulate Control Type	FGD System	SCR System	Toxecon Required?	ACI Type With 90% Hg Reduction
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	CS-ESP or BH (no FGC)	--	No	No	MPAC
Bit/Sub-bit/ Lig	--	Non-CFB	CS-ESP or BH (no FGC)	LSD	--	No	MPAC
Bit/Sub-bit/Lig	--	CFB	CS-ESP or BH (no FGC)	--	--	No	MPAC
Bit	< 1.6	Non-CFB	CS-ESP	Non-LSD	Yes	No	SPAC
Bit	≥ 1.6	Non-CFB	CS-ESP or BH	--	--	No	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	CS-ESP	--	--	Yes	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	BH	--	--	No	SPAC
Bit/Sub-bit/ Lig	--	Non-CFB	HESP	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	--	--	HESP or CS-ESP (with FGC)	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	BH	No	Yes	No	MPAC
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	CS-ESP (no FGC)	No	Yes	No	MPAC
Bit/Sub-bit/ Lig	--	--	No Control	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	< 1.6	--	BH	Non-LSD	Yes	No	SPAC
Sub-bit/ Lig	< 1.6	--	CS-ESP (no FGC)	Non-LSD	Yes	Yes	SPAC
Bit/Sub-bit/Lig	--	--	Cyclone	--	--	Yes	SPAC

Notes:

Legends:

ACI	Activated carbon injection
BH	Baghouse
Bit	Bituminous coal
CFB	Circulating fluidized-bed boiler
CS-ESP	Cold side electrostatic precipitator
FGC	Flue gas conditioning
HESP	Hot electrostatic precipitator
Lig	Lignite
MPAC	Modified powdered activated carbon
SPAC	Standard powdered activated carbon
Sub-bit	Subbituminous coal

If the existing equipment provides 90% Hg removal, no ACI system is required.

"--" means that the category type has no effect on the ACI application.

Appendix 5-1 Example Cost Calculation Worksheets for SO_2 Control Technologies in EPA Base Case v.4.10

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

Wet FGD Cost Development Methodology – Final

Table 3. Example Complete Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater then 100 MW)
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)	3	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.911*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	16	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		**Example**		**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty				
BMR ($) =	550000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$	46,024,000	Base absorber island cost
BMF ($) =	190000*(B)*((D*G)^0.3)*(A^0.716)	$	22,267,000	Base reagent preparation cost
BMW ($) =	100000*(B)*((D*G)^0.45)*(A^0.716)	$	13,713,000	Base waste handling cost
BMB ($) =	1010000*(B)*((F*G)^0.4)*(A^0.716)	$	84,698,000	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc...
BMWW ($) =		$	-	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$	166,702,000	Total base cost including retrofit factor
BM ($/KW) =			333	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	16,670,000	Engineering and Construction Management costs
A2 = 10% of BM		$	16,670,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$	16,670,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**216,712,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**433**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	10,836,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**227,548,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**455**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	22,755,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**250,303,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**601**	Total project cost per kW

Wet FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
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)	3	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (if MW>500 then 16 additional operators else 12 operators)*2080*T/(A*1000)	$	3.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.00	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.15	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =	$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**8.15**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	0.37	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	$	1.36	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.08	Variable O&M costs for makeup water
VOMWW ($/MWh) =	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**$**	**1.81**	

Table 3. Example Complete Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		**Example**		**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$	20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$	47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc...
BM ($) =	BMR + BMF + BMW + BMB	$	102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =			341	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$	10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

Appendix 5-2 Example Cost Calculation Worksheets for NO_x Post-Combustion Control Technologies in EPA Base Case v.4.10

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

SCR Cost Development Methodology – Final

Table 1. Example of the Capital Cost Estimate Work Sheet.

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9880	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.21	<--- User Input
SO2 Rate	E	(lb/MMBtu)	1.71	
Type of Coal	F		PRB	<--- User Input
Coal Factor	G		1.05	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.988	C/10000
Heat Input	I	(Btu/hr)	5.93E+09	A*C*1000
Capacity Factor	J	(%)	85	<--- User Input
Nox Removal Efficiency	K	%	70	
Nox Removal Factor	L		0.875	I/J
Nox Removed	M	lb/h	8.71E+02	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost 50% wt solution	R	($/ton)	310	
Catalyst Cost	S	($/m3)	8000	
Aux Power Cost	T	($/kWh)	0.06	
Steam Cost	U	($/klb)	4	
Operating Labor Rate	V	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.				
BMR ($) =	180000*(B)*(L)^0.2*(A*G*H)^0.92	$	65,199,000	SCR (Inlet Ductwork, Reactor, Bypass) Island Cost
BMF ($) =	410000*(M)^0.25	$	2,228,000	Base Reagent Preparation Cost
BMA ($) =	IF E ≥ 3 THEN 65000*(B)*(A*G*H)^0.78; ELSE 0	$	-	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB ($) =	380000*(B)*(A*G*H)^0.42	$	5,666,000	ID or booster fans & Auxiliary Power Modification Costs
BM ($) =	BMR + BMF + BMA + BMB	$	73,093,000	Total bare module cost including retrofit factor
BM ($/KW) =			122	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	7,309,000	Engineering and Construction Management costs
A2 = 10% of BM		$	7,309,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	7,309,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		$	95,020,000	Capital, engineering and construciton cost subtotal
CECC ($/kW) =			158	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	4,751,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1		$	5,986,000	AFUDC (Based on approximately 3% per year for a 2 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		$	105,757,000	Total project cost
TPC ($/kW) =			176	Total project cost per kW

SCR Cost Development Methodology – Final

Table 2. Example of the Fixed and Variable O&M Estimate Work Sheet.

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9880	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.21	<--- User Input
SO2 Rate	E	(lb/MMBtu)	1.71	
Type of Coal	F		PRB	<--- User Input
Coal Factor	G		1.05	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.988	C/10000
Heat Input	I	(Btu/hr)	5.93E+09	A*C*1000
Capacity Factor	J	(%)	85	<--- User Input
Nox Removal Efficiency	K	%	70	
Nox Removal Factor	L		0.875	I/J
Nox Removed	M	lb/h	8.71E+02	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost 50% wt solution	R	($/ton)	310	
Catalyst Cost	S	($/m3)	8000	
Aux Power Cost	T	($/kWh)	0.06	
Steam Cost	U	($/klb)	4	
Operating Labor Rate	V	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080**V/(A*1000)	$	0.10	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = IF A < 500 then $200,00 ELSE $300,000	$	0.50	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.60**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = N*R/A/1000	$	0.31	Variable O&M costs for Urea
VOMW ($/MWh) = discrete function of A, G, J, K, S	$	0.35	Variable O&M costs for catalyst: replacement & disposal
VOMM ($/MWh) = O*U/A/1000	$	0.01	Variable O&M costs for steam
VOM ($/MWh) = VOMR + VOMW + VOMM	**$**	**0.66**	

SNCR Cost Development Methodology – Final

Table 1. Example of the Capital Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.65E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	717	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.26; ELSE UF = 0.15
Water Required	M	(lb/hr)	6457	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMS ($) =	B*F/1.05*200000*(A*G)^0.42	$	2,090,000	SNCR (Injectors, Blowers, DCS, Reagent System) Cost
BMA ($) =	IF E ≥ 3 THEN 65000*(B)*(A*G)^0.78; ELSE 0	$	-	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB ($) =	270000*(A)^0.33*(K)^0.12	$	3,273,000	Balance of Plant Cost (Piping, Including Site Upgrades)
BM ($) =	BMS + BMA + BMB	$	5,363,000	Total bare module cost including retrofit factor
BM ($/KW) =			18	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	536,000	Engineering and Construction Management costs
A2 = 10% of BM		$	536,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	536,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		$	6,971,000	Capital, engineering and construciton cost subtotal
CECC ($/kW) =			23	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	349,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC ($) = CECC + B1		$	7,320,000	Total project cost
TPC ($/kW) =			24	Total project cost per kW

Table 2. Example of the Fixed and Variable O&M Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<— User Input
Unit Size	A	(MW)	300	<— User Input
Retrofit Factor	B		1	<— User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<— User Input
NOx Rate	D	(lb/MMBtu)	0.22	<— User Input
SO2 Rate	E	(lb/MMBtu)	2	
Type of Coal	E		Bituminous	<— User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<— User Input
Nox Removal Efficiency	J	%	25	
Nox Removed	K	lb/h	1.65E+02	D*H/10^6*J/100
Urea Rate (100%)	L	(lb/hr)	717	K/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	M	(lb/hr)	6457	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	($/ton)	310	
Aux Power Cost	Q	($/kWh)	0.06	
Dilution Water Cost	R	($/kgal)	1	
Operating Labor Rate	S	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000)	$	0.21	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = 0.012*BM/A/1000	$	0.21	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.42**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = L*P/A/1000	$	0.74	Variable O&M costs for Urea
VOMM ($/MWh) = O*R/A	$	0.00	Variable O&M costs for dilution water
VOM ($/MWh) = VOMR + VOMM	**$**	**0.74**	

6 CO_2 Capture, Transport, and Storage

6.1 CO_2 Capture

Among the potential (new) units that the model can build in EPA Base Case v.4.10 are advanced coal-fired units with CO_2 capture (carbon capture).[1] The cost and performance characteristics of these units are shown in Table 4-13 and are discussed in Chapter 4.

Besides offering carbon capture capabilities on potential units that the model builds from scratch, EPA Base Case v.4.10 also provides carbon capture as a retrofit option for existing pulverized coal plants. The incremental costs and performance assumptions for these retrofits are shown in Table 6-1.

Table 6-1 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Pulverized Coal Plants

Applicability (Original MW Size)	450-750 MW	> 750 MW
Incremental[1] Capital Cost (2007 $/kW)	1,972	1,599
Incremental[1] FOM (2007 $/kW-yr)	3.00	1.98
Incremental[1] VOM (2007 (mills/kWh)	2.35	2.35
Capacity Penalty (%)	-25%	-25%
Heat Rate Penalty (%)	33%	33%
CO_2 Removal (%)	90%	90%

Note:
[1]Incremental costs are applied to the derated (after retrofit) MW size.

The capital costs shown in Table 6-1 are based on the costs reported for Case 1 in a study[2] performed for the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) by a team consisting of Alstom Power, Inc., American Electric Power (AEP), ABB Global, and the Ohio Coal Development Office. For Case 1 this comprehensive engineering study, conducted from 1999-2001, evaluated the impacts on plant performance and the required cost to add facilities to capture greater than 90% of the CO_2 emitted by AEP's Conesville Ohio Unit #5. This is a 450 MW subcritical[3] pulverized bituminous coal plant with a lime based FGD, and an electrostatic precipitator for particulate control. The carbon capture method that was evaluated was an amine-based scrubber using the Kerr-McGee/ABB Lummus Global commercially available monoethanolamine (MEA) process. In this system the flue gas leaves the FGD (which has been modified to reduce the SO_2 concentration as required by the MEA process) and is cooled and ducted to the MEA system where more than 96% of the CO_2 can be removed. For use in EPA Base Case v.4.10 the capital cost was scaled to be applicable to the MW capacity sizes shown in Table 6-1 and converted to constant 2007$ from the 2006$ costs reported in the NETL study.

---

[1]The term "New Advanced Coal with CCS" encompasses various technologies that can provide carbon capture. These include supercritical steam generators with carbon capture and integrated gasification combined cycle (IGCC) with carbon capture. For purposes of characterizing the cost and performance characteristics of advanced coal with carbon capture, IGCC with carbon capture was used in Table 4-13.

[2]"Carbon Dioxide Capture from Existing Coal-Fired Power Plants" DOE/NETL-401/110907. Final Report (Original Issue Date, December 2006) Revision Date, November 2007 (http://www.netl.doe.gov/energy-analyses/pubs/CO2%20Retrofit%20From%20Existing%20Plants%20Revised%20November%2007.pdf. A summary of costs for each of the cases appears in Table 3-65 (p. 139).

[3]"Subcritical" refers to thermal power plants that operate below the "critical temperature" and "critical pressure" (220 bar) where boiling, i.e., the formation of steam bubbles in water, no longer occurs. Such units are less efficient than "supercritical" and "ultra supercritical" steam generators.

A capacity derating penalty of 25% was assumed, based on reported research and field experience as of the summer of 2010. The corresponding heat rate penalty was 33%. (For an explanation of the capacity and heat rate penalties and how they are calculated, see the discussion under VOM in section 5.1.1.)

Since the fixed (FOM) and variable operating and maintenance (VOM) costs from the Conesville study were given without documentation, another NETL study[4] which fully documented these costs was used to obtain the FOM and VOM values shown in Table 6-1. For FOM and VOM, the cost differential was calculated between Case 9, a 550 MW subcritical pulverized coal plant with CO_2 capture, and Case 10, a comparable unit but without CO_2 capture. These differentials provided the VOM and FOM costs for the "450-750 MW" case in Table 6-1. For the "greater than 750 MW" case these costs were scaled up by the ratio of a unit with an effective capacity of 750 MW to the effective capacity of the 450-750 MW case raised to a power (k), where k reflects the elasticity of the costs due to economies of scale. (The same approach was used to scale the capital costs.) For capital, FOM, and VOM, the value of k was 0.65, 0.30, and 1 respectively.

6.2 CO_2 Storage

The capacity and cost assumptions for CO_2 storage in EPA Base Case v.4.10 are based on GeoCAT (Geosequestration Cost Analysis Tool), a spreadsheet model developed for EPA by ICF International in support of EPA's draft Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Storage Wells.[5] The GeoCAT model combines detailed characteristics of sequestration capacity by state and geologic setting for the U.S. with costing algorithms for individual components of geologic sequestration of CO_2. The outputs of the model are regional sequestration cost curves that indicate how much potential storage capacity is available at different CO_2 storage cost points.

The GeoCAT model includes three modules: a unit cost specification module, a project scenario costing module, and a geologic and regional cost curve module. The unit cost module includes data and assumptions for 120 unit cost elements falling within the following cost categories:

- Geologic Site Characterization
- Monitoring the movement of CO_2 in the subsurface
- Injection Well Construction
- Area of Review and Corrective Action (including fluid flow and reservoir modeling during and after injection and identification, evaluation, and remediation of existing wells within the area of review)
- Well Operation
- Mechanical Integrity Testing
- Financial Responsibility (to maintain sufficient resources for activities related to closing and remediation of the site)
- General and Administrative

---

[4]"Cost and Performance Baseline for Fossil Energy Plants" DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report (Original Issue Date, May 2007) Revision 1, August 2007 (http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf). The VOM and FOM cost calculations for Case 9 appear in Exhibits 4-14 (p. 349) and for Case 10 in Exhibit 4-24 (p. 373).

[5]"Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells," *Federal Register*, July 25, 2008 (Volume 73, Number 144), pp. 43491-43541. www.epa.gov/fedrgstr/EPA-WATER/2008/July/Day-25/w16626.htm and www.epa.gov/safewater/uic/wells_sequestration.html#regdevelopment.

Of the ten cost categories for geologic CO_2 sequestration listed above, the largest cost drivers (in roughly descending order of magnitude) are well operation, injection well construction, and monitoring.

The costs derived in the unit cost specification module are used in the GeoCAT project scenario costing module to develop commercial scale costs for seven sequestration scenarios of geologic settings:

- saline reservoirs,
- depleted gas fields,
- depleted oil fields,
- enhanced oil recovery,
- enhanced coal bed methane recovery,
- enhanced shale gas, and
- basalt

EPA's application of GeoCAT includes only storage capacity for the first four scenarios. The last three reservoir types are not included because they are considered technically uncertain and minor for the foreseeable future.

The results of the project scenario costing module are taken as inputs into the geologic and regional cost curve module of GeoCAT which generates national and regional "cost curves" indicating the volume of sequestration capacity in each region and state in the U.S. as a function of cost. This module contains a database of sequestration capacity by state and geologic reservoir type. It incorporates assessments from the U.S. Department of Energy's "Carbon Sequestration Atlas of the United States and Canada"[6], enhanced by ICF International to include assessments of the Gulf of Mexico, shale gas sequestration potential, and the use of distribution of proved oil and gas recovery by region to estimate CO_2 potential in areas not covered in the DOE atlas. The geologic and regional cost curve module also has a characterization of regionalized costs, drilling depths, and other factors that go into the regional cost curves.[7]

For EPA Base Case v.4.10 GeoCAT identified storage opportunities in 33 of the lower 48 continental states and storage cost curves were developed for each of them.[8] The storage curve for California is designated as California offshore. Louisiana and Texas have both onshore and offshore storage cost curves. In addition, there are Atlantic offshore and Pacific offshore storage

---

[6]"Carbon Sequestration Atlas of the United States and Canada", U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, March, 2007.

[7]Detailed discussions of the GeoCAT model and its application for EPA can be found in U.S. Environmental Protection Agency, Office of Water, "Geologic CO_2 Sequestration Technology and Cost Analysis, Technical Support Document" (EPA 816-B-08-009) June 2008, http://www.epa.gov/ogwdw000/uic/pdfs/support_uic_co2_technologyandcostanalysis.pdf and Harry Vidas, Robert Hugman and Christa Clapp, "Analysis of Geologic Sequestration Costs for the United States and Implications for Climate Change Mitigation," Science Digest, Energy Procedia, Volume 1, Issue 1, February 2009, Pages 4281-4288. Available online at www.sciencedirect.com.

[8]The states without identified storage opportunities in EPA Base Case v.4.10 are Connecticut, Delaware, Idaho, Iowa, Maine, Maryland, Massachusetts, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Rhode Island, Vermont, and Wisconsin. This implies that these states did not present storage opportunities for the four sequestration scenarios included in EPA's inventory, i.e., saline reservoirs, depleted gas fields, depleted oil fields, and enhanced oil recovery.

cost curves. The result is a total of 37 storage cost curves which are shown in Appendix 6-1 ("CO_2 Storage Cost Curves in EPA Base Case").[9]

The cost curves shown in Appendix 6-1 are in the form of step functions. This implies that in any given year a specified amount of storage is available at a particular step price until either the annual storage limit (column 4) or the total storage capacity (column 5) is reached. In determining whether the total storage capacity has been reached, the model tracks the cumulative storage used up through the current year. Once the cumulative storage used equals the total storage capacity, no more storage is available going forward at the particular step price.

There are several additional things to note about the cost curves in Appendix 6-1. First, besides electric sector demand for CO_2 storage, there is expected to be demand from the industrial sector as well. Therefore, before being incorporated into EPA Base Case v.4.10, the original CO_2 storage capacity in each storage region was reduced by an estimate of the storage required for CO_2 generated by industrial sector sources. To do this, ICF first estimated the level of industrial demand in each CO_2 storage region expected at an allowance price of $150 per ton.[10] (An allowance price of $150/ton was chosen to provide a conservative estimate of the amount of storage available to the electricity sector, since under most CO_2 policies that would be analyzed with EPA Base Case v.4.1.0 the allowance price is expected to be below $150/ton.) Then, for each region ICF calculated the ratio of the industrial demand to total storage capacity available for less than $10/ton. (An upper limit of $10/ton was chosen because the considerable amount storage available up to that price could be expected to exhaust the industrial demand.) Converting this to a percent value and subtracting from 100%. ICF obtained the percent of storage capacity available to the electricity sector for less than $10/ton. Finally, the "Annual Step Bound (MMTons)" and "Total Storage Capacity (MMTons)" was multiplied by this percentage value for each step below $10/ton in the cost curves for the region to obtain the reduced storage capacity that went into the storage cost curves for the electric sector in EPA Base Case v.4.10. Thus, the values shown in Table 6-1 represent the storage available to the electric sector.

Second, price steps from region to region are the same. (That is, CO_2STEP5 (column 2) has a step cost value of $4.54/Ton (column 3) across all storage regions (column 1). This across-region price equivalency holds for every step.) However, the amount of storage available in any given year (labeled "Annual Step Bound (MMTons)" in column 4) and the total storage available over all years (labeled "Total Storage Capacity (MMTons)" in column 5) vary from region to region. Third, in any given region, the cost curves are the same for every year. Thus, the step cost, step bound, and total storage capacity shown in columns 4 and 5 in Appendix 6-1 remain the same from year to year. This feature implies the assumption that over the modeling time horizon, i.e., 2012-2050, no new storage will need to be added to augment the storage that is in today's storage inventory. This assumption is not meant to imply that additional storage is unavailable. It only implies that for purposes of modeling the assumption will only be revisited if model runs requiring storage exhaust key components in the storage inventory.

Finally, in each storage cost curve included in Appendix 6-1, CO_2STEP1 through CO_2STEP3 show a negative cost, and CO_2STEP4 shows a zero cost. These steps in the cost curves represent storage available from enhanced oil recovery (EOR) where oil producers either pay or

---

[9]For consistency across the emission costs represented in v.4.10, the costs shown in Appendices 9-1 and 9-2 are expressed in units of dollars per short ton. In IPM documentation and outputs the convention is to use the word "tons" to indicate short tons and the word "tonnes" to indicate metric tons. In discussing CO_2 outside of the modeling framework, the international convention is to use metric tons. To obtain the $/tonne equivalent multiply the $/ton values shown In Appendices 9-1 and 9-2 by 1.1023.

[10]The approach that ICF employed to estimate industrial demand for CO_2 storage is described in ICF International, "Methodology and Results for Initial Forecast of Industrial CCS Volumes," January 2009.

offer free storage for CO_2 which they inject into mature oil wells to enhance the amount of oil recovered.[11]

6.3 CO_2 Transport

Each of the 32 IPM model regions can send CO_2 to the 37 regions represented by the storage cost curves in Appendix 6-1. The associated transport costs (in 2007$/Ton) are shown in Appendix 6-2 (CO_2 Transportation Matrix in EPA Base Case v.4.0).

These costs were derived by ICF International by first calculating the pipeline distance from each of the CO_2 Production Regions to each of the CO_2 Storage Regions listed in Appendix 6-2. (For example, the distance from MACS to Louisiana Onshore was estimated as 997 miles.) Since there are large economies of scale for pipelines, CO_2 transportation costs would depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. Consequently, ICF's method assumes that the longer the distance from the source of the CO_2 (in our example MACS) to the sink for the CO_2 (in our example Louisiana Onshore), the more chance there is for other sources to share in the transportation costs with the pipeline diameter growing with distance as more sources are fed into the same system. Cost components include pipeline costs (in $/inch-mile) and cost of service (in $/ton per 75 miles). These cost components in turn are functions of the required diameter and thickness of the pipeline and the flow capacity of the pipeline, which themselves are functions of the assumed number of power plants using the pipeline. Table 6-2 illustrates the build-up of cost for the MACS to Louisiana Onshore example.

This example comes to $20.11 per ton of CO_2 (in 2007$) for the overall miles pipeline distance traveled. (This is the short ton equivalent to the $22.17 metric tonne value shown in Table 6-2.)

Table 6-2 CO_2 Transport Cost Calculation Example – MACS to Louisiana Onshore

CARBON DIOXIDE PIPELINES

Outside Dia. Inches	Inside Dia. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	Total Cost of Service in $/metric ton per 75 miles or 121 km	Flow Capacity in metric tons/day	Flow Capacity in million standard cubic feet per day (60 degrees F and 14.73 psi)		Number of 500 MW IGCC plants accomodated
12.75	12.0	0.39	$ 75,000	$4.36	10,775	203		0.97
16	15.0	0.49	$ 78,116	$3.25	19,139	361		1.73
24	22.5	0.73	$ 84,119	$2.02	53,385	1,007		4.83
30	28.2	0.92	$ 86,399	$1.56	93,887	1,771		8.49
36	33.8	1.10	$ 88,678	$1.27	148,913	2,808		13.46
42	39.4	1.28	$ 90,958	$1.10	219,942	4,148		19.88

Note: 500 MW IGCC plant would produce 512 metric tonnes of CO2 per hour. Of this, 90% or 461 tonnes would be captured. Maximum CO2 tranport needs would be 11,064 tonnes per power plant per day. Cost of service based on 7 cents per kWh electricity.

Example Spacial Assumptions

	Miles	$/Mile per Tonne	Cost per Tonne	Annual Cost per Power Plant @85 Utilization Rate
Single Power Plant Pipeline (12 inch, small gathering) distance in miles	**25**	$0.058	$1.45	$4,986,315
Two Power Plant Pipeline (16 inch, large gathering) distance in miles	**25**	$0.043	$1.08	$3,717,211
Eight Power Plant Pipeline (30 inch, mainline) distance in miles	**947**	$0.021	$19.64	$67,400,166
Total Distance & Costs	**997**	**$0.022**	**$22.17**	**$76,103,692**

[11]There is also a market for CO_2 injection in enhanced coal bed methane (ECBM) production. ECBM is excluded from EPA's inventory as discussed earlier.

Appendix 6-1 CO_2 Storage Cost Curves in EPA Base Case 4.10

Note: The curves for each region are applicable in each model run year 2012 - 2050.

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
Alabama	STEP1	-13.61	1	45
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	6
	STEP5	4.54	31	1,568
	STEP6	9.07	39	1,967
	STEP7	13.61	38	1,895
	STEP8	18.14	0	9
	STEP9	22.68	4	186
	STEP10	27.22	13	639
	STEP11	31.75	0	7
	STEP12	36.29	0	14
	STEP13	40.82	0	0
	STEP14	45.36	1	68
	STEP15	49.90	0	0
	STEP16	54.43	0	14
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Arizona	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	121	6,026
	STEP6	9.07	145	7,275
	STEP7	13.61	113	5,659
	STEP8	18.14	0	0
	STEP9	22.68	38	1,887
	STEP10	27.22	0	1
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Arkansas	STEP1	-13.61	1	62
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	146	7,297
	STEP6	9.07	177	8,863

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP7	13.61	142	7,110
	STEP8	18.14	1	35
	STEP9	22.68	51	2,568
	STEP10	27.22	3	128
	STEP11	31.75	0	0
	STEP12	36.29	1	53
	STEP13	40.82	0	0
	STEP14	45.36	1	71
	STEP15	49.90	0	0
	STEP16	54.43	1	53
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Atlantic Offshore	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	1,832	91,580
	STEP6	9.07	2,211	110,528
	STEP7	13.61	1,706	85,311
	STEP8	18.14	0	0
	STEP9	22.68	0	0
	STEP10	27.22	569	28,437
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
California Onshore	STEP1	-13.61	19	941
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	2	121
	STEP5	4.54	1,227	61,357
	STEP6	9.07	1,966	98,304
	STEP7	13.61	367	18,335
	STEP8	18.14	11	531
	STEP9	22.68	70	3,516
	STEP10	27.22	30	1,507
	STEP11	31.75	0	0
	STEP12	36.29	16	797
	STEP13	40.82	0	0
	STEP14	45.36	21	1,063

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP15	49.90	0	0
	STEP16	54.43	16	797
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Colorado	STEP1	-13.61	3	136
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	13	627
	STEP6	9.07	16	801
	STEP7	13.61	16	804
	STEP8	18.14	1	35
	STEP9	22.68	7	353
	STEP10	27.22	1	59
	STEP11	31.75	0	0
	STEP12	36.29	0	22
	STEP13	40.82	0	0
	STEP14	45.36	1	30
	STEP15	49.90	0	0
	STEP16	54.43	0	22
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Florida	STEP1	-13.61	2	105
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	456	22,813
	STEP6	9.07	550	27,479
	STEP7	13.61	426	21,317
	STEP8	18.14	0	13
	STEP9	22.68	143	7,172
	STEP10	27.22	1	33
	STEP11	31.75	0	0
	STEP12	36.29	0	20
	STEP13	40.82	0	0
	STEP14	45.36	1	26
	STEP15	49.90	0	0
	STEP16	54.43	0	20
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Georgia	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP4	0.00	0	0
	STEP5	4.54	42	2,117
	STEP6	9.07	51	2,555
	STEP7	13.61	40	2,000
	STEP8	18.14	0	0
	STEP9	22.68	0	0
	STEP10	27.22	13	667
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
	STEP1	-13.61	3	165
	STEP2	-9.07	0	16
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	309	15,455
	STEP6	9.07	373	18,653
	STEP7	13.61	303	15,168
	STEP8	18.14	1	73
	STEP9	22.68	108	5,420
Illinois	STEP10	27.22	4	180
	STEP11	31.75	0	0
	STEP12	36.29	2	109
	STEP13	40.82	0	0
	STEP14	45.36	3	144
	STEP15	49.90	0	0
	STEP16	54.43	2	108
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Indiana	STEP1	-13.61	0	17
	STEP2	-9.07	0	2
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	164	8,195
	STEP6	9.07	198	9,890
	STEP7	13.61	167	8,332
	STEP8	18.14	0	1
	STEP9	22.68	56	2,781
	STEP10	27.22	0	2
	STEP11	31.75	0	0

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP12	36.29	0	1
	STEP13	40.82	0	0
	STEP14	45.36	0	1
	STEP15	49.90	0	0
	STEP16	54.43	0	1
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Kansas	STEP1	-13.61	6	287
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	37	1,863
	STEP6	9.07	50	2,513
	STEP7	13.61	66	3,323
	STEP8	18.14	14	685
	STEP9	22.68	32	1,620
	STEP10	27.22	0	0
	STEP11	31.75	0	0
	STEP12	36.29	12	620
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Kentucky	STEP1	-13.61	0	7
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	54	2,694
	STEP6	9.07	86	4,310
	STEP7	13.61	16	808
	STEP8	18.14	1	26
	STEP9	22.68	4	208
	STEP10	27.22	1	64
	STEP11	31.75	0	0
	STEP12	36.29	4	182
	STEP13	40.82	0	0
	STEP14	45.36	1	52
	STEP15	49.90	0	0
	STEP16	54.43	1	39
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	2	86

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
Louisiana Onshore	STEP1	-13.61	20	1,012
	STEP2	-9.07	0	0
	STEP3	-4.54	3	130
	STEP4	0.00	0	0
	STEP5	4.54	918	45,891
	STEP6	9.07	1,127	56,334
	STEP7	13.61	949	47,463
	STEP8	18.14	7	353
	STEP9	22.68	47	2,342
	STEP10	27.22	334	16,704
	STEP11	31.75	0	0
	STEP12	36.29	8	397
	STEP13	40.82	0	0
	STEP14	45.36	26	1,292
	STEP15	49.90	3	134
	STEP16	54.43	11	530
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	8	397
Louisiana Offshore	STEP1	-13.61	23	1,128
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	0	0
	STEP6	9.07	0	0
	STEP7	13.61	661	33,069
	STEP8	18.14	2,535	126,766
	STEP9	22.68	0	0
	STEP10	27.22	677	33,829
	STEP11	31.75	2,208	110,376
	STEP12	36.29	992	49,604
	STEP13	40.82	20	1,012
	STEP14	45.36	1,695	84,765
	STEP15	49.90	0	0
	STEP16	54.43	1,338	66,898
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	1,159	57,975
Michigan	STEP1	-13.61	1	62
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	339	16,935
	STEP6	9.07	409	20,471
	STEP7	13.61	323	16,130
	STEP8	18.14	0	4

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP9	22.68	108	5,380
	STEP10	27.22	0	7
	STEP11	31.75	0	6
	STEP12	36.29	0	4
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	2
	STEP16	54.43	0	0
	STEP17	58.97	0	3
	STEP18	63.50	0	0
	STEP19	68.04	0	2
Mississippi	STEP1	-13.61	2	117
	STEP2	-9.07	0	0
	STEP3	-4.54	0	18
	STEP4	0.00	0	0
	STEP5	4.54	552	27,623
	STEP6	9.07	668	33,410
	STEP7	13.61	522	26,080
	STEP8	18.14	1	63
	STEP9	22.68	4	221
	STEP10	27.22	178	8,877
	STEP11	31.75	0	0
	STEP12	36.29	1	71
	STEP13	40.82	0	0
	STEP14	45.36	3	157
	STEP15	49.90	0	0
	STEP16	54.43	2	95
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	1	71
Montana	STEP1	-13.61	4	194
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	1,608	80,381
	STEP6	9.07	1,941	97,053
	STEP7	13.61	1,505	75,253
	STEP8	18.14	8	396
	STEP9	22.68	513	25,652
	STEP10	27.22	23	1,131
	STEP11	31.75	0	0
	STEP12	36.29	8	391
	STEP13	40.82	0	0
	STEP14	45.36	13	652
	STEP15	49.90	0	0
	STEP16	54.43	10	522

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	8	391
North Dakota	STEP1	-13.61	5	241
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	91	4,549
	STEP6	9.07	110	5,499
	STEP7	13.61	91	4,538
	STEP8	18.14	8	376
	STEP9	22.68	41	2,068
	STEP10	27.22	22	1,110
	STEP11	31.75	0	0
	STEP12	36.29	8	384
	STEP13	40.82	0	0
	STEP14	45.36	13	640
	STEP15	49.90	0	0
	STEP16	54.43	10	512
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	8	384
Nebraska	STEP1	-13.61	0	11
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	15	734
	STEP6	9.07	18	881
	STEP7	13.61	17	859
	STEP8	18.14	0	11
	STEP9	22.68	7	337
	STEP10	27.22	1	25
	STEP11	31.75	0	0
	STEP12	36.29	0	15
	STEP13	40.82	0	0
	STEP14	45.36	0	20
	STEP15	49.90	0	0
	STEP16	54.43	0	15
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Nevada	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	60	3,024

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP6	9.07	73	3,650
	STEP7	13.61	56	2,821
	STEP8	18.14	0	0
	STEP9	22.68	19	940
	STEP10	27.22	0	0
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
	STEP1	-13.61	13	672
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	36	1,791
	STEP6	9.07	67	3,338
	STEP7	13.61	103	5,130
	STEP8	18.14	6	285
	STEP9	22.68	59	2,960
New Mexico	STEP10	27.22	21	1,033
	STEP11	31.75	0	0
	STEP12	36.29	6	293
	STEP13	40.82	0	0
	STEP14	45.36	8	391
	STEP15	49.90	0	0
	STEP16	54.43	6	293
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
New York	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	0	0
	STEP6	9.07	0	8
	STEP7	13.61	1	54
	STEP8	18.14	0	15
	STEP9	22.68	1	39
	STEP10	27.22	0	7
	STEP11	31.75	0	0
	STEP12	36.29	0	23
	STEP13	40.82	0	0

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Ohio	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	213	10,634
	STEP6	9.07	257	12,835
	STEP7	13.61	206	10,320
	STEP8	18.14	0	13
	STEP9	22.68	71	3,551
	STEP10	27.22	1	33
	STEP11	31.75	0	0
	STEP12	36.29	3	130
	STEP13	40.82	0	0
	STEP14	45.36	1	26
	STEP15	49.90	0	0
	STEP16	54.43	0	20
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	1	66
Oklahoma	STEP1	-13.61	18	898
	STEP2	-9.07	2	116
	STEP3	-4.54	3	154
	STEP4	0.00	0	0
	STEP5	4.54	2	117
	STEP6	9.07	10	502
	STEP7	13.61	41	2,070
	STEP8	18.14	8	387
	STEP9	22.68	35	1,767
	STEP10	27.22	36	1,779
	STEP11	31.75	0	0
	STEP12	36.29	9	436
	STEP13	40.82	0	0
	STEP14	45.36	22	1,116
	STEP15	49.90	0	0
	STEP16	54.43	12	581
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	9	436
Oregon	STEP1	-13.61	0	0
	STEP2	-9.07	0	0

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	171	8,530
	STEP6	9.07	206	10,294
	STEP7	13.61	161	8,036
	STEP8	18.14	0	0
	STEP9	22.68	54	2,679
	STEP10	27.22	0	0
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Pacific Offshore	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	0	0
	STEP6	9.07	0	0
	STEP7	13.61	309	15,432
	STEP8	18.14	331	16,535
	STEP9	22.68	573	28,660
	STEP10	27.22	0	2
	STEP11	31.75	0	3
	STEP12	36.29	198	9,921
	STEP13	40.82	331	16,537
	STEP14	45.36	265	13,234
	STEP15	49.90	0	0
	STEP16	54.43	2	83
	STEP17	58.97	0	8
	STEP18	63.50	2	110
	STEP19	68.04	222	11,123
Pennsylvania	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	52	2,611
	STEP6	9.07	84	4,178
	STEP7	13.61	19	972
	STEP8	18.14	1	34
	STEP9	22.68	5	262
	STEP10	27.22	2	86

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP11	31.75	0	0
	STEP12	36.29	4	206
	STEP13	40.82	0	0
	STEP14	45.36	1	69
	STEP15	49.90	0	0
	STEP16	54.43	1	52
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	2	93
South Carolina	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	43	2,126
	STEP6	9.07	51	2,565
	STEP7	13.61	40	2,000
	STEP8	18.14	0	0
	STEP9	22.68	13	667
	STEP10	27.22	0	0
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
South Dakota	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	219	10,933
	STEP6	9.07	264	13,196
	STEP7	13.61	206	10,313
	STEP8	18.14	0	0
	STEP9	22.68	69	3,438
	STEP10	27.22	0	1
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP19	68.04	0	0
Tennessee	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	21	1,035
	STEP6	9.07	33	1,657
	STEP7	13.61	6	319
	STEP8	18.14	0	0
	STEP9	22.68	0	0
	STEP10	27.22	0	0
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Texas Onshore	STEP1	-13.61	113	5,633
	STEP2	-9.07	0	0
	STEP3	-4.54	14	724
	STEP4	0.00	0	0
	STEP5	4.54	1,800	90,016
	STEP6	9.07	2,195	109,766
	STEP7	13.61	1,913	95,669
	STEP8	18.14	25	1,258
	STEP9	22.68	228	11,406
	STEP10	27.22	690	34,524
	STEP11	31.75	0	0
	STEP12	36.29	38	1,887
	STEP13	40.82	0	0
	STEP14	45.36	81	4,041
	STEP15	49.90	0	0
	STEP16	54.43	38	1,887
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Texas Offshore	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	0	0
	STEP6	9.07	0	0
	STEP7	13.61	397	19,842

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP8	18.14	1,521	76,059
	STEP9	22.68	0	0
	STEP10	27.22	400	19,999
	STEP11	31.75	1,324	66,192
	STEP12	36.29	595	29,762
	STEP13	40.82	4	197
	STEP14	45.36	1,000	49,998
	STEP15	49.90	0	0
	STEP16	54.43	796	39,801
	STEP17	58.97	3	133
	STEP18	63.50	0	0
	STEP19	68.04	627	31,338
	STEP1	-13.61	4	195
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	2	106
	STEP6	9.07	4	184
	STEP7	13.61	5	251
	STEP8	18.14	1	36
	STEP9	22.68	3	137
Utah	STEP10	27.22	1	46
	STEP11	31.75	0	0
	STEP12	36.29	0	12
	STEP13	40.82	0	0
	STEP14	45.36	0	16
	STEP15	49.90	0	0
	STEP16	54.43	0	12
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Virginia	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	0	0
	STEP6	9.07	0	0
	STEP7	13.61	0	21
	STEP8	18.14	0	9
	STEP9	22.68	1	53
	STEP10	27.22	0	23
	STEP11	31.75	0	0
	STEP12	36.29	0	14
	STEP13	40.82	0	0
	STEP14	45.36	0	18
	STEP15	49.90	0	0

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP16	54.43	0	14
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
Washington	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	162	8,101
	STEP6	9.07	196	9,777
	STEP7	13.61	155	7,738
	STEP8	18.14	0	0
	STEP9	22.68	52	2,579
	STEP10	27.22	0	0
	STEP11	31.75	0	0
	STEP12	36.29	0	0
	STEP13	40.82	0	0
	STEP14	45.36	0	0
	STEP15	49.90	0	0
	STEP16	54.43	0	0
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	0
West Virginia	STEP1	-13.61	0	0
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0
	STEP5	4.54	47	2,351
	STEP6	9.07	75	3,761
	STEP7	13.61	14	721
	STEP8	18.14	1	38
	STEP9	22.68	5	227
	STEP10	27.22	2	94
	STEP11	31.75	0	0
	STEP12	36.29	1	73
	STEP13	40.82	0	0
	STEP14	45.36	2	75
	STEP15	49.90	0	0
	STEP16	54.43	1	57
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	0	10
Wyoming	STEP1	-13.61	6	324
	STEP2	-9.07	0	0
	STEP3	-4.54	0	0
	STEP4	0.00	0	0

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2007$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP5	4.54	2,644	132,195
	STEP6	9.07	3,198	159,909
	STEP7	13.61	2,486	124,304
	STEP8	18.14	2	100
	STEP9	22.68	836	41,794
	STEP10	27.22	10	496
	STEP11	31.75	0	0
	STEP12	36.29	1	65
	STEP13	40.82	0	0
	STEP14	45.36	7	339
	STEP15	49.90	0	0
	STEP16	54.43	2	87
	STEP17	58.97	0	0
	STEP18	63.50	0	0
	STEP19	68.04	1	65

Appendix 6-2 CO_2 Transportation Matrix in EPA Base Case v.4.10

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
AZNM	Alabama	26.30
	Arizona	3.50
	Arkansas	19.34
	Atlantic Offshore	35.66
	California Onshore	13.36
	Colorado	9.43
	Florida	34.30
	Georgia	32.10
	Illinois	23.54
	Indiana	25.54
	Kansas	11.13
	Kentucky	29.06
	Louisiana Onshore	22.58
	Louisiana Offshore	23.19
	Michigan	28.53
	Mississippi	23.21
	Montana	18.29
	North Dakota	18.73
	Nebraska	11.58
	Nevada	9.20
	New Mexico	3.30
	New York	34.34
	Ohio	30.66
	Oklahoma	12.63
	Oregon	20.63
	Pacific Offshore	12.18
	Pennsylvania	33.49
	South Carolina	32.35
	South Dakota	16.24
	Tennessee	27.12
	Texas Onshore	15.99
	Texas Offshore	21.22
	Utah	7.90
	Virginia	32.84
	West Virginia	30.89
	Wyoming	12.76
CA-N	Alabama	37.36
	Arizona	11.27
	Arkansas	30.35
	Atlantic Offshore	46.55
	California Onshore	4.67
	Colorado	17.69
	Florida	45.34
	Georgia	43.10
	Illinois	33.75
	Indiana	35.78

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Kansas	21.53
	Kentucky	39.54
	Louisiana Onshore	33.61
	Louisiana Offshore	34.04
	Michigan	37.98
	Mississippi	34.28
	Montana	22.73
	North Dakota	23.59
	Nebraska	19.92
	Nevada	5.18
	New Mexico	13.42
	New York	43.93
	Ohio	40.66
	Oklahoma	23.52
	Oregon	14.68
	Pacific Offshore	5.49
	Pennsylvania	43.47
	South Carolina	43.30
	South Dakota	22.18
	Tennessee	37.87
	Texas Onshore	26.74
	Texas Offshore	31.95
	Utah	12.50
	Virginia	43.36
	West Virginia	41.28
	Wyoming	18.13
CA-S	Alabama	33.45
	Arizona	7.46
	Arkansas	26.55
	Atlantic Offshore	42.90
	California Onshore	6.99
	Colorado	15.09
	Florida	41.31
	Georgia	39.32
	Illinois	30.57
	Indiana	32.59
	Kansas	18.18
	Kentucky	36.20
	Louisiana Onshore	29.58
	Louisiana Offshore	29.90
	Michigan	35.22
	Mississippi	30.34
	Montana	21.82
	North Dakota	22.54
	Nebraska	17.41
	Nevada	4.60
	New Mexico	9.72

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	New York	41.12
	Ohio	37.62
	Oklahoma	19.87
	Oregon	17.43
	Pacific Offshore	5.27
	Pennsylvania	40.45
	South Carolina	39.59
	South Dakota	20.67
	Tennessee	34.35
	Texas Onshore	22.59
	Texas Offshore	27.79
	Utah	10.69
	Virginia	40.00
	West Virginia	38.01
	Wyoming	16.62
COMD	Alabama	15.38
	Arizona	26.11
	Arkansas	13.19
	Atlantic Offshore	16.86
	California Onshore	34.86
	Colorado	18.43
	Florida	22.02
	Georgia	16.05
	Illinois	4.75
	Indiana	4.82
	Kansas	15.43
	Kentucky	8.40
	Louisiana Onshore	16.98
	Louisiana Offshore	20.13
	Michigan	4.81
	Mississippi	15.10
	Montana	18.69
	North Dakota	17.74
	Nebraska	16.28
	Nevada	30.94
	New Mexico	23.94
	New York	10.57
	Ohio	7.45
	Oklahoma	15.12
	Oregon	34.88
	Pacific Offshore	35.76
	Pennsylvania	10.14
	South Carolina	15.15
	South Dakota	16.60
	Tennessee	9.56
	Texas Onshore	20.39
	Texas Offshore	20.75

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Utah	23.86
	Virginia	11.68
	West Virginia	9.22
	Wyoming	19.55
DSNY	Alabama	20.59
	Arizona	39.27
	Arkansas	23.19
	Atlantic Offshore	13.07
	California Onshore	48.11
	Colorado	31.74
	Florida	22.09
	Georgia	16.20
	Illinois	16.14
	Indiana	14.22
	Kansas	28.47
	Kentucky	11.74
	Louisiana Onshore	24.54
	Louisiana Offshore	27.30
	Michigan	11.58
	Mississippi	22.44
	Montana	30.66
	North Dakota	29.63
	Nebraska	29.57
	Nevada	44.25
	New Mexico	37.07
	New York	5.72
	Ohio	8.97
	Oklahoma	27.58
	Oregon	47.39
	Pacific Offshore	48.99
	Pennsylvania	6.18
	South Carolina	14.74
	South Dakota	29.17
	Tennessee	14.78
	Texas Onshore	30.61
	Texas Offshore	28.92
	Utah	37.14
	Virginia	9.36
	West Virginia	9.81
	Wyoming	32.53
ENTG	Alabama	7.84
	Arizona	21.51
	Arkansas	3.44
	Atlantic Offshore	16.70
	California Onshore	31.99
	Colorado	17.06
	Florida	16.30

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Georgia	13.09
	Illinois	8.81
	Indiana	9.87
	Kansas	11.85
	Kentucky	11.53
	Louisiana Onshore	6.63
	Louisiana Offshore	9.61
	Michigan	15.04
	Mississippi	5.45
	Montana	22.95
	North Dakota	22.36
	Nebraska	16.04
	Nevada	27.84
	New Mexico	19.32
	New York	19.12
	Ohio	14.70
	Oklahoma	9.24
	Oregon	35.90
	Pacific Offshore	31.01
	Pennsylvania	17.17
	South Carolina	13.34
	South Dakota	19.94
	Tennessee	8.76
	Texas Onshore	10.31
	Texas Offshore	9.93
	Utah	22.29
	Virginia	14.87
	West Virginia	13.49
	Wyoming	20.78
ERCT	Alabama	11.70
	Arizona	17.85
	Arkansas	6.89
	Atlantic Offshore	22.16
	California Onshore	28.61
	Colorado	16.48
	Florida	19.08
	Georgia	18.02
	Illinois	15.08
	Indiana	16.40
	Kansas	11.44
	Kentucky	18.11
	Louisiana Onshore	7.38
	Louisiana Offshore	7.88
	Michigan	21.40
	Mississippi	8.61
	Montana	24.73
	North Dakota	24.42
	Nebraska	16.44

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Nevada	24.59
	New Mexico	15.94
	New York	25.74
	Ohio	21.33
	Oklahoma	8.37
	Oregon	34.69
	Pacific Offshore	26.55
	Pennsylvania	23.80
	South Carolina	18.68
	South Dakota	21.63
	Tennessee	15.19
	Texas Onshore	4.33
	Texas Offshore	6.27
	Utah	20.59
	Virginia	21.28
	West Virginia	20.06
	Wyoming	21.08
FRCC	Alabama	7.71
	Arizona	33.74
	Arkansas	14.94
	Atlantic Offshore	8.78
	California Onshore	44.39
	Colorado	29.83
	Florida	4.12
	Georgia	5.33
	Illinois	16.83
	Indiana	15.92
	Kansas	24.61
	Kentucky	13.10
	Louisiana Onshore	11.59
	Louisiana Offshore	12.45
	Michigan	20.06
	Mississippi	10.73
	Montana	34.81
	North Dakota	34.07
	Nebraska	28.72
	Nevada	40.31
	New Mexico	31.64
	New York	20.09
	Ohio	16.78
	Oklahoma	21.91
	Oregon	48.66
	Pacific Offshore	42.80
	Pennsylvania	17.31
	South Carolina	6.76
	South Dakota	31.99
	Tennessee	11.23
	Texas Onshore	19.12

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Texas Offshore	14.75
	Utah	35.06
	Virginia	12.94
	West Virginia	13.74
	Wyoming	33.33
GWAY	Alabama	12.18
	Arizona	23.91
	Arkansas	9.40
	Atlantic Offshore	16.05
	California Onshore	33.36
	Colorado	17.01
	Florida	19.59
	Georgia	14.19
	Illinois	3.25
	Indiana	4.03
	Kansas	13.08
	Kentucky	7.95
	Louisiana Onshore	13.27
	Louisiana Offshore	16.40
	Michigan	8.25
	Mississippi	11.47
	Montana	19.47
	North Dakota	18.64
	Nebraska	15.15
	Nevada	29.31
	New Mexico	21.68
	New York	13.25
	Ohio	9.20
	Oklahoma	12.12
	Oregon	34.74
	Pacific Offshore	33.66
	Pennsylvania	12.01
	South Carolina	13.61
	South Dakota	16.90
	Tennessee	7.49
	Texas Onshore	16.70
	Texas Offshore	16.94
	Utah	22.59
	Virginia	11.76
	West Virginia	9.55
	Wyoming	19.15
LILC	Alabama	20.91
	Arizona	40.31
	Arkansas	23.89
	Atlantic Offshore	12.75
	California Onshore	49.26
	Colorado	32.87
	Florida	21.86

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Georgia	16.18
	Illinois	17.12
	Indiana	15.16
	Kansas	29.50
	Kentucky	12.40
	Louisiana Onshore	24.99
	Louisiana Offshore	27.68
	Michigan	12.79
	Mississippi	22.91
	Montana	31.94
	North Dakota	30.91
	Nebraska	30.72
	Nevada	45.37
	New Mexico	38.10
	New York	6.99
	Ohio	9.97
	Oklahoma	28.52
	Oregon	48.65
	Pacific Offshore	50.04
	Pennsylvania	7.14
	South Carolina	14.74
	South Dakota	30.42
	Tennessee	15.36
	Texas Onshore	31.26
	Texas Offshore	29.36
	Utah	38.30
	Virginia	9.62
	West Virginia	10.45
	Wyoming	33.74
MACE	Alabama	18.55
	Arizona	38.48
	Arkansas	21.68
	Atlantic Offshore	10.69
	California Onshore	47.66
	Colorado	31.26
	Florida	19.72
	Georgia	13.89
	Illinois	15.24
	Indiana	13.24
	Kansas	27.66
	Kentucky	10.19
	Louisiana Onshore	22.64
	Louisiana Offshore	25.32
	Michigan	11.60
	Mississippi	20.57
	Montana	30.99
	North Dakota	29.97
	Nebraska	29.18

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Nevada	43.73
	New Mexico	36.26
	New York	6.45
	Ohio	8.24
	Oklahoma	26.53
	Oregon	47.58
	Pacific Offshore	48.24
	Pennsylvania	5.49
	South Carolina	12.45
	South Dakota	29.27
	Tennessee	13.07
	Texas Onshore	29.00
	Texas Offshore	27.02
	Utah	36.75
	Virginia	7.30
	West Virginia	8.23
	Wyoming	32.43
MACS	Alabama	16.44
	Arizona	36.43
	Arkansas	19.46
	Atlantic Offshore	9.47
	California Onshore	45.76
	Colorado	29.37
	Florida	18.22
	Georgia	12.14
	Illinois	13.21
	Indiana	11.19
	Kansas	25.61
	Kentucky	7.98
	Louisiana Onshore	20.47
	Louisiana Offshore	23.18
	Michigan	10.24
	Mississippi	18.39
	Montana	29.61
	North Dakota	28.61
	Nebraska	27.33
	Nevada	41.79
	New Mexico	34.20
	New York	6.22
	Ohio	6.46
	Oklahoma	24.39
	Oregon	46.05
	Pacific Offshore	46.19
	Pennsylvania	4.10
	South Carolina	10.68
	South Dakota	27.73
	Tennessee	10.85
	Texas Onshore	26.78

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Texas Offshore	24.84
	Utah	34.89
	Virginia	5.40
	West Virginia	6.02
	Wyoming	30.75
MACW	Alabama	18.02
	Arizona	36.52
	Arkansas	20.34
	Atlantic Offshore	11.63
	California Onshore	45.53
	Colorado	29.13
	Florida	20.31
	Georgia	14.14
	Illinois	13.33
	Indiana	11.38
	Kansas	25.71
	Kentucky	8.92
	Louisiana Onshore	21.83
	Louisiana Offshore	24.66
	Michigan	9.25
	Mississippi	19.72
	Montana	28.62
	North Dakota	27.60
	Nebraska	27.00
	Nevada	41.62
	New Mexico	34.31
	New York	4.24
	Ohio	6.18
	Oklahoma	24.75
	Oregon	45.23
	Pacific Offshore	46.26
	Pennsylvania	3.35
	South Carolina	12.68
	South Dakota	26.94
	Tennessee	12.01
	Texas Onshore	27.78
	Texas Offshore	26.20
	Utah	34.58
	Virginia	7.16
	West Virginia	7.03
	Wyoming	30.15
MECS	Alabama	16.68
	Arizona	29.60
	Arkansas	15.92
	Atlantic Offshore	15.62
	California Onshore	38.19
	Colorado	21.83

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Florida	22.17
	Georgia	15.84
	Illinois	7.49
	Indiana	6.33
	Kansas	18.94
	Kentucky	7.85
	Louisiana Onshore	19.10
	Louisiana Offshore	22.23
	Michigan	3.25
	Mississippi	17.07
	Montana	21.14
	North Dakota	20.13
	Nebraska	19.62
	Nevada	34.33
	New Mexico	27.44
	New York	7.11
	Ohio	4.97
	Oklahoma	18.56
	Oregon	37.67
	Pacific Offshore	39.24
	Pennsylvania	7.16
	South Carolina	14.68
	South Dakota	19.37
	Tennessee	10.21
	Texas Onshore	23.33
	Texas Offshore	23.15
	Utah	27.18
	Virginia	10.10
	West Virginia	7.73
	Wyoming	22.60
MRO	Alabama	19.01
	Arizona	19.94
	Arkansas	13.69
	Atlantic Offshore	23.49
	California Onshore	27.89
	Colorado	11.66
	Florida	26.95
	Georgia	21.76
	Illinois	9.29
	Indiana	10.96
	Kansas	10.29
	Kentucky	15.09
	Louisiana Onshore	18.68
	Louisiana Offshore	21.50
	Michigan	11.53
	Mississippi	17.42
	Montana	11.90

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	North Dakota	11.07
	Nebraska	9.34
	Nevada	24.07
	New Mexico	17.93
	New York	17.48
	Ohio	14.76
	Oklahoma	11.48
	Oregon	27.61
	Pacific Offshore	29.28
	Pennsylvania	17.42
	South Carolina	21.18
	South Dakota	9.43
	Tennessee	15.05
	Texas Onshore	18.97
	Texas Offshore	21.26
	Utah	16.81
	Virginia	18.68
	West Virginia	16.31
	Wyoming	12.27
NENG	Alabama	23.42
	Arizona	42.41
	Arkansas	26.33
	Atlantic Offshore	14.98
	California Onshore	51.13
	Colorado	34.79
	Florida	24.11
	Georgia	18.58
	Illinois	19.32
	Indiana	17.41
	Kansas	31.63
	Kentucky	14.85
	Louisiana Onshore	27.50
	Louisiana Offshore	30.19
	Michigan	14.53
	Mississippi	25.42
	Montana	33.26
	North Dakota	32.21
	Nebraska	32.59
	Nevada	47.30
	New Mexico	40.21
	New York	8.58
	Ohio	12.16
	Oklahoma	30.77
	Oregon	50.04
	Pacific Offshore	52.11
	Pennsylvania	9.37
	South Carolina	17.16

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	South Dakota	31.93
	Tennessee	17.84
	Texas Onshore	33.71
	Texas Offshore	31.88
	Utah	40.15
	Virginia	12.11
	West Virginia	12.91
	Wyoming	35.40
NWPE	Alabama	27.91
	Arizona	9.77
	Arkansas	20.78
	Atlantic Offshore	35.44
	California Onshore	14.70
	Colorado	5.96
	Florida	36.36
	Georgia	32.67
	Illinois	21.61
	Indiana	23.58
	Kansas	11.09
	Kentucky	27.62
	Louisiana Onshore	25.29
	Louisiana Offshore	26.89
	Michigan	25.00
	Mississippi	25.18
	Montana	10.32
	North Dakota	10.93
	Nebraska	7.21
	Nevada	10.98
	New Mexico	9.06
	New York	30.95
	Ohio	28.06
	Oklahoma	13.98
	Oregon	15.84
	Pacific Offshore	16.89
	Pennsylvania	30.80
	South Carolina	32.53
	South Dakota	8.96
	Tennessee	26.57
	Texas Onshore	20.66
	Texas Offshore	25.42
	Utah	3.71
	Virginia	31.39
	West Virginia	29.15
	Wyoming	5.44
NYC	Alabama	20.30
	Arizona	39.63
	Arkansas	23.21

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Atlantic Offshore	12.36
	California Onshore	48.61
	Colorado	32.22
	Florida	21.44
	Georgia	15.67
	Illinois	16.43
	Indiana	14.47
	Kansas	28.82
	Kentucky	11.72
	Louisiana Onshore	24.35
	Louisiana Offshore	27.05
	Michigan	12.18
	Mississippi	22.27
	Montana	31.39
	North Dakota	30.36
	Nebraska	30.08
	Nevada	44.72
	New Mexico	37.42
	New York	6.46
	Ohio	9.29
	Oklahoma	27.83
	Oregon	48.09
	Pacific Offshore	49.37
	Pennsylvania	6.46
	South Carolina	14.22
	South Dakota	29.83
	Tennessee	14.69
	Texas Onshore	30.58
	Texas Offshore	28.72
	Utah	37.65
	Virginia	9.02
	West Virginia	9.77
	Wyoming	33.13
PNW	Alabama	42.14
	Arizona	20.11
	Arkansas	35.04
	Atlantic Offshore	48.98
	California Onshore	13.81
	Colorado	20.04
	Florida	50.59
	Georgia	46.59
	Illinois	34.78
	Indiana	36.61
	Kansas	25.36
	Kentucky	40.75
	Louisiana Onshore	39.59
	Louisiana Offshore	41.10
	Michigan	36.69

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Mississippi	39.46
	Montana	17.43
	North Dakota	18.47
	Nebraska	21.01
	Nevada	14.85
	New Mexico	21.07
	New York	42.34
	Ohio	40.36
	Oklahoma	28.28
	Oregon	3.25
	Pacific Offshore	19.55
	Pennsylvania	42.86
	South Carolina	46.30
	South Dakota	19.07
	Tennessee	40.20
	Texas Onshore	34.51
	Texas Offshore	39.51
	Utah	15.41
	Virginia	44.36
	West Virginia	42.03
	Wyoming	16.74
RFCO	Alabama	13.04
	Arizona	28.50
	Arkansas	12.94
	Atlantic Offshore	13.05
	California Onshore	37.78
	Colorado	21.38
	Florida	18.74
	Georgia	12.54
	Illinois	5.27
	Indiana	3.35
	Kansas	17.68
	Kentucky	4.66
	Louisiana Onshore	15.63
	Louisiana Offshore	18.73
	Michigan	5.43
	Mississippi	13.56
	Montana	22.47
	North Dakota	21.53
	Nebraska	19.37
	Nevada	33.79
	New Mexico	26.28
	New York	8.87
	Ohio	4.60
	Oklahoma	16.70
	Oregon	38.47
	Pacific Offshore	38.25
	Pennsylvania	7.40

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	South Carolina	11.52
	South Dakota	20.26
	Tennessee	6.58
	Texas Onshore	20.46
	Texas Offshore	19.79
	Utah	26.91
	Virginia	7.97
	West Virginia	5.45
	Wyoming	23.00
RFCP	Alabama	13.89
	Arizona	32.04
	Arkansas	15.58
	Atlantic Offshore	10.62
	California Onshore	41.38
	Colorado	24.98
	Florida	17.85
	Georgia	11.42
	Illinois	8.80
	Indiana	6.79
	Kansas	21.22
	Kentucky	4.32
	Louisiana Onshore	17.34
	Louisiana Offshore	20.29
	Michigan	6.87
	Mississippi	15.22
	Montana	25.71
	North Dakota	24.74
	Nebraska	22.97
	Nevada	37.39
	New Mexico	29.81
	New York	6.63
	Ohio	3.25
	Oklahoma	20.08
	Oregon	41.93
	Pacific Offshore	41.80
	Pennsylvania	4.25
	South Carolina	10.11
	South Dakota	23.65
	Tennessee	7.49
	Texas Onshore	23.05
	Texas Offshore	21.68
	Utah	30.52
	Virginia	5.46
	West Virginia	3.25
	Wyoming	26.52
RMPA	Alabama	23.85
	Arizona	9.55

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Arkansas	16.71
	Atlantic Offshore	31.63
	California Onshore	17.46
	Colorado	3.49
	Florida	32.29
	Georgia	28.72
	Illinois	18.09
	Indiana	20.10
	Kansas	7.05
	Kentucky	24.03
	Louisiana Onshore	21.22
	Louisiana Offshore	22.89
	Michigan	22.12
	Mississippi	21.10
	Montana	11.42
	North Dakota	11.64
	Nebraska	4.18
	Nevada	13.38
	New Mexico	7.86
	New York	28.07
	Ohio	24.84
	Oklahoma	9.92
	Oregon	19.92
	Pacific Offshore	18.51
	Pennsylvania	27.64
	South Carolina	28.64
	South Dakota	8.93
	Tennessee	22.77
	Texas Onshore	16.93
	Texas Offshore	21.49
	Utah	6.49
	Virginia	27.84
	West Virginia	25.67
	Wyoming	6.65
SNV	Alabama	32.28
	Arizona	6.22
	Arkansas	25.26
	Atlantic Offshore	41.46
	California Onshore	7.58
	Colorado	13.07
	Florida	40.30
	Georgia	38.00
	Illinois	28.82
	Indiana	30.84
	Kansas	16.51
	Kentucky	34.55
	Louisiana Onshore	28.58

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Louisiana Offshore	29.13
	Michigan	33.30
	Mississippi	29.20
	Montana	19.63
	North Dakota	20.35
	Nebraska	15.37
	Nevada	3.47
	New Mexico	8.34
	New York	39.22
	Ohio	35.81
	Oklahoma	18.42
	Oregon	16.35
	Pacific Offshore	7.40
	Pennsylvania	38.63
	South Carolina	38.20
	South Dakota	18.48
	Tennessee	32.81
	Texas Onshore	21.87
	Texas Offshore	27.10
	Utah	8.50
	Virginia	38.36
	West Virginia	36.31
	Wyoming	14.43
SOU	Alabama	4.18
	Arizona	27.42
	Arkansas	8.43
	Atlantic Offshore	10.90
	California Onshore	37.87
	Colorado	22.64
	Florida	11.34
	Georgia	7.18
	Illinois	9.70
	Indiana	9.30
	Kansas	17.56
	Kentucky	8.20
	Louisiana Onshore	7.81
	Louisiana Offshore	10.55
	Michigan	14.28
	Mississippi	5.77
	Montana	27.31
	North Dakota	26.58
	Nebraska	21.36
	Nevada	33.74
	New Mexico	25.23
	New York	16.41
	Ohio	12.17
	Oklahoma	15.13

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Oregon	41.36
	Pacific Offshore	36.88
	Pennsylvania	13.91
	South Carolina	7.47
	South Dakota	24.49
	Tennessee	5.17
	Texas Onshore	14.74
	Texas Offshore	12.18
	Utah	28.01
	Virginia	10.43
	West Virginia	9.83
	Wyoming	25.93
SPPN	Alabama	13.64
	Arizona	18.28
	Arkansas	7.41
	Atlantic Offshore	20.61
	California Onshore	28.02
	Colorado	11.97
	Florida	22.01
	Georgia	17.82
	Illinois	7.70
	Indiana	9.68
	Kansas	7.49
	Kentucky	13.26
	Louisiana Onshore	12.47
	Louisiana Offshore	15.15
	Michigan	13.35
	Mississippi	11.49
	Montana	16.91
	North Dakota	16.32
	Nebraska	10.49
	Nevada	23.89
	New Mexico	16.05
	New York	18.80
	Ohio	14.87
	Oklahoma	6.58
	Oregon	30.49
	Pacific Offshore	28.03
	Pennsylvania	17.68
	South Carolina	17.65
	South Dakota	13.92
	Tennessee	11.76
	Texas Onshore	12.94
	Texas Offshore	14.83
	Utah	17.50
	Virginia	17.08
	West Virginia	15.04

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Wyoming	15.10
SPPS	Alabama	11.20
	Arizona	17.67
	Arkansas	4.43
	Atlantic Offshore	20.65
	California Onshore	28.28
	Colorado	14.16
	Florida	19.48
	Georgia	16.93
	Illinois	11.33
	Indiana	12.87
	Kansas	8.86
	Kentucky	15.21
	Louisiana Onshore	8.21
	Louisiana Offshore	10.25
	Michigan	17.63
	Mississippi	8.21
	Montana	21.41
	North Dakota	20.99
	Nebraska	13.59
	Nevada	24.13
	New Mexico	15.52
	New York	22.34
	Ohio	18.01
	Oklahoma	5.82
	Oregon	32.92
	Pacific Offshore	27.08
	Pennsylvania	20.64
	South Carolina	17.26
	South Dakota	18.31
	Tennessee	12.63
	Texas Onshore	7.79
	Texas Offshore	9.48
	Utah	19.01
	Virginia	18.71
	West Virginia	17.18
	Wyoming	18.39
TVA	Alabama	8.35
	Arizona	27.00
	Arkansas	9.27
	Atlantic Offshore	11.57
	California Onshore	37.00
	Colorado	21.01
	Florida	14.92
	Georgia	9.38
	Illinois	5.89

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Indiana	5.11
	Kansas	16.43
	Kentucky	4.98
	Louisiana Onshore	11.03
	Louisiana Offshore	14.09
	Michigan	10.09
	Mississippi	8.93
	Montana	24.27
	North Dakota	23.45
	Nebraska	19.38
	Nevada	32.90
	New Mexico	24.77
	New York	12.91
	Ohio	8.49
	Oklahoma	14.64
	Oregon	39.25
	Pacific Offshore	36.71
	Pennsylvania	10.73
	South Carolina	8.86
	South Dakota	21.65
	Tennessee	3.25
	Texas Onshore	16.66
	Texas Offshore	15.30
	Utah	26.56
	Virginia	8.43
	West Virginia	6.94
	Wyoming	23.64
TVAK	Alabama	10.73
	Arizona	27.75
	Arkansas	11.08
	Atlantic Offshore	12.03
	California Onshore	37.41
	Colorado	21.13
	Florida	16.77
	Georgia	10.78
	Illinois	4.94
	Indiana	3.25
	Kansas	16.98
	Kentucky	3.82
	Louisiana Onshore	13.38
	Louisiana Offshore	16.47
	Michigan	7.71
	Mississippi	11.30
	Montana	23.31
	North Dakota	22.43
	Nebraska	19.30
	Nevada	33.35

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	New Mexico	25.51
	New York	10.73
	Ohio	6.29
	Oklahoma	15.60
	Oregon	38.86
	Pacific Offshore	37.51
	Pennsylvania	8.79
	South Carolina	9.94
	South Dakota	20.88
	Tennessee	4.40
	Texas Onshore	18.59
	Texas Offshore	17.60
	Utah	26.71
	Virginia	7.66
	West Virginia	5.56
	Wyoming	23.27
UPNY	Alabama	20.03
	Arizona	36.09
	Arkansas	21.28
	Atlantic Offshore	14.72
	California Onshore	44.58
	Colorado	28.28
	Florida	23.17
	Georgia	16.86
	Illinois	13.43
	Indiana	11.72
	Kansas	25.39
	Kentucky	10.47
	Louisiana Onshore	23.46
	Louisiana Offshore	26.43
	Michigan	7.98
	Mississippi	21.34
	Montana	26.70
	North Dakota	25.66
	Nebraska	26.05
	Nevada	40.78
	New Mexico	33.92
	New York	3.25
	Ohio	6.70
	Oklahoma	24.84
	Oregon	43.46
	Pacific Offshore	45.73
	Pennsylvania	4.90
	South Carolina	15.43
	South Dakota	25.31
	Tennessee	13.63
	Texas Onshore	28.78
	Texas Offshore	27.77

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Utah	33.58
	Virginia	9.76
	West Virginia	8.90
	Wyoming	28.77
VACA	Alabama	10.50
	Arizona	34.30
	Arkansas	15.62
	Atlantic Offshore	4.12
	California Onshore	44.44
	Colorado	28.53
	Florida	11.33
	Georgia	5.19
	Illinois	12.80
	Indiana	11.12
	Kansas	23.89
	Kentucky	7.14
	Louisiana Onshore	14.99
	Louisiana Offshore	17.26
	Michigan	13.65
	Mississippi	13.12
	Montana	31.22
	North Dakota	30.33
	Nebraska	26.88
	Nevada	40.35
	New Mexico	32.07
	New York	12.49
	Ohio	9.80
	Oklahoma	21.89
	Oregon	46.66
	Pacific Offshore	43.93
	Pennsylvania	9.72
	South Carolina	3.74
	South Dakota	28.79
	Tennessee	7.53
	Texas Onshore	22.16
	Texas Offshore	19.21
	Utah	34.09
	Virginia	5.81
	West Virginia	6.77
	Wyoming	31.03
VAPW	Alabama	14.71
	Arizona	36.20
	Arkansas	18.50
	Atlantic Offshore	7.13
	California Onshore	45.84
	Colorado	29.54
	Florida	15.91

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Georgia	9.93
	Illinois	13.24
	Indiana	11.24
	Kansas	25.45
	Kentucky	7.42
	Louisiana Onshore	18.94
	Louisiana Offshore	21.50
	Michigan	11.51
	Mississippi	16.92
	Montana	30.58
	North Dakota	29.61
	Nebraska	27.61
	Nevada	41.82
	New Mexico	33.96
	New York	8.42
	Ohio	7.43
	Oklahoma	23.95
	Oregon	46.77
	Pacific Offshore	45.95
	Pennsylvania	5.91
	South Carolina	8.48
	South Dakota	28.52
	Tennessee	9.77
	Texas Onshore	25.61
	Texas Offshore	23.29
	Utah	35.10
	Virginia	4.65
	West Virginia	5.67
	Wyoming	31.30
WUMS	Alabama	18.36
	Arizona	26.16
	Arkansas	15.53
	Atlantic Offshore	19.56
	California Onshore	34.18
	Colorado	18.00
	Florida	25.05
	Georgia	19.02
	Illinois	7.54
	Indiana	7.86
	Kansas	15.92
	Kentucky	11.21
	Louisiana Onshore	19.69
	Louisiana Offshore	22.81
	Michigan	5.49
	Mississippi	17.89
	Montana	16.61
	North Dakota	15.61

CO_2 Production Region	CO_2 Storage Region	Cost (2007$/Ton)
	Nebraska	15.69
	Nevada	30.42
	New Mexico	24.08
	New York	11.28
	Ohio	9.37
	Oklahoma	16.23
	Oregon	33.18
	Pacific Offshore	35.61
	Pennsylvania	11.68
	South Carolina	18.07
	South Dakota	14.90
	Tennessee	12.58
	Texas Onshore	22.36
	Texas Offshore	23.26
	Utah	23.14
	Virginia	14.13
	West Virginia	11.73
	Wyoming	18.28

Note:
Production Regions are equal to IPM model regions

7 Set-up Parameters and Rules

The EPA Base Case v.4.10 includes a number of assumptions that affect the way IPM treats the analysis time horizon, retrofit assignments, and environmental specifications for trading and banking. This section provides an overview of those assumptions.

7.1 Run Year Mapping

Although IPM is capable of representing every individual year in an analysis time horizon, individual years are typically grouped into model run years to increase the speed of modeling. While the model makes decisions only for run years, information on non-run years can be captured by mapping run years to the individual years they represent.

The analysis time horizon for EPA Base Case v.4.10 extends from 2012 through 2054 with IPM seeking the least cost solution that meets all constraints and minimizes net present values over this 43-year period. The six years designated as "model run years" and the mapping of calendar years to run years is shown in Table 7-1.

Table 7-1 Run Years and Analysis Year Mapping Used in the EPA Base Case v.4.10

Run Year	Years Represented
2012	2012 - 2013
2015	2014 - 2016
2020	2017 - 2024
2030	2025 - 2034
2040	2035 - 2045
2050	2046 - 2054

7.2 Retrofit Assignments

In IPM, model plants that represent existing generating units have the option of maintaining their current system configuration, retrofitting with pollution controls, or retiring early. The decision to retrofit or retire is endogenous to IPM and based on the least cost approach to meeting the system and other operating constraints included in the EPA Base Case v.4.10. IPM is capable of modeling retrofits and early retirements in two stages, enabling model plants to install two different sets of retrofits incrementally at different points in time. At each stage a retrofit set may consist of a single retrofit (e.g. LSFO Scrubber) or pre-specified combinations of retrofits (e.g., ACI + LSFO Scrubber +SCR). In EPA Base Case v.4.10 first stage retrofit options are provided to existing coal-steam and oil/gas steam plants. These plants, as well as combined cycle plants, combustion turbines, and nuclear plants, are also given early retirement as an option in stage 1. Second stage retrofit options are provided to coal-steam plants only.

Table 7-2 and Table 7-3 present the first and second stage retrofit options respectively. The costs of multiple retrofits on the same model plant, whether installed in one or two stages, are assumed to be additive. In linear programming models like IPM, projections of pollution control equipment capacity and early retirements that can occur over the modeling time horizon are limited to those retrofit and retirement options that have been pre-specified when setting up the modeled scenario. While the model decides endogenously whether and how much of each retrofit option to install, it cannot provide a retrofit that was not pre-specified before the modeling scenario was run. Table 7-2 and Table 7-3 show all the retrofit options available in EPA Base Case v.4.10.

Table 7-2 First Stage Retrofit Assignment Scheme in EPA Base Case v.4.10

Plant Type	Retrofit Option 1st Stage	Criteria
Coal Steam	Coal Early Retirement	All coal steam boilers
	Coal Steam SCR	All coal steam boilers that are 25 MW or larger and do not possess an existing SCR control option
	Coal Steam SNCR – Cyclone Boilers	All cyclone coal steam boilers that are 25 MW or larger and smaller than 100 MW, and do not possess an existing post combustion NO_x control option
	Coal Steam SNCR – Non Cyclone Boilers and Non FBC Boilers	All non cyclone and non FBC coal steam boilers that are 25 MW or larger and smaller than 100 MW, and do not possess an existing post combustion NO_x control option
	Coal Steam SNCR – FBC Boilers	All coal FBC units that are 25 MW or larger and do not possess an existing post combustion NO_x control option
	LSD Scrubber	All unscrubbed and non FBC coal steam boilers 25 MW or larger and burning less than 3 lbs/MMBtu SO_2 coal
	LSFO Scrubber	All unscrubbed and non FBC coal steam boilers 25 MW or larger
	CO_2 Capture and Storage	All scrubbed coal steam boilers 400 MW or larger
	ACI - Hg Control Option (MPAC/ SPAC/ SPAC+ Toxecon)	All coal steam boilers larger than 25 MW that do not have an ACI and have an Hg EMF greater than 0.1. Actual ACI technology type will be based on the boilers fuel and technology configuration. See discussion in Chapter 5.
	LSD Scrubber + SCR	Combination options – Individual technology level restrictions apply
	LSD Scrubber + SNCR	
	LSFO Scrubber + SCR	
	LSFO Scrubber + SNCR	
	ACI + SCR	
	ACI + SNCR	
	ACI + LSD Scrubber	
	ACI + LSFO Scrubber	
	ACI + LSD Scrubber + SCR	
	ACI + LSFO Scrubber + SCR	
	ACI + LSD Scrubber + SNCR	
	ACI + LSFO Scrubber + SNCR	
Combined Cycle	CC Early Retirement	All combined cycle units
Combustion Turbine	CT Early Retirement	All combustion turbine units
Nuclear	Nuclear Early Retirement	All nuclear power units
Oil and Gas Steam	Oil/Gas Early Retirement	All O/G steam boilers
	Oil and Gas Steam SCR	All O/G steam boilers 25 MW or larger that do not possess an existing post combustion NO_x control option

Table 7-3 Second Stage Retrofit Assignment Scheme in EPA Base Case v.4.10

Plant Type	Retrofit Option 1st Stage	Retrofit Option 2nd Stage[5]
Coal Steam	NO_x Control Option[1]	SO_2 Control Option and/or Hg Control Option and/or CO_2 Control Option
	SO_2 Control Option[2]	NO_x Control Option and/or Hg Control Option and/or CO_2 Control Option
	Hg Control Option[3]	CO_2 Control Option
	CO_2 Control Option[4]	None
	NO_x Control Option[1] + SO_2 Control Option[2]	Hg Control Option
	NO_x Control Option[1] + Hg Control Option[3]	CO_2 Control Option
	SO_2 Control Option[2] + Hg Control Option[3]	CO_2 Control Option
	NO_x Control Option[1] + SO_2 Control Option[2] + Hg Control Option[3]	CO_2 Control Option

Notes:

[1]"NO_x Control Option" implies that a model plant may be retrofitted with one of the following NO_x control technologies:
SCR, SNCR - cyclone, SNCR - non-cyclone, or SNCR - FBC

[2]"SO_2 Control Option" implies that a model plant may be retrofitted with one of the following SO_2 control technologies:
LSFO scrubber or LSD scrubber

[3]"Hg Control Option" implies that a model plant may be retrofitted with one of the following activated carbon injection technology options for reduction of mercury emissions:
MPAC, SPAC, or SPAC + Toxecon

[4]"CO_2 Control Option" implies that a model plant may be retrofitted with carbon capture and storage technology

[5] Retrofits with multiple 2nd stage options may install any combination of the listed options.

7.3 Trading and Banking

Four regional or national environmental air regulations included in EPA Base Case v.4.10 involve trading and banking of emission allowances[47]: NO_x SIP Call program, the Title IV SO_2 program, the West Region Air Partnership's (WRAP) program regulating SO_2 (as part of the federal Regional Haze Rule), and the Regional Greenhouse Gas Initiative (RGGI) for CO_2. Table 7-4 below summarizes the key parameters of these four trading and banking programs as incorporated in EPA Base Case v.4.10. Trading and banking are modeled on a U.S. system-wide basis for the Title IV SO_2 program and on a regional basis for the other three programs. EPA Base Case v.4.10 does not include any explicit assumptions on the allocation of emission allowances among model plants under any of the four programs.

[47]For a detailed discussion of the assumptions of all the environmental air regulations included in the EPA Base Case v.4.10, see chapter 3.

Table 7-4 Trading and Banking Rules in EPA Base Case v.4.10

	SIP Call - Ozone Seasons NO_x	Title IV - SO_2	WRAP- SO_2	RGGI - CO_2
Coverage	All fossil units > 25 MW[1]	All fossil units > 25 MW	All fossil units > 25 MW[2]	All fossil units > 25 MW[3]
Timing	Ozone Season (May - September)	Annual	Annual	Annual
Size of Initial Bank	The bank starting in 2012 is assumed to be zero	The bank starting in 2012 is assumed to be 11 million tons	The bank starting in 2018 is assumed to be zero	The bank starting in 2012 is assumed to be zero
Total Allowances (MTons)	2012 - 2054: 527.5	2012: 19,679 2013: 8,407 2014: 8,397 2015: 8,327 2016: 8,312 2017: 8,287 2018: 8,169 2019: 8,155 2020 - 2054: 8,153	2018 - 2054: 144.7	2012 - 2014: 188,077 2015: 183,375 2016: 178,673 2017: 173,971 2018 - 2054: 169,269

Notes:
[1] Alabama, Connecticut, Delaware, District of Columbia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia
[2] Arizona, New Mexico, Oregon, Utah, Wyoming
[3] Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, Vermont, Rhode Island, Massachusetts, Maryland

7.4 Post-2030 Modeling Assumptions and Capabilities

Previous EPA base cases had at most a usable modeling time horizon out to year 2030. EPA Base Case v.4.10 has the capability to model out to 2050. However, bottom up models like IPM, which is used to build the EPA base case, require input data at the finest possible level of granularity. Preferably, such data would be based on gathered information obtained through regulatory submittals, surveys, and scientific, engineering, economic, and commercial assessments specifically related to the particular characteristics of the issue being modeled. Past 2030 or 2035 such information is rarely available.

As a result, a two tiered approach was taken to the inputs used to build EPA Base Case v.4.10. Prior to 2030 assumptions would be based to the greatest extent possible on verifiable empirical data gathered from the best available sources vetted using cross-checks against alternative data sources. Beyond 2030 a pragmatic approach was taken. Where credible empirical data was available, it would be used. Where empirical data was not available, technically plausible, explicitly articulated assumptions would be used to extrapolate pre-2030 assumptions out to 2050. While perhaps not optimal, such an approach was seen as potentially valuable, if only because it would focus attention on the long-range assumptions needed for bottom-up modeling and, in doing so, elicit comments from the interested public and technical experts. This could lead to future improvements in the long-range inputs with possible side benefits for all projections whether based on bottom-up, top-down or hybrid modeling approaches.

A corollary of this two tiered approach to input assumptions is that the modeling results past 2030 should be viewed somewhat differently from those prior to 2030. The pre-2030 modeling results

are expected to bear scrutiny at a fine level of granularity (answering questions like the plausibility of a particular generating unit being retrofit with a dry SO_2 scrubber and a SCR in a particular model run year or of another generating unit being retired by IPM in a certain year).

The post-2030 modeling results are not intended to be examined at such a fine grain level. Instead, the post-2030 modeling capability is designed to serve two purposes: The first purpose is to ensure that EPA Base Case v.4.10 takes into account the potential impact of post-2030 policy provisions on pre-2030 modeling results. For example, it would be useful to have the capability to project the impact on pre-2030 modeling results of a provision in a Climate Change bill that takes effect in 2042. The second purpose is to give a broad sense of directional trends beyond 2030. For example, using current technology cost and performance assumptions, the long-range modeling capability could provide a picture of the likely composition of the power sector in 2040 or 2050 with and without policy intervention. To take fuller advantage of this capability, five generic placeholder future generation technologies have been included in EPA Base Case v.4.10. While not playing a role in the base case itself, their presence allows a user to define their cost and performance characteristics at a later time and to perform sensitivity analysis to see the possible impact of new technologies on post-2030 trends.

Table 7-5 shows the underlying post-2030 modeling assumptions incorporated in EPA Base Case v.4.10 for key modeling parameters.

Table 7-5 Post-2030 Assumptions in EPA Base Case v.4.10

Topic	Post-2030 Assumptions
POWER SYSTEM OPERATION	
Model Regions	Same as pre-2030
Electric Load Modeling	
Electric Load Growth	Post 2035 growth rate is based on AEO 2010 2025-2035 growth rate
Net Internal Demand (Peak Demand)	Post 2035 growth rate is based on AEO 2010 2025-2035 growth rate
Load Duration Curves (LDCs)	2007 load curves adjusted to post 2030 energy and peak load projections. LDCs include six segments per season in run years 2012, 2015, 2020, and 2030 and four segments in 2040 and 2050.
Transmission	
Interregional Transmission Capability	Same as pre-2030
Transmission Link Wheeling Charge	Same as pre-2030
Transmission Losses	Same as pre-2030
International Imports	
Mexico	Same as 2030
Canada	Endogenously Modeled
Capacity, and Dispatch	
Availability	Same as pre-2030 for all plant types except nuclear Same as 2030 for nuclear
Capacity Factor	Same as 2030
Turndown	Same as pre-2030
Reserve Margins	Same as pre-2030
Power Plant Lifetimes	Same as pre-2030
Existing Environmental Regulation	
SO_2 Regulations	Same as 2030

Topic	Post-2030 Assumptions
NO_x Regulations	Same as 2030
State Specific Environmental Regulations	Same as 2030
New Source Review (NSR)	Same as 2030
Emission Assumptions for Potential (New) Units	Same as pre-2030
Capacity Deployment Constraints	Run year specific
GENERATING RESOURCES	
National Electric Energy Data System (NEEDS)	Same as pre-2030
Existing Units and Planned/Committed Units	
Population of Existing Units	Same as pre-2030
Capacity	Same as pre-2030
Plant Location	Same as pre-2030
Online Year	Same as pre-2030
Unit Configuration	Same as pre-2030
Model Plant Aggregation	Same as pre-2030
Cost and Performance of Existing Units	Same as pre-2030
Heat Rates	Same as pre-2030
NO_x Rates	Same as pre-2030
Potential Units	
Cost and Performance of Potential Conventional Technologies	Same as pre-2030
Cost and Performance of Potential Renewable Technologies	
Biomass	Same as 2030
Wind	Same as 2030
Solar	Same as 2030
Geothermal	Same as pre-2030
Landfill Gas	Same as 2030
Short Term Cost Adder	None
Regional Adjustment Factor	Same as pre-2030
Nuclear Units	
Existing Nuclear Units	
VOM and FOM Cost Assumptions for Nuclear Units	Same as pre-2030 (adjusted for life extension costs)
Nuclear Upratings (MW)	None
Nuclear Scheduled Retirements (MW)	Retirement at age 60 years
Potential Nuclear Units	Same as 2030
EMISSION CONTROL TECHNOLOGIES	
Sulfur Dioxide Control Technologies	
Limestone Forced Oxidation (LSFO)	Same as pre-2030
Lime Spray Drying (LSD)	Same as pre-2030
FGD Engineering Cost Equations	Same as pre-2030
Nitrogen Oxides Control Technology	
Combustion Controls	Same as pre-2030
Post-combustion Controls	Same as pre-2030
SCR and SNCR Engineering Cost Equations	Same as pre-2030
Mercury Control Technologies	
Mercury Content of Fuels	Same as pre-2030

Topic	Post-2030 Assumptions
Mercury Emission Modification Factors	Same as pre-2030
Mercury Control Capabilities	Same as pre-2030
ACI Engineering Cost Equations	Same as pre-2030
CO_2 Sequestration	
CO_2 capture	Same as pre-2030
CO_2 transport	Same as pre-2030
CO_2 storage cost curves	Same as pre-2030
SETUP PARAMETERS AND RULES	
Run Year Mapping	Run year specific
Retrofit Assignments	Same as pre-2030
FINANCIAL ASSUMPTIONS	
Methodology	
Capital Charge Rates for Investments	Same as 2030
Discount Rate for Capital and Non-Capital Costs	Same as pre-2030
FUEL ASSUMPTIONS	
Coal	
Coal Markets	Same as pre-2030
Coal Supply Curves	2030 cost-adjusted for labor productivity
Coal Transportation Costs	2030 cost-adjusted for fuel price changes
Coal Assignments	Same as pre-2030
Emission Factors	Same as pre-2030
Natural Gas	
Resources Data and Reservoir Description	
Field Development and Production Forecast Methodology	Same as pre-2030
Lower 48 States U.S. Resources	Same growth as pre-2030
Canada Resources	Same growth as pre-2030
Treatment of Frontier Resources	Alaska North Slope starts 2040
Exploration and Production (E&P) Technology Characterization	Same as 2030
End Use Demand Characterization	Same growth as pre-2030
Pipeline and Transport	
Existing pipelines	Same as pre-2030
Potential pipeline costs	Same growth as pre-2030
Emission Factors	Same as pre-2030
Fuel Oil	
Prices	Same as 2035
Emission Factors	Same as pre-2030
Biomass	
Biomass Supply Curves	Same as 2035
Emission Factors	Same as pre-2030
Nuclear Fuel Prices	Same as 2030

8 Financial Assumptions

This chapter presents the financial assumptions used in EPA Base Case v.4.10. The first section gives a summary of each of the key financial parameters. The remainder of the chapter presents an in-depth explanation of the theoretical underpinnings and methods used to develop the two most important financial parameters – the discount rate and capital charge rate.

8.1 Summary of Key Financial Parameters

8.1.1 Capital Charge Rate, Book Life, and Discount Rate for Capital Expenditures

EPA Base Case v.4.10 models a diverse set of generation and emission control technologies, each of which requires financing.[1] Table 8-1 presents the capital charge rate, discount rate, and book life assumptions for the technologies in base case v.4.10. As will be discussed more fully later in this chapter, the capital charge rate is used to convert the capital cost of a technology into a stream of levelized annual payments that ensure capital recovery. The discount rate is used to translate future cash flows into current dollars by taking into account factors (like inflation and the ability to earn interest), which make one dollar tomorrow worth less than one dollar today. The discount rate allows inter-temporal tradeoffs and represents the risk adjusted time value of money. The book life is the payback period on an investment.

There are several things to note about Table 8-1. The technology differentiated capital charge rates are used in v.4.10 to derive the associated capital charge rates shown in the table. However, while the technology-differentiated discount rates appearing in the table were used in deriving these capital charge rates, in EPA Base Case v.4.10 a single U.S. discount rate of 6.15% is used across all technologies.

[1] The capital charge rates discussed here apply to new (potential) units and environmental retrofits that IPM installs. The capital cost of existing and planned/committed generating units and the emission controls already on these units are considered “sunk costs” and are not represented in the model.

Table 8-1 U.S. Discount Rates and Capital Charge Rates in EPA Base Case v4.10

Investment Technology	Capital Charge Rate	Discount Rate	Book Life
Environmental Retrofits	11.3%	5.5%	30
Advanced Combined Cycle	12.1%	6.2%	30
Advanced Combustion Turbine	12.9%	6.9%	30
Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture[1]	14.1%	7.8%	40
Advanced Coal with Carbon Capture	11.1%	5.5%	40
Nuclear without Production Tax Credit (PTC)	10.8%	5.5%	40
Nuclear with Production Tax Credit (PTC)[2]	9.1%	5.5%	40
Biomass with ARRA Loan Guarantees[3]	9.3%	4.6%	40
Biomass without ARRA Loan Guarantees	11.1%	6.2%	40
Wind and Landfill Gas with ARRA Loan Guarantees[2]	10.1%	4.6%	20
Wind and Landfill Gas without ARRA Loan Guarantees	12.2%	6.2%	20
Solar and Geothermal with ARRA Loan Guarantees[2]	10.1%	4.6%	20
Solar and Geothermal without ARRA Loan Guarantees	12.2%	6.2%	20

Notes:
The discount rates appearing in the table were used in deriving these capital charge rates. However, as noted in the text, a single U.S. discount rate of 6.15% is used across all technologies in EPA Base Case v.4.10.
[1]The capital charge rate for these technologies includes a 3% climate change uncertainty adder. (See text.)
[2]The capital charge rate for this technology reflects the impact of the PTC provided under the Energy Policy Act of 2005. (See text.)
[3]The capital charge rate for these technologies reflects the impact of ARRA loan guarantees. (See text.)

Capital Cost Adder for Climate Change Uncertainty: Adopting the procedure followed in EIA's Annual Energy Outlook 2010, the capital charge rates shown in Table 8-1 for Supercritical Pulverized Coal and Integrated Gasification Combined Cycle (IGCC) without Carbon Capture include a 3% adder to the cost of debt and equity (see section 8.2.3 for discussion of debt and equity). This capital cost adder reflects increased financing costs for investment decisions involving coal plants without carbon capture caused by uncertainty surrounding possible future climate change policies that could limit CO_2 emissions from the power sector

ARRA Loan Guarantees for Renewables and Biofuels: The American Recovery and Reinvestment Act (ARRA) of 2009 (Public Law 111-5) provides loan guarantees for renewables and biofuels. Following the procedure implemented in AEO 2010, these loan guarantees are reflected in a reduction of 2% in the cost of debt and equity for biomass, wind, landfill gas, solar, and geothermal technologies. Capital charge rates with and without the 2% reduction appear in Table 8-1 because the loan guarantees expires in 2016.

Energy Policy Act Production Tax Credit for Nuclear: The Energy Policy Act of 2005 (Sections 1301, 1306, and 1307) provides a production tax credit (PTC) of 18 mills/kWh for 8 years up to 6,000 MW of new nuclear capacity. The financial impact of the credit is reflected in the capital charge rate shown in Table 8-1 for "Nuclear with Production Tax Credit (PTC)."

8.1.2 ARRA Production and Investment Tax Credit (PTC and ITC) for Renewables

In addition to the loan guarantees that are reflected in the capital charge rates for renewables shown in Table 8-1, ARRA 2009 (Division B, Title I, Sec. 1101, 1102, and 1603) also provides extensions of the PTC and 30 percent ITC to renewables. These are represented in EPA Base Case, v.4.10 as a 30% reduction in the capital cost of these technologies in 2012.

8.1.3 Discount Rate for Non-Capital Expenditures

The discount rate for non-capital expenditures (e.g., annual fuel, variable operations and maintenance, and fixed operations and maintenance costs) in EPA Base Case v.4.10 is assumed to be 6.15%. This serves as the default discount rate for all non-capital expenditures.

8.1.4 Inter-temporal Allowance Price Calculation

Under a perfectly competitive cap-and-trade program that allows banking, the allowance price always increases by the discount rate between periods if affected sources have allowances banked between those two periods. This is a standard economic result for cap-and-trade programs and prevents sources from profiting by arbitraging allowances between two periods.

The EPA Base Case v.4.10 uses the default discount rate of 6.15 percent in computing the increase in allowance price for cap-and-trade programs when banking is engaged as a compliance strategy.

8.1.5 Nominal and Real Dollars

EPA Base Case v.4.10 uses real 2007 dollars as its real dollar baseline. See Chapter 2 for further discussion on how IPM uses the real dollars for inter-temporal analysis.

8.2 Development of the Financial Assumptions for EPA Base Case v.4.10

This section explains the method used to derive the capital charge rate and discount rate as well as the assumptions underlying these financial parameters.

8.2.1 Introduction

As noted in section 8.1, the discount rate and the capital charge rate are the two parameters that encapsulate the financing assumptions for an investment option in EPA Base Case, v.4.10. The discount rate allows inter-temporal tradeoffs and represents the risk adjusted time value of money. The capital charge rate is used to convert the capital cost into a stream of levelized annual payments that ensures capital recovery of an investment.

Discount Rate

The discount rate is a function of the following parameters:

- Capital structure (Share of Equity vs. Debt)
- Post-tax cost of debt (Pre-tax cost of debt*(1-tax rate))
- Post-tax cost of equity

The weighted average cost of capital (WACC) is used as the discount rate and is calculated as follows:

WACC = [Share of Equity * Cost of Equity]
+ [Share of Preferred Stock * Cost of Preferred Stock]
+ [Share of Debt *After Tax Cost of Debt]

The focal point is on debt and equity (common stock) because preferred stock is generally a small share of capital structures.

Capital Charge Rate

The capital charge rate is a function of the parameters that overlap in part with the discount rate, but also include parameters related to the amortization of capital:

- Capital structure (Debt/Equity shares of an investment)
- Pre-tax debt rate (or interest cost)
- Debt Life

- Post-tax Return on Equity (ROE) (or cost of equity)
- Other costs such as property taxes and insurance
- State and Federal corporate income taxes
- Depreciation Schedule
- Book Life

The capital charge rate is calculated by solving for earnings before interest, taxes, and depreciation (EBITDA) or pure operating earnings such that the project is able to recover the cost of equity as the internal rate of return over the lifetime of the project. The sum of discounted cash flows to the equity holders over the lifetime of the project, discounted at the cost of equity is set equal to the initial investment. The capital charge rate so calculated is defined as follows:

- Capital Charge Rate = EBITDA/Total Investment

In other words, the capital charge rate is the rate of return required on invested capital, resulting from pure operations.

8.2.2 Method for Deriving Discount Rate and Capital Charge Rate in EPA Base Case v 4.10

Introduction to Risk

The risk of an investment in the power sector is heavily dependent on market structure risks. The range of risks has increased due to deregulation which has resulted in approximately 35 percent to 40 percent of capacity being deregulated IPP (Independent Power Producer) capacity. For example, merchant IPP's selling into spot market have more market risk than regulated plants or IPP's having long-term, known-price contracts with credit worthy counter parties. There are also technology risks and financing structure risks (corporate vs. project financings). Lastly, there is financial risk related to the extent of leverage.

The risk, especially to the extent it is correlated with overall market conditions, is an important driver of financing costs. Other risks are handled in the cash flows and are treated as non-correlated with the market. This emphasis on correlated market risk is based on the Capital Asset Pricing model and associated financial theory. This analysis takes into account differences in technology and market structure risks.

Differences between corporate and project financings are highlighted but no specific adjustment has been made for them.

Market Structure Risks

The power sector in North America can be divided into the traditional regulated sector (as known as "cost of service" sector) and deregulated merchant sector (as known as "competitive" sector).

- **Traditional Regulated** - The traditional regulated market structure is typical of the vertically integrated utilities where generation (and transmission and distribution, abbreviated T&D) investments are approved through a regulatory process and the investment is provided a regulated rate of return. Returns on investment in this form of market structure are cost plus regulated returns that are administratively determined. Returns are affected by market conditions due to regulatory lag and other imperfections in the process, but overall are less exposed to the market than deregulated investments, all else equal. In this report, we use the term "utility financing" to refer to this type of market structure. A closely related market structure is the situation where a plant is built under a power purchase agreement (PPA) with a utility with known pricing that allows for a very high degree of investment amortization during the contract period. In such an arrangement, the risks are more credit and performance related and much less market related.
- **Deregulated Merchant** - In a deregulated merchant market structure, investments bear the full or a very high degree of market risk as the price that they can sell electricity at is dependent on what the short-term markets will bear. Return on investment in this form of market structure is not only dependent on the state of the economy, but also on commodity

prices, as well as on capital investment cycles and remaining price related regulation, e.g., FERC price caps on capacity prices. The capital investment cycle can create a "boom and bust" cycle which imparts source risk or uncertainty to the sector. The operational cash flows from investments in this sector are more volatile as compared to in the traditional regulated sector, and hence, carry more business or market risk. In this report, we use the term "merchant financing" to refer to this type of market structure.

Technology Risks

The selection of new technology investment options is partially driven by the risk profile of these technology investments. For instance, in a deregulated merchant market, an investment in a combustion turbine is likely to be much more risky than an investment in a combined cycle unit because while a combustion turbine operates as a peaking unit and is able to generate revenues only in times of high demand, a combined cycle unit is able to generate revenues over a much larger number of hours in a year. An investor in a combined cycle unit, therefore, would require a lower risk premium than an investor in a combustion turbine.

Financing Structure Risks and Approach

While investments in new units differ based on market structure and technology risks, differences also may occur because of financing schemes available. There are two major types of financing schemes:

- Corporate finance is a category of financing where a developer raises capital on the strength of the balance sheet of a company rather than a single project. In this type of financing, the debtors have recourse to the entire company's assets.
- Project finance, as this category of financing is often labeled, allows developers to seek financing using only the project as recourse for the loan. For instance, a project developer may wish to develop a new combined cycle unit, but will seek to use project financing in such a way that if it defaults on the loan, debtors have recourse only to the project itself and not against the larger holdings of the project developer. This approach can be more risky than corporate finance, all else being equal, because there is less diversification than the corporation which can be thought as a collection of projects. However, there are some projects more suitable for project financing because: (1) they may have a self-sustaining revenue stream that is greater than the corporate average, or (2) risk is reduced through a long-term PPA with a credit worthy counterparty such as a vertically integrated utility or a regulated affiliate of a merchant company.

There are many benefits of a project financing structure but there are also costs associated with it. A project financing structure typically has higher transaction costs (and even higher debt costs as debt financing is largely privately placed), but it also solves some of the agency problems and underinvestment issues that corporate financed structures face1.

However, as noted above, this analysis does not make an effort to quantify the relative costs and benefits of one structure over the other. Rather, the approach used is based on the premise that regardless of financial structure, each project has its own risks based on market structure and technology. Further, because corporate financing is more observable than project financing2 and has evolved in the power sector to the level of making key risk inferences possible (e.g., IPP and utility stock trades), assessment of market correlated risks should be based on IPP and utility corporate financing.

---

[1] For more information on project financing, see paper titled "The Economic Motivations for Using Project Finance" by Benjamin C. Esty, Harvard Business School, Feb 2003

[2] Project Financing data is less observable as it's not explicitly traded. Also, often key financing parameters are unavailable due to confidentiality reasons.

Approach to Market Structure Risk
In EPA Base Case 4.10, a hybrid financing model is used, i.e., it is assumed that future development activity would be roughly evenly split between utility financings and pure merchant financings. This is designed to reflect a shift in the market in ownership and risk profiles for power generation assets, and recent development trends and emphasis on long term contracts3. In this approach, for modeling purposes, we assume that new units are financed as a weighted average of utility and merchant financing parameters. For new units we assume that both utility and merchant components get equal weights. For retrofits, we assume that utility component gets 2/3 and merchant component gets 1/3 weight4.

- Example 1: The debt to equity capital structure of a combustion turbine is 55/45 under utility financing and 30/70 under merchant financing. Under the assumption that utility and merchant components get equal weights, the debt to equity ratio under hybrid financing is D = (55 + 30)/2 = 42.5 / E = (45 + 70)/2 = 57.5.
- Example 2: The debt to equity capital structure of a retrofit is 55/45 under utility financing and 45/55 under merchant financing. Under the assumption of a 2/3, 1/3, utility/merchant weighting, the debt to equity ratio under hybrid financing is D = (55 * 2/3) + (45 * 1/3) = 51.6 / E = (45 * 2/3) + (55 * 1/3) = 48.3. A full summary for all technologies appears in Table 8-2 below.

Capital Charge Rate – A More Detailed Description
The capital charge rate is calculated by solving for earnings before interest, taxes, and depreciation (EBITDA) or pure operating earnings such that the project is able to recover the cost of equity as the internal rate of return over the lifetime of the project. The sum of discounted cash flows to the equity holders over the lifetime of the project, discounted at the cost of equity is set equal to the initial investment. The capital charge rate so calculated is defined as follows:

Table 8-2 Capital Structure Assumptions for EPA Base Case v4.10

Technology	Utility	Merchant	Hybrid
Combustion Turbine	55/45	30/70	42.5/57.5
Combined Cycle	55/45	45/55	50/50
Coal & Nuclear	55/45	60/40	57.5/42.5
Renewables	55/45	45/55	50/50
Retrofits	55/45	45/55	51.7/48.3

- Capital Charge Rate = EBITDA/Total Investment

In other words, the capital charge rate is the rate of return required on invested capital, resulting from pure operations.

---

[3]An alternate approach is to categorize the United States into the two previously discussed financial regions – Cost-of-service and competitive. The cost-of-service region will have capital charge rates based on utility financial assumptions and the competitive region will have capital charge rates based on merchant financial assumptions. Such an approach could result in overbuilding in the cost-of-service region due to lower capital charge rates in the absence of regulatory prohibitions or external sales. This is similar to the public vs. IOU financing arbitrage problem, i.e. what stops government utilities from supplying all power? In fact, there are formal and informal limits, and because fully characterizing these limits is extremely complex, a hybrid approach is used.

[4]Retrofits are largely associated with coal fired plants and most coal fired plants are currently owned and operated by utilities in a “utility financing” structure. Moreover, since the magnitude of the retrofit investment is not as large as a plant investment, the financing of a retrofit is more likely to happen from a firm’s internal cash flows instead of external financing.

The discounted cash flow to the equity holders of the project is characterized in terms of the Free Cash Flow to Equity (FCFE). FCFE is a valuation technique to estimate cash flows paid to the equity shareholders of a company after all expenses, reinvestment, and debt repayment have been made. The FCFE approach is suited for valuation of assets that have finite economic lives and where debt levels vary from year to year. In the FCFE approach, it is assumed that the asset has a finite life and debt reduces over time based on a mortgage-style repayment structure.

Specifically the cash flows to the equity5 are calculated as follows:

Cash Flows to Equity = EBIT (1-tax rate)
- Interest (1-tax rate)
+ Depreciation
- Capital Expenditures
- Working Capital Change
- Principal Payments
+ New Debt Issued

Discount Rates and Capital Charge Rates
Based on the above approach, the discount rates and capital charge rates summarized in Table 8-1 above were obtained for investments in the U.S. The procedures and assumptions used to calculate the rates in Table 8-1 are discussed in the sections below.

8.2.3 Calculation of the Hybrid Capital Charge Rates

ROE
The first step was the calculation of a return on equity (ROE) using an average ROE under utility financing (10.3%) and merchant financing (15.2%) assuming a 50:50 debt/equity ratio. This resulted in a ROE of 12.75%6. This ROE is kept the same across each technology7 but the risk differences across technologies are implemented through the capital structure. See the discussion of capital structures in this subsection under “Debt Equity Share” and the discussion of “Debt and Equity Shares and Technology Risk” in section 8.2.4.

Note that a 50:50 mix (corresponding to the hybrid capital structure for a combined cycle – see Table 8-2) has been chosen. This is because we assumed that the overall IPP risk was on average reflective of the risk profile of combined cycle units which in turn was assumed to be intermediate between base load and peaking. The combined cycle technology is considered to have “average” market risk being an intermediate type technology. Also, in the aggregate, the five selected IPP companies[8] have more combined cycle capacity in their supply mix than any other technology. Additionally, going forward, it is expected that gas will continue to play an increasingly important role in the supply mix of both utilities and merchant companies, with combined cycle technology playing a dominant role. For all of these reasons, it was considered appropriate to use the ROE corresponding to a combined cycle facility.

---

[5]An alternative definition of free cash flow to equity is as follows: Net Income + Depreciation – capital expenditures – working capital change – Principal Payments + New Debt Issued

[6]The Pennsylvania-New Jersey-Maryland Interconnection (PJM) uses a 12% ROE for a combined cycle at a 50:50 debt/equity ratio to calculate the cost of new entry (CONE) for their capacity markets. Hence, the estimates are fairly close to those used by a major RTO.

[7]Even though ROE is kept the same across all technologies, it doesn’t mean that the market risks are considered the same for each technology. See capital structure discussion in the next paragraph.

[8]Our merchant parameters are derived from market observations of five IPP companies – see discussion on development of merchant financed parameters.

Debt Equity Share
Second, the capital structures (D/E)9 for the various technology types were calculated using an average of utility and merchant financing. The utility debt capacity (and returns) is assumed to be independent of technology type based on the theoretical assumption that regulation will provide an average return to the entire rate base. The merchant debt capacity is based on market risk where a base load plant is likely to have a higher debt capacity than a combustion turbine plant. Table 8-2 presents the capital structure assumptions used in EPA Base Case v4.10.

The risk differences across technologies are implemented by varying the capital structure. As shown in Table 8-2 and discussed above, a peaking unit such as a combustion turbine is estimated to have a capital structure of 42.5/57.5 while a base load unit such as nuclear and coal is assumed to have a capital structure of 57.5/42.5. This is based on the intuition that less risky technologies can carry more leverage. As debt is less expensive than equity, this will automatically translate into a lower capital charge rate (and a lower discount rate) for base load technologies and a higher capital charge rate (and a higher discount rate) for peaking technology, assuming other components of the capital charge rate calculation remain the same.

Cost of Debt
Third, the cost of debt was adjusted to reflect the average cost of debt for utility and merchant financings for each technology. The utility cost of debt is assumed to be the same across all technologies while the merchant cost of debt is higher than utility and is higher for a combustion turbine unit than for a combined cycle or a coal plant. Table 8-3 summarizes the debt rates used in EPA Base Case v4.10.

Table 8-3 Debt Rates for EPA Base Case v4.10

Technology	Utility	Merchant	Hybrid
Combustion Turbine	6.25%	9%	7.63%
Combined Cycle	6.25%	8%	7.13%
Coal & Nuclear	6.25%	8%	7.13%
Wind	6.25%	8%	7.13%
Retrofits	6.25%	8%	6.83%

These financing parameters were then combined with taxation assumptions and technology specific assumptions on depreciation, book life and debt life to yield the capital charge rates outlined in Table 8-1 above.

8.2.4 Development of Merchant Financing Parameters

Merchant ROE
The Independent Power Producer (IPP) return on equity parameter was estimated to be 15.2%[10]. This was based on empirical analysis of stock price data of five pure play comparable merchant generation companies, namely Reliant, NRG, Dynegy, Mirant, and Calpine. First, levered betas[11] (a measure of total corporate risk which includes business and financial risk) for the five companies were calculated using five years of historical stock price data. Second, unlevered betas (a measure of business risk, i.e., those affected by a firm's investment decisions) were

[9]A project's capital structure is the appropriate debt capacity given a certain level of equity, commonly represented as "D/E," i.e., debt/equity. The debt is the sum of all interest bearing short term and long term liabilities while equity is the amount that the project sponsors inject as equity capital.

[10]Merchant ROE, as additionally observed by EIA, have risen over time.

[11]Levered beta is directly measured from the company's stock returns with no adjustment made for the debt financing undertaken by the company. It is also known as equity beta. Hence, levered beta incorporates both business and financing risk undertaken by the company.

calculated using the estimated levered beta, the companies' market debt/equity ratio, and the riskiness of debt. As most comparables historically had periods of financial distress, the unlevering[12] approach was modified to include the riskiness of debt, instead of purely using the Hamada equation.[13] The unlevered betas were then relevered[14] at the target debt/equity ratio of 50/50 to get the relevered equity betas and return on equity. The return on equity was determined using the Capital Asset Pricing Model (CAPM).

The CAPM parameters used to estimate the ROE are as follows:

- Risk Free Rate based on 20 year T bond rate: 4.9%[15]
- Market Risk Premium 1926-2006[16:] 7.1%
- Size Premium: 0.65%[17]

The estimation of the IPP ROE described here is fairly close to what EIA has published. EIA estimates a 2010 ROE of roughly 14.8% at a D/E ratio of 45/55 and increasing to approximately 16% by 2012.[18]

Merchant Cost of Debt
The cost of debt for the merchant sector was computed assuming an average 3-month LIBOR (London Interbank Offered Rate) of 4.9-5% and an average spread of 3% reflecting the low medium grade or low grade nature of merchant bonds. An additional one percent spread was assumed for combustion turbine units due to the high price risk for combustion turbine units.

Debt and Equity Shares and Technology Risk
The capitalization structure for merchant financings was estimated to be 45/55 based on empirical analyses. This capitalization structure was assumed to be on average reflective of the combined cycle for reasons discussed earlier in this document.

Each generation technology was considered to have its own risk profile. Some evidence indicated that the greater the base load share, the lower the asset risk. This is consistent with having revenues that are more related to variable cost advantages as well as the value of capacity as opposed to peaking units which are more dependent on scarcity or capacity revenue, which, in turn, has very high systemic risk.

There are two main mechanisms for reflecting the greater risk for peakers and the lower risk for base load. First, the ROE could have been adjusted such that for a given target leverage, the ROE would be higher for peakers, and lower for base load. For example, an unlevered beta and

---

[12]The unlevering process removes a company's financing decision from the beta calculation. The calculation therefore, attempts to isolate the business (operating risk) of the firm.

[13]The Hamada equation is described at http://www.answers.com/topic/hamada-equation as "A fundamental analysis method of analyzing a firm's costs of capital as it uses additional financial leverage, and how that relates to the overall riskiness of the firm. The measure is used to summarize the effects this type of leverage has on a firm's cost of capital (over and above the cost of capital as if the firm had no debt)."

[14]The relevering process estimates the levered beta of the firm given a target capital structure and the pure business risks of the firm as determined from the unlevering process

[15]Federal Reserve Statistical Release (H15 data), May 2007

[16]Source: Stocks, Bonds, Bills, and Inflation, 2007 Yearbook Valuation Edition, Morningstar/Ibbotson's Associates

[17]Source: Stocks, Bonds, Bills, and Inflation, 2007 Yearbook Valuation Edition, Morningstar/Ibbotson's Associates

[18]See Electricity Market Module of NEMS, EIA Annual Energy Outlook, May 2009

ROE (which assumes zero leverage) could have been calculated using the risk differentiated capital structures and then relevered at some target leverage. This would have yielded a different ROE for each technology but the same capital structure across all technologies.

The second option was to keep the same ROE while varying the capital structure. This was the adopted approach. Thus, even though the leverage of peakers was lowered, the ROE was not lowered. This raised the weighted average cost of capital and the resulting capital charge rate. This effectively also raised the unlevered beta for peakers relative to combined cycle. For base load, leverage was raised without raising ROE, effectively lowering the unlevered beta and the cost of capital.

8.2.5 Development of Utility Financing Parameters

Utility ROE

The utility return on equity was calculated to be 10.3%. This was based on empirical analysis of correlation of returns on the S&P utility Index vs. the broader S&P 500 market index for the last five years to determine the levered beta and then unlevering and relevering based on a process similar to that for merchant sector. The ROE is also consistent with what state commissions have awarded the shareholder-owned electric utilities recently.[19]

Utility Cost of Debt

The cost of debt for the utility sector was estimated to be 6.25%. The utility bonds were categorized into various credit rating rungs based on information obtained from the Edison Electric Institute.[20] Historical yields were analyzed for the various rungs based on data obtained from Bloomberg. A weighted average cost of debt was then determined based on the historical yields and percentages of utility credit rating classes. The estimated value was also corroborated against the yield to maturity of Moody's average utility bond index.

Debt and Equity Shares

The target capitalization structure for utilities was determined using US utility capitalization ratios derived from Bloomberg data. Similar CAPM parameters were used to estimate the ROE of the utility sector. The capitalization structure for utility financings was estimated to be 55/45 based on empirical analyses and this capitalization structure was assumed to be on average reflective of all technologies.

Technology Risks

For the utility financing, we assumed that the required returns for regulated utilities are independent of technology. This assumption was a simplifying assumption, and further empirical work may be warranted here.

8.2.6 Development of Other Parameters

Taxation and Insurance Costs

Corporate and State Income Taxes: The maximum US corporate income tax rate is 35%.[21] State taxes vary but on a national average basis, the state taxes are 6.50%.[22] This yields a net effective tax rate of 39.3%.

---

[19]See page 35, 2006 Financial Review, Annual Report of the U.S Shareholder Owned Electric Utility Industry

[20]2006 Financial Review, Annual Report of the U.S Shareholder Owned Electric Utility Industry

[21]Internal Revenue Service, Publication 542.

[22]Population weighted average based on 2008 state taxes information available at Federation of Tax Administrators, ttp://www.taxadmin.org/fta/rate/corp_inc.html.

State Property Taxes: US state property taxes are approximately 0.9% based on a national average basis. This is based on extensive primary and secondary research conducted by ICF using property tax rates obtained from various state agencies.

Insurance Costs: Insurance costs are approximately 0.3%. This is based on estimates of insurance costs on a national average basis.

Inflation
The inflation rate of 2.25% is based on an assessment of implied inflation from an analysis of yields on 5 year and 10 year Treasury securities and Treasury Inflation Protected Securities (TIPS).

Book life, Debt Life and Depreciation
Table 8-4 presents a summary of various assumed lives at the national level.

Table 8-4 Book Life, Debt Life and Depreciation Schedules for EPA Base Case v. 4.10

Technology	Book Life (Years)	Debt Life (Years)	US - MACRS Depreciation Schedule
Combined Cycle	30	20	20
Combustion Turbine	30	15	15
Coal Steam and IGCC	40	20	20
Nuclear	40	20	15
Solar and Geothermal	20	20	5
Biomass	40	20	7
Wind and Landfill Gas	20	20	7
Retrofits	30	20	20

Book Life or Useful Life of Plant:
The book life or useful life of a plant was estimated based on researching financial statements of utility and merchant generation companies. The financial statements[23] typically list the period over which long lived assets are depreciated for financial reporting purposes. The research conducted broadly supports the numbers outlined in the table above.

Debt Life: The debt life is assumed to be on a 20 years schedule except in the case of combustion turbine where debt life is lower.

Depreciation Schedule:
The US MACRS[24] depreciation schedules were obtained from IRS Publication 946[25] that lists the schedules based on asset classes. The document specifies a 5 years depreciation schedule for wind energy projects and 20 years for Electric Utility Steam Production plants. These exclude combustion turbines which have a separate listing at 15 years. Nuclear Power Plants are separately listed at 15 years as well.

[23]SEC 10K filings of electric utilities and pure merchant companies. For example, Calpine's 10K lists 35 years of useful life for base load plants, DTE energy uses 40 years for generation equipment; Dynegy gives a range of 20-40 years for power generation facilities; Mirant reports 14-35 years for power production equipment; Reliant: 10-35 years

[24]MACRS refers to the Modified Accelerated Cost Recovery System, issued after the release of the Tax Reform Act of 1986. It allowed faster depreciation than with previous methods.

[25]IRS Publication 946, "How to Depreciate Property", Table B-2, Class Lives and Recovery Periods.

9 Coal

The next three chapters cover the representation and underlying assumptions for fuels in EPA Base Case v.4.10. The current chapter focuses on coal, chapter 10 on natural gas, and chapter 11 on other fuels (fuel oil, biomass, nuclear fuel, and waste fuels) represented in the base case.

This chapter presents four main topics. The first is a description of how the coal market is represented in EPA Base Case v.4.10. This includes a discussion of coal supply and demand regions, coal quality characteristics, and the assignment of coals to power plants.

The next topic is the coal supply curves which were developed for EPA Base Case v.4.10 and the painstaking bottom-up, mine-based approach used to develop curves that would depict the coal choices and associated prices that power plants will face over the modeling time horizon. Included are discussions of the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 84 coal supply curves that are implemented in EPA Base Case v.4.10. Illustrative examples are included of the step-by-step approach employed in developing a supply curves.

The third topic is coal transportation. It includes a description of the transport network, the methodology used to assign costs to the links in the network, and a discussion of the geographic, infrastructure, and regulatory considerations that come into play in developing specific rail, barge and truck transport rates. The last topic covered in this chapter is coal exports, imports, and non-electric sector demand.

The assumptions for the coal supply curves and coal transportation were finalized in September 2008, and were developed through a collaborative process with EPA supported by the following team of coal experts (with key areas of responsibility noted in parenthesis): PA Consulting Group (coal transportation and team coordination), Wood Mackenzie (coal supply curve development), Hellerworx (coal transportation and third party review), and ICF Consulting (representation in IPM). The coal supply curves and transportation matrix implemented in EPA Base Case v.4.10 are included in appendices at the end of this chapter.

9.1 Coal Market Representation in EPA Base Case v.4.10

Coal supply, coal demand, coal quality, and the assignment of specific types of coals to individual coal fired generating units are the four key components of the endogenous coal market modeling framework in EPA Base Case v.4.10. The modeling representation attempts to realistically reflect the actual options available to each existing coal fired power plant while aggregating data sufficiently to keep the model size and solution time within acceptable bounds.

Each coal power plant modeled is assigned to one of 151 coal demand regions. The demand regions are defined to reflect the coal transportation options (rail, barge, truck, conveyer belt) that are available to the plants that they serve. These demand regions are interconnected by a transportation network to at least one of the 31 geographically dispersed coal supply regions. The model's supply-demand region links reflect actual on-the-ground transportation configurations. Every coal supply region can produce and each coal demand region can demand at least one grade of coal. Based on historical and engineering data (as described in Section 9.1.5 below), each coal fired unit is also assigned several coal grades which it may use if that coal type is available within its demand region.

In EPA Base Case v.4.10 the endogenous demand for coal is generated by coal fired power plants interacting with a set of exogenous supply curves (see Appendix 9-4 for coal supply curve data) for each coal grade in each supply region. The curves show the supply of coal (by coal supply region and coal grade) that is available to meet demand at a given price. The supply of and demand for each grade of coal is linked to and affected by the supply of and demand for every other coal grade across supply and demand regions. The transportation network or matrix (see Appendix 9-3 for coal transportation matrix data) also factors into the final determination of

delivered coal prices, given coal demand and supply. IPM derives the equilibrium coal consumption and prices that result when all electric system operating, emission, and other requirements are met and total electric system costs over the modeling time horizon are minimized.

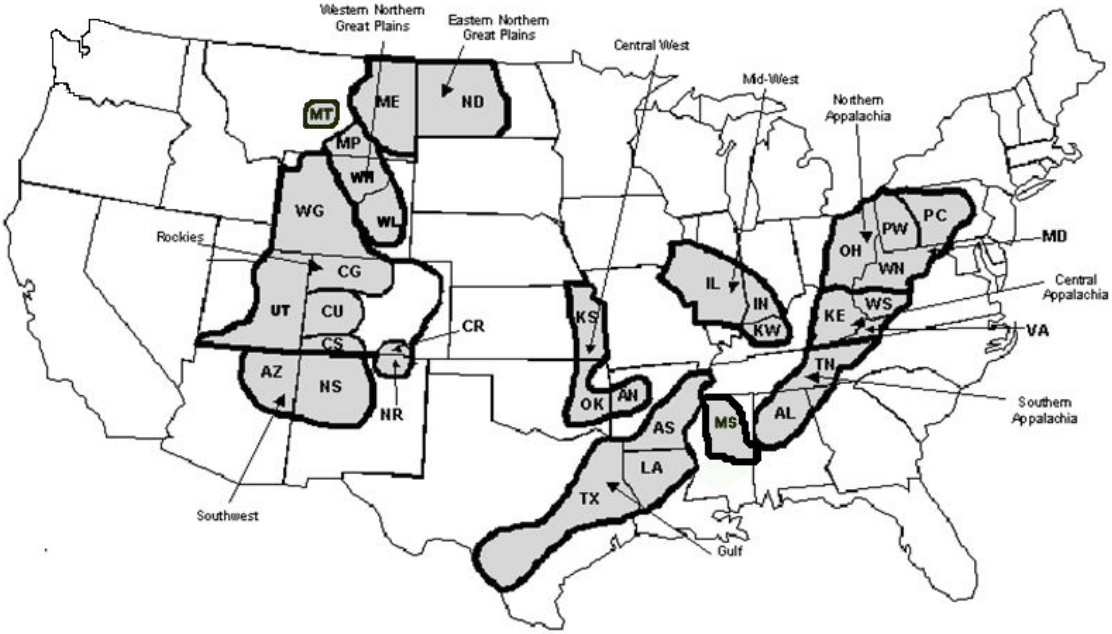
9.1.1 Coal Supply Regions

There are 31 coal supply regions in EPA Base Case v.4.10, each representing geographic aggregations of coal-mining areas that supply one or more coal grades. Coal supply regions may differ from one another in the types and quality of coal they can supply. Table 9-1 lists the coal supply regions included in EPA Base Case v.4.10. Figure 9-1 provides a map showing the location of both the coal supply regions listed in Table 9-1 and the broader supply basins commonly used when referring to U.S. coal reserves.

Table 9-1 Coal Supply Regions in EPA Base Case

Region	State	Supply Region
Central Appalachia	Kentucky, East	KE
Central Appalachia	Tennessee	TN
Central Appalachia	Virginia	VA
Central Appalachia	West Virginia, South	WS
Dakota Lignite	Montana, East	ME
Dakota Lignite	North Dakota	ND
East Interior	Illinois	IL
East Interior	Indiana	IN
East Interior	Kentucky, West	KW
East Interior	Mississippi	MS
Gulf Lignite	Louisiana	LA
Gulf Lignite	Texas	TX
Northern Appalachia	Maryland	MD
Northern Appalachia	Ohio	OH
Northern Appalachia	Pennsylvania, Central	PC
Northern Appalachia	Pennsylvania, West	PW
Northern Appalachia	West Virginia, North	WN
Rocky Mountains	Colorado, Green River	CG
Rocky Mountains	Colorado, Raton	CR
Rocky Mountains	Colorado, Uinta	CU
Rocky Mountains	Utah	UT
Southern Appalachia	Alabama	AL
Southwest	Arizona	AZ
Southwest	New Mexico, San Juan	NS
West Interior	Kansas	KS
West Interior	Oklahoma	OK
Western Montana	Montana, Bull Mountains	MT
Western Montana	Montana, Powder River	MP
Western Wyoming	Wyoming, Green River	WG
Wyoming Northern PRB	Wyoming, Powder River Basin	WH
Wyoming Southern PRB	Wyoming, Powder River Basin	WL

Figure 9-1 Map of the Coal Supply Regions in EPA Base Case v.4.10



9.1.2 Coal Demand Regions

Coal demand regions are designed to reflect coal transportation options available to power plants. Existing coal plants with similar transportation infrastructures (i.e., rail, barge, or truck/conveyor belt), proximity to mine (i.e., mine mouth or not mine mouth), transportation competitiveness levels (i.e., non-competitive, low-cost competitive, or high-cost competitive), and within the same geographic area are grouped into a coal demand region. Table 9-2 below lists the 135 coal demand regions used in EPA Base Case v.4.10 by code and descriptive name.

When IPM is run, it determines the amount and type of new generation capacity to add within each of IPM's 32 model regions. These model regions reflect the administrative, operational, and transmission geographic structure of the electricity grid. Since the coal demand regions do not typically coincide or overlap with the IPM model regions, new coal plants that IPM "builds" in specific model regions must be assigned to a particular coal demand region. The IPM-region-to-coal-demand-region assignments for new coal generating capacity are indicated in column 3 of Table 9-2. Also shown in the last column of Table 9-2 are instances where only one existing power plant is contained in a coal demand region. Forty-seven of the coal demand regions contain only one power plant.

Table 9-2 Coal Demand Regions in EPA Base Case

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
ALR1	Alabama High-Cost Competitive_Not Mine Mouth_Rail	--	
ALR2	Alabama Low-Cost Competitive_Not Mine Mouth_Barge	--	Greene County Plant
ALR3	Alabama Low-Cost Competitive_Not Mine Mouth_Rail	--	E C Gaston Plant
AMM1	New Mexico High-Cost Competitive_Mine Mouth_Rail	--	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
AMM2	Arizona, New Mexico High-Cost Competitive_Not Mine Mouth_Rail	--	Navajo Plant
AMM4	New Mexico Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	San Juan Plant
AMM5	New Mexico Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Raton Plant
AMN1	Arizona High-Cost Competitive_Not Mine Mouth_Rail	--	Apache Station
AMN2	Arizona Low-Cost Competitive_Not Mine Mouth_Rail	--	H Wilson Sundt Generating Station
AMN3	Arizona Non-Competitive_Not Mine Mouth_Rail	AZNM	
CAI1	Virginia High-Cost Competitive_Not Mine Mouth_Rail	--	
CAI2	Kentucky Low-Cost Competitive_Not Mine Mouth_Rail	--	
CAI3	Kentucky Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Tyrone Plant
CAR1	North and South Carolina High-Cost Competitive_Not Mine Mouth_Rail	--	
CAR2	North and South Carolina Low-Cost Competitive_Not Mine Mouth_Rail	--	
CAR3	North and South Carolina Non-Competitive_Not Mine Mouth_Rail	VACA	
CC1	Colorado High-Cost Competitive_Not Mine Mouth_Rail	--	
CC2	Colorado Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
CC3	Colorado Non-Competitive_Not Mine Mouth_Rail	RMPA	
CU1	Utah High-Cost Competitive_Not Mine Mouth_Rail	--	KUCC Plant
CU2	Utah Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	Huntington Plant
CU4	Utah Non-Competitive_Not Mine Mouth_Rail	--	
DAL1	North Dakota High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	Milton R Young Plant
DAL2	Montana, North Dakota Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
DAL4	North Dakota Non-Competitive_Not Mine Mouth_Rail	--	
EIM1	Iowa, Missouri High-Cost Competitive_Not Mine Mouth_Rail	--	Prairie Creek Plant
EIM2	Iowa Low-Cost Competitive_Not Mine	--	Fair Station Plant

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
	Mouth_Barge		
EIM3	Iowa, Missouri Low-Cost Competitive_Not Mine Mouth_Rail	--	
EIM4	Iowa Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Pella Plant
EIM5	Iowa, Missouri Non-Competitive_Not Mine Mouth_Rail	--	
FL1	Florida High-Cost Competitive_Not Mine Mouth_Rail	FRCC	
FL2	Florida Low-Cost Competitive_Not Mine Mouth_Barge	--	
FL3	Florida Low-Cost Competitive_Not Mine Mouth_Rail	--	
GAR1	Georgia, Mississippi Low-Cost Competitive_Not Mine Mouth_Rail	--	
GAR2	Georgia Non-Competitive_Not Mine Mouth_Rail	SOU	
GFB1	Alabama Low Cost Competitive_Not Mine Mouth_Rail	--	Barry Plant
GFB3	Mississippi Low-Cost Competitive_Not Mine Mouth_Barge	--	Jack Watson Plant
GFB4	Mississippi Non-Competitive_Not Mine Mouth_Rail	--	Victor J Daniel Jr Plant
GFR1	Mississippi, Texas High-Cost Competitive_Not Mine Mouth_Rail	ERCT	
GFR2	Arkansas, Louisiana, Texas Low-Cost Competitive_Not Mine Mouth_Rail	--	
GFR3	Arkansas, Louisiana, Texas Non-Competitive_Not Mine Mouth_Rail	ENTG	
GWAY	Illinois, Mine Mouth	GWAY	
IBB1	Kentucky High-Cost Competitive_Not Mine Mouth_Rail	--	Cane Run Plant
IBB2	Kentucky Low Cost Competitive_Not Mine Mouth_Rail	--	Mill Creek Plant
IBB3	Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Barge	--	
IBB4	Illinois, Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Rail	--	
III1	Illinois, Indiana High-Cost Competitive_Not Mine Mouth_Rail	--	
III2	Kentucky High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Green River Plant
III3	Illinois, Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Barge	--	
III4	Illinois, Indiana Low-Cost Competitive_Not Mine Mouth_Rail	COMD & RFCO	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
III5	Illinois, Indiana, Kentucky Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
III6	Indiana Non-Competitive_Mine Mouth_Truck/Conveyor Belt	--	Rank E Ratts Plant
III7	Illinois, Indiana, Kentucky Non-Competitive_Not Mine Mouth_Rail	TVAK	
IMB1	Illinois, Iowa, Missouri High-Cost Competitive_Not Mine Mouth_Rail	MRO	
IMB2	Iowa, Missouri Low-Cost Competitive_Not Mine Mouth_Rail	--	
IMB3	Missouri Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
IMB4	Iowa Non-Competitive_Not Mine Mouth_Rail	--	
MA-1	Maryland Low-Cost Competitive_Not Mine Mouth_Rail	--	
MA-2	Maryland Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
MA-3	Maryland Non-Competitive_Not Mine Mouth_Rail	MACS	
MAB1	Maryland Low-Cost Competitive_Not Mine Mouth_Rail	--	
MIB1	Michigan High-Cost Competitive_Not Mine Mouth_Rail	--	
MIB2	Michigan, Wisconsin Low-Cost Competitive_Not Mine Mouth_Barge	--	
MIB3	Michigan, Wisconsin Low-Cost Competitive_Not Mine Mouth_Rail	MECS	
MIB4	Michigan Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Endicott Station
MNR1	Minnesota, South Dakota High-Cost Competitive_Not Mine Mouth_Rail	--	
MNR2	Minnesota Low-Cost Competitive_Not Mine Mouth_Barge	--	Silver Bay Power Plant
MNR3	Minnesota Low-Cost Competitive_Not Mine Mouth_Rail	--	
MNR5	Minnesota, South Dakota Non-Competitive_Not Mine Mouth_Rail	--	
MWR1	Iowa, Kansas, Missouri, Nebraska, Oklahoma High-Cost Competitive_Not Mine Mouth_Rail	SPPN	
MWR2	Kansas, Missouri High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
MWR3	Kansas, Missouri, Nebraska, Oklahoma Low-Cost Competitive_Not Mine Mouth_Rail	SPPS	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
MWR5	Kansas, Missouri Non-Competitive_Not Mine Mouth_Rail	--	
NAI1	West Virginia High-Cost Competitive_Mine Mouth_Rail	RFCP	
NAI2	West Virginia High-Cost Competitive_Not Mine Mouth_Rail	--	Mt Storm Plant
NAI3	Pennsylvania, West Virginia Low-Cost Competitive_Not Mine Mouth_Barge	--	
NAI4	West Virginia Low-Cost Competitive_Not Mine Mouth_Rail	--	Willow Island Plant
NAI5	West Virginia Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Albright Plant
NAI6	Ohio Non-Competitive_Not Mine Mouth_Rail	--	Muskingum River Plant
NE1	Maine, Massachusetts, New Hampshire, New Jersey High-Cost Competitive_Not Mine Mouth_Rail	--	
NE2	Connecticut, Massachusetts, New Hampshire, New Jersey Low-Cost Competitive_Not Mine Mouth_Barge	--	
NE3	Connecticut, New York Low-Cost Competitive_Not Mine Mouth_Rail	DSNY	
NII1	Indiana High-Cost Competitive_Not Mine Mouth_Rail	--	
NII2	Illinois Low-Cost Competitive_Not Mine Mouth_Barge	--	
NII3	Illinois, Indiana Low-Cost Competitive_Not Mine Mouth_Rail	--	
NNR1	Nevada Non-Competitive_Not Mine Mouth_Rail	--	North Valmy Plant
NOR1	Ohio High-Cost Competitive_Not Mine Mouth_Rail	--	
NOR2	Ohio Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	Conesville Plant
NOR3	Ohio Low-Cost Competitive_Not Mine Mouth_Barge	--	
NOR4	Ohio Low-Cost Competitive_Not Mine Mouth_Rail	--	Hiles Plant
NOR5	Ohio Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	
NOR6	Ohio Non-Competitive_Not Mine Mouth_Rail	--	O H Hutchings Plant
NU1	New York High-Cost Competitive_Not Mine Mouth_Rail	UPNY	
NU2	New York Low-Cost Competitive_Not Mine Mouth_Rail	--	AES Westover Plant
ORP1	Ohio, Pennsylvania, West Virginia High-	--	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
	Cost Competitive_Not Mine Mouth_Rail		
ORP2	Ohio, Pennsylvania, West Virginia Low Cost Competitive_Not Mine Mouth_Rail	--	
ORP3	Ohio, West Virginia Low-Cost Competitive_Not Mine Mouth_Barge	--	
ORP4	Ohio, Pennsylvania, West Virginia Low-Cost Competitive_Not Mine Mouth_Rail	--	
PC1	Pennsylvania High-Cost Competitive_Not Mine Mouth_Rail	MACW	
PC2	Pennsylvania High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Homer City Station
PC3	Pennsylvania Low-Cost Competitive_Not Mine Mouth_Barge	--	
PC4	Pennsylvania Low-Cost Competitive_Not Mine Mouth_Rail	--	P H Glatfelter Plant
PC6	Pennsylvania Non-Competitive_Not Mine Mouth_Rail	--	PPL Montour Plant
PE1	New Jersey, Pennsylvania High-Cost Competitive_Not Mine Mouth_Rail	--	
PE2	Pennsylvania Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Shawville Plant
PE3	Delaware, New Jersey, Pennsylvania Non-Competitive_Not Mine Mouth_Rail	MACE	
PRB1	Wyoming High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
PRB3	Montana Low-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Colstrip Plant
PRB4	Wyoming Non-Competitive_Not Mine Mouth_Rail	--	
SNR1	Nevada Non-Competitive_Not Mine Mouth_Rail	SNV	Reid Gardner
TAB1	Alabama High-Cost Competitive_Not Mine Mouth_Rail	--	Charles R Lowman
TAB2	Alabama Low Cost Competitive_Not Mine Mouth_Rail	--	Widows Creek
TAB3	Alabama, Tennessee Low-Cost Competitive_Not Mine Mouth_Barge	--	
TKI1	Tennessee Low-Cost Competitive_Not Mine Mouth_Rail	--	
TKI2	Tennessee Non-Competitive_Not Mine Mouth_Rail	TVA	
TXL1	Mississippi, Texas High-Cost Competitive_Mine Mouth_Rail	--	
TXL2	Texas High-Cost Competitive_Not Mine Mouth_Rail	--	

Coal Demand Region Codes	Descriptive Name	IPM Model Regions with Potential Plants Assigned to this Coal Demand Region	Plant Name when Coal Demand Region Just Includes One Plant
TXL3	Texas High-Cost Competitive_Not Mine Mouth_Truck/Conveyor Belt	--	Twin Oaks Power One Plant
TXL4	Louisiana, Texas Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
TXL5	Texas Non-Competitive_Not Mine Mouth_Rail	--	Gibbons Creek
VAPW	Virginia, Mine Mouth	VAPW	
VEP1	South Carolina, Virginia High-Cost Competitive_Not Mine Mouth_Rail	--	
VEP2	Virginia Non-Competitive_Not Mine Mouth_Rail	--	
WIR1	Wisconsin High-Cost Competitive_Not Mine Mouth_Rail	--	
WIR2	Wisconsin Low-Cost Competitive_Not Mine Mouth_Rail	WUMS	
WIR4	Wisconsin Non-Competitive_Not Mine Mouth_Rail	--	
WOM1	Michigan Low-Cost Competitive_Not Mine Mouth_Rail	--	Eckert Station
WOM2	Michigan Non-Competitive_Not Mine Mouth_Rail	--	Erickson Station
WON1	California High-Cost Competitive_Not Mine Mouth_Rail	--	
WON2	California Low-Cost Competitive_Not Mine Mouth_Rail	--	ACE Cogeneration Facility
WON3	Montana, Oregon, Washington Non-Competitive_Not Mine Mouth_Rail	PNW	
WYG1	Wyoming High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	NWPE	
WYG2	Wyoming High-Cost Competitive_Not Mine Mouth_Rail	--	Osage Plant
WYG3	Wyoming Low-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	--	
WYG4	Wyoming Non-Competitive_Mine Mouth_Rail	--	Jim Bridger

9.1.3 Coal Quality Characteristics

Coal varies by heat content, SO_2 content and mercury content among other characteristics. To capture differences in the sulfur and heat content of coal, a two letter "coal grade" nomenclature is used. The first letter indicates the "coal rank" (bituminous, subbitumionus, or lignite) with their associated heat content ranges (as shown in Table 9-3). The second letter indicates their "sulfur grade," i.e., the SO_2 ranges associated with a given type of coal. (The sulfur grades and associated SO_2 ranges are shown in Table 9-4.)

Table 9-3 Coal Rank Heat Content Ranges

Coal Type	Heat Content (Btu/lb)	Classification
Bituminous	>10,260 – 13,000	B
Sub-bituminous	> 7,500 – 10,260	S
Lignite	less than 7,500	L

Table 9-4 Coal Grade SO_2 Content Ranges

SO_2 Grade	SO_2 Content Range (lbs/MMBtu)
A	0.00 – 0.80
B	0.81 – 1.20
D	1.21 – 1.66
E	1.67 – 3.34
G	3.35 – 5.00
H	> 5.00

The assumptions in EPA Base Case v.4.10 on the heat, mercury, SO_2, and ash content of coal are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR)[1]. A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit… with a capacity greater than 25 megawatts electric, as well as accurate information on the total amount of coal burned by each such unit,", and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations. Data regarding the SO_2 and ash content of the coal used was obtained along with mercury content.

The ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content, ash content, and other characteristics of coal burned at coal-fired utility units greater than 25 MW.

9.1.4 Emission Factors

To make this data usable in EPA Base Case v.4.10, the ICR data points were first grouped by IPM coal grades and IPM coal supply regions. Using the grouped ICR data, the average heat, SO_2, mercury, and ash content were calculated for each coal grade/supply region combination. In instances where no data were available for a particular coal grade in a specific supply region, the national average SO_2 and mercury values for the coal grade were used as the region's values. The resulting values are shown in Table 9-5.

[1] Data from the ICR can be found at http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html.

Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	Cluster Number
AL	BB	24.82	1.1	4.2	9.8	2
	BD	24	1.4	7.3	10.8	2
	BE	23.82	2.7	12.6	10.7	2
AZ	BB	24.64	1.1	5.3	7.9	2
CG	BA	21.49	0.7	3.1	7.3	1
	BB	22.01	0.9	4.1	8.4	2
CR	BA	25.5	0.7	3.5	7	1
	BD	22.2	1.4	7	8.3	1
CU	BA	23.8	0.7	2.6	6.3	1
	BB	23.22	0.9	4	7.8	2
	BD	23.21	1.3	3.1	8.1	1
IL	BE	23	2.2	6.5	6.6	2
	BG	23.01	4.6	6.5	8.1	1
	BH	22.19	5.6	5.4	9.1	1
IN	BD	22.62	1.4	3.8	7.4	1
	BE	23.43	2.3	5.2	8	2
	BG	23.37	4.3	7.2	8.2	1
	BH	23.41	6.1	7.1	8.6	1
KE	BA	25.32	0.7	3	6.1	1
	BB	25.79	1	4.8	6.4	2
	BD	25.33	1.4	6	7.4	1
	BE	25.14	2.1	7.9	7.7	2
	BG	24.09	3.8	12	10.2	3
KS	BG	25.32	4.8	4.1	8.5	1
KW	BD	24.23	1.6	5.6	6.2	1
	BE	24.45	2.8	7.1	7.4	2
	BG	23.93	4.5	6.9	8	1
	BH	22.84	5.7	8.2	10.2	1
LA	LE	14.09	2.5	7.3	17.1	2
MD	BB	24.64	1.1	5.3	7.9	2
	BD	26.32	1.6	7.8	9.5	2
	BE	24.85	2.8	15.6	11.7	1
	BG	23.26	3.6	16.6	16.6	3
ME	LD	13.36	1.4	8.6	11.3	1
MP	SA	18.9	0.6	4.2	4	1
	SD	17.23	1.5	4.5	10.1	1
MS	LE	13.19	2.8	12.4	21.5	1
MT	BB	21	1.1	5.3	7.9	2
ND	LD	13.7	1.5	6.4	10.7	1
	LE	13.46	2.3	8.3	12.8	1
NS	BB	26.4	1.1	5.3	7.9	2
	BD	18.1	1.6	5.5	19.6	1

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	Cluster Number
	BE	18.1	1.8	8.2	18.8	2
OH	BB	24.68	1.1	5.7	9.8	1
	BD	25.55	1.4	6.4	10.3	1
	BE	25.24	3.1	18.7	7.1	1
	BG	24.34	4	18.5	8	2
	BH	23.92	6.4	13.9	9.1	2
OK	BE	22.15	2.7	25.8	11.3	1
PC	BD	25.06	1.4	21.7	49.3	3
	BE	25.66	2.6	18	9.2	1
	BG	25.33	3.8	21.5	9.6	2
	BH	23.39	6.3	34.7	13.9	3
PW	BD	24.26	1.6	11.2	10	2
	BE	26.22	2.5	8.4	5.4	2
	BG	25.86	3.7	8.6	6.5	1
TN	BB	24.18	1.1	3.8	10.4	2
	BD	23.91	1.3	6.3	10.4	1
	BE	26.75	2.1	8.4	6.5	2
TX	LD	13.06	1.6	12	22.3	2
	LE	13.22	3	14.7	25.6	1
	LG	12.27	3.9	14.9	25.5	1
UT	BA	23.68	0.7	4.4	7.4	2
	BB	23.23	0.9	3.9	8.6	2
	BD	23.05	1.4	4.4	10.5	1
	BE	25.06	2.3	9.2	7.4	2
VA	BA	22.7	0.7	3.5	7	1
	BB	25.97	1	4.6	7	2
	BD	25.76	1.4	5.7	8	1
	BE	26.03	2.1	8.4	8.1	2
WG	BB	21.67	1.1	1.8	5.6	1
	SD	18.5	1.3	4.3	10	1
WH	SA	17.43	0.6	5.6	5.5	2
	SB	17.43	0.9	6.4	6.5	1
WL	SB	17.15	0.9	6.4	6.5	1
WN	BD	25.01	1.5	10.3	9.2	2
	BE	25.67	2.5	10.3	7.9	2
	BG	26.03	4	9.3	6.9	1
	BH	25.15	6.1	8.8	9.6	1
WS	BA	26.2	0.7	3.5	7	1
	BB	24.73	1.1	5.7	9.2	2
	BD	24.64	1.3	8.1	9.3	2
	BE	24.38	1.9	8.8	9.9	2
	BG	25.64	4.7	7.1	6.4	1

Next, a clustering algorithm was used to further aggregate the data in EPA Base Case v.4.10 for model size management purposes. The clustering analysis was performed on the mercury and SO_2 data shown in Table 9-5 using the SAS statistical software package. Clustering analysis places objects into groups or clusters, such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. (In the following write-up BG coal is used to illustrate how the procedure worked.) First, the number of clusters of mercury and SO_2 concentrations for each IPM coal type was determined based on the range in average mercury and SO_2 concentrations across all coal supply regions for a specific coal type. Each coal type used either one or two clusters. The total number of clusters for each coal grade was limited to keep the model size and run time within feasible limits. (Two clusters were used for BG coal.) Second, for each coal grade the clustering procedure was applied to all the regional SO_2 and mercury values shown in Table 9-5 for that coal grade. (In the BG coal example there are 11 such regional SO_2 and mercury values.) Using the SAS cluster procedure, each of the constituent regional values was assigned to a cluster and the cluster average SO_2 and mercury values were recorded. The resulting values are shown in Table 9-6 and Table 9-7. (For BG coal the Cluster #1 average SO_2 and mercury values are 4.36 lb/MMBtu and 7.10 lb/TBtu respectively. The Cluster #2 average SO_2 and mercury values are 3.89 lb/MMBtu and 20.04 lb/TBtu respectively. The Cluster #3 average SO_2 and mercury values are 3.68 lb/MMBtu and 14.31 lb/TBtu respectively.) Although not used in determining the clusters, ash and CO_2 values were calculated for each of the clusters. These values are shown in Table 9-8 and Table 9-9. (The CO_2 values were derived from data in the Energy Information Administration's *Annual Energy Outlook* 2009 (AEO 2009), not from data collected in the ICR.)

IPM input files retain the mapping between different coal grade/supply region combinations and the clusters. The mapping can be seen in the last column of Table 9-5 which shows the cluster number associated with the coal grade/supply region combination indicated in the first and second columns of this table. (For BG coal, the SAS cluster procedure mapped supply regions IL, IN, KS, KW, PW, WN, and WS to Cluster #1, supply regions OH and PC to Cluster #2, and MD and KE to Cluster #3. See Figure 9-2 for an illustration of this mapping.) Table 9-6 to Table 9-9 show the mercury, SO_2, ash, and CO_2 values assigned to coal grades and regions based on this cluster mapping. The values shown in Table 9-6 to Table 9-9 are used in EPA Base Case v.4.10 for calculating emissions.

Table 9-6 SO_2 Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	Sulfur Emission Factors (lbs/MMBtu)		
	Cluster #1	Cluster #2	Cluster # 3
Low Sulfur Eastern Bituminous (BA)	0.7	0.67	--
Low Sulfur Western Bituminous (BB)	1.13	1.03	--
Low Medium Sulfur Bituminous (BD)	1.43	1.45	1.42
Medium Sulfur Bituminous (BE)	2.78	2.3	--
High Sulfur Bituminous (BG)	4.36	3.89	3.68
High Sulfur Bituminous (BH)	5.89	6.43	6.29
Low Sulfur Subbituminous (SA)	0.62	0.58	--
Low Sulfur Subbituminous (SB)	0.94	--	--
Low Medium Sulfur Subbituminous (SD)	1.41	--	--
Low Medium Sulfur Lignite (LD)	1.46	1.61	--
Medium Sulfur Lignite (LE)	2.88	2.38	--
High Sulfur Lignite (LG)	3.91	--	--

Table 9-7 Mercury Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	Mercury Emission Factors (lbs/TBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous (BA)	3.19	4.37	--
Low Sulfur Western Bituminous (BB)	1.82	4.86	--
Low Medium Sulfur Bituminous (BD)	5.38	8.94	21.67
Medium Sulfur Bituminous (BE)	19.53	8.42	--
High Sulfur Bituminous (BG)	7.1	20.04	14.31
High Sulfur Bituminous (BH)	7.38	13.93	34.71
Low Sulfur Subbituminous (SA)	4.24	5.61	--
Low Sulfur Subbituminous (SB)	6.44	--	--
Low Medium Sulfur Subbituminous (SD)	4.43	--	--
Low Medium Sulfur Lignite (LD)	7.51	12	--
Medium Sulfur Lignite (LE)	13.55	7.81	--
High Sulfur Lignite (LG)	14.88	--	--

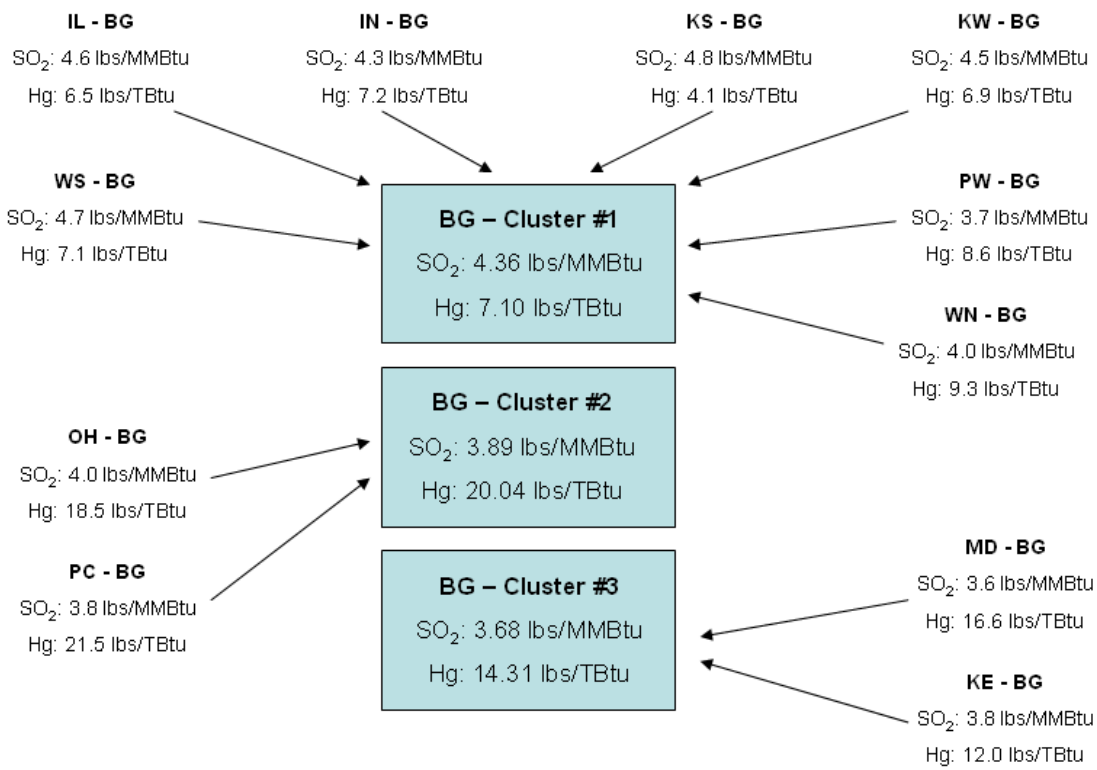
Table 9-8 Ash Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	Ash Emission Factors by Coal Sulfur Grades (lbs/MMBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous (BA)	6.77	7.39	--
Low Sulfur Western Bituminous (BB)	5.59	8.1	--
Low Medium Sulfur Bituminous (BD)	9.64	9.77	49.31
Medium Sulfur Bituminous (BE)	9.84	8.69	--
High Sulfur Bituminous (BG)	7.51	8.8	13.41
High Sulfur Bituminous (BH)	9.38	9.13	13.89
Low Sulfur Subbituminous (SA)	3.98	5.47	--
Low Sulfur Subbituminous (SB)	6.5	--	--
Low Medium Sulfur Subbituminous (SD)	10.08	--	--
Low Medium Sulfur Lignite (LD)	11.01	22.33	--
Medium Sulfur Lignite (LE)	23.58	15	--
High Sulfur Lignite (LG)	25.51	--	--

Table 9-9 CO_2 Emission Factors of Coal Used in EPA Base Case v.4.10

Coal Type by Sulfur Grade	CO_2 Emission Factors by Coal Sulfur Grades (lbs/MMBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Eastern Bituminous (BA)	205.4	205.4	--
Low Sulfur Western Bituminous (BB)	205.8	205.8	--
Low Medium Sulfur Bituminous (BD)	206.6	206.6	206.6
Medium Sulfur Bituminous (BE)	206.3	206.3	--
High Sulfur Bituminous (BG)	205.2	205.2	205.2
High Sulfur Bituminous (BH)	205.2	205.2	205.2
Low Sulfur Subbituminous (SA)	213.1	213.1	--
Low Sulfur Subbituminous (SB)	212.7	--	--
Low Medium Sulfur Subbituminous (SD)	213.1	--	--
Low Medium Sulfur Lignite (LD)	217	217	--
Medium Sulfur Lignite (LE)	214.8	214.8	--
High Sulfur Lignite (LG)	213.5	--	--

Figure 9-2 Cluster Mapping Example --- BG Coal



9.1.5 Coal Grade Assignments

The grades of coal that may be used by specific generating units were determined by an expert assessment of the ranks of coal that a unit had used in the past, the removal efficiency of the installed FGD, and the SO_2 permit rate of the unit. Examples of the coal grade assignments made for individual plants in EPA Base Case v.4.10 are shown in Table 9-10. Not all of the coal grades

allowed to a plant by the coal grade assignment are necessarily available in the plant's assigned coal demand region (due to transportation limitations). IPM endogenously selects the coal burned by a plant by taking into account both the constraint of the plant's coal grade assignment and the constraint of the coals actually available within a plant's coal demand region.

Table 9-10 Example of Coal Assignments Made in EPA Base Case

Plant Name	Unique ID	SIP SO_2 Limit (lbs/MMBtu)	Scrubber?	Fuels Allowed
Salem Harbor	1626_B_1	1.2	No	BA,BB
Dickerson	1572_B_3	2.8	No	BA,BB,BD,BE
Glen Lyn	3776_B_51	1.75	No	BA,BB,BD
Danskammer Generating Station	2480_B_3	1.1	No	BA,BB
R E Burger	2864_B_5	9.02	No	BA,BB,BD,BE,BG,BH
Moutaineer	6264_B_1	1	Yes	BA,BB,BD,BE,BG,BH, SA,SB,SD
Big Brown	3497_B_1	3	No	LD,LE,SA,SB,SD
Black River Generation	10464_B_E0001	3.8	Yes	BA,BB,BD,BE,BG,BH
E D Edwards	856_B_1	4.71	No	BA,BB,BD,BE,BG,SA, SB,SD
R Gallagher	1008_B_1	4.71	No	BA,BB,BD,BE,BG,SA, SB,SD

9.2 Coal Supply Curves

9.2.1 Nature of Supply Curves Developed for EPA Base Case v.4.10

In keeping with IPM's data-driven bottom-up modeling framework, a bottom-up approach (relying heavily on detailed economic and resource geology data and assessments) was used to prepare the coal supply curves for EPA Base Case v.4.10. Wood Mackenzie was chosen to develop the curves based on their extensive experience in preparing mine-by-mine estimates of cash operating costs for operating mines in the U.S., their access to both public and proprietary data sources, and their active updating of the data both through research and interviews.

In order to establish consistent nomenclature, Wood Mackenzie first mapped its internal list of coal regions and qualities to EPA's 31 coal supply regions (described above in sections 9.1.1) and 12 coal grades (described above in section 9.1.3). The combined code list is shown in Table 9-11 below with the IPM supply regions appearing in the rows and the coal grades in the columns. Wood Mackenzie then created supply curves for each region and coal-grade combination (indicated by the "x" in Table 9-11) for forecast years 2012, 2015, 2020, 2030, and 2040.

Table 9-11 Basin-Level Groupings Used in Preparing v.4.0 Coal Supply Curves

Coal Supply Regions and Coal Grades in EPA IPM, v.4.0

Geo. Region	Geo. Sub-Region	Coal Code / Region Code		BITUMINOUS						SUB-BITUMINOUS			LIGNITE			
				1 BA	2 BB	3 BD	4 BE	5 BG	6 BH	7 SA	8 SB	9 SD	10 LD	11 LE	12 LG	13 LH
Appalachia	Southern Appalachia	1	AL		X	X	X									
West	Southwest	2	AZ		X											
West	Rocky Mountain	3	CG	X	X											
West	Rocky Mountain	4	CR	X		X										
West	Rocky Mountain	5	CU	X	X	X										
Interior	East Interior (Illinois Basin)	6	IL				X	X	X							
Interior	East Interior (Illinois Basin)	7	IN			X	X	X	X							
Interior	Gulf Lignite	8	LA											X		
Appalachia	Northern Appalachia	9	MD		X	X	X	X								
West	Dakota Lignite	10	ME										X			
Appalachia	Central Appalachia	11	KE	X	X	X	X	X								
Interior	West Interior	12	KS					X								
Interior	East Interior (Illinois Basin)	13	KW			X	X	X	X							
West	Western Montana	14	MP							X		X				
Gulf	Gulf Coast Lignite	15	MS											X		
West	Western Montana	16	MT		X											
West	Dakota Lignite	17	ND										X	X		
West	Southwest	18	NS		X	X	X									
Appalachia	Northern Appalachia	19	OH		X	X	X	X	X							
Interior	West Interior	20	OK				X									
Appalachia	Northern Appalachia	21	PC			X	X	X	X							
Appalachia	Northern Appalachia	22	PW			X	X	X								
Appalachia	Central Appalachia	23	TN		X	X	X									
Gulf	Gulf Coast Lignite	24	TX										X	X	X	X
West	Rocky Mountain	25	UT	X	X	X	X									
Appalachia	Central Appalachia	26	VA	X	X	X	X									
West	Western Wyoming	27	WG		X							X				
West	Wyoming Powder River Basin	28	WH							X	X					
West	Wyoming Powder River Basin	29	WL								X					
Appalachia	Northern Appalachia	30	WN			X	X	X	X							
Appalachia	Central Appalachia	31	WS	X	X	X	X	X								

9.2.2 Procedure Employed in Determining Mining Costs

Wood Mackenzie estimates mine production costs on a mine-by-mine basis utilizing proprietary bottom-up engineering cost models. A mine's cash costs are the sum of its direct operating costs (DOCs), royalty tax, severance tax, property tax, reclamation tax and black lung fees. Using these mine costing models, costs curves are developed by summing the individual and incremental costs that make up mine cash-costs and assuming a built-in 10% discounted rate-of-return. As an illustration of the break-down of costs included in the mine costing models, Figure 9-3 lists the cost components included and calculations performed for a Powder River Basin mine supply curve. Appendix 9-1 contains a more detailed illustration of the procedure used to derive a supply curve from its constituent mine costing models.

Figure 9-3 Cost Calculations Included When Developing Coal Supply Curves (based on a Powder River Basin Mine Supply Curve Example)

10% DCFROR All cost curves assume mine operators are able to earn a minimum 10% discounted rate-of-return.

Cash Cost

Royalty = Revenue * Royalty %
Severance Tax = (Revenue - Royalty) * Sevr Tax Rate$_1$ * % Adjustment if needed
Property Tax = (Revenue - Royalty)* property tax rate
Reclamation Tax = Production * reclamation rate$_2$
Black Lung = Production * (the lesser of 0.55, or 4.4% * sales price of coal)

DOCs (surface mines)
Labor = Production * (Wages + Benefits) / Productivity
Unit Removal Costs
= Cost per yard $_{\text{by equipment type}}$ * Amount removed
Added coal haul = year-over-year mileage increase * haul rate * production
On-going reclamation = production * reclamation rate (as a function of coal depth)

< OR >

DOCs (deep mines)
Labor = Production * (Wages + Benefits) / Productivity
Materials & Supplies
Trucking costs = haul distance from mine to load-out * haul rate
Mine overhead = Cost associated with mine support
Division overhead = Company dependent costs for operations
Pension = company's portion of employee retirement

General Definitions:

Revenues = Tons coal produced * sale price/ton
Productivity (TPMH) = Tons coal produced / man hours worked in reporting period
Stripping Ratio = Overburden Yard / Coal Production
Production = Amount of coal removed from the mine in a given period

Cash cost: is the sum of a mine's Direct Operating Costs (DOCs), Royalty tax, Severance Tax, Property Tax, Reclamation Tax and Black Lung fees.
[1] Severance Tax Rate is state specific
[2] Reclamation Tax used was 0.15 for Deep Mines & 0.35 for Surface Mines

It is important to note that although the formula for calculating mine costs is consistent across regions, some tax rates and fees vary by state and mine type. In general, there are two mine types: underground (deep) or surface mines. Underground mining is categorized as being either a longwall (LW) or a continuous room-and-pillar mine (CM). Geologic conditions and characteristics of the coal seams determine which method will be used. Surface mines are typically categorized by the type of mining equipment used in their operation such as draglines (DL), or truck & shovels (TS). These distinctions are important because the equipment used by the mine affects productivity measures and ultimately mine costs.

Several methods are employed for cost estimation depending on the availability of information and the diversity of mining operations. When possible, Wood Mackenzie analysts develop detailed lists of mine related costs. Costs such as employee wages & benefits, diesel fuel, spare parts, roof bolts and explosives among a host of others are summed to form a mine's direct operating costs.

Direct costs categories include: mine labor, salaries, material and supplies, and mine overhead. The costs are estimated based on labor productivity and mining methods. Labor productivity is used to calculate mine labor and salaries by applying an average cost per employee hour to the labor productivity figure reported by MSHA or estimated based on comparable mines. For surface mines, material and supply costs are estimated based on the mining method (dragline, truck-shovel and other) and the number of yards of overburden[1] moved by each method. A cost per yard moved is estimated for each mining method and mining region. Where coal is washed, washing costs are based on the type of plant being used and the average washing cost per ton for the mining region. Overhead costs are estimated based on mine size.

Labor costs are estimated based on employment data reported to MSHA. MSHA data provides employment numbers, employee hours worked and tons of coal produced. These data are combined with labor rate estimates from various sources such as union contracts, census data and other sources such as state employment websites to determine a cost per ton for mine labor. Hourly labor costs vary between United Mine Workers of America (UMWA) and non-union mines, and include benefits and payroll taxes. Employees assigned to preparation plants, surface activities, and offices are excluded from this category and are accounted for under coal washing costs and mine overhead. These preparation plants may be located at the mine site or a central preparation plant that washes coal from a number of mines. If the coal is transported to an offsite location for washing, transportation costs to the plant are included in the total costs.

Supply costs are adjusted annually to reflect movements in the price of steel, diesel, natural gas and other commodities. Cost adjustments are averaged on an annual basis and analyzed to ensure that anomalous spikes in commodity prices are not carried forward in the cost analysis.

Royalties, severance taxes, black lung fees, reclamation taxes and property taxes are estimated using federal, state and local parameters.

In the Western United States, capital requirements are estimated for each mine and a life-of-mine discounted cash flow analysis is used to determine the price required to yield a 10% DCFROR[2], including income taxes. In the Eastern United States, the required price is estimated based on operating costs and production levels.

Where information is incomplete, cost items are grouped into categories that can be compared with industry averages by mine type and location. These averages can be adjusted up or down based on new information or added assumptions. The adjustments take the form of cost multipliers or parameter values. Specific cost multipliers are developed with the aid of industry experts and proprietary formulas. This method is at times used to convert materials and supplies, on-site trucking costs and mine and division overhead categories into unit removal costs by equipment type. (This was done in the example shown in Figure 9-3 above.) To check the accuracy of these cost estimates, cash flow analysis of publicly traded companies is used. Mine cash-costs are extracted from corporate cash flows and compared with the initial estimates. Adjustments for discrepancies are made on a case-by-case basis.

Many of the cost assumptions associated with labor and productivity were taken from the Mine Safety Health Administration (MSHA) database. All active mines report information specific to production levels, number of employees and employee hours worked. Wood Mackenzie supplements the basic MSHA data with information obtained from mine personnel interviews and industry contacts. Phone conversations and conferences with industry professionals provide

---

[1] Overburden refers to the surface soil and rock that must be removed to uncover the coal.

[2] DCFROR stands for discounted cash flow rate of return (also called “internal rate of return” (IRR) and “rate of return”). It is the annualized effective coupounded return that can be earned on invested capital.

additional non-reported information such as work schedules, equipment types, percentages of washed coal, and trucking distances from the mine to wash-plants and load-out terminals.

For each active or proposed mine, Wood Mackenzie reports the estimated cost to take coal from the mine to a logical point-of-sale. The logical point-of-sale may be a truck or railcar load-out or even a barge facility. This is done to produce a consistent cost comparison between mines. Any transport costs beyond the point-of-sale terminal are not part of this analysis and are not reflected in the supply curves themselves. (Transport costs are taken into account using a separate procedure which is described below in section 9.3.)

In cases where new mines are planned or recoverable reserves are available to support new mines (see sections 9.2.6 and 9.2.7 below), Wood Mackenzie uses nearby mines with similar geography and geology to estimate mine operating costs and productivity levels. Production levels for new mines are estimated based on known reserves, historic precedent, and region specific knowledge.

9.2.3 Supply Curve Development

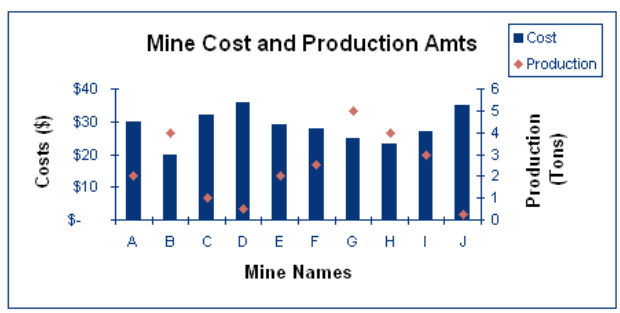
Once costs are estimated for all new or existing mines, they are sorted by cash cost, lowest to highest, and plotted cumulatively by production to form a supply curve. The supply curve then represents all mines – new or existing as well as both underground and surface mines– irrespective of market demand. Mines located toward the bottom of the curve have the lowest cost and are most likely to be developed while the mines at the top of the curve are higher cost and will likely wait to be developed. The process for developing a cumulative supply curve is illustrated in Figure 9-4 and Figure 9-5 below.

Figure 9-4 Illustration of Preliminary Step in Developing a Cumulative Coal Supply Curve

Key

E = EXISTING MINE
N = NEW MINE
U = UNDERGROUND MINE
S = SURFACE MINE

New or Existing?	Mine	Type	Cost	Production
N	A	S	$ 30	2
E	B	U	$ 20	4
N	C	S	$ 32	1
N	D	S	$ 36	0.5
E	E	S	$ 29	2
N	F	S	$ 28	2.5
E	G	U	$ 25	5
E	H	U	$ 23	4
E	I	U	$ 27	3
N	J	S	$ 35	0.25



•

In the table and graph above, mine costs and production are sorted alphabetically by mine name. To develop a supply curve from the above table the values must be sorted by mine costs from lowest to highest. A new column for cumulative production is added, and then a supply curve graph is created which shows the costs on the 'Y' axis and the cumulative production on the 'X' axis. Notice below that the curve contains all mines – new or existing as well as both underground and surface mines. The resulting curve is a continuous supply curve but can be modified to show costs as a stepped supply curve. (Supply curves in stepped format are used in linear programming models like IPM.) See Figure 9-6 for a stepped version of the supply curve example shown in Figure 9-5. Here each step represents an individual mine, the width of the step reflects the mine's production, and its height shows the cost of production. (See Appendix 9-1 for a more detailed example of how a supply curve is derived from constituent mine costing models.)

Figure 9-5 Illustration of Final Step in Developing a Cumulative Coal Supply Curve

New or Existing?	Mine	Type	Cost	Production	Cum Productio
E	B	U	$ 20	4	4
E	H	U	$ 23	4	8
E	G	U	$ 25	5	13
E	I	U	$ 27	3	16
N	F	S	$ 28	2.5	18.5
E	E	S	$ 29	2	20.5
N	A	S	$ 30	2	22.5
N	C	S	$ 32	1	23.5
N	J	S	$ 35	0.25	23.75
N	D	S	$ 36	0.5	24.25

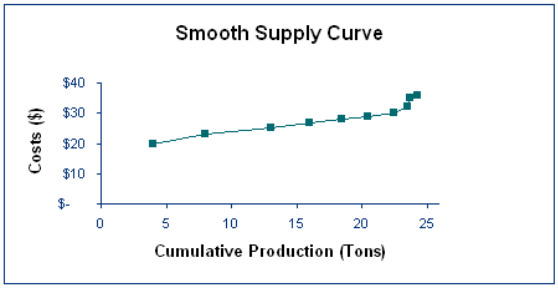
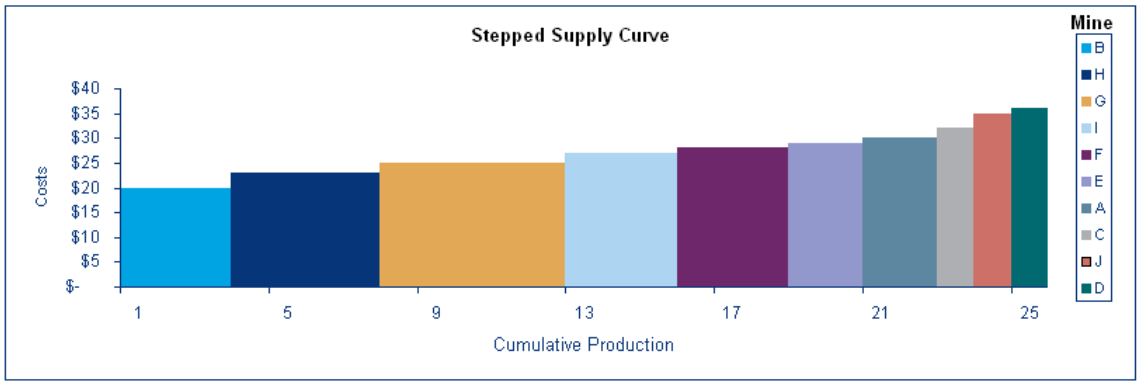


Figure 9-6 Example Coal Supply Curve in Stepped Format



PRODUCTION AMOUNT

MINE NAME →		B	H	G	I	F	E	A	C	J	D
New or Existing		4	8	13	16	18.5	20.5	22.5	24	25	25.5
E	1	$ 20	-	-	-	-	-	-	-	-	-
E	2	$ 20	-	-	-	-	-	-	-	-	-
E	3	$ 20	-	-	-	-	-	-	-	-	-
E	4	-	$ 23	-	-	-	-	-	-	-	-
E	5	-	$ 23	-	-	-	-	-	-	-	-
E	6	-	$ 23	-	-	-	-	-	-	-	-
E	7	-	$ 23	-	-	-	-	-	-	-	-
E	8	-	-	$ 25	-	-	-	-	-	-	-
E	9	-	-	$ 25	-	-	-	-	-	-	-
E	10	-	-	$ 25	-	-	-	-	-	-	-
E	11	-	-	$ 25	-	-	-	-	-	-	-
E	12	-	-	$ 25	-	-	-	-	-	-	-
E	13	-	-	-	$ 27	-	-	-	-	-	-
E	14	-	-	-	$ 27	-	-	-	-	-	-
E	15	-	-	-	$ 27	-	-	-	-	-	-
N	16	-	-	-	-	$ 28	-	-	-	-	-
N	17	-	-	-	-	$ 28	-	-	-	-	-
N	18	-	-	-	-	$ 28	-	-	-	-	-
E	19	-	-	-	-	-	$ 29	-	-	-	-
E	20	-	-	-	-	-	$ 29	-	-	-	-
N	21	-	-	-	-	-	-	$ 30	-	-	-
N	22	-	-	-	-	-	-	$ 30	-	-	-
N	23	-	-	-	-	-	-	-	$ 32	-	-
N	24	-	-	-	-	-	-	-	-	$ 35	-
N	25	-	-	-	-	-	-	-	-	-	$ 36

Production Scalar

9.2.4 Data Sources Used to Build the Curves

For active mines, data relating to labor and productivity is taken from MSHA databases. MSHA reports on individual mine production, number of employees and employee-hours worked. Corporate financial statements of publicly traded companies are listed with the Securities and Exchange Commission (SEC). Supplemental information on work schedules, equipment, percentages of washed coal, trucking distances between mine and preparation plants is obtained

in interviews performed for Wood Mackenzie's annually published county-by-county studies. Information on recoverable reserves comes from several sources such as Environmental Impact Statements (EIS), company annual reports, applications filed at state permitting offices or Lease by Application (LBA) filings for mines on federal lands.

For areas where public information is not available or is incomplete, reserves are estimated using geologic reports of nearby properties and some extrapolation by mining engineers and geologists.

9.2.5 Procedure Used In Determining Mine Productivity

Projected production and stripping ratios[3] are the key determinants of surface mine productivity. Wood Mackenzie assumes mining costs increase as stripping ratios increase. The stripping ratio is the quantity of overburden removed relative to the quantity of coal recovered. Assuming that reserves are developed where they are easiest to mine and deliver to market, general theory suggests that as the easy reserves are depleted, greater amounts of overburden must be handled for the same amount of coal production; thus causing a decrease in mining productivity. However, this productivity loss is often offset by technology improvements in labor saving equipment.

While an understanding of the forces affecting productivity is important, no attempt is made to develop a complex algorithm that tries to balance increased stripping ratios with added technology improvements. Instead, Wood Mackenzie uses reported aggregate productivity (in tons per employee hour) provided by MSHA as a starting point and divides the production by the productivity calculation to obtain aggregate employee-hours. Allocating aggregate employee hours among specific mines, production forecasts for these mines can be converted back into mine-specific productivity forecasts. These forecasts are then examined on a mine-by-mine basis by an industry expert with region specific knowledge.

A similar approach is used for underground mines. First, as background, the specific factors affecting productivity at such mines are identified. For example, underground mines do not have stripping ratios. Productivity estimates for these mines largely depend on the type of mining technique used (which is a function of the region's geology). For instance, longwall-mines can produce a high volume of low cost coal but geologic constraints like small reserve blocks and the occurrence of faulting tends to limit this technique to certain regions. In addition to geologic constraints, there are many variables that can impact underground-mine productivity but they are often difficult to quantify and forecast.

These factors are not used directly but provide a backdrop for deriving productivity estimates. As with surface mines Wood Mackenzie relies on MSHA data for its productivity estimates. Productivity estimates for underground mines start with the MSHA estimates and are carried forward into the forecast years without adjustment.

9.2.6 Procedure to Determine Total Recoverable Reserves by Region and Type

Before mine operators are allowed to mine coal, they must request various permits, conduct environmental impact studies (EIS) and, in many cases, notify corporate shareholders. In each of these instances, mine operators are asked to estimate annual production and total recoverable reserves. Wood Mackenzie uses the mine operators' statements as the starting point for production and reserves forecasts. If no other material is available, interviews with company personnel will provide an estimate.

Region and coal type determinations for unlisted reserves are based on public information reported for similarly located mines. Classifying reserves this way means considering not only a

---

[3] Stripping ratio is the amount of waste material (rock and/or soil) that must be removed to recover one unit (commonly expressed in short tons) of coal. For example, a stripping ratio of 9.8 means that to recover 1 ton of coal you must remove 9.8 tons of waste material. A lower stripping ratio means that less waste has to be removed.

mine's geographic location but also its geologic conditions such as depth and type of overburden and the specific identity of the coal seam(s) being mined. For areas where public information is not available or is incomplete, Wood Mackenzie engineers and geologists estimate reserve amounts based on land surveys and reports of coal depth and seam thickness provided by the U.S. Geologic Service (USGS). This information is then used to extrapolate reserve estimates from known coal sources to unknown sources. Coal quality determinations for unknown reserves are assigned in much the same way.

Once a mine becomes active, actual production numbers reported in corporate SEC filings and MSHA reports are subtracted from the total reserve number to arrive at current reserve amounts. Wood Mackenzie consistently updates the reserves database when announcements of new or amended reserves are made public. As a final check, the Wood Mackenzie supply estimates are balanced against the Demonstrated Reserve Base (DRB)[4] estimates to ensure that they do not exceed the DRB estimates.

9.2.7 New Mine Assumptions

New mines have been included based on information that Wood Mackenzie maintains on each supply region. They include announced projects, coal lease applications and unassigned reserves reported by mining companies. Where additional reserves are known to exist, additional incremental steps have been added. These incremental steps were added based on characteristics of the specific region, typical mine size, and cost trends. They do not necessarily imply a specific mine or mine type.

9.2.8 Other Notable Procedures

Cost Rounding

For simplification, the estimated mine costs were rounded so that costs less than 20 $/Ton were rounded to the nearest $0.25. Costs that fell between 20 and 50 $/Ton were rounded to the nearest $0.50 and costs greater than $50 were rounded to the nearest $1.00.

<=$20, round to nearest $0.25
>$20 and <=$50, round to nearest $0.50
>$50, round to nearest $1.00

Future Cost Adjustments

For consistency with the cost basis used in EPA Base Case v.4.10, costs are converted to real 2007$. Wood Mackenzie has assumed that improved productivity will lead to cost reductions in all regions except Central Appalachia where depleting reserves will lead to falling productivity and increased costs. Costs for all regions except Central Appalachia have been reduced at a rate of 0.4%/year. Central Appalachia's costs have been increased at a rate of 0.4%/year based on the assumption that labor costs on average account for 40% of the Cost of Production. These regional cost adjustments are derived from specific factors affecting costs in regions based on information maintained by Wood Mackenzie and their on-going dialog with industry professionals.

9.2.9 Region Specific Assumptions and Outlooks

Powder River Basin (PRB)

Powder River Basin cost curves are based on cost models run for each of the identified projects in Wood Mackenzie's coal supply database. These cost models are run on five year increments over a 20 year mine life. These models assume that federal lease tracts are acquired as necessary to achieve a 20 year mine life. In preparing the curves for EPA, it was assumed that existing mines would operate at projected levels through 2011 and reserves were adjusted to reflect remaining reserves at that time. Ten years additional reserves were then added to the remaining reserves

[4]Posted by the Energy Information Administration (EIA) in its January, 2007 Coal Production Report.

based on the assumption that additional reserves would be available for lease and the mines would continue to operate. Costs for the added reserves were increased by $3.00/ton to reflect increased coal leasing costs and increasing mining ratios in the PRB.

One existing mine, Decker, is expected to close prior to 2012 and was therefore not included in the cost curves.

A MT region was added to accommodate two proposed mines in Montana that do not fit the quality specifications for the ME or MP regions.

There is an annual limit of 612 million tons per year on Wyoming PRB coal production (i.e., coal codes WH and WL in Table 9-11) based on expected maximum production from existing mines plus potential production from four identified projects.

Western Bituminous Coalfields
The Western Bituminous Coalfields include the Colorado, Utah, southern Wyoming, New Mexico and Arizona coalfields. Life-of-mine costs are used for all operating mines and identified projects. Reserves have been reduced based on projected production through 2011 for existing mines and mines that are expected to go into production before 2012. Unlike the PRB no additional reserves have been added to the reserve base for existing mines.

Arizona mine costs are FOB[5] mine.

In Utah all costs except Deer Creek's include transportation to a loadout facility. Deer Creek costs are based on delivery to the Huntington Canyon power plant.

In New Mexico, all costs are FOB rail or FOB mine. It is assumed that the Navajo, San Juan Underground and the proposed Navajo South/Desert Rock mine will serve their respective mine-mouth power plants. One existing mine, McKinley, will be mined out by 2012. The proposed Carrizozo mine in SE New Mexico is included in the curve.

In Colorado all costs are FOB mine. This includes the Deserado mine which currently ships all of its production to the Bonanza power plant via a private railroad. A CR region has been added to accommodate two proposed mines in or near the Raton Basin.

Louisiana (LA)/ Mississippi (MS)
Louisiana cost curves are based on Wood Mackenzie cost models for existing and planned mines in Louisiana. Where a mine's reserves exceed production requirements over the forecast period, it has been assumed that a second mine could be opened on the reserves. A high cost mine with cost of $50/ton was added.

A Mississippi cost curve was added.

Montana Lignite (ME)
Montana Lignite curves are based on Wood Mackenzie cost estimates for GNP lignite properties. All costs are FOB mine. Because lignite typically does not ship well, it is assumed that any new mines will be developed to serve mine mouth customers.

---

[5] FOB stands for "Free On Board" or "Freight on Board." It indicates the point at which responsibility and costs for a goods is transferred from the seller (or shipper) to the buyer. "FOB mine" implies that the price includes costs up to the mine and that the buyer assumes costs beyond the mine. "FOB rail" implies the prices includes the cost of loading the coal onto a rail car.

North Dakota Lignite (ND)
North Dakota curves are based on Wood Mackenzie cost estimates for the region. Where a mine's reserves exceed production requirements over the forecast period, it has been assumed that a second mine could be opened on the reserves. Costs for the new mines were increased by $2.00/ton. A GNP project was added as a high cost new mine.

Oklahoma/Kansas (OK, KS)
The 2006 set of coal supply curves developed for EPA by Hill and Associates (now a unit of Wood Mackenzie) was updated by increasing costs 30% and adding a high cost mine with a cost of $100/ton.

Texas Lignite
Texas Lignite cost curves are based on cost models run for each of the existing mines and identified projects in Wood Mackenzie's coal supply database. Big Brown was deleted for the existing mines as its reserves will be depleted before 2011.

Illinois Basin (IL, IN, KW)
Illinois Basin cost curves are based on cost models run for each of the existing mines and identified projects in Wood Mackenzie's coal supply database. Where additional reserves are known to be available, additional next step mines were added based on information maintained by Wood Mackenzie on the region.

Appalachia (AL, OH, PC, PW, TN, VA, WN & WS)
Appalachian cost curves are based on Wood Mackenzie's extensive database of existing and planned mines. 2012 production and cost curves were prepared for each region and coal grade using the regional model to estimate cost, production and reserve data for existing mines. To protect the proprietary nature of the regional curves, mine data were aggregated to produce a curve similar to the regional curve without disclosing specific mine data. Cost and production estimates for each of the next step mines were prepared for each region and coal type based on information maintained by Wood Mackenzie's knowledge for each region.

9.2.10 Explanation of Coal Supply Curve Extensions to 2040

Wood Mackenzie added additional reserves at increased costs on a mine-by-mine basis for each region based on its extensive coal resource database and knowledge of the coal industry. A list of the mines added by region and coal grade can be found in Appendix 9-2. For modeling purposes the 2040 coal supply curves are used in 2050 as well.

9.3 Coal Transportation

Within the United States, steam coal for use in coal-fired power plants is shipped via a variety of transportation modes, including barge, conveyor belt, rail, truck, and lake/ocean vessel. A given coal-fired plant typically only has access to a few of these transportation options and, in some cases, only has access to a single type. The number of transportation options that a plant has when soliciting coal deliveries influences transportation rate levels that plant owners are able to negotiate with transportation providers.

Within the Eastern United States, rail service is provided predominately by two major rail carriers in the region, Norfolk Southern (NS) and CSX Transportation (CSX). Within the Western United States, rail service is also provided predominately by two major rail carriers, Burlington Northern Santa Fe (BNSF) and Union Pacific (UP). Plants in the Midwestern United States may have access to rail service from BNSF, CSX, NS, UP, the Canadian National (CN), Canadian Pacific (CP), or short-line railroads. Barge, truck, and vessel service is provided by multiple firms, and conveyor service is only applicable to coal-fired plants directly located next to mining operations (e.g., mine-mouth plants).

In recent years, transportation rates (especially rail rates) have increased significantly due to significant increases in input costs (including fuel prices, steel prices and labor costs), as well as a number of Surface Transportation Board (STB) rail rate case decisions that have allowed higher rail rates to be charged at plants that are served only by a single railroad.

The transportation methodology and rates presented below reflect expected long-run equilibrium transportation rates as of September 2008, when the coal transportation rate assumptions for EPA Base Case v.4.10 were finalized. It is important to remember that these rates do not reflect rates that transporters and coal-fired owners may currently be negotiating in the near-term (pre-2012). Instead, these rates reflect expected long-term equilibrium levels, including the long-term market dynamics that will drive these pricing levels.

All rates are represented in 2007 real dollars.

9.3.1 Coal Transportation Matrix Overview

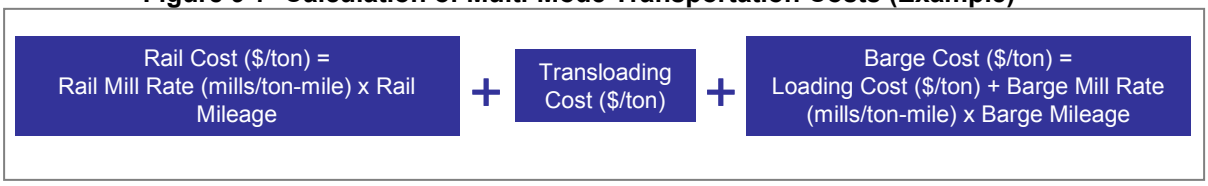
Description

In order to model coal transportation rates within the EPA's modeling construct, a coal transportation matrix was developed, which represents a matrix of all the coal demand regions and coal supply regions modeled within the IPM model for EPA Base Case v.4.10. The matrix includes the associated transportation costs between these supply and demand nodes. Each coal demand region covers a set of coal plants having similar transportation infrastructure, transportation competitiveness levels, and geographic location; in addition to these criteria, coal demand regions are also classified as either "mine-mouth" or "non mine-mouth" regions. Coal supply regions are represented by the major coal mining basins modeled in IPM; a more detailed discussion on these regions can be found in previous sections.

Methodology

Each coal supply region and coal demand region is connected via a transportation link, which can include multiple transportation modes. For each transportation link, cost estimates, in terms of $/ton, were calculated utilizing mode-based transportation cost factors, analysis of the competitive nature of the moves, and overall distance that the coal type must move over each applicable mode. An example of the calculation methodology for movements including multiple transportation modes is shown in Figure 9-7.

Figure 9-7 Calculation of Multi-Mode Transportation Costs (Example)

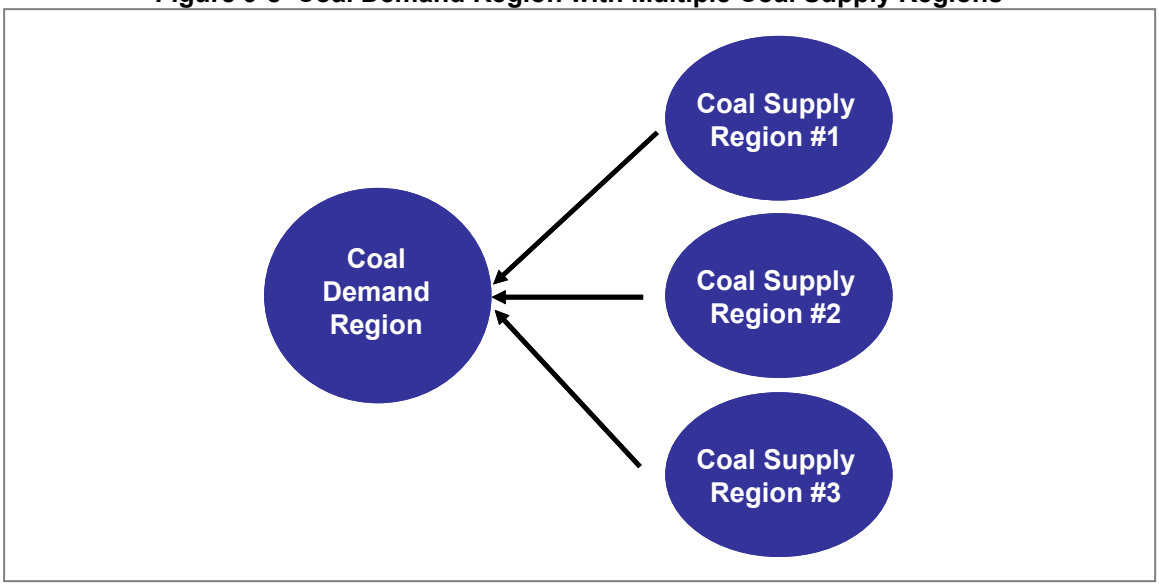


9.3.2 Calculation of Supply/Demand Region Distances

Definition of applicable supply/demand regions

Coal demand regions are linked to coal supply regions based on historical coal deliveries, as well as based on the potential for new coal supplies to serve a demand region going forward. A demand region may have transportation links with more than one supply region, depending on the various coal types that can be physically delivered and burned by generators within a given coal demand region.

Figure 9-8 Coal Demand Region with Multiple Coal Supply Regions



Transportation Links for Existing Coal-Fired Plants
Transportation routings for given coal supply regions and coal demand regions were developed based on third-party software[6] and other industry knowledge available to Hellerworx and PA Consulting Group. Origins for each coal supply region were based on significant mines or other significant delivery points within the supply region, and destinations for each coal demand region were based on geographical points located near, and with similar key delivery transportation characteristics, as the coal plants located within the given coal demand region. For routes utilizing multiple modes (e.g. rail-to-barge, truck-to-rail, etc.), distances were developed separately for each transportation mode.

Transportation Links for New Coal-Fired Plants
Within each coal demand region, coal transportation links representative of the typical transportation costs expected to be incurred by new coal plants within that region were developed. For coal demand regions where new coal plant construction is not expected to include mine-mouth plants, the transportation links for new plants are based on transportation links in the existing coal demand region that are expected to have costs most similar to those incurred by new plants. For coal demand regions where new coal plant construction is expected to consist primarily of mine-mouth plants, new transportation links reflecting short-distance transportation of local coal supplies were created as needed to properly represent the transportation costs incurred by new plants. This methodology helps ensure that coal transportation costs for new coal plants are properly integrated with and assessed fairly vis-à-vis existing coal-fired assets within the IPM modeling structure.

9.3.3 Overview of Rail Rates

Competition within the railroad industry is limited. Two major railroads in the Western U.S. (BNSF and UP) and two major railroads in the Eastern U.S. (CSX and NS) currently originate most of the U.S. coal traffic that moves by rail.

In recent years, railroads have increased coal transportation rates in real terms wherever they have the opportunity. However, rail rates at plants captive to a single rail carrier are now close to the maximum levels prescribed by the STB, which limits the potential for further real increases in these rates. Moreover, between 2004 and 2008, the differential between rates at captive plants and rates at competitively-served plants narrowed. For all of the coal supply regions except the

[6] Rail routing and mileage calculations utilize ALK Technologies PC*Miler software.

Powder River Basin (PRB), the current relatively small differentials between captive and competitive rates are expected to persist over the long-term.

All of the rail rates discussed below include railcar costs, and include fuel surcharges at expected 2012 fuel price levels.

Overview of Rail Competition Definitions
Within the transportation matrix, rail rates are classified as being either captive or competitive, depending on the ability of a given coal demand region to solicit supplies from multiple suppliers. Competitive rail rates are further subdivided into high- and low-cost competitive subcategories. Competition levels are affected both by the ability to take delivery of coal supplies from multiple rail carriers, the use of multiple rail carriers to deliver coal from a single source (e.g., BNSF/UP transfer to NS/CSX for PRB coal moving east), or the option to take delivery of coal via alternative transportation modes (e.g., barge, truck or vessel).

Table 9-12 Rail Competition Definitions

Competition Type	Definition
Captive	Demand source can only access coal supplies through a single provider; demand source has limited power when negotiating rates with railroads.
High-Cost Competitive	Demand source has some, albeit still limited, negotiating power with rail providers; definition typically applies to demand sources that have the option of taking delivery from either of the two major railroads in the region.
Low-Cost Competitive	Demand source has a strong position when negotiating with railroads; typically, these demand sources also have the option of taking coal supplies via modes other than rail (e.g., barge, truck, or lake/ocean vessel).

Rail Rates
As previously discussed, rail rates are subdivided into three competitive categories: captive, high-cost competitive, and low-cost competitive. Moves are further subdivided based on the distance that the coal supply must move over rail lines: <200 miles, 200-299 miles, 300-399 miles, 400-699 miles, and 700+ miles. Within the Western U.S., mileages are only subdivided into two categories (<300 miles and 300+ miles), given the longer distances that these coal supplies typically move.

Initial rate level assumptions were determined based on an analysis of recent rate movements, current rate levels in relation to maximum limits prescribed by the STB, expected coal demand, diesel prices, recent capital expenditures by railroads, and projected productivity improvements. In general, shorter moves result in higher applicable rail rates due to the lesser distance over which fixed costs can be spread. As previously discussed, rail rates reflect anticipated 2012 costs in 2007 real dollars.

Rates applicable to Eastern moves
Rail movements within the Eastern U.S. are handled predominately by the region's two major carriers, NS and CSX. Some short movements are handled by a variety of short-line railroads. Most plants in the Eastern U.S. are served solely by a single railroad (i.e., they are captive plants).

Table 9-13 Assumed Eastern Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	72	72	58
200-299	55	55	43
300-399	55	55	43
400-699	37	37	30
700+	35	35	28

Rates applicable to Midwestern moves

Plants in the Midwestern U. S. may be served by BNSF, CN, CP, CSX, NS, UP or short-line railroads. However, the rail network in the Midwestern U.S. is very complex, and most plants are served by only one of these railroads. The Midwestern U.S. also includes a higher proportion of barge-served and truck-served plants than is the case in the Eastern or Western U.S.

Table 9-14 Assumed Midwestern Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	72	72	58
200-299	55	55	43
300-399	55	55	43
400-699	36	36	29
700+	34	34	27

Rates applicable to Western moves

Rail moves within the Western U.S. are handled predominately by BNSF and UP. In addition to these incumbent carriers, CP acquired the Dakota, Minnesota and Eastern Railroad (DM&E) in October 2007, which increases the probability that DM&E's project to build a third rail line into the PRB will be completed. The analysis assumes that DM&E's entry into the market will influence transportation rates for PRB coal by 2012,[7] and the rail rate forecast for PRB coal shipments to competitively-served destinations reflects this expectation.

Rates for Western coal shipments from the PRB are forecast separately from rates for Western coal shipments from regions other than the PRB. This reflects the fact that in many cases coal shipments from the PRB are subject to competition between BNSF and UP (with the possible future entry of DM&E as a third competitor within this region), while rail movements of Western coal from regions other than the PRB consist primarily of Colorado and Utah coal shipments that originate on UP, and New Mexico coal shipments that originate on BNSF. PRB coal shipments also typically involve longer trains moving over longer average distances than coal shipments from the other Western U.S. coal supply regions, which means these shipments typically have lower costs per ton-mile than non-PRB coal shipments.

[7] Note that this is not equivalent to assuming that DM&E's PRB project would be operational by 2012. Construction of the DM&E's PRB project is expected to be a three-year process. However, in order to obtain financing and begin construction, DM&E would likely have to negotiate some rail contracts for PRB coal shipments. Thus, DM&E's presence as a third competitor in the market for PRB coal shipments might affect rail rates well before DM&E's additional rail line into the PRB became operational

Non-PRB coal moves

Table 9-15 Assumed Non-PRB Western Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	43	43	35
300+	25	21	21

PRB moves confined to BNSF/UP rail lines

Table 9-16 Assumed PRB Western Rail Rates (2007 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	43	43	35
300+	23	14	14

PRB moves transferring to Eastern railroads

For PRB coal moving west-to-east, the coal transportation matrix assumes that the applicable low-cost competitive assumption is applied to the BNSF/UP portion of the rail mileage, and an assumption of either $2.16 per ton or 28 mills per ton-mile (whichever is higher) is applied to the portion of the movement that occurs on railroads other than BNSF and UP. (The $2.16 per ton assumption is a minimum rate for short-distance movements of PRB coal on Eastern railroads.)

9.3.4 Truck rates

Truck rates include loading and transport components, and all trucking flows are considered competitive because highway access is open to any trucking firm. The truck rates shown in Table 9-17 are expected long-term equilibrium levels reflective of current rates as of September 2008, and expected changes in labor costs, fuel prices, and steel prices. The slightly higher truck rates in Utah reflect market conditions specific to that market, which is relatively remote.

Table 9-17 Assumed Truck Rates (2007 Real Dollars)

Market	Loading Cost ($/ton)	Transport (mills/ton-mile)
Outside of Utah Market	1.03	134
Utah Market	1.54	134

9.3.5 Barge and Lake Vessel Rates

As with truck rates, barge rates include loading and transport components, and all flows are considered competitive because river access is open to all barge firms. The transportation matrix subdivides barge moves into three categories, which are based on the direction of the movement (upstream vs. downstream) and the size of barges that can be utilized on a given river. As with the other types of transportation rates forecast in this analysis, the barge rate levels shown in Table 9-18 are expected long-term equilibrium levels reflective of current rates as of September 2008, and expected changes in labor costs, fuel prices, and steel prices.

Rates for transportation of coal by lake vessel on the Great Lakes were forecast on a plant-specific basis, taking into account the lake vessel distances applicable to each movement, the expected backhaul economics applicable to each movement (if any), and the expected changes in labor costs and fuel and steel prices over the long-term.

Table 9-18 Assumed Barge Rates (2007 Real Dollars)

Type of Barge Movement	Loading Cost ($/ton)	Transport (mills/ton-mile)
Mississippi River, and Downstream on the Ohio River	1.75	7.9
Smaller Size Barges (Allegheny, Kanawha, and Monongahela Rivers)	1.85	6.9
Upstream on Ohio River	1.95	10.4

9.3.6 Transportation Rates for Imported Coal

Transportation rates for imported coal reflect expectations regarding the long-term equilibrium level for ocean vessel rates, taking into account expected long-run equilibrium levels for fuel and steel prices, and expected continued strong demand for shipment of dry bulk commodities (especially coal and iron ore) from China and other Asian nations.

In EPA Base Case v.4.10, it is assumed that imported coal is likely to be used only at plants that can receive this coal by direct water delivery (i.e., via ocean vessel or barge delivery to the plant). This is based on an assessment of recent transportation market dynamics, which suggests that railroads are unlikely to quote rail rates that will allow imported coal to be cost-competitive at rail-served plants. Moreover, import rates are higher for the Alabama and Florida plants than for New England plants because many of the Alabama and Florida plants are barge-served (which requires the coal to be transloaded from ocean vessel to barge at an ocean terminal, and then moved by barge to the plant), whereas most of the New England plants can take imported coal directly by vessel. Transportation rates for imported coal moving to each coal demand region are shown in Table 9-19.

Table 9-19 Assumed Transportation Rates for Imported Coal (2007 Real Dollars)

Coal Demand Region	Coal Demand Region Description	Transportation Rate ($/ton)
ALR2	Alabama rail plants (ALRL)_Low-Cost Competitive Not Mine Mouth Barge	15.43
FL2	Florida plants (FL)_Low-Cost Competitive Not Mine Mouth Barge	15.43
FL3	Florida plants (FL)_Low-Cost Competitive Not Mine Mouth Rail	15.43
GFB1	Gulf barge plants (GFBG)_Low Cost Competitive Not Mine Mouth Rail	15.43
GFB3	Gulf barge plants (GFBG)_Low-Cost Competitive Not Mine Mouth Barge	15.43
NE2	New England / Hudson River plants / Hudson plant (NE)_Low-Cost Competitive Not Mine Mouth Barge	11.32
NE3	New England / Hudson River plants / Hudson plant (NE)_Low-Cost Competitive Not Mine Mouth Rail	13.37
TAB1	Tennessee and Northern Alabama river plants (TABG)_High-Cost Competitive Not Mine Mouth Rail	15.43

9.3.7 Other Transportation Costs

In addition to the transportation rates already discussed, the transportation matrix assumes various other rates that are applied on a case-by-case basis, depending on the logistical nature of a move. These charges apply when coal must be moved between different transportation modes (e.g., rail-to-barge or truck-to-barge) – see Table 9-20.

Table 9-20 Assumed Other Transportation Rates (2007 Real Dollars)

Coal Demand Region	Rate ($/ton)
Rail-to-Barge	1.23
Rail-to-Vessel	1.23
Rail-to-Rail	1.44
Truck-to-Barge	1.49
Conveyor	1.13

9.3.8 Long-Term Escalation of Transportation Rates

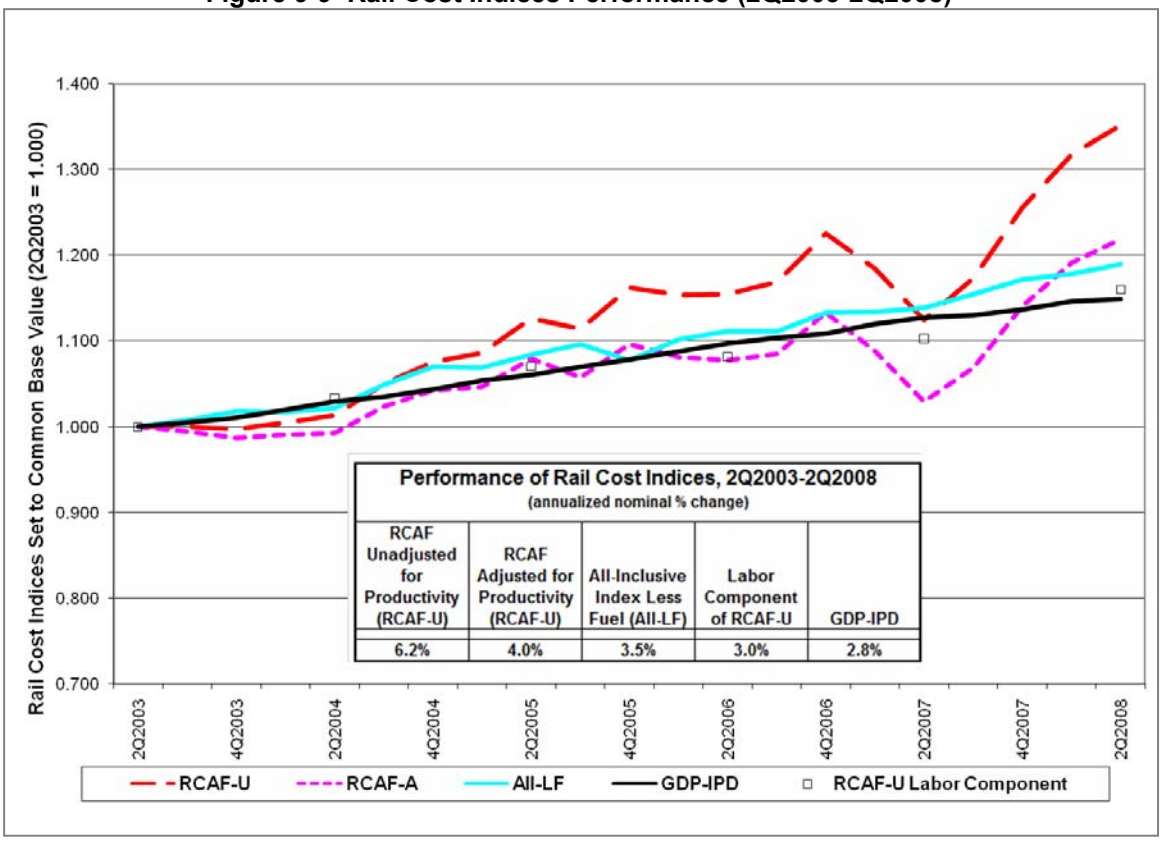
Overview of market drivers

According to data published by the Association of American Railroads (AAR), labor costs accounted for about 34% of the rail industry's operating costs in 2006, and fuel accounted for an additional 19%. The remaining 47% of the rail industry's costs relate primarily to locomotive and railcar ownership and maintenance, and track construction and maintenance.

The RCAF[8] Unadjusted for Productivity (RCAF-U), which tracks operating expenses for the rail industry, has increased at an annualized rate of 6.2%/year over the past five years, more than double the increase of 2.8%/year in general inflation (GDP-IPD) over the same period. However, this largely resulted from steep increases in diesel fuel prices. Excluding fuel, the rail industry's operating costs (as measured by the All-Inclusive Index Less Fuel, or AII-LF), increased by only 3.5%/year.

[8] The Rail Cost Adjustment Factor (RCAF) refers to several indices created for regulatory purposes by the STB, calculated by the AAR, and submitted to the STB for approval. The indices are intended to serve as measures of the rate of inflation in rail inputs. The meaning of various RCAF acronyms that appear in this section can be found in the insert in Figure 9-9.

Figure 9-9 Rail Cost Indices Performance (2Q2003-2Q2008)



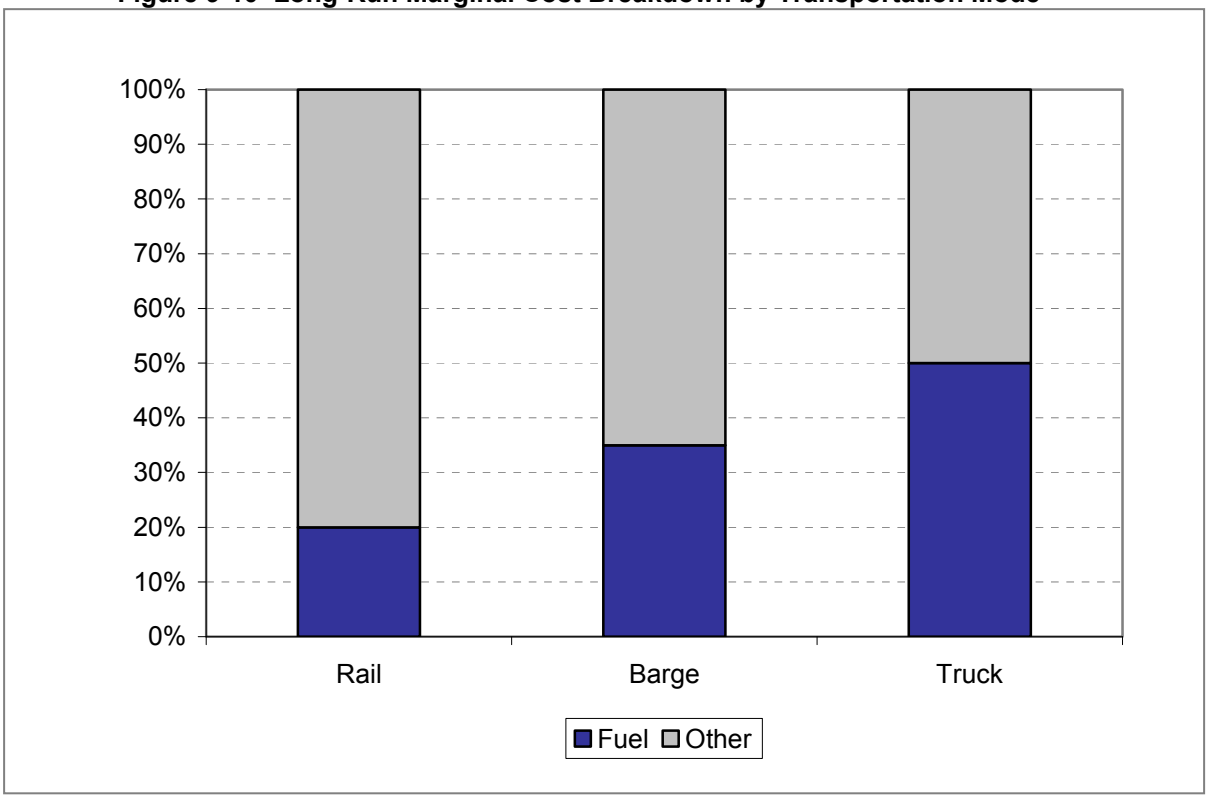
Performance of Rail Cost Indices, 2Q2003-2Q2008 (annualized nominal % change)				
RCAF Unadjusted for Productivity (RCAF-U)	RCAF Adjusted for Productivity (RCAF-U)	All-Inclusive Index Less Fuel (All-LF)	Labor Component of RCAF-U	GDP-IPD
6.2%	4.0%	3.5%	3.0%	2.8%

In addition to diesel fuel price increases, world prices for steel (which is a significant component of locomotive, railcar, and track construction and maintenance costs) also increased steeply over the past five years, rising from about $290/metric tonne as of June 2003 to about $650/metric tonne as of June 2007, and over $1,000/metric tonne as of June 2008. However, during the previous five years (2Q1998-2Q2003), when steel prices were less volatile, the AII-LF closely tracked general inflation, rising at about 2.1%/year compared with 2.0%/year for the GDP-IPD.

Additionally, over the past five years, the rate of increase in the rail industry's labor costs (3.0%/year) has closely tracked the increase in the GDP-IPD (2.8%/year.)

The other major transportation modes used to ship coal (barge and truck) have cost drivers broadly similar to those for rail transportation (labor costs, fuel costs, and equipment costs). However, a significant difference in cost drivers between the transportation modes relates to the relative weighting of fuel costs for the different transportation modes. Estimates show that, at 2006 fuel prices, fuel costs accounted for about 20% of long-run marginal costs for the rail industry, 35% of long-run marginal costs for barges, and 50% of long-run marginal costs for trucks.

Figure 9-10 Long-Run Marginal Cost Breakdown by Transportation Mode



9.3.9 Market Drivers Moving Forward

Diesel fuel prices

The Energy Information Administration's (EIA's) Annual Energy Outlook (AEO)[9] forecast of long-term equilibrium prices for diesel fuel shows expected prices ranging from about $2.62/gallon in 2012 to about $2.77/gallon in 2030 (2007 real dollars). This range of prices is comparable to the actual average on-highway diesel fuel price for 2006 which was $2.78/gallon (2007 real dollars). The coal transportation rate forecast for EPA Base Case v.4.10 assumes that diesel fuel prices will return to these long-run equilibrium levels by 2012.

Table 9-21 EIA AEO Diesel Fuel Forecast, 2012-2030 (2007 Real Dollars)

Year	Rate ($/gallon)
2012	2.62
2015	2.49
2020	2.57
2025	2.61
2030	2.77
Annualized % Change, 2025-2030	1.10%

Source: EIA

[9] As noted at the beginning of this section, the coal transportation rate assumptions for EPA Base Case v.4.10 were finalized in September 2008. At that time, the Annual Energy Outlook 2008 forecast was the latest available.

Iron ore prices
ABARE's[10] forecast of iron ore prices shows an expectation that iron ore prices will return to late 2007/early 2008 levels (i.e., to the levels prevailing before the most recent price spike) by 2012, and to decline by about 18% in real terms for their 5-year forecast period (2008-2013) as a whole.

Table 9-22 ABARE Forecast of Iron Ore Prices

	2007 $/metric tonne
ABARE Estimate of Average Price for Australian Iron Ore Exports, Year Ending (YE) March 2008	67.72
ABARE Forecast for YE Mar 2009	98.68
ABARE Forecast for YE Mar 2010	91.19
ABARE Forecast for YE Mar 2011	73.73
ABARE Forecast for YE Mar 2012	61.84
ABARE Forecast for YE Mar 2013	55.52
Total Percent Change (2008-2013)	-18.00%

Source: ABARE, Australian Commodities, vol. 15 no. 1 and 2, March and June Quarters 2008

Labor costs
Labor costs for the rail industry are expected to continue to escalate at approximately the same rate as overall inflation (i.e., labor costs are expected to be approximately flat in real terms). Due to the fact that competition is stronger in the barge and trucking industries than in the rail industry, labor costs in the barge and truck industries are likely to increase at rates similar to or slightly slower than the increase in rail labor costs.

Productivity gains
The most recent data published by AAR (covering 2002-2006) shows that rail industry productivity increased at an annualized rate of approximately 1.2% per year during this period. However, due to limited competition in the rail industry, these productivity gains were generally not passed through to shippers. In addition, the potential for significant productivity gains in the trucking industry is relatively limited since truck load sizes, operating speeds, and truck driver hours are all regulated by law.

Long-Term Escalation of Coal Transportation Rates
Based on the foregoing discussion, the transportation rate forecast assumes flat real escalation of rail and truck rates, and a 1% per year real decline in barge and lake vessel rates, which reflects some pass-through of productivity gains in those highly competitive industries, over the 2012-2025 period.

However, EIA's forecast of diesel fuel prices, which is essentially flat in real terms during the 2012-2025 period, predicts a relatively steep rise in diesel fuel prices (annualized increase of 1.1%/year) between 2025 and 2030. Because of this, coal transportation rates are assumed to escalate as follows during the 2026-2062 period:

- Rail: 1.1% annual real increase in fuel prices x 20% fuel cost weighting = real rate increase of 0.2%/year.
- Truck: 1.1% annual real increase in fuel prices x 50% fuel cost weighting = real rate increase of 0.5%/year.

[10] ABARE is a branch of the Australian government that forecasts prices and trade volumes for a wide variety of commodities that Australia exports. Australia is a major exporter of iron ore, accounting for about 32% of total worldwide iron ore exports in 2007. See www.abareconomics.com

- Barge and lake vessel: 1.1% annual real increase in fuel prices x 35% fuel cost weighting = real input cost increase of 0.4%/year, less 1% per year for pass-through of productivity gains = real rate decline of 0.6%/year.
- Conveyor: no change in real terms throughout the study period.

9.3.10 Other Considerations

Transportation constraints limiting the growth of PRB coal use

The rate at which coal shipments from the PRB (Montana and Wyoming) regions can be increased is somewhat limited in the near-term by the capacity of the rail lines that transport the coal from these regions. Hence, the following limits on the growth of PRB coal production are implemented in IPM:

- Wyoming PRB coal growth is limited to 15 million short tons additional production capacity each year.
- Montana coal growth is limited to 2 million short tons additional production capacity each year.

Table 9-23 Assumed Production Growth Rates

Coal Supply Source	Growth/Year (MM short tons)
Wyoming PRB	15
Montana	2

Other transportation constraints

This analysis does not consider the February 10, 2009 announcement by Norfolk Southern and Canadian National Railway to share rail lines and enhance the efficiency of service out of the Illinois Basin coal supply region (Mid-American Corridor). This announcement has the potential to alleviate an existing bottleneck (both rate-based and logistical-based) that has historically prevented large volumes of coal moving from the Illinois Basin to Southeastern coal-fired facilities, although it is too early to know the full impact of this arrangement.

Global recession

The analysis underlying the coal transportation assumptions as described above was completed prior to experiencing the full impact of the current global recession on the energy industry. In addition to downward pressure on fuel and steel prices, the recession led to large declines in industrial coal and electricity demand. Coal-fired plants, already faced with a glut of stockpiled coal, saw excess supply further balloon due to relatively mild temperatures throughout 2009 and historically low gas prices that led to some gas-fired facilities displacing more marginal, higher-cost, coal-fired facilities. In the face of declining demand, coal transporters saw movements fall dramatically as contracted tonnage was deferred and contracts were reworked. However, it remains to be seen how, or if, transporters will adjust rates in the face of changing demand dynamics. For example, railroads demonstrated little desire to lower rates in recent contract negotiations even as coal volumes shipped by rail were off 9.3% from year-to-date 2008 levels as of September 12, 2009.

9.4 Coal Exports, Imports, and Non-Electric Sectors Demand

The coal supply curves used in EPA Base Case v.4.10 represent the total steam coal supply in the United States. While the U.S. power sector is the largest consumer of native coal – roughly 93% of mined U.S. coal in 2007 was used in electricity generation – non-electric demand must also be taken into consideration in IPM modeling in order to determine the market clearing price. Furthermore, some coal mined within the U.S. is exported out of the domestic market, and some foreign coal is imported for use in electricity generation, and these changes in the coal supply must also be detailed in the modeling of the coal supply available to coal power plants. The projections for imports, exports, and non-electric sector coal demand are based on EIA's AEO 2010.

In EPA Base Case v.4.10 coal exports and coal-serving residential, commercial and industrial demand are designed to correspond as closely as possible to the projections in AEO 2010 both in terms of the coal supply regions and coal grades that meet this demand. The projections used exclude exports to Canada, as the Canadian market is modeled endogenously within IPM. First, the subset of coal supply regions and coal grades in EPA Base Case v.4.10 are identified that are contained in or overlap geographically with those EIA Coal Market Module (CMM) supply regions and coal grades that are projected as serving exports and non-electric sector demand in AEO 2010. Next, coal for exports and non-electric demand are constrained by CMM supply region and coal grade to meet the levels projected in AEO 2010. These levels are shown in Table 9-24 and Table 9-25. (Since the AEO 2010 time horizon extends to 2035 and EPA Base Case v.4.10 to 2050, the AEO projected levels for 2035 are maintained through 2050.). IPM then endogenously determines which IPM coal supply region(s) and coal grade(s) will be selected to meet the required export or non-electric sector coal demand as part of the cost-minimization coal market equilibrium. Since there are more coal supply regions and coal grades in EPA Base Case v.4.10 than in AEO 2010 the specific regions and coal grades that serve export and non-electric sector demand are not pre-specified but modeled.

Imported coal is assumed to cost 30.81 2007$/Ton, and is only available to plants in the eight demand regions which are eligible to receive imported coal. The eight coal demand regions which may receive imported coal, along with the cost of transporting this coal to the demand regions, are summarized in Table 9-19. The total US imports of steam coal are limited as shown in Table 9-26.

Table 9-24 Coal Exports

Name	2012	2015	2020	2030	2040 -2050
Rocky Mountains - Bituminous Low Sulfur	1.24	0.97	0.45	0.84	1.08
Central Appalachia - Bituminous Medium Sulfur	6.69	7.74	7.4	7.31	6.96
East Interior - Bituminous Medium Sulfur	6.46	4.29	0	0	0
Northern Appalachia - Bituminous Medium Sulfur	4.57	3.02	0	0	0
Wyoming Southern PRB - Subbituminous Low Sulfur	0.03	0.04	0.05	0.09	0.12

Table 9-25 Residential, Commercial, and Industrial Demand

Name	2012	2015	2020	2030	2040 - 2050
East Interior - Bituminous High Sulfur	6.84	7.06	7.1	6.97	6.88
Northern Appalachia - Bituminous High Sulfur	1.12	1.16	1.16	1.14	1.12
West Interior - Bituminous High Sulfur	1.59	1.85	1.99	1.98	1.95
Central Appalachia - Bituminous Low Sulfur	4.8	4.98	5.01	4.89	4.8
Southern Appalachia - Bituminous Low Sulfur	0.21	0.22	0.22	0.21	0.21
Rocky Mountain - Bituminous Low Sulfur	3.78	4.03	4.1	4.06	3.97
Arizona/New Mexico - Bituminous Low Sulfur	0.41	0.43	0.44	0.44	0.43
Central Appalachia - Bituminous Medium Sulfur	13.3	13.84	13.93	13.66	13.42
East Interior - Bituminous Medium Sulfur	0.82	0.84	0.84	0.83	0.82
Northern Appalachia - Bituminous Medium Sulfur	4.02	4.16	4.17	4.05	3.97
Southern Appalachia - Bituminous Medium Sulfur	1.36	1.41	1.42	1.4	1.37
Gulf Lignite - High Sulfur	2.46	2.57	2.59	2.54	2.49
Dakota Lignite - Medium Sulfur	5.26	5.43	5.46	5.36	5.3
Western Montana - Subbituminous Low Sulfur	0.43	0.19	0.03	0	0
Western Wyoming - Subbituminous Low Sulfur	0.92	0.98	1	1	0.98
Wyoming Northern PRB - Subbituminous Low Sulfur	3.85	3.99	4.01	3.94	3.88
Western Wyoming - Subbituminous Medium Sulfur	1.03	1.11	1.14	1.13	1.1
Arizona/New Mexico - Subbituminous Medium Sulfur	0.1	0.11	0.11	0.11	0.11

Table 9-26 Coal Import Limits

	2012	2015	2020	2030	2040 - 2050
Annual Coal Imports Cap (Million Short Tons)	30.0	28.9	36.0	36.2	51.5

Appendix 9-1. Illustrative Example of Wood Mackenzie Costing Procedure Used in Developing EPA's Coal Supply Curves

To further demonstrate the procedures used in preparing Wood Mackenzie's cost tables, a sample was prepared for the Colorado, Green River Basin, 0.81-1.20 lbs. SO_2/MMbtu coals. This region was selected because it contains both surface and underground mines as well as existing (E) and planned new mines (N).

The initial step was to prepare cost models for the selected mines. The mine names have been replaced with mine step designations: E01, E02, E03, N01, N02 and N03. Production and productivity assumptions for the mines have been modified to mask the mines selected for this sample procedure. Cost models were prepared for E01, E02, E03, N02 and N03. N01 was not modeled because it is a proposed replacement for E03 and is expected to have a cost structure very similar to E03. The cost model was run in 2008$ and used to solve for the sales price required to return a 10% DCFROR for the mine.

In the following pages of this appendix individual cost models (in the form of a series of spreadsheets) are provided for mines E01_S, EO2_UG, EO3_UG, NO2_UG, and NO3_UG, Each mine's spreadsheet consists of 4 pages that capture the costs and cash flows for the mines over the 2008 – 2035 time period. The first page in each spreadsheet model provides production and productivity data for the mine. The second page shows its capital requirements. The third page contains a summary of capital expenditures. The fourth page pulls together all costs and cash flows and (in the third row from the top) derives the required sales price on the assumption of a 10% rate of return.

The model results obtained for each mine were then loaded into the "EPA Cost Curve Worksheet," which appears on the last page of this appendix. (The "sales prices ($/ton)" from the mine costing models can be seen in the 11th column ("Cost of Production (2008$)") of the cost curve worksheet. This worksheet also contains EPA's coal region and coal type data as well as Wood Mackenzie region and type codes. (The Wood Mackenzie codes were included to assist in the proper assignment of costs for areas where cost data was prepared and grouped based on Wood Mackenzie codes.) Additional data includes mine names, step names, codes for existing or new mines, mine type (used for western mines), heat content, production rate and reserves.

In conjunction with transferring the costs generated for each mine to the "EPA Cost Curve Worksheet," a number of adjustments were made to support their use in EPA's IPM electric sector model:

(1) There are a number of differences in the values appearing in the 11th column and the corresponding "sales price" values that appeared in the individual mine costing models. For example, it was assumed the N01 production costs would be the same as the mine it is replacing but additional transportation will be required to move the coal to the mine loadout and partial washing would take place. To account for these additional costs $1.00/ton was added to the Cost of Production of E03 to estimate the cost for N01. In the case of N03, it was assumed that additional transportation from the mine mouth to the loadout will be required so an additional $1.00/ton was added to the model results. This adjustment was based on a separate modeling analysis that Wood Mackenzie performed to estimate the cost of production at N03. Because this modeling contained mine specific and proprietary data, it could not be included in this appendix.

(2) Because the mine costing model estimates were prepared in 2008$, the costs were converted (deflated) to constant 2007$, which is the cost basis used in EPA Base Case v.4.10. (This conversion can be seen in the 11th ("Cost of Production (2008$)") and 12th ("Cost of Production (2007$)") columns of the Cost Curve Worksheet.)

(3) In running the individual cost models for new mines, Wood Mackenzie makes certain assumptions regarding the start-up date for the mine. In transferring the costs generated by the cost models to the EPA Cost Curve Worksheet it is assumed that the new mines could be opened by 2012 if demand exists and EPA's IPM model is allowed to determine when the mine will be opened.

(4) Wood Mackenzie has assumed that labor productivity in all Producing Regions except Central Appalachia will increase at a rate of 1% per year. Productivity in Central Appalachia is expected to fall 1% per year. These productivity assumptions affect future Cost of Production estimates. All regions except Central Appalachia were deflated 0.4% per year while it was inflated by 0.4% per year. The 0.4% adjustment is based on the assumption that labor costs on average account for 40% of the Cost of Production. In the EPA Cost Curve Worksheet the productivity adjustments appear in the 13th ("deflator") and 14th ("deflated cost") columns. The 0.4% productivity growth assumption means that in the 4 years between 2008 (the net present value year used in the mine costing spreadsheets) and 2012 (the first model year in EPA's IPM base case) productivity would increase by a factor of 1.02 (shown in the 13th column) and, consequently, the cost shown in the 12th column would have to be divided by this deflator (13th column) to obtain the deflated costs shown in the 14th column

(5) Costs were then rounded by the procedure described above in section 9.3.8 to obtain the "Final Cost" values shown in the 15th column.

Besides the adjustments described above and shown in the cost curve worksheet, other adjustments to costs were made to meet EPA's need for cost and production data out to 2040 and beyond. Wood Mackenzie's cost models are generally run for a maximum of 20 years even though additional, higher cost reserves are known to exist. When production and reserve data were pushed past reserve estimates typically used in the cost models, additional reserves were added and costs were increased. Appendix 9-2 lists the new mines that were included in the 2040 curves. As a quality assurance check, if additional reserves were assigned to any coal region and type, the resulting totals were tested against EIA Reserve Estimate – 2006 (Table 15_06) to insure reserves were not overstated and to establish an upper geologic limit for reserves in any area.

Appendix 9-1 (Cont'd) Illustrative Example

Mine: [illegible]
Production Data

Year	Tons (000)	In-Situ DL Yds (000)	T/S Yds (000)	Total Yds (000)	Ratio	Effective DL % Rehandle	DL Yds (000)	T/S Yds (000)	Total Yds (000)	Ratio
2008	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2009	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2010	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2011	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2012	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2013	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2014	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2015	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2016	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2017	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2018	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2019	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2020	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2021	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2022	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2023	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2024	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2025	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2026	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2027	2,500	24,500	0	24,500	9.8	10%	26,950	0	26,950	10.8
2028										
2029										
2030										
2031										
2032										
	50,000	490,000	0	490,000	9.8		539,000	0	539,000	10.8
$/ton										

Mine: **E01_S**
Capital Requirements ($ X 1000)
Capital Contingency: 0%
Miles of Rail spur: 0
Coal Storage: 10000

Year	Acqisition	Develop.	Rail	Facilities	Truck Shovel		Dragline		Coal Load & Haul		Miscellaneous		Total	
					Initial	Repl	Initial	Repl	Initial	Repl	Initial	Repl	Initial	Repl
2008		0	0	15,878	0		64,680		9,720		16,368		106,646	0
2009					0		0		0		0		0	0
2010					0		0		0		0		0	0
2011					0		0		0		0		0	0
2012					0		0		0		0		0	0
2013					0		0		0		0		0	0
2014					0		0		0		0		0	0
2015					0		0		0		0	16,368	0	16,368
2016					0		0		0		0	0	0	0
2017					0		0		0		0	0	0	0
2018					0	0	0		0	4,082	0	0	0	4,082
2019					0	0	0		0	0	0	0	0	0
2020					0	0	0		0	0	0	0	0	0
2021					0	0	0		0	0	0	0	0	0
2022					0	0	0		0	0	0	16,368	0	16,368
2023					0	0	0		0	0	0	0	0	0
2024					0	0	0		0	0	0	0	0	0
2025					0	0	0		0	0	0	0	0	0
2026					0	0	0		0	0	0	0	0	0
2027					0	0	0		0	0	0	0	0	0
2028														
2029														
2030														
2031														
2032														
	0	0	0	15,878	0	0	64,680	0	9,720	4,082	16,368	32,736	106,646	36,818
	0.00	0.00	0.00	0.32	0.00	0.00	1.29	0.00	0.19	0.08	0.33	0.65	2.13	0.74

Mine: **E01_S**
Capital Expenditure Summary

Year	Acquisition	Development	Depreciable Assets	Property Tax Base	Depreciation	Working Capital	Total Capital
2008	0	0	106,646	106,646	14,025	3,993	110,639
2009	0	0	0	106,646	14,025	0	0
2010	0	0	0	106,646	14,025	0	0
2011	0	0	0	106,646	14,025	0	0
2012	0	0	0	106,646	14,025	0	0
2013	0	0	0	106,646	14,025	0	0
2014	0	0	0	106,646	14,025	0	0
2015	0	0	16,368	106,646	3,397	0	16,368
2016	0	0	0	106,646	3,397	0	0
2017	0	0	0	106,646	3,397	0	0
2018	0	0	4,082	106,646	3,980	0	4,082
2019	0	0	0	106,646	3,980	0	0
2020	0	0	0	106,646	3,980	0	0
2021	0	0	0	106,646	3,980	0	0
2022	0	0	16,368	106,646	3,980	0	16,368
2023	0	0	0	106,646	2,921	0	0
2024	0	0	0	106,646	2,921	0	0
2025	0	0	0	106,646	2,338	0	0
2026	0	0	0	106,646	2,338	0	0
2027	0	0	0	106,646	2,338	-3,993	-3,993
2028							
2029							
2030							
2031							
2032							
	0	0	143,464		141,126	0	143,464

Mine: **E01_S**

Required Sales Price

Sales Price ($/ton):	$20.716	Sev. Taxes:	Rate ($/ton)	$0.54
Discount Rate:	10%		Adjustment	0%
Net Present Value:	$0	Property Taxes	Mill Levy (in mills):	44
Cost Contingency Factors:	10%		Assessment rate:	25%
Initial Labor Productivity (t/mh):	9	Income Taxes:	Federal	34%
Average Coal Thickness (ft):	45		State	6%
UMWA (Y or N):	N	Royalty:		12.5%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property								
2008	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	110,639	-96,124
2009	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2010	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2011	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2012	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2013	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2014	2,500	51,789	23,958	6,474	702	1,375	875	570	0	14,025	306	122	184	14,515	0	14,515
2015	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,397	3,625	3,046	4,569	11,591	16,368	-4,777
2016	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,397	3,625	3,046	4,569	11,591	0	11,591
2017	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,397	3,625	3,046	4,569	11,591	0	11,591
2018	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	4,082	7,742
2019	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	0	11,825
2020	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	0	11,825
2021	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	0	11,825
2022	2,500	51,789	23,958	6,474	702	1,375	875	570	0	3,980	3,625	2,813	4,219	11,825	16,368	-4,543
2023	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,921	3,625	3,236	4,855	11,401	0	11,401
2024	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,921	3,625	3,236	4,855	11,401	0	11,401
2025	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,338	3,625	3,470	5,205	11,168	0	11,168
2026	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,338	3,625	3,470	5,205	11,168	0	11,168
2027	2,500	51,789	23,958	6,474	702	1,375	875	570	0	2,338	3,625	3,470	5,205	11,168	-3,993	15,161
2028																
2029																
2030																
2031																
2032																
	50,000	1,035,785	479,159	129,473	14,040	27,500	17,500	11,394	0	141,126	49,271	40,943	61,414	251,811	143,464	108,347
		20.72	9.58	2.59	0.28	0.55	0.35	0.23	0.00	2.82	0.99	0.82	1.23	5.04	2.87	2.17

Mine: **E02_UG**
Production & Productivity Data

% Washed	70%
Plant Recovery:	70%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2008	2,000	0	506	2,026	2,532	79%	0
2009	2,000	0	506	2,026	2,532	79%	0
2010	2,000	0	506	2,026	2,532	79%	0
2011	2,000	0	506	2,026	2,532	79%	0
2012	2,000	0	506	2,026	2,532	79%	0
2013	2,000	0	506	2,026	2,532	79%	0
2014	2,000	0	506	2,026	2,532	79%	0
2015	2,000	0	506	2,026	2,532	79%	0
2016	2,000	0	506	2,026	2,532	79%	0
2017	2,000	0	506	2,026	2,532	79%	0
2018	2,000	0	506	2,026	2,532	79%	0
2019	2,000	0	506	2,026	2,532	79%	0
2020	2,000	0	506	2,026	2,532	79%	0
2021	2,000	0	506	2,026	2,532	79%	0
2022	2,000	0	506	2,026	2,532	79%	0
2023	2,000	0	506	2,026	2,532	79%	0
2024	2,000	0	506	2,026	2,532	79%	0
2025	2,000	0	506	2,026	2,532	79%	0
2026	2,000	0	506	2,026	2,532	79%	0
2027	2,000	0	506	2,026	2,532	79%	0
2028	2,000	0	506	2,026	2,532	79%	0
2029							
2030							
2031							
2032							
	42,000		10,634	42,538	53,172	79%	
$/ton							

Mine: **E02_UG**
Capital Requirements ($ X 1000)

Capital Contingency:	0%	CV Mining Ht:	8.0	Capital Contingency:	production -75% < 500k
Miles of Rail spur:	0	CM Mining Ht:	8.0		-50% 500k<= & < 750k
Coal Storage:	0	LW Mining Ht:	8.0		0% >750k
Depth to Shafts:	100				
No. of Men/Supply Shafts	1				
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air if prod > 1000k, 2 M&S + 1 Air

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections			Continuous Miners			Longwalls			Fixed U/G Equip.		Total	
								Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Initial $	Repl $	Initial $	Repl $
2008		1,920	59,940	13,774	11,391	18,990	0	0	0		2	9,000		1	37,500		20,629		173,144	0
2009								0	0		2	0		1	0		0		0	0
2010								0	0		2	0		1	0		0		0	0
2011								0	0		2	0		1	0		0		0	0
2012								0	0		2	0		1	0		0		0	0
2013								0	0		2	0		1	0		0		0	0
2014								0	0		2	0		1	0		0	0	0	0
2015								0	0	0	2	0	9,000	1	0	37,500	0	20,629	0	67,129
2016								0	0	0	2	0	0	1	0	0	0	0	0	0
2017								0	0	0	2	0	0	1	0	0	0	0	0	0
2018								0	0	0	2	0	0	1	0	0	0	0	0	0
2019								0	0	0	2	0	0	1	0	0	0	0	0	0
2020								0	0	0	2	0	0	1	0	0	0	0	0	0
2021								0	0	0	2	0	0	1	0	0	0	0	0	0
2022								0	0	0	2	0	9,000	1	0	37,500	0	20,629	0	67,129
2023								0	0	0	2	0	0	1	0	0	0	0	0	0
2024								0	0	0	2	0	0	1	0	0	0	0	0	0
2025								0	0	0	2	0	0	1	0	0	0	0	0	0
2026								0	0		2	0		1	0		0		0	0
2027								0	0		2	0		1	0		0		0	0
2028								0	0		2	0		1	0		0		0	0
2029																				
2030																				
2031																				
2032																				
	0	1,920	59,940	13,774	11,391	18,990	0		0	0		9,000	18,000		37,500	75,000	20,629	41,257	173,144	134,257
	0.00	0.05	1.43	0.33	0.27		0.00		0.00	0.00		0.21	0.43		0.89	1.79	0.49	0.98	4.12	3.20

Mine: **E02_UG**
Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets			Property Tax Base	Depreciation			Working Capital	Total Capital
			7 Year Life	15 Year Life	Total		7 Year Life	15 Year Life	Total		
2008	0	1,920	67,129	104,095	171,224	171,224	9,590	6,940	16,529	5,789	178,933
2009	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2010	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2011	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2012	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2013	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2014	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2015	0	0	67,129	0	67,129	171,224	9,590	6,940	16,529	0	67,129
2016	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2017	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2018	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2019	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2020	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2021	0	0	0	0	0	171,224	9,590	6,940	16,529	0	0
2022	0	0	67,129	0	67,129	171,224	9,590	6,940	16,529	0	67,129
2023	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2024	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2025	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2026	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2027	0	0	0	0	0	171,224	9,590	0	9,590	0	0
2028	0	0	0	0	0	171,224	9,590	0	9,590	-5,789	-5,789
2029											
2030											
2031											
2032											
	0	1,920	201,386	104,095	305,481		201,386	104,095	305,481	0	307,401
	0.00	0.05	4.79	2.48	7.27		4.79	2.48	7.27	0.00	7.32

Mine: **E02_UG**
Required Sales Price ($ X 1000)

Sales Price ($/ton):	$36.476
Discount Rate:	10.00%
Net Present Value:	$0
Cost Contingency Factors:	10%
Average Coal Thickness (ft):	6
Tons/Man-hour	6.0
UMWA (Y or N):	Y
Product (Steam or Met)	S

Sev. Taxes:	Rate	$0.27
	Adjustment	100.0%
Prop. Taxes	Tax Rate (in mills)	60
	% of revenue basis for tax Assessment rate:	25.0%
Income Taxes	Federal	34.00%
	State	6.00%
Royalty		8.0%
% of Reserve owned:		0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income) Severance	Black Lung	Recl.	Property	Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
2008	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	1,920	16,529	4,004	1,601	2,402	22,935	177,013	-154,078
2009	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2010	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2011	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2012	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2013	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2014	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2015	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	67,129	-42,657
2016	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2017	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2018	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2019	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2020	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2021	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	0	24,471
2022	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	16,529	4,964	1,985	2,978	24,471	67,129	-42,657
2023	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2024	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2025	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2026	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2027	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	0	21,858
2028	2,000	72,953	34,737	5,836	216	2,200	300	1,007	2,200	0	9,590	5,369	4,599	6,899	21,858	-5,789	27,647
2029																	
2030																	
2031																	
2032																	
	42,000	1,532,003	729,469	122,560	4,536	46,200	6,300	21,142	46,200	1,920	305,481	105,712	56,993	85,490	496,683	305,481	191,202
		36.48	17.37	2.92	0.11	1.10	0.15	0.50	1.10	0.05	7.27	2.52	1.36	2.04	11.83	7.27	4.55

Mine: **E03_UG**
Production & Productivity Data

% Washed	0%
Plant Recovery:	100%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2008	9,000	0	1,800	7,200	9,000	100%	0
2009	9,000	0	1,800	7,200	9,000	100%	0
2010	9,000	0	1,800	7,200	9,000	100%	0
2011	9,000	0	1,800	7,200	9,000	100%	0
2012	9,000	0	1,800	7,200	9,000	100%	0
2013	9,000	0	1,800	7,200	9,000	100%	0
2014	9,000	0	1,800	7,200	9,000	100%	0
2015	9,000	0	1,800	7,200	9,000	100%	0
2016	9,000	0	1,800	7,200	9,000	100%	0
2017	9,000	0	1,800	7,200	9,000	100%	0
2018	9,000	0	1,800	7,200	9,000	100%	0
2019	9,000	0	1,800	7,200	9,000	100%	0
2020	9,000	0	1,800	7,200	9,000	100%	0
2021	9,000	0	1,800	7,200	9,000	100%	0
2022	9,000	0	1,800	7,200	9,000	100%	0
2023	9,000	0	1,800	7,200	9,000	100%	0
2024	9,000	0	1,800	7,200	9,000	100%	0
2025	9,000	0	1,800	7,200	9,000	100%	0
2026	9,000	0	1,800	7,200	9,000	100%	0
2027	9,000	0	1,800	7,200	9,000	100%	0
2028	9,000	0	1,800	7,200	9,000	100%	0
2029							
2030							
2031							
2032							
	189,000		37,800	151,200	189,000	100%	
$/ton							

Mine: **E03_UG**
Capital Requirements ($ X 1000)

Capital Contingency:	0%	CV Mining Ht:	10.0	Capital Contingency:	production -75% < 500k
Miles of Rail spur:	0	CM Mining Ht:	10.0		-50% 500k<= & < 750k
Coal Storage:	0	LW Mining Ht:	10.0		0% >750k
Depth to Shafts:	100				
No. of Men/Supply Shafts	1				
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air if prod > 1000k, 2 M&S + 1 Air

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections			Continuous Miners			longwall initial 100 million $ Longwalls			Fixed U/G Equip.		Total	
								Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Initial $	Repl $	Initial $	Repl $
2008		2,590	91,705	9,183	11,878	0	0	0	0		4	12,000		1	100,000		31,562		258,917	0
2009								0	0		4	0		1	0		0		0	0
2010								0	0		4	0		1	0		0		0	0
2011								0	0		4	0		1	0		0		0	0
2012								0	0		4	0		1	0		0		0	0
2013								0	0		4	0		1	0		0		0	0
2014								0	0		4	0		1	0		0	0	0	0
2015								0	0	0	4	0	12,000	1	0	100,000	0	31,562	0	143,562
2016								0	0	0	4	0	0	1	0	0	0	0	0	0
2017								0	0	0	4	0	0	1	0	0	0	0	0	0
2018								0	0	0	4	0	0	1	0	0	0	0	0	0
2019								0	0	0	4	0	0	1	0	0	0	0	0	0
2020								0	0	0	4	0	0	1	0	0	0	0	0	0
2021								0	0	0	4	0	0	1	0	0	0	0	0	0
2022								0	0	0	4	0	12,000	1	0	100,000	0	31,562	0	143,562
2023								0	0	0	4	0	0	1	0	0	0	0	0	0
2024								0	0	0	4	0	0	1	0	0	0	0	0	0
2025								0	0	0	4	0	0	1	0	0	0	0	0	0
2026								0	0		4	0		1	0		0		0	0
2027								0	0		4	0		1	0		0		0	0
2028								0	0		4	0		1	0		0		0	0
2029																				
2030																				
2031																				
2032																				
	0	2,590	91,705	9,183	11,878	0	0		0	0		12,000	24,000		100,000	200,000	31,562	63,124	258,917	287,124
	0.00	0.01	0.49	0.05	0.06		0.00		0.00	0.00		0.06	0.13		0.53	1.06	0.17	0.33	1.37	1.52

Mine: **E03_UG**
Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets 7 Year Life	15 Year Life	Total	Property Tax Base	Depreciation 7 Year Life	15 Year Life	Total	Working Capital	Total Capital	Year
2008	0	2,590	143,562	112,766	256,327	256,327	20,509	7,518	28,027	19,092	278,009	2008
2009	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2009
2010	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2010
2011	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2011
2012	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2012
2013	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2013
2014	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2014
2015	0	0	143,562	0	143,562	256,327	20,509	7,518	28,027	0	143,562	2015
2016	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2016
2017	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2017
2018	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2018
2019	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2019
2020	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2020
2021	0	0	0	0	0	256,327	20,509	7,518	28,027	0	0	2021
2022	0	0	143,562	0	143,562	256,327	20,509	7,518	28,027	0	143,562	2022
2023	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2023
2024	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2024
2025	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2025
2026	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2026
2027	0	0	0	0	0	256,327	20,509	0	20,509	0	0	2027
2028	0	0	0	0	0	256,327	20,509	0	20,509	-19,092	-19,092	2028
2029												2029
2030												2030
2031												2031
2032												2032
	0	2,590	430,685	112,766	543,451		430,685	112,766	543,451	0	546,041	
	0.00	0.01	2.28	0.60	2.88		2.28	0.60	2.88	0.00	2.89	

Mine: **E03_UG**

Required Sales Price ($ X 1000)

Sales Price ($/ton):	$21.439
Discount Rate:	10.00%
Net Present Value:	($0)
Cost Contingency Factors:	10%
Average Coal Thickness (ft):	10
Tons/Man-hour	6.9
UMWA (Y or N):	N
Product (Steam or Met)	S

Sev. Taxes:	Rate	$0.27
	Adjustment	100.0%
Prop. Taxes	Tax Rate (in mills)	60
	% of revenue basis for tax Assessment rate:	25.0%
Income Taxes	Federal	34.00%
	State	6.00%
Royalty		8.0%
% of Reserve owned:		0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property									
2008	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	2,590	28,027	6,669	2,667	4,001	38,696	275,419	-236,723
2009	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2010	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2011	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2012	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2013	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2014	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2015	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	143,562	-102,793
2016	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2017	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2018	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2019	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2020	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2021	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	0	40,768
2022	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	28,027	7,964	3,185	4,778	40,768	143,562	-102,793
2023	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2024	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2025	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2026	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2027	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	0	39,265
2028	9,000	192,950	114,552	15,436	2,106	8,490	1,350	2,663	4,400	0	20,509	11,722	4,689	7,033	39,265	-19,092	58,357
2029																	
2030																	
2031																	
2032																	
	189,000	4,051,948	2,405,584	324,156	44,226	178,286	28,350	55,917	92,400	2,590	543,451	188,494	75,398	113,096	845,041	543,451	301,590
		21.44	12.73	1.72	0.23	0.94	0.15	0.30	0.49	0.01	2.88	1.00	0.40	0.60	4.47	2.88	1.60

Mine: **N02_UG**
Production & Productivity Data

% Washed	0%
Plant Recovery:	100%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2011							
2012							
2013							
2014							
2015	500	0	500	0	500	100%	0
2016	3,000	0	600	2,400	3,000	100%	0
2017	5,000	0	1,000	4,000	5,000	100%	0
2018	5,000	0	1,000	4,000	5,000	100%	0
2019	5,000	0	1,000	4,000	5,000	100%	0
2020	5,000	0	1,000	4,000	5,000	100%	0
2021	5,000	0	1,000	4,000	5,000	100%	0
2022	5,000	0	1,000	4,000	5,000	100%	0
2023	5,000	0	1,000	4,000	5,000	100%	0
2024	5,000	0	1,000	4,000	5,000	100%	0
2025	5,000	0	1,000	4,000	5,000	100%	0
2026	5,000	0	1,000	4,000	5,000	100%	0
2027	5,000	0	1,000	4,000	5,000	100%	0
2028	5,000	0	1,000	4,000	5,000	100%	0
2029	5,000	0	1,000	4,000	5,000	100%	0
2030	5,000	0	1,000	4,000	5,000	100%	0
2031	5,000	0	1,000	4,000	5,000	100%	0
2032	5,000	0	1,000	4,000	5,000	100%	0
2033	5,000	0	1,000	4,000	5,000	100%	0
2034	5,000	0	1,000	4,000	5,000	100%	0
2035	5,000	0	1,000	4,000	5,000	100%	0
	98,500		20,100	78,400	98,500	100%	
$/ton							

Mine: **N02_UG**
Capital Requirements ($ X 1000)

Capital Contingency:	0%	CV Mining Ht:	8.0	Capital Contingency:	production -75% < 500k
Miles of Rail spur:	0	CM Mining Ht:	8.0		-50% 500k<= & < 750k
Coal Storage:	0	LW Mining Ht:	8.0		0% >750k
Depth to Shafts:	1000				
No. of Men/Supply Shafts	1				
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air if prod > 1000k, 2 M&S + 1 Air

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections			Continuous Miners			Longwalls			Fixed U/G Equip.		Total	
								Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Initial $	Repl $	Initial $	Repl $
2011		350	0	0		0	0	0	0		0	0		0	0		1,109		1,459	0
2012		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2013		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2014		1,030	30,085	45,174	6,777	0	0	0	0		0	0		0	0		0		52,981	0
2015								0	0		2	6,000		0	0		1,631		7,631	0
2016								0	0		2	0		1	25,000		6,798		31,798	0
2017								0	0		3	3,000		1	0		816	0	3,816	0
2018								0	0	0	3	0	0	1	0	0	0	1,109	0	1,109
2019								0	0	0	3	0	0	1	0	0	0	0	0	0
2020								0	0	0	3	0	0	1	0	0	0	0	0	0
2021								0	0	0	3	0	0	1	0	0	0	0	0	0
2022								0	0	0	3	0	6,000	1	0	0	0	1,631	0	7,631
2023								0	0	0	3	0	0	1	0	25,000	0	6,798	0	31,798
2024								0	0	0	3	0	3,000	1	0	0	0	816	0	3,816
2025								0	0	0	3	0	0	1	0	0	0	1,109	0	1,109
2026								0	0	0	3	0	0	1	0	0	0	0	0	0
2027								0	0	0	3	0	0	1	0	0	0	0	0	0
2028								0	0	0	3	0	0	1	0	0	0	0	0	0
2029								0	0		3	0		1	0		0		0	0
2030								0	0		3	0		1	0		0		0	0
2031								0	0		3	0		1	0		0		0	0
2032								0	0		3	0		1	0		0		0	0
2033								0	0		3	0		1	0		0		0	0
2034								0	0		3	0		1	0		0		0	0
2035								0	0		3	0		1	0		0		0	0
	0	2,080	30,085	45,174	6,777	0	0		0	0		9,000	9,000		25,000	25,000	10,354	11,463	98,384	45,463
	0.00	0.02	0.31	0.46	0.07		0.00		0.00	0.00		0.09	0.09		0.25	0.25	0.11	0.12	1.00	0.46

Mine: **N02_UG**
Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets 7 Year Life	15 Year Life	Total	Property Tax Base	Depreciation 7 Year Life	15 Year Life	Total	Working Capital	Total Capital	Year
2011	0	350	1,109	0	1,109	1,109	158	0	158	0	1,459	2011
2012	0	350	0	0	0	1,109	158	0	158	0	350	2012
2013	0	350	0	0	0	1,109	158	0	158	0	350	2013
2014	0	1,030	0	82,036	82,036	53,060	158	5,469	5,627	0	83,066	2014
2015	0	0	7,631	0	7,631	60,691	1,249	5,469	6,718	1,015	8,646	2015
2016	0	0	31,798	0	31,798	92,489	5,791	5,469	11,260	4,840	36,638	2016
2017	0	0	3,816	0	3,816	96,304	6,336	5,469	11,805	3,903	7,719	2017
2018	0	0	1,109	0	1,109	96,304	6,336	5,469	11,805	0	1,109	2018
2019	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2019
2020	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2020
2021	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2021
2022	0	0	7,631	0	7,631	96,304	6,336	5,469	11,805	0	7,631	2022
2023	0	0	31,798	0	31,798	96,304	6,336	5,469	11,805	0	31,798	2023
2024	0	0	3,816	0	3,816	96,304	6,336	5,469	11,805	0	3,816	2024
2025	0	0	1,109	0	1,109	96,304	6,336	5,469	11,805	0	1,109	2025
2026	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2026
2027	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2027
2028	0	0	0	0	0	96,304	6,336	5,469	11,805	0	0	2028
2029	0	0	0	0	0	96,304	5,246	0	5,246	0	0	2029
2030	0	0	0	0	0	96,304	704	0	704	0	0	2030
2031	0	0	0	0	0	96,304	158	0	158	0	0	2031
2032	0	0	0	0	0	96,304	0	0	0	0	0	2032
2033	0	0	0	0	0	96,304	0	0	0	0	0	2033
2034	0	0	0	0	0	96,304	0	0	0	0	0	2034
2035	0	0	0	0	0	96,304	0	0	0	-9,759	-9,759	2035
	0	2,080	89,816	82,036	171,852		89,816	82,036	171,852	0	173,932	
	0.00	0.02	0.91	0.83	1.74		0.91	0.83	1.74	0.00	1.77	

Mine: **N02_UG**

Required Sales Price ($ X 1000)

Sales Price ($/ton):	$20.007
Discount Rate:	10.00%
Net Present Value:	($0)
Cost Contingency Factors:	10%
Average Coal Thickness (ft):	8
Tons/Man-hour	8.0
UMWA (Y or N):	N
Product (Steam or Met)	S

Sev. Taxes:	Rate	$0.27
	Adjustment	100.0%
Prop. Taxes	Tax Rate (in mills)	60
	% of revenue basis for tax Assessment rate:	25.0%
Income Taxes	Federal	34.00%
	State	6.00%
Royalty		8.0%
% of Reserve owned:		0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property									
2011	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	1,109	-1,256
2012	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2013	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2014	0	0	0	0	0	0	0	0	0	1,030	5,627	0	-2,663	-3,994	1,633	82,036	-80,403
2015	500	10,003	6,089	800	0	440	75	138	550	0	6,718	0	-1,923	-2,884	3,834	8,646	-4,812
2016	3,000	60,021	35,131	4,802	486	2,641	450	828	3,300	0	11,260	562	225	337	12,159	36,638	-24,479
2017	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	7,719	11,860
2018	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	1,109	18,470
2019	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2020	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2021	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2022	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	7,631	11,948
2023	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	31,798	-12,218
2024	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	3,816	15,764
2025	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	1,109	18,470
2026	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2027	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2028	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	11,805	4,859	1,944	2,915	19,579	0	19,579
2029	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	5,246	7,363	3,566	5,349	17,957	0	17,957
2030	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	704	7,363	5,383	8,074	16,140	0	16,140
2031	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	158	7,363	5,601	8,401	15,922	0	15,922
2032	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	0	15,859
2033	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	0	15,859
2034	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	0	15,859
2035	5,000	100,035	58,551	8,003	1,026	4,402	750	1,380	4,400	0	0	7,363	5,664	8,496	15,859	-9,759	25,617
	98,500	1,970,686	1,153,690	157,655	19,980	86,710	14,775	27,195	87,450	2,080	171,852	110,405	55,557	83,336	365,593	171,852	193,741
		20.01	11.71	1.60	0.20	0.88	0.15	0.28	0.89	0.02	1.74	1.12	0.56	0.85	3.71	1.74	1.97

Mine: **N03_UG**

Production & Productivity Data

% Washed	0%
Plant Recovery:	100%
Production by Equipment at Full Production	
% Longwall Production:	80%
% CM Production:	20%
% CV Production:	0%

Year	Clean Tons (000)	CV ROM Tons (000)	CM ROM Tons (000)	LW ROM Tons (000)	Total ROM Tons (000)	Overall Recovery %	Haul Distance (miles)
2007							
2008							
2009							
2010							
2011		0	0	0	0	#DIV/0!	0
2012		0	0	0	0	#DIV/0!	0
2013		0	0	0	0	#DIV/0!	0
2014	1,000	0	200	800	1,000	100%	0
2015	5,000	0	1,000	4,000	5,000	100%	0
2016	5,000	0	1,000	4,000	5,000	100%	0
2017	5,000	0	1,000	4,000	5,000	100%	0
2018	5,000	0	1,000	4,000	5,000	100%	0
2019	5,000	0	1,000	4,000	5,000	100%	0
2020	5,000	0	1,000	4,000	5,000	100%	0
2021	5,000	0	1,000	4,000	5,000	100%	0
2022	5,000	0	1,000	4,000	5,000	100%	0
2023	5,000	0	1,000	4,000	5,000	100%	0
2024	5,000	0	1,000	4,000	5,000	100%	0
2025	5,000	0	1,000	4,000	5,000	100%	0
2026	5,000	0	1,000	4,000	5,000	100%	0
2027	5,000	0	1,000	4,000	5,000	100%	0
2028	5,000	0	1,000	4,000	5,000	100%	0
2029	5,000	0	1,000	4,000	5,000	100%	0
2030	5,000	0	1,000	4,000	5,000	100%	0
2031	5,000	0	1,000	4,000	5,000	100%	0
	86,000		17,200	68,800	86,000	100%	
$/ton							

Mine: **N03_UG**
Capital Requirements ($ X 1000)

Capital Contingency:	0%	CV Mining Ht:	10.0	Capital Contingency:	production -75% < 500k -50% 500k<= & < 750k 0% >750k
Miles of Rail spur:	0	CM Mining Ht:	10.0		
Coal Storage:	0	LW Mining Ht:	10.0		
Depth to Shafts:	100				
No. of Men/Supply Shafts	1				
No. of Air Shafts	1			Shafts:	if prod < 1000k, 1 M&S + 1 Air if prod > 1000k, 2 M&S + 1 Air

Year	Acqisition	Exploration & Engineering	Development Labor	Shaft Capital Cost	Surface Facilities & Equip.	Prep Plant	Rail	Conventional Sections			Continuous Miners			Longwalls			Fixed U/G Equip.		Total	
								Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Units Required	Initial $	Repl $	Initial $	Repl $	Initial $	Repl $
2007		350	0	0		0	0	0	0		0	0		0	0		1,109		1,459	0
2008		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2009		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2010		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2011		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2012		350	0	0		0	0	0	0		0	0		0	0		0		350	0
2013		1,530	49,835	9,183	8,412	0	0	0	0		0	0		0	0		0	0	19,124	0
2014								0	0	0	1	3,000	0	1	50,000	0	14,411	1,109	67,411	1,109
2015								0	0	0	3	6,000	0	1	0	0	1,631	0	7,631	0
2016								0	0	0	3	0	0	1	0	0	0	0	0	0
2017								0	0	0	3	0	0	1	0	0	0	0	0	0
2018								0	0	0	3	0	0	1	0	0	0	0	0	0
2019								0	0	0	3	0	0	1	0	0	0	0	0	0
2020								0	0	0	3	0	0	1	0	0	0	0	0	0
2021								0	0	0	3	0	3,000	1	0	50,000	0	15,520	0	68,520
2022								0	0	0	3	0	6,000	1	0	0	0	1,631	0	7,631
2023								0	0	0	3	0	0	1	0	0	0	0	0	0
2024								0	0	0	3	0	0	1	0	0	0	0	0	0
2025								0	0		3	0		1	0		0		0	0
2026								0	0		3	0		1	0		0		0	0
2027								0	0		3	0		1	0		0		0	0
2028								0	0		3	0		1	0		0		0	0
2029								0	0		3	0		1	0		0		0	0
2030								0	0		3	0		1	0		0		0	0
2031								0	0		3	0		1	0		0		0	0
	0	3,630	49,835	9,183	8,412	0	0		0	0		9,000	9,000		50,000	50,000	17,151	18,260	97,375	77,260
	0.00	0.04	0.58	0.11	0.10		0.00		0.00	0.00		0.10	0.10		0.58	0.58	0.20	0.21	1.13	0.90

Mine: **N03_UG**
Capital Expenditure Summary

Year	Acquisition	Exploration & Engineering	Depreciable Assets			Property Tax Base	Depreciation			Working Capital	Total Capital
			7 Year Life	15 Year Life	Total		7 Year Life	15 Year Life	Total		
2007	0	350	1,109	0	1,109	1,109	158	0	158	0	1,459
2008	0	350	0	0	0	1,109	158	0	158	0	350
2009	0	350	0	0	0	1,109	158	0	158	0	350
2010	0	350	0	0	0	1,109	158	0	158	0	350
2011	0	350	0	0	0	1,109	158	0	158	0	350
2012	0	350	0	0	0	1,109	158	0	158	0	350
2013	0	1,530	0	67,429	67,429	18,703	158	4,495	4,654	0	68,959
2014	0	0	68,520	0	68,520	86,114	9,789	4,495	14,284	1,745	70,265
2015	0	0	7,631	0	7,631	93,745	10,879	4,495	15,374	6,982	14,613
2016	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2017	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2018	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2019	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2020	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2021	0	0	68,520	0	68,520	93,745	10,879	4,495	15,374	0	68,520
2022	0	0	7,631	0	7,631	93,745	10,879	4,495	15,374	0	7,631
2023	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2024	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2025	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2026	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2027	0	0	0	0	0	93,745	10,879	4,495	15,374	0	0
2028	0	0	0	0	0	93,745	1,090	0	1,090	0	0
2029	0	0	0	0	0	93,745	0	0	0	0	0
2030	0	0	0	0	0	93,745	0	0	0	0	0
2031	0	0	0	0	0	93,745	0	0	0	-8,727	-8,727
	0	3,630	153,411	67,429	220,841		153,411	67,429	220,841	0	224,471
	0.00	0.04	1.78	0.78	2.57		1.78	0.78	2.57	0.00	2.61

Mine: **N03_UG**

Required Sales Price ($ X 1000)

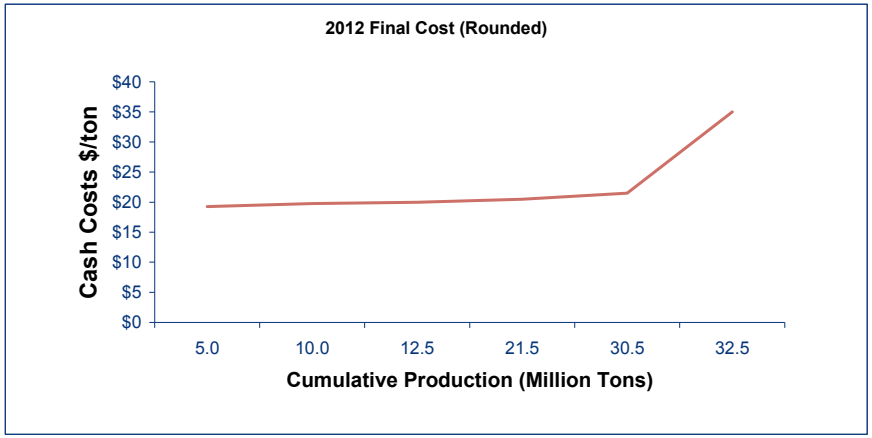
Sales Price ($/ton):	$19.670
Discount Rate:	10.00%
Net Present Value:	$0
Cost Contingency Factors:	10%
Average Coal Thickness (ft):	8
Tons/Man-hour	10.0
UMWA (Y or N):	N
Product (Steam or Met)	S

Sev. Taxes:	Rate	$0.27
	Adjustment	100.0%
Prop. Taxes	Tax Rate (in mills)	60
	% of revenue basis for tax Assessment rate:	25.0%
Income Taxes	Federal	34.00%
	State	6.00%
Royalty		8.0%
% of Reserve owned:		0%

Year	Tons	Revenue	Direct Operating Cost	Royalty	Taxes (other than income)				Corp G&A, Selling & Acc. Pen.	Development Cost	Depreciation	Depletion	Taxes	Net Income	Operating Cash Flow	Capital Expenditures	Annual Cash Flow
					Severance	Black Lung	Recl.	Property									
2007	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	1,109	-1,256
2008	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2009	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2010	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2011	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2012	0	0	0	0	0	0	0	0	0	350	158	0	-203	-305	-147	0	-147
2013	0	0	0	0	0	0	0	0	0	1,530	4,654	0	-2,473	-3,710	943	67,429	-66,486
2014	1,000	19,670	10,473	1,574	0	865	150	271	990	0	14,284	0	-3,575	-5,362	8,921	70,265	-61,344
2015	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	14,613	9,467
2016	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2017	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2018	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2019	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2020	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2021	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	68,520	-44,440
2022	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	7,631	16,449
2023	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2024	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2025	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2026	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2027	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	15,374	5,441	2,177	3,265	24,080	0	24,080
2028	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	1,090	7,238	7,171	10,757	19,085	0	19,085
2029	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	0	7,238	7,607	11,411	18,649	0	18,649
2030	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	0	7,238	7,607	11,411	18,649	0	18,649
2031	5,000	98,349	52,364	7,868	1,026	4,327	750	1,357	4,400	0	0	7,238	7,607	11,411	18,649	-8,727	27,377
	86,000	1,691,596	900,654	135,328	17,442	74,430	12,900	23,344	75,790	3,630	220,841	99,690	51,019	76,528	397,059	220,841	176,219
		19.67	10.47	1.57	0.20	0.87	0.15	0.27	0.88	0.04	2.57	1.16	0.59	0.89	4.62	2.57	2.05

Note: Mine cost ($19.67/ton) plus transportation and loadout costs ($1.00/ton) = Total FOB cost ($20.67/ton)

		EPA CODES		WM CODES										deflator =- 0.004/yr for all reg		2012 Prob. Prod.		2012 Est. Reserves
Year	**Abbrev**	**CoalType_Grade**		**CODER**	**CODEF**	**Mine**	**Step Name**	**Existing or New**	**Mine Type**	**Heat Content (MMBtu/Ton)**	**Cost of Production (2008$/Ton)**	**Cost of Production (2007$/Ton)**	deflator	deflated cost	**Final Cost (Rounded)**	**Coal Production (Million Tons/Year)**	**Cum Production**	**Coal Reserves (Million Tons)**
2012	CG	BB		CGH	SCZ	N02	N02	N	U	22.01	$20.01	$19.59	1.02	$19.21	$19.25	5.000	5.000	50.00
2012	CG	BB		CGH	SCZ	N03	N03	N	U	22.01	$20.67	$20.24	1.02	$19.84	$19.75	5.000	10.000	95.00
2012	CG	BB		CGM	SCZ	E01	E01	E	S	22.01	$20.72	$20.29	1.02	$19.89	$20.00	2.500	12.500	20.00
2012	CG	BB		CGH	SCZ	E03	E03	E	U	22.01	$21.44	$20.99	1.02	$20.58	$20.50	9.000	21.500	80.00
2012	CG	BB		CGH	SCZ	N01	N01	N	U	22.01	$22.44	$21.97	1.02	$21.54	$21.50	9.000	30.500	70.00
2012	CG	BB		CGM	SCZ	E02	E02	E	U	22.01	$36.48	$35.72	1.02	$35.01	$35.00	2.000	32.500	20.00



Appendix 9-2 New Mines Included in 2040 Curves

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	AL	BB	N01	24.82	$39.50	4	13
2040	AL	BB	N02	24.82	$42.00	0	25
2040	AL	BB	N03	24.82	$44.50	4	50
2040	AL	BB	N04	24.82	$47.00	0	50
2040	AL	BD	N01	24	$47.00	2	49
2040	AL	BD	N02	24	$58.00	2	50
2040	AL	BD	N03	24	$70.00	2	50
2040	AL	BD	N04	24	$82.00	2	50
2040	AL	BE	N01	23.82	$63.00	0.5	121
2040	AL	BE	N02	23.82	$69.00	0.5	115
2040	AL	BE	N03	23.82	$75.00	0.5	115
2040	AL	BE	N04	23.82	$82.00	0.5	98
2040	AZ	BB	N01	24.64	$16.75	5	450
2040	CG	BA	N01	21.49	$18.25	12	70
2040	CG	BA	N02	21.49	$29.00	1	40
2040	CG	BA	N03	21.49	$23.00	3	350
2040	CG	BB	N01	22.01	$19.25	9	70
2040	CG	BB	N02	22.01	$16.75	5	50
2040	CG	BB	N03	22.01	$17.75	5	95
2040	CR	BA	N02	25.5	$27.00	3	60
2040	CR	BD	N01	22.2	$27.00	0.3	10
2040	CU	BB	N01	23.22	$19.25	8	100
2040	IL	BE	N01	23	$32.50	1	55
2040	IL	BE	N02	23	$32.00	1	15
2040	IL	BE	N03	23	$33.50	1	15
2040	IL	BE	N04	23	$35.00	1	15
2040	IL	BE	N05	23	$37.00	1	15
2040	IL	BE	N06	23	$38.50	1	15
2040	IL	BE	N07	23	$40.50	1	15
2040	IL	BE	N08	23	$42.00	1	15
2040	IL	BE	N09	23	$44.00	1	15
2040	IL	BE	N10	23	$45.50	1	15
2040	IL	BE	N11	23	$47.00	1	15
2040	IL	BE	N12	23	$49.00	1	15
2040	IL	BE	N13	23	$51.00	1	15
2040	IL	BE	N14	23	$52.00	1	15
2040	IL	BE	N15	23	$86.00	1	15
2040	IL	BG	N01	23.01	$24.00	5	398
2040	IL	BG	N02	23.01	$27.00	2.5	9.6
2040	IL	BG	N03	23.01	$28.50	3	38
2040	IL	BG	N04	23.01	$37.50	4	130
2040	IL	BG	N05	23.01	$46.00	0.5	8
2040	IL	BG	N06	23.01	$28.50	4	200
2040	IL	BG	N07	23.01	$32.50	4	200

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	IL	BG	N08	23.01	$37.00	4	200
2040	IL	BG	N09	23.01	$41.00	4	200
2040	IL	BG	N10	23.01	$45.50	4	200
2040	IL	BG	N11	23.01	$54.00	4	200
2040	IL	BG	N12	23.01	$86.00	4	200
2040	IL	BH	N01	22.19	$24.00	5	177.4
2040	IL	BH	N02	22.19	$24.00	5	253.2
2040	IL	BH	N03	22.19	$24.00	5	221.9
2040	IL	BH	N04	22.19	$24.50	3.7	107.5
2040	IL	BH	N05	22.19	$24.00	3	70
2040	IL	BH	N06	22.19	$24.00	3	60
2040	IL	BH	N07	22.19	$27.50	7.8	460
2040	IL	BH	N08	22.19	$29.00	0.5	2
2040	IL	BH	N09	22.19	$31.50	2.2	125
2040	IL	BH	N10	22.19	$35.00	0.2	3
2040	IL	BH	N11	22.19	$38.50	1.9	37.8
2040	IL	BH	N12	22.19	$48.50	0.8	20
2040	IL	BH	N13	22.19	$53.00	0.5	4
2040	IL	BH	N14	22.19	$86.00	5	250
2040	IN	BD	N01	22.62	$30.00	0.5	10
2040	IN	BD	N02	22.62	$32.00	0.5	10
2040	IN	BD	N03	22.62	$34.50	0.5	10
2040	IN	BD	N04	22.62	$86.00	0.5	10
2040	IN	BE	N01	23.43	$24.00	0.1	0.5
2040	IN	BE	N02	23.43	$34.50	1	15
2040	IN	BE	N03	23.43	$37.00	1	26
2040	IN	BE	N04	23.43	$86.00	1	15
2040	IN	BG	N01	23.37	$27.50	1.5	30
2040	IN	BG	N02	23.37	$30.50	1.5	30
2040	IN	BG	N03	23.37	$33.00	0.5	6
2040	IN	BG	N04	23.37	$35.00	1.6	9.5
2040	IN	BG	N05	23.37	$38.00	1	418.1
2040	IN	BG	N06	23.37	$84.00	1	5
2040	IN	BH	N01	23.41	$31.00	1.5	60
2040	IN	BH	N02	23.41	$34.00	0.2	3
2040	IN	BH	N03	23.41	$49.50	0.8	11
2040	IN	BH	N04	23.41	$28.50	1.5	60
2040	IN	BH	N05	23.41	$29.50	1.5	60
2040	IN	BH	N06	23.41	$30.00	1.5	60
2040	IN	BH	N07	23.41	$31.00	1.5	60
2040	IN	BH	N08	23.41	$32.00	1.5	60
2040	IN	BH	N09	23.41	$33.00	1.5	60
2040	IN	BH	N10	23.41	$34.00	1.5	60
2040	IN	BH	N11	23.41	$35.00	1.5	60
2040	IN	BH	N12	23.41	$36.00	1.5	60

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	IN	BH	N13	23.41	$37.00	1.5	60
2040	IN	BH	N14	23.41	$38.00	1.5	60
2040	IN	BH	N15	23.41	$39.00	1.5	60
2040	IN	BH	N16	23.41	$40.00	1.5	60
2040	IN	BH	N17	23.41	$40.50	1.5	60
2040	IN	BH	N18	23.41	$41.50	1.5	60
2040	IN	BH	N19	23.41	$42.50	1.5	60
2040	IN	BH	N20	23.41	$43.50	1.5	60
2040	IN	BH	N21	23.41	$44.50	1.5	60
2040	IN	BH	N22	23.41	$45.50	1.5	60
2040	IN	BH	N23	23.41	$46.50	1.5	60
2040	IN	BH	N24	23.41	$47.50	1.5	60
2040	IN	BH	N25	23.41	$48.50	1.5	60
2040	IN	BH	N26	23.41	$49.50	1.5	60
2040	IN	BH	N27	23.41	$50.00	1.5	60
2040	IN	BH	N28	23.41	$51.00	1.5	60
2040	IN	BH	N29	23.41	$52.00	1.5	60
2040	IN	BH	N30	23.41	$53.00	1.5	60
2040	IN	BH	N31	23.41	$54.00	1.5	60
2040	IN	BH	N32	23.41	$86.00	1.5	60
2040	KE	BA	N01	25.32	$68.00	0.3	11.9
2040	KE	BA	N02	25.32	$88.00	0.3	15
2040	KE	BA	N03	25.32	$108.00	0.3	15
2040	KE	BA	N04	25.32	$128.00	0.3	15
2040	KE	BB	N01	25.79	$87.00	0.5	71.1
2040	KE	BB	N02	25.79	$99.00	0.5	80
2040	KE	BB	N03	25.79	$111.00	0.5	80
2040	KE	BB	N04	25.79	$123.00	0.5	80
2040	KE	BD	N01	25.33	$74.00	4.1	192.7
2040	KE	BD	N02	25.33	$87.00	3	170
2040	KE	BD	N03	25.33	$100.00	2	180
2040	KE	BD	N04	25.33	$114.00	1	152
2040	KE	BE	N01	25.14	$71.00	4.1	351.8
2040	KE	BE	N02	25.14	$91.00	3	320
2040	KE	BE	N03	25.14	$111.00	2	150
2040	KE	BE	N04	25.14	$130.00	1	145
2040	KE	BG	N01	24.09	$57.00	0.3	4
2040	KE	BG	N02	24.09	$87.00	0.3	4
2040	KE	BG	N03	24.09	$117.00	0.3	4
2040	KE	BG	N04	24.09	$148.00	0.3	4
2040	KS	BG	N01	25.32	$36.50	0.1	1.2
2040	KS	BG	N02	25.32	$44.50	0.1	1.2
2040	KS	BG	N03	25.32	$52.00	0.1	1.2
2040	KS	BG	N04	25.32	$59.00	0.1	1.2
2040	KS	BG	N05	25.32	$67.00	0.1	1.2

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	KS	BG	N06	25.32	$86.00	0.1	1.2
2040	KW	BD	N01	24.23	$59.00	0.7	10
2040	KW	BD	N02	24.23	$67.00	0.5	105
2040	KW	BD	N03	24.23	$86.00	0.5	105
2040	KW	BE	N01	24.45	$30.50	2	300
2040	KW	BE	N02	24.45	$33.50	0.5	30
2040	KW	BE	N03	24.45	$34.00	0.5	30
2040	KW	BE	N04	24.45	$34.50	0.5	30
2040	KW	BE	N05	24.45	$35.00	0.5	30
2040	KW	BE	N06	24.45	$35.50	0.5	30
2040	KW	BE	N07	24.45	$36.50	0.5	30
2040	KW	BE	N08	24.45	$37.00	0.5	30
2040	KW	BE	N09	24.45	$37.50	0.5	30
2040	KW	BE	N10	24.45	$38.00	0.5	30
2040	KW	BE	N11	24.45	$38.50	0.5	30
2040	KW	BE	N12	24.45	$39.00	0.5	30
2040	KW	BE	N13	24.45	$39.50	0.5	30
2040	KW	BE	N14	24.45	$40.00	0.5	30
2040	KW	BE	N15	24.45	$40.50	0.5	30
2040	KW	BE	N16	24.45	$41.50	0.5	30
2040	KW	BE	N17	24.45	$42.00	0.5	30
2040	KW	BE	N18	24.45	$42.50	0.5	30
2040	KW	BE	N19	24.45	$43.00	0.5	30
2040	KW	BE	N20	24.45	$86.00	0.5	30
2040	KW	BG	N01	23.93	$26.00	3	24.8
2040	KW	BG	N02	23.93	$30.00	3	195
2040	KW	BG	N03	23.93	$32.00	3	156.8
2040	KW	BG	N04	23.93	$36.50	4	104.5
2040	KW	BG	N05	23.93	$37.00	2	20
2040	KW	BG	N06	23.93	$50.00	3	180
2040	KW	BG	N07	23.93	$86.00	3	180
2040	KW	BH	N01	22.84	$29.50	5	17
2040	KW	BH	N02	22.84	$32.00	1	4
2040	KW	BH	N03	22.84	$34.00	2	22
2040	KW	BH	N04	22.84	$38.00	1	7.8
2040	KW	BH	N05	22.84	$53.00	1	30
2040	KW	BH	N06	22.84	$53.00	2	240
2040	KW	BH	N07	22.84	$53.00	2	240
2040	KW	BH	N08	22.84	$53.00	2	240
2040	KW	BH	N09	22.84	$53.00	2	240
2040	KW	BH	N10	22.84	$53.00	2	240
2040	KW	BH	N11	22.84	$54.00	2	240
2040	KW	BH	N12	22.84	$86.00	2	240
2040	LA	LE	N01	14.09	$19.00	2	75
2040	LA	LE	N02	14.09	$43.00	2	75

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	MD	BB	N01	24.64	$71.00	0.3	5
2040	MD	BB	N02	24.64	$76.00	0.3	5
2040	MD	BB	N03	24.64	$80.00	0.3	5
2040	MD	BB	N04	24.64	$85.00	0.3	5
2040	MD	BD	N01	26.32	$65.00	0.7	2.5
2040	MD	BD	N02	26.32	$70.00	0.7	7.5
2040	MD	BD	N03	26.32	$76.00	0.7	8
2040	MD	BD	N04	26.32	$85.00	0.7	7
2040	MD	BE	N01	24.85	$44.00	0.3	3
2040	MD	BE	N02	24.85	$58.00	0.3	3
2040	MD	BE	N03	24.85	$73.00	0.3	3
2040	MD	BE	N04	24.85	$88.00	0.3	3
2040	MD	BG	N01	23.26	$55.00	0.4	15
2040	MD	BG	N02	23.26	$62.00	0.4	15
2040	MD	BG	N03	23.26	$69.00	0.4	15
2040	MD	BG	N04	23.26	$78.00	0.4	15
2040	ME	LD	N01	13	$11.75	15	550
2040	ME	LD	N02	13.55	$12.50	15	550
2040	ME	LD	N03	13.85	$14.75	15	400
2040	ME	LD	N04	13.1	$15.00	1	50
2040	ME	LD	N05	14.2	$15.50	15	3500
2040	ME	LD	N06	13	$16.00	15	970
2040	ME	LD	N07	13.4	$17.00	15	1400
2040	ME	LD	N08	13.3	$17.00	15	455
2040	ME	LD	N09	13.2	$24.00	10	215
2040	MP	SA	N01	18.9	$13.75	15	450
2040	MP	SA	N02	18.9	$14.75	15	450
2040	MP	SA	N03	18.9	$17.00	15	450
2040	MP	SD	N01	17.23	$14.25	15	450
2040	MP	SD	N02	17.23	$13.00	15	450
2040	MP	SD	N03	17.23	$15.25	15	450
2040	MS	LE	N01	12.8	$15.75	3	96
2040	MS	LE	N02	12.8	$43.00	1	40
2040	MT	BB	N01	21	$23.50	5	450
2040	ND	LD	N01	13.7	$15.75	18	500
2040	ND	LD	N02	13.7	$15.25	9	565
2040	ND	LD	N03	13.7	$13.75	1	512
2040	ND	LE	N01	13.46	$13.75	6	589
2040	ND	LE	N02	13.46	$17.00	4	500
2040	ND	LE	N03	13.46	$26.50	2	51
2040	NS	BB	N01	26.4	$43.00	0.6	22
2040	NS	BD	N01	22	$23.00	0.4	16
2040	NS	BD	N02	22	$43.00	0.4	20
2040	NS	BE	N01	17	$14.25	6	180
2040	NS	BE	N02	22	$43.00	0.4	20

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	OH	BB	N01	24.68	$76.00	1	50
2040	OH	BB	N02	24.68	$83.00	1	50
2040	OH	BB	N03	24.68	$91.00	1	50
2040	OH	BB	N04	24.68	$100.00	1	50
2040	OH	BD	N01	25.55	$63.00	0.3	94
2040	OH	BD	N02	25.55	$69.00	0.3	100
2040	OH	BD	N03	25.55	$75.00	0.3	100
2040	OH	BD	N04	25.55	$82.00	0.3	100
2040	OH	BE	N01	25.24	$57.00	0.5	208
2040	OH	BE	N02	25.24	$69.00	0.5	210
2040	OH	BE	N03	25.24	$81.00	0.5	210
2040	OH	BE	N04	25.24	$94.00	0.5	230
2040	OH	BG	N01	24.34	$49.00	4	446
2040	OH	BG	N02	24.34	$60.00	4	450
2040	OH	BG	N03	24.34	$70.00	4	450
2040	OH	BG	N04	24.34	$82.00	4	450
2040	OH	BH	N01	23.92	$50.00	4	500
2040	OH	BH	N02	23.92	$60.00	4	500
2040	OH	BH	N03	23.92	$72.00	4	500
2040	OH	BH	N04	23.92	$86.00	4	500
2040	OK	BE	N01	22.15	$45.00	0.3	3.6
2040	OK	BE	N02	22.15	$48.00	0.3	3.6
2040	OK	BE	N03	22.15	$51.00	0.3	3.6
2040	OK	BE	N04	22.15	$55.00	0.3	3.6
2040	OK	BE	N05	22.15	$86.00	0.3	3.6
2040	PC	BD	N01	25.06	$64.00	0.5	7.6
2040	PC	BD	N02	25.06	$73.00	0.5	5
2040	PC	BD	N03	25.06	$83.00	0.5	5
2040	PC	BD	N04	25.06	$94.00	0.5	5
2040	PC	BE	N01	25.66	$39.50	1.5	15
2040	PC	BE	N02	25.66	$54.00	1.5	15
2040	PC	BE	N03	25.66	$69.00	1.5	15
2040	PC	BE	N04	25.66	$84.00	1.5	15
2040	PC	BG	N01	25.33	$51.00	1	22
2040	PC	BG	N02	25.33	$60.00	1	25
2040	PC	BG	N03	25.33	$68.00	1	20
2040	PC	BG	N04	25.33	$77.00	1	20
2040	PC	BH	N01	23.39	$51.00	0.5	10
2040	PC	BH	N02	23.39	$60.00	0.5	10
2040	PC	BH	N03	23.39	$68.00	0.5	10
2040	PC	BH	N04	23.39	$77.00	0.5	10
2040	PW	BD	N01	24.26	$38.50	0.8	122
2040	PW	BD	N02	24.26	$43.00	0.8	126
2040	PW	BD	N03	24.26	$47.00	0.8	130
2040	PW	BD	N04	24.26	$51.00	0.8	134

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	PW	BE	N01	26.22	$37.00	2	744
2040	PW	BE	N02	26.22	$40.50	2	784
2040	PW	BE	N03	26.22	$44.00	2	824
2040	PW	BE	N04	26.22	$46.00	2	864
2040	PW	BG	N01	25.86	$37.00	5	567
2040	PW	BG	N02	25.86	$39.50	5	667
2040	PW	BG	N03	25.86	$42.50	5	767
2040	PW	BG	N04	25.86	$64.00	1	767
2040	TN	BB	N01	24.18	$101.00	0.3	3.8
2040	TN	BB	N02	24.18	$106.00	0.3	3.8
2040	TN	BB	N03	24.18	$112.00	0.3	3.8
2040	TN	BB	N04	24.18	$118.00	0.3	3.8
2040	TN	BD	N01	23.91	$101.00	0.3	4.5
2040	TN	BD	N02	23.91	$104.00	0.3	4.5
2040	TN	BD	N03	23.91	$107.00	0.3	4.5
2040	TN	BD	N04	23.91	$110.00	0.3	4.2
2040	TN	BE	N01	26.75	$85.00	0.3	6.3
2040	TN	BE	N02	26.75	$93.00	0.3	6
2040	TN	BE	N03	26.75	$101.00	0.3	6
2040	TN	BE	N04	26.75	$110.00	0.3	6
2040	TX	LE	N01	13.22	$11.50	11	219
2040	TX	LE	N02	13.22	$14.75	4	150
2040	TX	LE	N03	13.22	$15.75	6	127
2040	TX	LE	N04	13.22	$15.25	7	114
2040	UT	BA	N01	23.68	$20.00	1	10
2040	UT	BA	N02	23.68	$24.50	4	80
2040	UT	BA	N03	23.68	$24.50	4	25
2040	UT	BB	N01	23.23	$25.50	4	50
2040	UT	BB	N02	23.23	$21.50	2	22
2040	UT	BD	N01	23.05	$24.00	4	45
2040	UT	BD	N02	23.05	$41.00	3	50
2040	UT	BE	N01	25.06	$28.50	2	40
2040	VA	BA	N01	22.7	$103.00	0.3	44.4
2040	VA	BA	N02	22.7	$108.00	0.3	40
2040	VA	BA	N03	22.7	$115.00	0.3	40
2040	VA	BA	N04	22.7	$121.00	0.3	39
2040	VA	BB	N01	25.97	$94.00	0.8	87.2
2040	VA	BB	N02	25.97	$103.00	0.8	85
2040	VA	BB	N03	25.97	$112.00	0.8	85
2040	VA	BB	N04	25.97	$120.00	0.8	84
2040	VA	BD	N01	25.76	$85.00	1.1	68.4
2040	VA	BD	N02	25.76	$94.00	0.8	50
2040	VA	BD	N03	25.76	$103.00	0.8	50
2040	VA	BD	N04	25.76	$112.00	0.8	42
2040	VA	BE	N01	26.03	$68.00	0.5	40.6

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	VA	BE	N02	26.03	$78.00	0.5	26
2040	VA	BE	N03	26.03	$89.00	0.5	26
2040	VA	BE	N04	26.03	$112.00	0.5	26
2040	WG	BB	N01	21.67	$24.50	0.5	15
2040	WG	BB	N02	21.67	$23.50	6	190
2040	WG	BB	N03	21.67	$22.50	3	55
2040	WG	SD	N01	18.5	$19.75	1	13
2040	WL	SB	N01	17.15	$17.75	15	450
2040	WL	SB	N02	17.15	$10.75	15	450
2040	WL	SB	N03	17.15	$11.75	15	450
2040	WL	SB	N04	17.15	$13.00	15	450
2040	WN	BD	N01	25.01	$45.50	0.4	1.6
2040	WN	BD	N02	25.01	$65.00	0.4	2
2040	WN	BD	N03	25.01	$85.00	0.4	2
2040	WN	BD	N04	25.01	$104.00	0.4	2
2040	WN	BE	N01	25.67	$29.00	2	40
2040	WN	BE	N02	25.67	$49.00	2	40
2040	WN	BE	N03	25.67	$69.00	2	40
2040	WN	BE	N04	25.67	$89.00	2	40
2040	WN	BG	N01	26.03	$32.50	6.5	600
2040	WN	BG	N02	26.03	$48.00	5	600
2040	WN	BG	N03	26.03	$64.00	5	600
2040	WN	BG	N04	26.03	$80.00	5	600
2040	WN	BH	N01	25.15	$34.00	5	125
2040	WN	BH	N02	25.15	$53.00	5	125
2040	WN	BH	N03	25.15	$72.00	5	125
2040	WN	BH	N04	25.15	$91.00	5	75
2040	WS	BA	N01	26.2	$98.00	0.3	4.7
2040	WS	BA	N02	26.2	$107.00	0.3	4.7
2040	WS	BA	N03	26.2	$112.00	0.3	4.7
2040	WS	BA	N04	26.2	$122.00	0.3	4.6
2040	WS	BB	N01	24.73	$90.00	0.5	106.8
2040	WS	BB	N02	24.73	$107.00	0.5	100
2040	WS	BB	N03	24.73	$114.00	0.5	100
2040	WS	BB	N04	24.73	$122.00	0.5	100
2040	WS	BD	N01	24.64	$82.00	1.5	384.8
2040	WS	BD	N02	24.64	$89.00	1.5	333
2040	WS	BD	N03	24.64	$120.00	1.5	333
2040	WS	BD	N04	24.64	$147.00	1.5	333
2040	WS	BE	N01	24.38	$69.00	1.4	420.7
2040	WS	BE	N02	24.38	$84.00	1.3	420
2040	WS	BE	N03	24.38	$99.00	1.3	420
2040	WS	BE	N04	24.38	$113.00	1.3	420
2040	WS	BG	N01	25.64	$69.00	0.8	80
2040	WS	BG	N02	25.64	$80.00	0.8	79

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2040	WS	BG	N03	25.64	$92.00	0.8	79
2040	WS	BG	N04	25.64	$104.00	0.8	80

Appendix 9-3 Coal Transportation Matrix in EPA Base Case v.4.10

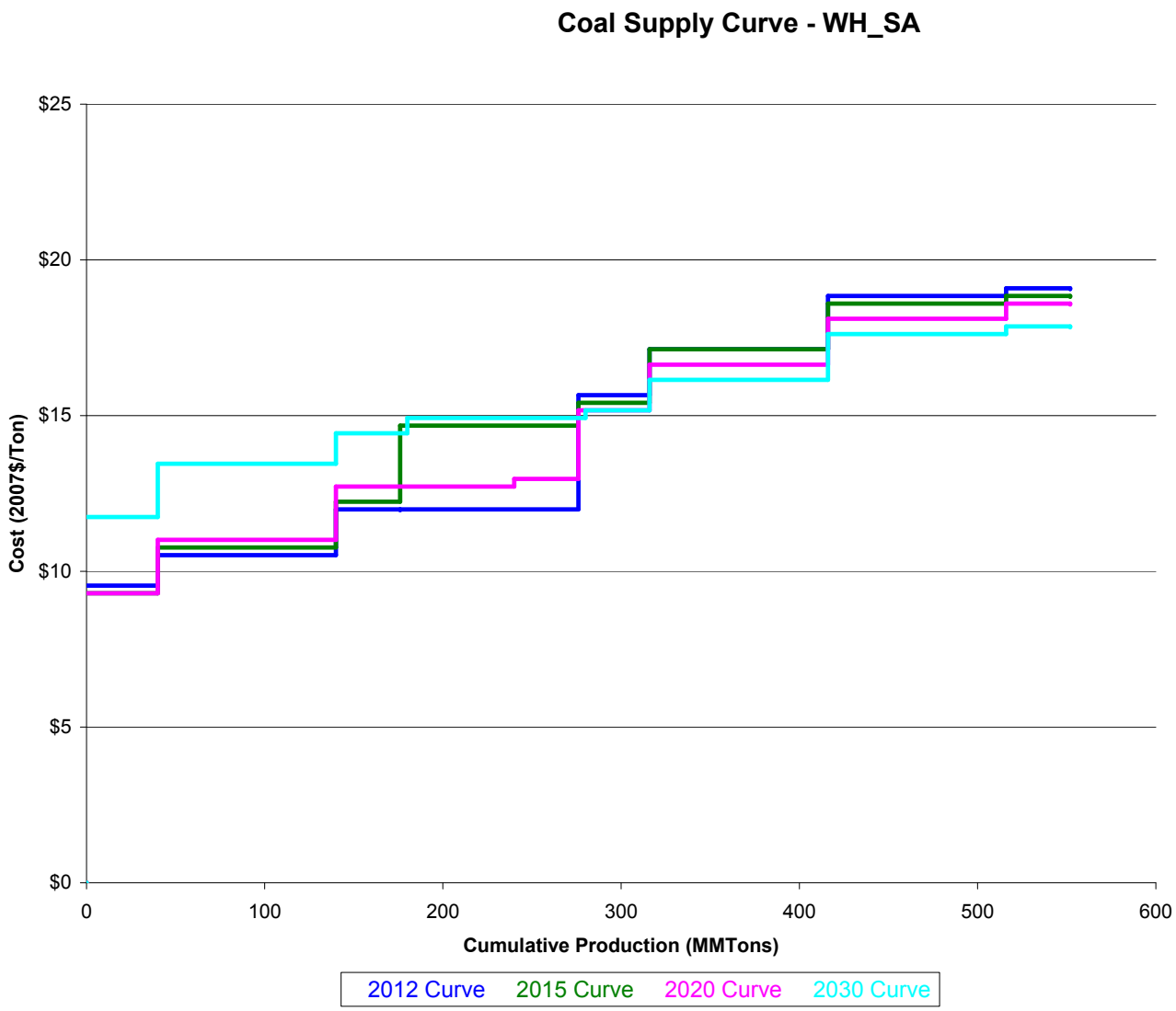
This is a small excerpt of the data in Appendix 9-3. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

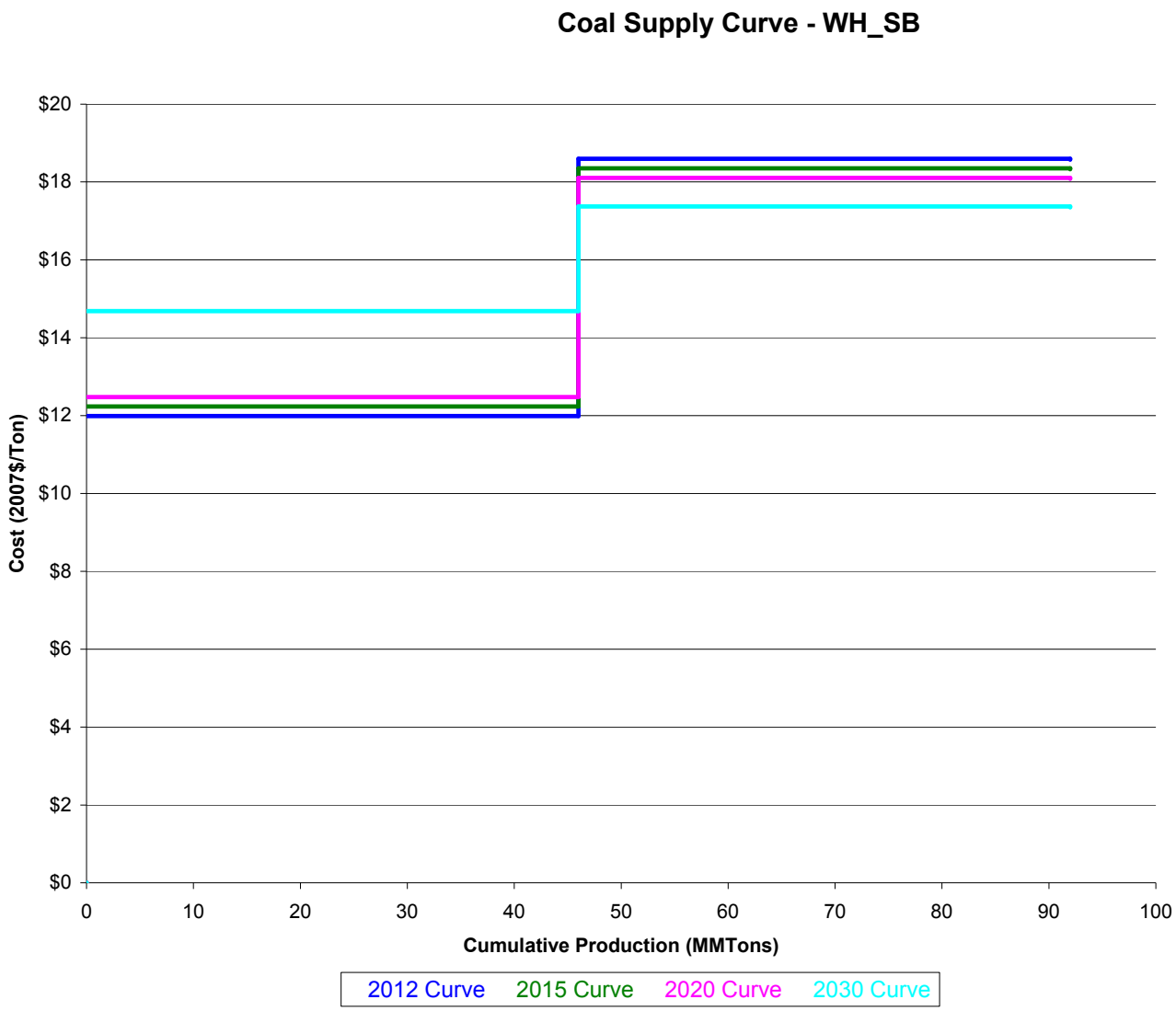
Coal Supply Region – Description	Coal Demand Region	Coal Demand Region Description	Total Cost (2007$/Ton)	Escalation/ Year (2012-2025)	Escalation/ Year (2026-2054)
Arizona	AMM1	AMMM_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
New Mexico, San Juan	AMM1	AMMM_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
West Virginia, North	NAI1	NAIN_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
Wyoming, Powder River Basin (8400)	NAI1	NAIN_High-Cost Competitive_Mine Mouth_Rail	36.93	1	1.0021
Louisiana	TXL1	TXLG_High-Cost Competitive_Mine Mouth_Rail	1.13	1	1
Wyoming, Powder River Basin (8400)	TXL1	TXLG_High-Cost Competitive_Mine Mouth_Rail	24.58	1	1.0021
Wyoming, Powder River Basin (8800)	NAI1	NAIN_High-Cost Competitive_Mine Mouth_Rail	37.3	1	1.0021
Wyoming, Powder River Basin (8800)	TXL1	TXLG_High-Cost Competitive_Mine Mouth_Rail	22.63	1	1.0021
Montana, East	DAL1	DALG_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	4.83	1	1.0042
Wyoming, Powder River Basin (8400)	DAL1	DALG_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	10.79	1	1.002
Wyoming, Powder River Basin (8400)	PRB1	PRB_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	2.21	1	1.0011
Wyoming, Powder River Basin (8400)	WYG1	WYGR_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	2.21	1	1.0011
Wyoming, Powder River Basin (8800)	DAL1	DALG_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	11.23	1	1.002
Wyoming, Powder River Basin (8800)	PRB1	PRB_High-Cost Competitive_Mine Mouth_Truck/Conveyor Belt	1.13	1	1
Alabama	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	0	1	1
Colorado, Green River	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	33.86	1	1.0022
Colorado, Uinta	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	39.76	1	1.0022
Illinois	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	25.73	1	1.0022
Indiana	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	23.32	1	1.0022
Kentucky East	ALR1	ALRL_High-Cost Competitive_Not Mine Mouth_Rail	26.57	1	1.0022

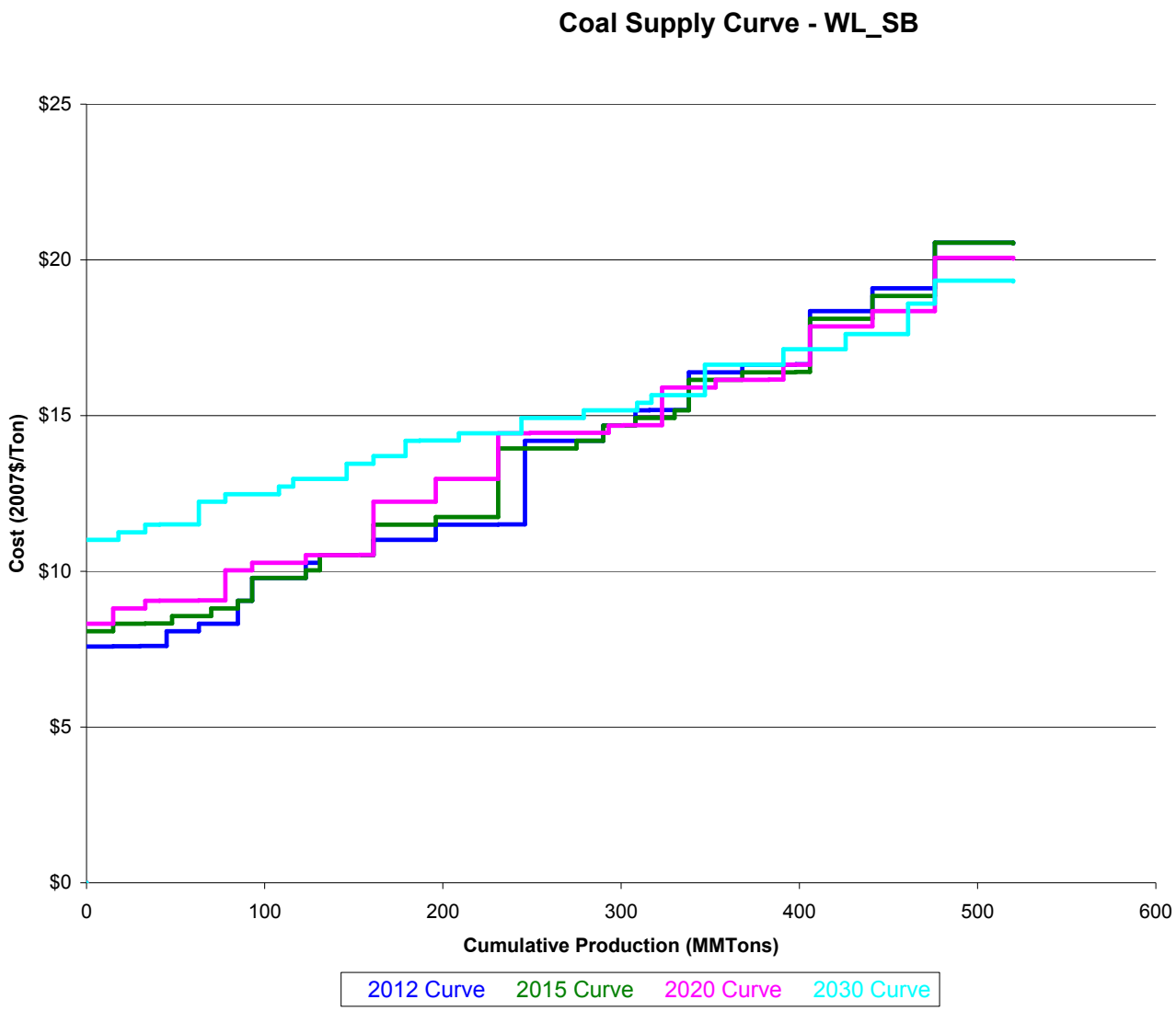
Appendix 9-4 Coal Supply Curves in EPA Base Case v.4.10

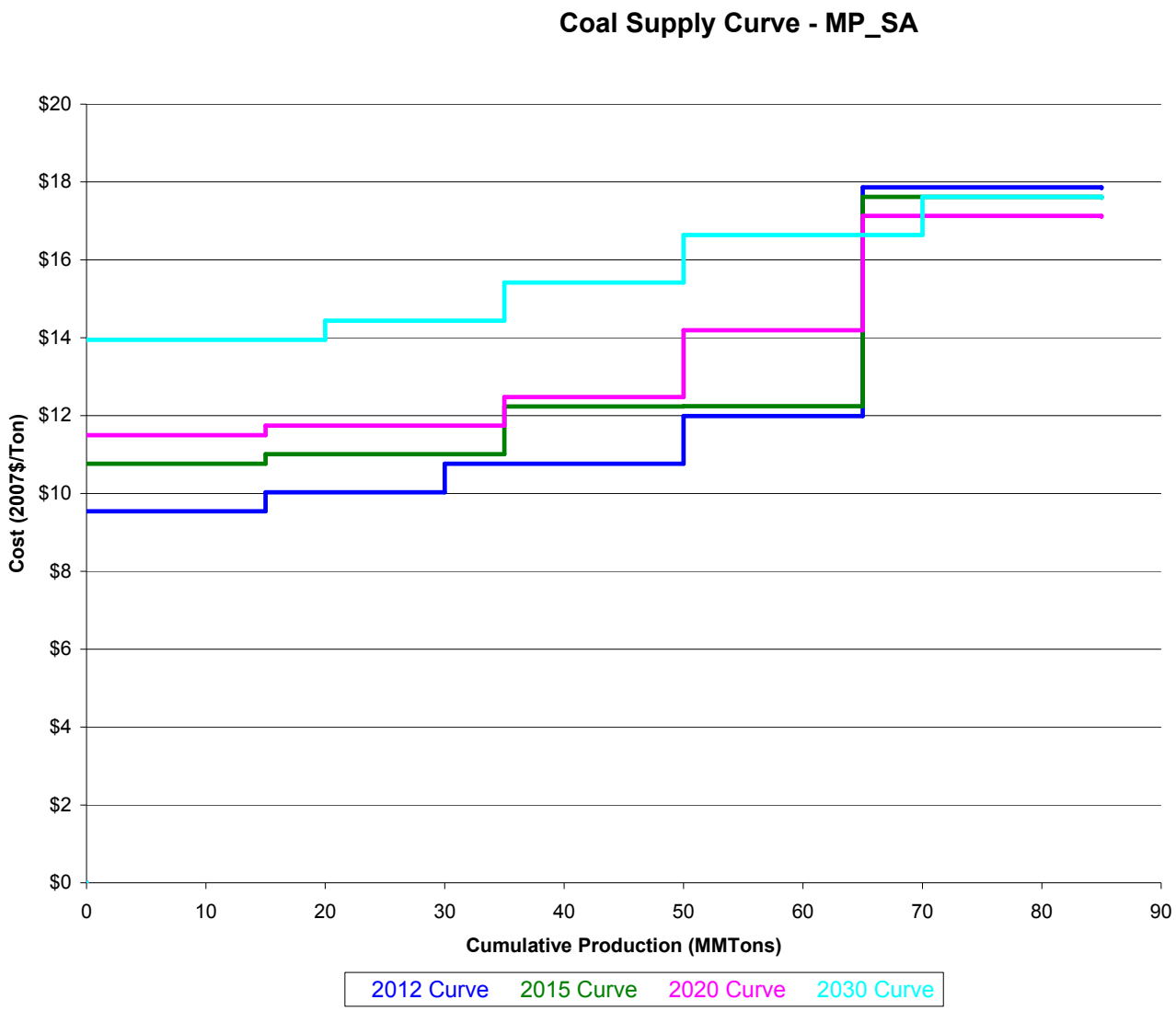
This is a small excerpt of the data in Appendix 9-4. The complete data set in spreadsheet format and complete set of graphs can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

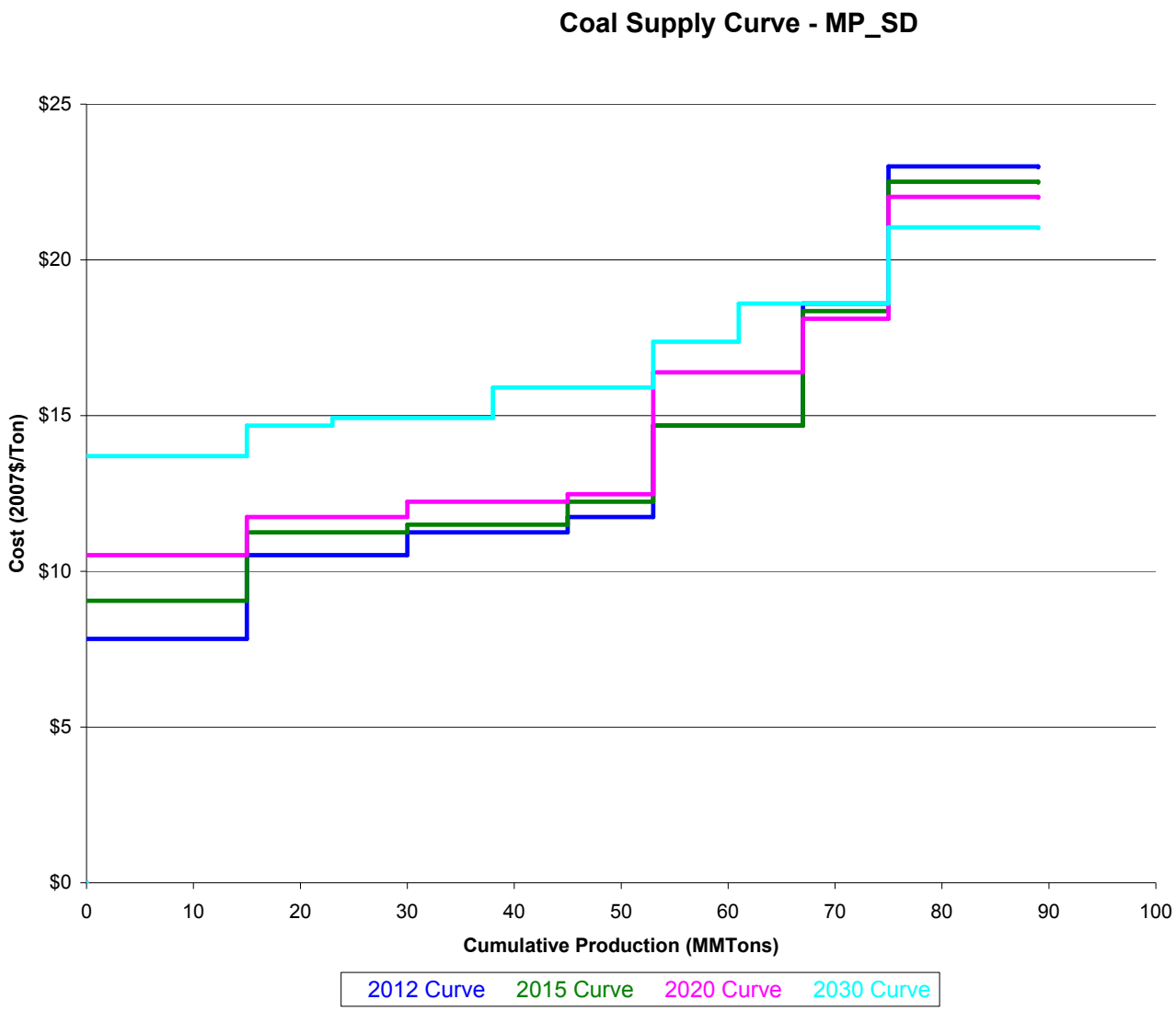
Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/Ton)	Cost of Production (2007$/Ton)	Coal Production (Million Tons/Year)	Coal Reserves (Million Tons)
2012	AL	BB	E01	24.82	43.1	1.0	111
2012	AL	BB	N01	24.82	44.5	4.0	13
2012	AL	BB	N02	24.82	47.0	0.0	25
2012	AL	BB	E02	24.82	48.9	0.9	51
2012	AL	BB	E03	24.82	49.9	5.6	73
2012	AL	BB	N03	24.82	49.9	4.0	50
2012	AL	BB	E04	24.82	50.9	1.0	5
2012	AL	BB	N04	24.82	52.9	0.0	50
2012	AL	BB	E05	24.82	53.8	0.8	22
2012	AL	BD	E01	24	43.1	0.4	233
2012	AL	BD	E02	24	44.5	0.3	9
2012	AL	BD	E03	24	48.9	0.4	16
2012	AL	BD	E04	24	52.9	0.9	10
2012	AL	BD	N01	24	52.9	2.0	49
2012	AL	BD	E05	24	53.8	0.3	1
2012	AL	BD	E06	24	56.8	0.7	26
2012	AL	BD	E07	24	64.6	0.4	24
2012	AL	BD	N02	24	65.6	2.0	50
2012	AL	BD	E08	24	73.4	0.1	6
2012	AL	BD	N03	24	78.3	2.0	50
2012	AL	BD	E09	24	85.1	0.5	26
2012	AL	BD	N04	24	92.0	2.0	50
2012	AL	BE	E01	23.82	36.2	1.8	93
2012	AL	BE	E02	23.82	43.1	0.4	14
2012	AL	BE	E03	23.82	45.5	0.1	0
2012	AL	BE	E04	23.82	50.9	0.4	10
2012	AL	BE	E05	23.82	54.8	0.9	16
2012	AL	BE	E06	23.82	62.6	0.2	5
2012	AL	BE	N01	23.82	70.5	0.5	121

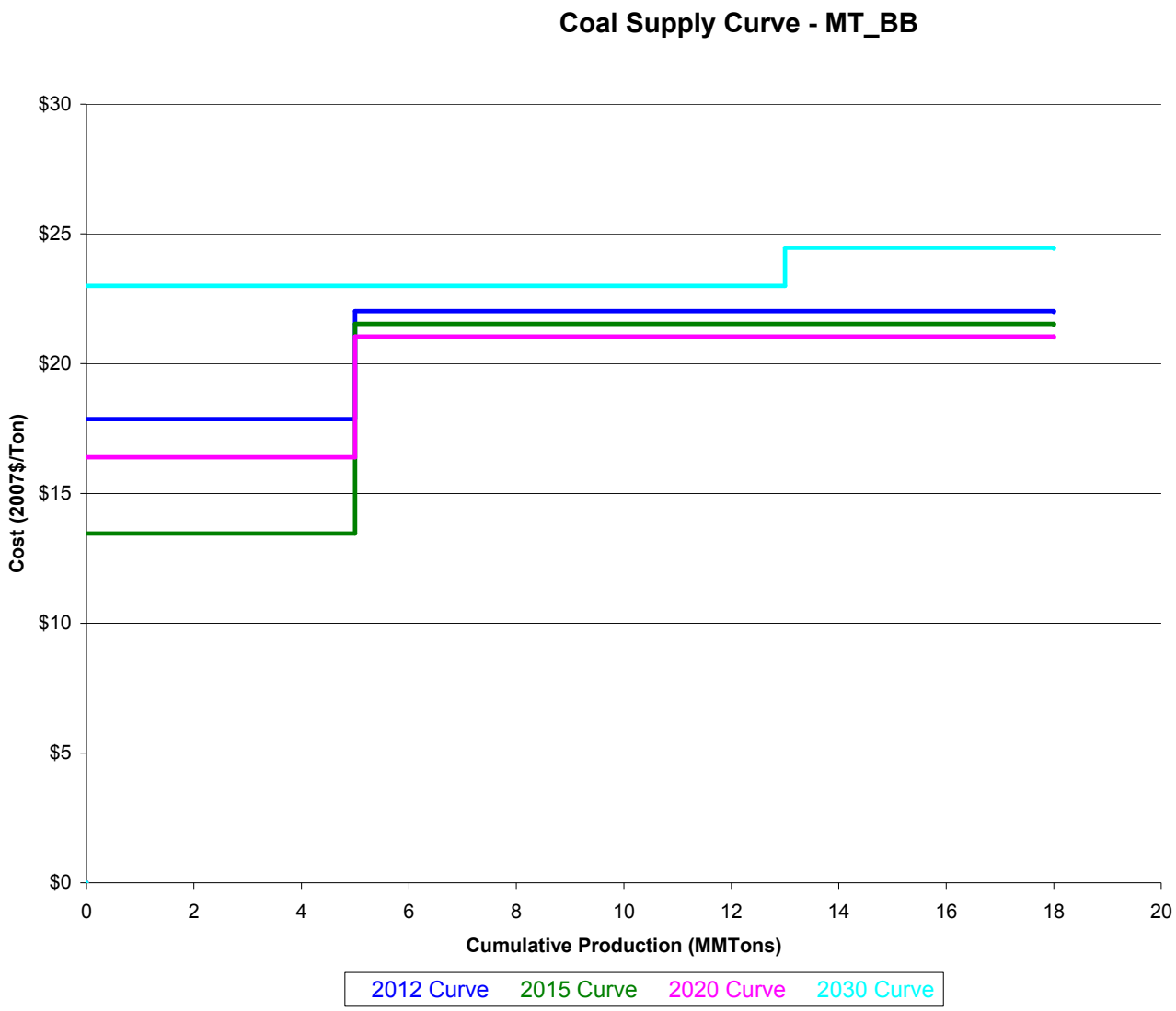

Coal Supply Curve - WH_SA
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
100
200
300
400
500
600
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

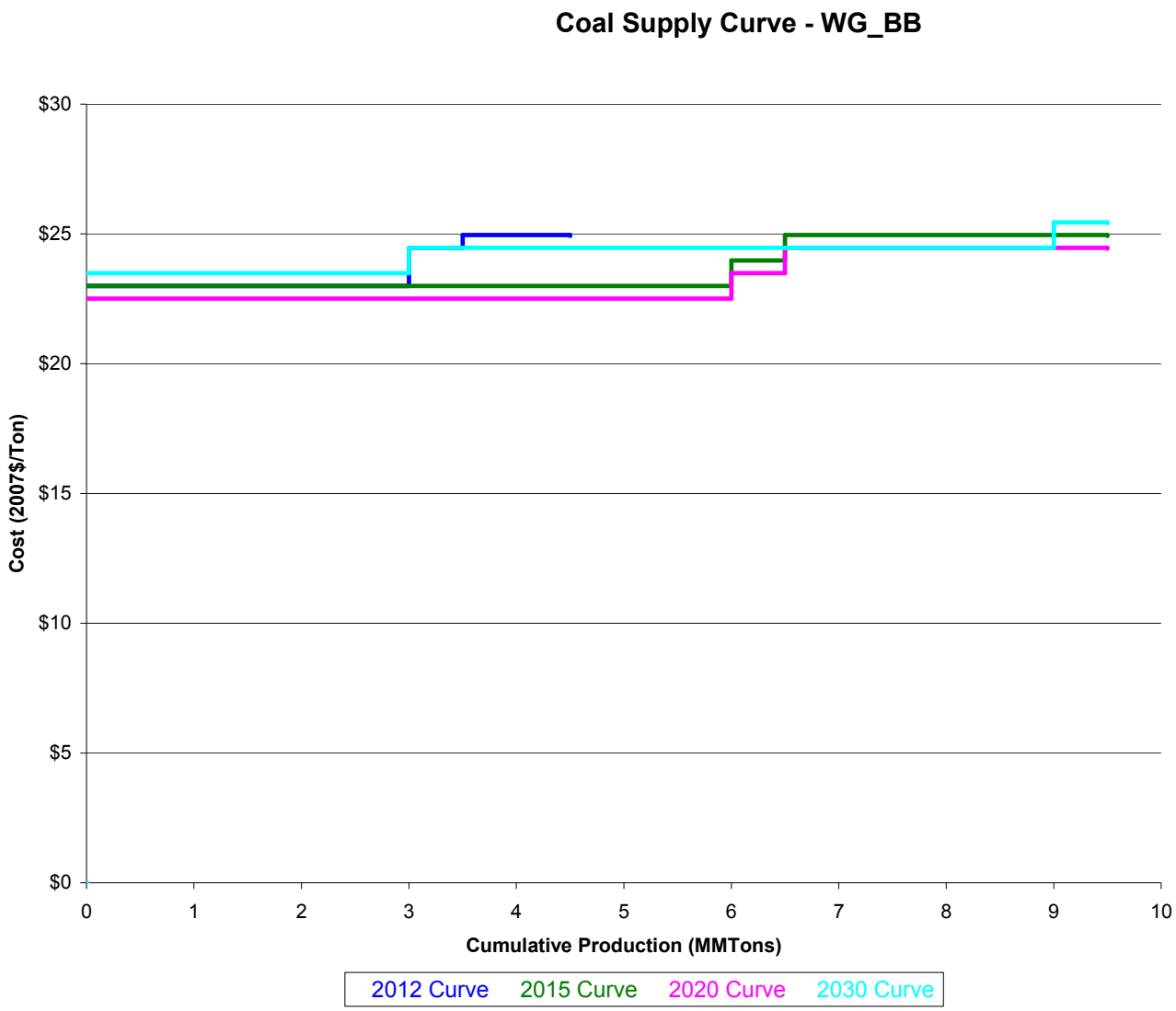

Coal Supply Curve - WH_SB
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
80
90
100
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

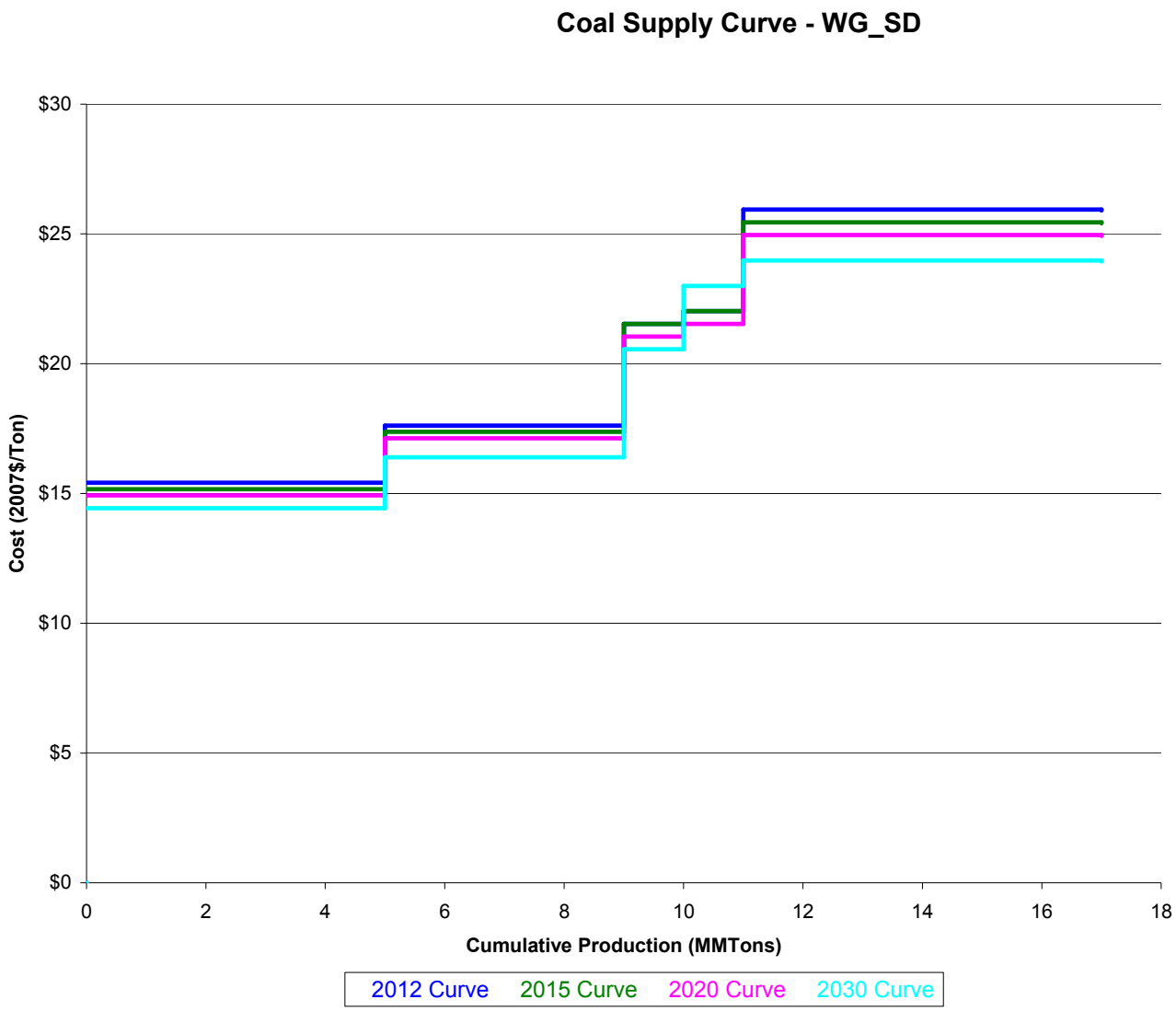

Coal Supply Curve - WL_SB
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
100
200
300
400
500
600
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

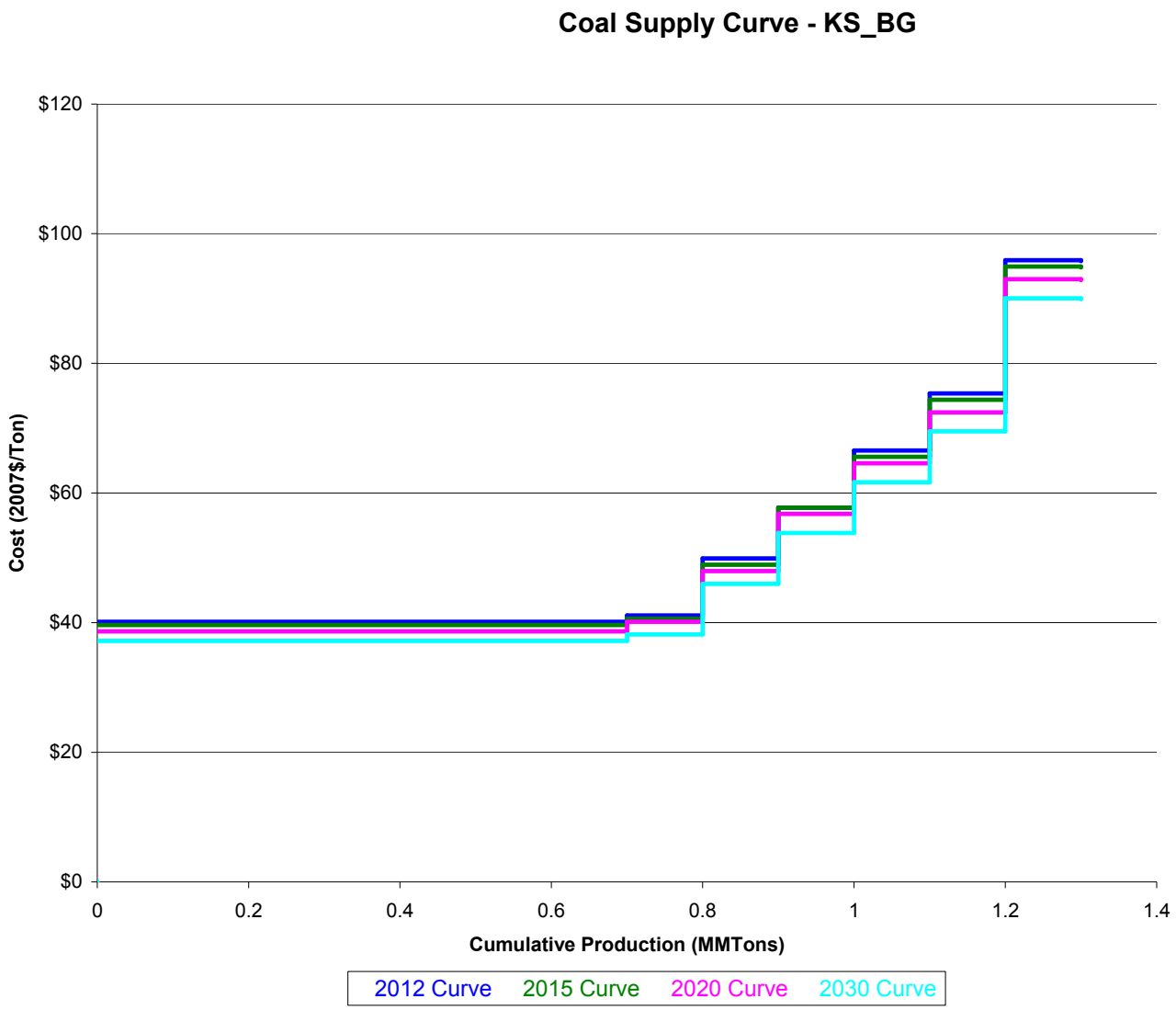

Coal Supply Curve - MP_SA
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
80
90
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

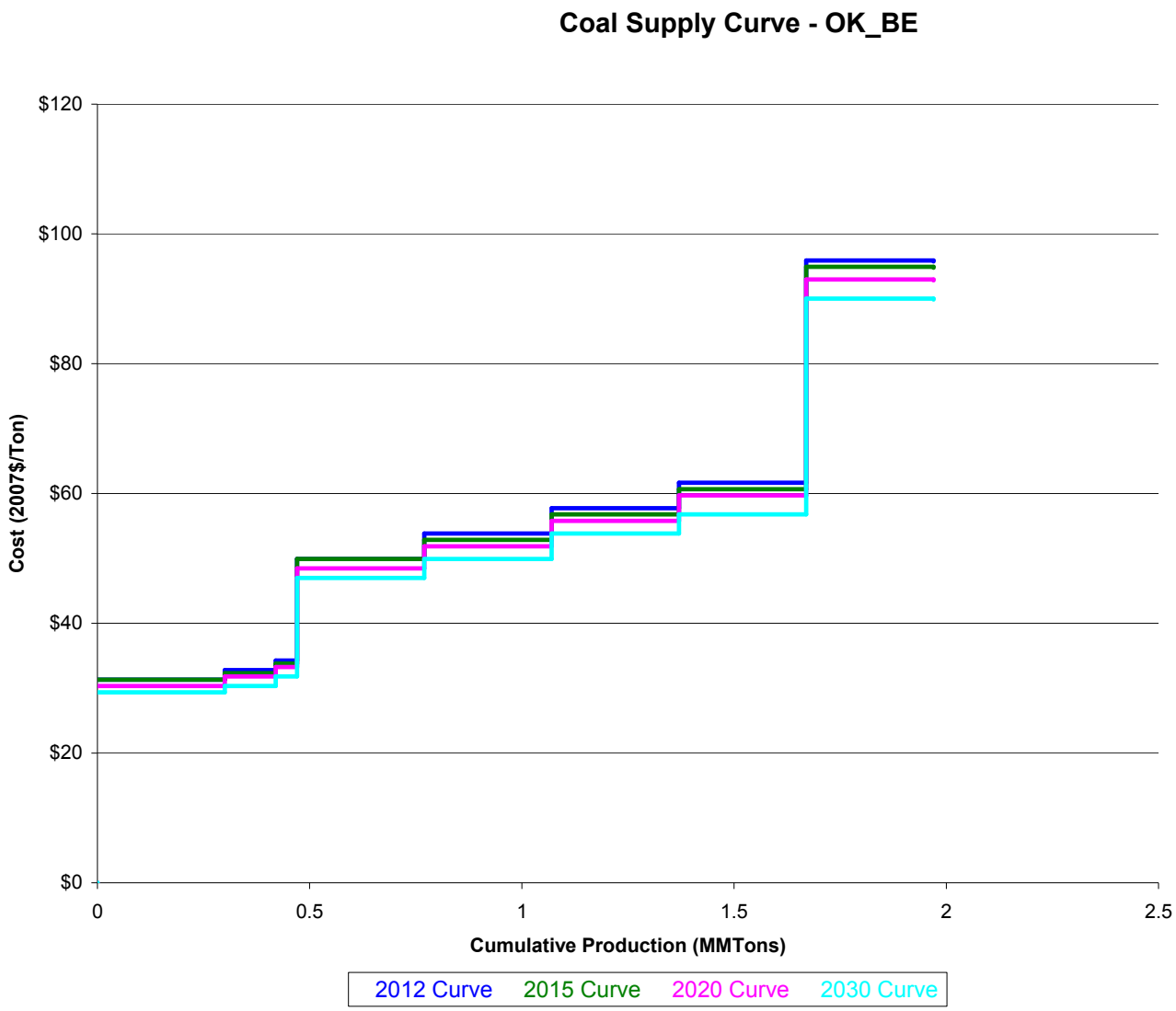

Coal Supply Curve - MP_SD
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
80
90
100
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

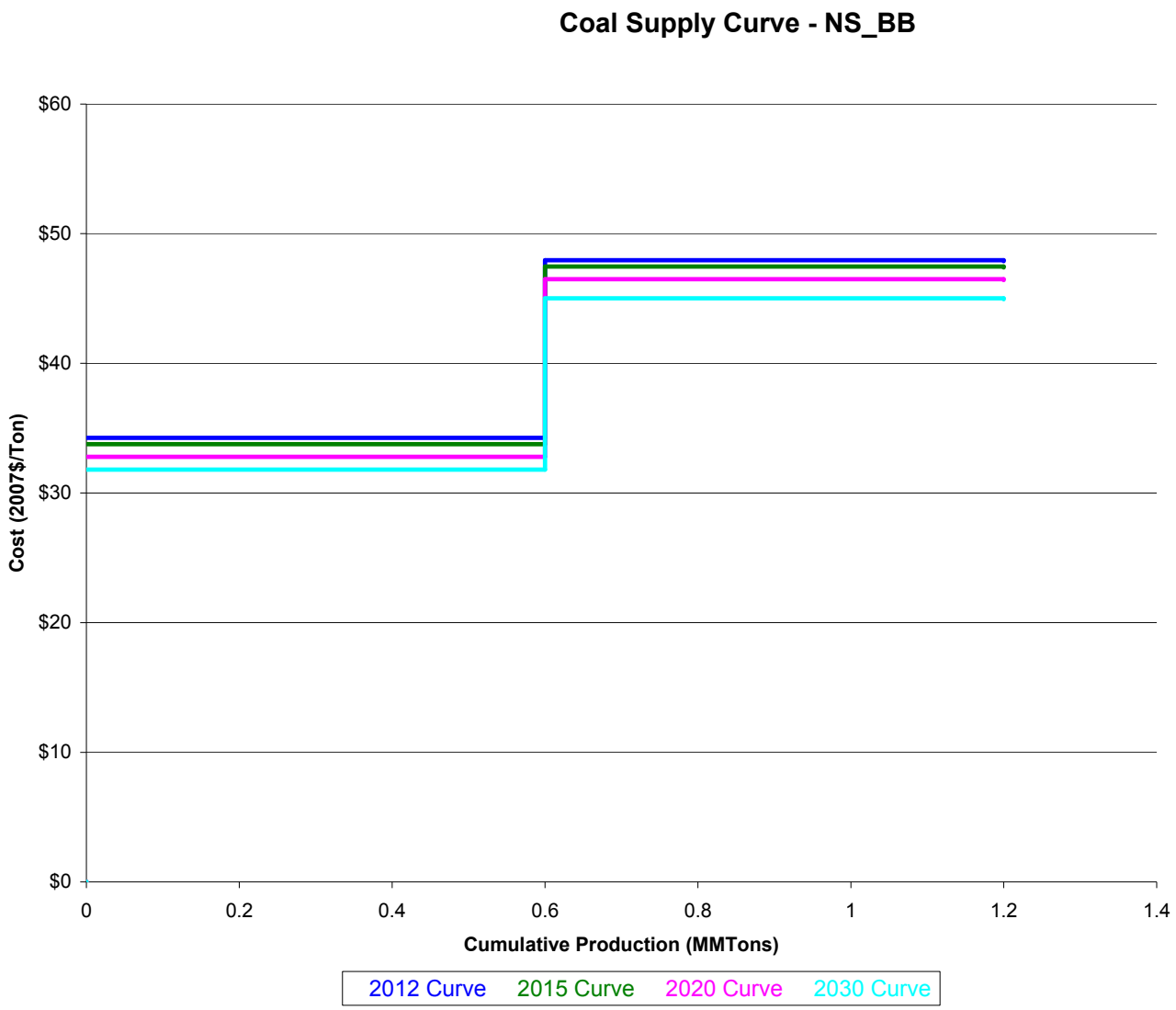

Coal Supply Curve - MT_BB
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
20
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

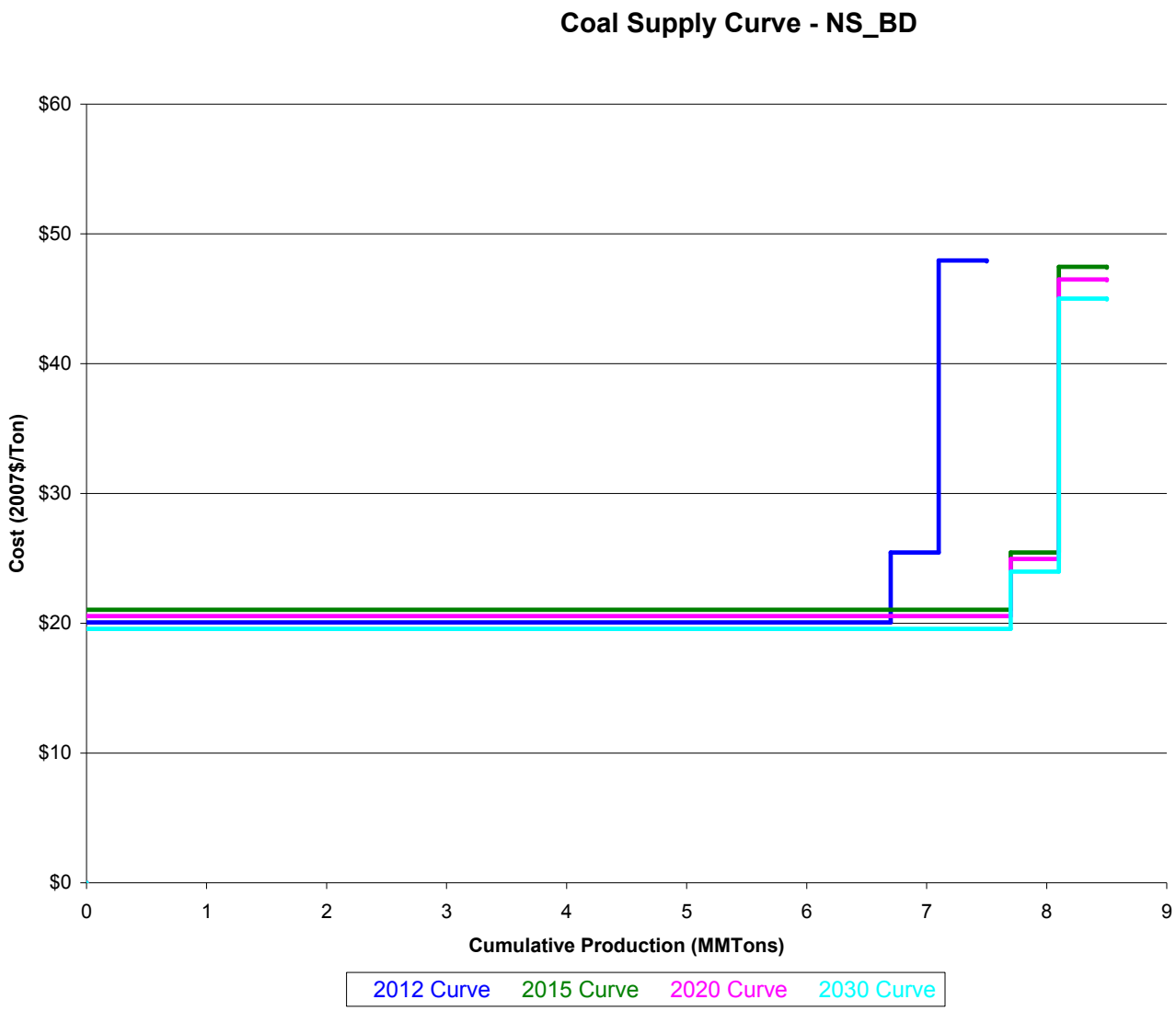

Coal Supply Curve - WG_BB
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
10
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

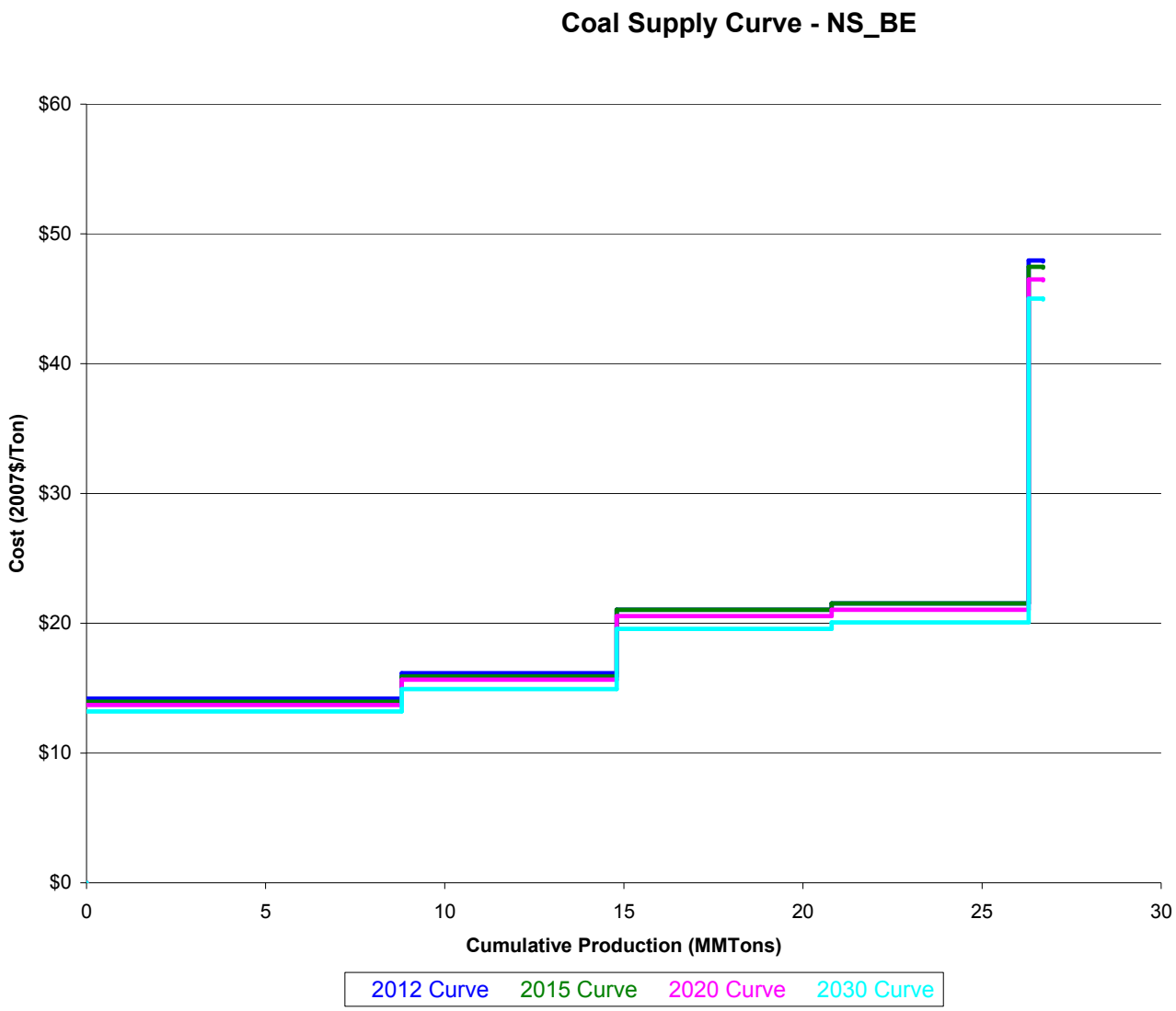

Coal Supply Curve - WG_SD
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

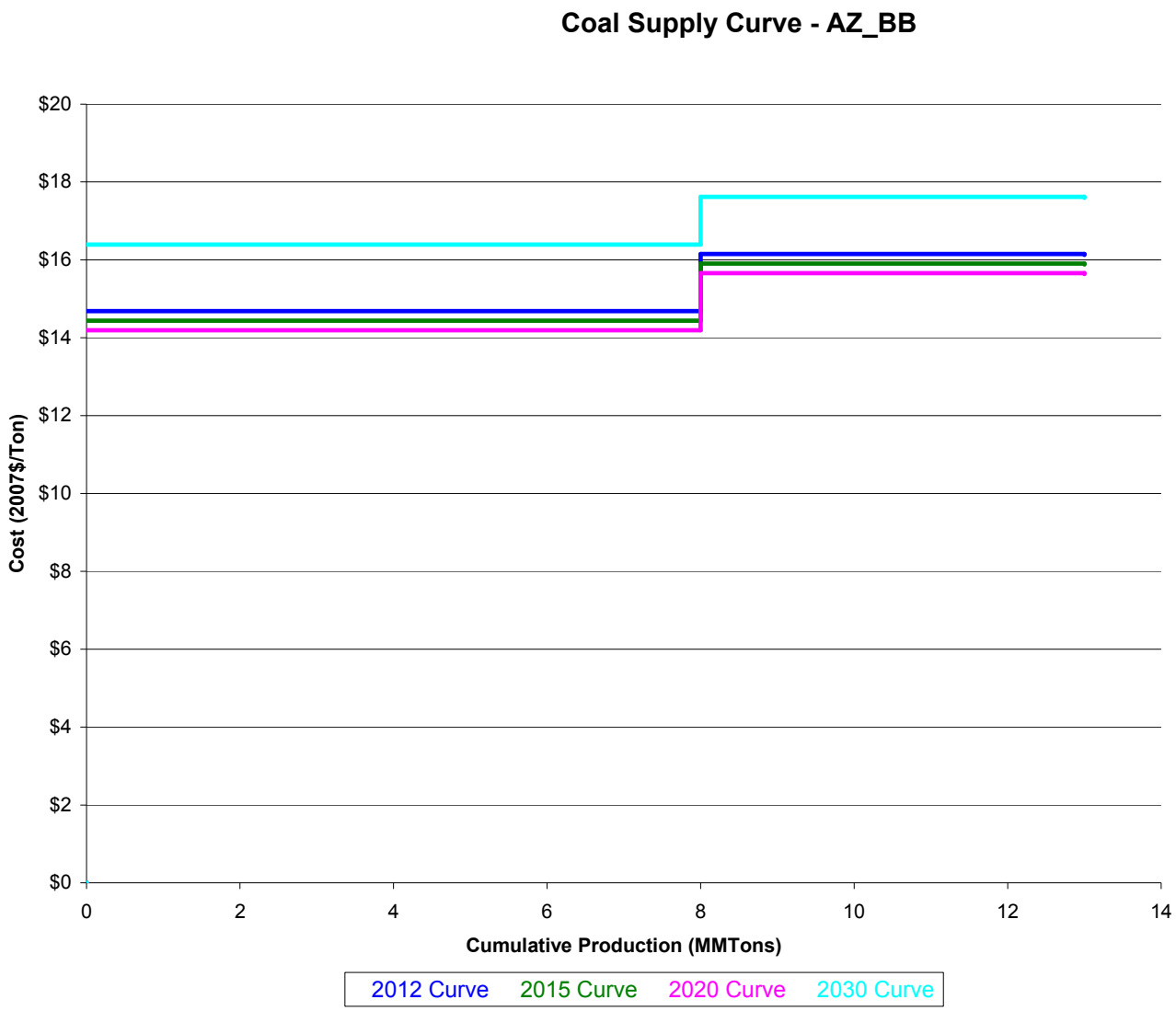

Coal Supply Curve - KS_BG
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

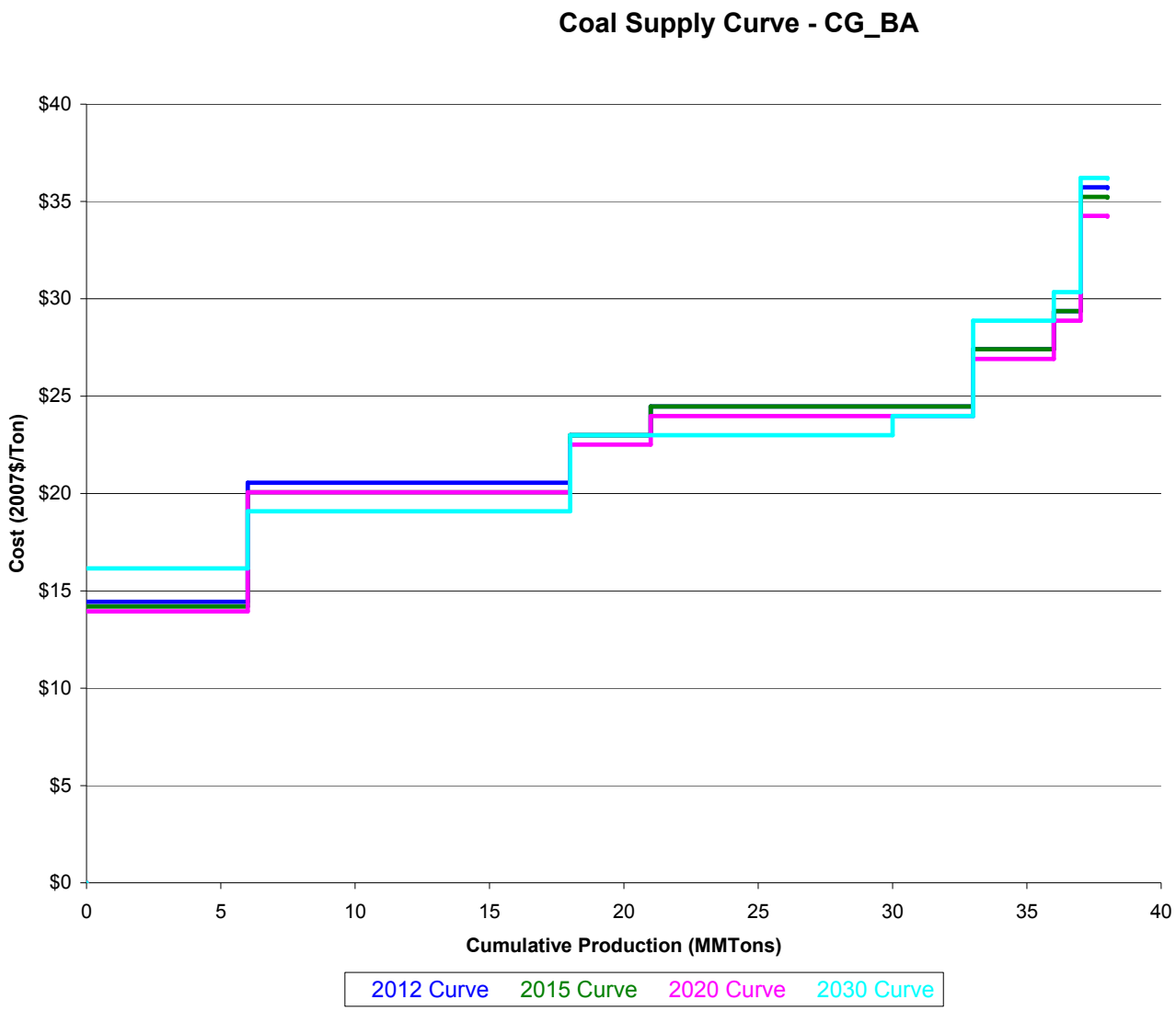

Coal Supply Curve - OK_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

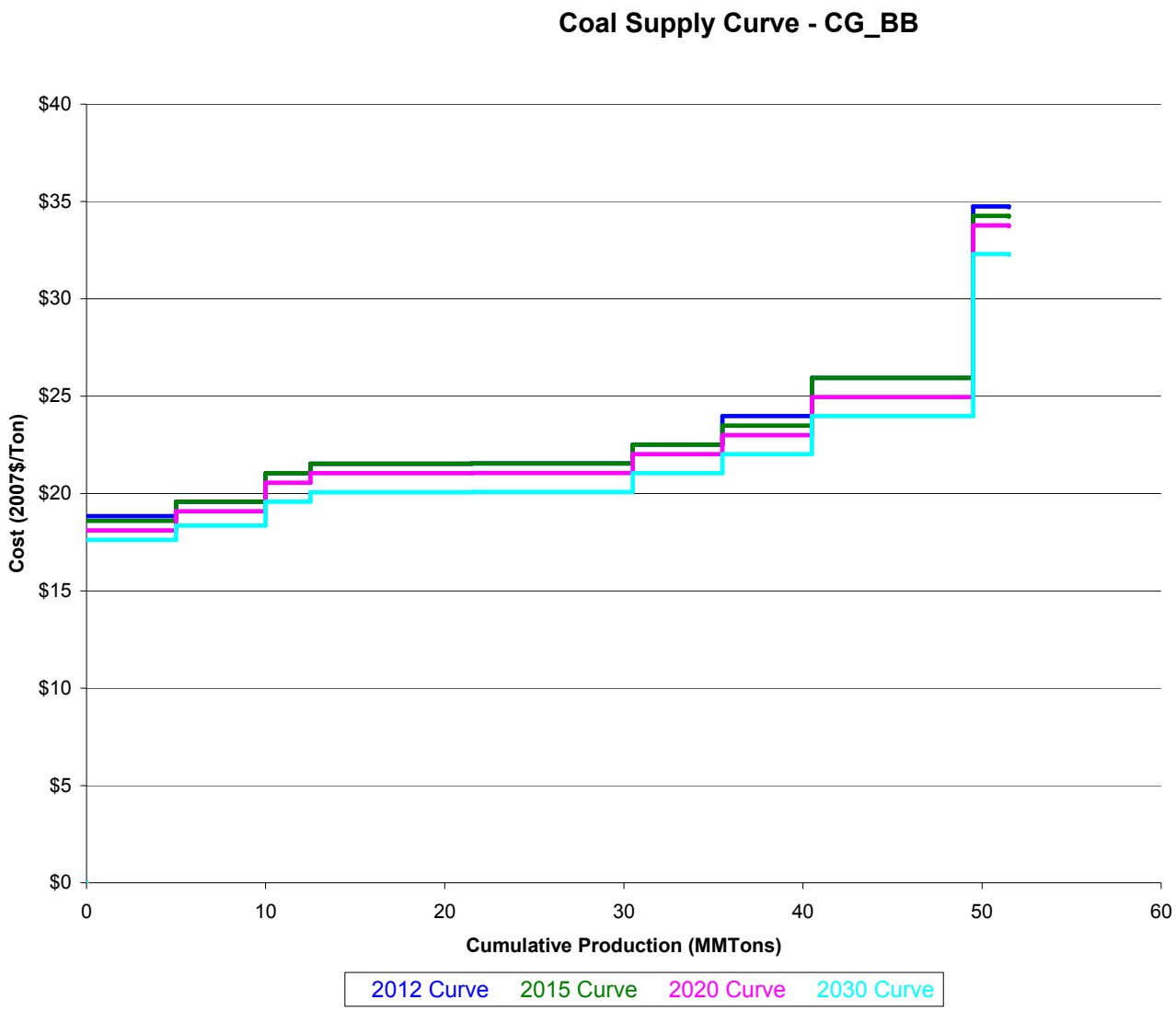

Coal Supply Curve - NS_BB
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

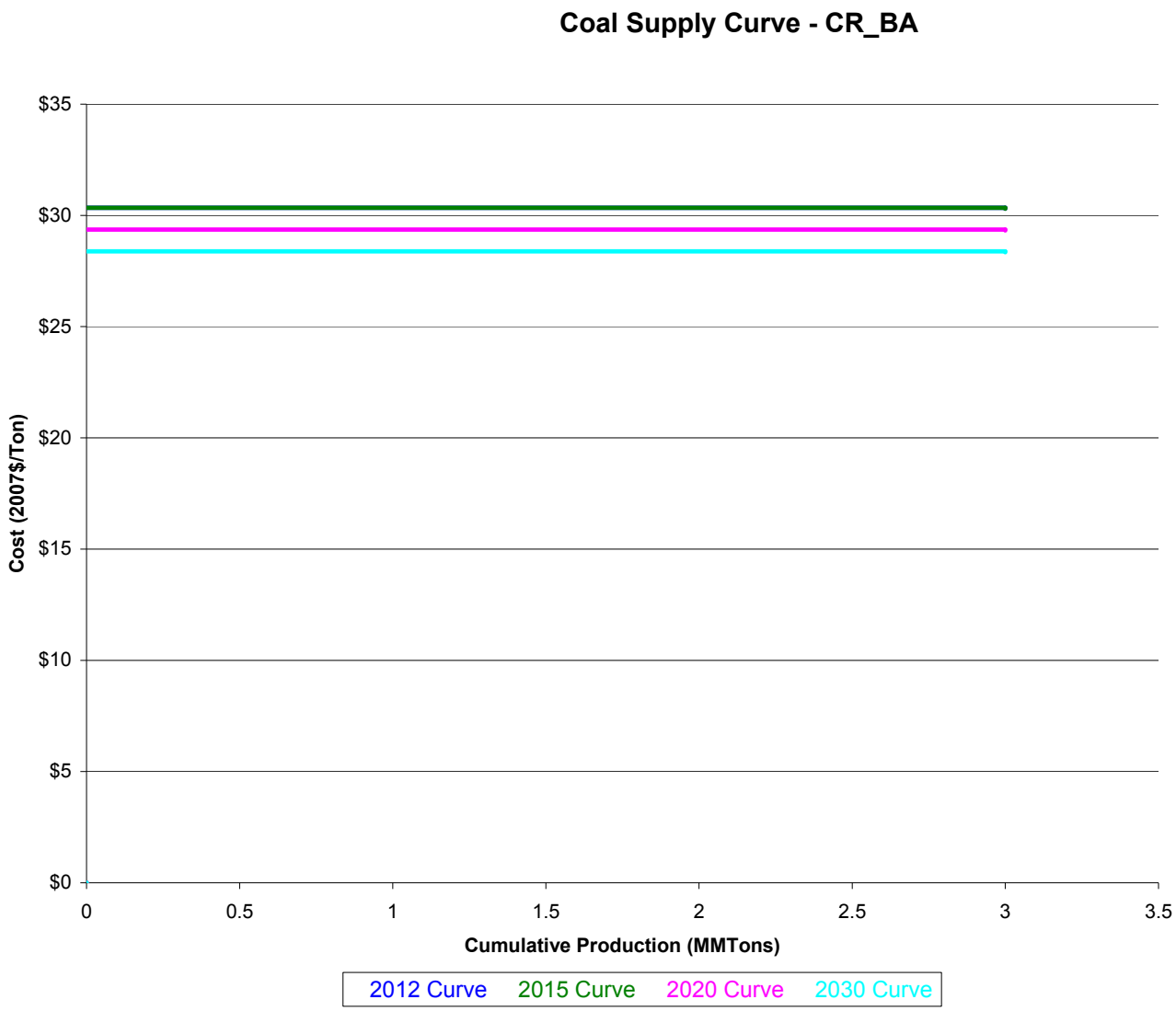

Coal Supply Curve - NS_BD
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

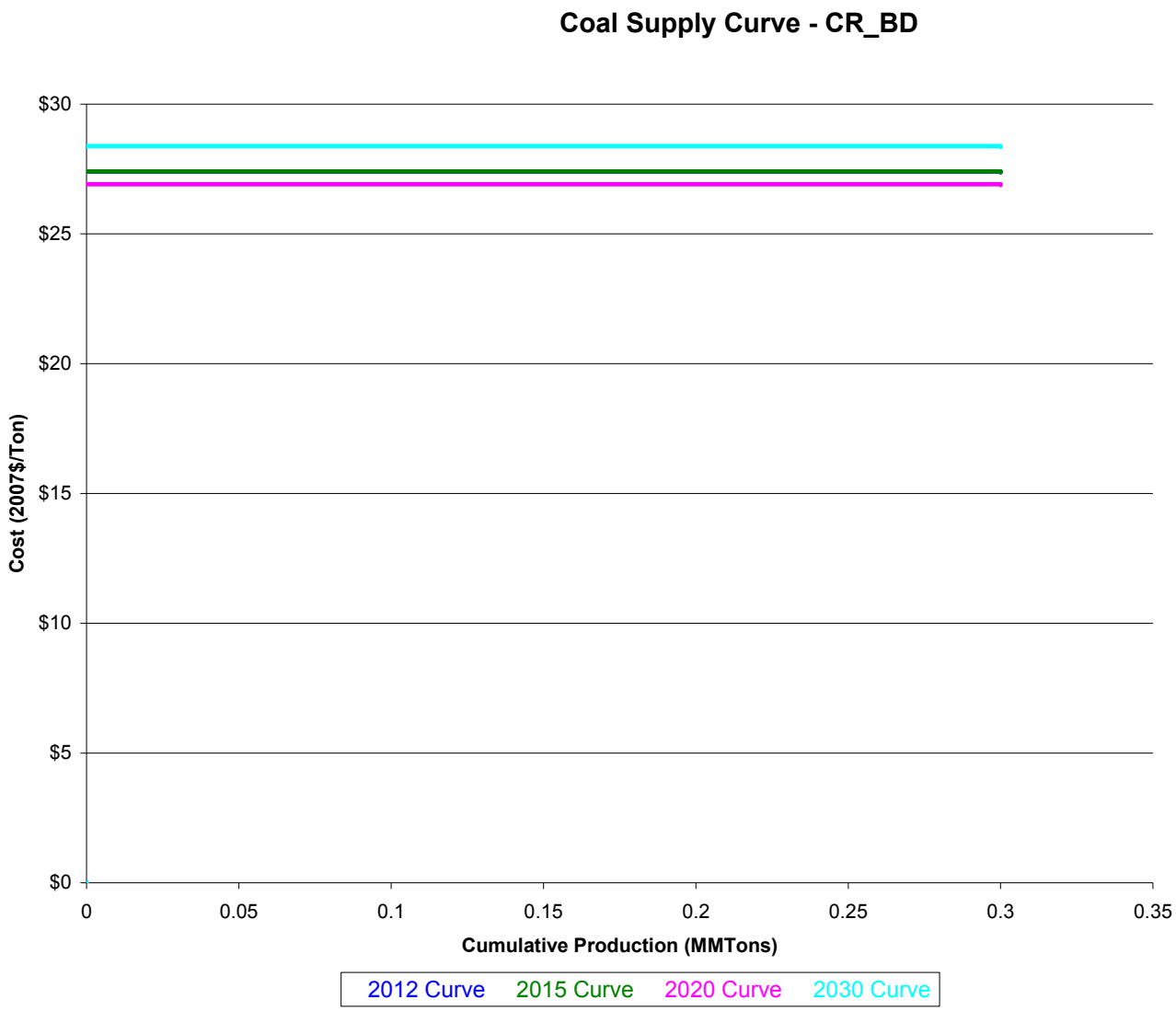

Coal Supply Curve - NS_BE
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

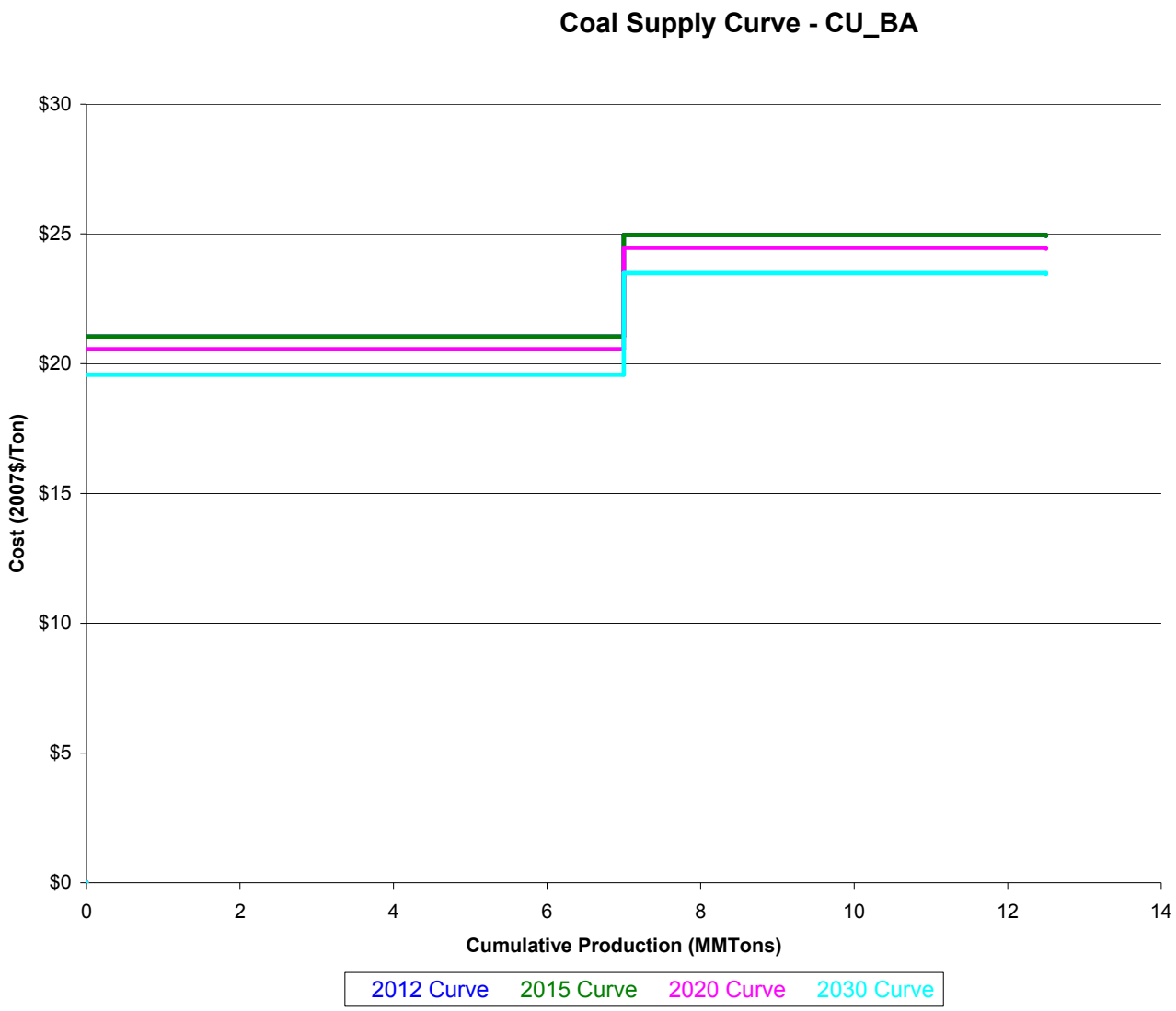

Coal Supply Curve - AZ_BB
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

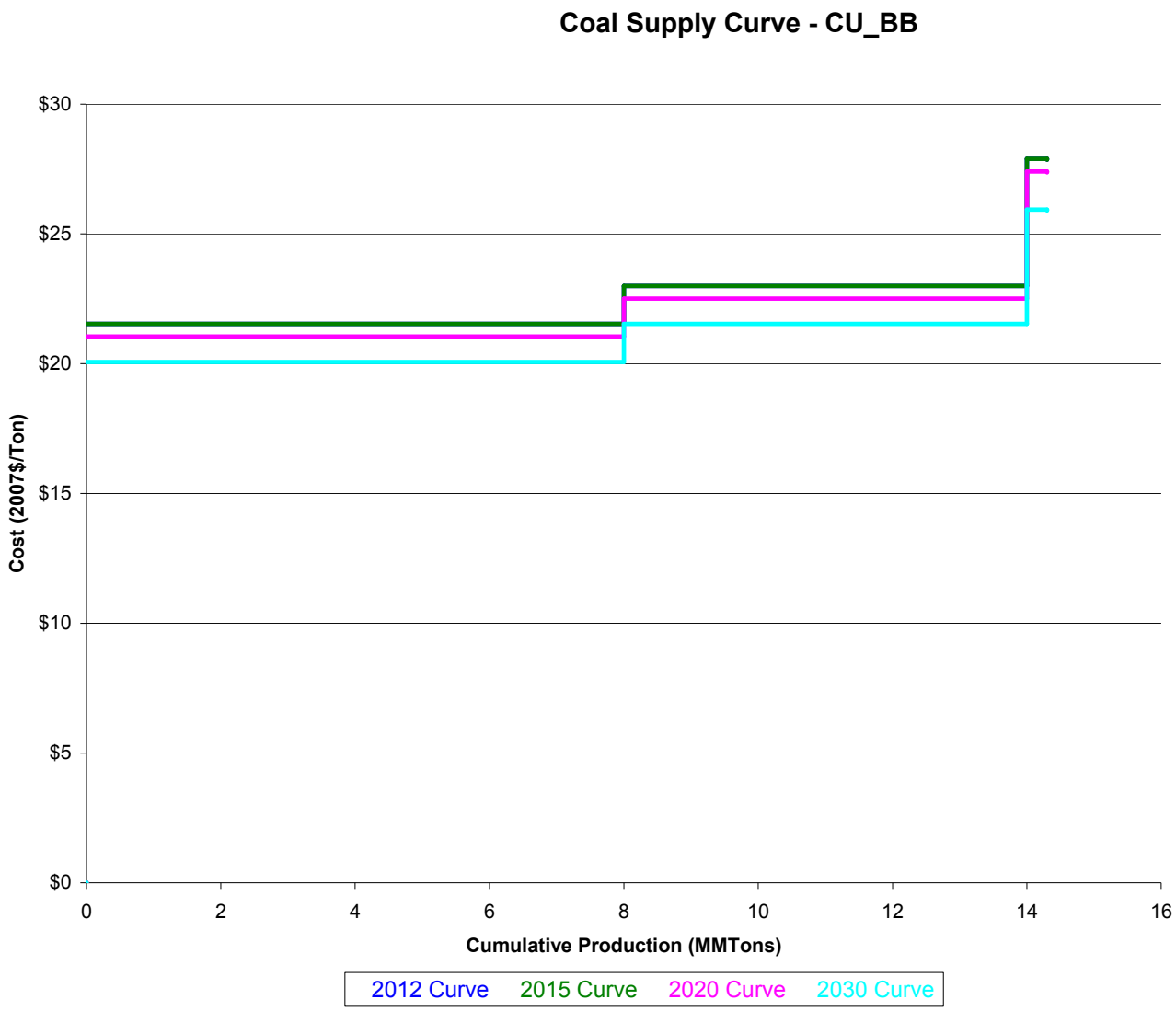

Coal Supply Curve - CG_BA
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
35
40
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

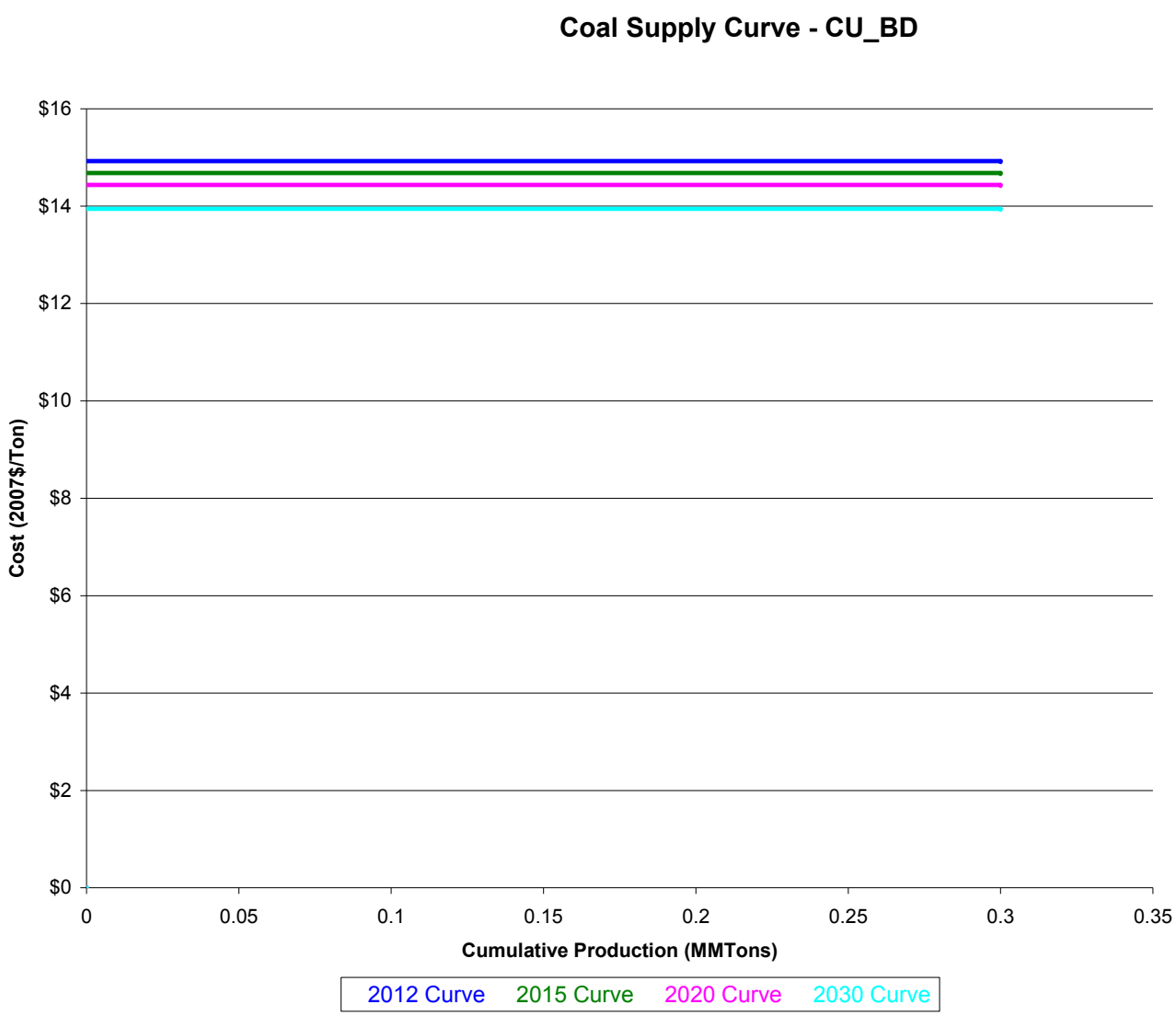

Coal Supply Curve - CG_BB
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

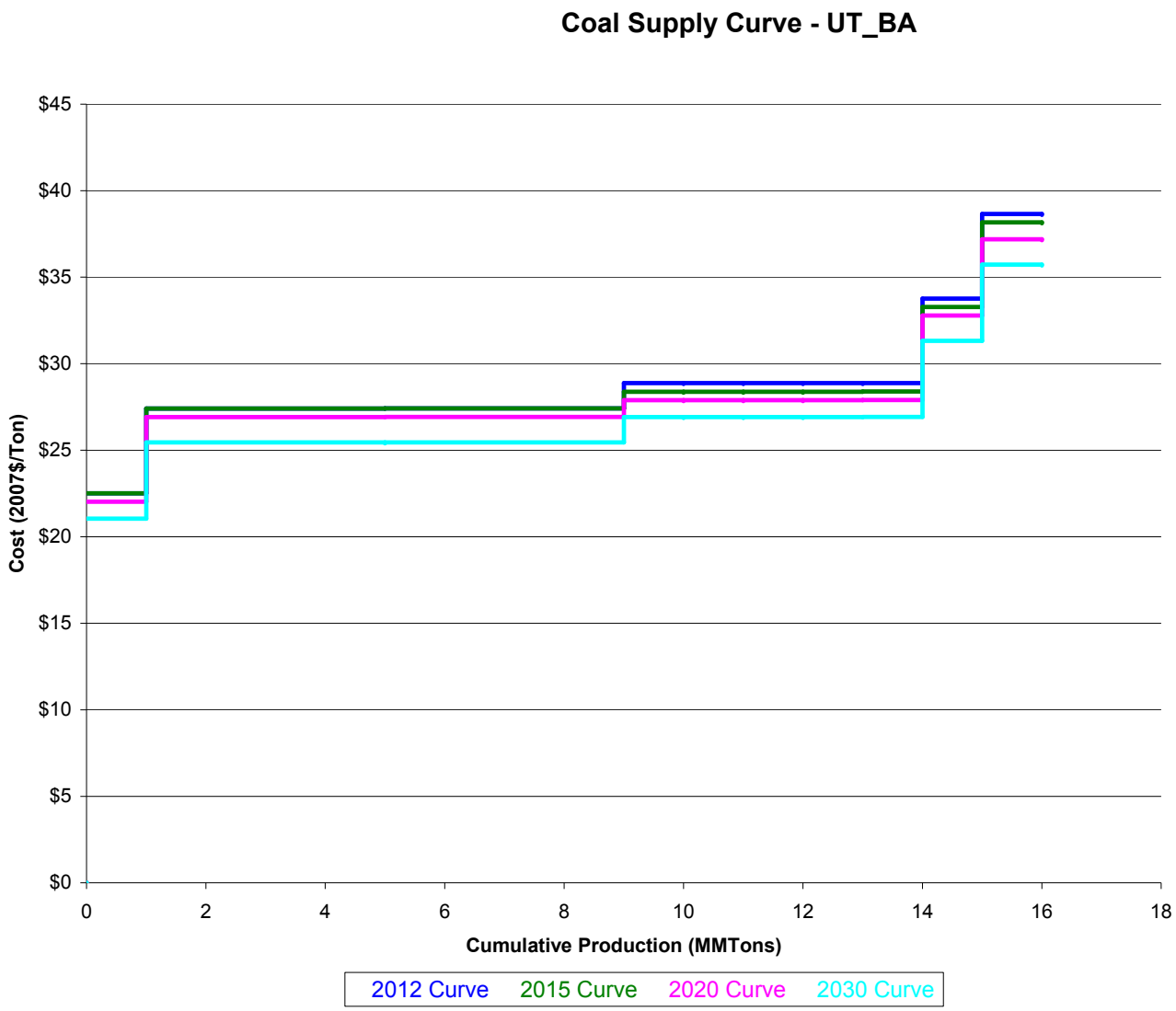

Coal Supply Curve - CR_BA
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

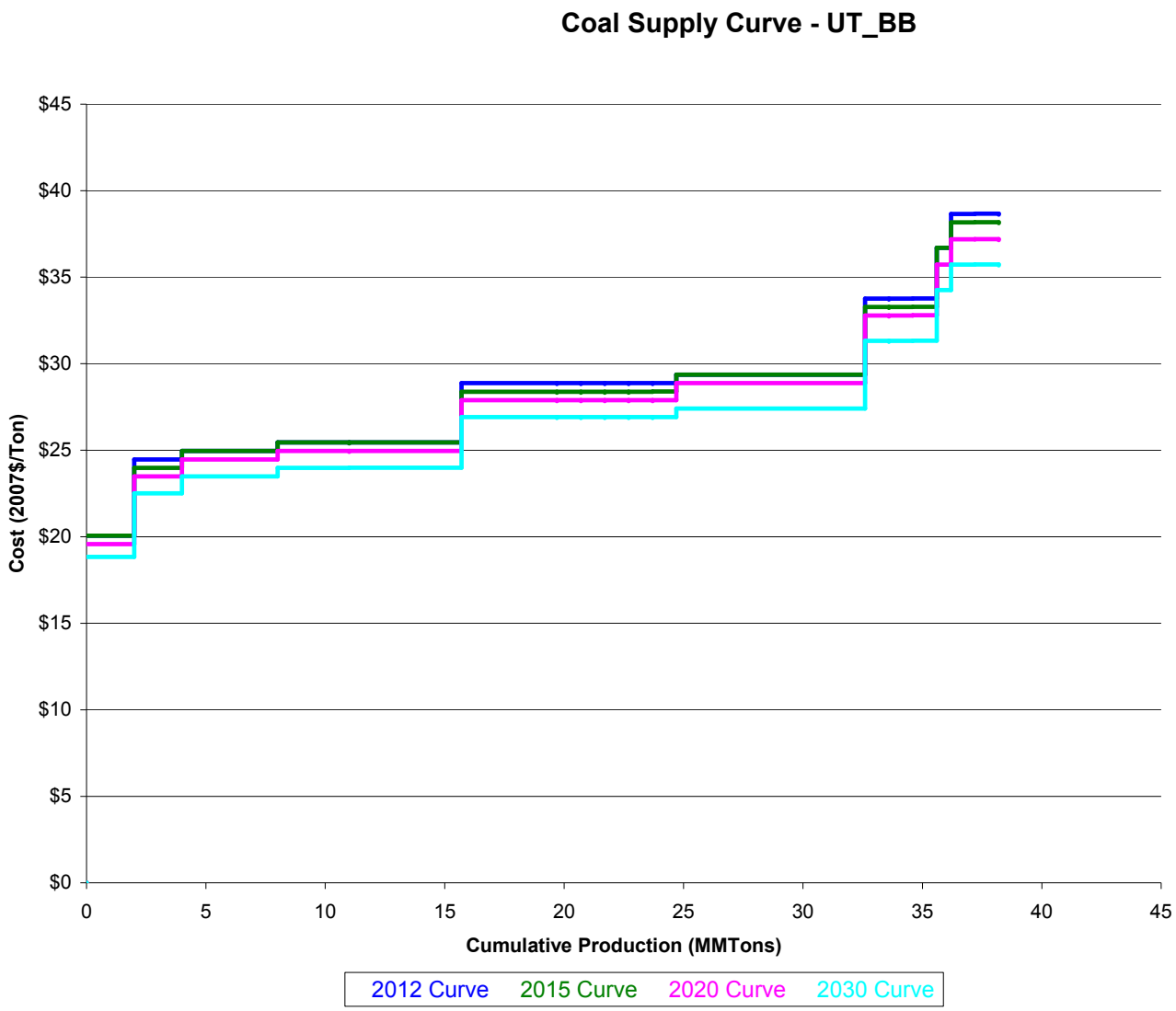

Coal Supply Curve - CR_BD
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

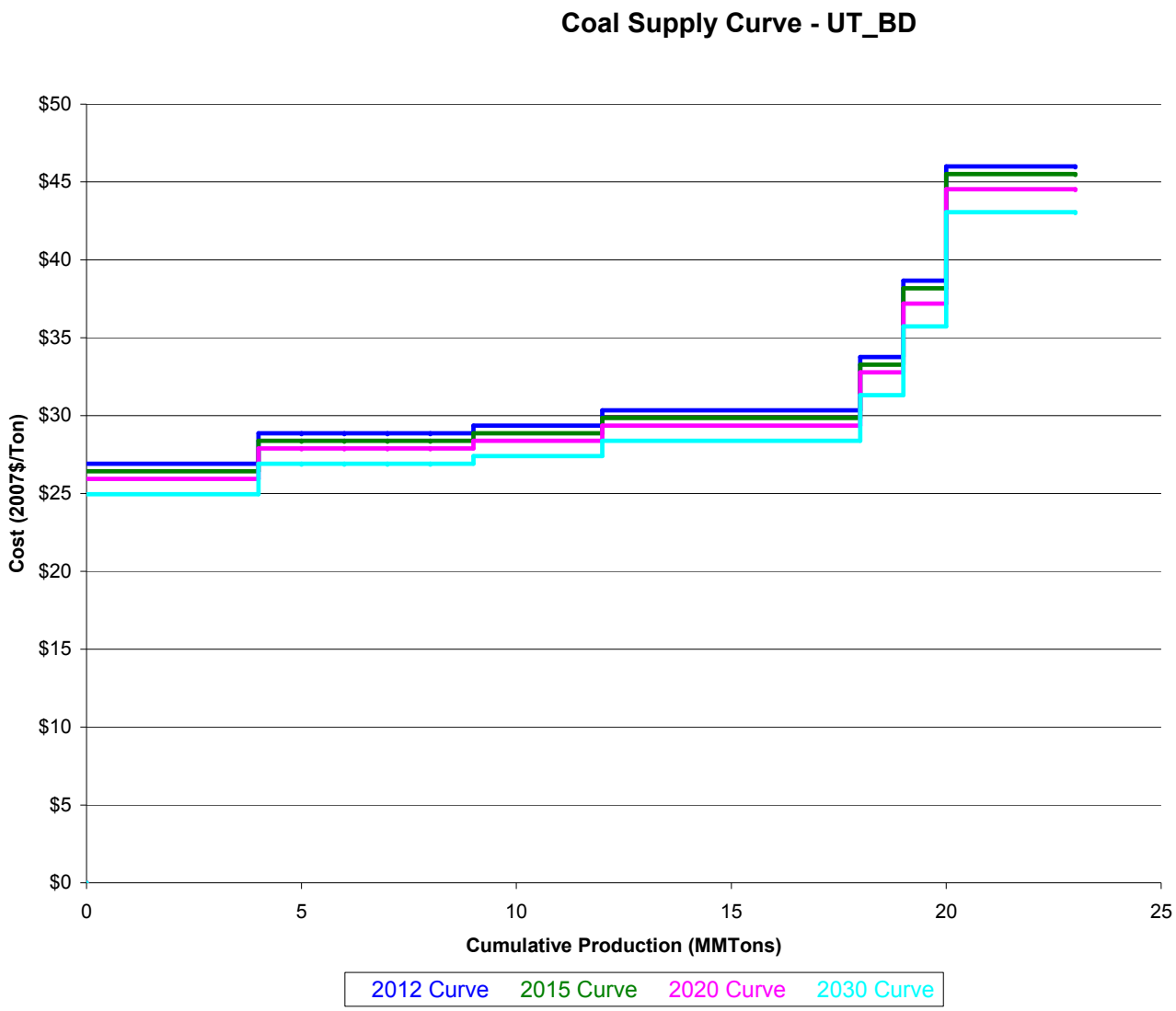

Coal Supply Curve - CU_BA
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

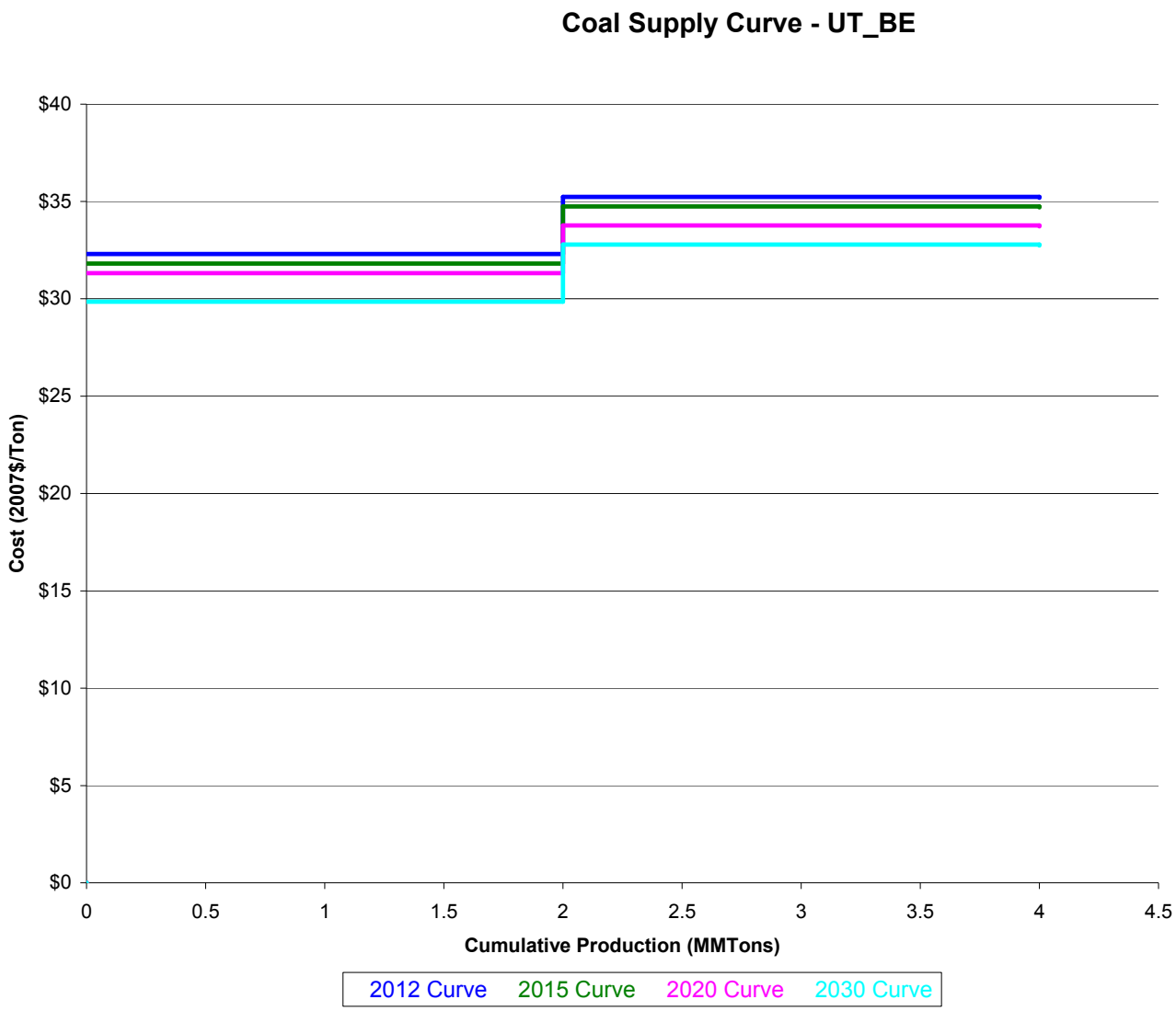

Coal Supply Curve - CU_BB
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

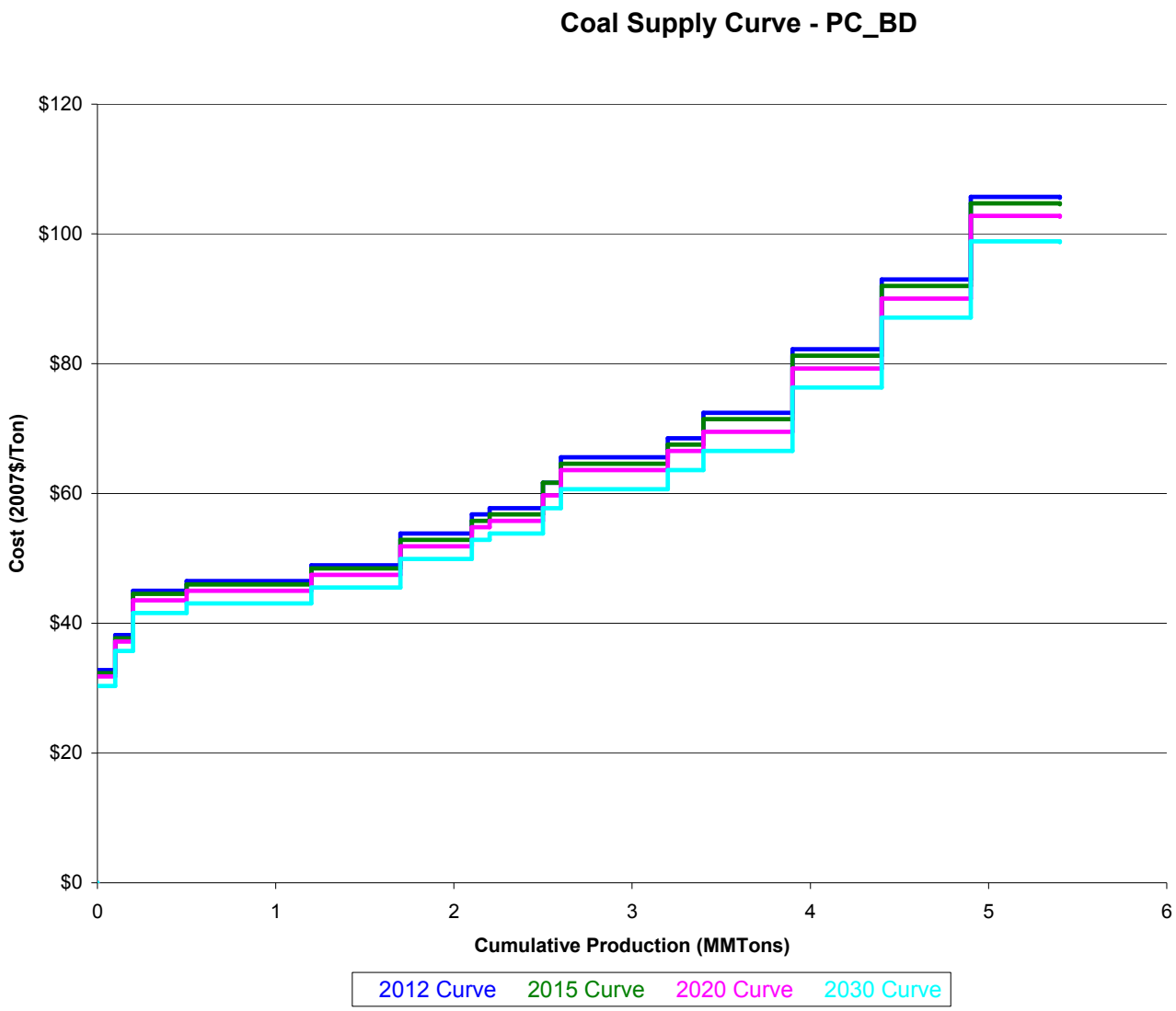

Coal Supply Curve - CU_BD
$16
$14
$12
$10
$8
$6
$4
$2
$0
Cost (2007$/Ton)
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

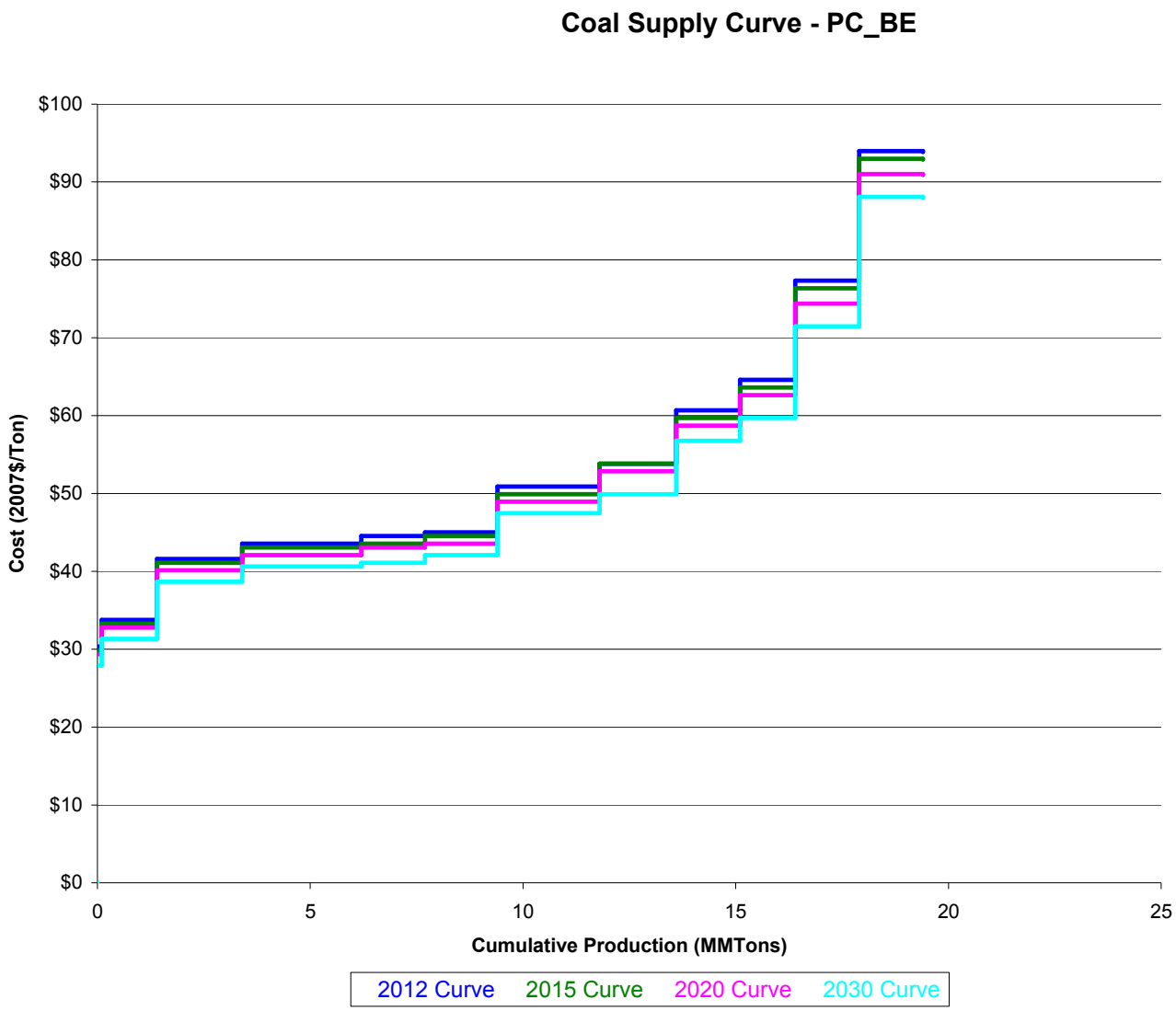

Coal Supply Curve - UT_BA
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

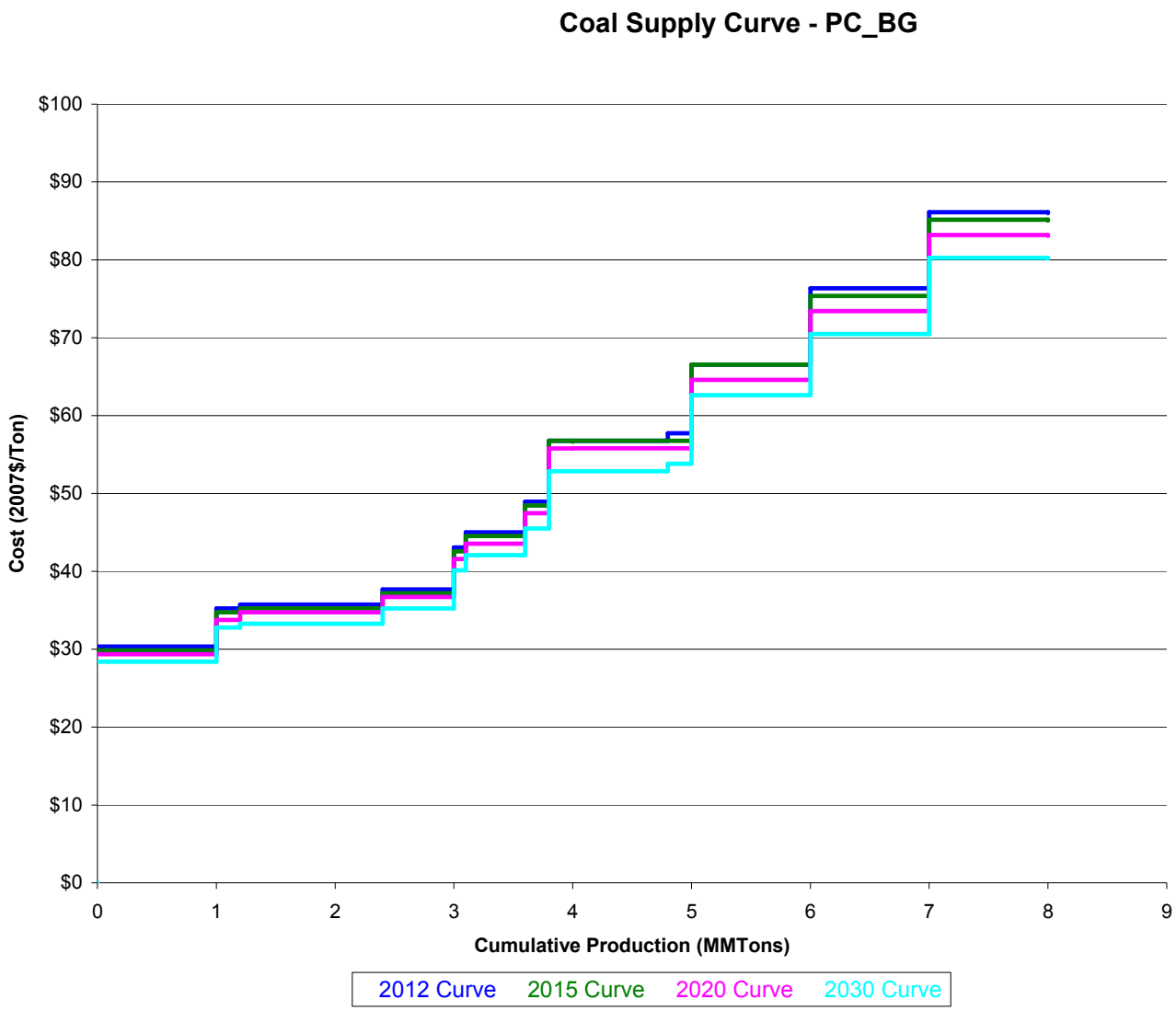

Coal Supply Curve - UT_BB
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

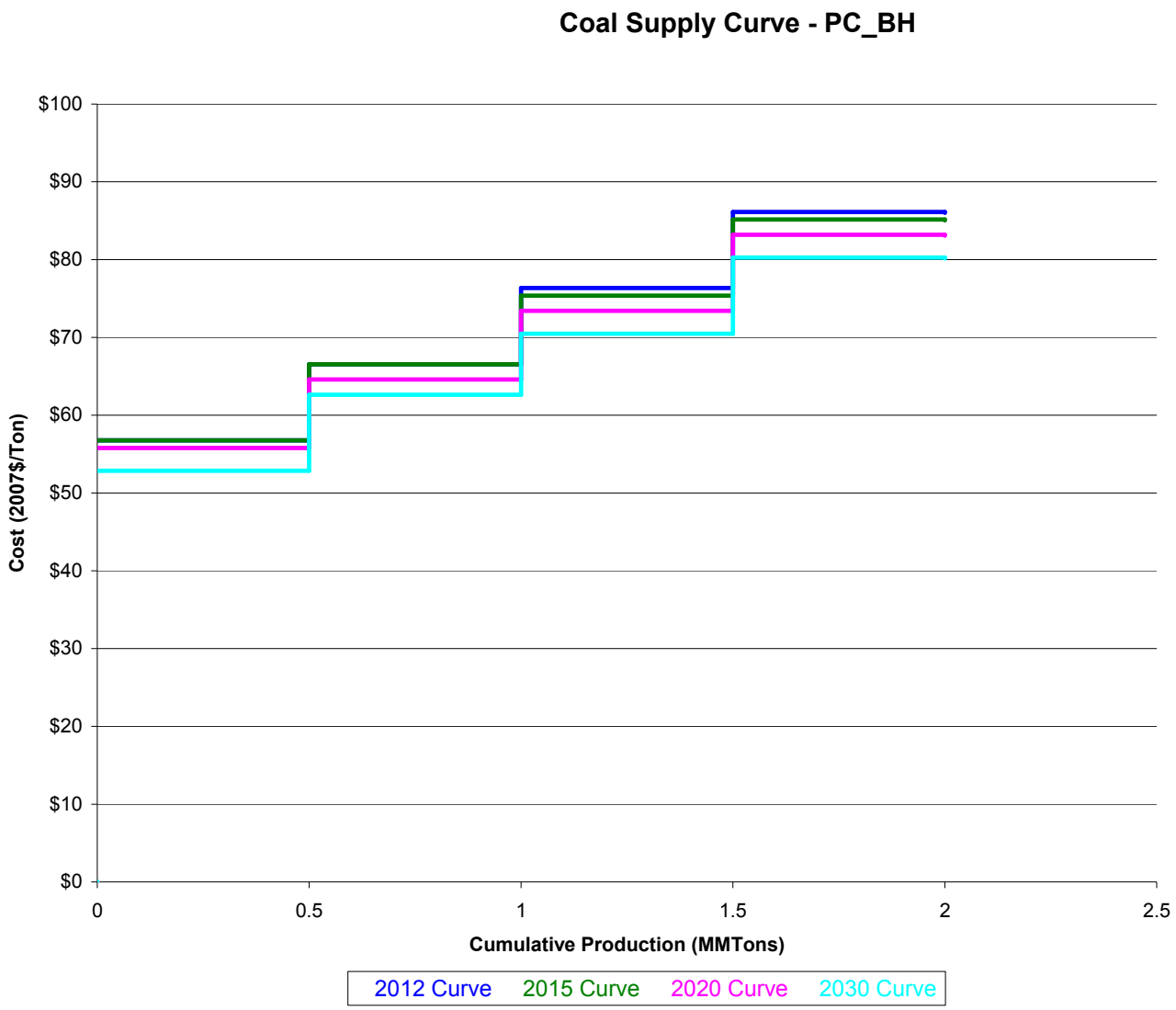

Coal Supply Curve - UT_BD
$50
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

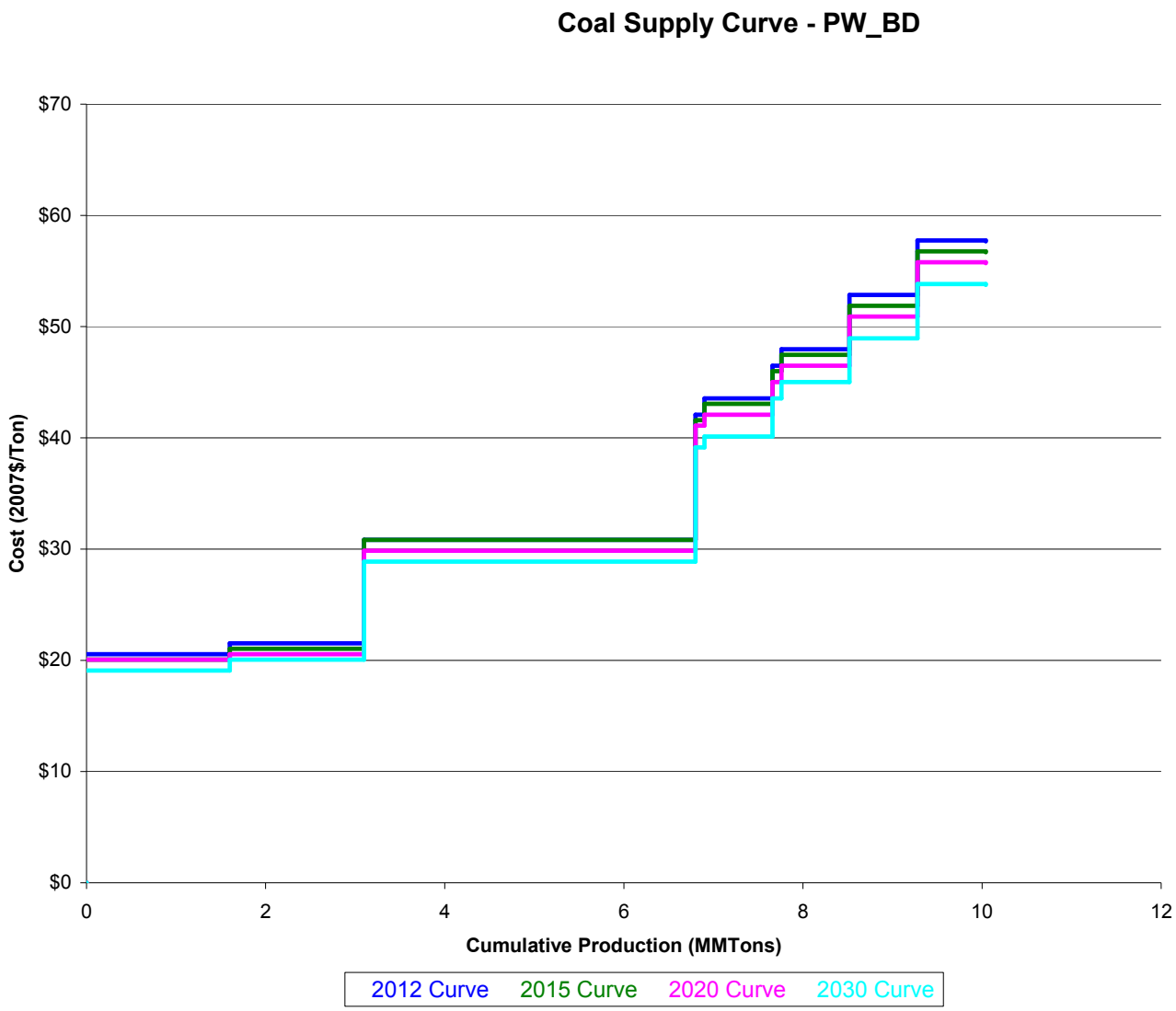

Coal Supply Curve - UT_BE
$40
$35
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

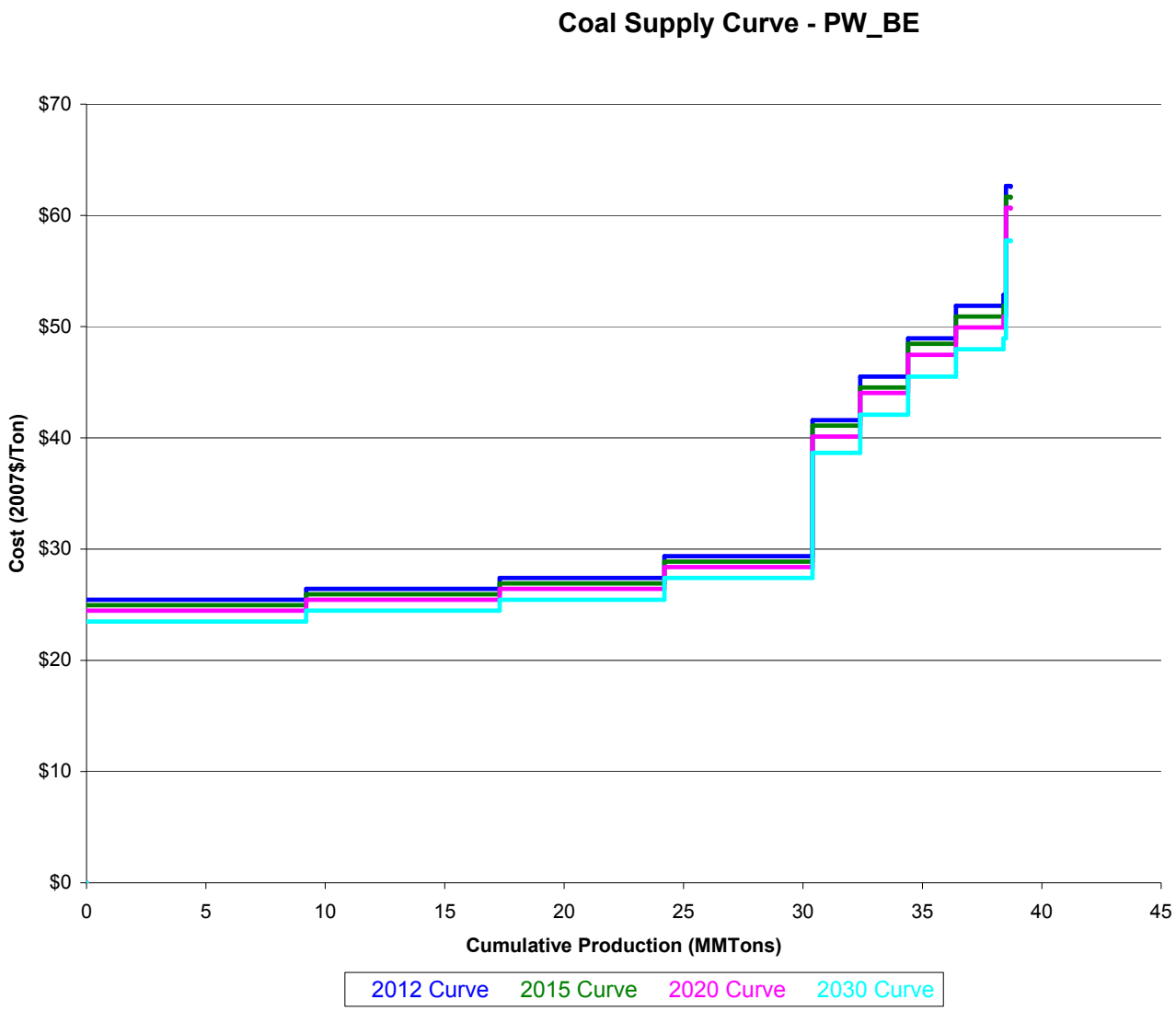

Coal Supply Curve - PC_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

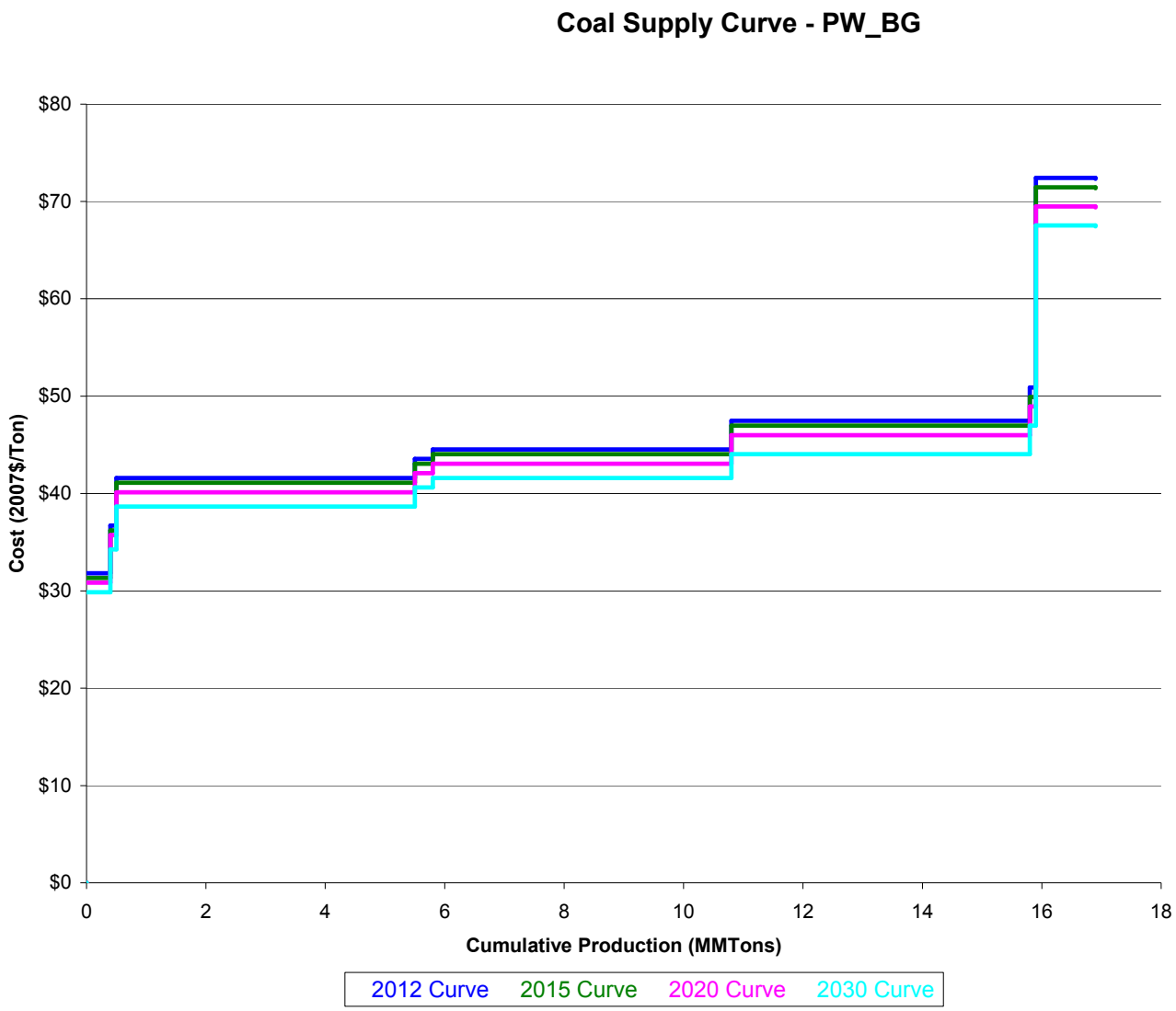

Coal Supply Curve - PC_BE
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

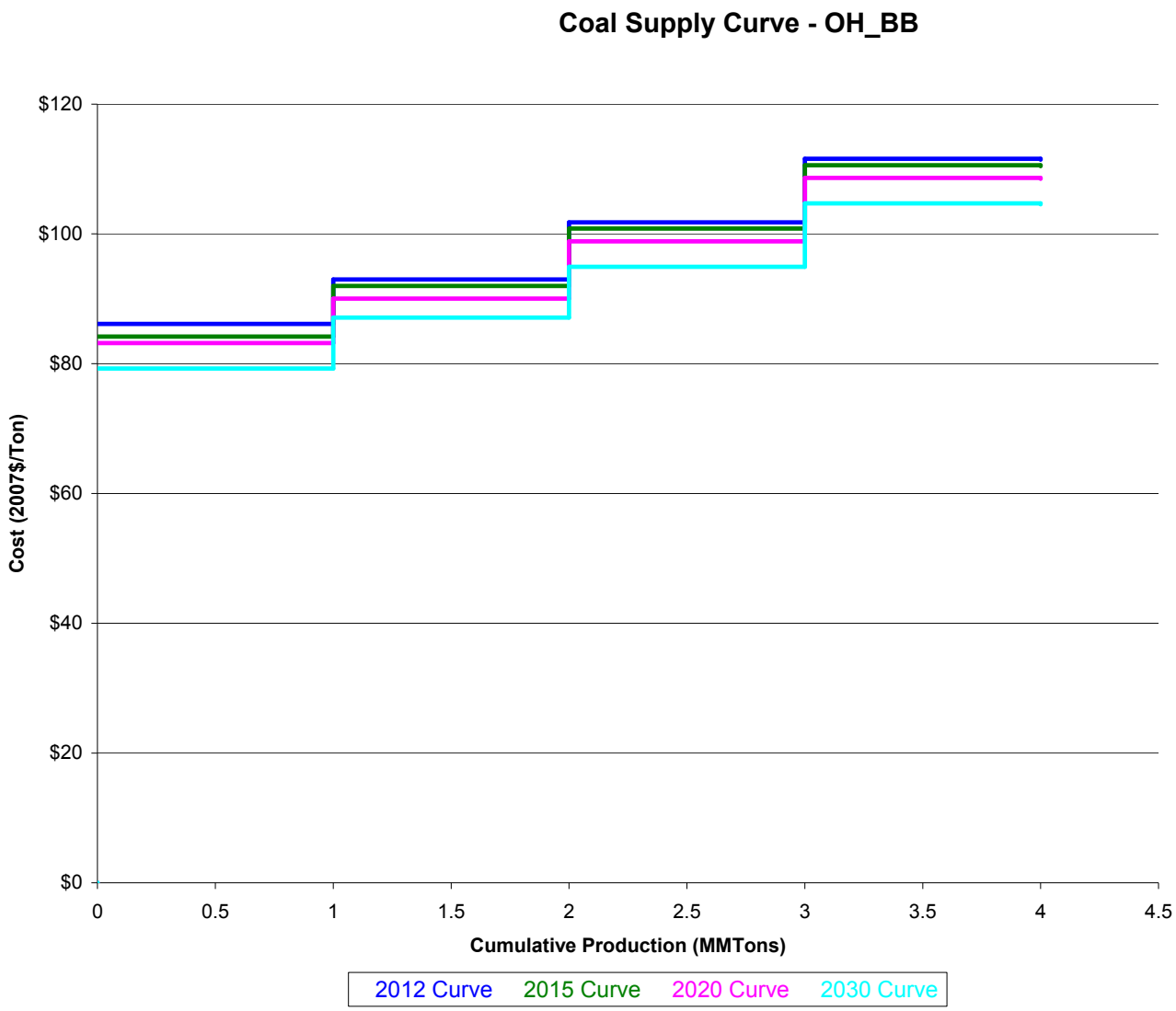

Coal Supply Curve - PC_BG
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

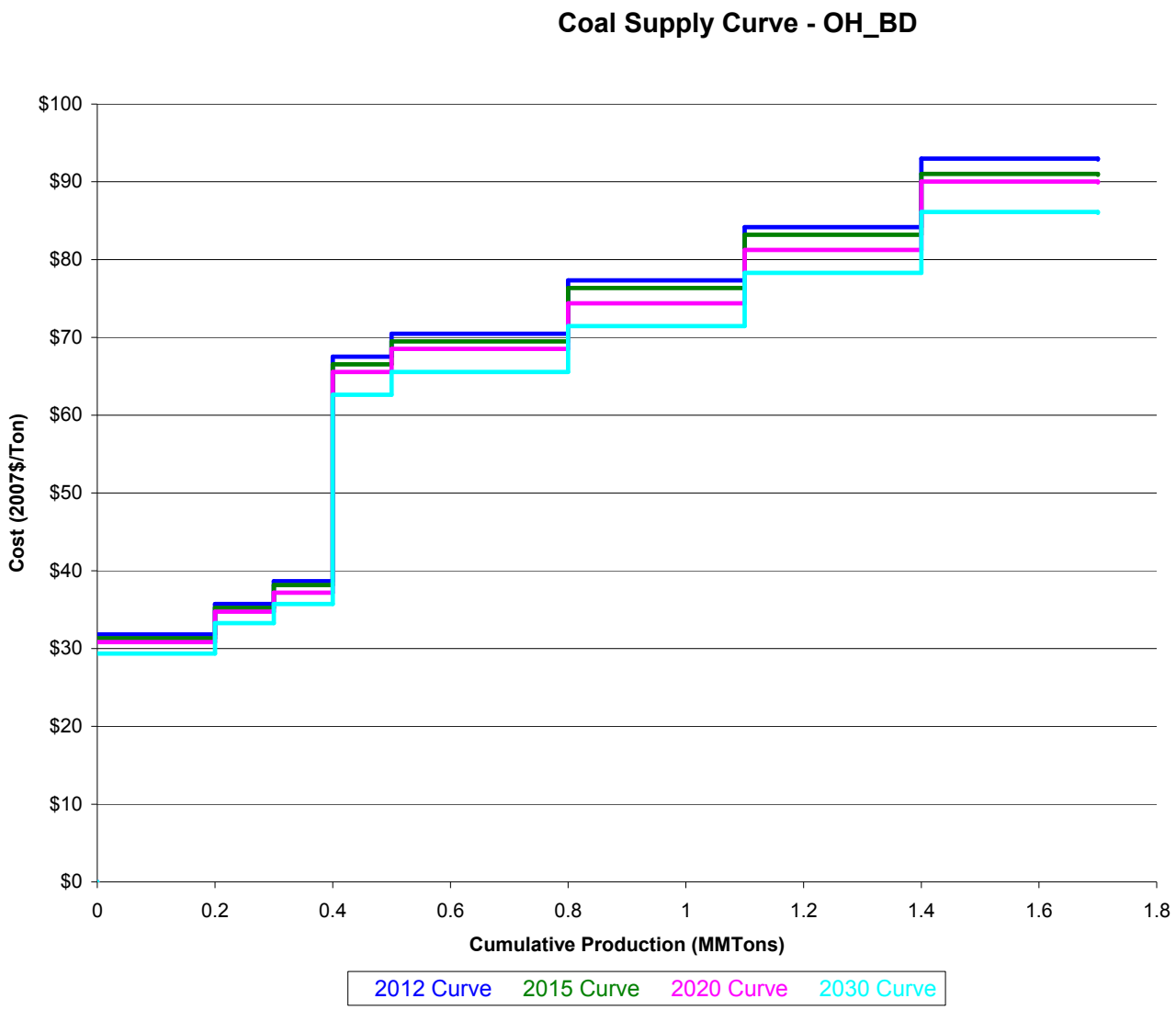

Coal Supply Curve - PC_BH
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

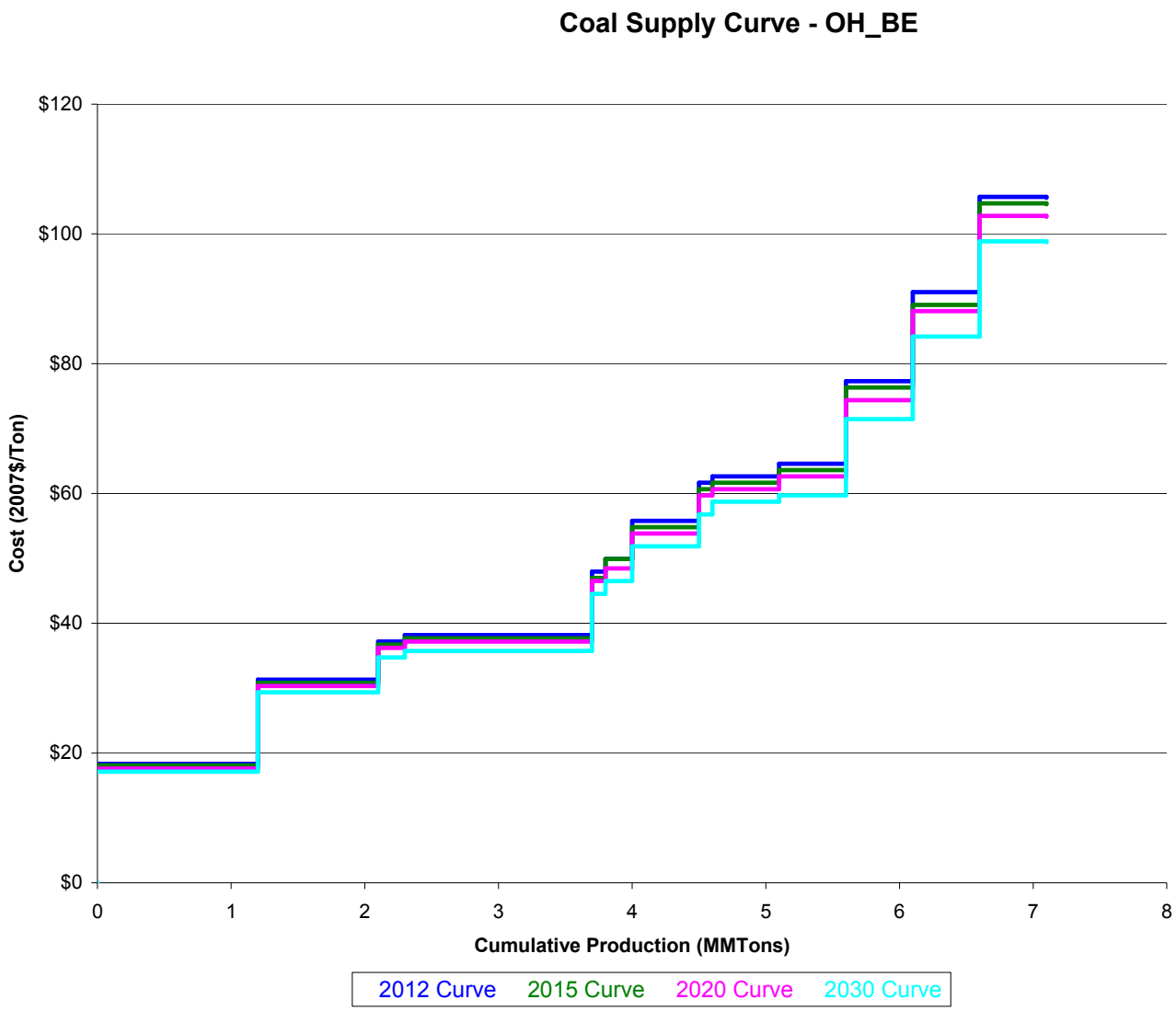

Coal Supply Curve - PW_BD
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

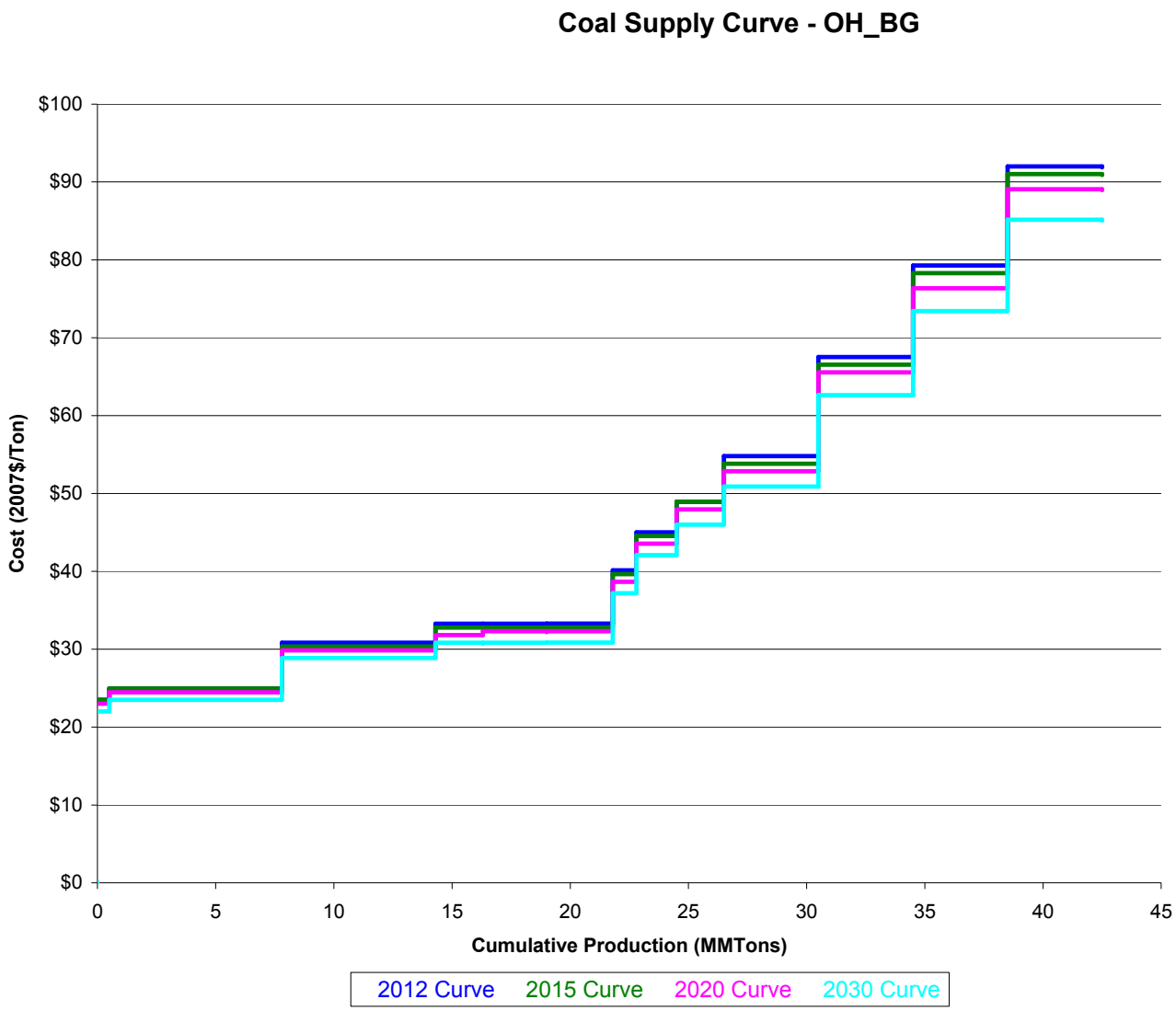

Coal Supply Curve - PW_BE
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

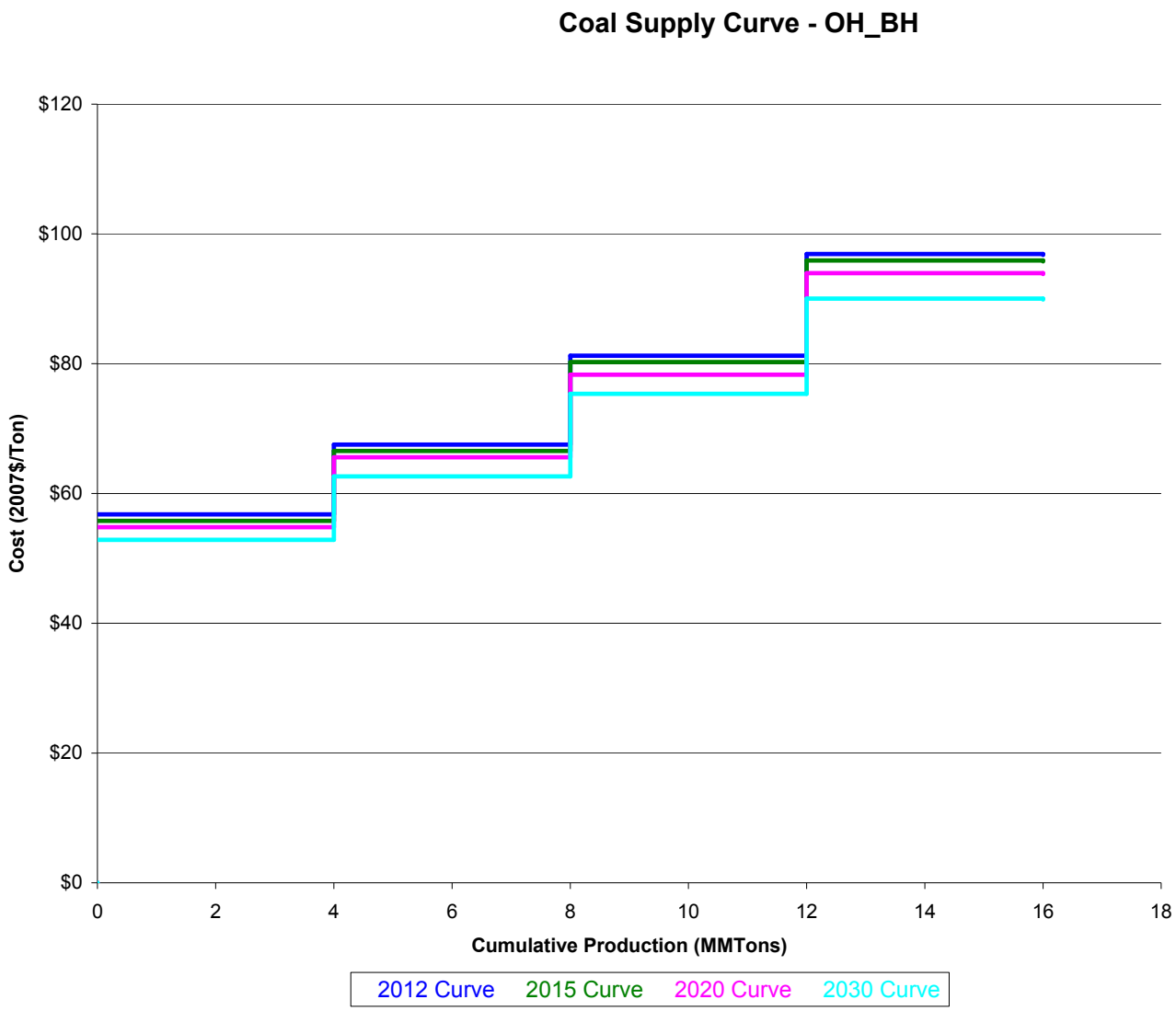

Coal Supply Curve - PW_BG
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

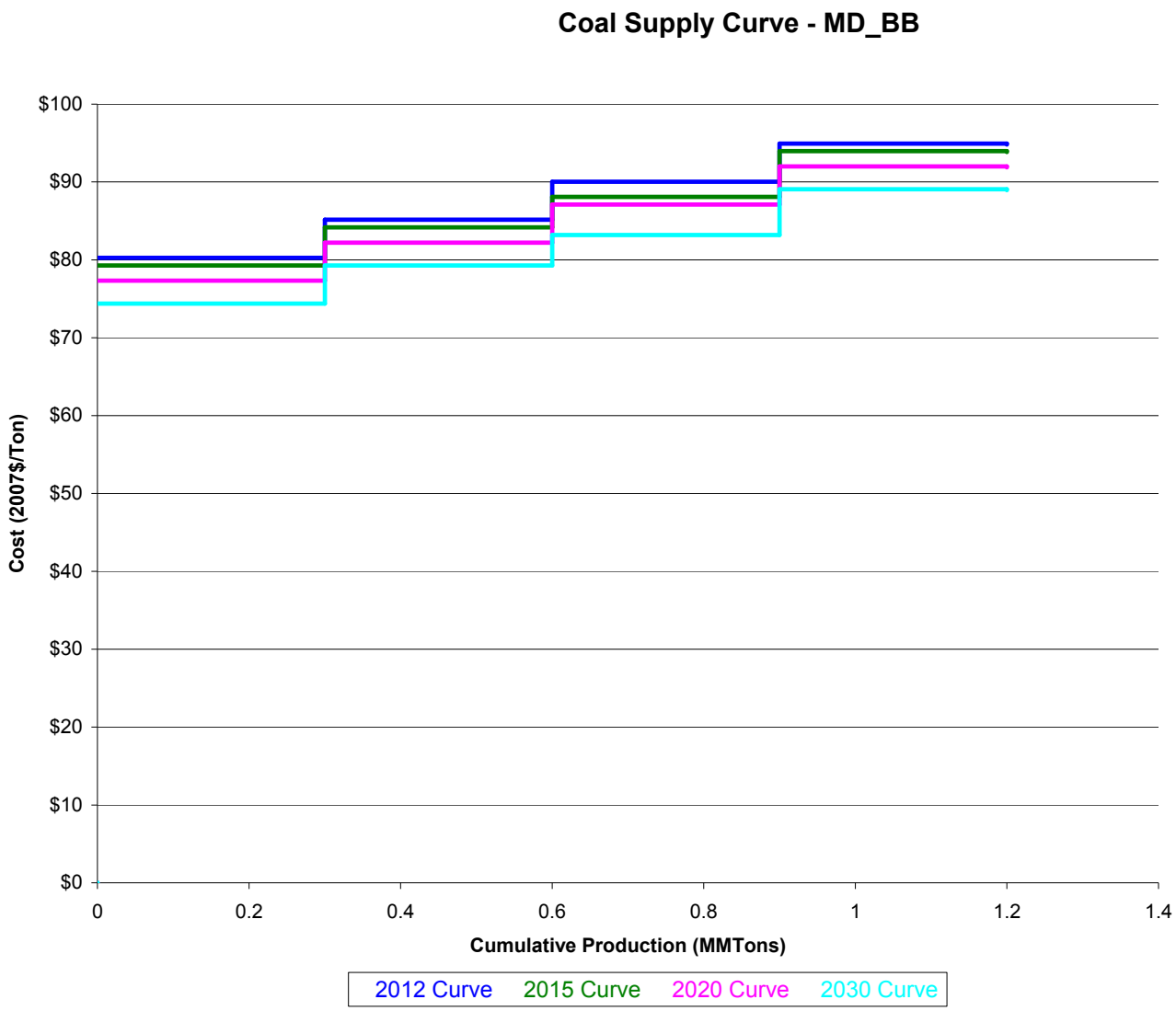

Coal Supply Curve - OH_BB
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

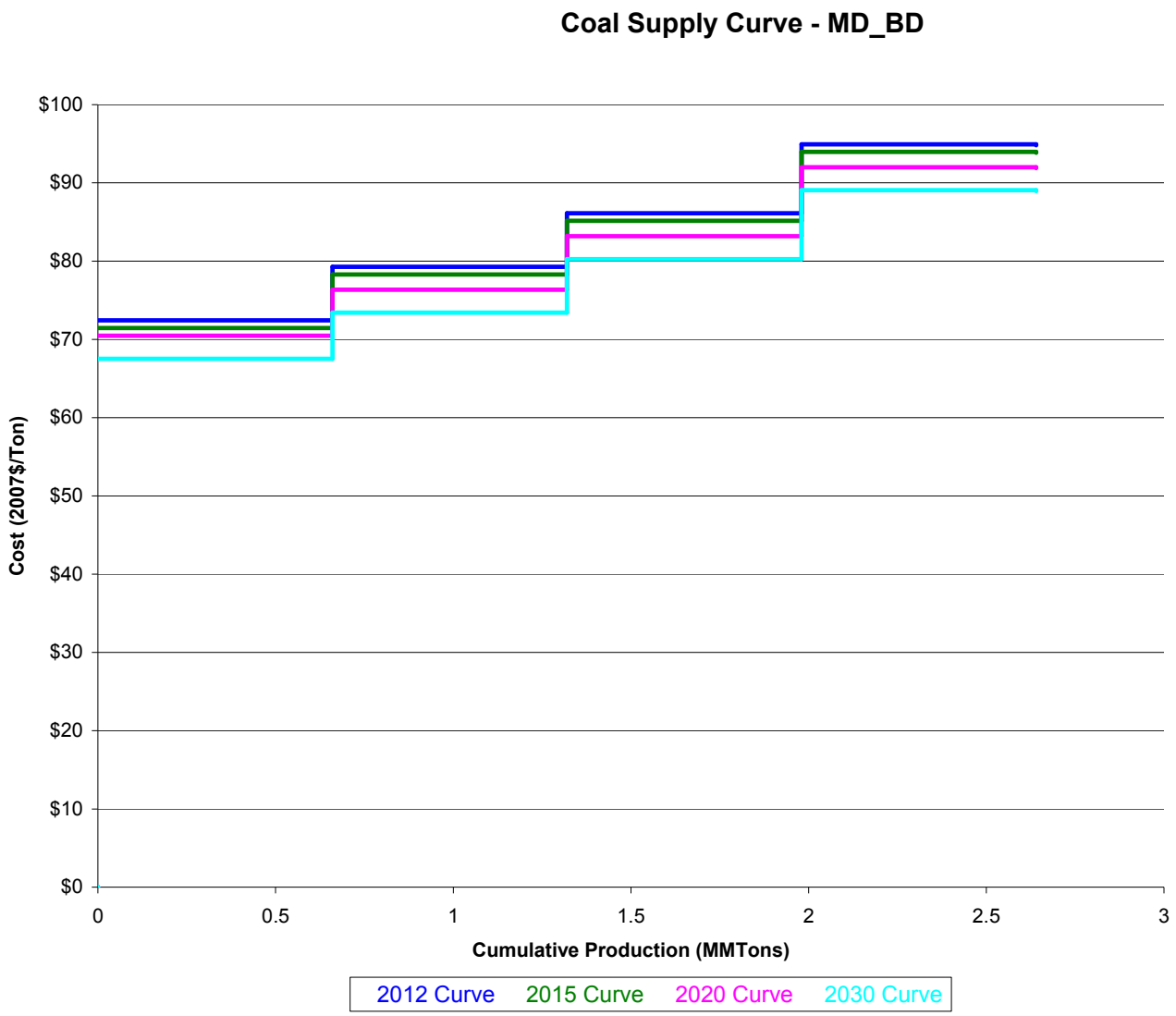

Coal Supply Curve - OH_BD
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

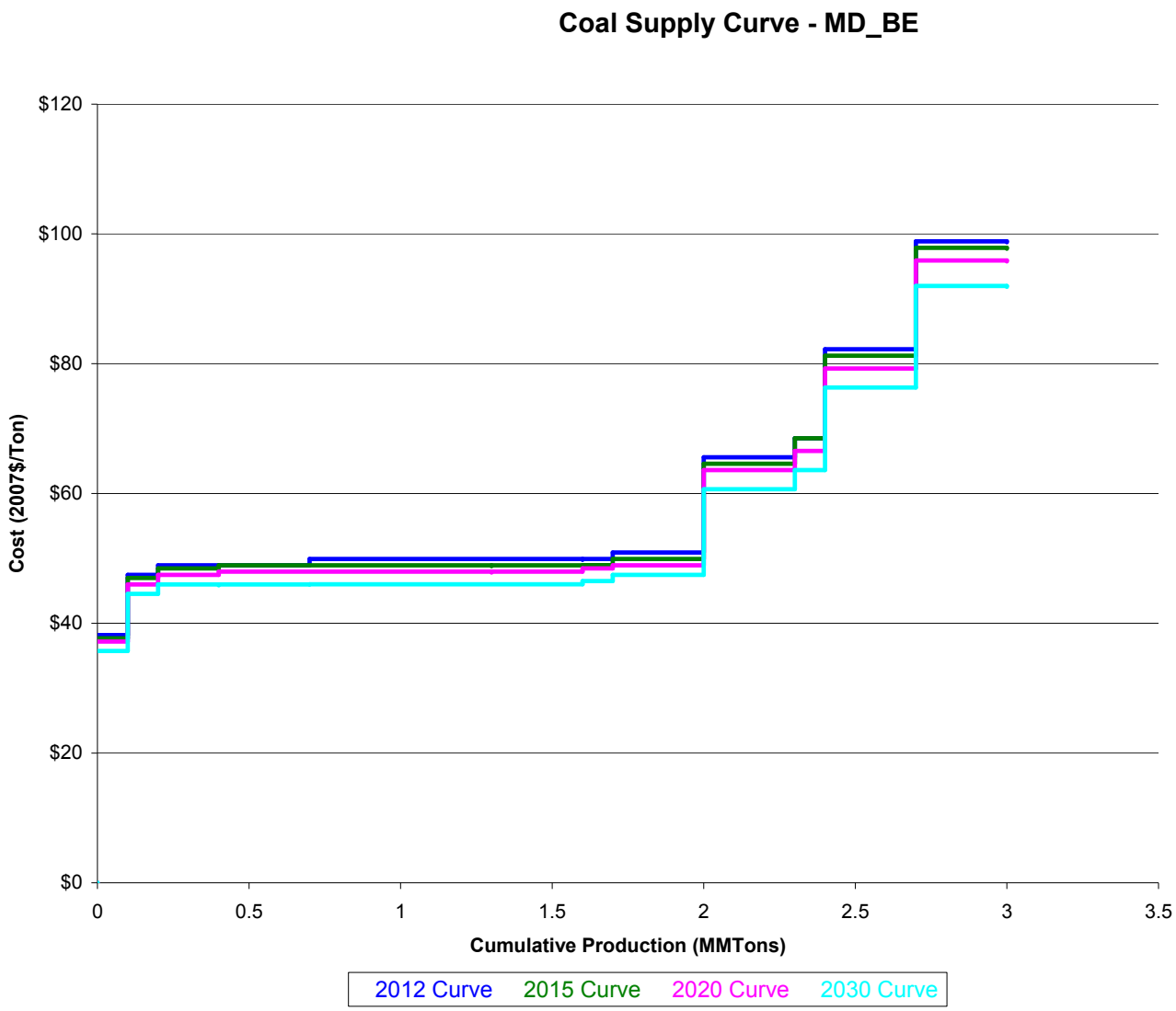

Coal Supply Curve - OH_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

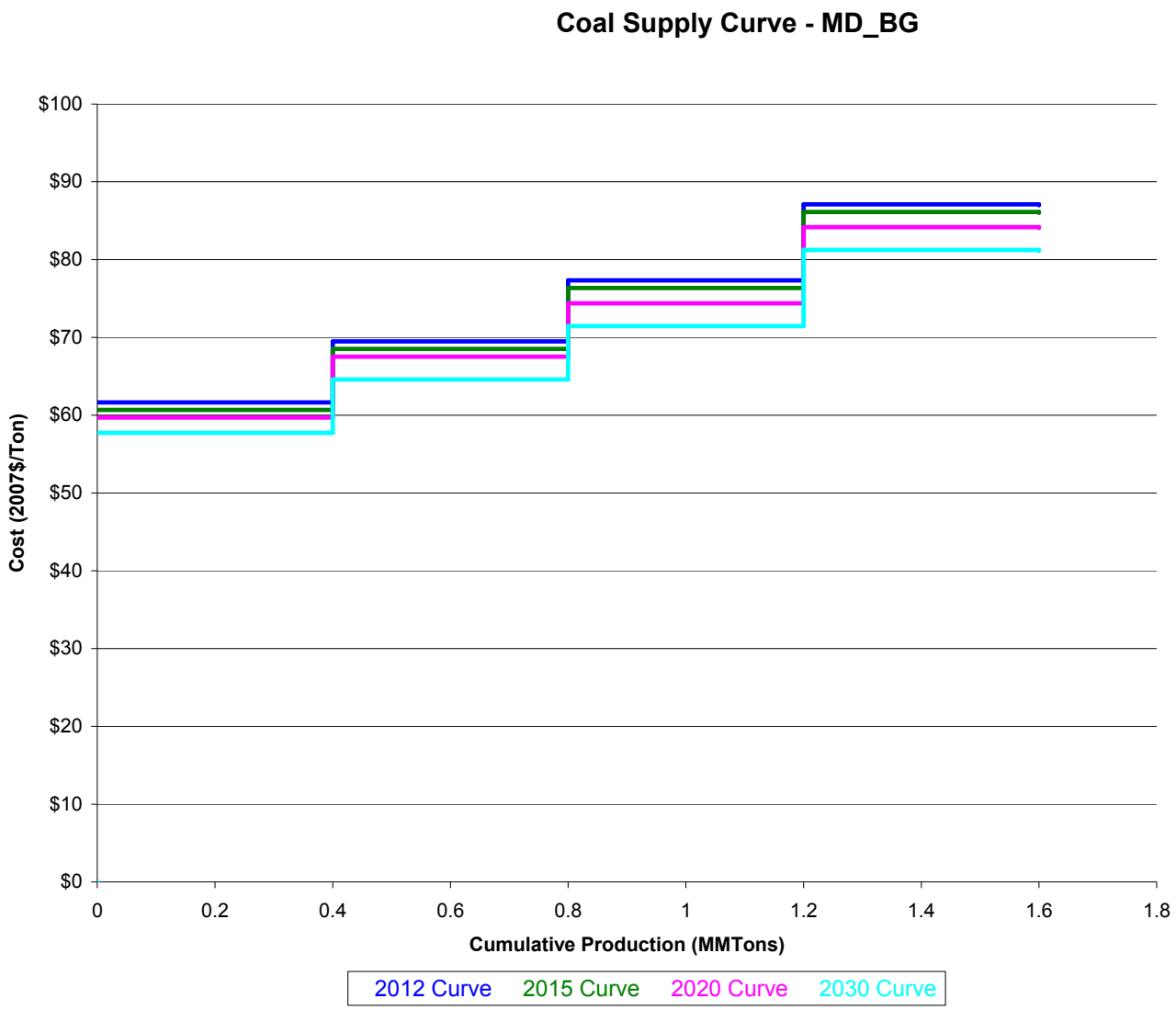

Coal Supply Curve - OH_BG
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

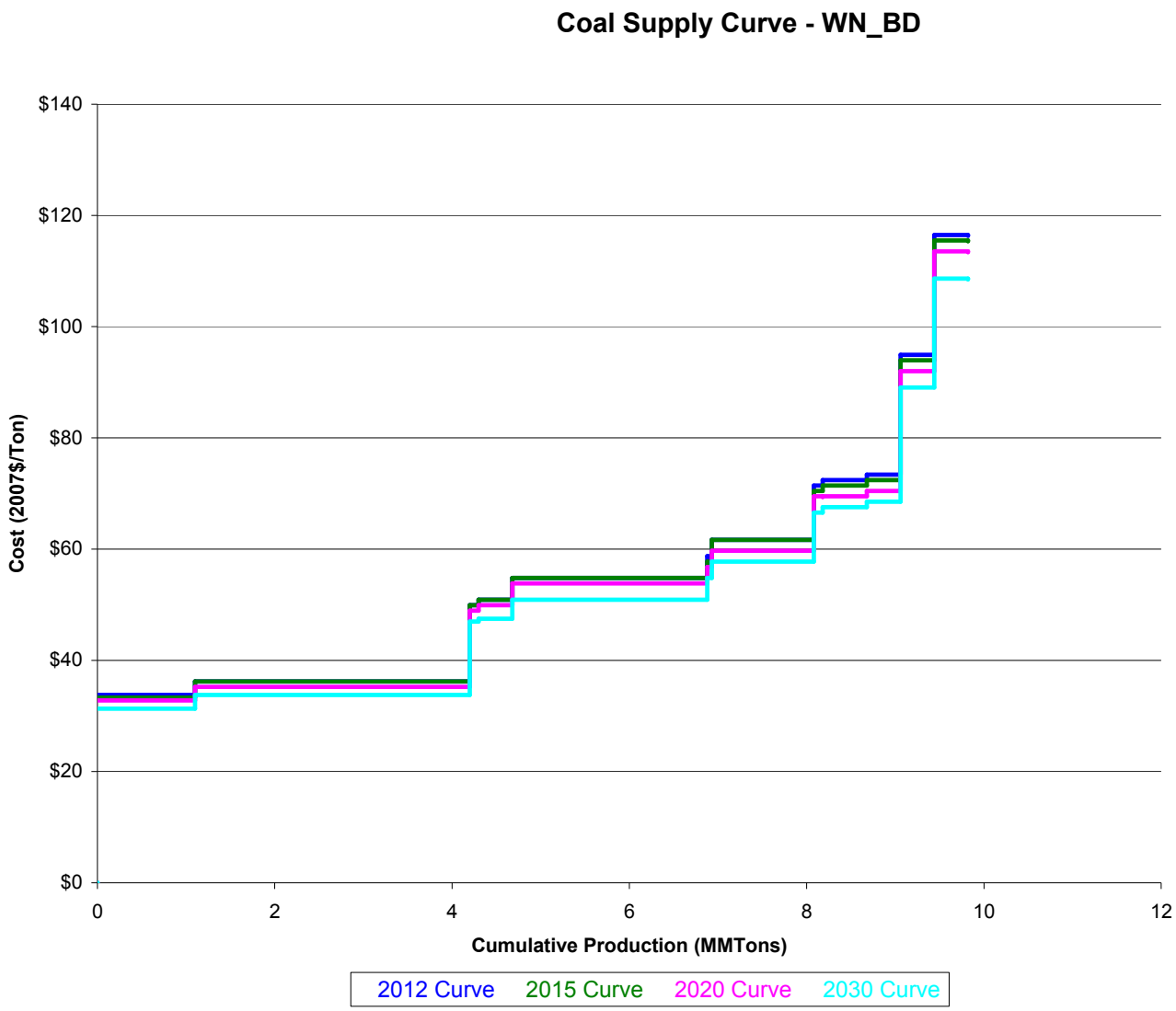

Coal Supply Curve - OH_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

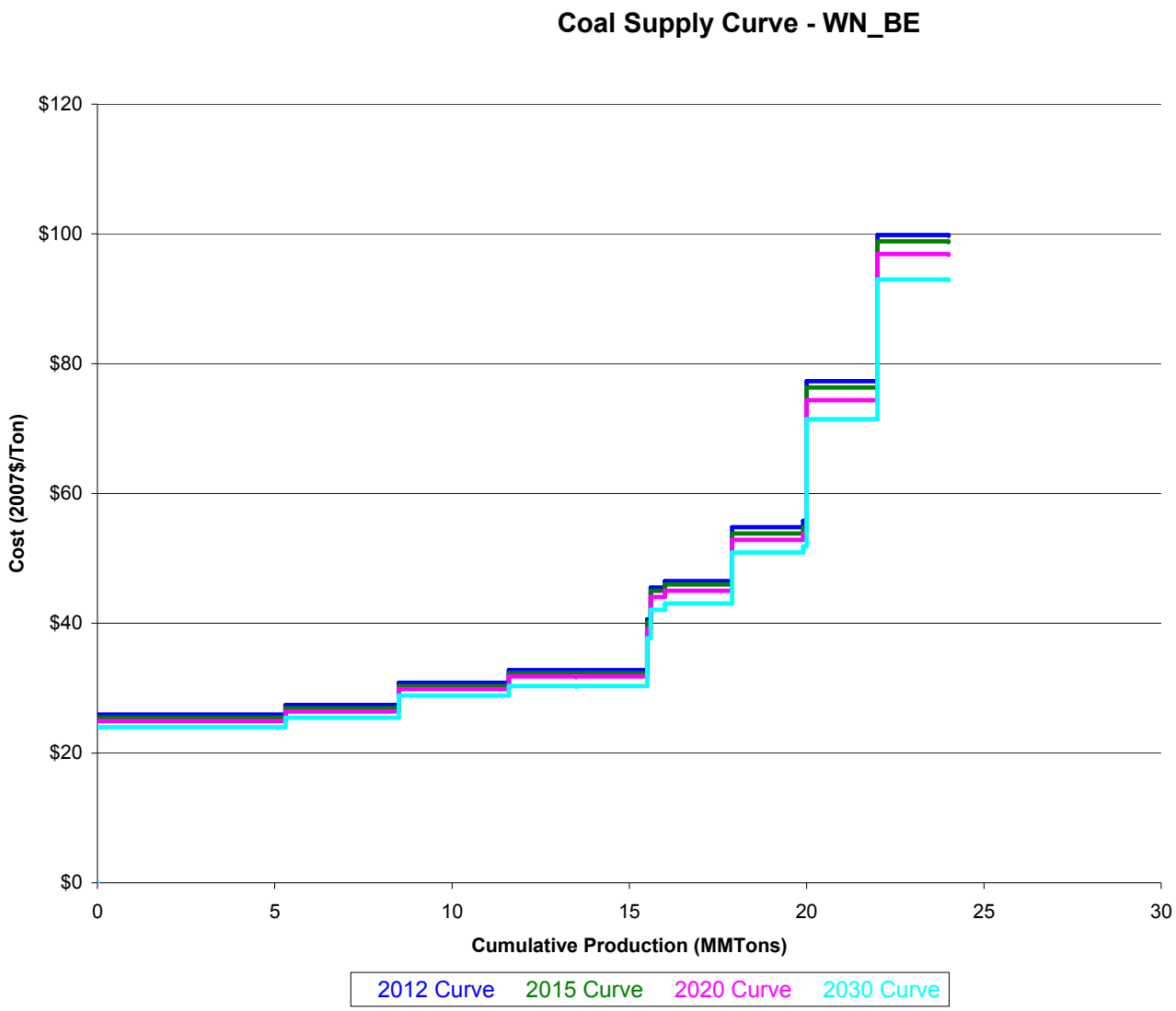

Coal Supply Curve - MD_BB
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

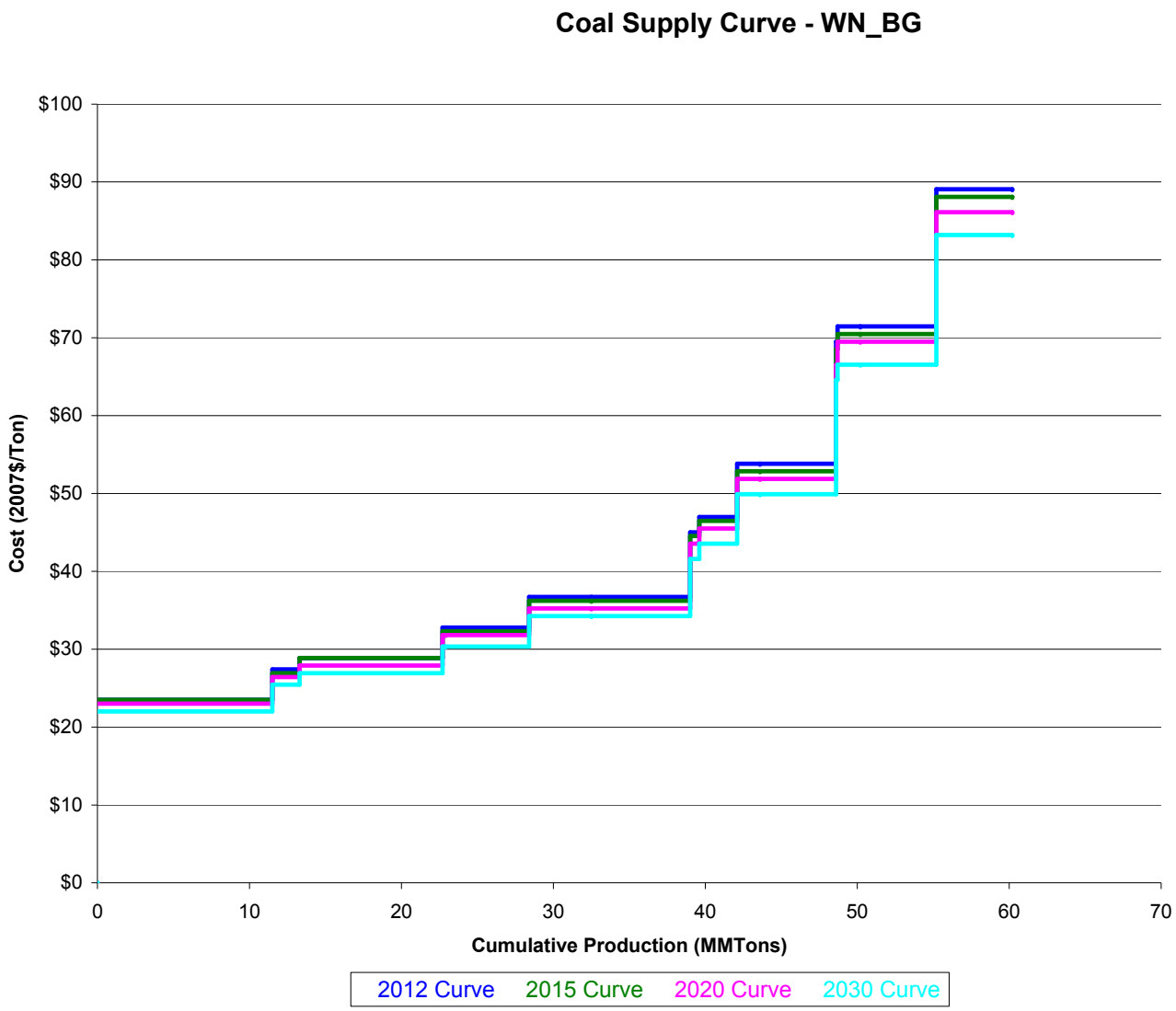

Coal Supply Curve - MD_BD
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

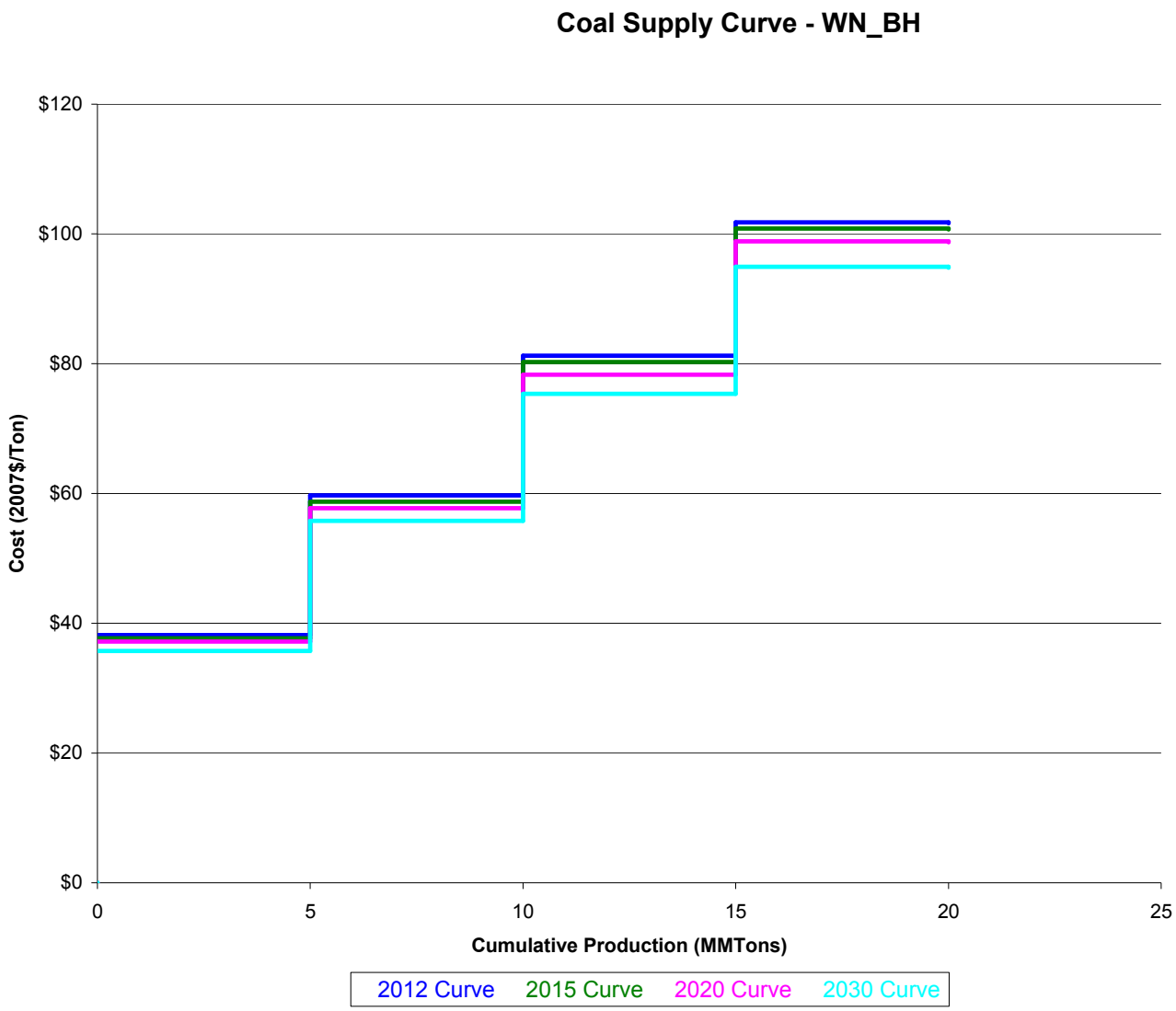

Coal Supply Curve - MD_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

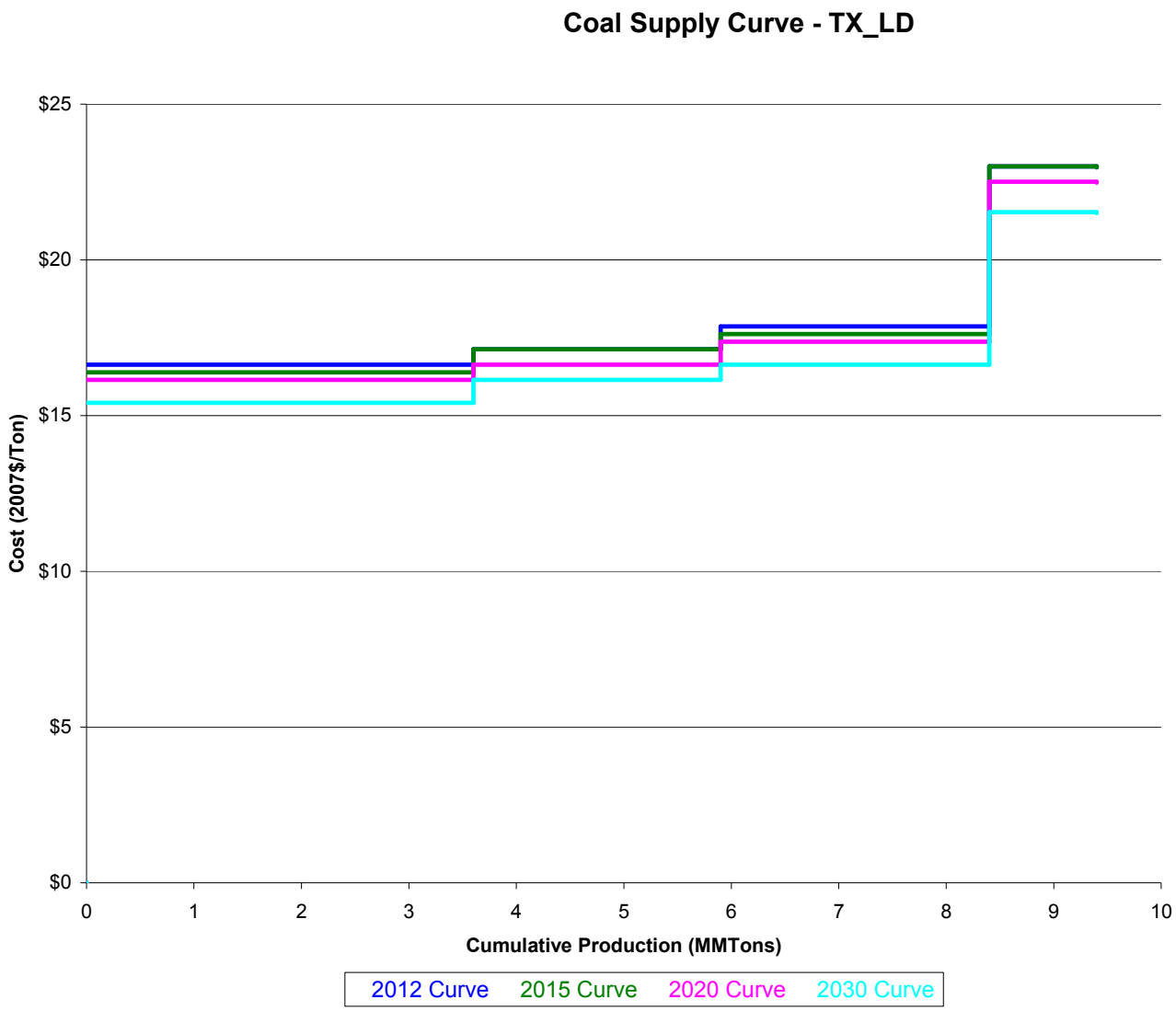

Coal Supply Curve - MD_BG
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

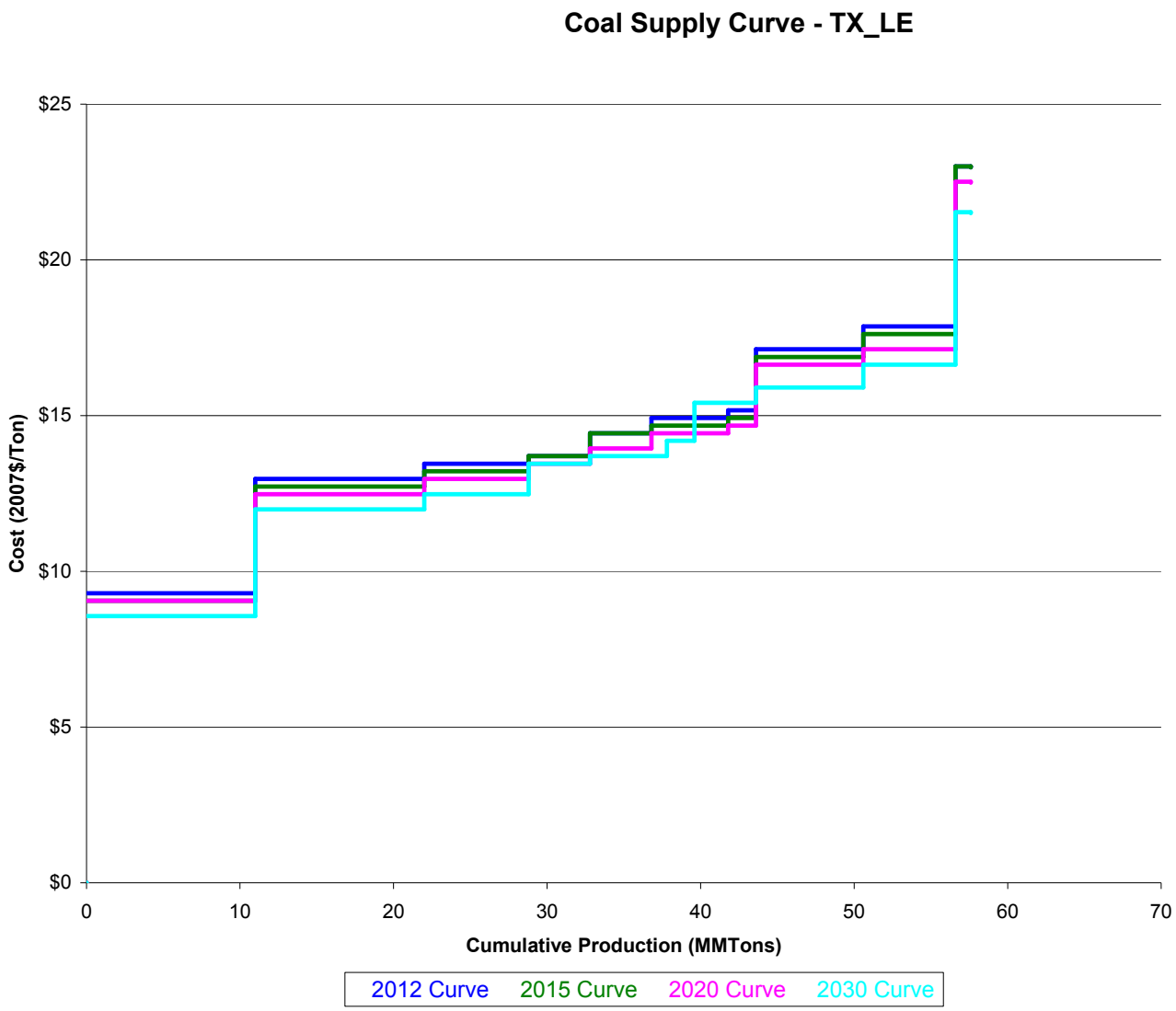

Coal Supply Curve - WN_BD
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

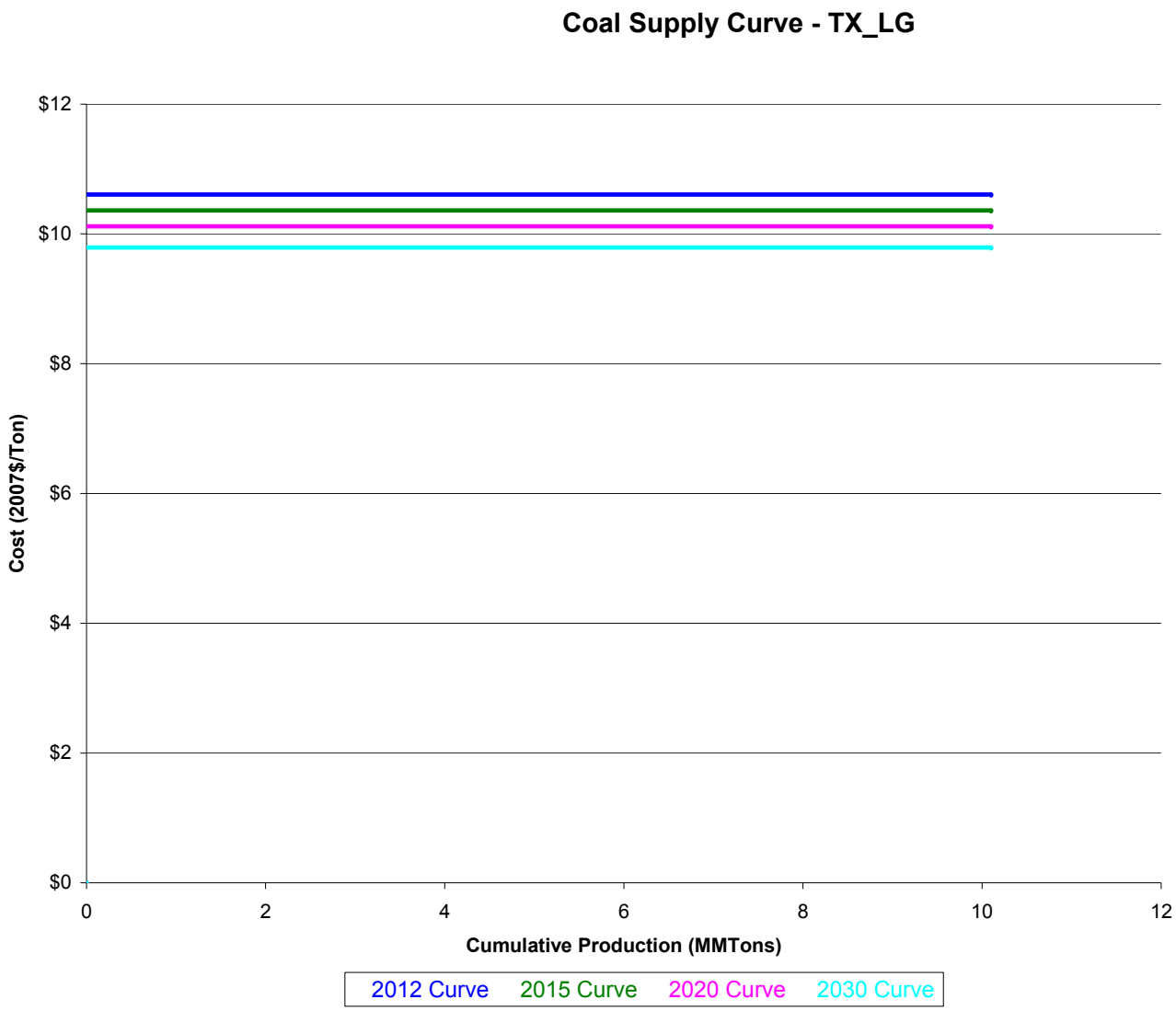

Coal Supply Curve - WN_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

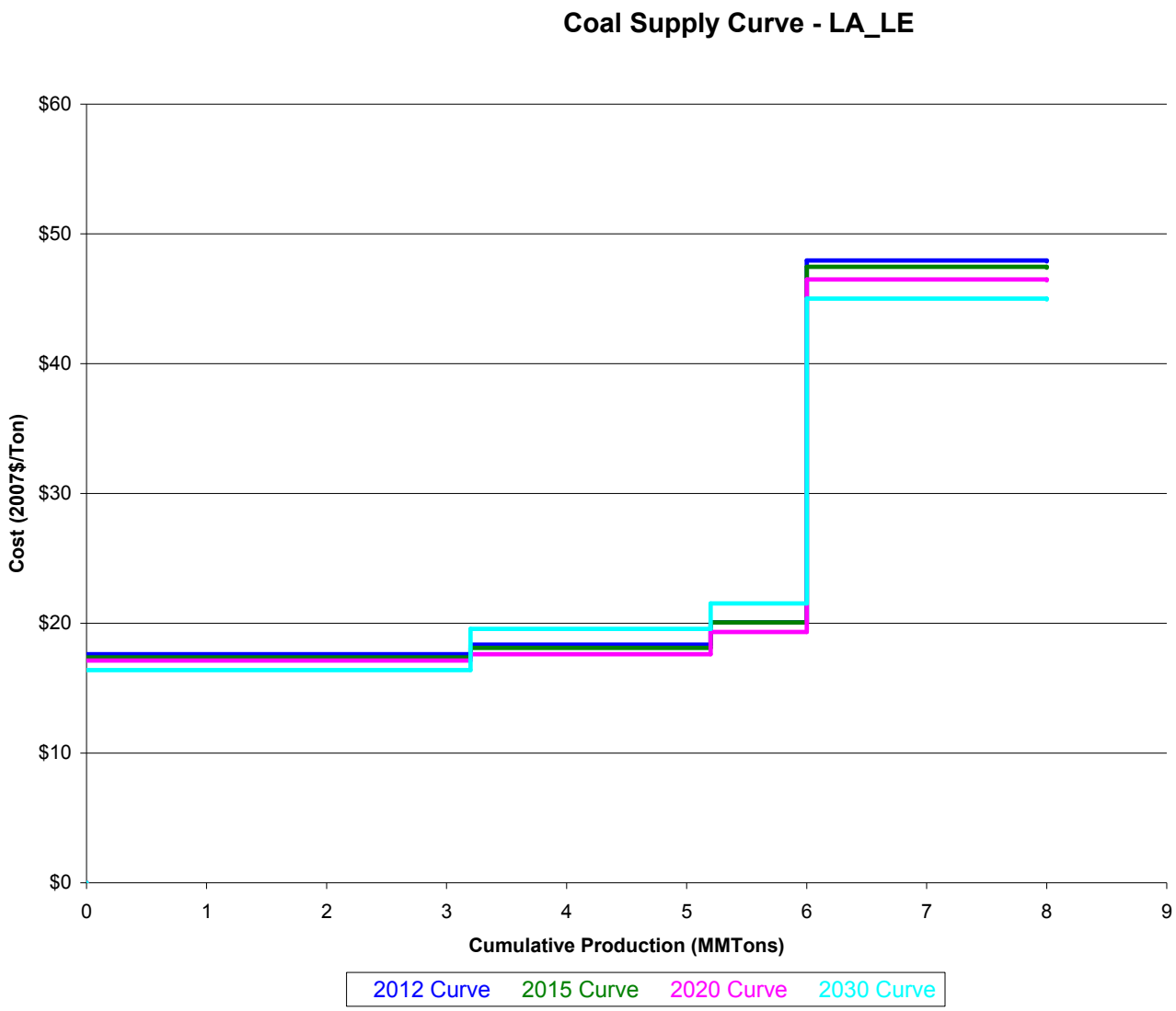

Coal Supply Curve - WN_BG
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

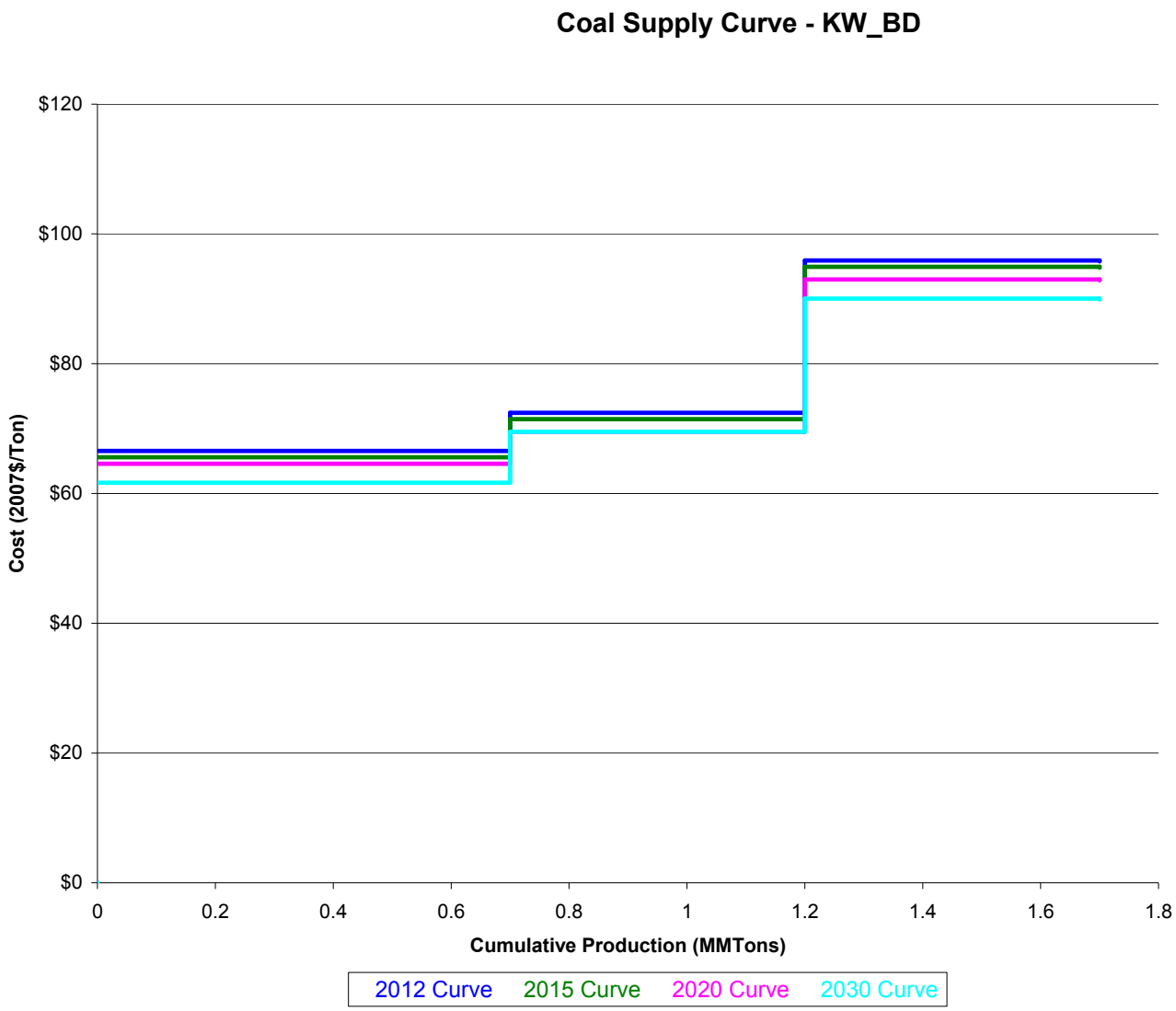

Coal Supply Curve - WN_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

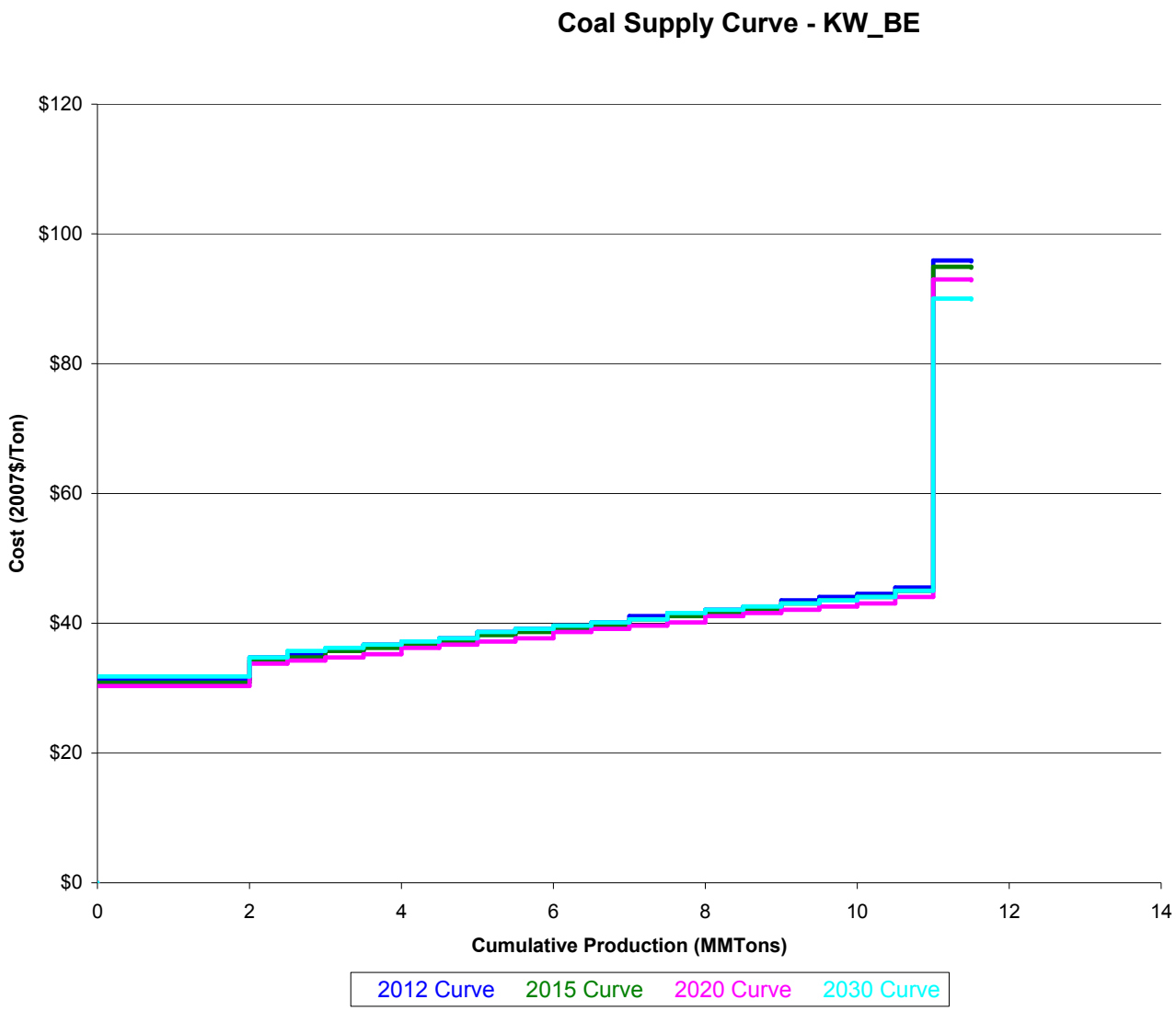

Coal Supply Curve - TX_LD
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
10
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

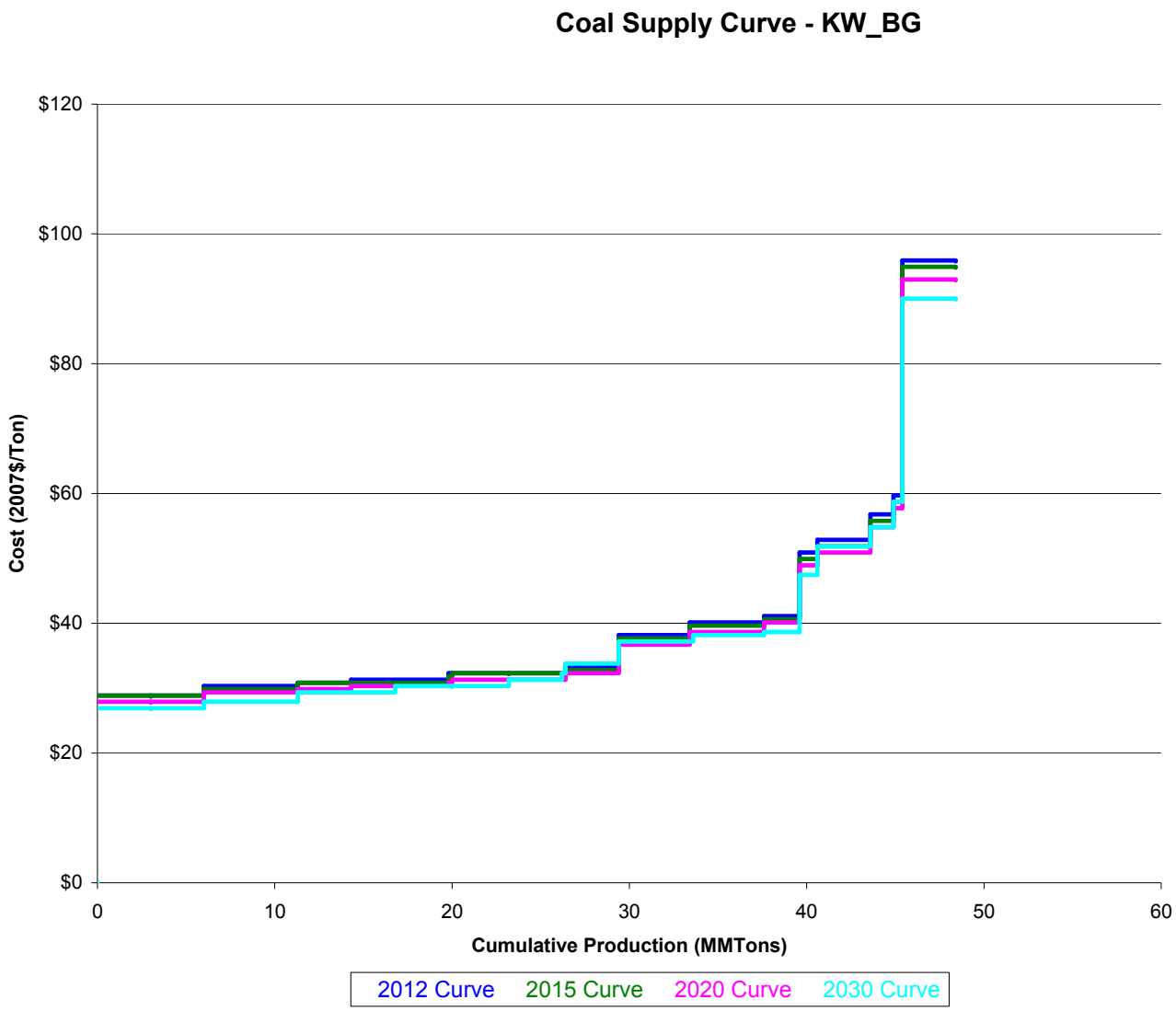

Coal Supply Curve - TX_LE
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

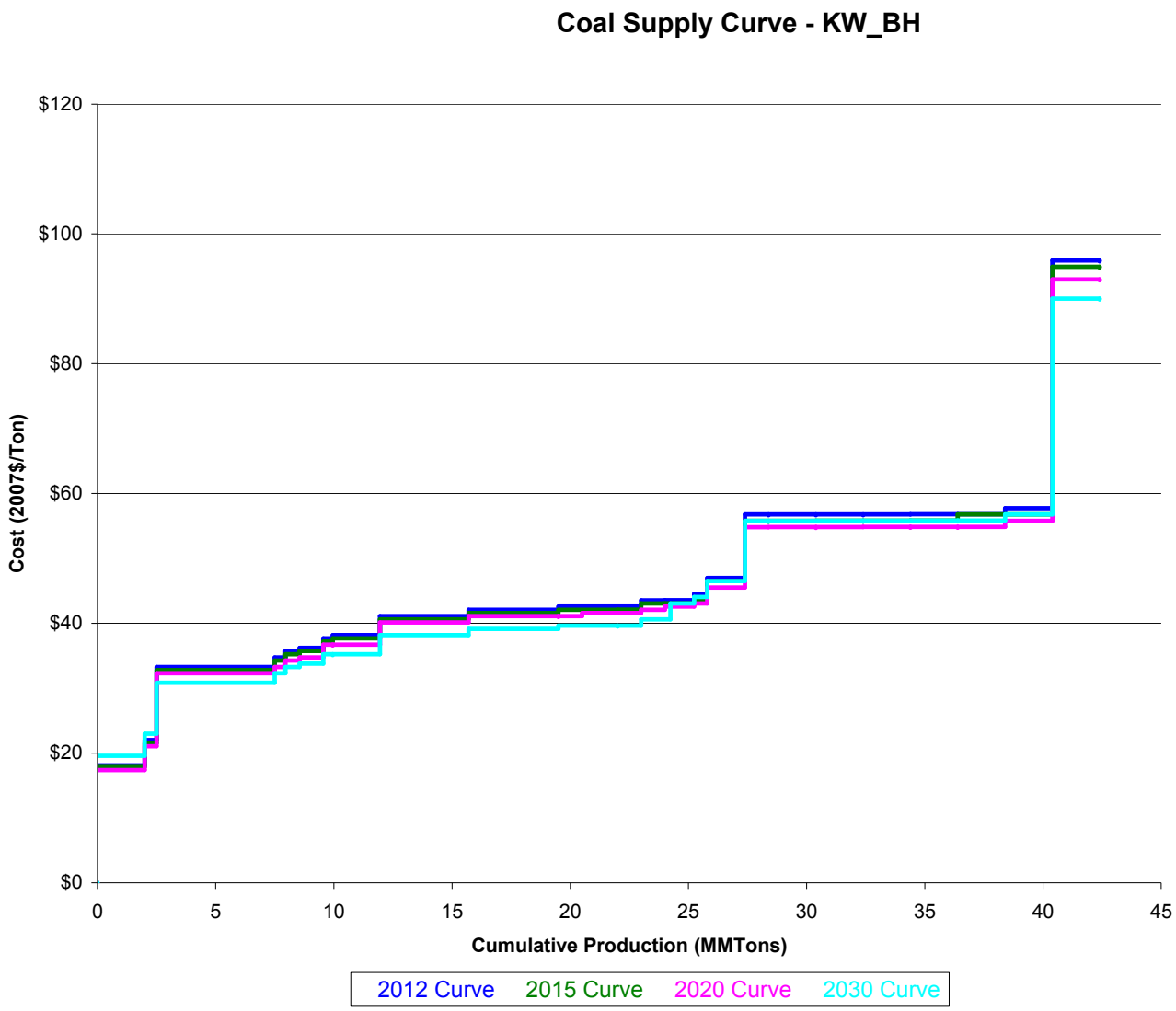

Coal Supply Curve - TX_LG
$12
$10
$8
$6
$4
$2
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

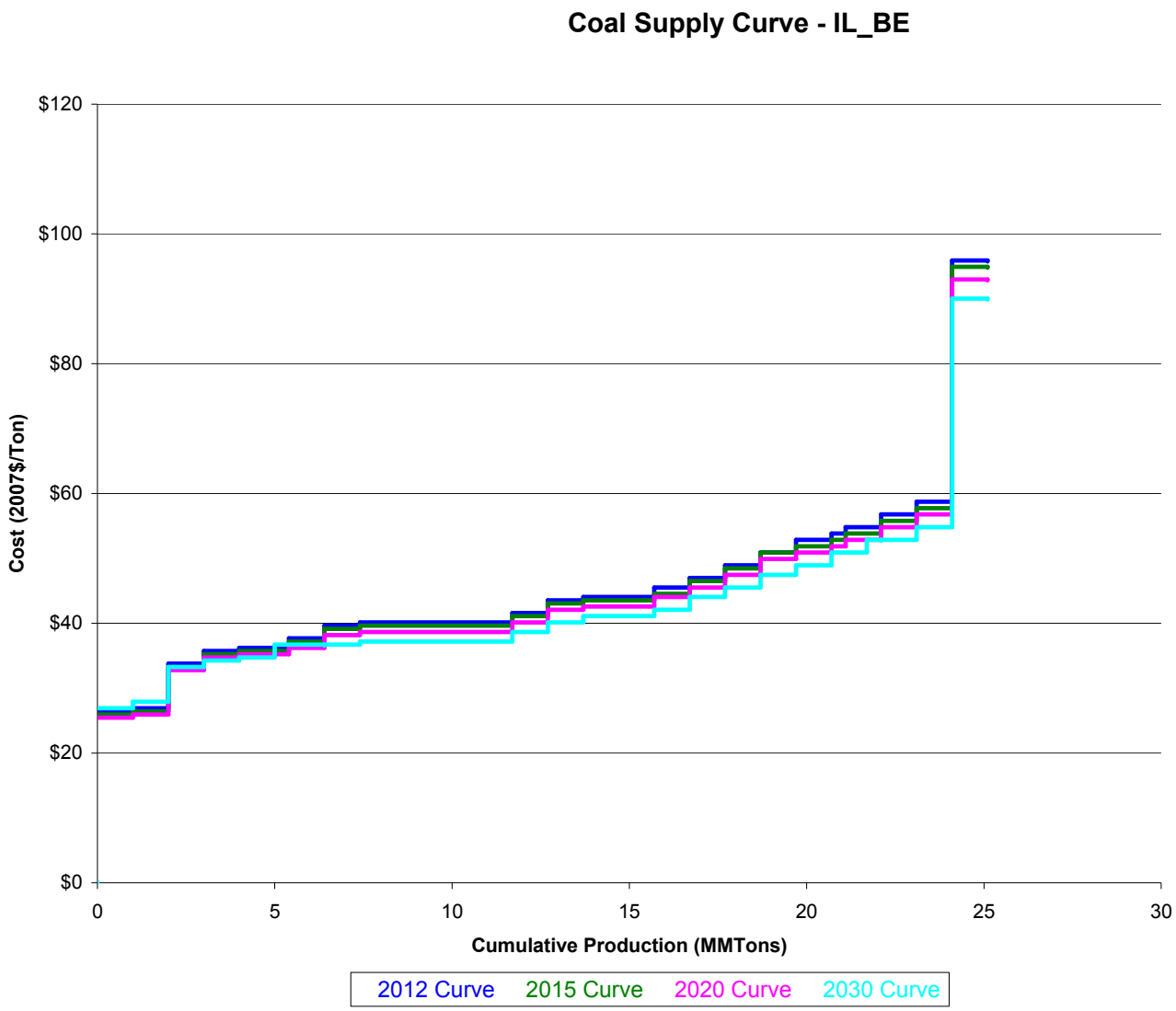

Coal Supply Curve - LA_LE
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

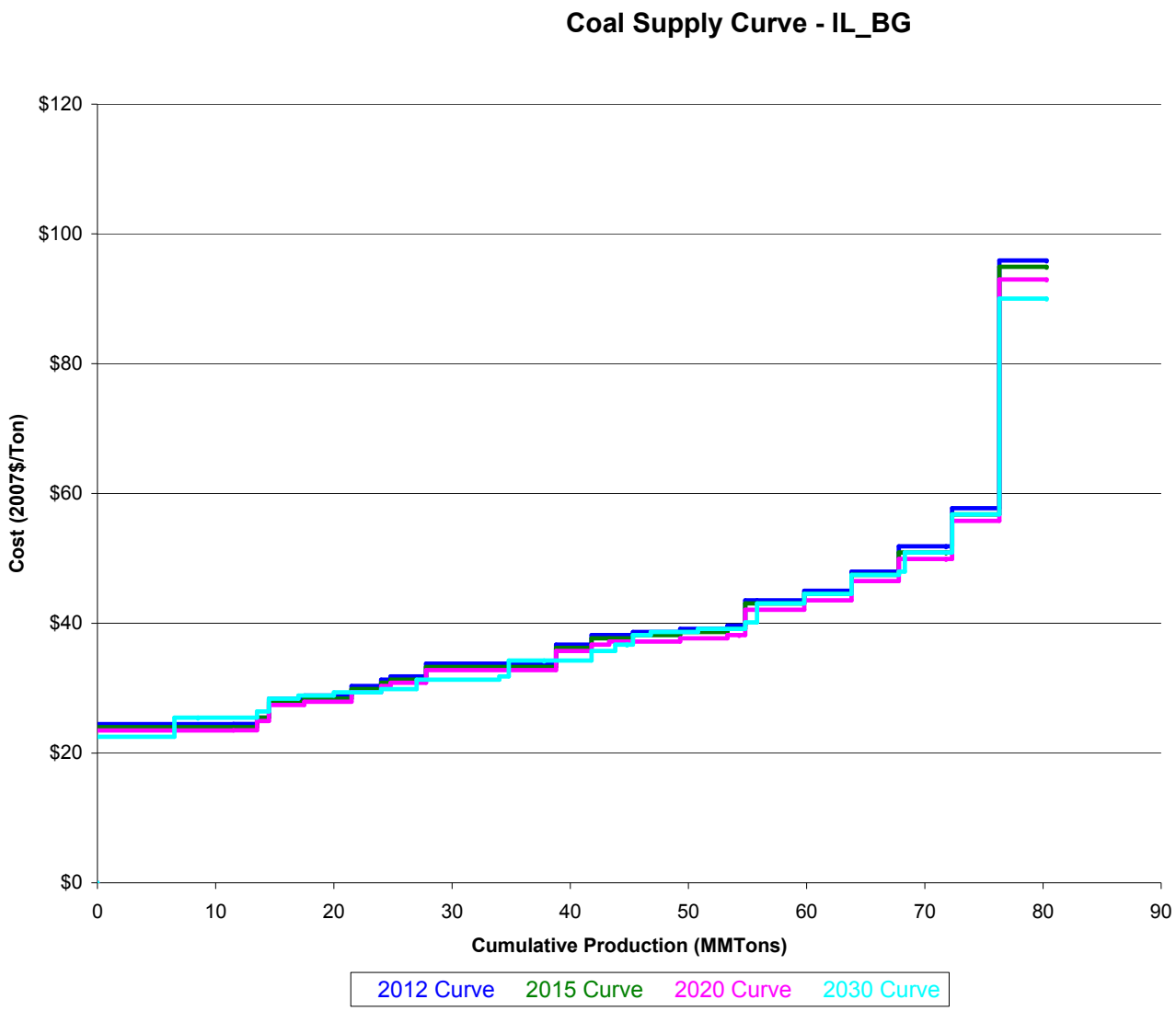

Coal Supply Curve - KW_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

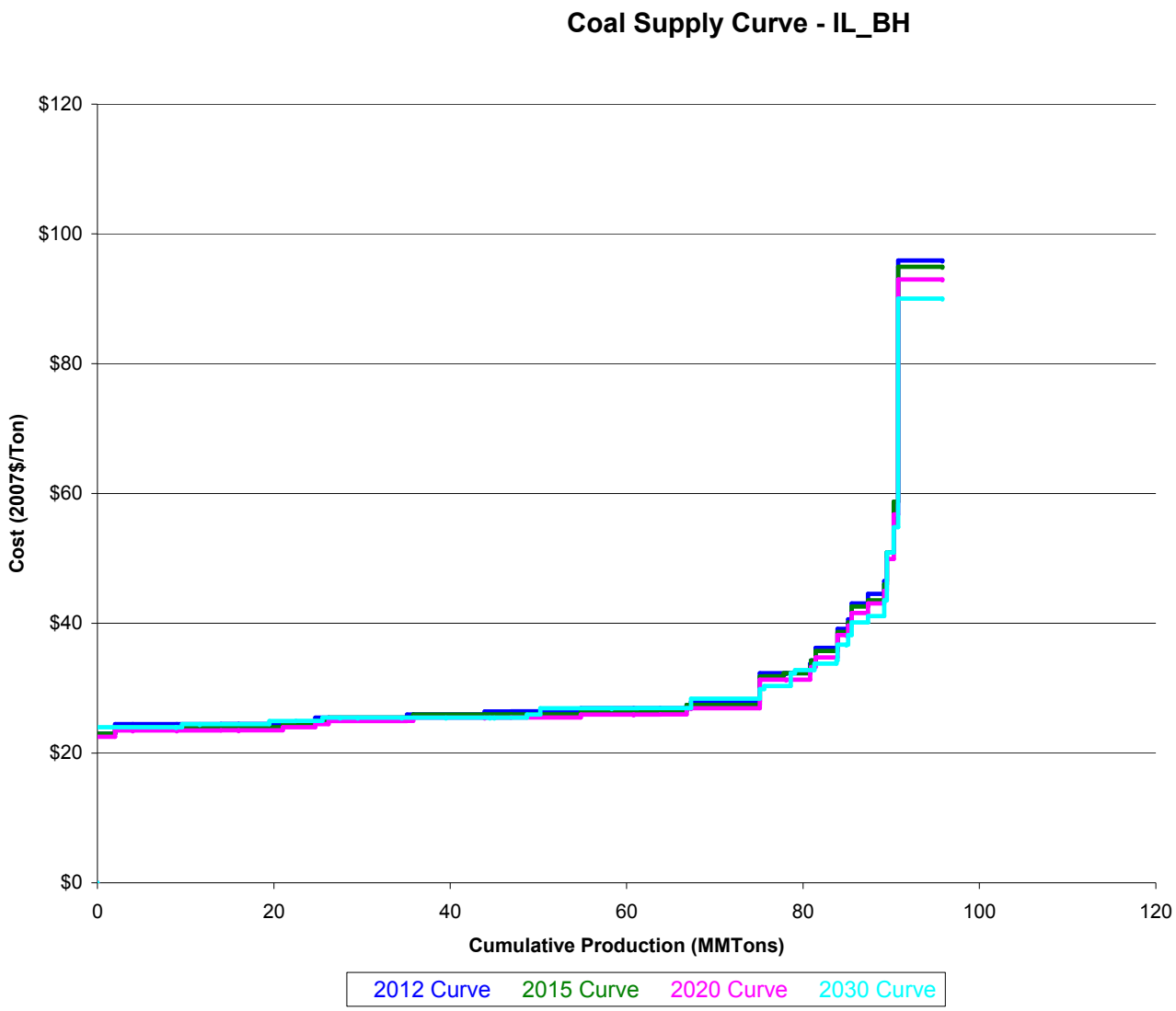

Coal Supply Curve - KW_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

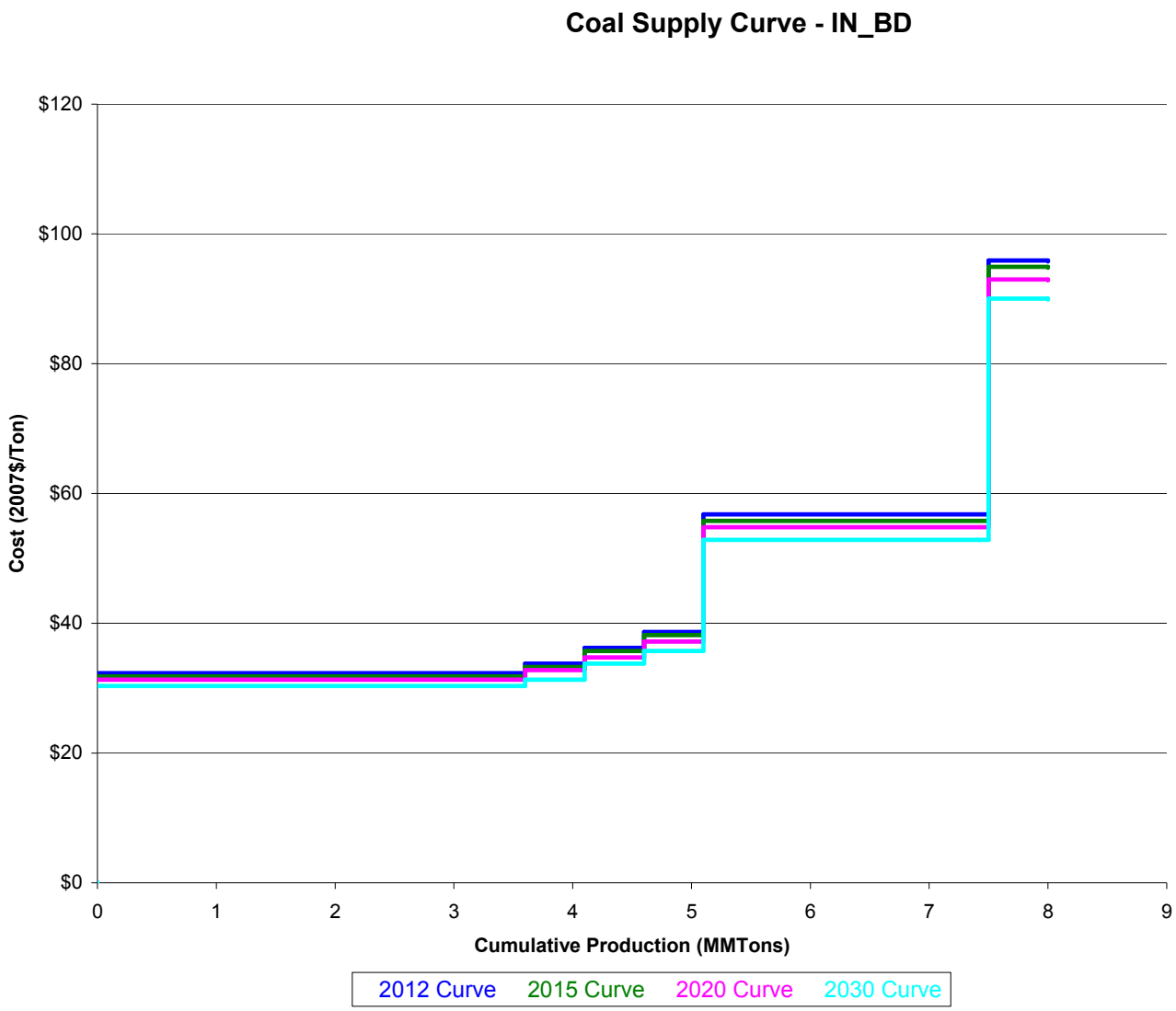

Coal Supply Curve - KW_BG
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

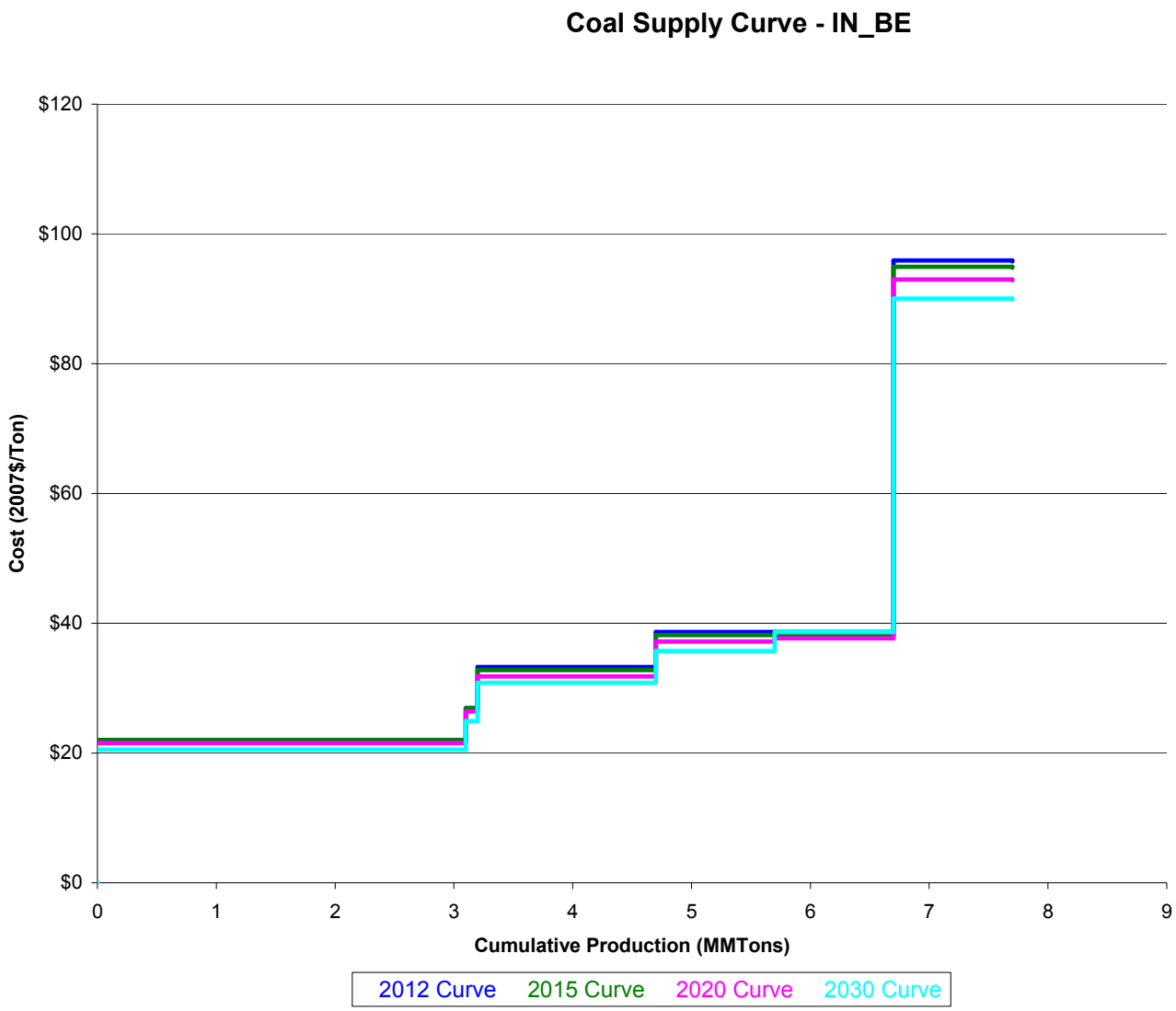

Coal Supply Curve - KW_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
35
40
45
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

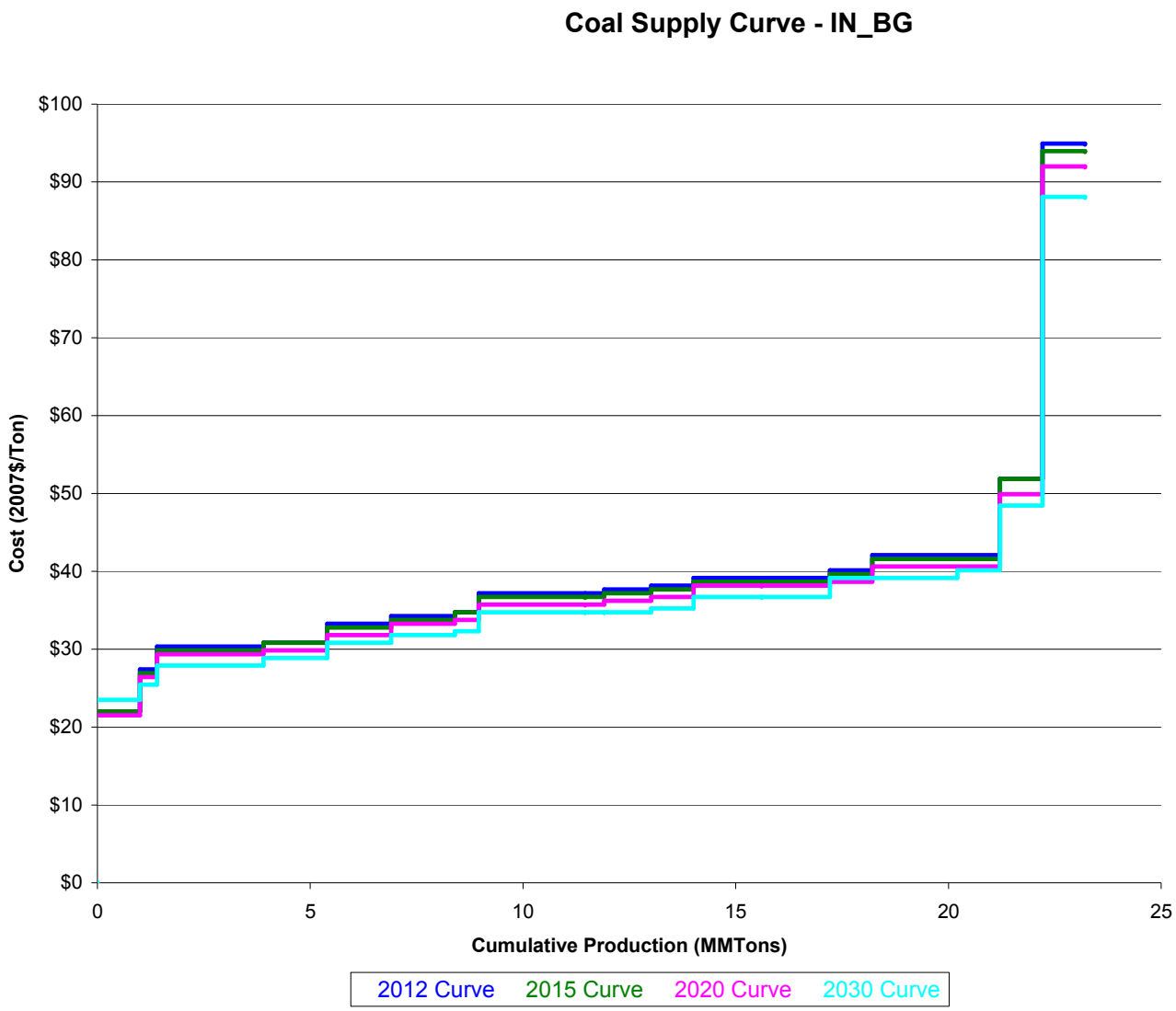

Coal Supply Curve - IL_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

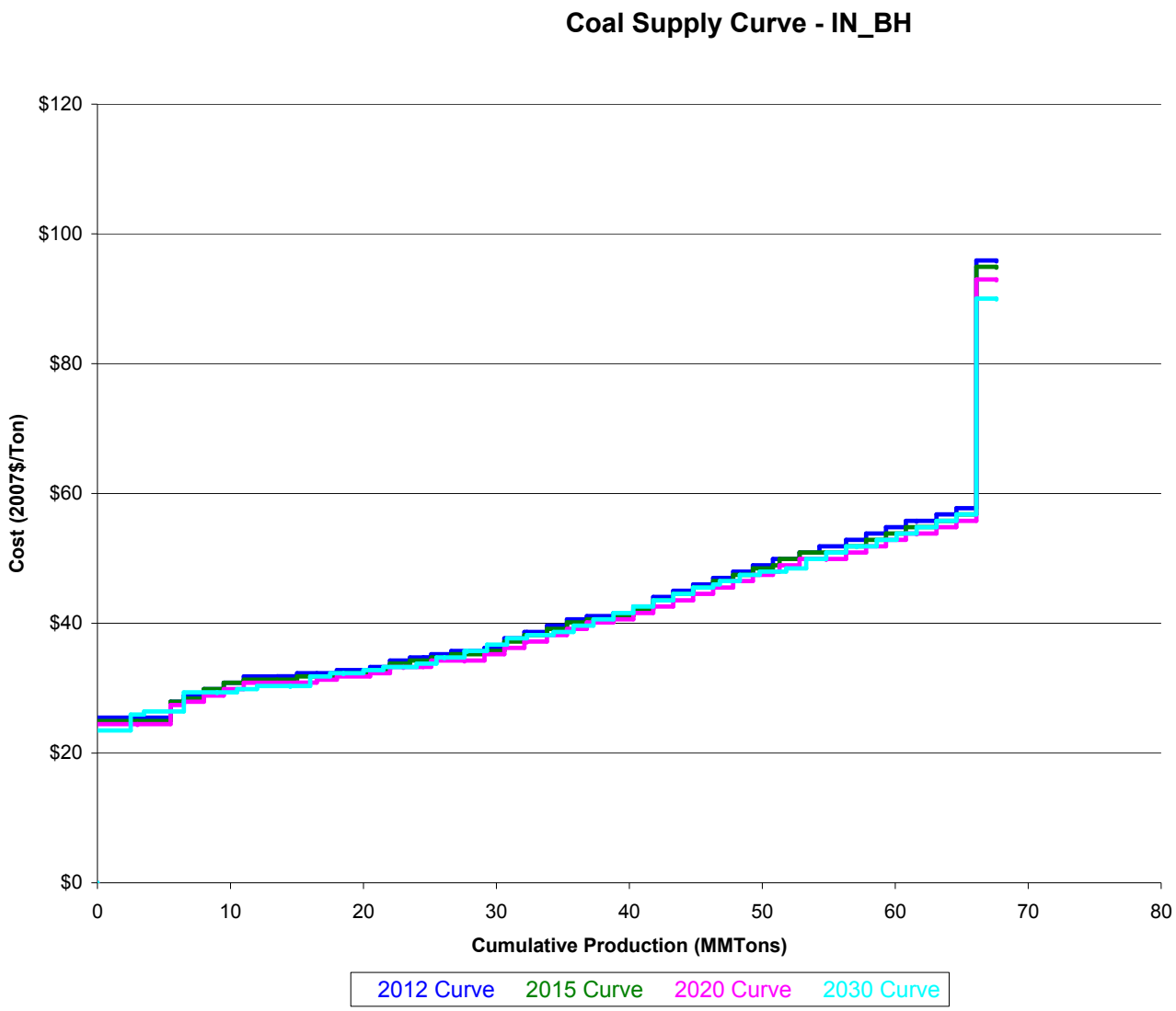

Coal Supply Curve - IL_BG
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
80
90
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

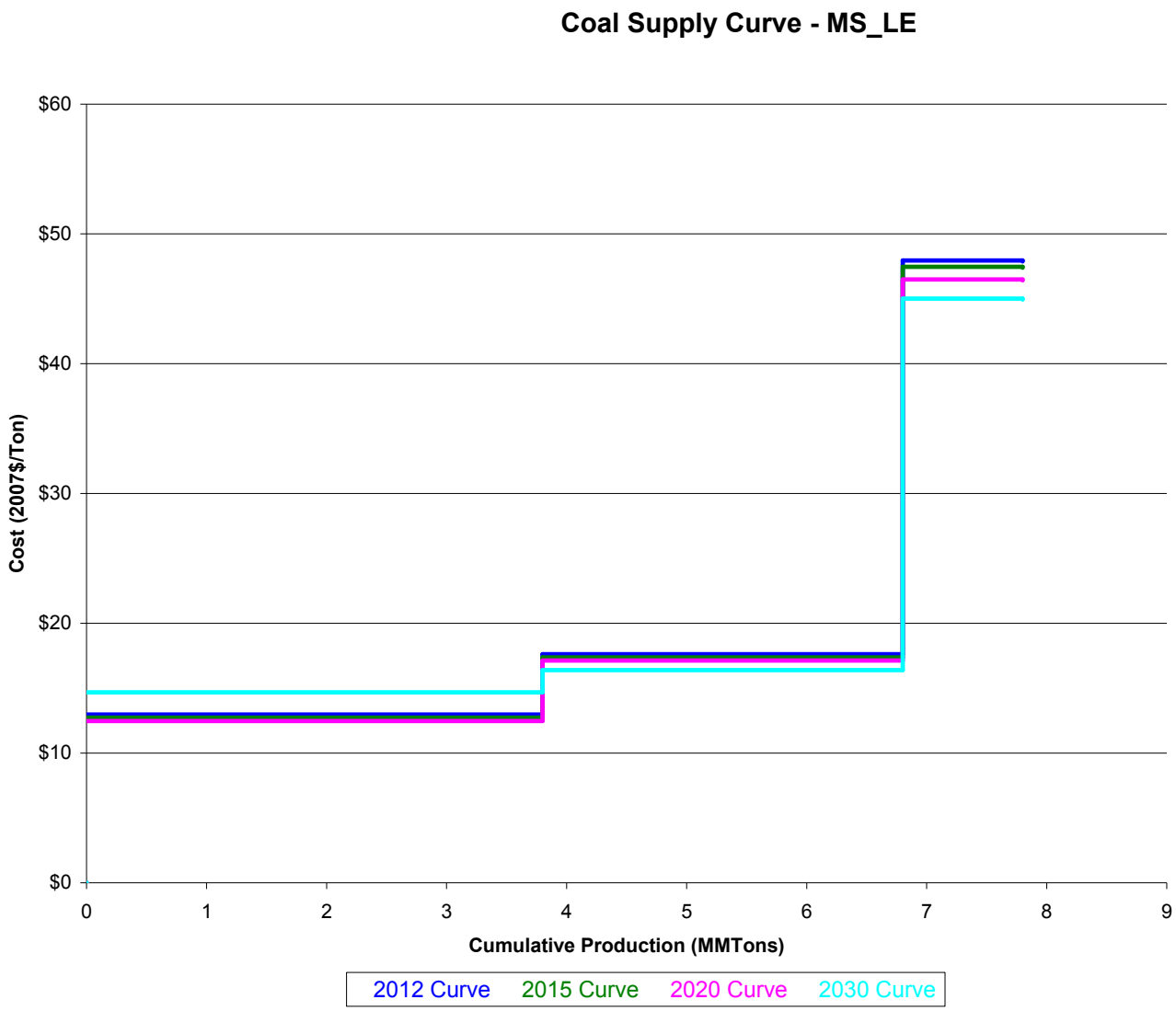

Coal Supply Curve - IL_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
20
40
60
80
100
120
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

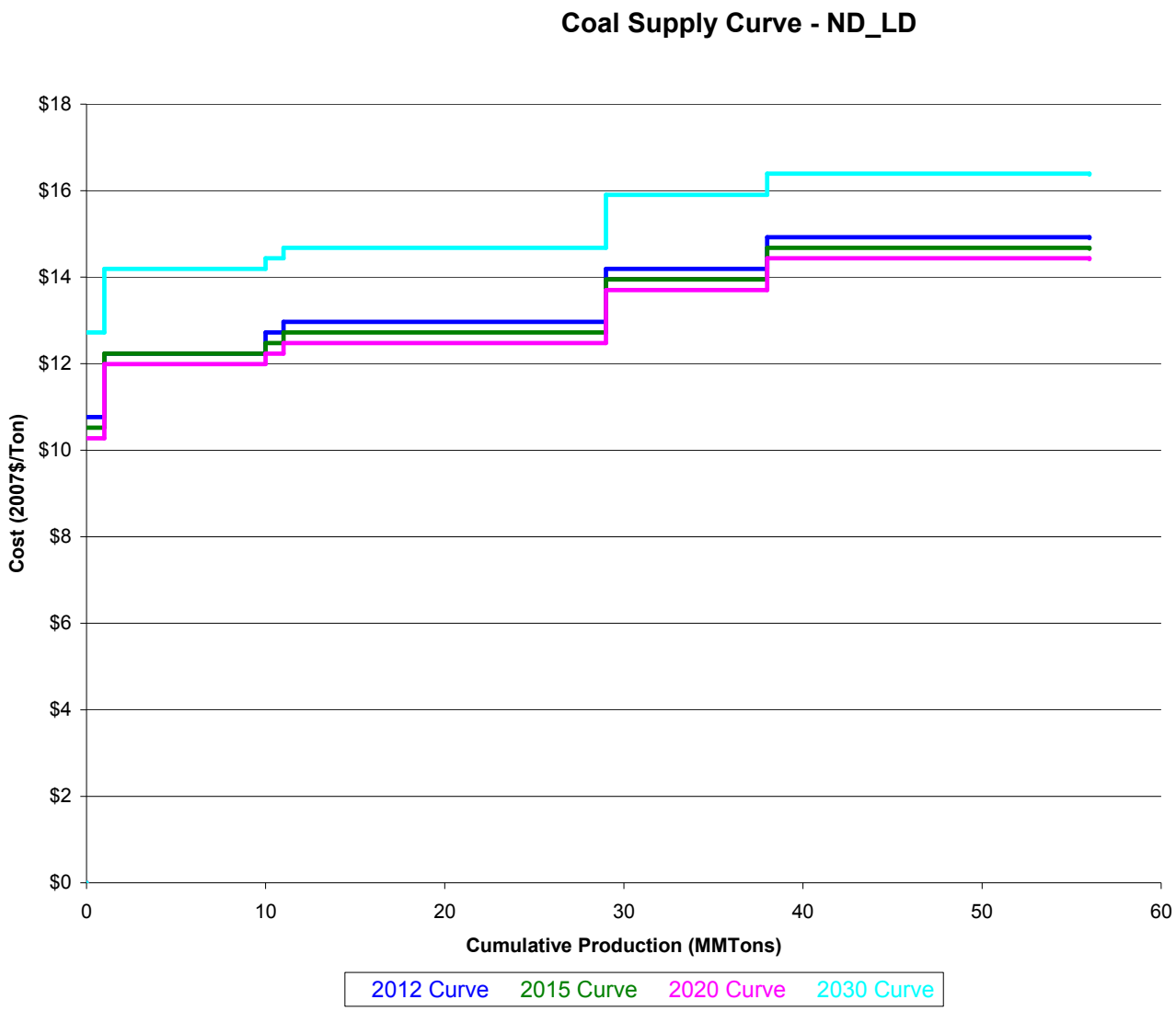

Coal Supply Curve - IN_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

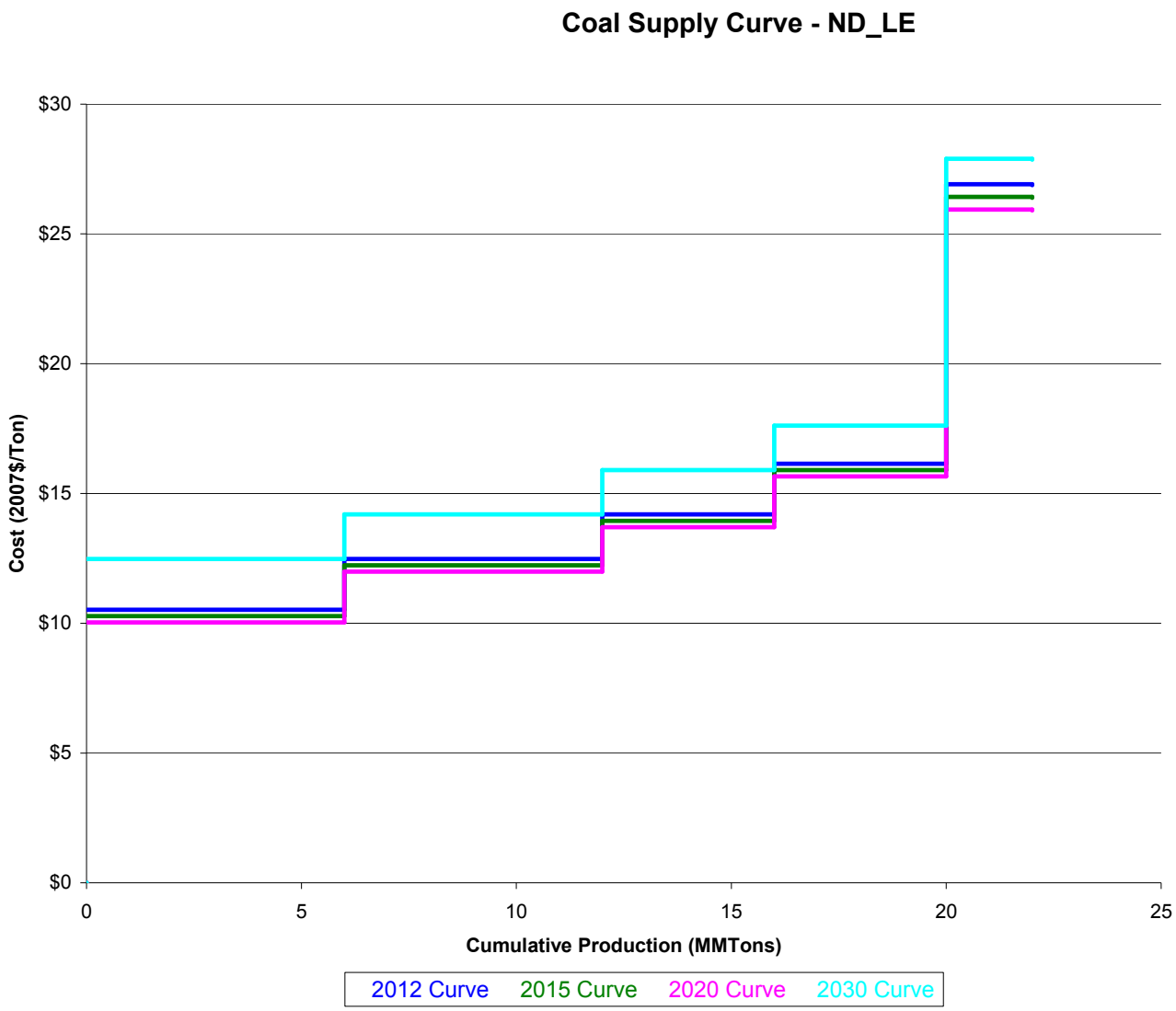

Coal Supply Curve - IN_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

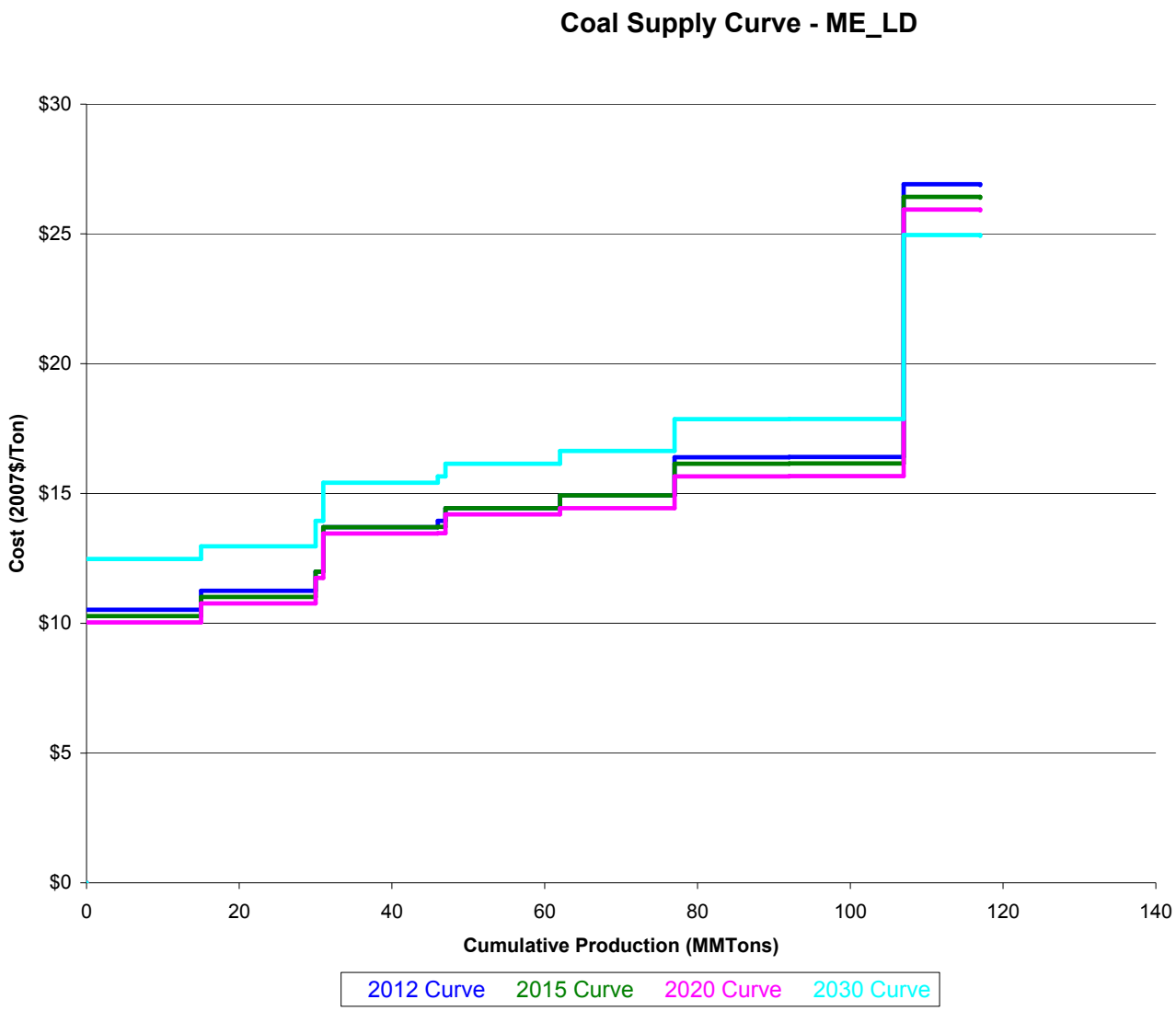

Coal Supply Curve - IN_BG
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

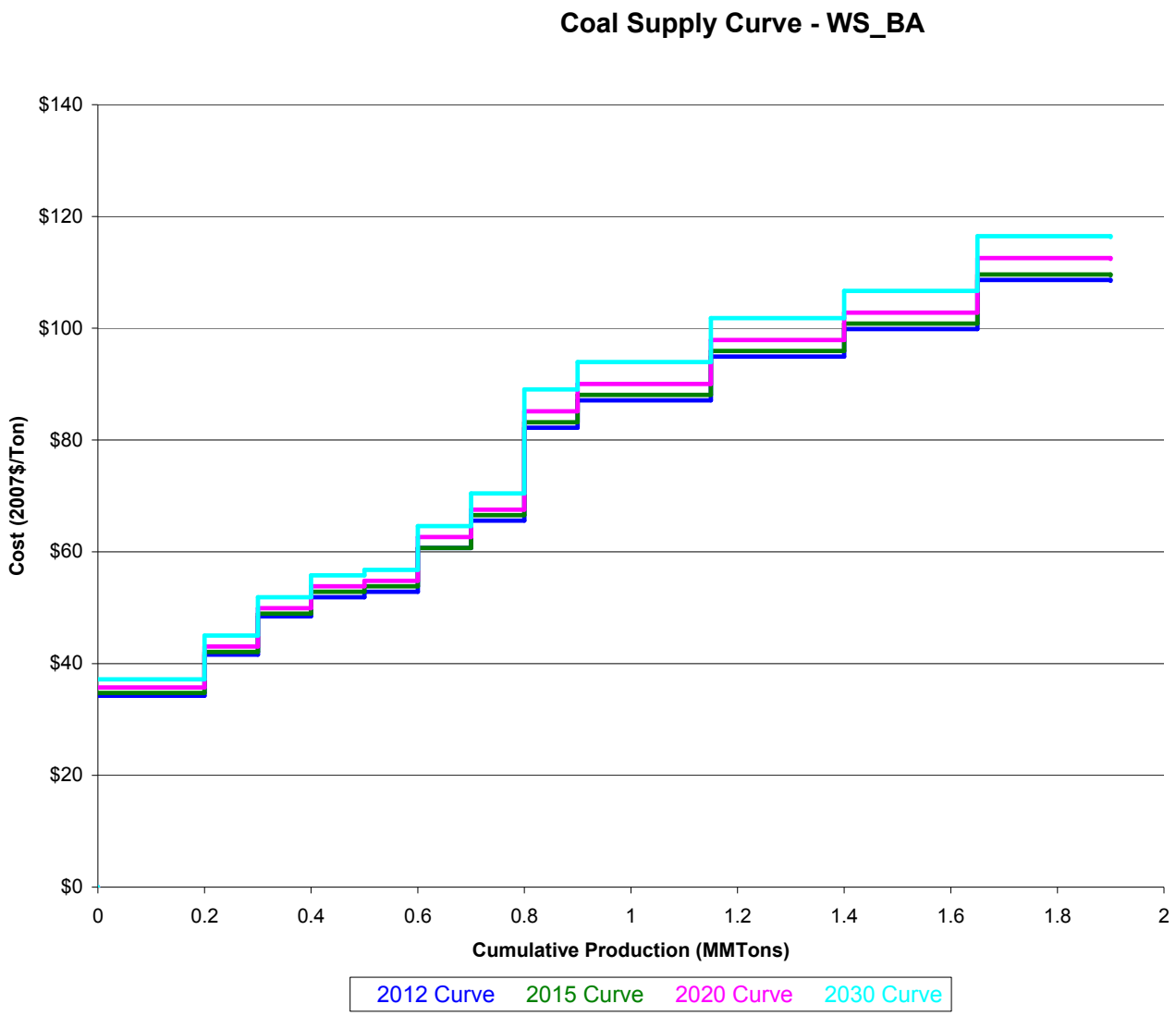

Coal Supply Curve - IN_BH
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
80
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

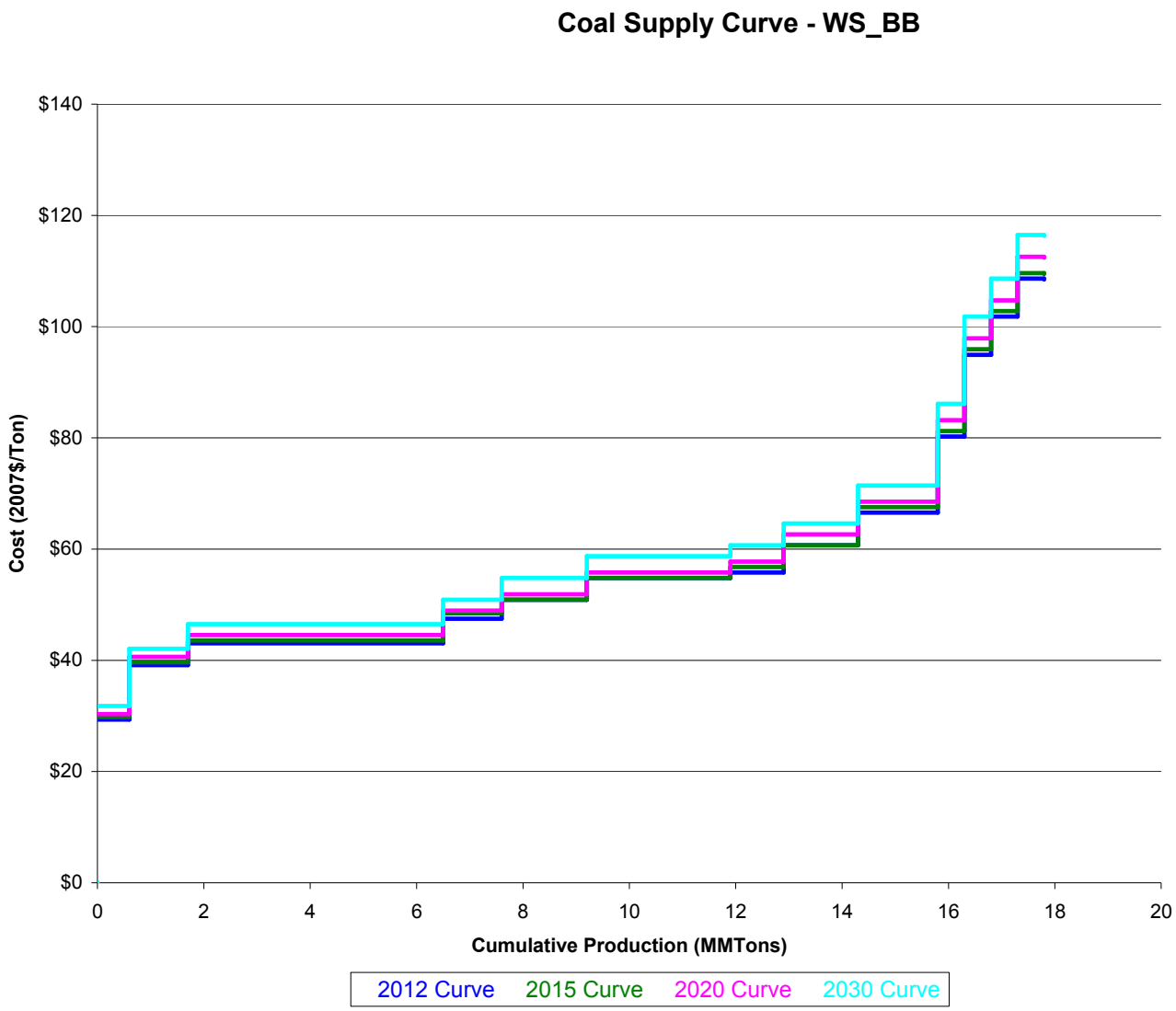

Coal Supply Curve - MS_LE
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
8
9
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

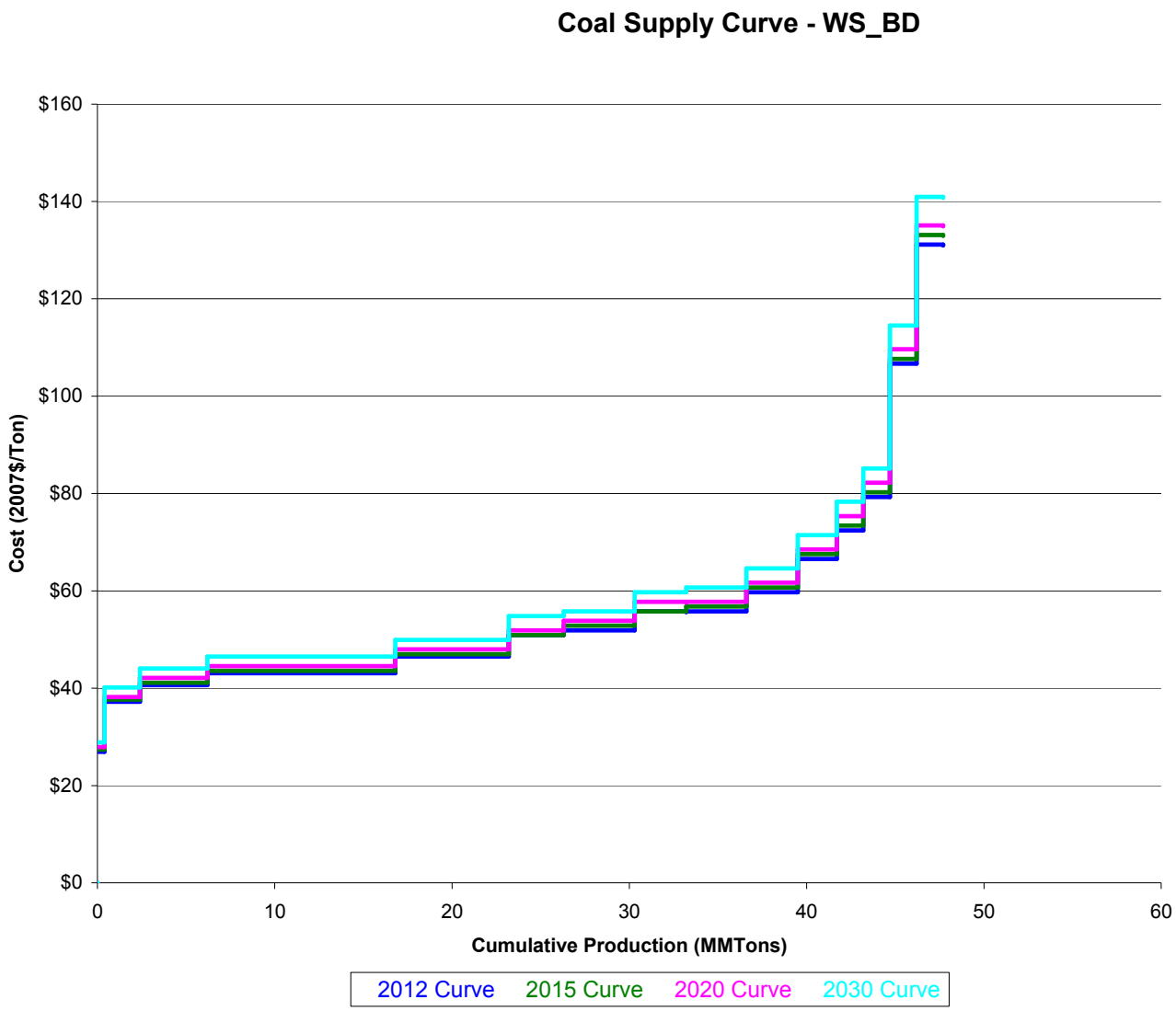

Coal Supply Curve - ND_LD
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

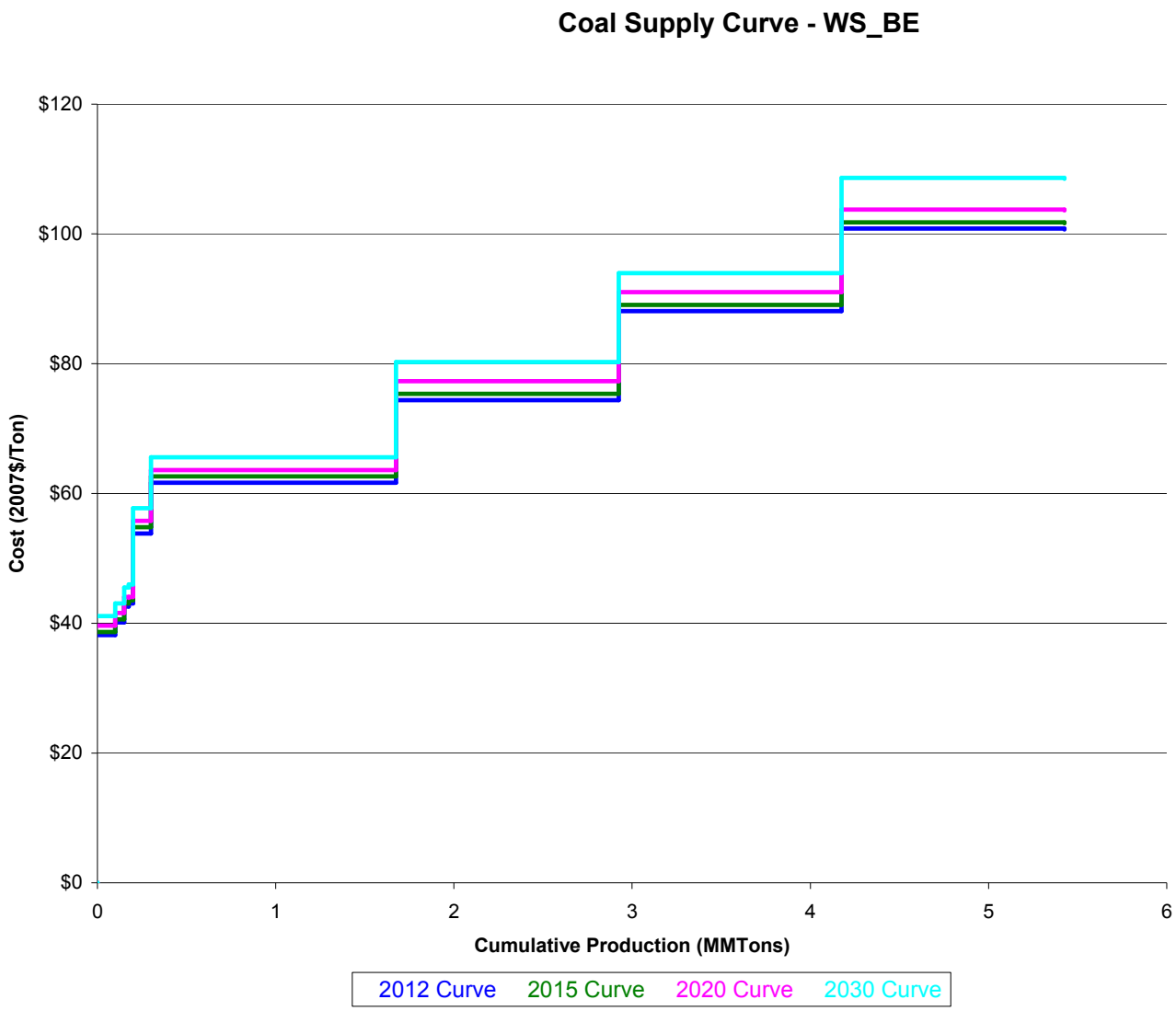

Coal Supply Curve - ND_LE
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
5
10
15
20
25
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

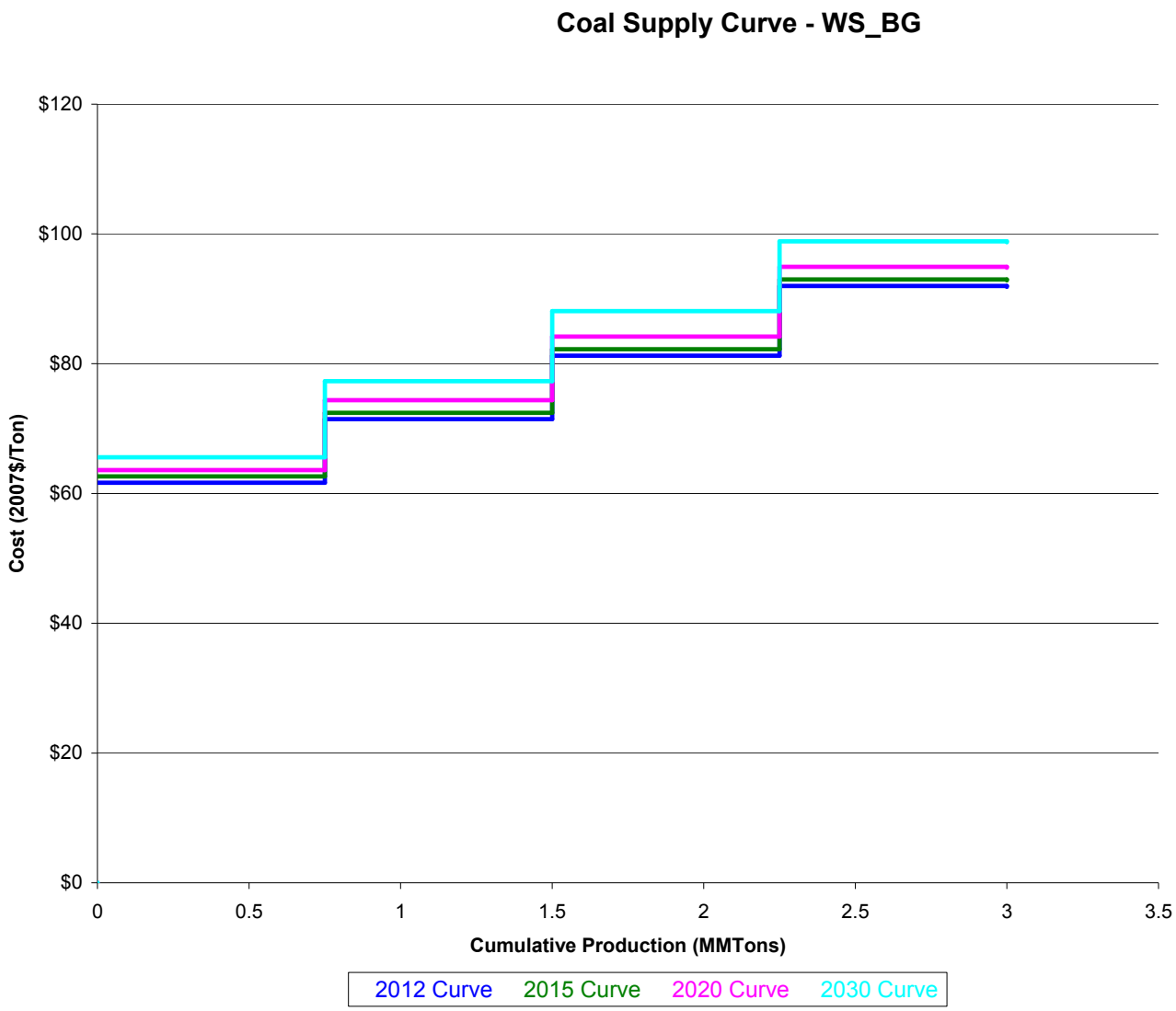

Coal Supply Curve - ME_LD
$30
$25
$20
$15
$10
$5
$0
Cost (2007$/Ton)
0
20
40
60
80
100
120
140
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

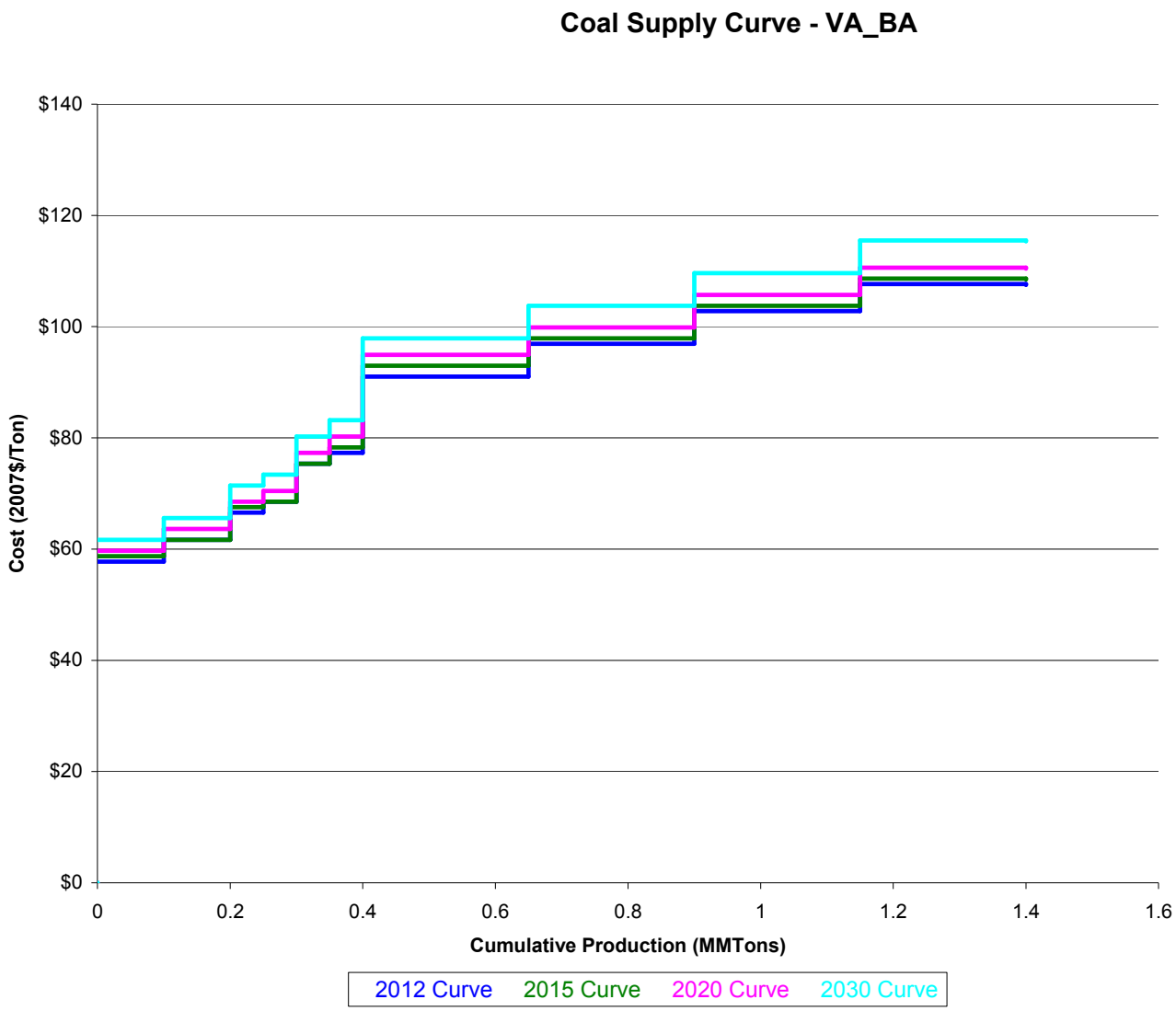

Coal Supply Curve - WS_BA
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
1.8
2
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

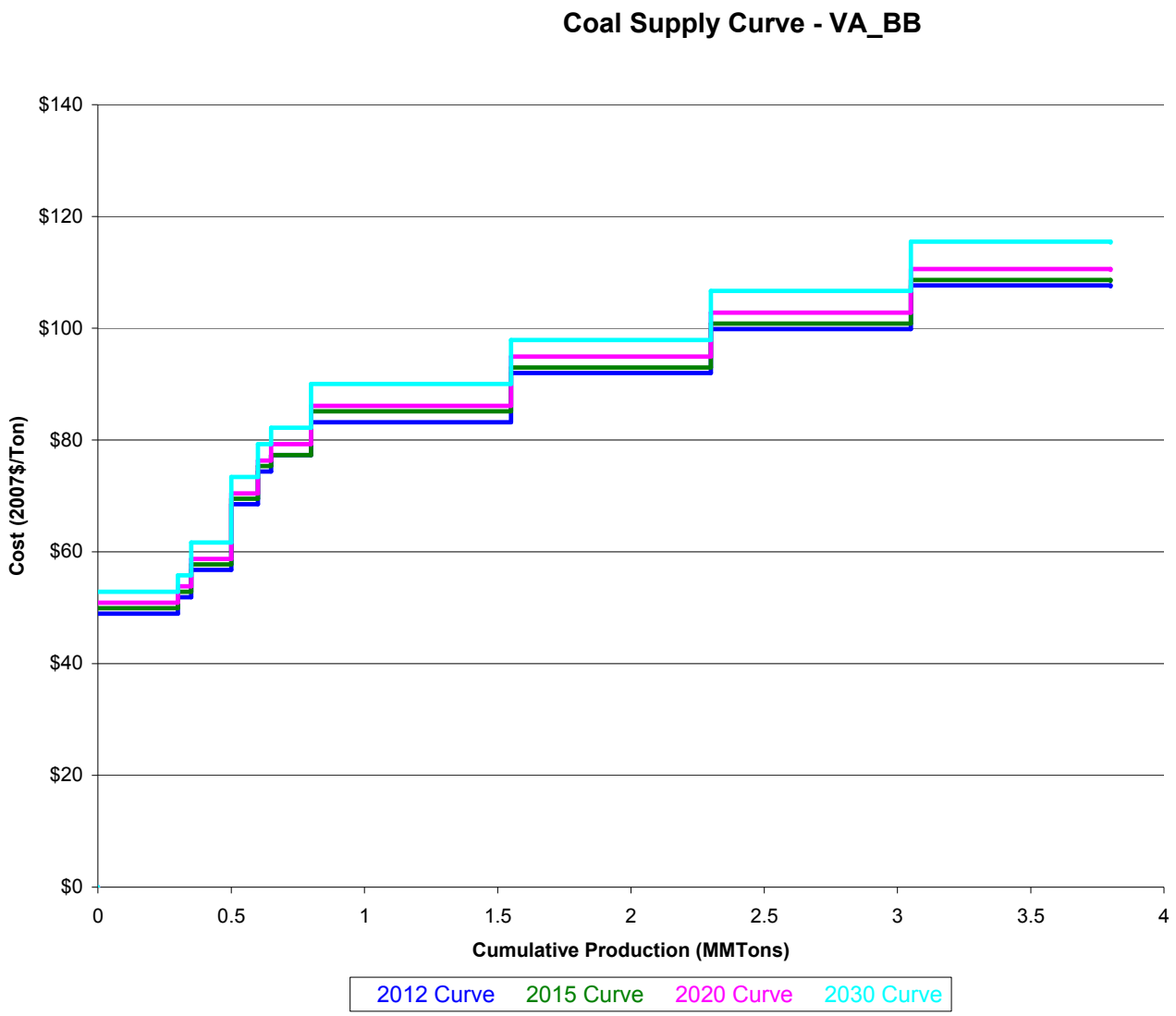

Coal Supply Curve - WS_BB
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
20
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

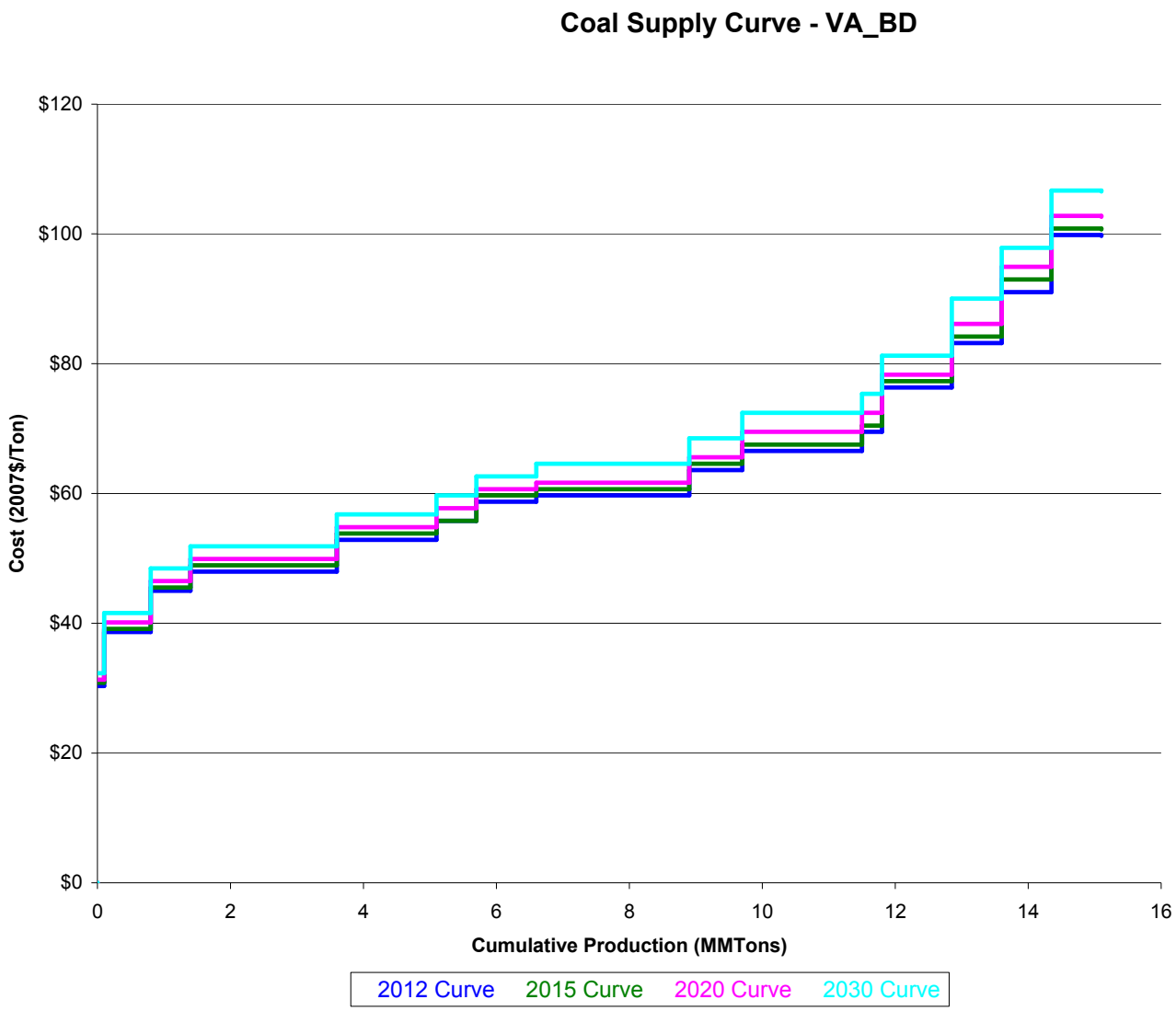

Coal Supply Curve - WS_BD
$160
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

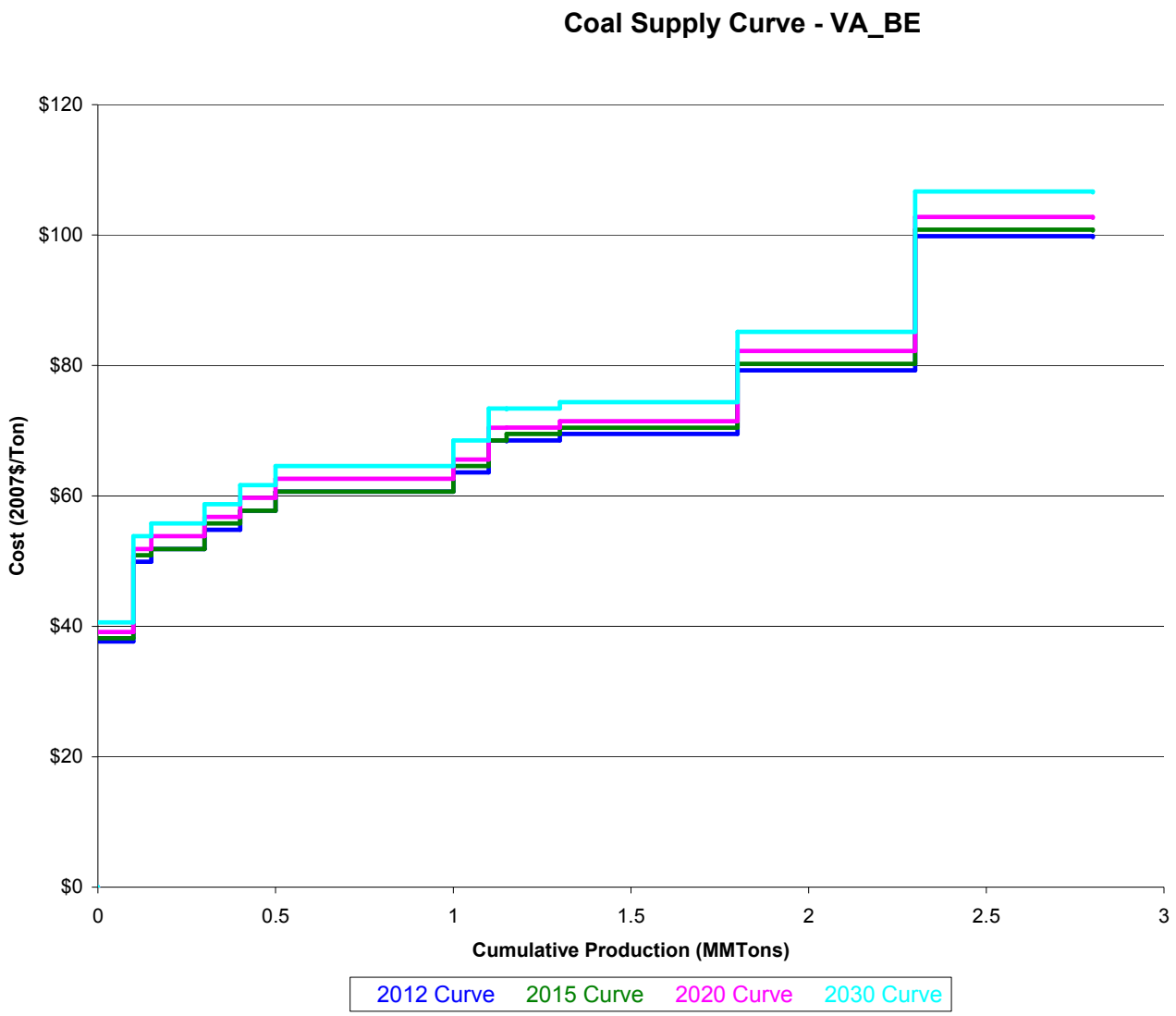

Coal Supply Curve - WS_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

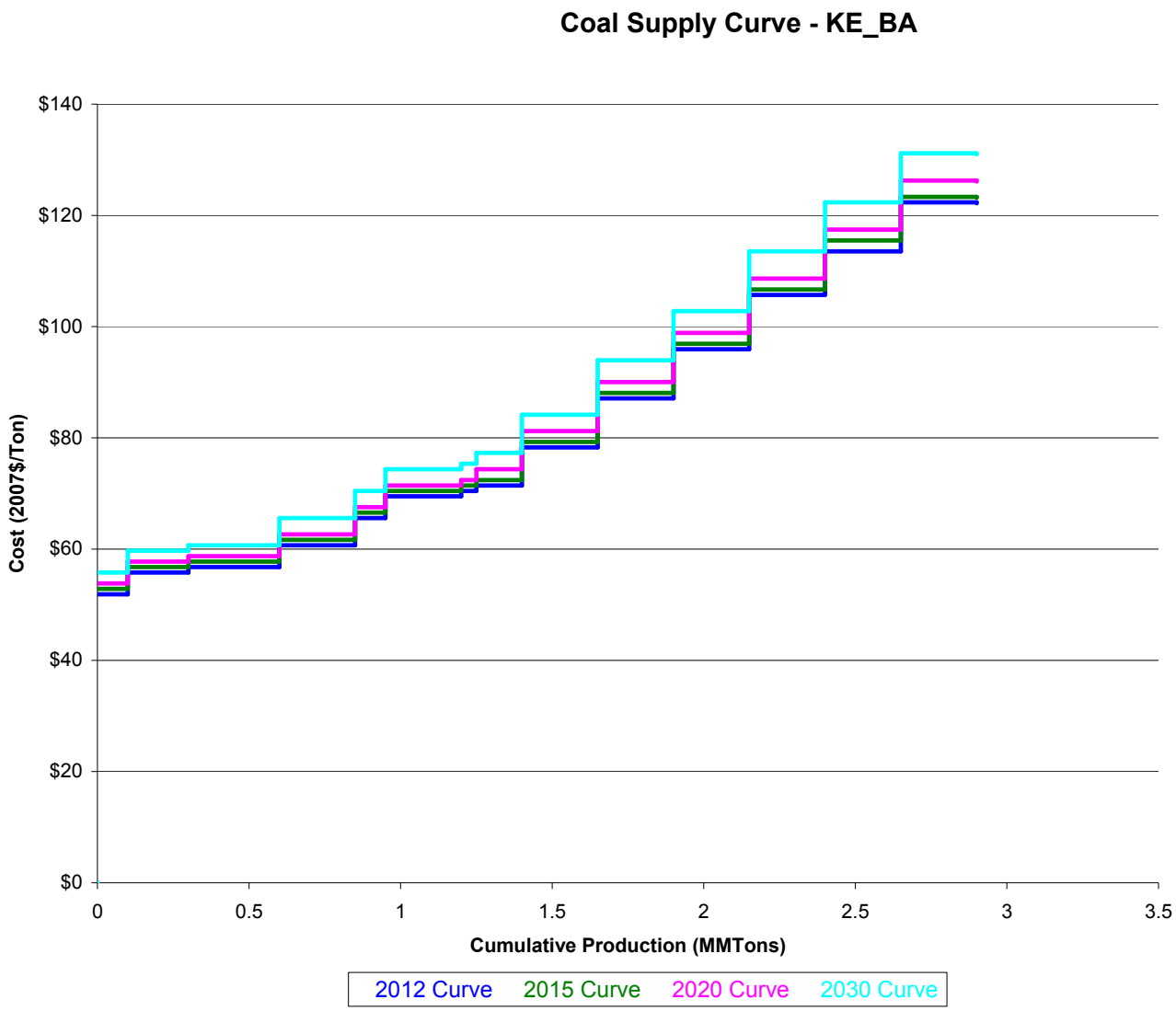

Coal Supply Curve - WS_BG
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

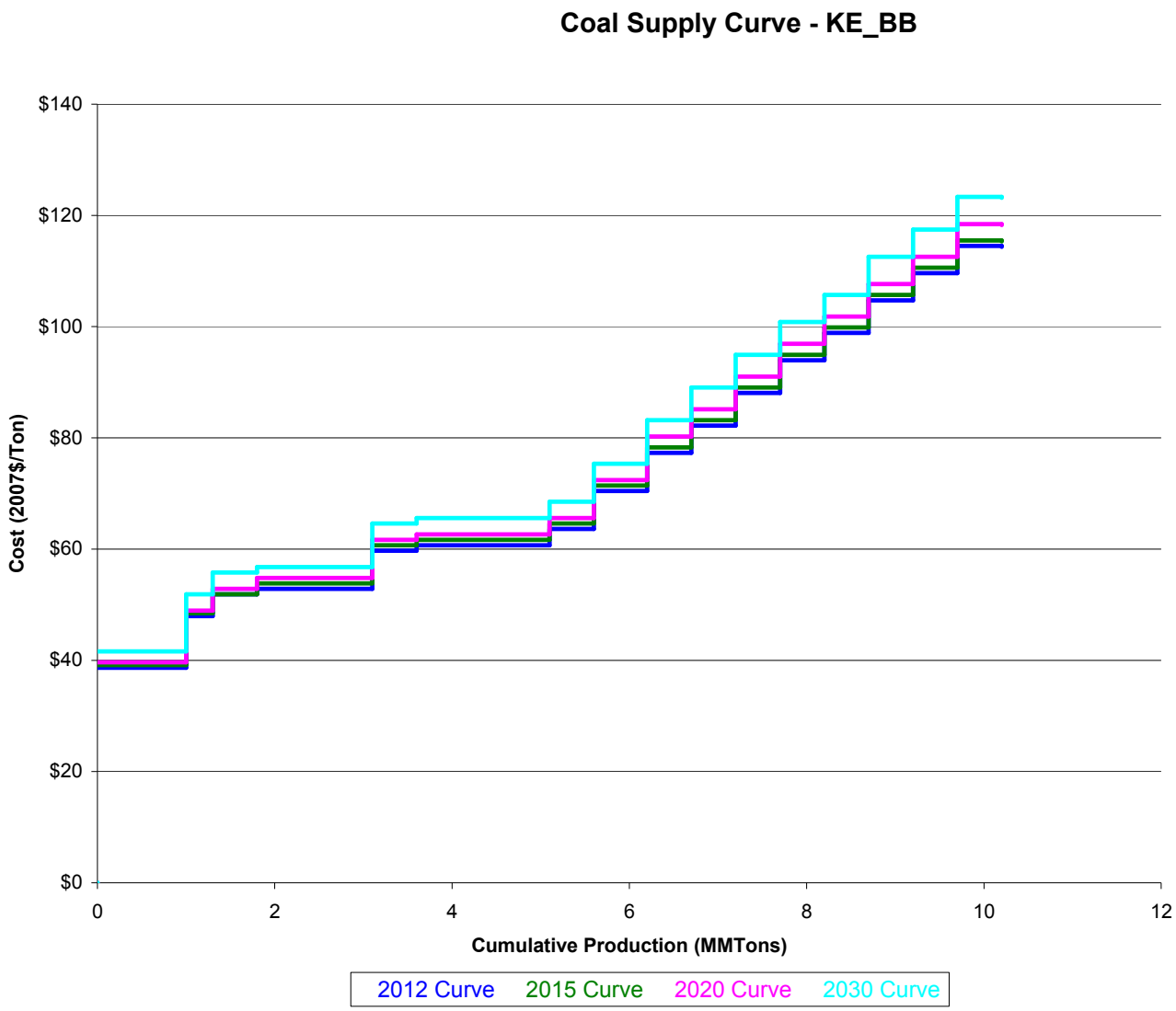

Coal Supply Curve - VA_BA
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

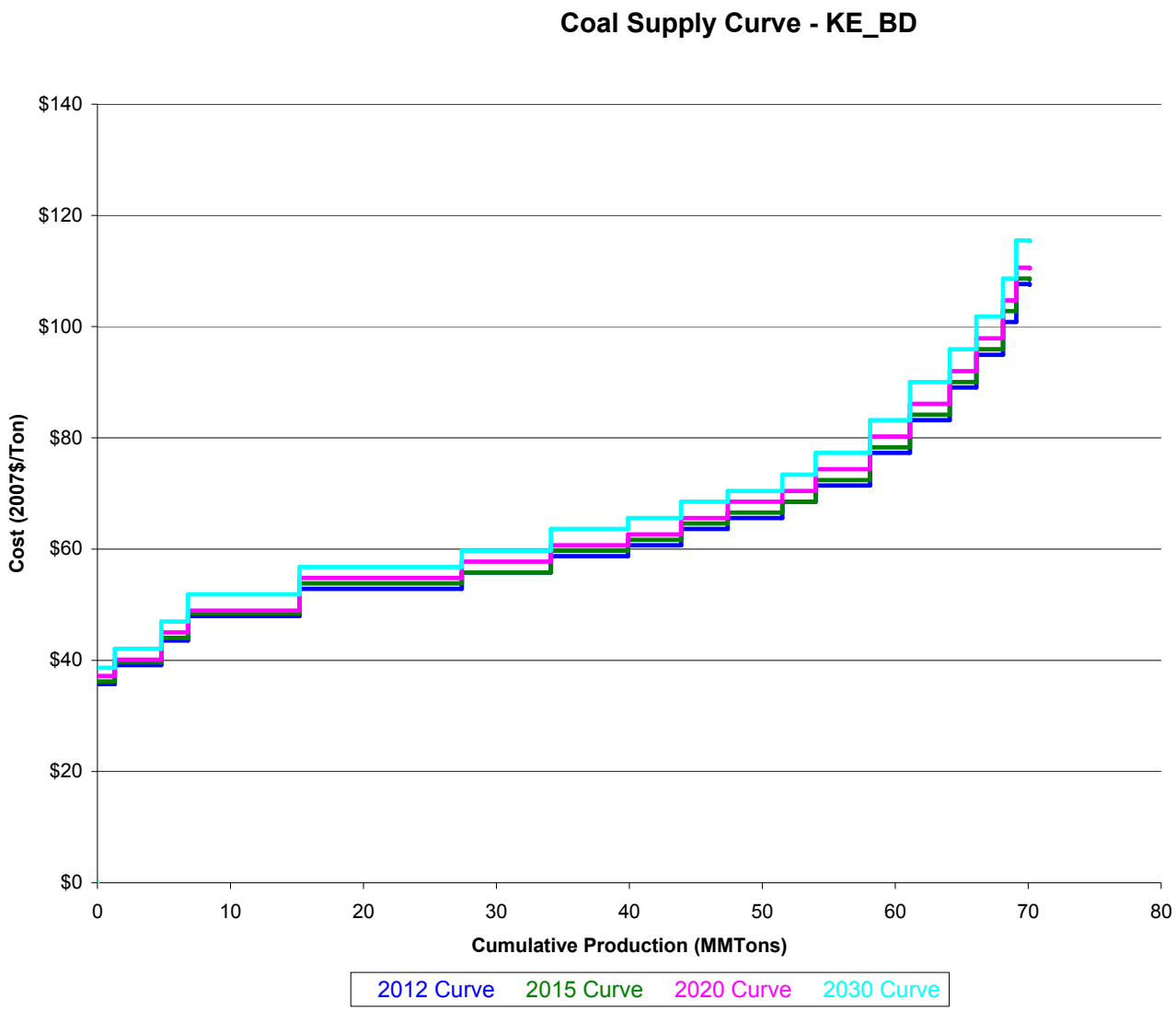

Coal Supply Curve - VA_BB
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

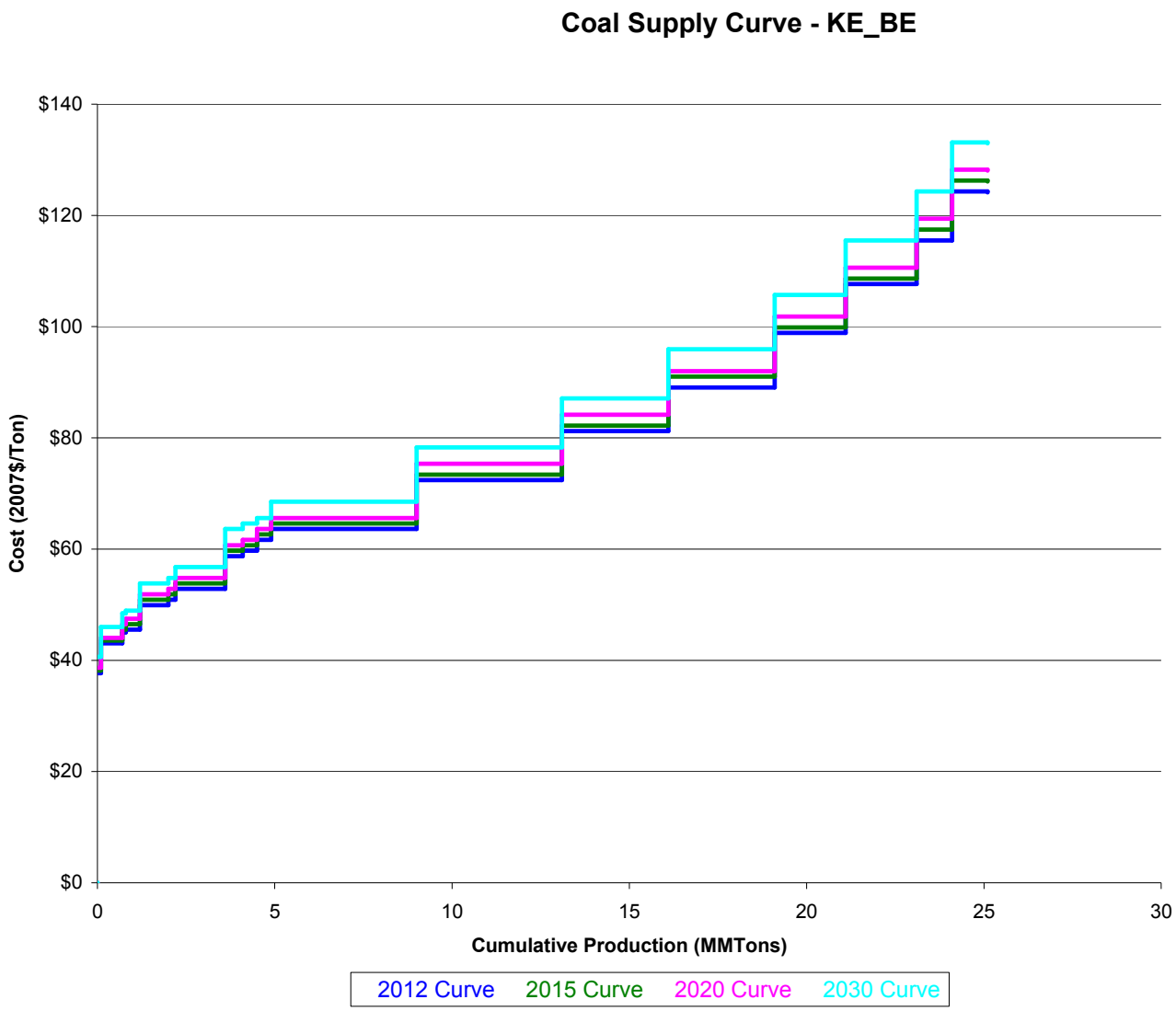

Coal Supply Curve - VA_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

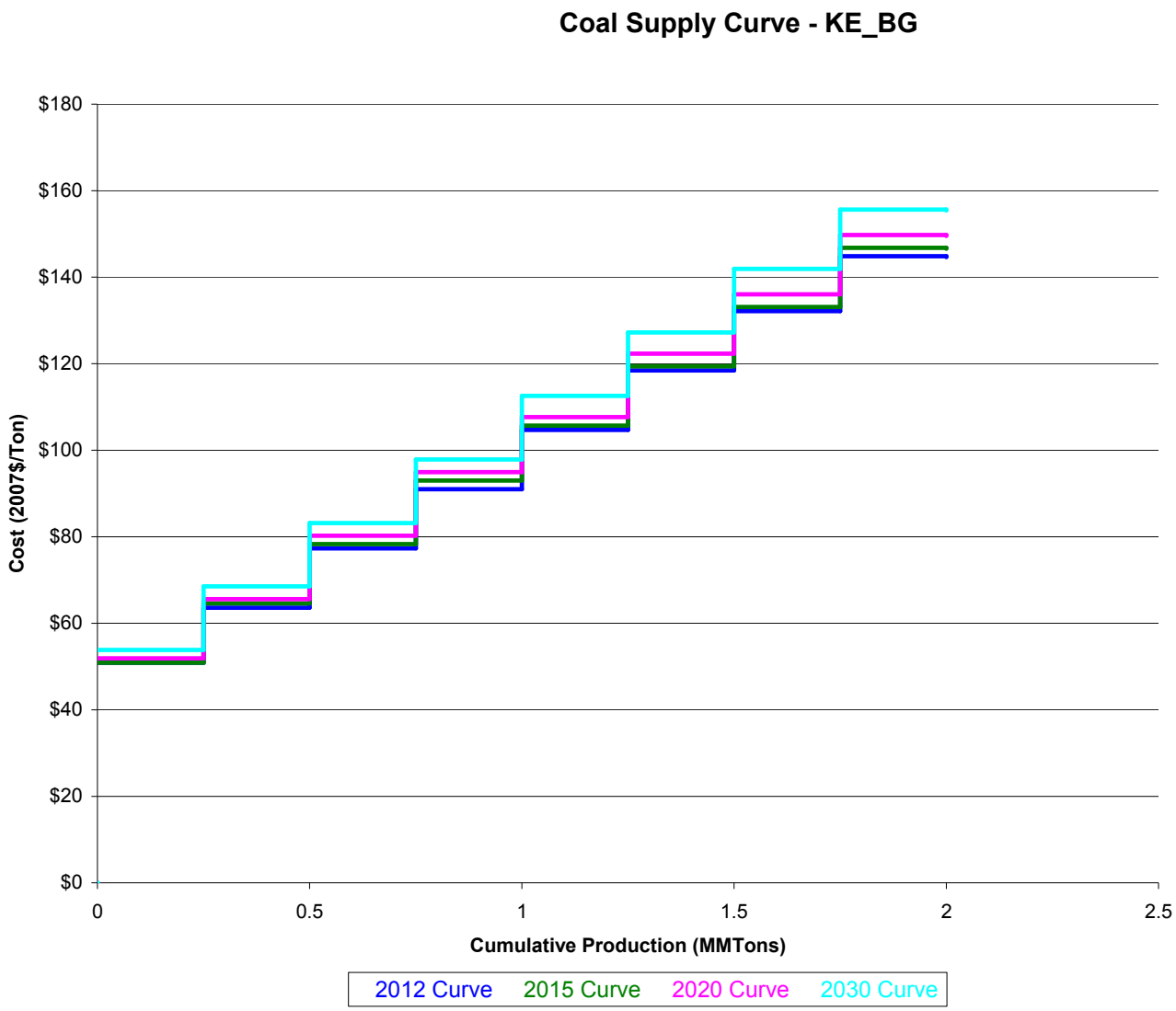

Coal Supply Curve - VA_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

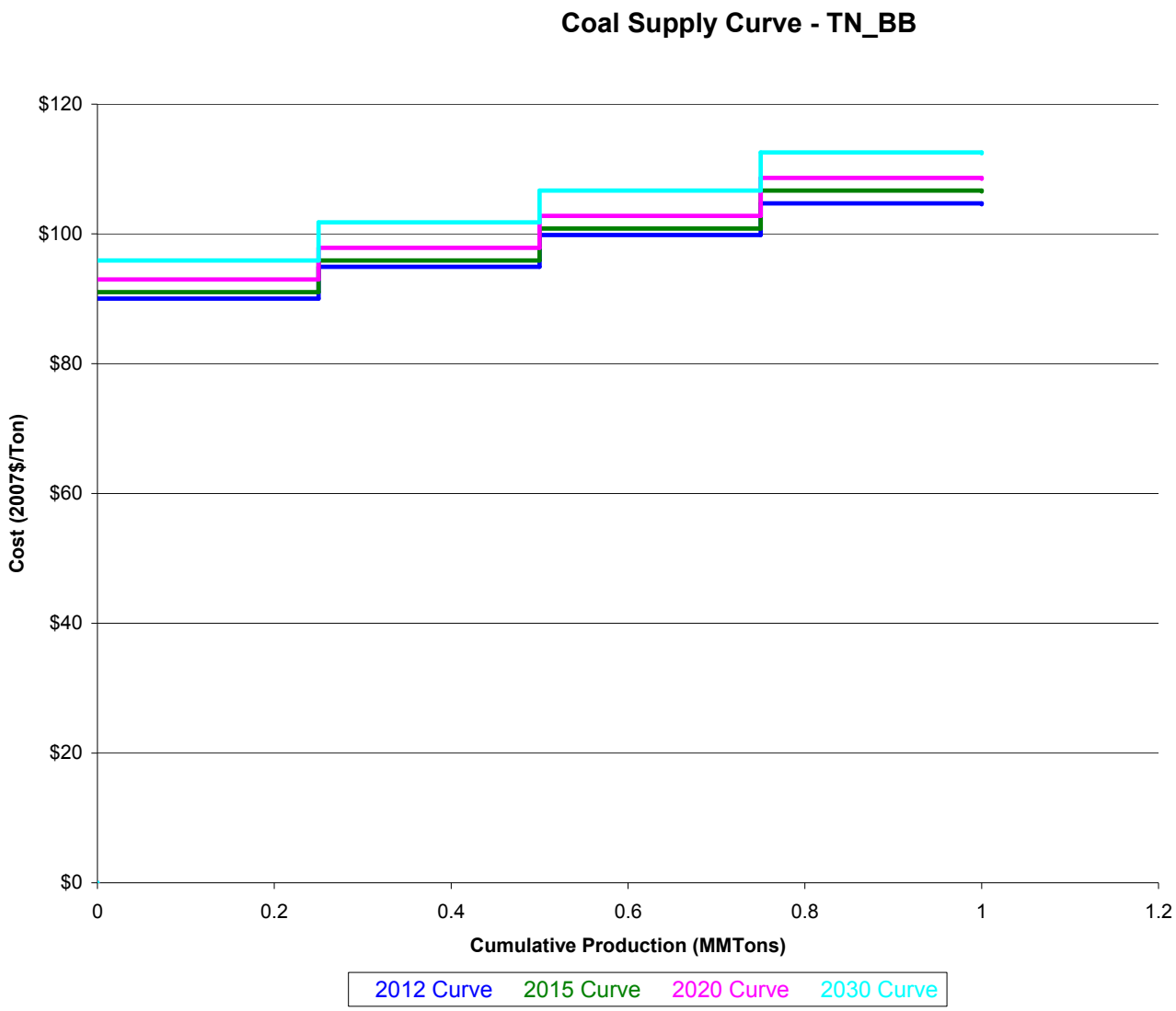

Coal Supply Curve - KE_BA
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

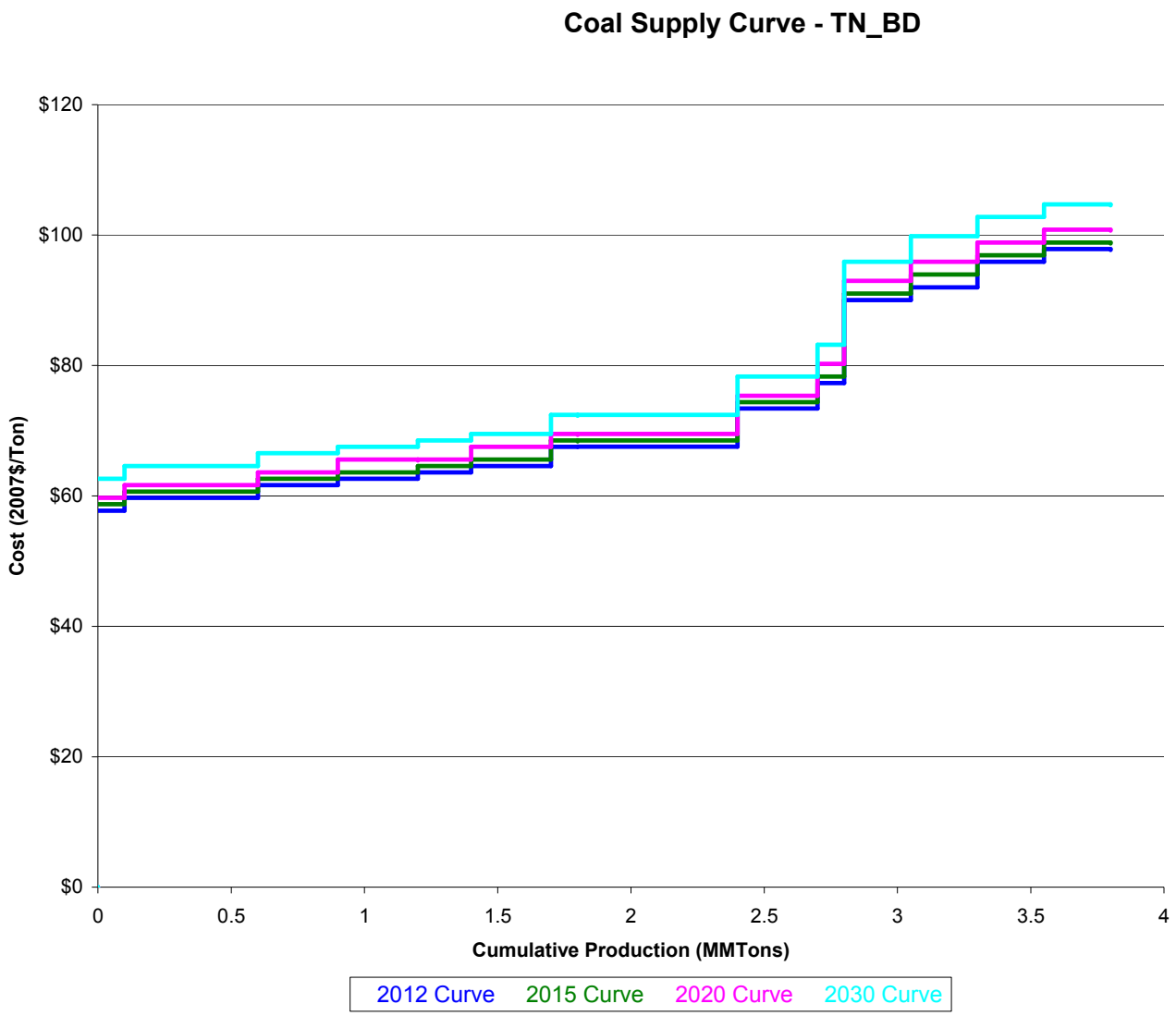

Coal Supply Curve - KE_BB
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

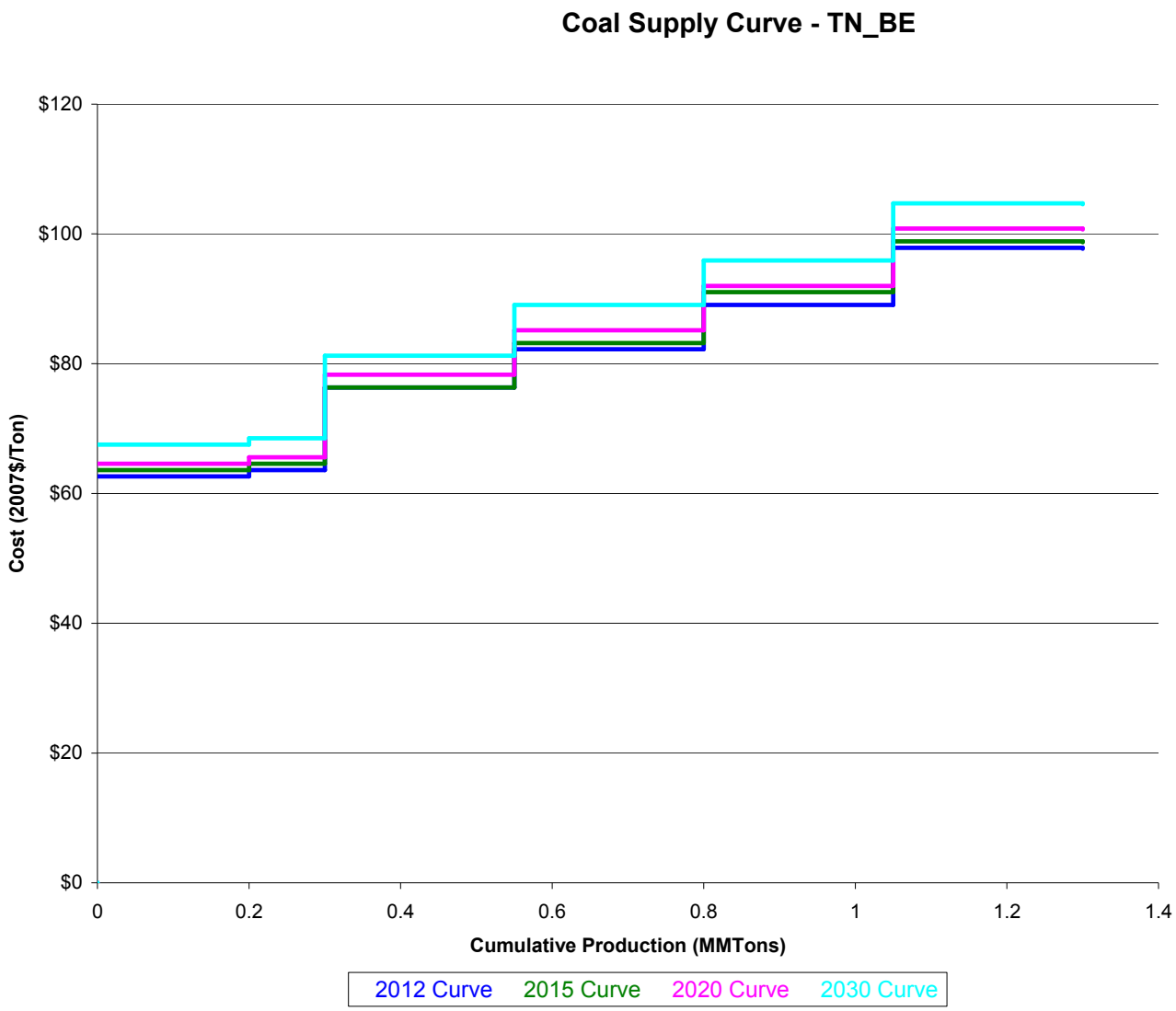

Coal Supply Curve - KE_BD
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
10
20
30
40
50
60
70
80
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

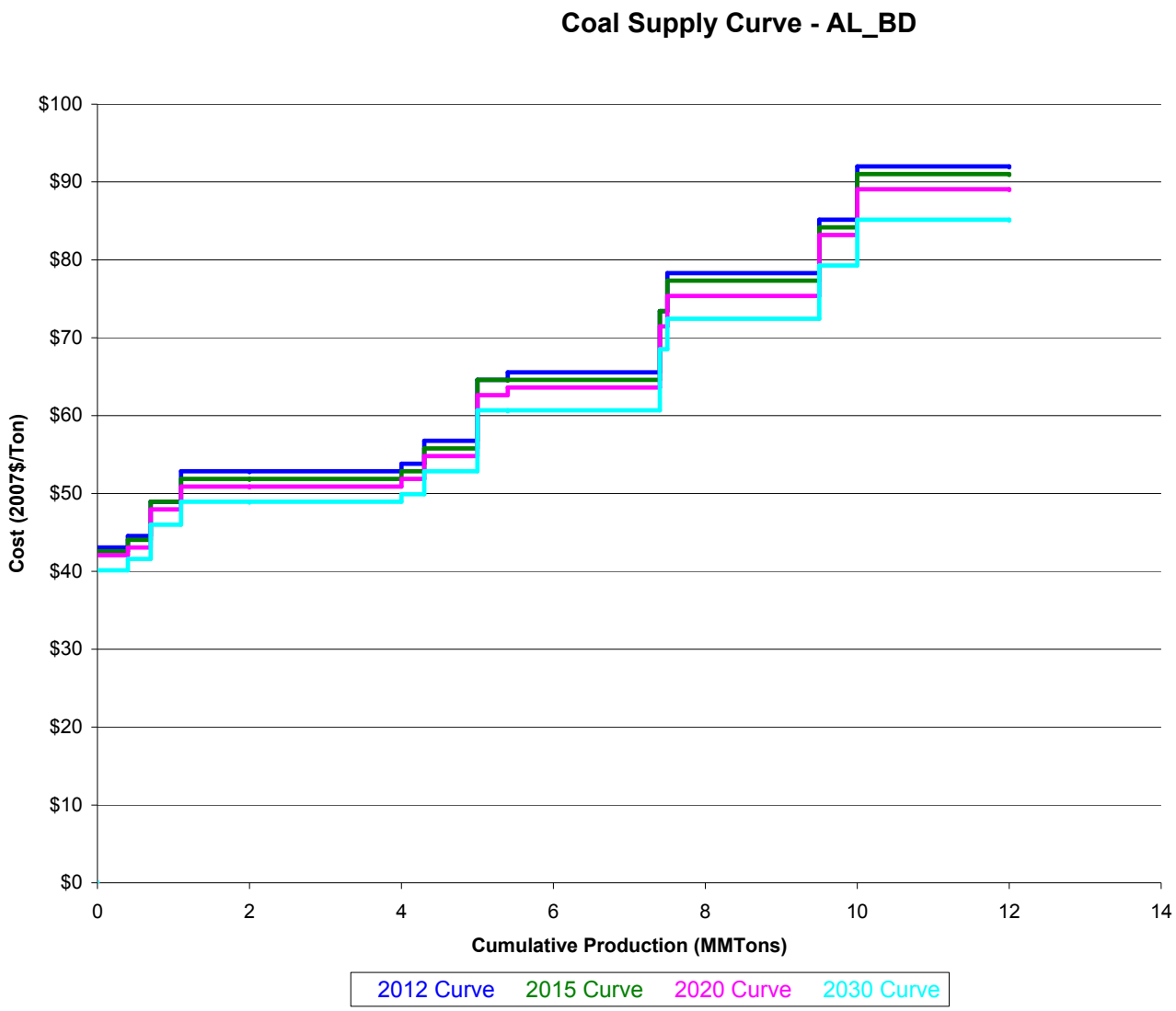

Coal Supply Curve - KE_BE
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
5
10
15
20
25
30
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

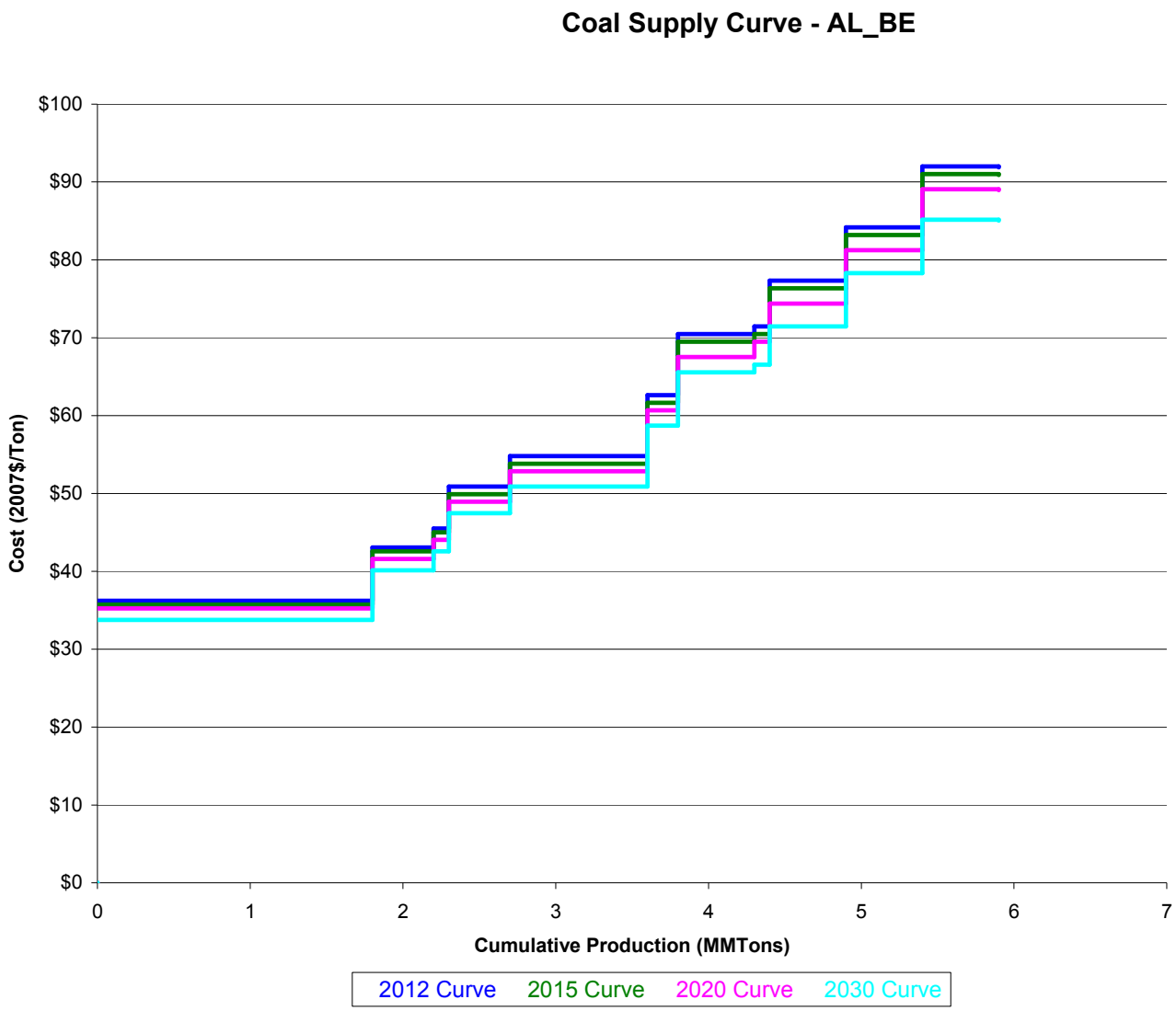

Coal Supply Curve - KE_BG
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

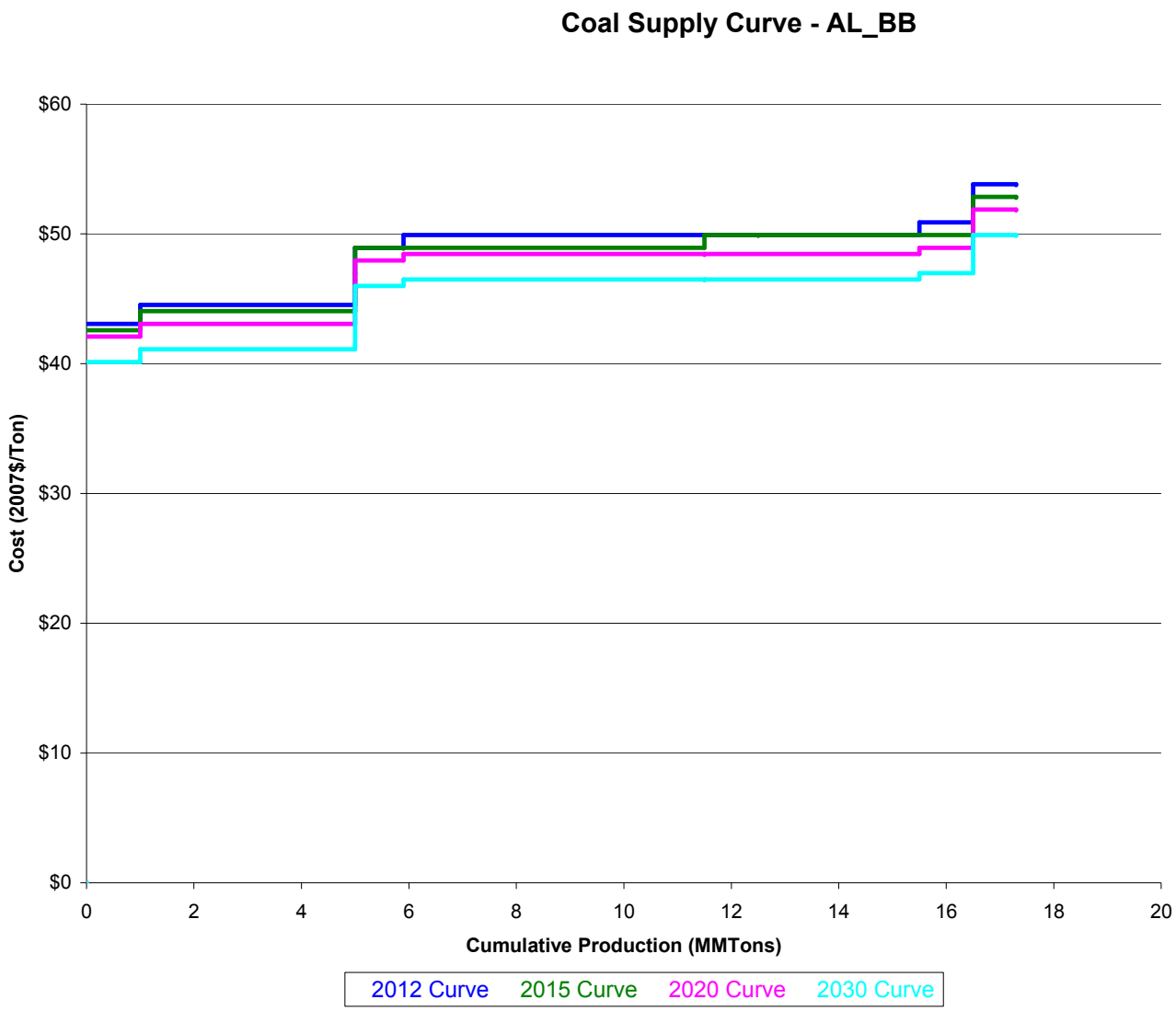

Coal Supply Curve - TN_BB
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - TN_BD
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.5
1
1.5
2
2.5
3
3.5
4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - TN_BE
$120
$100
$80
$60
$40
$20
$0
Cost (2007$/Ton)
0
0.2
0.4
0.6
0.8
1
1.2
1.4
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - AL_BD
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - AL_BE
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
1
2
3
4
5
6
7
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve


Coal Supply Curve - AL_BB
$60
$50
$40
$30
$20
$10
$0
Cost (2007$/Ton)
0
2
4
6
8
10
12
14
16
18
20
Cumulative Production (MMTons)
2012 Curve
2015 Curve
2020 Curve
2030 Curve

10 Natural Gas

This chapter describes how natural gas supply, demand, and costing are modeled in EPA Base Case v.4.10. Section 10.1 indicates that natural gas supply dynamics are directly (i.e., endogenously) modeled in the new base case. This contrasts to previous EPA base cases where natural gas supply curves and related assumptions were developed outside of IPM and then treated as an (exogenous) input to the base case. Section 10.2 gives an overview of the new natural gas module. Section 3.9 treats in detail the specific components of the module that are only briefly described in Section 10.2. Specifically, Sections 10.3 and 10.4 describe the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. These sections also discuss resource constraints affecting production and the assumptions (in the form of cost indices) used to depict expected changes in costs over the 2012-2050 modeling time horizon.

Section 10.5 describes how liquefied natural gas (LNG) imports are represented in the natural gas module. The section covers the assumptions regarding liquefaction facilities, LNG supply, regasification capacity, and related costs. Section 10.6 turns to demand side issues, in particular, how non-power sector residential, commercial, and industrial demand is represented. Section 10.7 describes the detailed characterization of the natural gas pipeline network, the pipeline capacity expansion logic, and the assumptions and procedures used to capture pipeline transportation costs. Section 10.8 treats issues related to natural gas storage: capacity characterization and expansion logic, injection/withdrawal rates, and associated costs. Section 10.9 describes the crude oil and natural gas liquids (NGL) price projections that are exogenous inputs in the natural gas module. They figure in the modeling of natural gas because they are a source of revenue which influence the exploration and development of hydrocarbon resources. The chapter concludes in Section 10.10 with a discussion of key gas market parameters in the report and proxy natural gas supply curves from the new integrated model based on results in EPA Base Case v.4.10. The proxy curves are meant to provide a point of comparison with the natural gas supply curves used in previous EPA IPM base case.

10.1 Overview of IPM's Natural Gas Module

In previous EPA base cases natural gas supply curves and related assumptions were developed outside of IPM and provided in an iterative fashion as static inputs to the base case. Regional gas price forecast, in the form of basis differentials[1], was also provided as static inputs for delivered gas price calculations. The iteration process began with a set of supply curves and basis differentials generated from a series of runs using external stand-alone gas model. Results from the IPM run such as power sector gas demand and heat rates were fed back to the gas model as inputs for the next iteration. It was a time consuming process as it took several iterations to converge and involving human interaction between iterations.

In EPA Base Case v.4.10 natural gas supply, demand, transportation, storage, and related costs are modeled directly in IPM through the incorporation of a new natural gas module. In the new system, natural gas supply curves are generated endogenously for each region, and the balance between the natural gas supply and demand is solved in all regions simultaneously. Integrating natural gas modeling into IPM as illustrated in Figure 10-1 and Figure 10-2 has some advantages over the previous modeling approach. The direct interaction between the electric and the gas modules captures the overall gas supply and demand dynamic and requires no iteration. The

[1] In natural gas discussions "basis" refers to differences in the price of natural gas in two different geographical locations. In the marketplace "basis" typically means the difference between the NYMEX futures price at the Henry Hub and the cash price at other market points. In the modeling context "basis" means the difference in natural gas prices between any two nodes at the same instance in time.

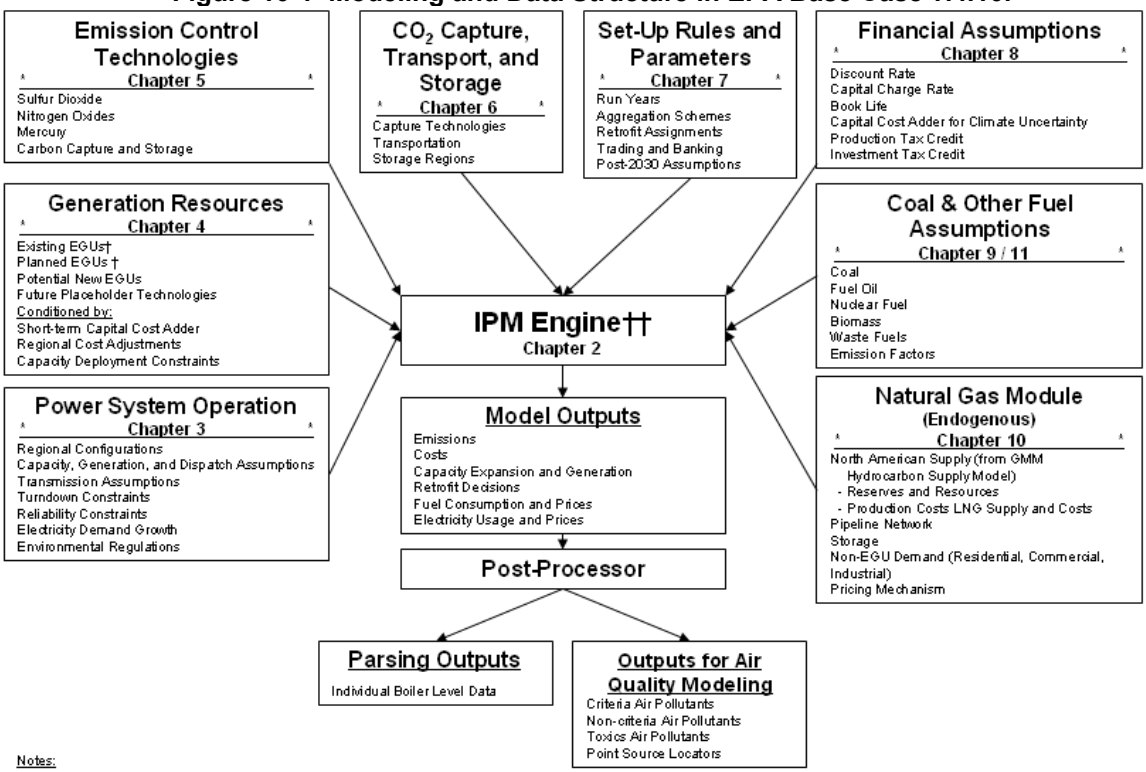
model solves for gas price in each region, therefore, it does not need to import gas price basis differentials as in the previous approach.

The result from a modeling standpoint is a new integrated natural gas module with a linear programming (LP) structure that is fully consistent and compatible with that used in IPM. Natural gas LP components, which include objective function parameters consistent in form with IPM's cost minimization, a series of decision variables, and a set of constraints, have been added to the original LP structure of the IPM electricity module. This integration makes the gas module a working component of the IPM modeling framework.

To a certain extent, the design and assumptions of the new natural gas module are similar to those in ICF International's private practice Gas Market Model (GMM) which has been used extensively for forecasting and market analyses in the North American natural gas market. To provide these new natural gas modeling capabilities within IPM and still maintain an acceptable model size and solution time, however, simplifications of some of the GMM design and assumptions were made.

Seasonality in the gas module is made consistent with that in IPM and is currently modeled with two seasons (summer and winter), each with up to six IPM load periods that correspond to the IPM electric sector load duration curve (LDC) segments. The gas module also employs a similar run year concept as in IPM where, in order to manage model size, individual calendar years over the entire modeling period are mapped to a lesser number of run years. In the current version, both modules use the same run year mapping.

Figure 10-1 Modeling and Data Structure in EPA Base Case v.4.10.

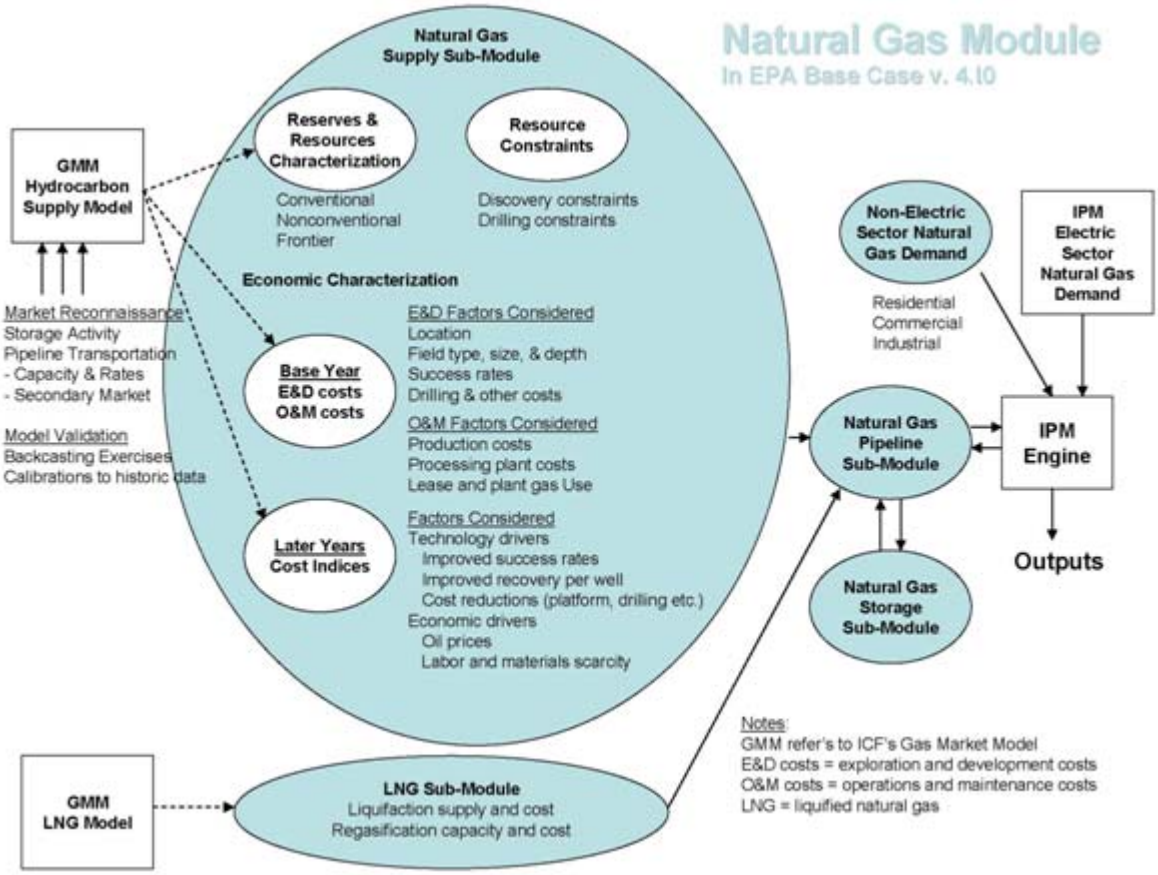


Notes:

† Information on existing and planned electric generating units (EGUs) is contained in the National Electrical Energy Data System (NEEDS) data base maintained for EPA by ICF International. Planned EGUs are those which were under construction or had obtained financing at the time that the EPA Base Case was finalized.

††IPM Engine is the model structure described in Chapter 2

Figure 10-2 Natural Gas Module in EPA Base Case v.4.10.



10.2 Key Components of the New IPM Natural Gas Module

The new gas module is a full supply/demand equilibrium model of the North American gas market. Most of the structure and data for the gas module are derived from ICF's Gas Market Model (GMM). It consists of 114 supply/demand/storage nodes and 14 LNG regasification facility locations that are tied together by a series of links that represent the North American natural gas transmission network as shown in Figure 10-3. The list of the 114 nodes is tabulated in Table 10-1.

Key elements of the natural gas module (which are described in detail in Sections 10.3-10.9) include:

Natural Gas Resources are modeled by a set of base year resource cost curves, which represent undiscovered resource availability or recoverable resource as a function of exploration & development (E&D) cost for 77 supply regions. "Resource Appreciation"[2] is added to the resource base to account for additional resources from plays that are not included in the resource base estimates due to lack of knowledge and technology to economically recover the resources. The construction of the resource cost curves are based on resource characterizations and economic evaluations from the Hydrocarbon Supply Model (HSM) of the GMM. (The HSM is discussed in greater detail in Sections 10.3 and 10.4 below.) Figure 10-4 depicts the geographic locations of the supply regions and Table 10-2 provides a list of the supply regions and a mapping of the regions to the modeling nodes.

Natural Gas production from the 77 supply regions is calculated from the resource cost curves based on exploration and development activities that are a function of drilling success rate, rigs availability, reserves-to-production (R/P) ratio, and the costs of exploration, reserves development, and production that are applicable in the specific regions.

LNG import level for each of the LNG regasification facilities is calculated from LNG supply availability curves (derived from the LNG supply curve module of GMM) based on the solution gas price and the regasification capacity at the corresponding LNG node. Availability and regasification capacity of the facilities are specified as inputs. The model has the capability to expand regasification capacity. However, due to excess of LNG regasification capacity already in the system and a relatively low electricity demand growth assumption in the EPA Base Case v.4.10, the regasification expansion feature is turned off. If future economic demands more LNG capacity, it can be turned back on.

End use natural gas demand for the non-power sectors (i.e. the residential, commercial, and industrial sectors) is incorporated in the IPM LP structure through node-level interruptible and firm demand curves derived from the GMM natural gas demand module. (These are discussed in greater detail in Section 10.6 below.) The gas consumption in the non-power sectors is calculated within the gas module and the power sector consumption is calculated within the IPM electricity dispatch module. Figure 10-5 shows the geographic locations of the demand regions.

[2] Resource appreciation represents growth in ultimate resource estimates attributed to success in extracting resource from known plays such as natural gas from shales, coal seams, offshore deepwater, and gas hydrates that are not included in the resource base estimates.

Figure 10-3 Gas Transmission Network Map

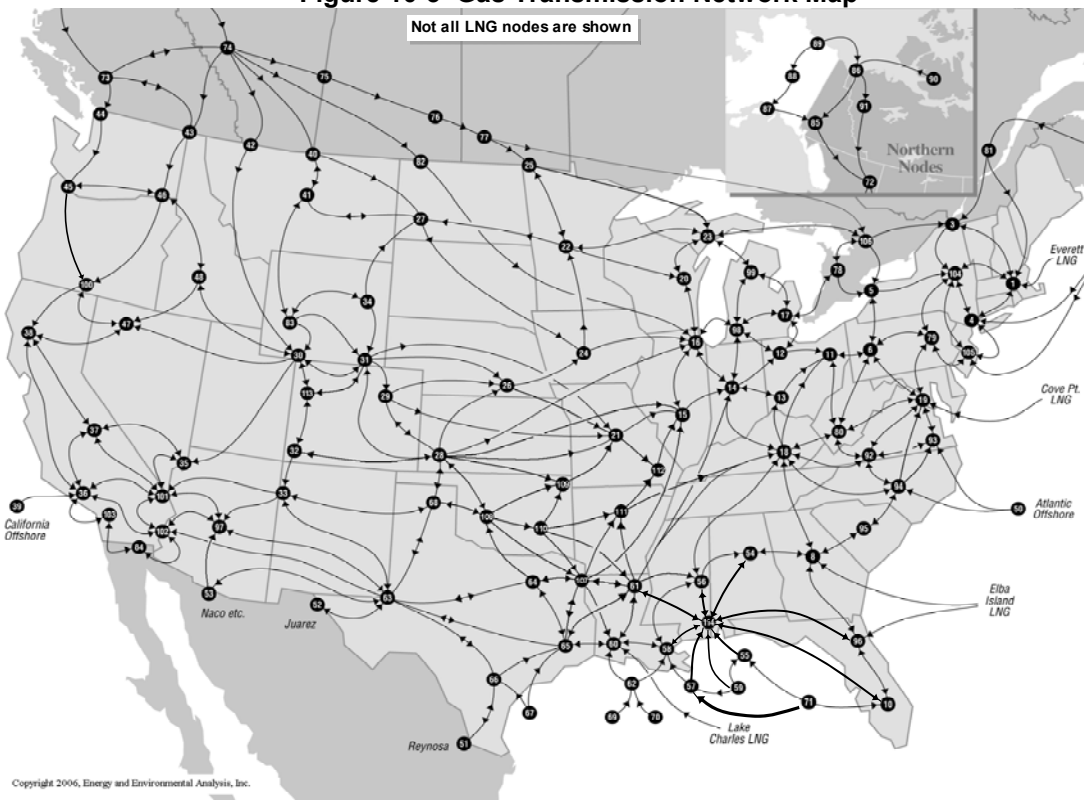


Table 10-1 List of Nodes

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
1	New England		X			X
2	Everett TRANS			X		
3	Quebec		X			X
4	New York City		X			X
5	Niagara	X	X		X	X
6	Leidy	X	X		X	X
7	Cove Point TRANS			X		
8	Georgia		X			X
9	Elba Is TRANS			X		
10	South Florida		X			X
11	East Ohio	X	X		X	X
12	Maumee/Defiance	X	X			X
13	Lebanon	X	X			X
14	Indiana	X	X		X	X
15	South Illinois	X	X		X	X
16	North Illinois	X	X		X	X
17	Southeast Michigan	X	X		X	X
18	Tennessee/Kentucky	X	X		X	X
19	MD/DC/Northern VA		X			X
20	Wisconsin	X	X			X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
21	Northern Missouri	X	X			X
22	Minnesota	X	X		X	X
23	Crystal Falls	X	X			X
24	Ventura	X	X		X	X
25	Emerson Imports			X		
26	Nebraska	X	X		X	X
27	Great Plains			X		
28	Kansas	X	X		X	X
29	East Colorado	X	X		X	X
30	Opal	X	X		X	X
31	Cheyenne	X	X		X	
32	San Juan Basin	X	X		X	
33	EPNG/TW	X	X			X
34	North Wyoming	X	X		X	
35	South Nevada	X	X			X
36	SOCAL Area	X	X		X	X
37	Enhanced Oil Recovery Region	X	X			
38	PGE Area	X	X		X	X
39	Pacific Offshore	X				
40	Monchy Imports			X		
41	Montana/North Dakota	X	X		X	X
42	Wild Horse Imports			X		
43	Kingsgate Imports			X		
44	Huntingdon Imports			X		
45	Pacific Northwest	X	X		X	X
46	NPC/PGT Hub		X			X
47	North Nevada	X	X			X
48	Idaho	X	X			X
49	Eastern Canada Offshore	X				
50	Atlantic Offshore	X				
51	Reynosa Imp/Exp			X		
52	Juarez Imp/Exp			X		
53	Naco Imp/Exp			X		
54	North Alabama	X	X		X	X
55	Alabama Offshore	X				
56	North Mississippi	X	X		X	X
57	East Louisiana Shelf	X				
58	Eastern Louisiana Hub	X	X		X	X
59	Viosca Knoll/Desoto/Miss Canyon	X				
60	Henry Hub	X	X		X	X
61	North Louisiana Hub	X	X		X	X
62	Central and West Louisiana Shelf	X				
63	Southwest Texas	X	X		X	
64	Dallas/Ft Worth	X	X		X	X
65	E. TX (Katy)	X	X		X	X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
66	S. TX	X	X			X
67	Offshore Texas	X				
68	NW TX	X	X			X
69	Garden Banks	X				
70	Green Canyon	X				
71	Eastern Gulf	X				
72	North British Columbia	X	X			X
73	South British Columbia		X			X
74	Caroline	X	X			X
75	Empress			X		
76	Saskatchewan	X	X			X
77	Manitoba	X	X			X
78	Dawn	X	X			X
79	Philadelphia		X			X
80	West Virginia	X	X		X	X
81	Eastern Canada Demand		X			X
82	Alliance Border Crossing			X		
83	Wind River Basin	X	X		X	
84	California Mexican Exports			X		
85	Whitehorse			X		
86	MacKenzie Delta	X				
87	South Alaska	X		X		
88	Central Alaska	X				
89	North Alaska	X				
90	Arctic	X				
91	Norman Wells	X				
92	Southwest VA	X	X		X	X
93	Southeast VA		X			X
94	North Carolina		X			X
95	South Carolina		X			X
96	North Florida	X	X			X
97	Arizona		X		X	X
98	Southwest Michigan	X	X		X	X
99	Northern Michigan	X	X		X	X
100	Malin Interchange			X		
101	Topock Interchange			X		
102	Ehrenberg Interchange			X		
103	SDG&E Demand		X			X
104	Eastern New York		X			X
105	New Jersey		X			X
106	Toronto		X			X
107	Carthage	X	X		X	X
108	Southwest Oklahoma	X	X		X	X
109	Northeast Oklahoma	X	X		X	X
110	Southeastern Oklahoma	X	X		X	X
111	Northern Arkansas	X	X		X	X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage
112	Southeast Missouri	X	X		X	X
113	Uinta/Piceance	X	X		X	X
114	South MS/AL	X	X		X	X

Figure 10-4 Gas Supply Regions Map

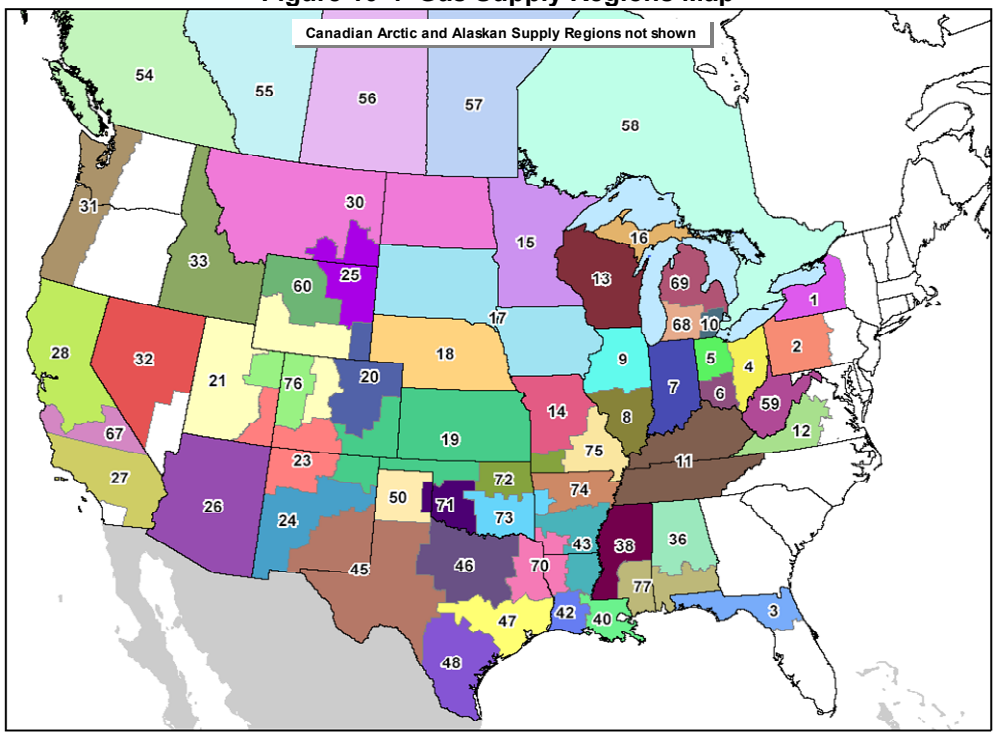
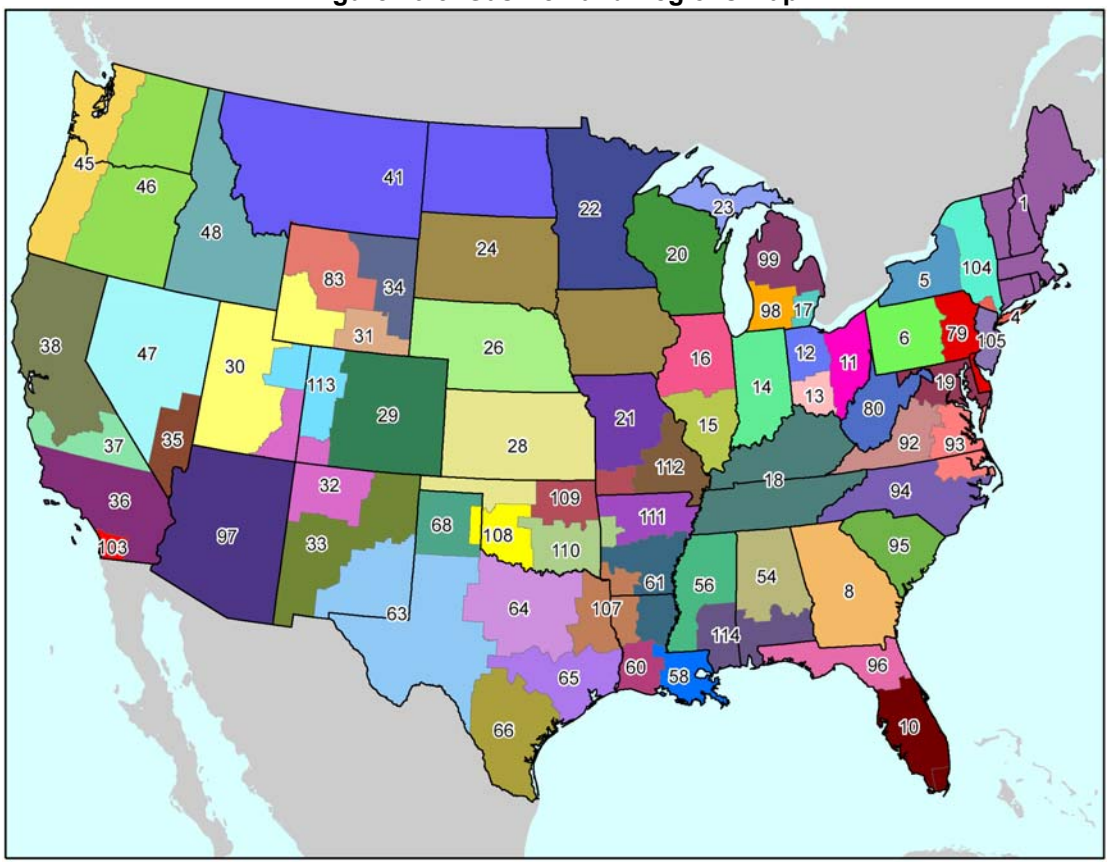


Table 10-2 List of Gas Supply Regions

Supply Region Number	Node Number	Region Name
1	5	Niagara
2	6	Leidy
3	96	Florida
4	11	East Ohio
5	12	Maumee/ Defiance
6	13	Lebanon
7	14	Indiana
8	15	South Illinois
9	16	North Illinois
10	17	Southeast Michigan
11	18	Tennessee/Kentucky
12	92	SW Virginia
13	20	Wisconsin
14	21	Northern Missouri
15	22	Minnesota
16	23	Crystal Falls
17	24	Ventura
18	26	Nebraska
19	28	Kansas
20	29	East Colorado
21	30	Opal
22	31	Cheyenne
23	32	San Juan Basin
24	33	EPNG/TW
25	34	North Wyoming
26	97	Arizona
27	36	SOCAL Area
28	38	PGE Area
29	39	California Offshore
30	41	Montana/ North Dakota
31	45	Pacific Northwest
32	47	North Nevada
33	48	Idaho
34	49	Eastern Canada Offshore
35	50	Atlantic Offshore
36	54	North Alabama
37	55	Alabama Offshore
38	56	North Mississippi
39	57	East Louisiana Shelf
40	58	Eastern Louisiana Hub
41	59	Viosca Knoll S./ Desoto Canyon/Mississippi Canyon
42	60	Henry Hub
43	61	North Louisiana Hub
44	62	Central and West Louisiana Shelf

Supply Region Number	Node Number	Region Name
45	63	Southwest Texas
46	64	Dallas/Fort Worth
47	65	E. TX (Katy)
48	66	S. TX
49	67	Offshore Texas
50	68	NW TX
51	69	Garden Banks
52	70	Green Canyon
53	71	Florida off-shore moratorium area
54	72	North British Columbia
55	74	Caroline
56	76	Saskatchewan
57	77	Manitoba
58	78	Dawn
59	80	West Virginia
60	83	Wind River Basin
61	86	McKenzie Delta
62	87	Southern Alaska
63	88	Central Alaska
64	89	Northern Alaska
65	90	Arctic
66	91	Norman Wells
67	37	Enhanced Oil Recovery Region
68	98	Southwest Michigan
69	99	Central Michigan
70	107	Carthage
71	108	Southwest Oklahoma
72	109	Northeast Oklahoma
73	110	Southeastern Oklahoma
74	111	Northern Arkansas
75	112	Southeast Missouri
76	113	Uinta/Piceance
77	114	South MS/AL

Figure 10-5 Gas Demand Regions Map



Natural gas pipeline network is modeled by 343 transmission links or segments (excluding pipeline connections with LNG nodes) that represent major interstate transmission corridors throughout North America (Figure 10-3). The pipeline corridors represent a group of interstate pipelines along the corridor. The list of key interstate pipelines by links is tabulated in Table 10-3. Each of the links has an associated discount curve (derived from GMM natural gas transportation module), which represents the marginal value of gas transmission on that pipeline segment as a function of the pipeline's load factor.[1] Starting year of operation and transmission capacity (in units of BBtu/day) are specified as inputs and the model allows for capacity expansions.

Table 10-3 List of Key Pipelines

Link	Pipeline
6 - 5	DOMINION TRANS (CNG)
6 - 5	COLUMBIA GAS TRANS CORP
5 - 6	NATIONAL FUEL GAS SUPPLY CO
11 - 6	DOMINION TRANS (CNG)
11 - 6	COLUMBIA GAS TRANS CORP
6 - 19	DOMINION TRANS (CNG)
6 - 79	TEXAS EASTERN TRANS CORP
6 - 79	TRANSCONTINENTAL GAS P L CO

[1] In this context "load factor" refers to the percentage of the pipeline capacity that is utilized at a given time.

Link	Pipeline
6 - 79	TENNESSEE GAS PIPELINE CO
80 - 6	COLUMBIA GAS TRANS CORP
80 - 6	EQUITRANS INC
96 - 8	SOUTHERN NATURAL GAS CO
96 - 10	FLORIDA GAS TRANS CO
80 - 11	COLUMBIA GAS TRANS CORP
17 - 12	ANR PIPELINE CO
98 - 12	ANR PIPELINE CO
14 - 13	PANHANDLE EASTERN P L CO
98 - 14	TRUNKLINE GAS CO
16 - 15	NAT GAS P L CO OF AMERICA
16 - 20	ANR PIPELINE CO
16 - 98	ANR PIPELINE CO
78 - 17	BLUEWATER PIPELINE CO
99 - 17	MICHCON
18 - 80	COLUMBIA GAS TRANS CORP
18 - 92	EAST TENNESSEE NAT GAS CO
79 - 19	EASTERN SHORE NAT GAS CO
19 - 79	TRANSCONTINENTAL GAS P L CO
19 - 79	COLUMBIA GAS TRANS CORP
92 - 19	COLUMBIA GAS TRANS CORP
23 - 99	GREAT LAKES GAS TRANS LTD
106 - 23	GREAT LAKES GAS TRANS LTD
41 - 27	WILLISTON BASIN P L CO
28 - 29	COLORADO INTERSTATE GAS
68 - 28	COLORADO INTERSTATE GAS
31 - 30	COLORADO INTERSTATE GAS
31 - 30	SOUTHERN STAR CENTRAL (WILLIAMS)
30 - 31	WYOMING INTERSTATE CO
30 - 48	NORTHWEST PIPELINE CORP
113 - 30	NORTHWEST PIPELINE CORP
113 - 32	NORTHWEST PIPELINE CORP
63 - 33	EL PASO NAT GAS CO
63 - 33	TRANSWESTERN PIPELINE CO
68 - 33	TRANSWESTERN PIPELINE CO
37 - 36	SOCAL GAS
37 - 38	PACIFIC GAS & ELECTRIC
40 - 41	NORTHWEST ENERGY
41 - 83	WILLISTON BASIN P L CO
73 - 43	TERASEN (BC GAS)
46 - 45	NORTHWEST PIPELINE CORP
46 - 48	NORTHWEST PIPELINE CORP
66 - 51	TENNESSEE GAS PIPELINE CO
51 - 66	TEXAS EASTERN TRANS CORP
54 - 114	TRANSCONTINENTAL GAS P L CO
58 - 56	GULF SOUTH (KOCH)
60 - 58	TRANSCONTINENTAL GAS P L CO

Link	Pipeline
60 - 58	SOUTHERN NATURAL GAS CO
60 - 58	FLORIDA GAS TRANS CO
60 - 58	TENNESSEE GAS PIPELINE CO
60 - 58	TEXAS EASTERN TRANS CORP
60 - 58	GULF SOUTH (KOCH)
60 - 65	NAT GAS P L CO OF AMERICA
61 - 107	CENTERPOINT ENERGY (RELIANT)
64 - 63	TXU LONESTAR GAS PIPELINE
64 - 63	EPGT TEXAS PIPELINE (VALERO)
65 - 63	OASIS
66 - 63	EPGT TEXAS PIPELINE (VALERO)
68 - 63	TRANSWESTERN PIPELINE CO
63 - 68	EL PASO NAT GAS CO
63 - 97	EL PASO NAT GAS CO
65 - 64	TXU FUEL CO
65 - 64	TXU LONESTAR GAS PIPELINE
108 - 68	NAT GAS P L CO OF AMERICA
108 - 68	EL PASO NAT GAS CO
68 - 108	ANR PIPELINE CO
106 - 78	UNION GAS
102 - 84	BAJA NORTE
99 - 98	ANR PIPELINE CO
99 - 98	MICHIGAN GAS STORAGE
101 - 102	EL PASO NAT GAS CO

Natural gas storage is modeled by 180 underground and LNG peak shaving[2] storage facilities that are linked to individual nodes. The underground storage is grouped into three categories based on storage "Days Service"[3]: (1) 20-day for high deliverability[4] storage such as salt caverns, (2) 80-day for depleted[5] and aquifer[6] reservoirs, and (3) over 80 days mainly for depleted reservoirs. Figure 10-6 shows natural gas storage facility node map. The level of gas storage withdrawals and injections are calculated within the supply and demand balance algorithm based on working gas[7] levels, gas prices, and extraction/injection rates and costs. Starting year of

[2] LNG peak shaving facilities supplement deliveries of natural gas during times of peak periods. LNG peak shaving facilities have a regasification unit attached, but may or may not have a liquefaction unit. Facilities without a liquefaction unit depend upon tank trucks to bring LNG from nearby sources.

[3] "Days Service" refers to the number of days required to completely withdraw the maximum working gas inventory associated with an underground storage facility.

[4] High deliverability storage is depleted reservoir storage facility or Salt Cavern storage whose design allows a relatively quick turnover of the working gas capacity.

[5] A gas or oil reservoir that is converted for gas storage operations. Its economically recoverable reserves have usually been nearly or completely produced prior to the conversion.

[6] The underground storage of natural gas in a porous and permeable rock formation topped by an impermeable cap rock, the pore space of which was originally filled with water.

[7] The term "working gas" refers to natural gas that has been injected into an underground storage facility and stored therein temporarily with the intention of withdrawing it. It is distinguished from "base (or cushion) gas" which refers to the volume of gas that remains permanently in the storage

operation and working gas capacity (in units of BBtu) are specified as inputs and the model allows for capacity expansions. The location of the storage facilities is shown in Figure 10-6.

Natural gas prices are market clearing prices derived from the supply and demand balance at each of the model's nodes for each segment of IPM's electricity sector's seasonal load duration curve (LDC). On the supply-side, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also affected by the "pipeline discount" curves discussed earlier, which represent the marginal value of gas transmission as a function of a pipeline's load factor and result in changes in basis differential. On the demand-side, the price/quantity relationship is represented by demand curves that capture the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes and yields market clearing prices determined by the specific shape of the supply and demand curves at each node.

10.2.1 Note on the Modeling Time Horizon and Pre- and Post-2030 Input Assumptions

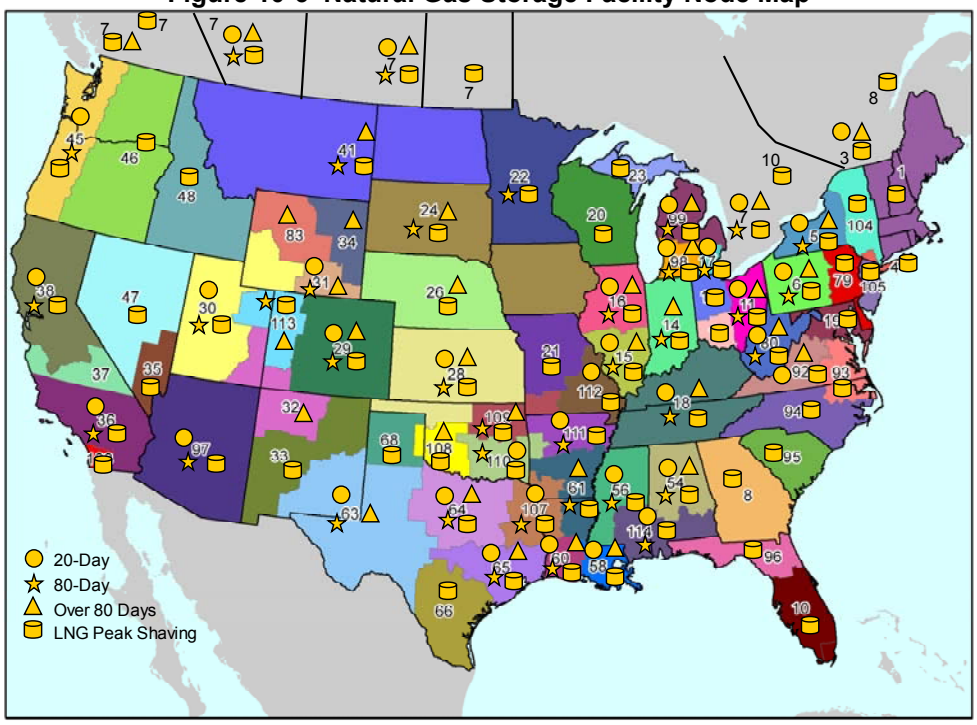
The time horizon of previous EPA IPM base cases extended no further than 2030. This made possible a detailed bottom-up development of natural gas assumptions from available data sources. To support analysis of climate change policies, which have a longer time horizon than previously analyzed policies for conventional air pollutants, the time horizon of EPA's new Base Case v.4.10 extends to 2050. The same detailed bottom-up approach that was employed previously is employed out to 2030. Beyond 2030, where detailed data is not readily available, various technically plausible simplifying assumptions were made. For example, natural gas demand growth from 2030 to 2050 for the non-power sectors (i.e. residential, commercial, and industrial) is assumed to be the same as the level of growth from 2020 to 2030. Resource growth assumptions (for resource appreciation) that were applied for pre-2030 are extended beyond 2030. Post 2030 price projections for crude oil and natural gas liquid[8] (NGL) are assumed to be flat at 2030 price levels. The pre-2030 price projections were adapted from AEO 2010.

---

reservoir in order to maintain adequate pressure and deliverability rates throughout the withdrawal season.

[8] Those hydrocarbons in natural gas that are separated from the gas as liquids in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline, and liquefied petroleum gases.

Figure 10-6 Natural Gas Storage Facility Node Map



10.3 Resource Characterization and Economic Evaluation

The GMM Hydrocarbon Supply Model (HSM) provides data related to resource characterization and economic evaluation for use in the IPM natural gas module. The current section describes data sources and methods used in the HSM to characterize the North American natural gas resource base. This section concludes with a description of how the HSM resource characterization is used in the EPA Base Case v.4.10 gas module. The next section (i.e., Section 10.4) describes the economic evaluation procedures applied to Exploration and Development (E&D) activities in the HSM and various constraints affecting E&D activities.

The HSM was designed for the simulation, forecasting and analysis of natural gas, crude oil and natural gas liquids supply and cost trends in the United States and Canada. The HSM includes a highly detailed description of both the undiscovered and discovered resources in the US and Canada. The resource base is described on a field-by-field basis. The individual fields are characterized by type (i.e., oil or gas), size, and location. Location is defined both geographically and by depth. The HSM is a process-engineering model with a very detailed representation of potential gas resources and the technologies with which those resources can be proven[9] and produced. The degree and timing by which resources are proven and produced are determined in the model through discounted cashflow analyses of alternative investment options and behavioral assumptions in the form of inertial and cashflow constraints, and the logic underlying producers' market expectations (e.g., their response to future gas prices).

Supply results from the HSM model include undeveloped resource accounting and detailed well, reserve addition, decline rate, and financial results. These results are utilized to provide estimates

[9] The term "proven" refers to the estimation of the quantities of natural gas resources that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Among the factors considered are drilling results, production, and historical trends. Proven reserves are the most certain portion of the resource base.

of base year economically recoverable natural gas resources and remaining reserves as a function of E&D cost for the 77 supply regions in the IPM natural gas module. The HSM also provides other data such as the level of remaining resource that could be discovered and developed in a year, exploration and development drilling requirements, production operation and maintenance (O&M) cost, resource share of crude oil and natural gas liquids, natural gas reserves to production ratio, and natural gas requirement for lease and plant use.[10]

10.3.1 Resource and Reserves[11] Assessment

Data sources: The HSM uses the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and Canadian Gas Potential Committee (CGPC) play-level[12] resource assessments as the starting point for the new field/new pool[13] assessments. Beyond the resource assessment data, ICF has access to numerous databases that were used for the HSM model development and other analysis. Completion-level production is based on IHS Energy completion level oil and gas production databases for the U.S. and Canada. The U.S. database contains information on approximately 300,000 U.S. completions. A structured system is employed to process this information and add certain ICF data (region, play, ultimate recovery, and gas composition) to each record. ICF also performs extensive quality control checks using other data sources such as the MMS completion and production data for Outer Continental Shelf (OCS) areas and state production reports.

In the area of unconventional gas[14], ICF has worked for many years with the Gas Research Institute (GRI)/Gas Technology Institute (GTI) to develop a database of tight gas, coalbed methane, and Devonian Shale reservoirs in the U.S. and Canada. Along with USGS assessments of continuous plays, the database was used to help develop the HSM's "cells", which represent resources in a specific geographic area, characterizing the unconventional resource in each basin, historical unconventional reserves estimates and typical decline curves.[15]

---

[10] As discussed more fully in Section 10.4, natural gas for "lease and plant use" refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants.

[11] When referring to natural gas a distinction is made between "resources" and "reserves." "Resources" are concentrations of natural gas that are or may become of potential economic interest. "Reserves" are that part of the natural gas resource that has been fully evaluated and determined to be commercially viable to produce.

[12] A "play" refers to a set of known or postulated natural gas (or oil) accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.

[13] A "pool" is a subsurface accumulation of oil and other hydrocarbons. Pools are not necessarily big caverns. They can be small oil-filled pores. A "field" is an accumulation of hydrocarbons in the subsurface of sufficient size to be of economic interest. A field can consist of one or more pools.

[14] Unconventional gas refers to natural gas found in geological environments that differ from conventional hydrocarbon traps. It includes: (a) "tight gas," i.e., natural gas found in relatively impermeable (very low porosity and permeability) sandstone and carbonate rocks; (b) "shale gas," i.e., natural gas in the joints, fractures or the matrix of shales, the most prevalent low permeability low porosity sedimentary rock on earth; and (c) "coalbed methane," which refers to methane (the key component of natural gas) found in coal seams, where it was generated during coal formation and contained in the microstructure of coal. Unconventional natural gas is distinguished from conventional gas which is extracted using traditional methods, typically from a well drilled into a geological formation exploiting natural subsurface pressure or artificial lifting to bring the gas and associated hydrocarbons to the wellhead at the surface.

[15] A decline curve is a plot of the rate of gas production against time. Since the production rate decline is associated with pressure decreases from oil and gas production, the curve tends to smoothly decline from a high early production rate to lower later production rate. Exponential,

ICF has recently revised the unconventional gas resource assessments based on new gas industry information on the geology, well production characteristics, and costs. The new assessments include major shale units such as the Fort Worth Barnett Shale, the Marcellus Shale, the Haynessville Shale, and Western Canada shale plays. ICF has built up a database on gas compositions in the United States and has merged that data with production data to allow the analysis of net versus raw gas production.[16]

In Canada, gas composition data are obtained from provincial agencies. These data were used to develop dry gas[17] production/reserves by region and processing costs in the HSM and to characterize ethane rejection[18] by regions. Information on oil and gas fields and pools in the U.S. come originally from Dwight's Energydata (now IHS Energy) TOTL reservoir database. ICF has made extensive modifications to the database during the creation of the Gas Information System (GASIS) database for the U.S. Department of Energy (DOE) and other projects. Field and reservoir data for Canada comes from the provincial agency databases. These data are used to estimate the number and size of undiscovered fields or pools and their rate of discovery per increment of exploratory drilling. Additional data were obtained from the Significant Field Data Base of NRG Associates.

Methodology and assumptions: Resources in the HSM model are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

Conventional resource – new fields/new pools: The modeling of conventional resource is based on a modified "Arps Roberts" equation[19] to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its area extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. Finding that the original Arps-Roberts equation did not replicate historical discovery patterns for many of the smaller field sizes, ICF modified the equation to improve its ability to accurately track discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas of the U.S. and Western Canada Sedimentary Basin (WCSB), the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas. An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and the economics of developing each.

---

harmonic, and hyperbolic equations are typically used to represent the decline curve.

[16] Raw gas production refers to the volumes of natural gas extracted from underground sources, whereas net gas production refers to the volume of purified, marketable natural gas leaving the natural gas processing plant.

[17] Natural gas is a combustible mixture of hydrocarbon gases. Although consisting primarily of methane, the composition of natural gas can vary widely to include propane, butane, ethane, and pentane. Natural gas is referred to as 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is called 'wet'.

[18] Ethane rejection occurs when the ethane component in the natural gas stream is not recovered in a gas processing plant but left in the marketable natural gas stream. Ethane rejection is deployed when the value of ethane is worth more in the gas stream than as an a separate commodity or as a component of natural gas liquids (NGL), which collectively refers to ethane, propane, normal butane, isobutane, and pentanes in processed and purified finished form. Information that characterizes ethane rejection by region can play a role in determining the production level and cost of natural gas by region.

[19] "Arps-Roberts equation" refers to the statistical model of petroleum discovery developed by J. J. Arps, and T. G. Roberts, T. G.,in the 1950's.

Conventional resource – field appreciation: The model maintains inventories of potential resources that can be proved from already discovered fields. These inventories are referred to as appreciation, growth-to-known or "probables." As the model simulation proceeds, these probables inventories are drawn down as the resources are proved. At the same time, the inventories of probables are increased due to future year appreciation of new fields that are added to the discovered fields' data set during the model simulation.

Unconventional resource: The Enhanced Recovery Module (or ERM) within the HSM, covers that portion of the resource base which falls outside the scope of the "conventional" oil and gas field discovery process dealt with elsewhere in the model. The ERM includes coalbed methane, shale gas, and tight gas. These resources generally correspond to the "continuous plays" designated by the USGS in its resource assessments. The ERM is organized by "cells", which represent resources in a specific geographic area. A cell can represent any size of area ranging from the entire region/depth interval to a single formation in a few townships of a basin. Each cell is evaluated in the model using the same discounted cashflow analysis used for new and old field investments. The ERM cells also are subject to the inertial and cashflow constraints affecting the other types of investment options in the model. The model reports total wells drilled, reserve additions, production, and dollars invested for each type of ERM cell (e.g., coalbed methane) within a region.

10.3.2 Frontier Resources (Alaska and Mackenzie Delta)

Besides the three general categories of resources described above, the handling of frontier resources in the HSM is worth noting. Frontier resources such as Alaska North Slope and Mackenzie Delta are subject to similar resource assessment and economic evaluation procedures as applied to other regions. Results from HSM simulation for the two frontier regions can be seen in Table 10-4. It shows an undiscovered resource potential is 126.8 Tcf for Alaska North Slope and 32.9 Tcf for Mackenzie Delta and remaining gas reserves of 25.5 Tcf and 0.4 Tcf for Alaska North Slope and Mackenzie Delta, respectively. However, unlike other regions, the resources from these regions are stranded to date due to lack of effective commercial access to markets. In fact, 6-8 Bcf/d of gas that is currently produced as part of the oil activities in the Alaska North Slope is re-injected back into the Slope's oil reservoirs as part of the pressure maintenance programs. Several development proposals have been put forward for bringing this gas to market in order to realize the long-held goal of monetizing the Alaska North Slope and Mackenzie Delta gas.

In developing the gas resource assumptions for EPA Base Case v.4.10, two gas pipeline projects were identified for bringing the two frontier gas supply resources to the markets in the U.S. and Canada. A diagnostic run was made with both potential pipeline projects turned on, letting the model decide the starting year of the projects and subsequent pipeline capacity expansions. Analysis of pipeline capacities and flows indicated that the Alaska gas pipeline project would be feasible starting from 2035, but the Mackenzie Delta pipeline project would not be feasible at all due to relatively low pipeline flows. These were the assumptions used for EPA Base Case v.4.10.

Table 10-4 U.S. and Canada Natural Gas Resources and Reserves

Region	End of Year 2008		End of Year 2010	
	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)
Lower 48 Onshore Non Associated	1,629.0	208.5	1,616.2	208.0
Conventional	313.3	50.1	306.6	50.0
Northeast	15.4	3.8	15.0	3.8
Gulf Coast	133.9	16.4	131.5	16.4
Midcontinent	54.4	11.2	52.7	11.2

Region	End of Year 2008		End of Year 2010	
	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)	Undiscovered Dry Gas Resource (Tcf)	Dry Gas Reserves (Tcf)
Southwest	19.2	5.6	18.6	5.6
Rocky Mountain	84.0	10.7	82.6	10.7
West Coast	6.4	2.4	6.2	2.3
Shale Gas	921.2	38.5	917.2	38.4
Northeast	254.8	3.5	254.4	3.5
Gulf Coast	433.1	13.5	431.6	13.4
Midcontinent	133.9	10.9	132.9	10.8
Southwest	61.3	10.7	60.3	10.6
Rocky Mountain	37.9	-	37.7	-
West Coast	0.3	-	0.3	-
Coalbed Methane	73.9	20.5	73.1	20.4
Northeast	9.5	2.0	9.5	2.0
Gulf Coast	4.3	1.2	4.2	1.2
Midcontinent	9.6	2.2	9.5	2.2
Southwest	-	-	-	-
Rocky Mountain	49.8	15.1	49.3	15.0
West Coast	0.7	-	0.6	-
Tight Gas	320.7	99.5	319.2	99.2
Northeast	33.7	6.6	34.0	6.6
Gulf Coast	59.6	28.9	58.2	28.9
Midcontinent	4.6	7.5	4.6	7.5
Southwest	6.1	15.2	5.9	15.1
Rocky Mountain	205.1	41.2	204.9	41.1
West Coast	11.5	-	11.6	-
Lower 48 Offshore Non Associated	137.1	10.5	136.3	10.5
Lower 48 Associated-Dissolved Gas	145.1	17.9	143.5	17.9
Total Lower 48	1,911.2	237.0	1,895.9	236.3
Alaska	153.6	35.2	153.3	35.2
Alaska North Slope	126.8	25.2	126.8	25.2
Alaska - Other	26.8	9.9	26.5	9.9
Total U.S.	2,064.8	272.1	2,049.2	271.5
Canada Non Associated	667.9	56.7	667.3	56.5
Conventional	121.4	43.6	119.6	43.5
Shale Gas	508.8	0.5	511.1	0.5
Coalbed Methane	27.4	12.5	26.7	12.5
Tight Gas	10.3	-	9.9	-
Canada Associated-Dissolved Gas	8.1	2.7	8.0	2.7
Eastern Canada Offshore	71.8	2.5	71.6	2.5
MacKenzie Delta	32.9	0.4	32.9	0.4
Total Canada	780.8	62.3	779.8	62.1

10.3.3 Use of the HSM resource and reserves data in EPA Base Case using IPM v.4.10 Natural Gas Module

The base year for the integrated gas-electricity module in EPA Base Case using IPM v.4.10 is 2012. Having a base year in the future has implications on how the model is run and how the gas reserves and resources data are set up. The IPM run begins with a gas module only run for year 2011 to provide end of year (EOY) 2011 reserves and resources as the starting point for the integrated run from 2012 onward. This in turn requires the reserves and resources data to be provided for the EOY 2010. Since the data from the HSM are as of EOY 2008, a two-year production forecast needs to be conducted to estimate the EOY 2010 gas resources and reserves. This production forecast is done using the GMM with the EPA Base Case assumptions. In the future if an IPM sensitivity analysis case is performed whose assumptions are likely to have a significant impact on gas reserves and resources in the 2009-2010 timeframe, the HSM projection of EOY 2010 gas resources and reserves may have to be re-run.

The last two columns in Table 10-4 give a snapshot of the starting natural gas resource and reserve assumptions that were provided by HSM to EPA Base Case v.4.10 for EOY 2010. In this table, undiscovered resources represent the economic volume of dry gas that could be discovered and developed with current technology through exploration and development at a specified maximum wellhead gas price. The reserves are remaining dry gas volumes to be produced from existing developed fields. For EPA Base Case the maximum wellhead price for the resource cost curves is capped at around $14/MMBtu (in real 2007 dollars). The ultimate potential undiscovered resources available are actually higher than those presented in Table 10-4 but it would cost more than $14/MMBtu to recover them. (It is important to note that this price is for wet[20] gas at the wellhead in the production nodes and is found to be high enough to cover the range of wellhead prices for EPA scenarios. The dry gas price at the receiving nodes can be higher than $14/MMBtu which depends on the share of dry gas, lease and plant use, gas processing cost, production O&M cost, and pipeline transportation costs.) The approach used in the HSM to derive these costs is described more fully in section 10.4 below.

Since the new IPM natural gas module differentiates conventional gas from unconventional gas, these are shown separately in Table 10-4. The conventional gas is subcategorized into non-associated gas from gas fields and associated gas[21] from oil fields. The unconventional gas is subdivided into coalbed methane, shale gas, and tight gas. The U.S. and Canada natural gas undiscovered resources and remaining reserves as of EOY 2008 and their estimates for the EOY 2010 are also shown in Table 10-4.

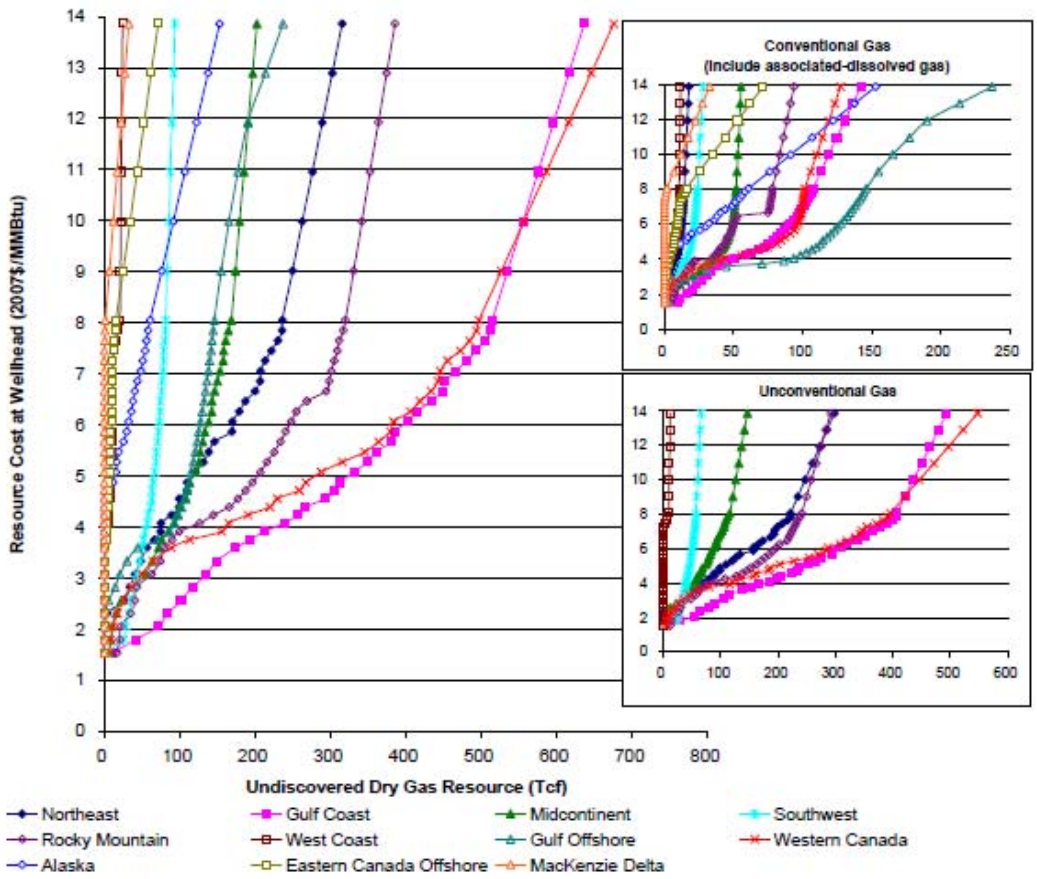
Figure 10-7 presents resource cost curves for the EOY 2010 initializing gas assumptions that the HSM provides for EPA Base Case v.4.10. The cost curves show the recoverable resources at different price levels. Separate resource cost curves are shown for key regions as well as for conventional and unconventional gas. The recoverable resources shown at maximum wellhead prices in these graphs are those tabulated in Table 10-4 under EOY 2010 column. The y-axis of the resource cost curves shows the cost at the wellhead of bringing the volume of undiscovered resource indicated on the x-axis into the reserves category. Figure 10-8 diagrams the exploration & development and production processes and the associated costs required to bring undiscovered resource into reserves and production.

---

[20] A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium.

[21] Associated gas refers to natural gas that is produced in association with crude oil production, whereas non-associated gas is natural gas that is not in contact with significant quantities of crude oil in the reservoir.

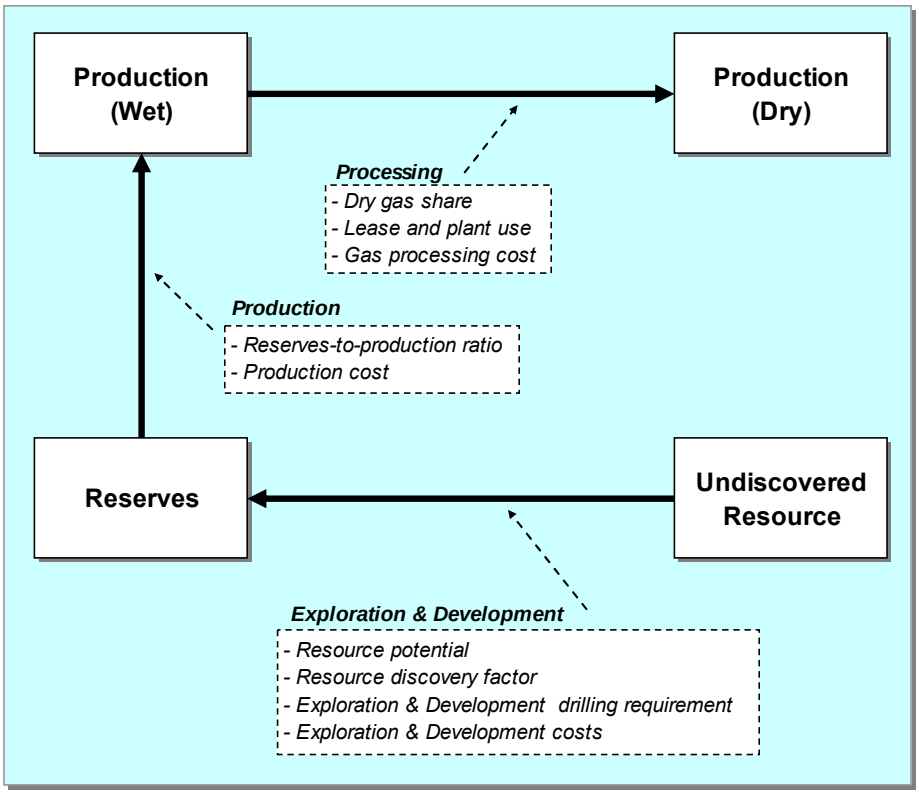
Figure 10-7 Resource Cost Curves at the End of Year 2010



10.3.4 Undiscovered Resource Appreciation

Undiscovered resource appreciation is additional resources from hydrocarbon plays that were not included in the resource base estimates. It differs from field appreciation or reserves appreciation category discussed above which comes from already discovered fields. Natural gas from shales, coal seams, offshore deepwater, and gas hydrates may not be included in the resource base assessments due to lack of knowledge and technology to economically recover the resource. As new technology becomes available, these untapped resources can be produced economically in the future. One example is the advancements in horizontal drilling and hydraulic fracture technologies to produce gas from shale formations. For EPA Base Case, the undiscovered gas resource is assumed to grow at 0.2% per year for conventional gas and 0.75% per year for unconventional gas. The EOY 2010 undiscovered resources in Table 10-4 and Figure 10-7 include resource appreciation in 2009 and 2010.

Figure 10-8 Exploration & Development and Production Processes and Costs to Bring Undiscovered Resource into Reserves and Production



10.4 Exploration, Development, and Production Costs and Constraints

10.4.1 Exploration and Development Cost

Exploration and development (E&D) cost or resource cost is the expenditure for activities related to discovering and developing hydrocarbon resources. The E&D cost for natural gas resources is a function of many factors such as geographic location, field type, size, depth, exploratory success rates, and platform, drilling and other costs. The HSM contains base year cost for wells, platforms, operating costs and all other relevant cost items. In addition to the base year costs, the HSM contains cost indices that adjust costs over time. These indices are partly a function of technology drivers such as improved exploratory success rates, cost reductions in platform, drilling and other costs, improved recovery per well, and partly a function of regression-based algorithms that relate cost to oil and gas prices and industry activity. As oil and gas prices and industry activity increase, the cost for seismic, drilling & completion services, casing and tubing and lease equipment goes up.

Other technology drivers affect exploratory success rates and reduce the need to drill exploratory wells. A similar adjustment is made to take into account changes over time in development success rates, but the relative effect is much smaller because development success rates are already rather high. The technology drivers that increase recovery per well are differentiated in the HSM by region and by type of gas. Generally, the improvements are specified as being greater for unconventional gas because their recovery factors are much lower than those of conventional gas.

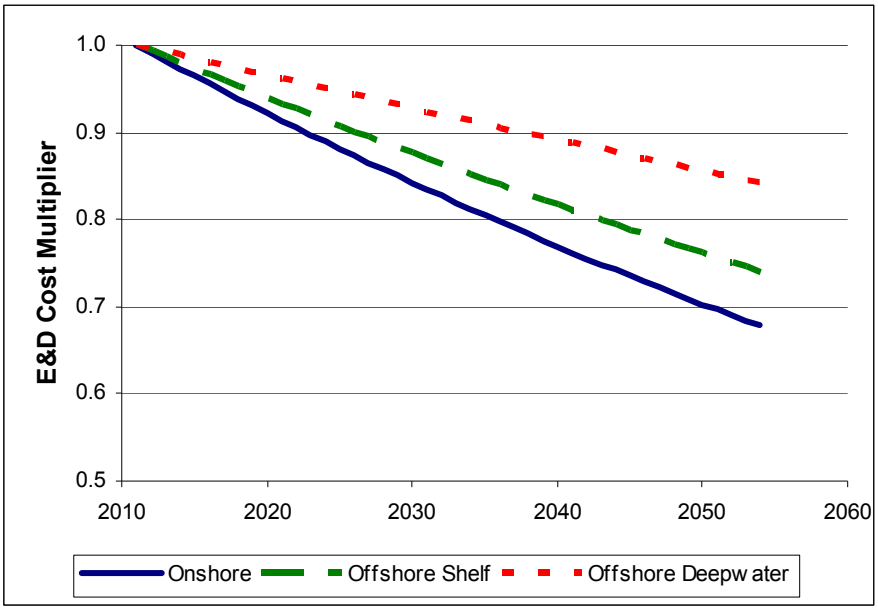
The HSM model provides estimates of E&D cost and the level of economically viable gas resource by region as a function of E&D cost. The HSM increased recovery as a function of technology improvement by region is converted to E&D and production technology improvement over time in the form of cost reduction factors by onshore, offshore shelf, and offshore deepwater as shown in

Figure 10-9. The average cost reduction factors for onshore, offshore shelf, and offshore deepwater E&D activities are -0.9% per year, -0.7% per year, and -0.4% per year, respectively. These factors are predominantly affected by the level of E&D investments in the regions. The expected aggressive onshore E&D activities to find and produce unconventional gas resources, such as shale gas, will lead to more research in horizontal drilling and hydraulic fracturing technologies to improve productions and lower the costs. This is reflected in higher cost reduction factors for the onshore regions.

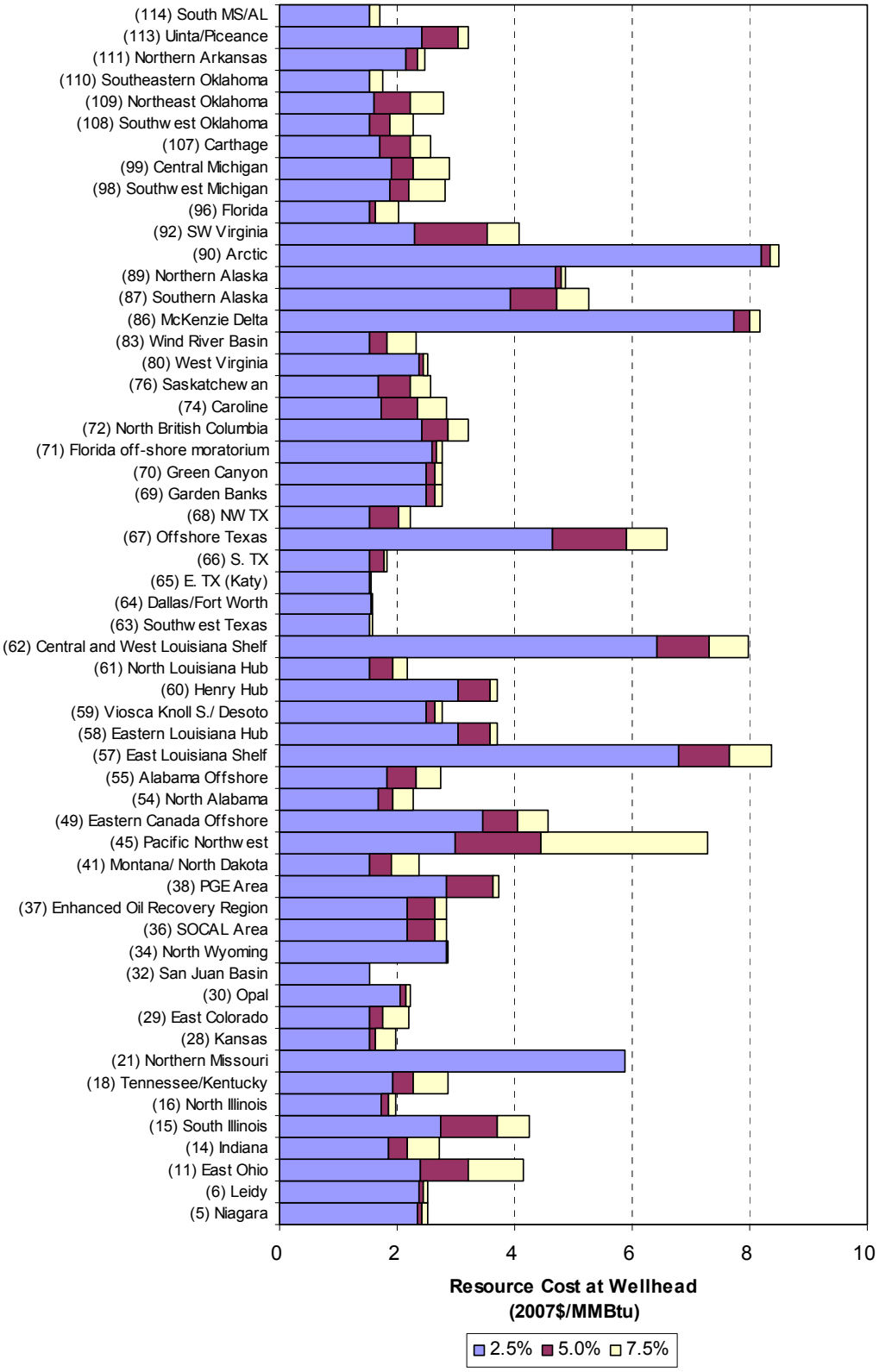
Figure 10-10 shows E&D cost needed to discover and develop 2.5%, 5%, and 7.5% of the remaining undiscovered resource in 2011 by natural gas supply region.

Figure 10-9 E&D and Production Technology Improvement Factor

Figure 10-10



Incremental E&D Cost (EOY 2010) by Percentage of Resource Found



10.4.2 Resource Discovery and Drilling Constraints

As mentioned above the simulation in HSM also provides other data such as resource discovery factors which describe the maximum share of remaining undiscovered resource that could be discovered and developed in a year and drilling requirements which describe the drilling required for successful exploration and development. These two parameters are constraints to the development of the resource and their values are not time dependent. The resource discovery constraint is the same for all regions and is assumed to be 4% of the remaining undiscovered resource (column 4 in Table 10-5). The drilling requirement constraint (column 5 in Table 10-5) is 10,000 feet for every billion cubic feet of incremental resource discovered for onshore and 2,500 feet/Bcf for offshore.

Table 10-5 Exploration and Development Assumptions for EPA Base Case v.4.10

Region	Fraction of Hydrocarbons that are Natural Gas Liquids (NGLs) (Fraction)	Fraction of Hydrocarbons that are Crude Oil (Fraction)	Max Share of Resources that can be Developed per Year (Fraction)	Exploration, Development Drilling Required (Ft/Bcf)	Lease and Plant Use (Fraction)
(5) Niagara	0.01	0.04	0.04	10,000	0.05
(6) Leidy	0.00	0.05	0.04	10,000	0.03
(11) East Ohio	0.00	0.23	0.04	10,000	0.01
(14) Indiana	0.05	0.81	0.04	10,000	0.02
(15) South Illinois	0.10	0.10	0.04	10,000	0.30
(16) North Illinois	0.10	0.10	0.04	10,000	0.30
(18) Tennessee/Kentucky	0.12	0.10	0.04	10,000	0.04
(21) Northern Missouri	0.15	0.46	0.04	10,000	0.04
(28) Kansas	0.13	0.17	0.04	10,000	0.04
(29) East Colorado	0.09	0.10	0.04	10,000	0.05
(30) Opal	0.09	0.10	0.04	10,000	0.05
(32) San Juan Basin	0.09	0.10	0.04	10,000	0.13
(34) North Wyoming	0.09	0.10	0.04	10,000	0.05
(36) SOCAL Area	0.01	0.91	0.04	10,000	0.13
(37) Enhanced Oil Recovery Region	0.02	0.81	0.04	10,000	0.13
(38) PGE Area	0.03	0.88	0.04	10,000	0.13
(41) Montana/ North Dakota	0.04	0.72	0.04	10,000	0.13
(45) Pacific Northwest	0.26	0.00	0.04	10,000	0.02
(49) Eastern Canada Offshore	0.01	0.88	0.04	2,500	0.06
(54) North Alabama	0.04	0.22	0.04	10,000	0.03
(55) Alabama Offshore	0.04	0.22	0.04	2,500	0.03
(57) East Louisiana Shelf	0.07	0.52	0.04	2,500	0.04
(58) Eastern Louisiana Hub	0.11	0.27	0.04	10,000	0.04
(59) Viosca Knoll S./ Desoto Canyon/Mississippi Canyon	0.07	0.52	0.04	2,500	0.04
(60) Henry Hub	0.11	0.27	0.04	10,000	0.04

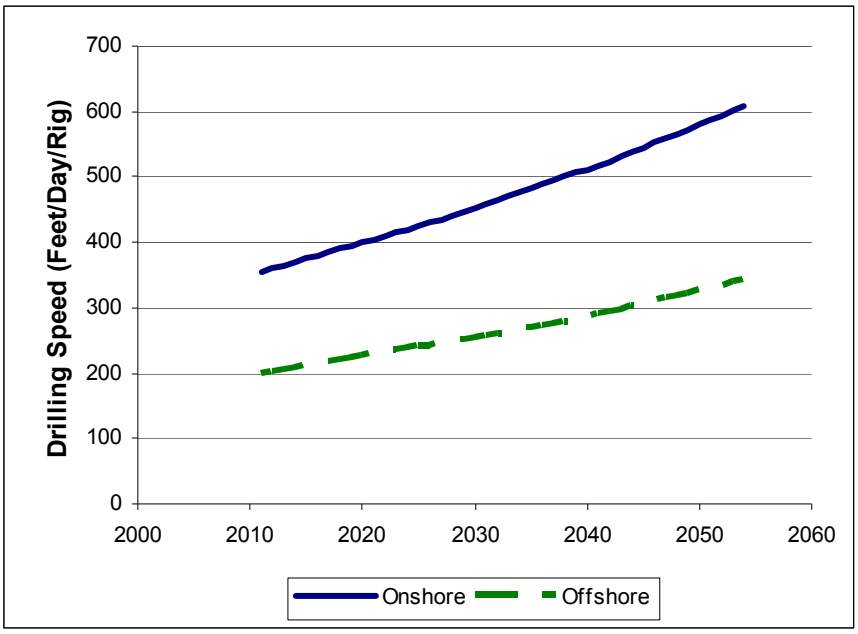
Region	Fraction of Hydrocarbons that are Natural Gas Liquids (NGLs) (Fraction)	Fraction of Hydrocarbons that are Crude Oil (Fraction)	Max Share of Resources that can be Developed per Year (Fraction)	Exploration, Development Drilling Required (Ft/Bcf)	Lease and Plant Use (Fraction)
(61) North Louisiana Hub	0.08	0.08	0.04	10,000	0.04
(62) Central and West Louisiana Shelf	0.07	0.52	0.04	2,500	0.04
(63) Southwest Texas	0.12	0.52	0.04	10,000	0.05
(64) Dallas/Fort Worth	0.07	0.06	0.04	10,000	0.05
(65) E. TX (Katy)	0.17	0.19	0.04	10,000	0.05
(66) S. TX	0.12	0.07	0.04	10,000	0.05
(67) Offshore Texas	0.06	0.25	0.04	2,500	0.05
(68) NW TX	0.22	0.05	0.04	10,000	0.05
(69) Garden Banks	0.06	0.25	0.04	2,500	0.04
(70) Green Canyon	0.07	0.52	0.04	2,500	0.04
(71) Florida off-shore moratorium area	0.07	0.52	0.04	2,500	0.04
(72) North British Columbia	0.01	0.05	0.04	10,000	0.08
(74) Caroline	0.03	0.19	0.04	10,000	0.10
(76) Saskatchewan	0.00	0.73	0.04	10,000	0.07
(80) West Virginia	0.07	0.04	0.04	10,000	0.04
(83) Wind River Basin	0.09	0.10	0.04	10,000	0.05
(86) McKenzie Delta	0.00	0.00	0.04	10,000	0.08
(87) Southern Alaska	0.00	0.00	0.04	10,000	0.08
(89) Northern Alaska	0.00	0.00	0.04	10,000	0.08
(90) Arctic	0.05	0.55	0.04	10,000	0.08
(92) SW Virginia	0.00	0.01	0.04	10,000	0.02
(96) Florida	0.02	0.82	0.04	10,000	0.21
(98) Southwest Michigan	0.04	0.11	0.04	10,000	0.04
(99) Central Michigan	0.04	0.11	0.04	10,000	0.04
(107) Carthage	0.08	0.08	0.04	10,000	0.05
(108) Southwest Oklahoma	0.13	0.17	0.04	10,000	0.04
(109) Northeast Oklahoma	0.13	0.17	0.04	10,000	0.04
(110) Southeastern Oklahoma	0.13	0.17	0.04	10,000	0.04
(111) Northern Arkansas	0.00	0.13	0.04	10,000	0.04
(113) Uinta/Piceance	0.09	0.10	0.04	10,000	0.05
(114) South MS/AL	0.04	0.22	0.04	10,000	0.03

Other drilling constraints include rig capacity, rig retirement, rig growth, and drilling speed. Values for the constraints are specified for each of the three drilling category: (1) onshore, (2) offshore shelf, and (3) offshore deepwater. The drilling rig capacity constraint shows the number of drilling rigs initially available in the base year 2011. The initial rig counts are 3,798 rigs for onshore, 115 rigs for offshore shelf, and 115 rigs for offshore deepwater and the numbers can change over time controlled by rig retirement and rig growth constraints. The drilling rig retirement constraint is the

share of rig capacity that can retire in a year. The drilling rig growth constraint is the maximum increase of total rig count in a year. The drilling retirement and growth are assumed to be the same for all drilling category and the constraints are set to 0.5% per year and 3.5% per year, respectively.

Another growth constraint, minimum drilling capacity increase, is implemented to force the rig count to grow by at least one rig in each drilling category. The drilling speed constraint is the required speed in feet/day/rig for successful exploration and development. The drilling speed required for successful E&D grows over time, as shown in Figure 10-11 and differs for onshore and offshore (which in this case includes both shelf and deep shelf).

Figure 10-11 Drilling Rig Speed Constraint



10.4.3 Reserves-to-Production (R/P) Ratio

The reserves-to-production ratio is the remaining amount of reserves, expressed in years, to be produced with a current annual production rate. In the IPM gas module, the R/P data obtained from the HSM is provided in the form of production-to-reserves (P/R) ratio (or reciprocal of the R/P ratio). The P/R ratio is used to calculate annual wet gas production from the reserves and the value varies by resource type and production node. For conventional gas the P/R ratio ranges from 0.04 (or 25 years of R/P) to 0.25 (or 4 years of R/P) with average of 0.13 (or 8 years of R/P). The P/R ratio of shale and tight gas is half of that of the conventional gas with average P/R ratio of 0.06 (or 16 years of R/P). Coalbed methane gas has the lowest P/R ratio with average of 0.03 (or 32 years of R/P) or half of that of the tight and shale gas.

10.4.4 Variable Costs, Natural Gas Liquid Share, and Crude Oil Share

In the IPM natural gas module, the variable costs include production operations and maintenance (O&M) cost and gas processing cost. The production O&M cost for 2011 is estimated to be $0.51/MMBtu (in real 2007 dollars) and is assumed to be the same for all supply regions. The production O&M cost is expected to decline over time due to improvements in production technology. In the model the same technology improvement factor shown in Figure 10-9 is applied to the production O&M cost.

The resource data from the HSM is provided in the form of total hydrocarbon (oil, gas, and NGL) resource. The HSM also provides the allocations of the hydrocarbon for dry gas, oil, and NGL.

Table 10-5 shows the shares of NGL (column 2) and crude oil (column 3) by supply region. Associated gas from crude oil and NGL from wet gas are processed in gas processing plants to produce pipeline quality dry gas. Node level gas processing cost for IPM natural gas module is obtained from the GMM. The processing cost varies from $0.07/MMBtu (of wet gas in real 2007 dollars) to $0.56/MMBtu with average of $0.22/MMBtu.

10.4.5 Lease and Plant Gas Use

The term "lease and plant gas" refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants. The data for lease and plant gas use is derived for the HSM as a fraction of wet gas production and varies by region. The value ranges from 0.01 to as high as 0.3 with an average of around 0.06 (column 6 in Table 10-5).

10.5 Liquefied Natural Gas (LNG) Imports

As described earlier, most of the data related to North American LNG imports is derived from the GMM LNG model. Based on a comprehensive database of existing and potential liquefaction and regasification facilities and worldwide LNG import/export activities, the model uses a simulation procedure to create the base year 2011 North American LNG supply curves and projections of regasification capacity and costs.

Key elements of the LNG model are described below.

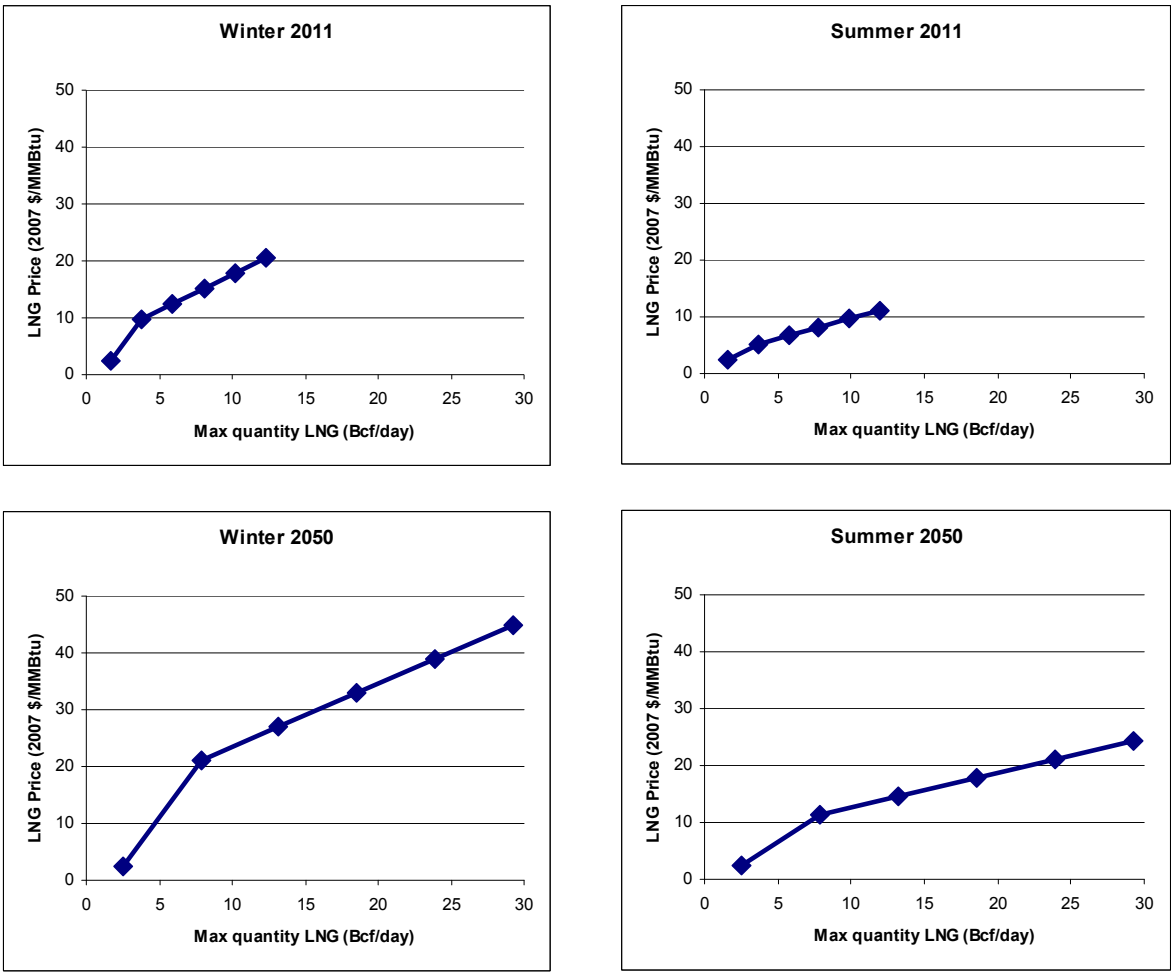
10.5.1 Liquefaction Facilities and LNG Supply

The supply side of the GMM LNG model takes into account capacities from existing as well as potential liquefaction facilities. The lower and upper boundaries of supply capacity allocated for each North American regasification facility are set by available firm contracts and swing supplies. Three point LNG supply curves are generated within this envelope where: (1) the lower point is the amount of firm LNG supply, (2) the upper bound is the firm imports plus the maximum swing imports available for that facility, and (3) the midpoint is the average of the minimum and maximum values. Prices for the minimum and maximum points are tied to Refiner Acquisition Cost of Crude (RACC) price.[22] The minimum price represents minimum production cost for liquefaction facilities and is set at 0.5 of RACC price and the maximum price is set at 1.5 of RACC price. The prices are then shifted up for winter months and shifted down in the summer months to represent the seasonal variation in competition from European LNG consumers.

The individual LNG supply curves from the GMM LNG model are aggregated to create total North American LNG supply curves describing LNG availability serving the North American regasification facilities. The three point curves are converted to six points by linear interpolation to provide more supply steps in the IPM natural gas module. Two LNG supply curves, one for winter and one for summer, are specified for each year starting from 2011 until 2054 to capture growth as well as seasonal variation of the LNG supplies. Figure 10-12 shows the North American LNG supply curves for the winters and summers of 2011 and 2050.

[22] Refiner Acquisition Cost of Crude Oil (RACC) is a term commonly use in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs.

Figure 10-12 North American LNG Supply Curves



10.5.2 Regasification Facilities

For the EPA Base Case, ten existing and four potentials North American LNG regasification facilities are considered in the IPM natural gas module. Table 10-6 lists the 14 facilities (current existing facilities are highlighted), the destination nodes where the LNG are delivered, and the base year 2011 capacity for each of the regasification facility. Figure 10-13 provides a map of these facilities. Existing Penuelas LNG facilities in Puerto Rico are not included because they are not part of the natural gas network in the IPM gas module. However, the electric generating units that consume gas from the Penuelas LNG facilities are included in the IPM electric module. In EPA Base Case v.4.10. the Penuelas LNG facilities are modeled with a fixed 150 MMcfd gas supply into Florida node and a link to connect the gas supply to the electric generating units in Puerto Rico.

Table 10-6 North American LNG Regasification Facilities

No	LNG Regasification Facility	Node Location	Base Year (2011) Regasification Capacity (Bcf/day)
1	Cove Point	(7) Cove Point TRANS	1.50
2	Elba Island	(9) Elba Is TRANS	2.10
3	Everett	(2) Everett TRANS	0.70

No	LNG Regasification Facility	Node Location	Base Year (2011) Regasification Capacity (Bcf/day)
4	Gulf Gateway	(69) Garden Banks	0.50
5	Lake Charles	(60) Henry Hub	2.10
6	Altamira	(51) Reynosa Imp/Exp	1.00
7	Costa Azul	(84) California Mexican Exports	2.00
8	Cameron LNG	(60) Henry Hub	1.50
9	Freeport LNG	(65) E. TX (Katy)	1.50
10	Golden Pass	(65) E. TX (Katy)	2.00
11	Canaport	(49) Eastern Canada Offshore	1.00
12	Sabine Pass	(60) Henry Hub	2.60
13	Gulf LNG Energy LLC	(56) North Mississippi	1.00
14	Northeast Gateway	(1) New England	0.80

Figure 10-13 North American LNG Regasification Facilities Map

10.5.3 LNG Regasification Capacity Expansions

The IPM natural gas module has two constraints for the regasification capacity expansion: (1) minimum LNG regasification facility capacity expansion and (2) maximum LNG regasification facility capacity expansion. The values are specified for each facility and year where the minimum constraint is used to force the model to add regasification capacity and the maximum constraint is the upper bound for the capacity expansion.

The decision of whether to expand regasification capacity is controlled by the two constraints and by a levelized capital cost for regasification capacity expansion. The base year 2011 levelized capital cost for capacity expansion (in real 2007 dollars per MMBtu of capacity expansion) is specified for each facility. A cost multiplier can be applied to represent the increase in levelized capital cost over time. The constraints for the capacity expansion can be used to turn on or off the regasification capacity expansion feature in the model. Setting both constraints to zero will deactivate this feature.

If the regasification capacity is allowed to expand, the model can add capacity to a facility within the minimum and maximum constraints if the cost of the regasification expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for adding new regasification capacity less their revenues. The model takes into account all possible options/projects (including regasification capacity expansions) in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function value. In this way, regasification capacity expansion projects will compete with each other and even with other projects such as pipeline expansions, storage expansions, etc.

Due to excess LNG regasification capacity already in the system the regasification capacity expansion feature is not deployed in EPA Base Case v.4.10. EPA scenario results show very low total LNG utilizations, less than 15%, throughout the projection period which suggest the base year LNG regasification capacity is already high and requires no expansion.

10.6 End Use Demand

Non-power sector demand (i.e. the residential, commercial, and industrial) is modeled in the new gas module in the form of node-level firm and interruptible demand curves23. The firm demand curves are developed and used for residential, commercial, and some industrial sources, while the interruptible demand curves are developed and used exclusively for industrial sources.

A three step process is used to prepare these curves for use in the IPM gas module. First, GMM is used to develop sector specific econometric models representing the non-power sector demand. Since the GMM econometric models are functions of weather, economic growth, price elasticity, efficiency and technology improvements, and other factors, these drivers, in effect, are embedded in the resulting IPM natural gas module demand curves. Second, projections are made using the GMM econometric models and assembled into monthly gas demand curves by sector and demand node. Third, using a second model, seasonal and load segment specific demand curves are derived from the monthly gas demand curves. The sections below describe each of these steps in further detail.

10.6.1 Step 1: Developing Sector Specific Econometric Models of Non-Power Sector Demand

Residential/Commercial Sector

The GMM econometric models of residential and commercial demand are based on regression analysis of historical data for 41 demand regions and are adjusted to reflect conservation, efficiency, and technology changes over time. The regional data is allocated to the node level based on population data and information from the Energy Information Administration's "Annual Report of Natural and Supplemental Gas Supply & Disposition" (EIA Form-176). Specifically, the econometric models used monthly Department of Energy/Energy Information Administration (DOE/EIA) data from January 1984 through December 2002 for the U.S. and monthly Statistics Canada data from January 1988 through December 2000 for Canada.

---

23 "Firm" refers to natural gas demand that is not subject to interruptions from the supplier, whereas "interruptible" refers to natural gas demand that is subject to curtailment or cessation by the supplier.

The GMM econometric models showed node-level residential and commercial gas demand to be a function of heating degree days, elasticity of gas demand relative to GDP, and elasticity of gas demand relative to gas price. The GDP elasticity was generally about 0.4 for the residential sector and 0.6 for the commercial sector. The gas price elasticity was generally less than 0.1 for both sectors. Since gas demand in these sectors is relatively inelastic, GDP and price changes have small effects on demand.

U.S. Industrial Sector
The GMM econometric model of U.S. industrial gas demand employed historical data for 11 census-based regions and ten industry sectors, focusing on gas-intensive industries such as:

- Food
- Pulp and Paper
- Petroleum Refining
- Chemicals
- Stone, Clay and Glass
- Iron and Steel
- Primary Aluminum
- Other Primary Metals
- Other Manufacturing
- Non-Manufacturing

For each of these sectors three end-use categories (process heat, boilers, and other end uses) are modeled separately:

- Process heat: This includes all uses of gas for direct heating as opposed to indirect heating (e.g., steam production). The GMM econometric modeling indicated that forecasts for process heat for each industrial sector are a function of growth in output, the energy intensity trend, and the price elasticity. Growth in output over time for most industries is controlled by industrial production indices. Energy intensity is a measure of the amount of gas consumed per unit of output. Energy intensity tends to decrease over time as industries become more efficient.
- Boilers: This category includes natural gas-fired boilers whose purpose is to meet industrial steam demand. GMM econometric models indicated that gas demand for boilers is a function of the growth in industrial output and the amount of gas-to-oil switching. Industry steam requirements grow based on industrial production growth. A large percentage of the nominally “dual-fired” boilers cannot switch due to environmental and technical constraints.
- Other end uses: This category includes all other uses for gas, including non-boiler cogeneration, on-site electricity generation, and space heating. Like the forecasts for process heat, the GMM econometric modeling showed “other end uses” for each industrial sector to be a function of growth in output, the energy intensity trend, and the price elasticity.

In addition to these demand models, a separate regression model was use to characterize the chemicals sector’s demand for natural gas as a feedstock for ammonia, methanol, and non-refinery hydrogen. Growth in the chemicals industry is represented by a log-linear regression model that relates the growth to GDP and natural gas prices. As GDP growth increases, chemical industry production increases; and as gas prices increase, chemical industry production decreases.

The GMM econometric models for the U.S. industrial sector used DOE/EIA monthly data from January 1991 through December 2000.

Canada Industrial Sector
The industrial sector in Canada is modeled in less detail. Canada is divided into 6 regions based on provincial boundaries. The approach employs a regression fit of historic data similar to that

used in the residential/commercial sectors. Sub-sectors of Canadian industrial demand are not modeled separately. The Canadian industrial sector also includes power generation gas demand. The model used Statistics Canada monthly data from January 1991 through December 2000.

10.6.2 Step 2: Use projections based on the GMM econometric models to produce monthly gas demand curves by sector and demand node

The regression functions resulting from the econometric exercises described in Step 1 are used to create monthly sector- and nodal-specific gas demand curves. To do this the functions are first populated with the macroeconomic assumptions that are consistent with those used in EPA Base Case 4.10. For these purposes a U.S. annual GDP growth rate of 3.0%, a U.S. annual industrial production growth rate of 2.3%, and a Canadian annual GDP growth rate of 2.5 % are assumed. Then, a range of natural gas prices are fed into the regression functions. At each gas price the regression functions report out projected monthly demand by sector and node. These are the GMM's nodal demand curves.

10.6.3 Step 3: Develop non-electric sector natural gas demand curves that correspond to the seasons and segments in the load duration curves used in IPM

A second model, the Daily Gas Load Model (DGLM), is used to create daily gas load curves based on the GMM monthly gas demand curves obtained in Step 2. The DGLM uses the same gas demand algorithms as the GMM, but uses a daily temperature series to generate daily variations in demand, in contrast to the seasonal variations in gas demand that are obtained from the GMM.

The resulting daily nodal demand data for each non-power demand sector are then re-aggregated into the two gas demand categories used in the IPM gas module: all of the residential and commercial demand plus 10% of the industrial demand is allocated to the firm gas demand curves, and the remaining 90% of the industrial demand is allocated to the interruptible gas demand curves.

IPM, the power sector model, has to take into account natural gas demand faced by electric generating units that dispatch in different segments of the load duration curves, since demand for natural gas and its resulting price may be very different for units dispatching in the peak load segment than it is for units dispatching in the base, high shoulder, mid shoulder, or low shoulder load segments. In addition, since seasonal differences in demand can be significant, IPM requires separate load segment demand data for each season that is modeled. In EPA Base Case v.4.10, there are two seasons: Summer (May 1 – September 30) and winter (October 1 – April 30). Therefore, the firm and interruptible daily gas demand and associated prices are allocated to the summer and winter load segment based on the applicable season and prevailing load conditions to produce the final non-electric sector gas demand curves that are used in IPM.

In EPA Base Case v.4.10, each of the summer and winter periods uses 6 load segments for pre-2030 and 4 load segments for post-2030 as shown in Table 10-7. The "Peak" load segment in post-2030 is an aggregate of "Needle Peak" and "Near Peak" load segments in the pre-2030. The "High Shoulder" load segment in post-2030 is an aggregate of "High Shoulder" and "Middle Shoulder" load segments in the pre-2030. The same definitions of "Low Shoulder" and "Base" load segments are applied to both pre-2030 and post-2030. Input data for firm and interruptible demand curves are specified for all six load segments listed in the pre-2030 column of Table 10-7.

Table 10-7 Summer and Winter Load Segments in EPA Base Case v.4.10

Pre 2030		Post 2030	
1	Needle Peak	1	Peak
2	Near Peak		
3	High Shoulder	2	High Shoulder
4	Middle Shoulder		
5	Low Shoulder	3	Low Shoulder
6	Base	4	Base

Aggregation of summer and winter load segments from six in the pre-2030 to four in the post-2030 is performed endogenously in the model.

The non-electric sector demand curves (firm and interruptible) are generated based on GMM regressions described above with macroeconomic assumptions consistent with those of EPA Base Case v.4.10. A set of firm and interruptible gas demand curves is generated for each node and year. Examples of node-specific firm and interruptible demand curves for summer and winter load segments are shown in Figure 10-14 and Figure 10-15. It should be noted that firm gas demand (Figure 10-14) is very inelastic; only a small fraction of demand is shed as prices increase. The interruptible gas demand in the peak segments is also very inelastic as expected with higher elasticities in the shoulder and base load segments.

It is important to note that the non-electric gas demand curves provided to the IPM/Gas model are static inputs. The implied elasticities in the curves represent short-term elasticities based on EPA Base Case v.4.10 macroeconomic assumptions. Long-term elasticity is not factored into the gas demand curves. In other words, changes in the assumptions that affect the price/volume solutions have no effect to the long-term gas demand elasticity. Sensitivity runs with slight modifications to the macroeconomic assumptions can still use the same curves if the gas demand forecast is expected not to be much different than that from the base case. In this case, changes in the gas demand solutions have minor effect to the long-term elasticity. However, a sensitivity run (e.g. carbon policy run) with major changes in CO_2 allowance prices should not use the same gas demand curves because it will have higher impact to the long-term gas demand elasticity. A new set of non-electric gas demand curves needs to be generated for this type of run.

Figure 10-14 Examples of Firm Demand Curves by Electric Load Segment

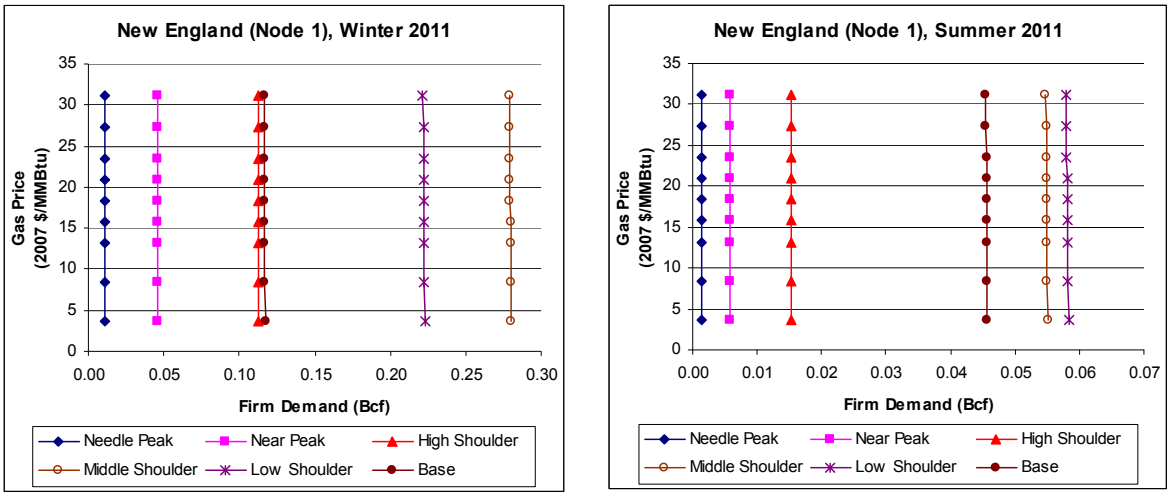
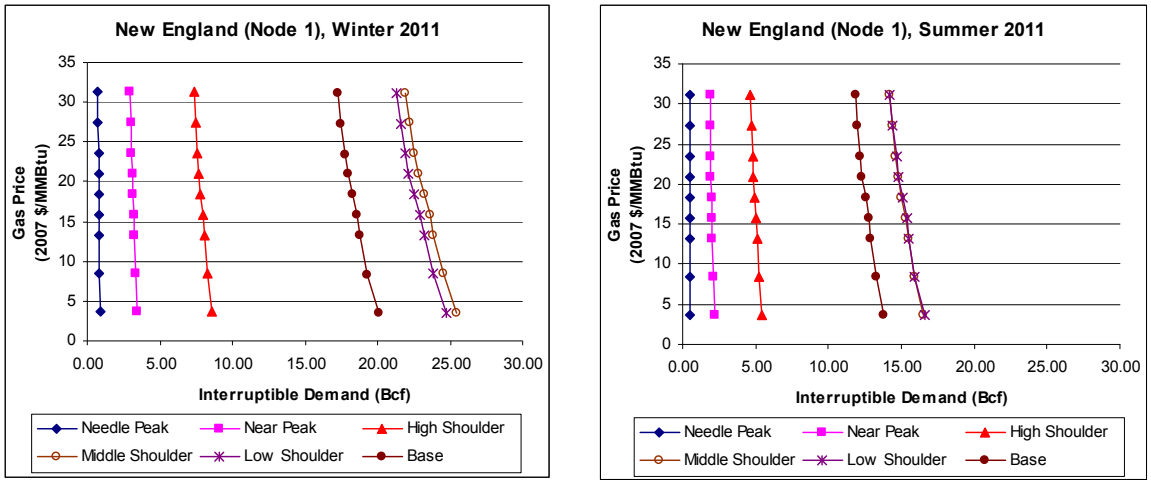


Figure 10-15 Examples of Interruptible Demand Curves by Electric Load Segment



10.7 Pipeline Network

10.7.1 Network Structure

The pipeline network in the IPM natural gas module represents major transmission corridors (not individual pipelines) throughout North America. It contains 343[1] gas pipeline corridors (including bi-directional links) between the 114 nodes (Figure 10-3). Each corridor is characterized by maximum capacity and a "value of service" (discount curve) relationship that determines the market value of capacity as a function of load factor.[2] The node structure is developed to reflect points of change or influence on the pipeline system such as:

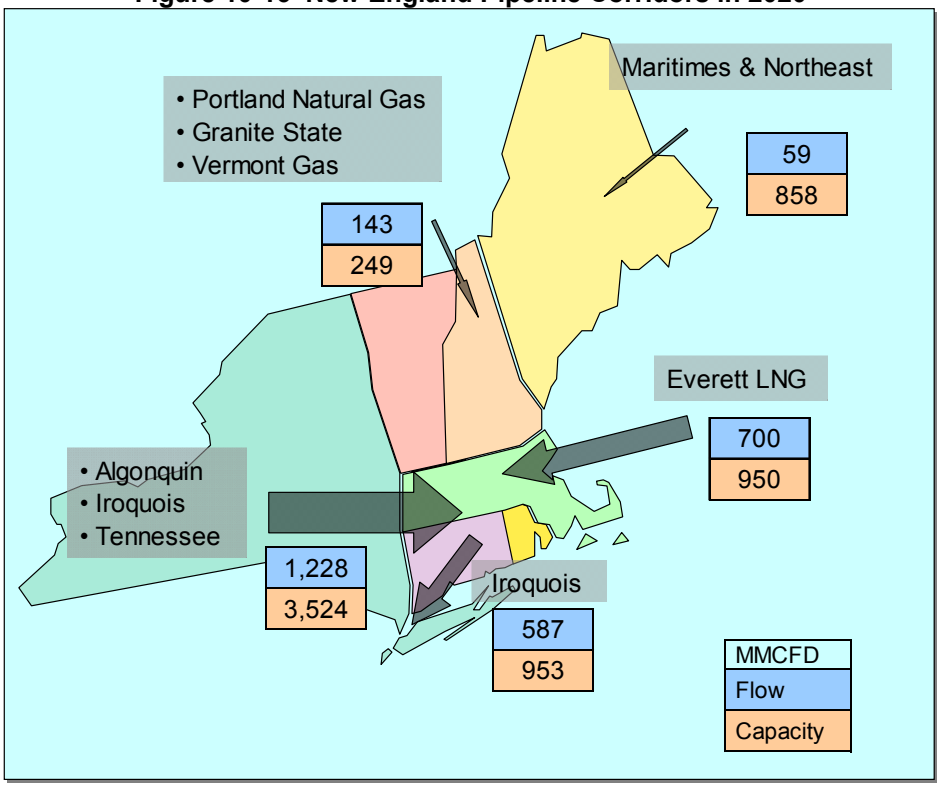
- Major demand and supply centers
- Pipeline Hubs and market centers
- Points of divergence in pipeline corridors

To illustrate the relationship of corridors and pipelines, Figure 10-16 shows the flow and capacity of five pipeline corridors in New England in 2020. Gas flows into New England along three pipeline corridors (indicated in Figure 10-16 by 3 of the 4 arrows that point into the region) representing a total of seven pipeline systems (indicated by name labels in Figure 10-16). New England also receives gas via the Everett LNG terminal (indicated in Figure 10-16 by the 4th arrow that points into the region). Also, some of the gas that flows into New England on the Iroquois system flows through the region and back to downstate New York; this is represented on the map as an export from New England (indicated in Figure 10-16 by the arrow that points away from the region).

[1]Excluding LNG import Terminal nodes and their pipeline connections.

[2] See footnote #3 above for a definition of "load factor."

Figure 10-16 New England Pipeline Corridors in 2020



10.7.2 Pipeline Transportation Costs

In the IPM natural gas module, the natural gas moves over the pipeline network at variable cost. The variable cost as a function pipeline throughput (or pipeline discount curve) is used to determine transportation basis[3] (i.e., the market value of capacity) for each period in the forecast for each pipeline link. The 4-point pipeline discount curves in the IPM natural gas module are simplified forms of the more robust continuous discount curves from the GMM pipeline module. The GMM pipeline discount curves have been derived in the course of extensive work to calibrate the model to actual history. The curves have been fit to basis differentials observed from actual gas prices and to annual load factors from pipeline electronic bulletin boards via Lippman Consulting, Inc.

The GMM continuous discount curves are converted to 4-point linear curves for the IPM natural gas module capturing deflection points in the GMM discount curves. Figure 10-17 depicts the base year 2011 discount curve for the pipeline corridor connecting nodes (61) North Louisiana Hub and (18) Tennessee/Kentucky. Cost growth factors shown in Figure 10-18 are applied to the pipeline discount curves to reflect cost increase over time. The cost is assumed to grow at an average rate of 0.5 percent per year.

[3] See footnote #1 above for a definition of "basis."

Figure 10-17 Example Pipeline Discount Curve

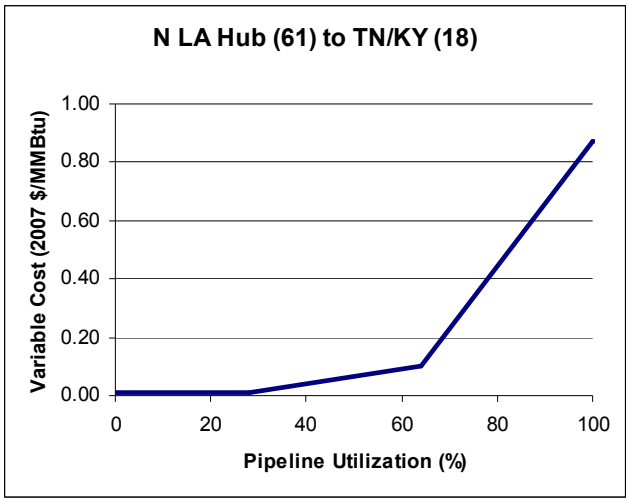
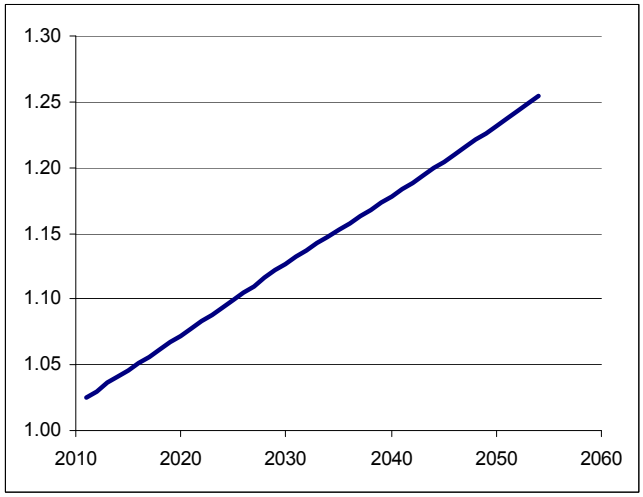


Figure 10-18 Pipeline Cost Growth Factor



10.7.3 Pipeline Capacity Expansion Logic

Base year pipeline capacity, derived from GMM, includes existing capacities and planned capacities that are expected to be operational from the beginning of 2011. The IPM natural gas module has the capability to endogenously expand the pipeline capacity. The decision of whether to expand pipeline capacity is controlled by two constraints, which stipulate minimum and maximum capacity additions and by the levelized capital cost of expanding pipeline capacity in the specific corridor and year. The minimum capacity addition constraint forces the model to add capacity in a specified corridor and year. The maximum capacity constraint is the upper bound on capacity additions in a specified corridor and year. For most pipeline corridors there is no minimum or maximum capacity requirement, and so they are assigned a value of zero as their minimum capacity addition requirement and infinity[4] as their maximum capacity addition requirement. Where this occurs, the pipeline expansion is only controlled by the pipeline capital cost.

[4]In the model this is achieved by assigning a large number, e.g., 100 Bcfd, for every year where there is no constraint on maximum capacity.

The model is allowed to add capacity to a pipeline corridor within the minimum and maximum capacity addition constraints if the cost of the pipeline expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for pipeline capacity expansion, less their revenues. The model takes into account all possible options/projects including capacity additions for pipeline corridors in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function. In this way, pipeline corridor expansion projects will compete with each other and even with other projects such as LNG regasification capacity expansions, storage expansions, etc.

For EPA Base Case v.4.10, pipeline corridors connecting North Alaska (node 89) and Mackenzie Delta (node 86) to North British Columbia (node 72) have the minimum and maximum capacity addition constraints. Based on diagnostic run analysis discussed in Section 3, the Mackenzie Delta pipeline project is not made available throughout the projection. Both capacity addition constraints for Mackenzie delta are set to zero. Based on the same analysis, the Alaska pipeline corridors (connecting nodes 89, 88, 87, and 72) are set to come online from 2035. The minimum capacity constraint is set to zero throughout the projection. The maximum capacity constraint is initially set to zero to restrict pipeline builds and then set to infinity from 2035.

Expansions in other pipeline corridors are not restricted. The model is allowed to build capacity to any pipeline corridors at any time as long as it contributes to minimization of the objective function. There is no reason for restricting the upper bound for capacity expansion since the IPM/Gas model was designed to be used as a long-term policy tool rather than a pipeline analysis tool. Having no restriction to the minimum capacity expansion, however, is a limitation of the model as it may lead to unrealistic capacity expansions especially for large pipeline projects such as Alaska and Mackenzie Delta. Without restricting the starting dates and the capacities, the model may build unrealistically low incremental capacities throughout the projection. This was the reason for conducting the diagnostic run for Alaska and Mackenzie Delta projects. Theoretically, it is possible to add capability in the model to make decisions on minimum incremental pipeline capacity expansions. However, it requires adding a lot more constraints to the LP which may result in prohibitively large model. The workaround for ensuring reasonable capacity expansion results is to perform diagnostic runs such as that for Alaska and Mackenzie Delta.

The base year 2011 levelized pipeline capital cost (in real 2007 dollars per MMBtu/Day of pipeline capacity addition) is specified for each of the 343 pipeline links. The cost growth factors shown in Figure 10-18 are applied to derive the cost increase over time. The average levelized capital cost for pipeline capacity expansion for 2011 is $154 per MMBtu/Day. The expected levelized capital cost for North Alaska pipeline for 2035 is $305 per MMBtu/Day.

10.8 Gas Storage

The IPM natural gas module has 108 underground storage facilities that are linked to 48 nodes. The underground storage is grouped into three categories based on storage "Days Service."[5]

- "20-Day" high deliverability storage – 35 storage facilities
- "80-Day" depleted/aquifer reservoirs – 38 storage facilities
- "Over 80 Days" depleted/aquifer reservoirs – 35 storage facilities

The model also includes existing and potential LNG peak shaving storage facilities. The existing facilities are linked to 24 nodes with allocations based on historical capacity data. There are 48 other nodes that are linked to LNG peakshaving storage. These facilities do not currently have capacity but are included in the storage database for the purpose of future expansion. The map of storage facility locations is shown in Figure 10-6 and the list of storage facility nodes is shown in Table 10-8.

[5] See footnote #5 above for a definition of "Days Service."

In Table 10-8 an X in columns 2 ("20-Day"), 3 ("80-Day"), or 4 ("Over 80-Days") represents an underground storage facility. There are 108 such X's which correspond to the 108 underground storage facilities noted in the previous paragraph. These 108 X's appear in 48 rows, which represent the linked nodes noted in the previous paragraph. The identities of these nodes are found in column 1 ("Node"). Similarly, 24 X's in columns 5 ("Existing") represent the 24 existing LNG peakshaving facilities and 48 X's in column 6 ("Potential") represent the 48 prospective LNG storage facilities.

Table 10-8 List of Storage Nodes

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(1) New England				X	
(3) Quebec	X		X		X
(4) New York City				X	
(5) Niagara	X	X	X		X
(6) Leidy	X	X	X		X
(8) Georgia				X	
(10) South Florida					X
(11) East Ohio	X	X	X		X
(12) Maumee/Defiance					X
(13) Lebanon					X
(14) Indiana		X	X	X	
(15) South Illinois	X	X	X		X
(16) North Illinois	X	X	X	X	
(17) Southeast Michigan	X	X			X
(18) Tennessee/Kentucky	X	X	X	X	
(19) MD/DC/Northern VA				X	
(20) Wisconsin				X	
(21) Northern Missouri					X
(22) Minnesota		X		X	
(23) Crystal Falls					X
(24) Ventura		X	X	X	
(26) Nebraska			X	X	
(28) Kansas	X	X	X		X
(29) East Colorado	X	X	X		X
(30) Opal	X	X			X
(31) Cheyenne	X	X	X		
(32) San Juan Basin			X		
(33) EPNG/TW					X
(34) North Wyoming			X		
(35) South Nevada					X
(36) SOCAL Area	X	X			X
(38) PGE Area	X	X			X
(41) Montana/North Dakota		X	X		X
(45) Pacific Northwest	X	X		X	

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(46) NPC/PGT Hub				X	
(47) North Nevada				X	
(48) Idaho				X	
(54) North Alabama	X	X	X	X	
(56) North Mississippi	X	X			X
(58) Eastern Louisiana Hub	X		X		X
(60) Henry Hub	X	X	X		X
(61) North Louisiana Hub		X	X		X
(63) Southwest Texas	X	X	X		
(64) Dallas/Ft Worth	X	X	X		X
(65) E. TX (Katy)	X	X	X		X
(66) S. TX					X
(68) NW TX					X
(72) North British Columbia					X
(73) South British Columbia			X		X
(74) Caroline	X	X	X		X
(76) Saskatchewan	X	X	X		X
(77) Manitoba					X
(78) Dawn	X	X	X		X
(79) Philadelphia				X	
(80) West Virginia	X	X	X		X
(81) Eastern Canada Demand					X
(83) Wind River Basin			X		
(92) Southwest VA	X		X	X	
(93) Southeast VA				X	
(94) North Carolina				X	
(95) South Carolina				X	
(96) North Florida					X
(97) Arizona	X	X			X
(98) Southwest Michigan	X	X	X		X
(99) Northern Michigan	X	X	X		X
(103) SDG&E Demand				X	
(104) Eastern New York					X
(105) New Jersey				X	
(106) Toronto					X
(107) Carthage	X	X			X
(108) Southwest Oklahoma			X		X
(109) Northeast Oklahoma		X	X		X
(110) Southeastern Oklahoma	X	X			X
(111) Northern Arkansas	X	X		X	
(112) Southeast Missouri	X				X
(113) Uinta/Piceance		X	X		X

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(114) South MS/AL	X	X			X

10.8.1 Storage Capacity and Injection/Withdrawal Constraints

Working gas capacity is initially allocated in the GMM to individual nodes based on historical data. Since the base year in EPA Base Case using IPM v.4.10 gas module is 2011, a projection of natural gas storage capacity at the end of 2010 is needed as a starting point. The expected working gas capacity as of EOY 2010 by location and storage type is obtained from the GMM as are injection and withdrawals rates. These serve as inputs to the IPM gas module, which uses them to endogenously derive gas storage withdrawals, injections, storage expansions, and associated costs. To give a sense of the EOY 2010 GMM storage input assumption in the IPM gas module, Table 10-9 shows the total working gas capacity and the average daily injection and withdrawal rates as percentage of working gas capacity for the four types of storage. Note that these are aggregated values (i.e., totals and averages); the actual GMM EOY 2010 inputs to the IPM gas module vary by location and storage type.

Table 10-9 Storage Capacity and Injection/Withdrawal Rates (EOY 2010)

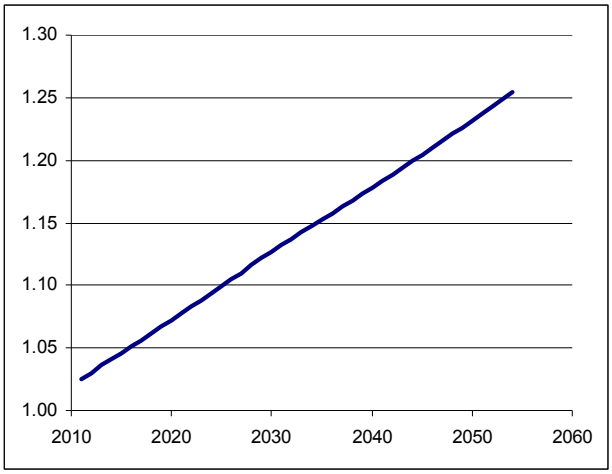
	Working Gas Capacity (Bcf)	Average Daily Injection Rate (Percent of WG Capacity)	Average Daily Withdrawal Rate (Percent of WG Capacity)
Underground Storage			
20 Day	458	6.7	9.3
80 Day	3,353	1.3	2.2
Over 80 Days	944	0.5	0.9
Total	4,755		
LNG Peakshaving Storage	84	0.5	12.5

10.8.2 Variable Cost and Fuel Use

In the IPM natural gas module, the natural gas is injected to storage or withdrawn from storage at variable cost. The base year 2011 variable cost or commodity[6] charge for underground storage facilities is assumed to be 1.54 cents/MMBtu and is the same for all underground storage nodes and types. The variable cost for LNG peakshaving facility is much higher at 36 cents/MMBtu as it includes variable costs for gas liquefaction (in gas injection process) and LNG regasification (in gas withdrawal process). The variable cost is assumed to be the same for all LNG peakshaving nodes. A storage cost growth factor shown in Figure 10-19 is applied to the injection/withdrawal cost to reflect cost increase over time. The cost is assumed to grow at an average rate of 0.5 percent per year.

[6] Storage commodity (variable) charge is generally a charge per unit of gas injected and/or withdrawn from storage as per the rights and obligations pertaining to a gas storage lease. Analogous to commodity charges for gas pipeline service

Figure 10-19 Storage Cost Growth Factor

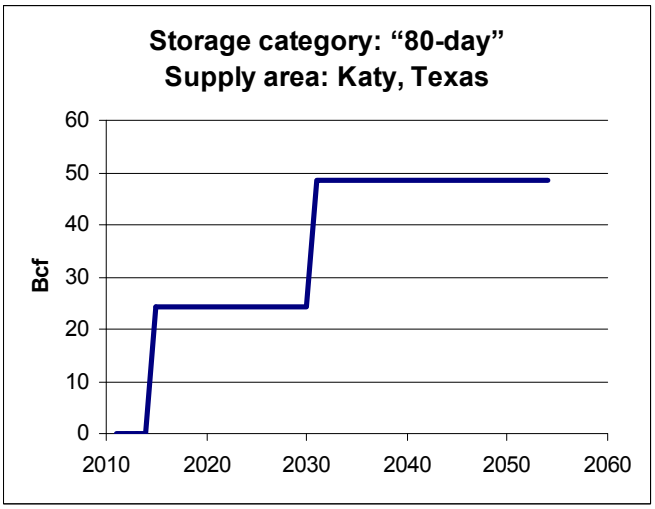


Fuel use for injection and withdrawal for underground storage is 1% of the gas throughput. The withdrawal fuel use for the LNG peakshaving storage is also 1% but the injection fuel use is much higher at 11% of the injection gas as it includes fuel use for gas liquefaction.

10.8.3 Storage Capacity Expansion Logic

The endogenous modeling decision of whether to expand working gas storage capacity is controlled by two constraints, which stipulate minimum and maximum capacity additions for each storage facility and year, and by the levelized capital cost of the storage expansion. The two constraints are specified as input data for each storage facility and year. The minimum constraint forces the model to add working gas capacity to the specified facility and year and the maximum constraint is the cap for the expansion. Figure 10-20 shows projected maximum storage expansion constraints for the "80-day" category storage facility in supply area Katy, Texas.

Figure 10-20 Example Maximum Storage Capacity Expansion



The model is allowed to add working gas capacity to a storage facility within the two constraints if the cost of storage expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for working gas capacity expansion less their revenues. The model takes into account all possible options/projects including working gas capacity additions for storage facilities in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function value. In this way,

storage capacity expansion projects will compete with each other and even with other projects such as LNG regasification capacity expansions, pipeline expansions, etc.

The base year 2011 levelized storage capital cost (in real 2007 dollars per MMBtu of storage capacity addition) is specified for each of the 180 storage facilities. Table 10-10 lists the average base year 2011 levelized storage capital cost for the four types of storage facility. Amongst the underground storage facilities the higher capital costs represent more storage cycles[7] that could be achieved in a year. On average, the capital costs for the "80-Day" and "20-Day" storage facilities are assumed to be 20 percent and 50 percent, respectively, higher than that of the "Over 80 Days" storage facility. The levelized capital cost for LNG peakshaving storage is much higher due to higher capital cost for the liquefaction unit. The cost growth factors shown in Figure 10-19 are applied to the capital cost to derive the cost increase over time. The capital cost is assumed to grow at an average rate of 0.5 percent per year.

Table 10-10 Base Year 2011 Average Levelized Storage Capital Cost

Storage Type	Average Levelized Storage Capital Cost (2007$/MMBtu)
Underground Storage	
20-Day	1.09
80-Day	0.86
Over 80 Days	0.72
LNG Peakshaving Storage	5.13

10.9 Fuel Prices

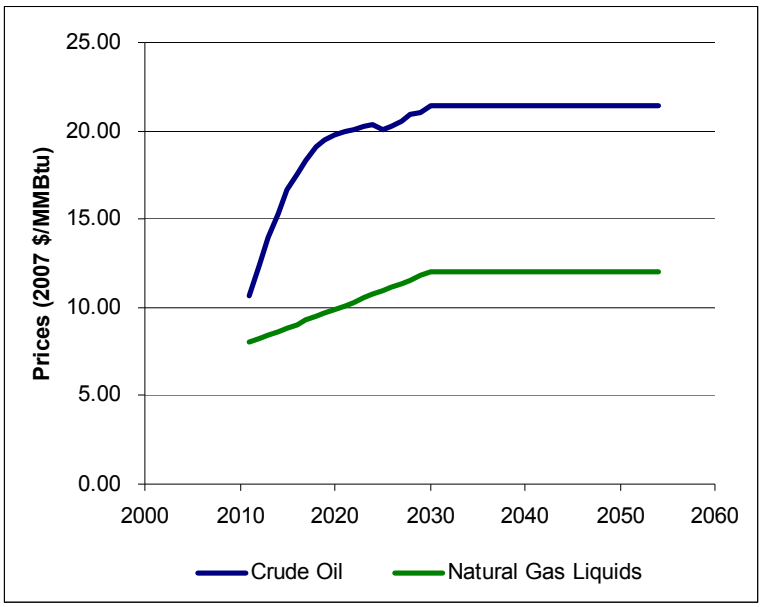
10.9.1 Crude Oil and Natural Gas Liquids Prices

Since a fraction of the hydrocarbons produced in the natural gas exploration and development process are crude oil and NGLs (see columns 2 and 3 in Table 10-5), revenues from crude oil and NGL production play a key role in determining the extent of exploration and development for natural gas. To take into account these revenues, crude oil and NGL price projections are provided as inputs to the IPM natural gas module and factored into the calculation of costs in the IPM objective function.

The crude oil and NGL price projections used in the IPM natural gas module are shown in Figure 10-21. These price projections were adapted from AEO 2009. No attempt was made to project prices beyond 2030 other than to assume that prices remain at their 2030 levels. The projected prices shown in Figure 10-21 are expressed in units of 2007$ per MMBtu. Using a crude oil Btu content of 5.8 MMBtu/Bbl, the projected crude oil prices in Figure 10-21 can be translated into the more familiar units of dollars per barrel (Bbl), in which case, prices in this figure are equivalent to $62/Bbl in 2011, $97/Bbl in 2015, $114/Bbl in 2020, and constant at $124/Bbl from 2030 (in real 2007 dollars) onward.

[7] One storage cycle is the theoretical time required to completely inject and withdraw the working gas quantity for any given underground gas storage facility or the turnover time for the working gas capacity rating of the facility. The cycle rate of any storage facility is usually expressed in cycles per year and is the number of times the working gas volumes can theoretically be turned over each storage year. The cycle rating for Porous Storage varies from 1 to 6 per year while that for Salt Cavern Storage are as high as 12 per year.

Figure 10-21 Crude Oil and NGL Prices



10.9.2 Natural Gas Prices

Node-level natural gas prices are outputs of the model and are obtained from the optimal solution of the combined IPM electric power sector and natural gas linear programming (LP) model. From a technical modeling standpoint, the node gas prices are what are called "shadow prices" or "dual variable values" associated with the node mass balance constraints at the optimal LP solution.

10.10 Outputs and Proxy Natural Gas Supply Curves

10.10.1 Outputs from the New IPM Natural Gas Module

Previous EPA IPM base cases reported natural gas consumption (in TBtu), Henry Hub and delivered natural gas prices (in $/MMBtu). In addition to these reports, the new natural gas module in EPA Base Case v.4.10 is capable of reporting natural gas supply (in Tcf), disposition (in Tcf), prices (in $/MMBtu), production (in Tcf) by supply region, end-of-year reserves and annual reserve additions (in Tcf), imports and exports (in Tcf), consumption by end-use sector and census division (in Tcf), prices by census division (in $/MMBtu), and inter-regional pipeline flows and LNG imports (in Bcf).

10.10.2 Proxy Natural Gas Supply Curves

In previous EPA IPM base cases a set of gas supply curves was generated outside of IPM (most recently by ICF's NANGAS (North American Natural Gas Analysis System) model) and then used in IPM as part of the base case input assumptions. (For a description of this approach see Appendix 8-2.9 "Technical Background Paper on the Development of Natural Gas Supply Curves for EPA Base Case 2004, v.2.1.9" in *Standalone Documentation for EPA Base Case 2004 (V.2.1.9) Using the Integrated Planning Model* EPA 430-R-05-011, September 2005. It is available for viewing and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/bc8appendix.pdf.) The incorporation of the new fully integrated natural gas module into IPM eliminates the use of explicit gas supply curves, replacing them with more dynamic and responsive representation of an integrated natural gas supply chain and the U.S. power sector. However, it is recognized that it would be useful to have a set of proxy natural gas supply curves from the new integrated approach that could be compared to the natural gas supply curves used in previous EPA Base Cases. The proxy curves would only represent a one-time snapshot of supply/price relations resulting from the new integrated approach, but at least it would provide a point of comparison with the natural gas supply curves used in previous EPA IPM base cases.

Table 10-11 contains the proxy supply curves for the electric power sector for 2015 and 2020. (These are years that would be directly comparable with supply curves from previous base cases.) The curves were generated based on GMM supply elasticities and gas demand and price solutions from the IPM/Gas model. The supply elasticity is calculated from GMM for each of the IPM run years. The gas supply curve, for each IPM run year, is constructed by applying the supply elasticity around the price/quantity solution of gas consumption in the power sector from the IPM/Gas model (highlighted rows in

Table 10-11) varying the price from $3/MMBtu to $15/MMBtu (in real 2007 dollar). The supply elasticity, in the same run year, is assumed to be constant within the price range.

The proxy supply curves below specify annual price and volume relationships at the Henry Hub. For each listed step the price applies for all increments of supply greater than the value shown in the preceding step up to and including the supply level indicated in the current step.

Table 10-11 Proxy Natural Gas Supply Curves for EPA Base Case v.4.10

2015		2020	
Gas Price (2007$/MMBtu)	**Gas Supply to Electric Sector (TBtu)**	**Gas Price (2007$/MMBtu)**	**Gas Supply to Electric Sector (TBtu)**
3.00	4,385	3.00	5,688
3.11	4,469	3.08	5,762
3.23	4,552	3.16	5,836
3.34	4,633	3.23	5,909
3.45	4,713	3.31	5,981
3.56	4,792	3.39	6,052
3.68	4,870	3.47	6,123
3.79	4,946	3.55	6,192
3.90	5,022	3.63	6,261
4.02	5,096	3.70	6,329
4.13	5,169	3.78	6,397
4.24	5,242	3.86	6,464
4.36	5,313	3.94	6,530
4.47	5,384	4.02	6,595
4.58	5,453	4.09	6,660
4.69	5,522	4.17	6,724
4.81	5,590	4.25	6,788
5.08	5,741	4.53	7,000
5.34	5,887	4.82	7,205
5.61	6,030	5.10	7,405
5.88	6,171	5.38	7,601
6.15	6,308	5.66	7,791
6.42	6,442	5.95	7,977
6.69	6,574	6.23	8,159
6.95	6,703	6.51	8,337
7.22	6,831	6.80	8,511
7.49	6,956	7.08	8,682
7.76	7,078	7.36	8,850
8.03	7,199	7.64	9,014
8.29	7,318	7.93	9,176

2015		2020	
Gas Price (2007$/MMBtu)	Gas Supply to Electric Sector (TBtu)	Gas Price (2007$/MMBtu)	Gas Supply to Electric Sector (TBtu)
8.56	7,435	8.21	9,335
8.83	7,551	8.49	9,492
9.10	7,665	8.78	9,646
9.37	7,777	9.06	9,798
9.64	7,888	9.34	9,947
9.90	7,997	9.63	10,094
10.17	8,105	9.91	10,240
10.44	8,212	10.19	10,383
10.71	8,317	10.47	10,524
10.98	8,421	10.76	10,664
11.25	8,524	11.04	10,802
11.51	8,626	11.32	10,938
11.78	8,726	11.61	11,073
12.05	8,826	11.89	11,206
12.32	8,924	12.17	11,337
12.59	9,022	12.45	11,467
12.85	9,118	12.74	11,596
13.12	9,214	13.02	11,723
13.39	9,308	13.30	11,849
13.66	9,402	13.59	11,973
13.93	9,495	13.87	12,097
14.20	9,587	14.15	12,219
14.46	9,678	14.43	12,340
14.73	9,768	14.72	12,460
15.00	9,859	15.00	12,581

Glossary of Terms Used in this Section

For ease of reference Table 10-12 assembles in one table terms that have been defined in footnotes throughout this chapter.

Table 10-12 Glossary of Natural Gas Terms Used in Documentation

Term	Definition
Arps-Roberts equation	"Arps-Roberts equation" refers to the statistical model of petroleum discovery developed by J. J. Arps, and T. G. Roberts, T. G., in the 1950's.
Associated gas	Associated gas refers to natural gas that is produced in association with crude oil production, whereas non-associated gas is natural gas that is not in contact with significant quantities of crude oil in the reservoir.
Basis	In natural gas discussions "basis" refers to differences in the price of natural gas in two different geographical locations. In the marketplace "basis" typically means the difference between the NYMEX futures price at the Henry Hub and the cash price at other market points. In the modeling context "basis" means the difference in natural gas prices between any two nodes at the same instance in time.

Term	Definition
Decline curve	A decline curve is a plot of the rate of gas production against time. Since the production rate decline is associated with pressure decreases from oil and gas production, the curve tends to smoothly decline from a high early production rate to lower later production rate. Exponential, harmonic, and hyperbolic equations are typically used to represent the decline curve.
Depleted reservoir storage	A gas or oil reservoir that is converted for gas storage operations. Its economically recoverable reserves have usually been nearly or completely produced prior to the conversion.
Dry gas	Natural gas is a combustible mixture of hydrocarbon gases. Although consisting primarily of methane, the composition of natural gas can vary widely to include propane, butane, ethane, and pentane. Natural gas is referred to as 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is called 'wet'.
Ethane rejection	Ethane rejection occurs when the ethane component in the natural gas stream is not recovered in a gas processing plant but left in the marketable natural gas stream. Ethane rejection is deployed when the value of ethane is worth more in the gas stream than as an a separate commodity or as a component of natural gas liquids (NGL), which collectively refers to ethane, propane, normal butane, isobutane, and pentanes in processed and purified finished form. Information that characterizes ethane rejection by region can play a role in determining the production level and cost of natural gas by region.
Firm and interruptible demand	“Firm” refers to natural gas demand that is not subject to interruptions from the supplier, whereas “interruptible” refers to natural gas demand that is subject to curtailment or cessation by the supplier.
High deliverability storage	High deliverability storage is depleted reservoir storage facility or Salt Cavern storage whose design allows a relatively quick turnover of the working gas capacity.
Lease and plant use	Natural gas for “lease and plant use” refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants.
Liquefied Natural Gas (LNG)	LNG is natural gas converted to liquid form by cooling it down to about -260° F. Known as liquefaction, the cooling process is performed in an “LNG train” (the liquefaction and purification facilities in LNG plants), which reduces the gas to 1/600th of its original volume. The volume reduction resulting from liquefaction makes it cost effective to transport the LNG over long distances, typically by specially designed, double-hulled ships known as LNG carriers. Once the carriers reach their import terminal destination, the LNG is transferred in liquid form to specially designed storage tanks. When needed for customers, the LNG is warmed back to a gaseous state in a regasification facility and transported to its final destination by pipelines.
LNG peakshaving facility	LNG peakshaving facilities supplement deliveries of natural gas during times of peak periods. LNG peak shaving facilities have a regasification unit attached, but may or may not have a liquefaction unit. Facilities without a liquefaction unit depend upon tank trucks to bring LNG from nearby sources.

Term	Definition
Load factor	In the natural gas context “load factor” refers to the percentage of the pipeline capacity that is utilized at a given time.
Natural gas liquid (NGL)	Those hydrocarbons in natural gas that are separated from the gas as liquids in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline, and liquefied petroleum gases.
Play	A “play” refers to a set of known or postulated natural gas (or oil) accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
Pool	A “pool” is a subsurface accumulation of oil and other hydrocarbons. Pools are not necessarily big caverns. They can be small oil-filled pores. A “field” is an accumulation of hydrocarbons in the subsurface of sufficient size to be of economic interest. A field can consist of one or more pools.
Proven (or proved)	The term “proven” refers to the estimation of the quantities of natural gas resources that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Among the factors considered are drilling results, production, and historical trends. Proven reserves are the most certain portion of the resource base.
RACC price	Refiner Acquisition Cost of Crude Oil (RACC) is a term commonly use in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs.
Raw gas	Raw gas production refers to the volumes of natural gas extracted from underground sources, whereas net gas production refers to the volume of purified, marketable natural gas leaving the natural gas processing plant.
Reserves-to-production (R/P) ratio	Reserves-to-production ratio is the remaining amount of reserves, expressed in years, to be produced with a current annual production rate.
Resource and reserves	When referring to natural gas a distinction is made between “resources” and “reserves.” “Resources” are concentrations of natural gas that are or may become of potential economic interest. “Reserves” are that part of the natural gas resource that has been fully evaluated and determined to be commercially viable to produce.
Resource appreciation	Resource appreciation represents growth in ultimate resource estimates attributed to success in extracting resource from known plays such as natural gas from shales, coal seams, offshore deepwater, and gas hydrates that are not included in the resource base estimates.
Storage "Days Service"	Storage “Days Service” refers to the number of days required to completely withdraw the maximum working gas inventory associated with an underground storage facility.
Storage commodity charge	Storage commodity (variable) charge is generally a charge per unit of gas injected and/or withdrawn from storage as per the rights and obligations pertaining to a gas storage lease. Analogous to commodity charges for gas pipeline service

Term	Definition
Storage cycle	One storage cycle is the theoretical time required to completely inject and withdraw the working gas quantity for any given underground gas storage facility or the turnover time for the working gas capacity rating of the facility. The cycle rate of any storage facility is usually expressed in cycles per year and is the number of times the working gas volumes can theoretically be turned over each storage year. The cycle rating for Porous Storage varies from 1 to 6 per year while that for Salt Cavern Storage are as high as 12 per year.
Unconventional gas	Unconventional gas refers to natural gas found in geological environments that differ from conventional hydrocarbon traps. It includes: (a) “tight gas,” i.e., natural gas found in relatively impermeable (very low porosity and permeability) sandstone and carbonate rocks; (b) “shale gas,” i.e., natural gas in the joints, fractures or the matrix of shales, the most prevalent low permeability low porosity sedimentary rock on earth; and (c) “coal bed methane,” which refers to methane (the key component of natural gas) found in coal seams, where it was generated during coal formation and contained in the microstructure of coal. Unconventional natural gas is distinguished from conventional gas which is extracted using traditional methods, typically from a well drilled into a geological formation exploiting natural subsurface pressure or artificial lifting to bring the gas and associated hydrocarbons to the wellhead at the surface.
Underground storage	The underground storage of natural gas in a porous and permeable rock formation topped by an impermeable cap rock, the pore space of which was originally filled with water.
Wet gas	A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium.
Working gas	The term “working gas” refers to natural gas that has been injected into an underground storage facility and stored therein temporarily with the intention of withdrawing it. It is distinguished from “base (or cushion) gas” which refers to the volume of gas that remains permanently in the storage reservoir in order to maintain adequate pressure and deliverability rates throughout the withdrawal season.

Appendix 10-1 EPA Base Case v.4.10 with AEO Gas Resource Assumptions

For purposes of comparison a variant of EPA Base Case v.4.10 was prepared with natural gas resource assumptions that were set to approximate those in the Energy Information Administration's Annual Energy Outlook 2010.

To set up this case, EPA asked ICF International, who had developed the natural gas module for EPA Base Case v.4.10, to determine how best to represent the AEO 2010 resource assumptions in IPM in view of structural differences between the two models. It should be noted that the only change between the original EPA base case and this variant are the natural gas resource assumptions. The base year proved reserves assumptions were not changed.[1] The following is a summary of the findings of ICF's comparison and the approach that was implemented in setting up the AEO 2010 gas resource base case variant.

ICF's analysis of the AEO 2010 natural gas resource assumptions was based on the AEO 2010 assumptions document.[2] ICF found that the gas resource base in AEO 2010 is defined as technically recoverable resources (as of beginning of year 2008) without reference to economic profitability, whereas the gas resource base in IPM is defined as the economically recoverable resource (as of end of year 2010) which represents that portion of the original-gas-in-place that is economic to develop at wellhead prices[3] below $14/MMBtu (in 2007 dollars) given current technologies and industry costs.

ICF made adjustments to convert the AEO technically recoverable gas resources so that it could be used in the IPM Natural Gas Module. Their analysis found that the economically recoverable gas resource as defined in the IPM natural gas module was about 15% to 30% lower than the technically recoverable gas resource without economic consideration as used in AEO 2010. However, since the resource base for conventional, tight gas, and coalbed methane gas in the EPA base case was already 15% to 30% lower than the gas resources in the AEO 2010, ICF did not change the gas resource base for these resource types.

On the other hand, ICF found that the shale gas resource in the EPA base case was much higher than in AEO 2010. To quantify the difference in shale gas resource, ICF first calculated that a 20% reduction was needed in order both to translate the AEO technically recoverable shale gas resource into the equivalent economically recoverable resource used in IPM and to account for resource development between 2008 (base year for the AEO gas resources) and 2011 (base year for the IPM gas resource). Once the two resource bases were expressed so they could be compared, ICF found that the AEO shale gas resource assumption was about 31% of that used in the EPA base case.

To implement this in the alternative base case, the total shale gas resource was set so it would be 31% of the shale gas resource base assumed in EPA Base Case v.4.10. No attempt was made

---

[1] The base year proved reserves assumptions are described in section 10.3 of this chapter under the header "Use of the HSM resource and reserves data in EPA Base Case using IPM v.4.10 Natural Gas Module."

[2] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010: Natural Gas Transmission and Distribution Module*, DOE/EIA-0554(2010), April 9, 2010. www.eia.doe.gov/oiaf/aeo/assumption/nat_gas.html

[3] The wellhead price is the price required to cover total wellhead resource costs including capital expenditures, cost of capital, operating costs, royalties, severance taxes and income taxes. Wellhead economics are based upon standard discounted cash flow analysis. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per fracture stage and number of fracture stages. Drilling costs, well lateral length, number of fracture stages, and cost per fracture stage are based on analysis and data from industry.

to adjust shale gas resources by supply region so that the regional shale gas resources in AEO 2010 and EPA's AEO Supply Case would match.

Table 10-1.1 shows the resulting shale gas resource base assumptions for AEO 2010, EPA Base Case v.4.10, and the AEO Supply Case of the EPA base case. The location of the U.S. natural gas supply regions listed in Table 10-1.1 are shown in the map in Figure 10-1.1.

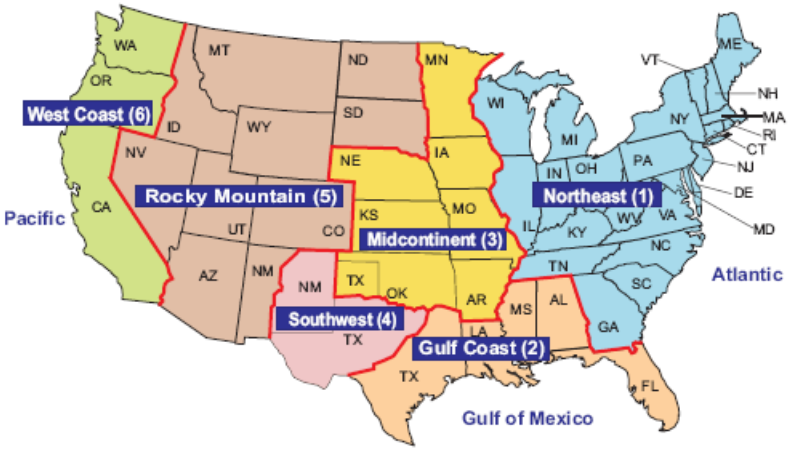
Table 10-1.1 Shale Gas Resource Base in Tcf (does not include proved reserves)

	AEO 2010[(a)] (as of BOY 2008)	EPA Base Case[(b)] (as of EOY 2010)	AEO Supply Case[(b)] (as of EOY 2010)
U.S.	**346.5**	**917.2**	**284.9**
Northeast	73.2	254.4	79.0
Gulf Coast	90.3	431.6	134.1
Midcontinent	51.0	132.9	41.3
Southwest	59.5	60.3	18.7
Rocky Mountain	21.6	37.7	11.7
West Coast	50.9	0.3	0.1
Canada	**NA**	**511.1**	**158.7**

[(a)] *Technically recoverable resources without reference to economic profitability.*

[(b)] *Economically recoverable resources under wellhead gas price of $14/MMBtu (2007 dollars).*

Figure 10-1.1 U.S. Supply Region



11 Other Fuels and Fuel Emission Factor Assumptions

Besides coal (chapter 9) and natural gas (chapter 10) EPA Base Case v.4.10 also includes assumptions for residual fuel oil, biomass, nuclear fuels, and various waste fuels. The assumptions described in this chapter pertain to fuel characteristics, fuel market structures, and fuel prices for these fuels. As seen in the previous chapter, there is an endogenous resource costing model for natural gas built into EPA Base Case v.4.10. Coal is represented via an elaborate set of supply curves and a detailed representation of the associated coal transport network. Together they are designed to capture the intricacies of the resource base and market for this fuel which currently powers about 45% of U.S. electric generating capacity. As with coal, the price and quantity of biomass combusted is determined by balancing supply and demand using a set of geographically differentiated supply curves. In contrast, fuel oil and nuclear fuel prices are exogenously determined and entered into IPM during model set-up as constant price points which apply to all levels of supply. Generally, the waste fuels are also modeled using price points. In this chapter each of the remaining fuels is treated in turn. The chapter concludes with a discussion of the emission factors for all the fuels represented in EPA Base Case v.4.10.

11.1 Fuel Oil

Two petroleum derived fuels are included in EPA Base Case v.4.10: As its name implies distillate fuel oil is distilled from crude oil, whereas residual fuel oil is left as a residue of the distillation process. The fuel oil prices in EPA Base Case v.4.10 are from AEO 2010 and are shown in Table 11-1. They are regionally differentiated according to the NEMS (National Energy Modeling System) regions used in AEO 2010 and are mapped to their corresponding IPM regions for use in EPA Base Case v.4.10.

Table 11-1 Fuel Oil Prices by NEMS Region in EPA Base Case v.4.10

Residual Fuel Oil Prices (2007$/MMBtu)					
NEMS Region	**2012**	**2015**	**2020**	**2030**	**2040 - 2050**
ECAR	16.40	30.04	41.07	54.20	63.77
ERCOT	20.00	21.96	23.40	25.42	26.91
MAAC	9.85	11.84	13.63	15.65	17.05
MAIN	91.20	104.84	115.87	129.00	138.57
MAPP	17.14	8.61	8.61	8.61	16.19
NY	9.63	11.73	13.59	15.61	16.99
NE	9.80	11.91	13.77	15.80	17.19
FL	10.50	12.48	13.92	15.95	17.44
SERC	10.96	12.83	14.28	16.32	17.81
SPP	17.36	21.73	23.15	25.14	26.60
NWP	19.56	21.58	23.06	25.00	26.50
RA	19.68	21.67	23.14	25.09	26.59
CA	21.63	23.83	25.10	27.24	28.56

Distillate Fuel Oil Prices (2007$/MMBtu)					
NEMS Region	**2012**	**2015**	**2020**	**2030**	**2040 - 2050**
ECAR	14.8	16.96	19.87	22.25	24.19
ERCOT	14.75	16.86	19.71	22.09	24.03
MAAC	14.82	16.99	19.9	22.3	24.25
MAIN	14.86	17.04	19.94	22.31	24.24
MAPP	14.88	17.05	19.95	22.32	24.25
NY	14.87	17.05	19.98	22.38	24.33
NE	15.07	17.23	20.13	22.53	24.49

Distillate Fuel Oil Prices (2007$/MMBtu)					
NEMS Region	**2012**	**2015**	**2020**	**2030**	**2040 - 2050**
FL	14.67	16.78	19.65	22.04	23.99
SERC	14.65	16.8	19.69	22.08	24.03
SPP	14.8	16.93	19.8	22.18	24.12
NWP	15.84	17.85	20.29	22.84	24.74
RA	15.59	17.73	20.6	23.02	24.97
CA	16.21	17.95	19.99	22.66	24.53

11.2 Biomass

Biomass is offered as a fuel for existing dedicated biomass power plants and potential (new) biomass direct fired boilers (built by the model prior to 2020) and to potential (new) biomass gasification combined cycle units built by the model from 2020 forward. (See chapter 4 for a presentation of the cost and performance characteristics for these two technologies.) In addition to its use as the prime mover fuel for these plants, it is also offered for co-firing to all coal fired power plants. (See section 5.3 for a discussion of the representation of biomass co-firing in EPA Base Case v.4.10.) As noted in the discussion in chapter 5, the combustion of biomass fuel is considered to have a net zero impact on atmospheric carbon dioxide levels since the emissions released are equivalent in carbon content to the carbon absorbed during fuel crop growth[1].

EPA Base Case v.4.10 uses biomass supply curves based on those in AEO 2010. There are fourteen regional biomass fuel supply curves, one for each of the 14 NEMS coal demand regions represented in AEO 2010. Plants demand biomass from the supply curve corresponding to the NEMS coal demand region in which they are located. No inter-regional trading of biomass is allowed. Each biomass supply curve depicts the price-quantity relationship for biomass and varies over time. There is a separate curve for each model run year. The supply component of the curve represents the aggregate supply in a region of four types of biomass fuels: forestry residue, agricultural residue, urban wood waste, and mill residue and energy crops. The price component of the curve includes transportation cost and represents the delivered fuel cost at the plant gate. The original AEO 2010 supply curves contained 48 price steps, and are modeled as-is in EPA Base Case v.4.10. Appendix 11-1 contains the 2012-2035 biomass supply curves.

The supply curves in Appendix 11-1 represent the biomass available to both the electric and non-electric sectors. In any given region at any point in time the power sector demand from IPM has to be combined with the non-electric sector demand for biomass to obtain the price faced by the power sector. The non-electric sector demand distribution is by NEMS coal demand region based on AEO 2010. The total national projection from AEO 2010 was scaled up to the projections obtained from the Forest and Agricultural Sector Optimization Model (FASOM), a dynamic, nonlinear programming model of the U.S. forest and agricultural sectors developed for EPA by Bruce A. McCarl, Professor of Agricultural Economics at Texas A&M University. Table 11-2 shows the non-electric sector demand by run year and NEMS region.

Table 11-2 Non-Electric Biomass Demand by NEMS Region in EPA Base Case v.4.10

Non-Electric Biomass Demand (TBtu)						
NEMS Coal Demand Region		**2012**	**2015**	**2020**	**2030**	**2040 - 2050**
1	CT, MA, ME, NH, RI, and VT	--	--	--	17.1	15.7
2	NY, PA, and NJ	--	--	--	--	0.0
3	WV, MD, DC, DE, VA, NC, and SC	19.4	126.7	336.1	354.1	324.2
4	GA and FL	12.7	80.3	201.7	202.4	185.3

[1]Hughes, E., Role of Renewables in Greenhouse Gas Reduction, Electric Power Research Institute (EPRI): November, 1998. Report TR-111883, p. 28.

Non-Electric Biomass Demand (TBtu)						
NEMS Coal Demand Region		2012	2015	2020	2030	2040 - 2050
5	OH	--	--	--	--	0.0
6	IN, IL, MI, and WI	--	--	--	--	0.0
7	KY and TN	--	--	--	--	0.0
8	AL and MS	--	--	--	--	0.0
9	MN, IA, ND, SD, NE, MO, and KS	131.8	184.3	63.8	48.0	43.9
10	TX, LA, OK, and AR	0.9	0.3	0.1	0.1	0.1
11	MT, WY, and ID	0.4	0.1	0.0	13.2	12.1
12	CO, UT, and NV	0.3	0.1	0.0	11.8	10.8
13	AZ and NM	0.3	0.1	0.0	9.0	8.2
14	WA, OR, and CA	0.2	22.7	506.7	467.6	428.1

Once the non-electric demand for biomass is factored in, biomass prices in EPA Base Case v.4.10 are derived endogenously based on the aggregate power sector demand for biomass in each region. The results are unique market-clearing prices for each supply region. All plants using biomass from that supply region face the same market-clearing price.

11.3 Nuclear Fuel

The AEO 2009 price assumption for nuclear fuel is used as the nuclear fuel price assumption for 2012-2050 in EPA Base Case v.4.10. The 2012, 2015, 2020, and 2030 prices are 0.71, 0.75, 0.76, and 0.84 lbs/MMBtu, respectively.

11.4 Waste Fuels

Among the “modeled fuels” shown for existing generating units in the NEEDS, v.4.10 (the database which serves as the source of data on existing units for EPA Base Case v.4.10) are a number of waste fuels, including waste coal, petroleum coke, fossil waste, non-fossil waste, tires, and municipal solid waste (MSW). Table 11-3 describes these fuels, shows their extent of their representation in NEEDS, and then indicates the assumptions adopted in EPA Base Case v.4.10 to represent their use and pricing. It should be noted that these fuels are only provided to existing and planned committed units in EPA Base Case v.4.10. Potential new generating units that the model “builds” are not given the option to burn these fuels. In IPM reported output, tires, MSW, and non-fossil waste are all included under existing non-fossil other, while waste coal and petroleum coke is included under coal.

Table 11-3 Waste Fuels in NEEDS, v.4.10 and EPA Base Case v.4.10

Modeled Fuel in NEEDS	Number of Units in NEEDS	Total Capacity in NEEDS	Description	Supply and Cost	
				Modeled By	Assumed Price
Waste Coal	3	2,205 MW	"Usable material that is a byproduct of previous coal processing operations. Waste coal is usually composed of mixed coal, soil, and rock (mine waste). Most waste coal is burned as-is in unconventional fluidized-bed combustors. For some uses, waste coal may be partially cleaned by removing some extraneous noncombustible constituents. Examples of waste coal include fine coal, coal obtained from a refuse bank or slurry dam, anthracite culm, bituminous gob, and lignite waste." http://www.eia.doe.gov/glossary/index.cfm?id=W	Supply Curve Based on AEO 2010	AEO 2010
Petroleum Coke	29	3,442 MW	A residual product, high in carbon content and low in hydrogen, from the cracking process used in crude oil refining	Price Point	$42.24/ MMBtu
Fossil Waste	28	982 MW	Waste products of petroleum or natural gas including blast furnace and coke oven gas. They do not include petroleum coke or waste coal which are specified separately among the "Modeled Fuels"	Price Point	0
Non-Fossil Waste	66	874 MW	Non-fossil waste products that do not themselves qualify as biomass. These include waste products of liquid and gaseous renewable fuels (e.g., red and black liquor from pulping processes, digester gases from waste water treatment). They do not include urban wood waste which is included in biomass.	Price Point	0
Tires	3	44 MW	Discarded vehicle tires.	Price Point	0
Municipal Solid Waste	183	2,197 MW	"Residential solid waste and some nonhazardous commercial, institutional, and industrial wastes." http://www.eia.doe.gov/glossary/index.cfm	Price Point	0

11.5 Fuel Emission Factors

Table 11-4 brings together all the fuel emission factor assumptions as implemented in EPA Base Case v.4.10. For sulfur dioxide and mercury in coal, where emission factors vary widely based on the rank, grade, and supply seam source of the coal, cross references are given to tables that provide more detailed treatment of the topic. Nitrogen oxides (NO_X) are not included in Table 11-4 because NO_X levels are not primarily fuel based but are a factor of the combustion process.

Table 11-4 Fuel Emission Factor Assumptions in EPA Base Case v.4.10

Fuel Type	Heat Content (Btu/lb)[1]	Carbon Dioxide (lbs/MMBtu)[2]	Sulfur Dioxide (lbs/MMBtu)[3]	Mercury (lbs/TBtu)[3]
Coal				
Bituminous	>10,260 - 13,000	205.2 - 206.6	0.67 - 6.43	1.82 - 34.71
Subbituminous	> 7,500 - 10,260	212.7 - 213.1	0.58 - 1.41	4.24 - 6.44
Lignite	< 7,500	213.5 - 217.0	1.46 - 3.91	7.51 - 14.88
Natural Gas	--	117.08	0	0.00014
Fuel Oil				
Distillate	--	161.4	0	0.48
Residual	--	161.4 - 173.9	0.3 - 2.65	0.48
Biomass	--	0	0.08	0.57
Waste Fuels				
Waste Coal	6,175	205.7	5.36	63.9
Petroleum Coke	14,150	225.1	7.27	23.18
Fossil Waste	--	321.1	0.08	0
Non-Fossil Waste	--	0	0	0
Tires	--	189.5	1.65	3.58
Municipal Solid Waste	--	91.9	0.35	71.85

Notes:

[1]Distillate and Residual Oils, Biomass, Fossil Waste, Non-Fossil Waste, Tires, and Municipal Solid Waste (MSW) are priced at a $/MMBtu basis and hence heat content is not required for modeling.

[2]Also see Table 9-9

[3]Also see Table 9-6, and Table 9-7

Biomass fuel is considered to have a net zero impact on atmospheric carbon dioxide levels since the emissions released are equivalent in carbon content to the carbon absorbed during fuel crop growth. (See, for example, Hughes, E., Role of Renewables in Greenhouse Gas Reduction, Electric Power Research Institute (EPRI): November, 1998. Report TR-111883, p. 28.)

"Biomass Co-firing," Chapter 2 in *Renewable Energy Technology Characterizations*, U.S. Department of Energy and Electric Power Research Institute (EPRI), 1997.

Analysis of Emissions Reduction Option for the Electric Power Industry, Office of Air and Radiation, U.S. Environmental Protection Agency, March 1999.

Appendix 11-1 Biomass Supply Curves in EPA Base Case v.4.10

This is a small excerpt of the data in Appendix 11-1. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html

Year	Biomass Supply Region	Step Name	Cost of Production (2007$/MMBtu)	Biomass Production (TBtu/Year)
2012	AL, MS	BM01	0.00	0
2012	AL, MS	BM02	1.83	21.28
2012	AL, MS	BM03	2.12	21.04
2012	AL, MS	BM04	2.39	19.44
2012	AL, MS	BM05	2.68	13.27
2012	AL, MS	BM06	2.97	10.35
2012	AL, MS	BM07	3.26	7.33
2012	AL, MS	BM08	3.54	78
2012	AL, MS	BM09	3.83	2.95
2012	AL, MS	BM010	4.11	1.22
2012	AL, MS	BM011	4.40	0.2
2012	AL, MS	BM012	4.68	0
2012	AL, MS	BM013	4.97	0
2012	AL, MS	BM014	5.26	0
2012	AL, MS	BM015	5.54	0
2012	AL, MS	BM016	5.82	0
2012	AL, MS	BM017	6.11	0
2012	AL, MS	BM018	6.40	0
2012	AL, MS	BM019	6.82	5
2012	AL, MS	BM020	7.24	5
2012	AL, MS	BM021	7.66	5
2012	AL, MS	BM022	8.07	5
2012	AL, MS	BM023	8.49	5
2012	AL, MS	BM024	8.91	5
2012	AL, MS	BM025	9.33	5
2012	AL, MS	BM026	9.76	5
2012	AL, MS	BM027	10.18	5
2012	AL, MS	BM028	10.60	5
2012	AL, MS	BM029	11.02	5
2012	AL, MS	BM030	11.44	5
2012	AL, MS	BM031	11.86	5
2012	AL, MS	BM032	12.28	5
2012	AL, MS	BM033	12.70	5
2012	AL, MS	BM034	13.12	5
2012	AL, MS	BM035	13.54	5
2012	AL, MS	BM036	13.97	5
2012	AL, MS	BM037	14.38	5
2012	AL, MS	BM038	14.80	5
2012	AL, MS	BM039	15.22	5
2012	AL, MS	BM040	15.64	5