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Coal Market Module of the National Energy Modeling System: Model Documentation 2020

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Update Information

This edition of the *Coal Market Module of the National Energy Modeling System: Model Documentation 2020* (CMM) has been updated to include changes to the Coal Market Module (CMM) modeling structure used in producing the *Annual Energy Outlook 2020* (AEO2020). The updates include the following items:

- The Coal Production Submodule (CPS) regression equation dataset was updated to include data for the years 1992 through 2015 (previously the data covered 1978 through 2009). The regression parameters associated with the coal-pricing model were re-estimated using the Eviews econometric analysis package and were updated for AEO2019.

- The benchmarking procedure was modified for AEO2019 to add an automatic scaling factor to adjust exports of steam and coking coal to match the STEO exports within tolerances.

- A new methodology for projecting international ocean freight shipping cost was implemented in AEO2020 to better represent the seaborne cost of shipping between each export origin (e) to import destination (i) pair represented in the International Coal Distribution Submodule (ICDS). The methodology was redesigned to allow for endogenous changes in fuel prices and account for exogenous assumptions for vessel operating and port costs, shipping distances, vessel speed, and days in port based on the size of the vessel (Panamax or Cape). The shipping costs include calculations for port usage fees, daily hiring rates by vessel class, and fuel costs for both *"at sea" or "in port"* days on each available transport path.

The AIMMS software is required for an outside party to be able run the CMM. For AEO2020, the solver was CPLEX 12.6.3. Slight differences in model results can occur depending on the version of CPLEX selected by the user.

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Executive Summary

Purpose of this report

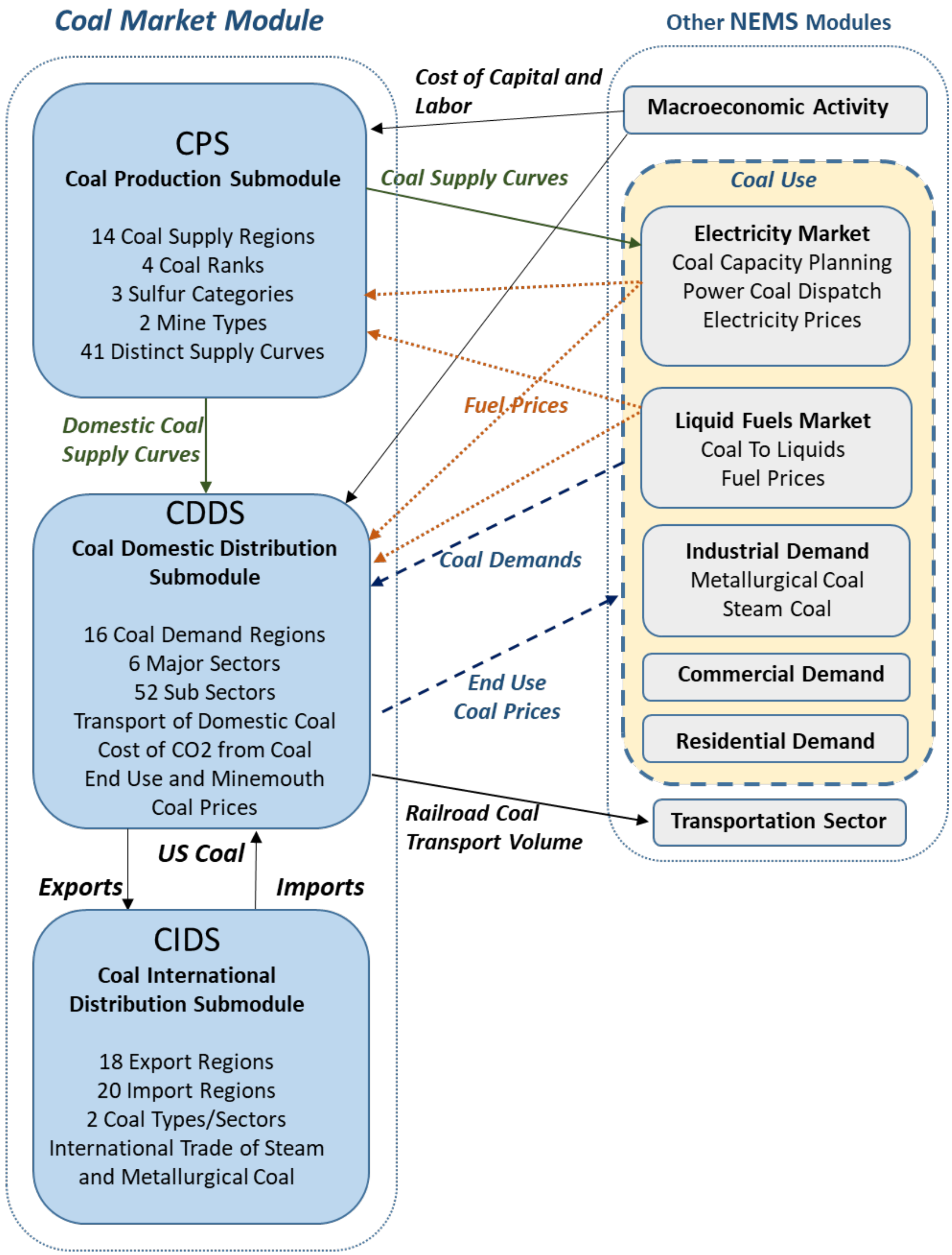
This report documents the objectives and the conceptual and methodological approaches used in the development of the National Energy Modeling System's (NEMS) Coal Market Module (CMM) used to develop the *Annual Energy Outlook 2020* (AEO2020). This report catalogues and describes the assumptions, methodology, estimation techniques, and source code of the CMM.

This document has three purposes. It is a reference document that provides a description of the CMM for model analysts and the public. It meets the legal requirement of the U.S. Energy Information Administration (EIA) to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, Federal Energy Administration Act of 1974, Section 57(B)(1), as amended by Public Law 94-385). Finally, it facilitates continuity in model development by providing documentation from which energy analysts can undertake model evaluations, model enhancements, data updates, and parameter refinements to improve the quality of the module.

Module summary

The CMM provides annual forecasts of prices, production, and consumption of coal through 2050 for NEMS. The Coal Production Submodule (CPS) generates a set of minemouth coal supply curves by coal supply region, coal type, and mine type. The supply curves are passed to the Domestic Coal Distribution Submodule (DCDS), along with regional coal demand requirements from other NEMS components. The CMM provides delivered coal prices and quantities to the NEMS economic sectors and regions. The DCDS solves for the interregional flows of coal from supply region to demand region by minimizing the production and transportation costs. The International Coal Distribution Submodule (ICDS) forecasts annual world coal trade flows from major international supply to major demand regions and provides annual forecasts of U.S. coal exports.

Figure A. Information flow between the CMM and other components of NEMS



Archival media

The documentation is archived as part of the NEMS production runs.

Coal Least Cost Solution

The CMM uses the AIMMS linear programming solver to determine the least-cost supplies of coal to meet a given set of U.S. domestic and international coal demands by sector and region.[1]

Coal Production Submodule (CPS)

The CPS generates a different set of supply curves for the CMM for each year in the forecast period. The construction of these curves involves three steps for any given year. First, the CPS calibrates a previously estimated regression model of minemouth prices (see Appendix 1.D) to base-year production and price levels by region, mine type, and coal type. Second, the CPS converts the regression equation into continuous coal supply curves. Finally, the supply curves are converted to step-function form, as required by the CMM's coal distribution routines, and prices for each step are calibrated to base-year data (2018 for AEO2020).

Domestic Coal Distribution Submodule (DCDS)

The Domestic Coal Distribution Submodule (DCDS) determines the least-cost (minemouth price plus transportation cost plus sulfur and mercury allowance costs) supplies of coal by supply region for a given set of coal demands in each demand sector in each demand region using a linear programming algorithm. Delivered prices to each demand region and sector are a function of the transportation costs, which are assumed to change over time based on a demand index described in a later section. The DCDS uses the available data on existing coal contracts (tonnage, duration, coal type, origin, and destination of shipments) as reported by electricity generators to represent coal under contract up to the contract's expiration date.

International Coal Distribution Submodule (ICDS)

The International Coal Distribution Submodule (ICDS) provides annual forecasts of U.S. coal exports and imports in the context of world coal trade demand, which is estimated outside of NEMS. The model uses 17 coal export regions (including 5 U.S. export regions) and 20 coal import regions (including 4 U.S. import regions) to forecast the international flow of steam and metallurgical coal. The model solves for exports and imports of coal by minimizing total delivered cost given constraints on the LP model for regional export capabilities, sulfur dioxide limits, and exogenously specified international coal supply curves.

Organization of this report

The report is divided into three sections. The first provides specifics of the CPS, the second describes the DCDS, and the third section details international trade in the ICDS. Within each section, the objectives, assumptions, mathematical structure, and primary input and output variables for each modeling area are described. Descriptions of the relationships within the CMM, as well as the CMM's interactions with other modules of the NEMS integrating system, are also provided.

The appendixes of each of the three major sections provide supporting documentation for the CMM files. The appendixes include detailed descriptions of the CMM input files, parameter estimates,

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[1] For AEO2020 the AIMMS software called the solver CPLEX 12.6.3. Slight differences in model results can occur depending on the version of CPLEX selected by the user.

forecast variables, and model outputs. The appendixes also include a mathematical description of the computational algorithms used in the respective submodule section of the CMM, including model equations and variable transformations; a bibliography of reference materials used in the development process of each section; and a description of data quality and estimation methods. A list of common abbreviations and acronyms is provided below in this summary section. In some tables and lists, state names have been abbreviated using U.S. postal abbreviations although it is EIA's accepted convention to spell out state names where possible.

List of Abbreviations and Acronyms

2SLS:	Two-stage least squares
AIMMS	Advanced Interactive Multidimensional Modeling System; the modeling software platform
ACI:	Activated carbon injection
AEO:	*Annual Energy Outlook*
BOM:	Bureau of Mines
Btu:	British thermal units[2]
CAAA90:	Clean Air Act Amendments of 1990
CAIR:	Clean Air Interstate Rule
CBTL:	Coal- and Biomass-to-Liquids
DCDS:	Domestic Coal Distribution Submodule
ICDS:	International Coal Distribution Submodule
CEUM:	Coal and Electric Utilities Model
CIF:	Cost plus insurance and freight; the FOB cost of coal plus the cost of insurance and freight
CMM:	Coal Market Module
CO2:	Carbon dioxide
CPS:	Coal Production Submodule
CSTM	Coal Supply and Transportation Model
CSAPR:	Cross-State Air Pollution Rule
CTL:	Coal-to-liquids; references modeled sector in which coal is be converted from a solid to a liquid
DWT:	Deadweight ton (2,240 pounds)
ECP:	Electricity Capacity Planning Submodule
EFD:	Electricity Fuel Dispatch Submodule
EIA:	Energy Information Administration
EMM:	Electricity Market Module
EPA:	Environmental Protection Agency
FERC:	Federal Energy Regulatory Commission
FOB:	Free on board

[2] British thermal unit (BTU), a measure of the quantity of heat, defined since 1956 as approximately equal to 1,055 joules, or 252 gram calories. It was defined formerly as the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

Hg:	Mercury
ICR:	Information collection request
LFMM:	Liquid Fuels Market Module
LP:	Linear program or linear programming
MAM:	Macroeconomic Activity Module
MATS:	Mercury Air Toxics Standard
MMBtu:	Million British thermal units
NCM	National Coal Model
NEMS:	National Energy Modeling System
NGMM:	Natural Gas Market Module
NOX:	Nitrogen oxides
OLS:	Ordinary least squares
OML:	Optimization Management Library (linear programming solver)
PCI:	Pulverized coal injection
PIES:	Project Independence Evaluation System
PPI:	Producer price index
PRB:	Powder River Basin
RAMC:	Resource Allocation and Mine Costing Model
RHS:	Right-hand side of linear programming constraints
SO2:	Sulfur dioxide
TBtu:	Trillion British thermal units
WOCTES:	World Coal Trade Expert System

1. Coal Production Submodule (CPS)

Introduction

Section 1 of the Coal Market Module (CMM) documentation report addresses the objectives and the conceptual and methodological approach for the Coal Production Submodule (CPS). This section provides descriptions of the assumptions, methodology, estimation techniques, and source code of the CPS. The CPS is built in a software platform called AIMMS.[3] As a reference document, it facilitates continuity in model development by providing documentation from which energy analysts can undertake model enhancements, data updates, and parameter refinements to improve the quality of the module.

Model summary

The modeling approach to regional coal supply curve construction discussed here addresses the relationship between the minemouth price of coal and corresponding levels of capacity utilization at mines, productive capacity, labor productivity, wages, fuel costs, other mine operating costs, and a term representing the annual user cost of mining machinery and equipment. These relationships are estimated through the use of a regression model that makes use of regional-level data by mine type (underground and surface) for the years 1992 through 2015. The regression equation, together with projected levels of productive capacity, labor productivity, miner wages, cost of capital, fuel prices, and other mine operating costs, produces minemouth price estimates for coal by region, mine type, and coal type for different levels of capacity utilization.

The measure used for the price of fuel in the AEO2020 coal-pricing model is based on both the price of electricity to industrial consumers and the price of No. 2 diesel fuel to end users. According to data published by the U.S. Department of Commerce, electricity accounted for 86% of the fuel consumption at U.S. underground mines in 2002 on a British thermal unit (Btu) basis and an estimated 21% of the fuel consumption at surface mines. Fuel oil (distillate and residual) accounted for 14% of the fuel consumption at underground mines in 2002 and 79% of the fuel consumption at surface mines.[4] The data used to calculate these percentages exclude estimated consumption of fuels for which the type of fuel consumed is unknown and small amounts of other fuels consumed at U.S. coal mines, such as motor gasoline, natural gas, and coal.

The CPS generates a different set of supply curves within the CMM for each year in the forecast period. The construction of these curves involves three main steps for any given forecast year. First, the CPS calibrates the regression model to base-year production and price levels by region, mine type, and coal type. Second, the CPS converts the regression equation into coal supply curves. Finally, the supply curves are converted to step-function form, and prices for each step are adjusted to the year dollars

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[3] AIMMS (Advanced Interactive Multidimensional Modeling System) is a software system designed for modeling and solving large-scale optimization and scheduling-type problems. It consists of an algebraic modeling language, an integrated development environment for both editing models and creating a graphical user interface around these models, and a graphical end-user environment.

[4] U.S. Census Bureau, *2002 Census of Mineral Industries*, *Bituminous Coal and Lignite Surface Mining 2002*, EC902-211-212111(RV) (Washington, DC, December 2004); *Bituminous Coal Underground Mining 2002*, EC02-211-212112(RV) (Washington, DC, December 2004); *Anthracite Mining 2002*, EC02-211-212113 (Washington, DC, October 2004).

required by the CMM's Domestic Coal Distribution Submodule (DCDS). The completed supply curves are used by the DCDS to find the least-cost solution satisfying the projected annual levels of domestic and international coal demand, taking into account minemouth coal prices, transportation costs, and the cost of emissions.

Organization

Section 1 of this report describes the modeling approach used in the CPS. You can find the following within this section:

- The model purpose and scope, including discussions of the model objectives, the coal classification plan, model inputs and outputs, and the relationship to other models
- The model rationale, including a discussion of the theoretical approach and basis in observed market behavior
- The model structure, including key computations and equations

An inventory of model inputs and outputs, detailed mathematical specifications, bibliography, and model abstract for the CPS are included in appendixes 1.A to 1.E.

Model purpose and scope

Model objectives

The objective of the CPS routine is to develop annual domestic coal supply curves for the Linear Programing (LP) solver of the Coal Market Module (CMM) of the National Energy Modeling System (NEMS) through the year 2050. The supply curves relate annual production to the marginal cost of supplying coal. Separate supply curves are developed for each unique combination of supply region, mine type (surface or underground), and coal type.

Classification plan

U.S. coal supply curves are categorized by region and typology (in other words, parameters that define coal quality and general mining method).

Coal supply regions

The 14 coal supply regions represented in the CPS are listed in Table 1.1 and shown in Figure 1.1. The coal supply regions generally correspond to major U.S. coal basins and existing coal production areas.

The geographical split for the two Wyoming Powder River Basin (PRB) supply regions is based primarily on differences in the average heat content of the coal reserves in these regions. Production from mines in the Wyoming Northern PRB region have a heat content of approximately 16.8 million Btu per ton[5] (8,400 Btu per pound), and production from mines in the Wyoming Southern PRB region have a slightly higher heat content of about 17.6 million Btu per ton (8,800 Btu per pound). Base-year input data for the Wyoming Northern PRB supply region included production from the nine Wyoming PRB coal mines located north of the Black Thunder mine, and the Wyoming Southern PRB region included production from the three southernmost mines in Wyoming's PRB (Arch Coal's Black Thunder mine, Peabody's North Antelope/Rochelle mine, and Cloud Peak Energy's Antelope mine). In addition to heat content,

[5] Unless otherwise specified, tons refer to short tons (2,000 pounds) throughout this document.

the supply curves for the two Wyoming PRB supply regions have slightly different assignments for sulfur and mercury content (see Table 2.1).

Coal typology

The model's coal typology includes four thermal and three sulfur grades of coal for surface and underground mining. The four thermal grades correspond generally to the three ranks of coal (bituminous, subbituminous, and lignite) and a premium grade bituminous coal used primarily for metallurgical purposes. The three sulfur grades represented are low, medium, and high. The three sulfur content categories are required to model the regulatory restrictions on SO2 emissions and to accurately estimate projected levels of SO2 emissions for the electric power sector. Although each of the coal supply curves represented in the CMM are grouped into one of the three sulfur grades, actual sulfur content assignments for each curve are based on regional-level data, and therefore they can vary across the supply regions. For example, the average sulfur content of low-sulfur bituminous coal shipments from mines in Central Appalachia in recent years has been about 0.55 pounds per million Btu heat input, while the sulfur content of low-sulfur subbituminous coal shipped from mines in Wyoming's Southern Powder River has averaged less than 0.35 pounds per million Btu heat input. In total, nine coal types (unique combinations of thermal grade and sulfur content) and two mine types (underground and surface) are represented in the CPS (Table 1.1).

Coal supply curve delineation

U.S. coal supply is represented through the use of 41 supply curves, reflecting the combination of supply regions, coal types, and mine types (Table 1.1). The required number of coal supply curves varies by region because not all coal types are represented in the coal reserve base for each of the 14 supply regions modeled in the CMM. For example, Northern Appalachia is represented with six supply curves, the most of any of the regions, while the Western Interior, Dakota Lignite, and Alaska/Washington regions are each represented with a single supply curve. In some instances, the coal reserves base for a region may contain coal types that are not represented in the CMM, generally because the quantity of available reserves is considered to be of an insufficient quantity to model. An example is the small quantities of low-sulfur bituminous coal reserves that are not modeled for the Northern Appalachian supply region.[6]

Model inputs and outputs

Model input requirements are grouped into two categories:

- User-specified inputs
- Inputs provided by other NEMS modules and submodules

User-specified inputs for the base year include capacity utilization at mines, productive capacity, minemouth coal prices, miner wages, labor productivity, cost of mining equipment, and the price of electricity. Other user-specified inputs required for the NEMS forecast years include annual growth rates for labor productivity and wages and annual producer price indices for the cost of mining machinery and

[6] U.S. Energy Information Administration, *U.S. Coal Reserves: 1997 Update*, DOE/EIA-0529(97) (Washington, DC, February 1999).

equipment, iron and steel, and explosives. Inputs obtained from other NEMS modules include coal production for year t-1, the minemouth coal price for years t and t-1, electricity prices, and the real interest rate (Figure 1.2). The updated AIMMS version of the CMM reads some of the user-specified inputs from an Access database (CPS.mdb) found in the NEMS input directory. User inputs may also be read in from text files. Appendix 1.C includes a complete list of input variables and specification levels.

The primary outputs of the model are annual coal supply curves (price/production schedules), provided for each supply region, mine type, and coal type.

Table 1.1. Combinations of coal supply regions and coal/mine types used in the CMM

Supply regions	States	Underground mine types	Surface mine types
Appalachia			
1. "01NA" – Northern Appalachia	PA, OH, MD, No. WV	MDB(1), HDB(2), MDP(3)	MSB(4), HSB(5), HSG(6)
2. "02CA" – Central Appalachia	So. WV, VA, East KY, No. TN	CDB(7), MDB(8), MDP(9)	CSB(10), MSB(11)
3. "03SA" – Southern Appalachia	Al & So. TN	CDB(12), MDB(13), CDP(14)	CSB(15), MSB(16)
Interior			
4. "04EI" – East Interior	West KY, IL, IN, MS	MDB(17), HDB(18)	MSB(19), HSB(20), MSL(21)
5. "05WI" – West Interior	IA, MO, KS, AR, OK, TX		HSB(22)
6. "06GL" – Gulf Lignite	TX, LA		MSL(23), HSL(24)
Northern Great Plains			
7. "07DL" – Dakota Lignite	ND & East MT		MSL(25)
8. "08WM" – Western Montana	West MT	CDB(26)	CSS(27), MSS(28)
9. "09NW" – Wyoming Northern PRB	WY, Northern Power River Basin		CSS(29), MSS(30)
10. "10SW" – Wyoming Southern PRB	WY, Southern Powder River Basin		CSS(31)
11. "11WW" – Western Wyoming	West WY	CDS(32)	CSS(33), MSS(34)
Other West			
12. "12RM" – Rocky Mountains	CO & UT	CDB(35), CDP(36)	CSS(37)
13. "13ZN" – Arizona/New Mexico	NM & AZ	MDB(38)	CSB(39), MSS(40)
14. "14AW" – Alaskan/Washington	AK & WA		CSS(41)

Key to Coal Mine Type Abbreviations

Sulfur Emissions Categories
"C_ " – "Compliance": < = 1.2 pounds (lbs.) SO2 per million Btu
"M_ " –"Medium": > 1.2, <= 3.33 lbs. SO2 per million Btu
"H_ " – "High": > 3.33 lbs. SO2 per million Btu

Mine Types
"_D_" underground mining
"_S_ " surface mining

Coal Grade or Rank

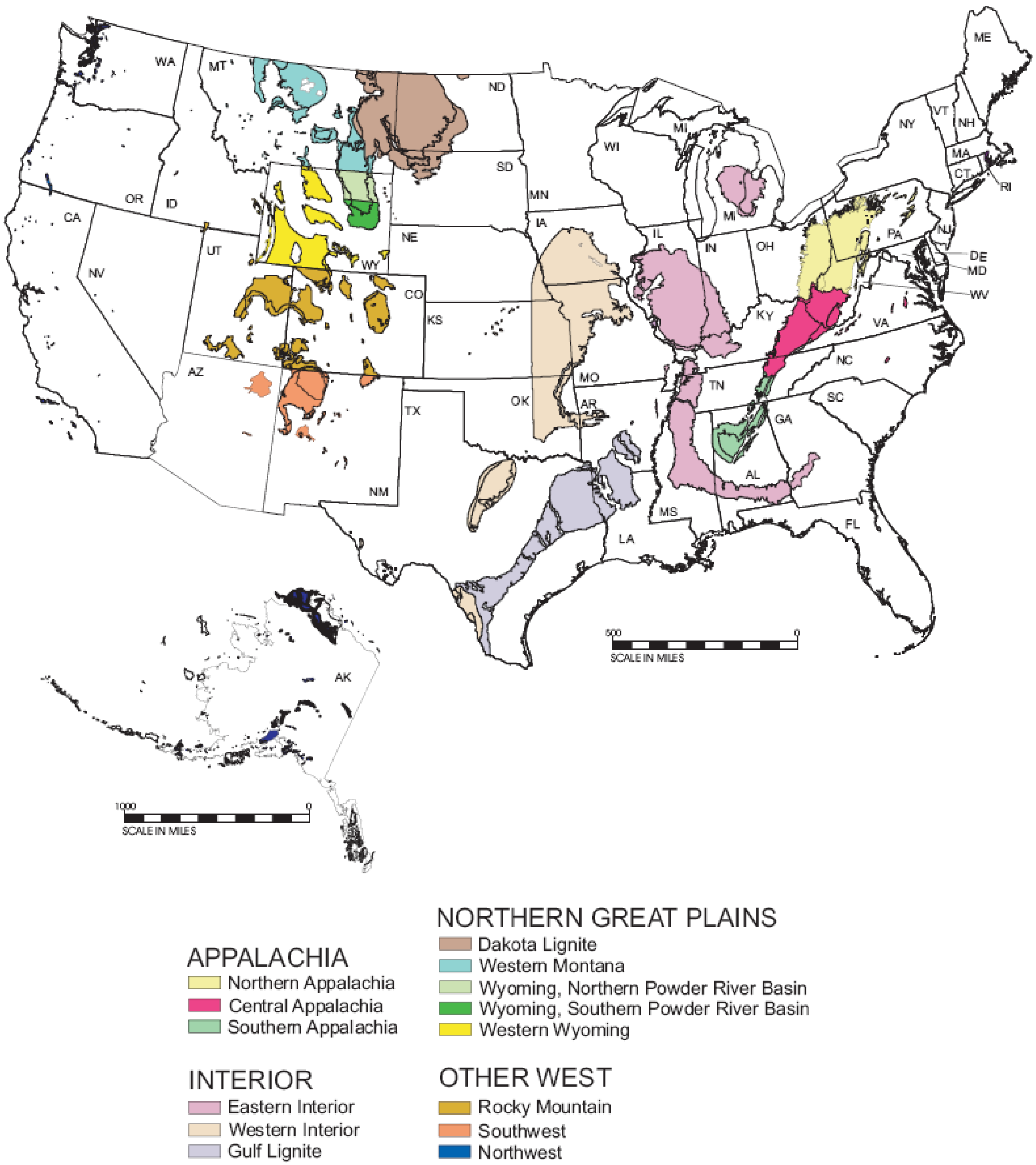
"_ P", Premium or metallurgical coal
"_ B", Bituminous and anthracite steam coal
"_ S", Subbituminous steam coal
"_ L", Lignite
"_G", Bituminous gob, or anthracite culm steam coal

Order (Scrv1)

Display order used in AIMMS model
(1) to (41)

Example: MDB type is medium sulfur grade underground bituminous coal mining.

Figure 1.1. Coal supply regions



Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

Relationship to other components of NEMS

The model generates regional coal supply curves. A distinct set of supply curves is determined for each forecast year through 2050. The supply curves are required input to the LP solver of the CMM as well as the NEMS Electricity and Liquid Fuels Market Modules. The information flow between the model and other components of NEMS is shown in Figure 1.2. Information obtained from the CDS and other NEMS modules is as follows:

- Electricity prices by census division are obtained from the Electricity Market Module (EMM) for year *t*
- National-level distillate fuel price is obtained from the Liquid Fuels Market Module (LFMM) for year *t*
- Real interest rate is obtained from the Macroeconomic Activity Module (MAM) for year t
- Coal production by CPS supply curve for year *t-1*
- Minemouth coal prices by CPS supply curve for years t and *t-1*

Model rationale

This section presents the econometric model used to produce coal supply curves for the AEO2020 forecasts. The primary criteria guiding the development of the coal-pricing model were that the model should conform to economic theory and that parameter estimates should be unbiased and statistically significant. Following economic theory, an increase in output or factor input prices should result in higher minemouth prices, and increases in coal mining productivity should result in lower minemouth prices. In addition, the model should account for a substantial portion of the variation in minemouth prices over the historical period of study.

Theoretical approach

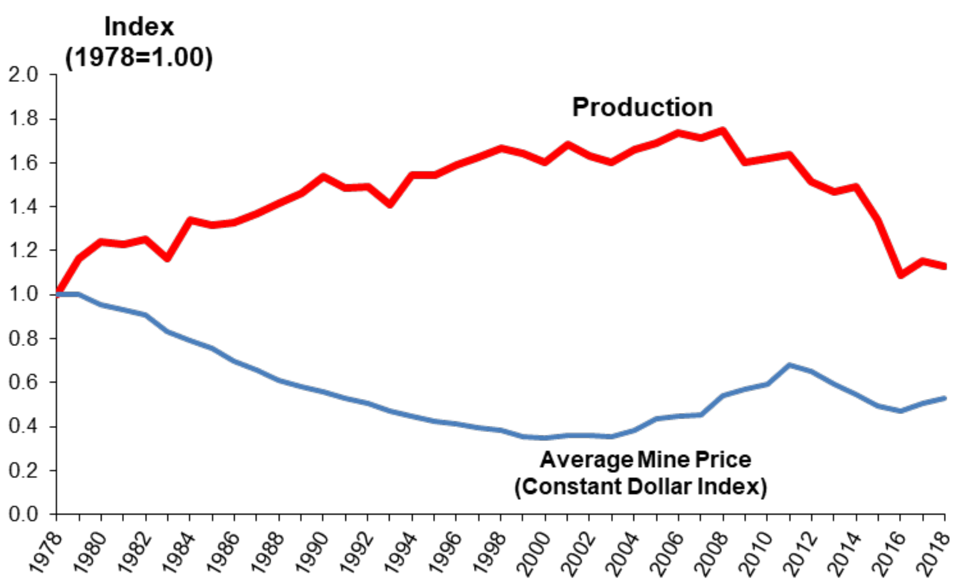
The CPS constructs a distinct set of coal supply curves for each forecast year in NEMS. The construction of these curves involves three main steps for any given forecast year. First, the CPS calibrates the regression model to base-year production and price levels by region, mine type, and coal type. Second, the CPS converts the regression equation into coal supply curves. Third, the supply curves are converted to step-function form for input to the LP solver, which finds the least-cost solution for satisfying the projected annual levels of domestic and international coal demand, given the set of minemouth prices and transportation rates.

The CPS addresses the relationship between the minemouth price of coal and corresponding levels of capacity utilization at mines, productive capacity, labor productivity, wages, fuel costs, other mine operating costs, and a term representing the annual user cost of mining machinery and equipment. These relationships are estimated through the use of a regression model that makes use of annual historical regional level data. The regression equation, together with projected levels of productive capacity, labor productivity, miner wages, capital costs, fuel prices, and other mine operating costs, produces minemouth price estimates for coal by region, mine type, and coal type for different levels of capacity utilization.

Basis in observed market behavior

Between 1978 and 2004, the average mine price of coal in the United States, in constant 2005 dollars, fell from $54.11 per ton to $20.74 per ton, a decline of 62% (Figure 1.2). During the same period, total U.S. coal production increased by 66%, from 670 million tons to 1,112 million tons. The inverse relationship between the production of coal and its price over time is attributable to many factors, including gains in labor productivity and declines in factor input costs. U.S. coal production between 1997 and 2011 remained flat at about 1,100 million short tons per year, decreasing slightly from 2012 to 2014 to around 1 billion short tons[7] per year, and more sharply between 2015 and 2018 to production levels of around 750 million tons. In the same 1997 to 2011 timeframe, coal mining productivity fell from 6.0 tons per hour to 5.2 tons per hour. Between 2004 and 2011, the average U.S. minemouth coal price, in inflation-adjusted dollars, rose by 74%, and coal mining productivity declined by 24%, falling from 6.8 tons per miner hour to 5.2 tons per miner hour.[8] Between 2011 and 2016, the average minemouth coal price fell by about 7% per year, and coal mining productivity increased back to 6.6 tons per miner hour in 2016. Higher prices in 2017 and 2018 saw some less productive mines return to service, diminishing productivity slightly to 6.2 tons per miner hour in 2018.

Figure 1.2. U. S. coal production and prices, 1978-2018



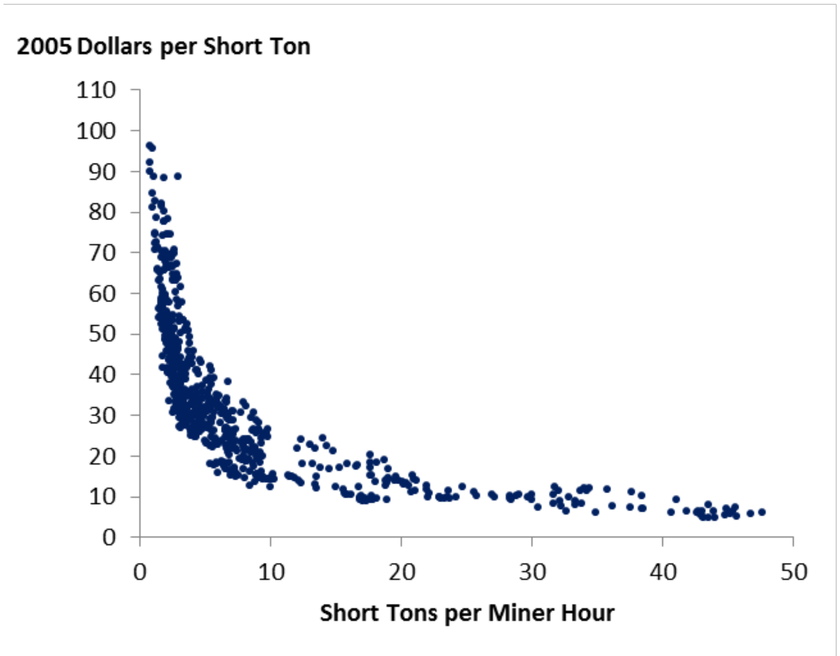
Productivity has had a significant effect on competition in the U.S. coal industry. Between 1978 and 2004, labor productivity at U.S. mines rose from 1.8 tons per miner hour to 6.8 tons per miner hour, representing an increase of 5.3% per year. This growth contributed to a downward shift in costs over

[7] All references to "ton" in this document unless specified otherwise are "short tons" equal to 2,000 pounds-mass or 907.18474 kilograms in the metric system as opposed to "metric tons" or "tonne" of 1,000 kilograms or 2,204.62262 pounds or "long ton" or "imperial ton" of 2,240 pounds or 1,016.0469088 kilograms.

[8] U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*; and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, *Quarterly Mine Employment and Coal Production Report*.

time, making additional quantities of coal available at lower prices. A graphical representation of labor productivity and the average price of coal at mines for the unique combinations of region, mine type, and year as represented in the AEO2020 coal-pricing model indicates the strong negative historical correlation between prices and productivity (Figure 1.3).

Figure 1.3. Minemouth coal prices and labor productivity for CMM regions, 1978-2015



A model of the coal market

The model of the U.S. coal market developed for the CPS recognizes that prices in a competitive market are a function of factors that affect either the supply or demand for coal.[9] The general form of the model is that a competitive market converges toward equilibrium, where the quantity supplied equals the quantity demanded for region i and mining type j in year t:

$$Q_{i,j,t}^{S} = Q_{i,j,t}^{D} = Q_{i,j,t} \qquad (1.1)$$

In this equality, $Q_{i,j,t}$ represents the long-run equilibrium quantity of supply and demand for coal in a competitive market.

The formal specification of the coal-pricing model is as follows.

For demand,

$$Q_{i,j,t}^{D} = f(P, ELEC_{t-1}, ELEC\_SHARE_{t-1}, INDUSTRY_{t-1}, OTHPROD_{t-1}, EXPORTS_{t-1}, PGAS_{i,t}, \qquad (1.2)$$

$$WOP_{t}, STOCKS_{t-1}, DAYS\_SUP_{t-1}, BTU\_TON_{i,j,t}, SULFUR_{i,j,t}, ASH_{i,j,t}) + e_{i,j,t}^{D}$$

[9] K. Forbes and C. Minnucci, Science Applications International Corporation, "An Econometric Model of Coal Supply: Final Report" (unpublished report prepared for the U.S. Energy Information Administration, December 20, 1996).

For supply,

$$P = f\left(\left(Q_{i,j,t}^{S} / PRODCAP_{i,j,t}\right), PRODCAP_{i,j,t}, TPH_{i,j,t}, WAGE_{t}, PCSTCAP_{t}, PFUEL_{i,t}, OTH\_OPER_{i,j,t}\right) + e_{i,j,t}^{S} \qquad (1.3)$$

The term Q^S/PRODCAP is the average annual capacity utilization at coal mines. Throughout the remaining sections and appendixes of Section 1, this term is referred to as CAPUTIL.

The demand-side variables are as follows:

Q^D is the quantity of coal demanded from region i, mine type j, in year t in million tons.

ELEC is U.S. coal-fired electricity generation in billion kilowatthours in year t-1.

ELEC_SHARE is the share of total U.S. electricity generation accounted for by generation at natural-gas-fired power plants in year t-1.

INDUSTRY is U.S. industrial coal consumption (steam and coking) in million short tons for each year t-1.

OTHPROD is the total U.S. coal production in million tons minus coal production for region i and mine type j for each year t-1.

EXPORTS is the level of U.S. coal exports in million tons in year t-1.

PGAS is the delivered price of natural gas to the electricity sector in constant 1992 dollars per thousand cubic feet for region i in year t.

WOP is the world oil price in constant 1992 dollars per barrel in year t.

STOCKS is the quantity of coal inventories held at plants in the electric power sector in million tons at the beginning of year t-1.

DAYS_SUP is the average days of supply of coal inventories held at electricity sector plants in year t-1.

BTU_TON is the average heat content of coal receipts at electric power sector plants in million Btu per ton for region i and mine type j, in year t.

SULFUR is the average sulfur content of coal receipts at electric power sector plants specified as pounds of sulfur per million Btu for region i and mine type j, in year t.

ASH is the average ash content of coal receipts at electric power sector plants specified as percent ash by weight for region i and mine type j, in year t.

e^D is a random term representing unaccounted factors in the demand function for region i and mine type j, in year t.

The supply-side variables are as follows:

P is the average minemouth price of coal in constant 1992 dollars per ton for region i and mine type j, in year t.

Q^S is the quantity of coal supplied in million tons from region i for mine type j in year t.

PRODCAP is the annual coal productive capacity in million tons for region i and mine type j, in year t.

Q^S/PRODCAP (or CAPUTIL) is the average annual capacity utilization (as a percentage) at coal mines for region i and mine type j, in year t.

TPH is the average annual labor productivity of coal mines in tons per miner hour for region i and mine type j, in year t.

WAGE is the average annual coal industry wage in constant 1992 dollars for region i, in year t.

PCSTCAP is the annualized user cost of mining equipment in constant 1992 dollars, for mine type j, in year t.

PFUEL is the weighted average of the price of electricity in the industrial sector and the price of No. 2 diesel fuel to end users (excluding taxes) in 1992 dollars per million Btu for region i, in year t.

OTH_OPER is a constant-dollar index representing a measure for mine operating costs other than wages and fuel specified by supply region i, mine type j, in year t. Examples of other operating costs include items such as replacement parts for equipment, roof bolts, and explosives.

e^S is a random term representing unaccounted factors in the supply function for region i and mine type j, in year t.

In this model, the amount of coal demanded from region i and mine type j in year t is determined by the minemouth price of coal, electricity generation, industrial coal consumption, coal exports, the price of natural gas, the world oil price, the level of coal stocks, and the heat, sulfur, and ash content of the coal. On the supply side of the market, the minemouth price is assumed to be determined by the capacity utilization at mines, productive capacity, the level of labor productivity, the average level of wages, the annualized cost of mining equipment, and the cost of fuel used by mines.

Estimation methodology

The supply function for coal cannot be evaluated in isolation when the relationship between quantity and price is being studied. The solution is to include the demand function and estimate the demand and supply functions together. A two-stage least squares (2SLS) methodology is used to estimate the set of simultaneous equations representing the supply and demand for coal, accordingly.

The rationale for using 2SLS rather than ordinary least squares (OLS) results from the structure of equations (1.2) and (1.3). In equation (1.3), the error term in the supply equation (e^S) affects the minemouth price (P); however, in Equation (1.2), price influences the quantity demanded (Q^D). As a result, the quantity of coal supplied (Q^S) on the right-hand side of the supply equation is correlated with the error term in the same equation. This result violates one of the fundamental assumptions underlying the use of OLS, namely, that the error term is independent from the regressors. As a result, the OLS estimator will not be consistent.

In addition, while WAGE, PCSTCAP, PFUEL, OTH_OPER, and TPH are all hypothesized to affect the price of coal, they are also affected by the price of coal. For example, an increase in the price of coal resulting from increased demand for coal may affect the wages paid in the coal industry, the cost of mining equipment, and the price of fuels. Prices may also influence the level of productivity. If prices decrease (increase), marginal mines are abandoned (opened), increasing (lowering) labor productivity. This result violates the assumption underlying the use of OLS, making it an inappropriate method for estimating the supply function.

An accepted solution to the problem of biased least squares estimators is the use of 2SLS, where the objective is to make the explanatory endogenous variable uncorrelated with the error term. [10] This is accomplished in two stages. In the first stage of the estimation, the endogenous explanatory variables are regressed on the exogenous and predetermined variables. This stage produces predicted values of the endogenous explanatory variables that are uncorrelated with the error term. The predicted values are employed in the second stage of the technique to estimate the relationship between the dependent endogenous variable and the independent variables. The result from the second-stage (structural) equation represents the model implemented in the CMM. The first stage (reduced form) equations are used only to obtain the predicted values for the endogenous explanatory variables included in the second stage, effectively purging the demand effects from the supply-side variables.

The structural equation for the coal-pricing model was specified in log-linear form using the variables listed above. In this specification, the values for all variables (except for the constant terms) are transformed by taking their natural logarithm. All observations were pooled into a single regression equation. In addition to the overall constant term for the model, intercept dummy variables were included for some regions. Slope dummy variables were included for the productivity and productive capacity variables to allow the coefficients for those terms to vary across regions and mine types. The Durbin-Watson test for first-order positive autocorrelation indicated that the hypothesis of no autocorrelation should be rejected. As a consequence, a correction for serial correlation was incorporated. In addition, a formal test indicated that the null hypothesis of homoscedasticity (the assumption that the errors in the regression equation have a common variance) across regions should be rejected, and, as a result, a weighted regression technique to correct for heteroscedasticity in the error term was employed to obtain more efficient parameter estimates. In Appendix 1.C, Table 1.C.1 lists the statistical results of the regression analysis, and Appendix 1.C provides additional detail on the equation used for predicting future levels of minemouth coal prices by region, mine type, and coal type.

In general, the results satisfy the performance criteria specified for the model. Indicative of the high R^2 statistic, there is a close correspondence between the predicted and actual minemouth prices (a discussion of how the R^2 statistic is calculated is provided in Appendix 1.C). Moreover, all parameter estimates have their predicted signs and are generally statistically significant.

Average annual seam thickness by region and mine type also was tested as a supply-side variable. The model results, however, did not support the hypothesis that decreases (increases) in seam thickness have exerted upward (downward) pressure on prices.

[10] G.S. Maddala, *Introduction to Econometrics: Second Edition* (New York, MacMillan Publishing Company, 1992), 355–403.

Labor productivity

Historically, the U.S. coal mining industry has developed or adopted a number of technological changes in each stage of production and achieved economies of scale that have contributed to overall productivity improvements. Examples include mining equipment and materials handling in underground mines, surface mining equipment and methods, equipment monitoring and automation, and mine planning. In the future, the rate at which productivity will improve is dependent on the mix of relatively new technologies that are contributing to the gains, the significance of individual technologies in realizing productivity improvement, and their stage in the technology diffusion cycle.

In addition to gradual improvements in mining equipment and techniques, the U.S. coal industry has experienced the introduction and penetration of fundamentally new mining systems. At underground mines, examples include the introduction and gradual diffusion of the continuous mining method that began in the 1940s, and the introduction and penetration of longwall mining systems that began in this country in the 1960s. Continuous mining saw its share of total U.S. underground production increase from 2% in 1951 to 31% in 1961. By 1971, the share of continuous mining coal production was 55%, and, in 1990, continuous mining accounted for 64% of total underground production.[11]

Similarly, longwall mines saw their share of total underground production increase from less than 1% in 1966 to 4% in 1976 and to approximately 16 to 20% by 1982.[12] Recent data collected by EIA showed continuing penetration of the longwall mining technique in the U.S. coal industry for another two decades, with this mining technique's share of underground production rising to 37% in 1990 and to more than 52% in 2002.[13] From 2003 to 2011, longwall's share of underground coal production stabilized in a range of between 49% and 52%. In 2014 the share of underground coal production originating from longwall mines reached a new peak of more than 58%, primarily the result of a resurgence in longwall production in the Eastern Interior supply region. Although the outlook for longwall production looks promising in the Eastern Interior region, additional penetration of the longwall mining technique in other supply regions may be limited by a number of factors, such as concerns about surface subsidence and reduced availability of new sites with appropriate geologic characteristics and reserve blocks. The fragmentation of reserves and relatively thin coal seams of Central Appalachia are key factors underlying the recent decline in longwall production in this major supply region, where its share of underground production dropped from a peak of 23% in 2003 to 15% in 2012. For surface mines, improvements in the size and capacity of the various types of equipment used (including shovels, draglines, front-end loaders, and trucks) resulted in substantial productivity gains through 2001, particularly in the Powder River Basin (PRB). However, increasing overburden

[11] J. I. Rosenberg, et al., *Manpower for the Coal Mining Industry: An Assessment of Adequacy through 2000*, prepared for the U.S. Department of Energy (Washington, DC, March 1979).
[12] Paul C. Merritt, "Longwalls Having Their Ups and Downs," *Coal*, MacLean Hunter (February 1992), pp. 26–27.
[13] U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*; and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, *Quarterly Mine Employment and Coal Production Report*.

removal requirements and declining production from surface mines outweighed the average labor productivity gains from technology, resulting in a general decrease in labor productivity since 2001.

Whether technological change represents improvements to existing technologies or fundamental changes in technology systems, the change has a substantial impact on productivity and costs. With few exceptions, transition in the coal industry to new technology has been gradual, as has been the effect on productivity and cost.[14] The gradual introduction of new technology development is expected to continue during the NEMS forecasting horizon. Potential technology improvements in underground mining during the next several years include larger motors and improved designs of longwall shearers and continuous miners, larger conveyor motors and belt sizes for coal haulage, overall improvements in the design of underground coal haulage systems, better diagnostic monitoring of production equipment for preventive maintenance by sensors and computers, and more precise control of longwall shearers and shields through the use of computer-supported equipment.[15] Potential improvements in surface mining technology include the increased use of onboard computers for equipment monitoring, the increased use of blast casting for overburden removal, and the continuation in the long-term trend toward higher capacity equipment (for example, larger bucket sizes for draglines and loading shovels and larger trucks for overburden and coal haulage).

In the CMM, different rates of productivity improvement are input for each of the 41 coal supply curves used to represent U.S. coal supply. In addition to assumptions about incremental improvements in coal mining technologies over the forecast horizon, the productivity inputs for the CMM take into consideration the adverse impact on productivity that results as U.S. coal producers gradually move into more difficult-to-mine coal reserves. An example of a region where mining conditions are becoming increasingly difficult is Wyoming's Powder River Basin, where coal producers are faced with steadily increasing overburden thicknesses as their surface mining operations advance to the west. This situation has faced coal producers in this region since the start of major surface mining operations in the early 1970s. For years, advancements in mine equipment, mining techniques, and economies of scale appeared to have been winning out over the increasing overburden thicknesses at mines, as evidenced by steady improvements in coal mining productivity. For example, data collected by EIA and the Mine Safety and Health Administration indicate that coal mining productivity at mines in Wyoming's Powder River Basin rose from 12.18 tons per miner hour in 1978 to 46.77 tons per miner hour in 2001.[16] Since then, however, productivity for this region has leveled off and declined, and the most recent data indicate productivity of 30.19 tons per miner hour in 2018. This productivity level seems to be an

[14] Perhaps the most notable exception has been the dramatic, ongoing rise in longwall productivity, rapidly following the introduction of a new generation of longwall equipment in the last decade. Between 1986 and 1990, longwall productivity nearly doubled, and although this increase should not be attributed solely to the improvements in longwall technology, the introduction and rapid penetration of the new longwall equipment was unquestionably a major contributing factor.

[15] S. Fiscor, "U.S. Longwall Census," *Coal Age*, Vol. 119, No. 2 (February 2014) and prior issues; Edward J. Flynn, "Impact of Technological Change and Productivity on The Coal Market," U.S. Energy Information Administration (Washington, DC, October 2000), http://www.eia.gov/oiaf/analysispaper/pdf/coal.pdf; S.C. Suboleski, et. al., *Central Appalachia: Coal Mine Productivity and Expansion (EPRI Report Series on Low-Sulfur Coal Supplies)* (Palo Alto, CA: Electric Power Research Institute (Publication Number IE-7117), September 1991).

[16] U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*; and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, *Quarterly Mine Employment and Coal Production Report*.

indication that the more difficult mining conditions in this region are outpacing the advancements in surface coal mining technologies.

In the CMM, the cost effect of labor productivity change for each year is determined using the coal-pricing regression model that incorporates both regional and mine type coefficients. In each forecast year, the regression model determines the change in cost as a result of the changes in labor productivity and the costs of factor inputs. This calculation is based on exogenous productivity forecasts together with forecasts of the various factor input costs. The cost factor inputs to mining operations captured by the model include projected and estimated changes in real labor costs, real electricity and diesel fuel prices, other mine operating costs, and the annualized cost of capital over the forecast period.

Model structure

This chapter discusses the modeling structure and approach used by the CPS to construct coal supply curves. The chapter provides a general description of the model, including a discussion of the key relationships and procedures used for constructing the supply curves. A detailed mathematical description of the CPS, showing the estimating equations and the sequence of computations, is provided in Appendix 1.A.

The model constructs a distinct set of supply curves for each forecast year in three separate steps, as follows:

- Step 1: Calibrate the regression model to base-year production and price levels by region, mine type, and coal type.
- Step 2: Convert regression equation to continuous-function supply curves.
- Step 3: Construct step-function supply curves for input to the LP.

Step 1: Model calibration

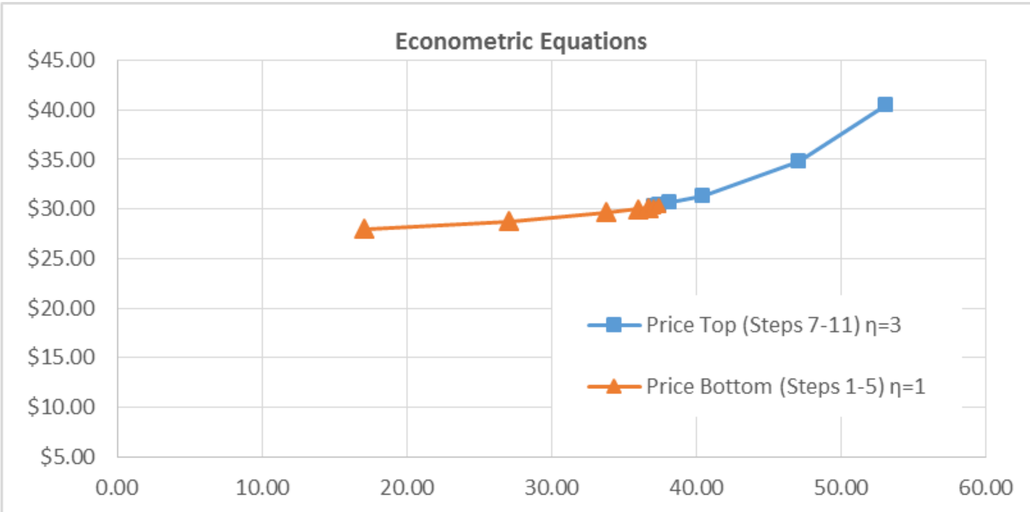
To calibrate the model to the most recent historical data, a constant value is added to the regression equation for each CPS supply curve. Therefore, when using the base-year values of the independent variables, the model solution will equal the base-year price as input by the user.

The calibration constants are automatically computed as part of a NEMS run. First, the coal-pricing equation is solved using the base-year values for the independent variables. Second, this estimated price is then subtracted from the actual base-year price input by the user. For calibration purposes, the simplifying assumption is made that the lagged values of the independent variables (used in those terms of the equation needed to correct for autocorrelation) are the same as the base-year values. This assumption obviates the need to provide the model with two years of base data and is believed to yield a reasonable approximation of the *true* calibration constant.

Step 2: Convert regression equation to continuous supply curves

A regression equation is used to estimate the relationship between minemouth prices and the projected or assumed values of production, productivity, wages, capital costs, and fuel prices. A distinct supply curve is developed for each active combination of region, mine type, and coal type. The CPS generates a set of 41 separate coal supply curves (see Table 1.1 or Table1.B-1) for each year of the NEMS forecast period, where a supply curve represents the price and supply relationship for a unique combination of supply region (map in Figure 1.1), mine type (surface vs. underground), and coal type. Coal type is a unique combination of thermal grade (rank) and sulfur content (category or sulfur grade). Figure 1.4 shows an example of a supply curve in the CPS as price in dollars per ton versus production in tons.

Figure 1.4. Graphical supply curve representation



Following initial base-year calibration, the regression equations must be converted into supply curves in which price is represented as a function of production alone. This conversion is accomplished by consolidating all of the non-capacity utilization terms in the regression equation into a single multiplier, computed using the forecast-year values of the independent variables. The value of the multiplier is computed by solving the regression equation with the capacity utilization term excluded and all other independent variables equal to their forecast-year values. A separate value of the multiplier is computed for each unique supply area representing a combination of region, mine type, and coal type. For example, supply curve 14 is 03SACDP or in AIMMS model version (03SA, 1C, 2D, 4P), which represents low-sulfur, premium (coking) coal from underground mines in Southern Appalachia. Another example is supply curve 30, which represents low-sulfur, subbituminous coal from surface mines in Northern Wyoming PRB (09NW, 1C, 1S, 2S).

Some of the required forecast-year values of the various independent variables are supplied endogenously by other NEMS modules, while others—including labor productivity growth factors, the average coal industry wage index, and the PPI (producer price index) for mining machinery and equipment, steel and iron, and explosives—are provided as user inputs. Two different PPI series are used to represent costs of mining equipment: one representing equipment used primarily at underground mines and a second representing equipment used primarily at surface mines.

It should be noted that the AIMMS code contains (but does not use) code that allows the user to compute the wage values based on inputs from the macroeconomic model. Currently future wages are computed based on input data from the coal-user input data tables ***Tinp_CLUSER_SCrv*** and ***Tinp_CLUSER_SCrv_Yr*** in the CPS.mdb database, which contains parameters for the supply curve formulation.

In the CPS, labor productivity is used as a way of capturing the effects of technological improvements on mining costs, in lieu of representing explicitly the cost impact of each potential incremental technology improvement. In general, technological improvements affect labor productivity as follows: (1) technological improvements reduce the costs of capital; (2) the reduced capital costs lead to substitution of capital for labor; and (3) more capital per miner results in increased labor productivity. As determined by the econometric-based coal-pricing model developed for the CPS, increases in labor productivity translate into lower mining costs on a per-ton basis. The change in labor productivity by forecast year is a critical model assumption that can be set separately for each supply curve.

Step 3: Construct step-function supply curves

The CMM is formulated as a linear program (LP) and cannot directly use the supply curves generated by the CPS regression model, whose functional form is logarithmic. Rather, the LP requires step-function supply curves for input. Using an initial target quantity and percentage variations from that quantity, an 11-step curve is constructed as a subset of the full supply curve and is input to the LP. For each supply curve and year, the CMM uses an iterative approach to find the target quantity that creates the optimal 11-step supply curve given the projected level of demand. The user can vary the length of the steps and, subsequently, the vertical distances between the steps by making adjustments to the percentage variations from the target quantity via input parameters contained in the input table ***Tinp_CLUSER_SCrv_Steps*** in CPS.mdb. The selection of step-lengths is based primarily on the premise that the model solution will lie close to the target quantity supplied by the CDS. As a result, the variation from the target quantity is fairly tight on the middle five to seven steps of the curve. The outer four steps are primarily there to ensure that there is sufficient supply on the step-function curve to meet any substantial swings in coal demand that might result within a single iteration of NEMS.

The method by which these step-function curves are constructed is as follows. First, the CPS computes 11 quantities by multiplying the target quantity, obtained from the LP output, by the 11 user-specified scalars obtained from the ***Tinp_CLUSER_SCrv_Steps*** input table. The model then computes the prices corresponding to each of the 11 quantities, using the supply curve equations. Finally, prices for each step are adjusted to the year dollars required by the LP using the GDP chain-type price index supplied by the NEMS Macroeconomic Activity Module. The resulting production and price values are used by the LP to determine the least cost supplies of coal for meeting the projected levels of annual coal demand.

Appendix 1.A. Detailed Mathematical Description of the Model

This appendix provides a detailed description of the model, including a specification of the model's equations and procedures for constructing the supply curves. The appendix describes the model's order of computations and main relationships.

Note that the mathematical formulations in this document use a naming convention consistent with the original Coal Market Model (CMM) code, which was developed in Fortran. Although the mathematical structure underlying the CMM remains the same, a revised naming convention was implemented in the AIMMS code when the model moved to the AIMMS platform. The revised AIMMS variable names are included as brown text with brackets {AIMMS variable} as a helpful reference for users of the coal model. Input file names are referenced in bold italic text, for example, ***file_or_table_name.txt***.

The model is described in the order in which distinct processing steps are executed in the program. These steps are as follows:

Step 1: Calibrate the regression model to base-year production and price levels by region, mine type, and coal type

Step 2: Convert the regression equation into supply curves

Step 3: Construct step-function supply curves for input to the LP

In the equations below, EXP represents the exponential function and the subscripted indices represent the following attributes:

i = supply region {Sreg}

j = mining method (surface or underground) {MTyp}

k = coal type {Rank}

t = year {yr}

by = base year (for AEO2020, the base year was 2018) {CPSBaseYr}

z = individual step on the step-function supply curves generated by the CPS for input to the Domestic Coal Distribution Submodule {Scrv1Step}

Step 1: Initialization and Base-Year Calibration

The AIMMS model computes the following parameters based on CPS.mdb input tables. These parameters are based on the econometric fits and the base year values. The $BB_{i,j,k}$ consolidation term shown in equation 1.A-1 does not change throughout the model projection years.

For calibration purposes, base-year values of productive capacity, capacity utilization, productivity, labor costs, the fuel price, capital costs, and the average minemouth price are provided as inputs to the equation. Using these base-year values, the regression equation is populated for each CPS supply region, mining method, and coal type. Note that for calibration purposes the simplifying assumption is made that the lagged values of the independent variables (used in those terms of the equation needed to correct for autocorrelation) are the same as the base-year values. This assumption obviates the need to provide the model with two years of base data and is believed to yield a reasonable approximation of the *true* calibration constant.

The annual multiplier $K_{I,j,k,BY}$ is populated with base year values. The formulation is simplified by combining regression coefficients and repeated calculation terms. The values for estimated coefficients appear in Appendix 1.C

The minemouth prices $P_{i,j,k,by}$ for coal in the base year are estimated as shown in equation 1.A-3. Note that these prices are different than the historically observed minemouth price $BYP_{i,j,k}$, which we input into the model.

$$BB_{i,j,k,by} = EXP\,[RC\_Cont_{i,j,k} * (1\text{-}rho)] * [TPH_{i,j,BY}^{(TPHADJ_{i,j,k} * (1\text{-}rho))}] * \qquad (1.A\text{-}1)$$

$$[PROD\_CAP\_ADJ_{i,j,k}^{((RC\_ProdCap_{i,j,k} * (1\text{-}rho))}] * [PRI\_ADJ_{i,j,k}^{(-rho)}] * [PRODCAP_{i,j,k,BY}^{(PRODCAPADJ_{i,j,k} * (1\text{-}rho))}]$$

$$K_{I,j,k,BY} = BB_{I,j,k,by} * TPH_{i,j,by}^{RC\_TPH_{i,j,k}} * WAGE_{i,by}^{RC\_WAGE_{i,j,k}} * PCSTCAP_{j,by}^{\beta_{12}} * PFUEL_{i,by}^{RC\_FUEL} * \qquad (1.A\text{-}2)$$

$$PRODCAP_{i,j,k,by}^{RC\_PRODCAP_{I,j,k}} * OTH\_OPER_{i,j,by}^{\beta_{14}} * P_{i,j,k,by}^{rho} * TPH_{i,j,by}^{(-rho * (RC\_TPH_{i,j,k})} *$$

$$WAGE_{i,by}^{(-rho * RC\_WAGE_{i,j,k})} * PCSTCAP_{j,by}^{(-rho * \beta_{12})} * PFUEL_{i,by}^{(-rho * RC\_FUEL_{i,j,k})} *$$

$$PRODCAP_{i,j,k,by}^{(-rho * RC\_ProdCap_{i,j,k})} * OTH\_OPER_{i,j,by}^{(-rho * \beta_{14})} *$$

$$(CAPUTIL_{i,j,k,by} * 100)^{(-rho * RC\_UTIL_{i,j,k} * CU\_BY\_SC_{i,j,k})} *$$

$$CAPUTIL\_HIST_{i,j,k}^{[RC\_UTIL_{i,j,k} - (RC\_UTIL_{i,j,k} * CU\_BY\_SC_{i,j,k})] * (-rho)]}$$

where $CU\_BY\_SC = (CAPUTIL_{i,j,k,by} * 100/CAPUTIL\_HIST_{i,j,k})^{\eta}$

$$RC\_Cont_{i,j,k} = A + \beta_{j,1} + \beta_{i,2} + \beta_{i,j,15}$$

$$RC\_ProdCap_{i,j,k} = \beta_3 + \beta_{j,4}$$

$$RC\_UTIL_{i,j,k} = \beta_5 + \beta_{Ii,j,17}$$

$$RC\_TPH_{i,j,k} = \beta_6 + \beta_{i,7} + \beta_{j,8} + \beta_{i,j,9}$$

$$RC\_WAGE_{i,j,k} = \beta_{10} + \beta_{j,11}$$

$$RC\_FUEL_{i,j,k} = \beta_{13} + \beta_{j,16}$$

$$P_{i,j,k,by} = K_{I,j,k,BY} * (CAPUTIL_{i,j,k,by} * 100)^{(RC\_UTIL_{i,j,k} * CU\_BY\_SC_{I,j,k})} * \qquad (1.A\text{-}3)$$

$$CAPUTIL\_HIST_{i,j,k}^{[RC\_UTIL_{i,j,k} - (RC\_UTIL_{i,j,k} * CU\_BY\_SC_{i,j,k})]}$$

Variables

$P_{i,j,k,by}$	- average annual minemouth price of coal for supply region i, mine type j, and coal type k, computed from the regression equation using base-year values of the independent variables {PPRI }
A	- overall constant term for the model {RCoe_OCont}
$BB_{i,j,k}$	-consolidation term for intercept and pricing equation adjustments {BB}
$RC\_Cont_{i,j,k}$	- combined regression constant term for region i, mine type j, and coal type k added to overall constant A {RC_Cont_T}
$RC\_ProdCap_{i,j,k}$	- combined regression coefficient productive capacity term {RC_PROD_CAP_T}
$RC\_UTIL_{i,j,k}$	- combined regression coefficient for the capacity utilization term {RC_UTIL_T}
$RC\_TPH_{i,j,k}$	- combined regression coefficient productivity term {RC_TPH_T}
$RC\_WAGE_{i,j,k}$	- combined regression coefficient labor cost term {RC_WAGE_T}
$RC\_FUEL_{i,j,k}$	- combined regression coefficient mine fuel term {RC_FUEL_T}
$PRODCAP_{i,j,k,by}$	- annual productive capacity of coal mines for supply region i, mine type j, and coal type k for the base year {BY_PROD_CAP}
$PROD\_CAP\_ADJ_{i,j,k}$	- factor used to adjust intercept for the model to account for the fact that the levels of productive capacity used to estimate the coal-pricing equation were specified by mine type, while the model is implemented in NEMS by mine type and coal type {BY_PROD_CAP_ADJ}
$PRODCAPADJ_{i,j,k}$	- represents a potential user-specified change to the parameter estimate for the productive capacity term β_3 (set to 0.0 for AEO2020, but in AEO2018 it was -0.2) {ProdCap_SDA}
$CAPUTIL_{i,j,k,by}$	- annual capacity utilization (the ratio of annual production to annual productive capacity) of coal mines for supply region i, mine type j, and coal type k for the base year (modeled as a percentage) {BY_CAP_UTIL}
$TPH_{i,j,by}$	- coal mine labor productivity for supply region i and mine type j for the base year {BY_TPH}
$TPHADJ_{i,j,k}$	- represents a potential user-specified change to the parameter estimate for the overall productivity term β_6 (currently set to zero for all curves) {TPH_SDA}

$WAGE_{i,by}$ - average annual wage for coal miners for supply region i for the base year {BY_WAGE, BY_WAGE92}

$PCSTCAP_{j,by}$ - index for the annual user cost of capital for mine type j, for the base year {Usr_Cst_Capital}

$PFUEL_{i,by}$ - weighted annual average of the electricity price and the diesel fuel price for supply region i for the base year {MINE_FUEL}

$OTH\_OPER_{i,j,by}$ - constant-dollar index representing a measure for mine operating costs other than wages and fuel costs specified for supply region i and mine type j for the base year {P_OPER_OTH}

$P_{i,j,k,by}$ - average minemouth price of coal for supply region i, mine type j, and coal type k for the base year {BY_MMP, BY_MMP92}

$PRI\_ADJ_{i,j,k}$ - factor used to adjust intercept for the model to account for the fact that the coal prices used to estimate the coal-pricing equation were specified by mine type, while the model is implemented in NEMS by mine type and coal type {BY_MMP_ADJ}

$CAPUTIL\_HIST_{i,j,k}$ - representative coal-mine capacity utilization for the time period over which the coal-pricing model is estimated for supply region i, mine type j, and coal type k {CAP_UTIL_HIST}

$CU\_BY\_SC_{i,j,k}$ - scalar used to adjust regression coefficient for the capacity utilization term for levels of average coal-mine capacity utilization that lie outside the range of utilization rates contained in the coal-pricing model's historical database {(BY_CAP_UTIL*100/CAP_UTIL_HIST)^UtilExpTop}

η - exponent representing the theoretical functional form of the capacity utilization term for levels of capacity utilization that are outside the range of utilization rates observed in the price equation fits where the exponent is different for the top and bottom segments of the price equation to give the curve a concave upward shape. (η_{TOP} =3 and η_{BOTTOM} =1) Please see Figure 1.4 {UtilExpTop, UtilExpBot}

Regression Coefficients (values provided in Table 1.C-1)

A overall constant for the model {RCoe_Ocont}
$\beta_{j,1}$ is the coefficient for mine type j {RCoe_MTypeCont}
$\beta_{i,2}$ is the coefficient for supply region i {RCoe_SRegCont}
β_3 for the productive capacity term {RCoe_ProdCap}
$\beta_{j,4}$ for the productive capacity term by mine type j {RCoe_MTypeProdCap}
β_5 for the capacity utilization term {RCoe_Util}
β_6 for the labor productivity term {RCoe_TPH}
$\beta_{i,7}$ for the labor productivity term by supply region I {RCoe_SRegTPH}

$\beta_{j,8}$ for the labor productivity term by mine type j {RCoe_MTypeTPH}
$\beta_{i,j,9}$ for the labor productivity term by supply region i and mine type j {RCoe_SRegMTypeTPH}
β_{10} for the labor cost term {RCoe_Wage}
$\beta_{j,11}$ for the labor cost term by mine type j {RCoe_MTypeWage}
β_{12} for the user cost of capital term {RCoe_UserCstCap}
β_{13} for the fuel price term {RCoe_Fuel}
β_{14} for the other mine operating costs term {Rcoe_POperOth}
$\beta_{i,j,15}$ is the coefficient for special combinations of mine type and supply region {RCoe_SRegMTCont}
$\beta_{j,16}$ for the fuel price term by mine type {RCoe_MTypeFuel}
$\beta_{i,j,17}$ for the capacity utilization term for special combinations of mine type and supply region {RCoe_MTypeUtil}
rho for the first-order autocorrelation term {RCoe_Rho}

As shown in equation 1.A-4, the calibration constants are determined as the difference between the minemouth price of coal ($P_{i,j,k,by}$) calculated with the CPS pricing equation using base-year values for the independent variables and the corresponding base-year mine price of coal ($BYP_{i,j,k}$), which is an input to the CLUSER file.

$$CAL\_FACTOR_{i,j,k} = (BYP_{i,j,k} - P_{i,j,k,by}) \quad (1.A\text{-}4)$$

Variables

$CAL\_FACTOR_{i,j,k}$	- constant added to the regression equation for each supply region i, mine type j, and coal type k to calibrate the model to current price levels {CALK}
$BYP_{i,j,k}$	- average base-year mine price for region i, mine type j, and coal type k {BY_MMP, BY_MMP92}
$P_{i,j,k,by}$	- price computed from regression equation using base-year values of the independent variables, for region i, mine type j, and coal type k for the base year {PPRI}

The calibration constants thus calculated are used to make vertical adjustments to each CPS supply curve. Thus, when using the base-year values of the independent variables, the model solution will equal the base-year price as specified in the CLUSER file.

Step 2: Convert the regression equation into supply curves

Following initial base-year calibration, the regression equations must be converted into supply curves in which price is represented as a function of capacity utilization alone. This conversion is accomplished by consolidating all of the non-capacity utilization terms in the regression equation into a single multiplier ($K_{i,j,k}$), computed using the forecast-year values of the independent variables as shown in equation 1.A-5.

$$K_{i,j,k,t} = BB_{i,j,k,by} * TPH_{i,j,t}^{RC\_TPH_{i,j,k}} * WAGE_{i,t}^{RC\_WAGE_{i,j,k}} * PCSTCAP_{j,t}^{\beta_{12}} * PFUEL_{i,j,y}^{RC\_FUEL} * \quad (1.A\text{-}5)$$

$$PRODCAP_{i,j,k,t}^{RC\_PRODCAP_{I,j,k}} * OTH\_OPER_{i,j,t}^{\beta_{14}} * P_{i,j,k,t-1}^{rho} * TPH_{i,j,t}^{(-rho * (RC\_TPH_{i,j,k})} *$$

$$WAGE_{i,t}{}^{(-rho * RC\_WAGE_{i,j,k})} * PCSTCAP_{j,t}{}^{(-rho * \beta_{12})} * PFUEL_{i,t}{}^{(-rho * RC\_FUEL_{i,j,k})} *$$

$$PRODCAP_{i,j,k,t}{}^{(-rho * RC\_ProdCap_{i,j,k})} * OTH\_OPER_{i,j,t}{}^{(-rho * \beta_{14})} *$$

$$(CAPUTIL_{i,j,k,t-1} * 100)^{(-rho * RC\_UTIL_{i,j,k} * CU\_BY\_SC)} *$$

$$CAPUTIL\_HIST_{i,j,k}{}^{[RC\_UTIL_{i,j,k} - (RC\_UTIL_{i,j,k} * CU\_BY\_SC)] * (-rho)}$$

where $CAPUTIL_{i,j,k,t-1} = PROD_{i,j,k,t-1} / PRODCAP_{i,j,k,t-1}$

$$CU\_FY\_SC = ((CAPUTIL_{i,j,k,t-1} * 100) / CAPUTIL\_HIST_{i,j,k})^{\eta}$$

$$RC\_Cont_{i,j,k} = A + \beta_{j,1} + \beta_{i,2} + \beta_{i,j,15}$$

$$RC\_ProdCap_{i,j,k} = \beta_3 + \beta_{j,4}$$

$$RC\_UTIL_{i,j,k} = \beta_5 + \beta_{I,j,17}$$

$$RC\_TPH_{i,j,k} = \beta_6 + \beta_{i,7} + \beta_{j,8} + \beta_{i,j,9}$$

$$RC\_WAGE_{i,j,k} = \beta_{10} + \beta_{j,11}$$

$$RC\_FUEL_{i,j,k} = \beta_{13} + \beta_{j,16}$$

$$BB_{i,j,k,by} = EXP [RC\_Cont_{i,j,k} * (1-rho)]\}* [TPH_{i,j,t=1}{}^{(TPHADJ_{i,j,k} * (1-rho))}] *$$

$$[PROD\_CAP\_ADJ_{i,j,k}{}^{((RC\_ProdCap_{i,j,k} * (1-rho))}] * [PRI\_ADJ_{i,j,k}{}^{(-rho)}] *$$

$$[PRODCAP_{i,j,k,BY}{}^{(PRODCAPADJ * (1-rho))}]$$

Variables

Defined the same as equation 1.A-2 except where listed below.

$K_{i,j,k,t}$ - annual multiplier, specified by supply region i, mine type j, and coal type k, calculated by solving the CPS coal-pricing equation for production equal to zero for year t equal to zero and all other independent variables set equal to their forecast-year values (for years t and t-1) {Mult}

$PRODCAP_{i,j,k,t}$ - annual productive capacity of coal mines for supply region i, mine type j, coal type k, and year t {FY_PROD_CAP}

$TPH_{i,j,t}$ - coal mine labor productivity for supply region i, mine type j, and year t {FY_TPH}

$WAGE_{i,t}$ - average annual wage for coal miners for supply region i, in year t {FY_WAGE}

$PCSTCAP_{j,t}$ - index for the annual user cost of capital for mine type j, in year t {Usr_Cst_Capital}

$PFUEL_{i,t}$ - weighted annual average of the electricity price and the diesel fuel price for supply region i and year t {MINE_FUEL}

$OTH\_OPER_{i,j,t}$ - constant-dollar index representing a measure for mine operating costs other than wages and fuel costs specified for supply region i and mine type j, in year t {P_OPER_OTH}

$P_{i,j,k,t-1}$ - average minemouth price of coal for supply region i, mine type j, coal type k, and year t-1, as determined in the previous NEMS iteration for year t-1 (LAG_PRI}

$PRODCAP_{i,j,k,t-1}$ - annual productive capacity of coal mines for supply region i, mine type j, coal type k, and year t-1 {FY_PROD_CAP}

$PROD_{i,j,k,t-1}$ Production solution from CDS for year t-1 {LAG_PROD}

$CAPUTIL_{i,j,k,t-1}$ - average annual capacity utilization (the ratio of annual production to annual productive capacity) of coal mines for supply region i, mine type j, coal type k, and year t-1 (modeled as a percentage) {LAG_PROD/FY_PROD_CAP}

A separate value of $K_{i,j,k,t}$ is computed for each region i, mine type j, coal type k, and year t. Some of the required forecast-year values of the various independent variables are supplied endogenously by other NEMS modules, while others, including labor productivity, the average coal industry wage, the PPI (producer price index) for mining machinery and equipment, the PPI for iron and steel, and the PPI for explosives, are provided as user inputs. In place of a user input for the PPI for iron and steel, the table ***Timp_CLUSER_Singular_Data_Inputs*** in CPS.mdb also contains a switch that, if set equal to 1, provides for the use of the related PPI for metals and metal products data (series id: WPI10) supplied by the NEMS Macroeconomic Activity Module.

Incorporating the calibration constant and the production term, the CPS supply curves take on the following form (equation 1.A-6):

$$P_{i,j,k,t} = CAL\_FACTOR_{i,j,k} + [K_{i,j,k,t} * CAPUTIL_{i,j,k,t}{}^{RC\_UTIL_{i,j,k}}] \qquad (1.A\text{-}6)$$

Variables

$P_{i,j,k,t}$ - minemouth price of coal by supply region i, mine type j, and coal type k computed as a function of output ($Q_{i,j,k,t}$) {SC_PRICE}

$CAL\_FACTOR_{i,j,k}$ - constant added to the regression equation for each supply region i, mine type j, and coal type k to calibrate the model to current price levels {CALK}

$K_{i,j,k,t}$ - annual multiplier, specified by supply region i, mine type j, and coal type k, calculated by solving the CPS coal-pricing equation for production equal to zero for year t equal to zero and all other independent variables set equal to their forecast-year values (for years t and t-1) {Mult(SCrv1,SReg,Sulf,MTyp,Rank,yr)}

$CAPUTIL_{i,j,k,t}$ - average annual capacity utilization (the ratio of annual production to annual productive capacity) of coal mines for supply region i, mine type j, coal type k, and year t (modeled as a percentage) {T_QUAN/FY_PROD_CAP}

$RC\_UTIL_{i,j,k}$ - Combined regression coefficient for the capacity utilization term {RC_UTIL_T}

Step 3: Construct step-function supply curves for input to the LP

The CMM is formulated as a linear program (LP) and cannot directly use the supply curves generated by the CPS regression model, whose functional form is logarithmic. Rather, the LP requires step-function supply curves for input. Using an initial target quantity and percentage variations from that quantity, an 11-step curve is constructed as a subset of the full supply curve and is input to the LP. For each supply curve and year, the CMM uses an iterative approach to find the target quantity that creates the optimal 11-step supply curve given the projected level of demand. The user can vary the length of the steps, and, subsequently, the vertical distances between the steps, by making adjustments to the percentage variations from the target quantity via input parameters contained in the input table ***Tinp_CLUSER_SCrv_Steps*** in CPS.mdb.

The method by which these step-function curves are constructed is as follows. First, the CPS computes 11 supply quantities corresponding to fixed percentages of a target quantity obtained from the LP. The steps are small percentages near the target quantity, and they get larger as they move away from the center of the curve, which is step 6, such that steps 1 and 11 represent the largest quantity steps. Please see Figure 1.4. The model then computes the prices corresponding to each of the 11 quantities, using the supply curve equations.

Equation 1.A-7 shows the pricing equation used for generating the prices for the step-function supply curves.

$$P_{i,j,k,z,t} = CAL\_FACTOR_{i,j,k} + [K_{i,j,k,t} * CAPUTIL\_HIST_{i,j,k}{}^{(RC\_UTIL - (RC\_UTIL * CU\_STEP\_SC)} * (Q_{i,j,k,z,t} / PRODCAP_{i,j,k,t})^{(RC\_UTIL * CU\_STEP\_SC)}] \tag{1.A-7}$$

where

$$CU\_STEP\_SC = ((Q_{i,j,k,z,t} / PRODCAP_{i,j,k,t}) / CAPUTIL\_HIST_{i,j,k})^{\eta}$$

Variables

$P_{i,j,k,z}$ - price associated with step z for region i, mine type j, coal type k, and year t specified as a percent variation from the target price {SC_PRICE}

$CAL\_FACTOR_{i,j,k}$ - calibration constant for each supply curve {CALK}

$Q_{i,j,k,z}$ - production associated with step z for region i, mine type j, coal type k, and year t (the target quantity is obtained from the table ***Tinp_CLUSER_SCrv*** in CPS.mdb file for year one of the forecast period and from the model for all remaining years of the forecast period) {T_QUAN}

$RC\_UTIL_{i,j,k}$ - Combined regression coefficient for the capacity utilization term {RC_UTIL_T}

$K_{i,j,k,t}$ - multiplier for the non-production terms in the regression equation {Mult}

$PRODCAP_{i,j,k,t}$ - annual productive capacity of coal mines for supply region i, mine type j, coal type k, and year t {FY_PROD_CAP}

$CAPUTIL\_HIST_{i,j,k}$ - representative coal-mine capacity utilization for the period during which the coal-pricing model is estimated for supply region i, mine type j, and coal type k {CAP_UTIL_HIST}

CU_STEP_SC - scalar - used to adjust regression coefficient for the capacity utilization term for levels of average coal-mine capacity utilization that lie outside the range of utilization rates contained in the coal-pricing model's historical database {((T_QUAN/FY_PROD_CAP*100)/CAP_UTIL__HIST)^UtilExp-TopBot}

η - exponent representing the theoretical functional form of the capacity utilization term for levels of capacity utilization that are outside the range of utilization rates observed in the price equation fits where the exponent is different for the top and bottom segments of the price equation {UtilExpTop, UtilExpBot}

The scalar for the capacity utilization term reflects the basic premise that mining costs will increase substantially as the capacity utilization of coal mines approaches 100%. For most combinations of region and mine type, rates of coal-mine capacity utilization rarely approach 100% in the historical data series used to estimate the coal-pricing model. In general, the highest rates of capacity utilization are reported by captive lignite operations in Texas, Louisiana, and North Dakota. Between 1991 and 2012, the average annual capacity utilization for Texas lignite production ranged from a low of 90.3% in 1991 to a high of 98.5% in 2006.[17] During this same period, the average annual capacity utilization for surface coal mines in Wyoming's Northern Powder River Basin ranged from a low of 65.1% in 1993 to a high of 93.2% in 2007.

Equation 1.A-8 shows the coal-pricing equation used for generating the quantities for the step-function supply curves.

$$STEP\_Q_{i,j,k,z,t} = Q_{i,j,k,z,t} - Q_{i,j,k,z-1,t} \qquad (1.A\text{-}8)$$

Variables

$STEP\_Q_{i,j,k,z,t}$ - quantity associated with step z for region i, mine type j, coal type k, and year t {SC_QUAN}

$Q_{i,j,k,z,t}$ - production associated with step z for region i, mine type j, coal type k, and year t {T_QUAN}

[17] U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*; and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, *Quarterly Mine Employment and Coal Production Report*.

$Q_{i,j,k,z-1,t}$ - production associated with step z-1 for region i, mine type j, coal type k, and year t {T_QUAN}

Finally, prices for each step are adjusted to the year dollars required by the model using the gross domestic product (GDP) chain-type price index supplied by the NEMS Macroeconomic Activity Module. The resulting production and price values are used by the LP to determine the least cost supplies of coal for meeting the projected levels of annual coal demand. The specific outputs provided by the model are described in Appendix 1.B.

Other calculations for the CPS

The user cost of capital index by mine type and year was calculated as follows:

$PCSTCAP = (r + \delta - (p_t - p_{t-1})/p_{t-1}) * p_t$

where

r is a proxy for the real rate of interest, equal to the AA Utility Bond Rate minus the percentage change in the implicit GDP deflator for year t. In equation form,
$r_t = (\text{AA Utility Bond Rate}_t/100) – [(\text{GDP Deflator}_t – \text{GDP Deflator}_{t-1})/\text{GDP Deflator}_{t-1}]$

δ is the rate of depreciation on mining equipment, assumed to equal 10%; and p_t is the PPI for mining equipment, adjusted to constant 1987 dollars using the GDP deflator for year t.
The three terms represented in the annual user cost of mining equipment are defined as follows:

- rp_t is the opportunity cost of having funds tied up in mine capital equipment in year t;
- δp_t is the compensation to the mine owner for depreciation in year t; and
- $((p_t - p_{t-1})/ p_{t-1}) p_t$ is the capital gain on mining equipment (in a period of declining capital prices, this term will take on a negative value, increasing the user cost of capital for year t).

Appendix 1.B. Inventory of Input Data, Parameter Estimates, and Model Outputs

Model inputs

Model inputs are classified into two categories: user-specified inputs and inputs provided by other NEMS components.

Supply Curve Inputs. User-specified inputs to define the supply in previous versions were read from ***cluser.txt***. With the model redesign into the AIMMS platform the supply curve order is now indexed by the additional set variable {SCrv1}, which is a compound index of the set variables of supply region {SReg}, mine type (surface or underground/deep) {MTyp}, coal type {Rank}, and sulfur grade {sulf} that are active in the model. Instead of a matrix of (region X mine type X rank X sulfur), the Scrv1 index has the 41 elements listed in Table 1.B-1.

Table 1.B-1. Supply curves defined in CPS

SCrv1	Sreg	Supply region name	States	Mtyp	Mine type	Rank	Rank name	Sulf	Sulfur grade
1	01NA	Northern Appalachia	PA,OH,MD,N.WV	2D	Deep	1B	Bituminous	2M	Medium
2	01NA	Northern Appalachia	PA,OH,MD,N.WV	2D	Deep	1B	Bituminous	3H	High
3	01NA	Northern Appalachia	PA,OH,MD,N.WV	2D	Underground	4P	Premium	2M	Medium
4	01NA	Northern Appalachia	PA,OH,MD,N.WV	1S	Surface	1B	Bituminous	2M	Medium
5	01NA	Northern Appalachia	PA,OH,MD,N.WV	1S	Surface	1B	Bituminous	3H	High
6	01NA	Northern Appalachia	PA,OH,MD,N.WV	1S	Surface	5G	GOB	3H	High
7	02CA	Central Appalachia	S.WV,VA,E.KY,N.TN	2D	Deep	1B	Bituminous	1C	Low
8	02CA	Central Appalachia	S.WV,VA,E.KY,N.TN	2D	Deep	1B	Bituminous	2M	Medium
9	02CA	Central Appalachia	S.WV,VA,E.KY,N.TN	2D	Underground	4P	Premium	2M	Medium
10	02CA	Central Appalachia	S.WV,VA,E.KY,N.TN	1S	Surface	1B	Bituminous	1C	Low
11	02CA	Central Appalachia	S.WV,VA,E.KY,N.TN	1S	Surface	1B	Bituminous	2M	Medium
12	03SA	Southern Appalachia	AL,S.TN	2D	Deep	1B	Bituminous	1C	Low
13	03SA	Southern Appalachia	AL,S.TN	2D	Deep	1B	Bituminous	2M	Medium
14	03SA	Southern Appalachia	AL,S.TN	2D	Underground	4P	Premium	1C	Low
15	03SA	Southern Appalachia	AL,S.TN	1S	Surface	1B	Bituminous	1C	Low
16	03SA	Southern Appalachia	AL,S.TN	1S	Surface	1B	Bituminous	2M	Medium
17	04EI	East Interior	W.KY,IL,IN,MS	2D	Deep	1B	Bituminous	2M	Medium
18	04EI	East Interior	W.KY,IL,IN,MS	2D	Deep	1B	Bituminous	3H	High
19	04EI	East Interior	W.KY,IL,IN,MS	1S	Surface	1B	Bituminous	2M	Medium
20	04EI	East Interior	W.KY,IL,IN,MS	1S	Surface	1B	Bituminous	3H	High
21	04EI	East Interior	W.KY,IL,IN,MS	1S	Surface	3L	Lignite	2M	Medium

Table 1.B-1. Supply curves defined in CPS (Continued)

SCrv1	Sreg	Supply region name	States	Mtyp	Mine type	Rank	Rank name	Sulf	Sulfur grade
22	05WI	West Interior	IA,MO,KS,AR,OK,TX	1S	Surface	1B	Bituminous	3H	High
23	06GL	Gulf Lignite	TX,LA	1S	Surface	3L	Lignite	2M	Medium
24	06GL	Gulf Lignite	TX,LA	1S	Surface	3L	Lignite	3H	High
25	07DL	Dakota Lignite	ND,E.MT	1S	Surface	3L	Lignite	2M	Medium
26	08WM	Western Montana	W.MT	2D	Deep	1B	Bituminous	1C	Low
27	08WM	Western Montana	W.MT	1S	Surface	2S	Subbituminous	1C	Low
28	08WM	Western Montana	W.MT	1S	Surface	2S	Subbituminous	2M	Medium
29	09NW	Wyoming Northern PRB	WY N.PRB	1S	Surface	2S	Subbituminous	1C	Low
30	09NW	Wyoming Northern PRB	WY N.PRB	1S	Surface	2S	Subbituminous	2M	Medium
31	10SW	Wyoming Southern PRB	WY S.PRB	1S	Surface	2S	Subbituminous	1C	Low
32	11WW	Western Wyoming	W.WY	2D	Deep	2S	Subbituminous	1C	Low
33	11WW	Western Wyoming	W.WY	1S	Surface	2S	Subbituminous	1C	Low
34	11WW	Western Wyoming	W.WY	1S	Surface	2S	Subbituminous	2M	Medium
35	12RM	Rocky Mountain	CO,UT	2D	Deep	1B	Bituminous	1C	Low
36	12RM	Rocky Mountain	CO,UT	2D	Underground	4P	Premium	1C	Low
37	12RM	Rocky Mountain	CO,UT	1S	Surface	2S	Subbituminous	1C	Low
38	13ZN	Arizona/New Mexico	AZ,NM	2D	Deep	1B	Bituminous	2M	Medium
39	13ZN	Arizona/New Mexico	AZ,NM	1S	Surface	1B	Bituminous	1C	Low
40	13ZN	Arizona/New Mexico	AZ,NM	1S	Surface	2S	Subbituminous	2M	Medium
41	14AW	Alaska/Washington	AK,WA	1S	Surface	2S	Subbituminous	1C	Low

Table 1.B-2 lists each input, the variable name, the units for the input, and the level of detail at which the input must be specified. Future levels of labor productivity are estimated by EIA. Productivity improvements are assumed to continue at a reduced rate over the forecast horizon. Rates of improvement are developed based on econometric estimates using historical data by region and by mine type (surface and underground). The average heat and sulfur content values are estimated from data obtained from the EIA-923 database for coal consumed at electric power plants and from the EIA-3 and EIA-5 databases for coal consumed at industrial facilities and coke plants, respectively. The EIA-3 and EIA-5 surveys were combined in 2015, but EIA maintains the data sets separately. Please see the assumptions document for AEO2020 for more discussion of specific inputs to the CMM.

The values for the input variables listed in Table 1.B-2 are contained in the file CPS.mdb. This Microsoft Access database contains six main groups of data: (1) forecast-year estimates for labor costs, coal-mine productivity, and the PPIs for mining machinery and equipment, iron and steel, and explosives; (2) base-year quantities for production, productive capacity, capacity utilization, prices, and coal quality (heat content, sulfur content, mercury content, and carbon dioxide emission factors) by supply curve; (3) share of annual fuel costs at U.S. coal mines represented by electricity and diesel fuel; (4) coefficients for the coal-pricing equation; (5) forecast-year production capacity limitations by supply curve (no near-term constraints on production capacity were input for AEO2020); and (6) capacity utilization trigger points by region and mine type used to determine when to add or retire coal-mining productive capacity. Each trigger point is assigned a unique multiplier used to adjust annual productive capacity either upward or downward.

The indices used in the tables are defined as follows:

g = supply curve order {SCrv1}
i = supply region {SReg}
j = mine type (surface or underground) {MTyp}
k = coal type {Rank}
t = year {yr}
by = base year (for AEO2020 the base year was 2018) {CPSBaseYr}
z = individual step on the step-function supply curves {Scrv1Step}

Table 1.B-2. User-specified inputs required by the CPS

AIMMS name	CPS.mdb table	Data field name	Description	Specification level	Units	Variable used in equations	Source or EIA survey
SCrv1Step	TInp_CLUSER_SCrv_Steps	Step	Defines 11 steps to build supply curves		--	--	Model definition
StepSize	TInp_CLUSER_SCrv_Steps	StepSize	Variable use to establish production levels for each of the 11 steps represented on the CPS step-function supply curves	National	Fraction	--	EIA specification
Minebyr	Initialized in AIMMS Code	Minebyr=2018	Historical production data Base Year		--	--	Model definition
SCrv1	(multiple tables)	CMM_CSCURVE_INDEX=41	Numeric region code (ordered)	Supply curve region	--	--	Model definition
SReg	(multiple tables)	SupReg_Code	Four character code (##$$) order+Region Abbreviation	Supply region	--	i	Model definition
Sulf	(multiple tables)	sulf_code	Two character code for Sulfur grade	Sulfur grade	--	--	Model definition
MTyp	(multiple tables)	mtyp_code	Two character code for Mine Type	Mine type (1S/2D)	--	j	Model definition
Rank	(multiple tables)	Rank_Code	Two character code for Coal Type	Coal type	--	k	Model definition
CPSCoalTyp	TInp_CLUSER_SCrv	MCNT_CTYPE	Numeric coal type code	Supply region/ coal type	--	--	Model definition
BY_PROD	TInp_CLUSER_SCrv	Prod	Base-year (2014) production (surface and deep)	Supply region/ mine type/coal type	Million Tons	--	EIA-7A
Btu	TInp_CLUSER_SCrv	AvgBTUCont	Average heat content (surface and deep)	Supply region/ mine type/coal type	MMBtu/ton	--	FERC-423
Sulfur	TInp_CLUSER_SCrv	AvgSulfCont	Average sulfur content (surface and deep)	Supply region/ mine type/coal type	Lbs. Sulfur/MMBtu	--	FERC-423
Carbon	TInp_CLUSER_SCrv	AvgCO2EmisFctr	Average carbon dioxide emission factor (surface and deep)	Supply region/ coal type	Lbs. CO2/MMBtu	--	U.S. EPA
BY_MMP	TInp_CLUSER_SCrv	MinePrice	Base-year (2014) coal mine price	Supply region/ mine type/coal type	1987 Dollars/Ton	$BYP_{i,j,k}$	EIA-7A
Mercury	TInp_CLUSER_SCrv	AveMercCont	Average mercury content (surface and deep)	Supply region/ mine type/coal type	Lbs. Hg/trillion Btu	--	U.S. EPA
BY_CAP_UTIL	TInp_CLUSER_SCrv	BCapUtil	Base-year (2014) capacity utilization of coal mines (surface and deep)	Supply region/ mine type	Fraction	$CAPUTIL_{i,j,k,by}$	EIA-7A
BY_TPH	TInp_CLUSER_SCrv	by_tph	Base-year productivity	Supply region/ mine type/coal type	Tons/miner hour	$LP_{i,j,by}$	EIA-7A

Table 1.B-2. User-specified inputs required by the CPS (cont.)

AIMMS name	CPS.mdb table	Data field name	Description	Specification level	Units	Variable used in equations	Source or EIA survey
BY_PROD_CAP	TInp_CLUSER_SCrv	ProdCap	Base-year (2012) productive capacity (surface and deep)	Supply region/ mine type/coal type	Million Tons	$PRODCAP_{i,j,k,by}$	EIA-7A
BY_PROD_CAP_ADJ	TInp_CLUSER_SCrv	ProdCapAdj	Factor used to adjust intercept for the model to account for the fact that the levels of productive capacity used to estimate the coal-pricing equation were specified by region and mine type, while the model is implemented in NEMS by region, mine type, and coal type (unique combination of heat and sulfur content)	Supply region/ mine type/coal type	--	$PROD\_CAP\_ADJ_{i,j,k,by}$	EIA-7A
BY_MMP_ADJ	TInp_CLUSER_SCrv	PriceAdj	Factor used to adjust intercept for the model to account for the fact that the minemouth coal prices used to estimate the coal-pricing equation were specified by region and mine type, while the model is implemented in NEMS by region, mine type, and coal type (unique combination of heat and sulfur content)	Supply region/ mine type/coal type	--	$PRI\_ADJ_{i,j,k,by}$	EIA-7A
CAP_UTIL_HIST	TInp_CLUSER_SCrv	BUtilHist	Representative coal-mine capacity utilization for the period during which the coal-pricing model is estimated (surface and deep)	Supply region/ mine type/coal type	Percent	$CAPUTIL\_HIST_{i,j,k}$	EIA specification
ELEC_SHARE	TInp_CLUSER_SCrv	ElecShare	Share of total fuel costs at mines represented by electricity	Supply region/ mine type	Fraction	--	U.S. Census Bureau
DIST_SHARE	TInp_CLUSER_SCrv	DistShare	Share of total fuel costs at mines represented by diesel fuel	Supply region/ mine type	Fraction	--	U.S. Census Bureau
RCoe_OCont	TInp_CLUSER_SCrv	RCoe_OCont	Overall constant for CPS regression model	National	--	A	Regression analysis
RCoe_Util	TInp_CLUSER_SCrv	RCoe_Util	Pricing model coefficient (capacity utilization term)	National	--	β_5	Regression analysis

Table 1.B-2. User-specified inputs required by the CPS (cont.)

AIMMS name	CPS.mdb table	Data field name	Description	Specification level	Units	Variable used in equations	Source or EIA survey
RCoe_Wage	TInp_CLUSER_SCrv	RCoe_Wage	Pricing model coefficient (labor cost term)	National	--	β_{10}	Regression analysis
RCoe_UserCstCap	TInp_CLUSER_SCrv	RCoe_UserCstCap	Pricing model coefficient (cost of capital term)	National	--	β_{12}	Regression analysis
RCoe_Fuel	TInp_CLUSER_SCrv	RCoe_Fuel	Pricing model coefficient (fuel price term)	National	--	β_{13}	Regression analysis
RCoe_POperOth	TInp_CLUSER_SCrv	RCoe_POperOth	Pricing model coefficient (other operating costs term)	National	--	β_{14}	Regression analysis
RCoe_TPH	TInp_CLUSER_SCrv	RCoe_TPH	Pricing model coefficient (overall productivity term)	National	--	β_{6}	Regression analysis
RCoe_MTypeCont	TInp_CLUSER_SCrv	RCoe_DeepCont	Pricing model coefficient (mine type productivity term)	Mine type	--	$\beta_{j,8}$	Regression analysis
RCoe_ProdCap	TInp_CLUSER_SCrv	RCoe_ProdCap	Pricing model coefficient (overall productive capacity term)	National	--	β_{3}	Regression analysis
RCoe_Rho	TInp_CLUSER_SCrv	RCoe_Rho	Pricing model coefficient (first-order autocorrelation term)	National	--	Rho	Regression analysis
TPH_SDA	TInp_CLUSER_SCrv	TPH_SDA	Pricing model adjustment factor applied to overall constant term to account for user-specified revisions of the labor productivity coefficient	National	--	$TPHADJ_{i,j,k}$	Regression analysis
RCoe_MTypeProdCap	TInp_CLUSER_SCrv	RCoe_MTypeProdCap	Pricing model coefficient (mine type productive capacity term)	Mine type	--	$\beta_{j,4}$	Regression analysis
RCoe_MTypeWage	TInp_CLUSER_SCrv	RCoe_MTypeWage	Pricing model coefficient (mine type labor cost term)	Mine type	--	$\beta_{j,11}$	Regression analysis
ProdCap_SDA	TInp_CLUSER_SCrv	ProdCap_SDA	Pricing model adjustment factor applied to overall constant term to account for user-specified revisions of the coefficient for the productive capacity regression variable	National	--	$PRODCAPADJ_{i,j,k}$	EIA specification
RCoe_MTypeCont	TInp_CLUSER_SCrv	RCoe_DeepCont	Pricing model coefficients (intercept dummy variable for mine type)	Mine type	--	$\beta_{j,1}$	Regression analysis
BY_WAGE	TInp_CLUSER_SCrv	BYWAGE	Base-year annual wage	Supply region	1987 Dollars /Year	WAGE	Bureau of Labor Statistics

Table 1.B-2. User-specified inputs required by the CPS (cont.)

AIMMS name	CPS.mdb table	Data field name	Description	Specification level	Units	Variable used in equations	Source or EIA survey
BY_ELEC_PRICE	TInp_CLUSER_SCrv	BYElecPrice	Base-year electricity price (industrial sector)	Supply region	1992 Dollars/ MMBtu	--	EIA
RCoe_SregCont	TInp_CLUSER_SCrv	RCoe_SregCont	Pricing model coefficients (intercept dummy variables for supply regions)	Supply region	--	$\beta_{i,2}$	Regression analysis
RCoe_SRegMTypeCon	TInp_CLUSER_SCrv	RCoe_SRegMTypeCon	Pricing model coefficients for region/mine type intercept term (Previously *only* used to adjust underground WM, WW, and ZN regions)	Supply region/ mine type	--	$\beta ij,2$	Regression analysis
RCoe_SRegTPH	TInp_CLUSER_SCrv	RCoe_SRegTPH	Pricing model coefficients (regional productivity terms)	Supply region	--	$\beta_{i,7}$	Regression analysis
RCoe_SRegMTypeTPH	TInp_CLUSER_SCrv	RCoe_SRegMTypeTPH	Pricing model coefficients (regional and mine type productivity terms)	Supply region/ mine type	--	$\beta_{i,j,9}$	Regression analysis
P_EQUIP	TInp_CLUSER_SCrv_Yr	P_EQUIP	PPI for mining machinery and equipment (AIMMS version combines two indexes—series values differ by mine type)	Year	Constant-dollar index (1992 dollars)	--	Bureau of Labor Statistics
PPI_STEEL_EXPLO	TInp_CLUSER_SCrv_Yr	P_OPER_OTH	PPI for iron and steel, and PPI for explosives (AIMMS version combines two indexes—series values differ by mine type)	Year	Constant-dollar index (1992 dollars)	--	Bureau of Labor Statistics
SCLIMIT	TInp_CLUSER_SCrv_Yr	SCLIMIT	Supply curve Limit (All set at 999.99)	Supply region/ mine type/coal type/year	MM Tons	--	EIA estimate
WAGE_MULTIPLIER	Timp_cluser_Scrv_yr	CMM_FCST_YR_WAGE	Real labor cost escalator	National/year	--	--	EIA projection
TPH_Growth_Rate	Timp_cluser_Scrv_yr	CMM_FCST_YR_PROD	Forecast-year productivity (as a fraction of BY_PROD)	Supply region/ mine type/coal type/year	--	$LP_{i,j,t}$	EIA projection
ADJ_MMP_MULT	Timp_cluser_Scrv_yr	ADJ_MMP_MULT	Price adjustment variable (multiplier)	Supply region/ mine type/coal type/year	Scalar	--	EIA estimate
ADJ_MMP_ADD	Timp_cluser_Scrv_yr	ADJ_MMP_ADD	Price adjustment variable (additive)	Supply region/ mine type/coal type/year	1987 Dollars/ Ton	--	EIA estimate

Table 1.B-2. User-specified inputs required by the CPS (cont.)

AIMMS name	CPS.mdb table	Data field name	Description	Specification level	Units	Variable used in equations	Source or EIA survey
UtilExpTop	Initialized in AIMMS code[18]	UtilExpTop=3	Real number used to revise the coefficient for the coal-pricing model's capacity utilization term for levels of capacity utilization that are outside the upper range of utilization rates contained in the coal-pricing model database. This factor (set to 3.0 for AEO2020) is used for calculating prices for steps 6–11 of the 11-step CPS supply curves.	National	--	η	EIA specification
UtilExpBot	Initialized in AIMMS code	UtilExpBot=1	Real number used to revise the coefficient for the coal-pricing model's capacity utilization term for levels of capacity utilization that are outside the lower range of utilization rates contained in the coal-pricing model database. This factor (set to 1.0 for AEO2020) is used for calculating prices for steps 1–5 of the 11-step CPS supply curves.	National	--	η	EIA specification
CLMaxItr	Initialized in AIMMS code	CLMaxItr=4	Maximum number of coal iterations	National	--		Model specification
PPIMetalsSwitch	Initialized in AIMMS code	PPI_METALS_SWITCH	Switch to choose either the user-specified PPI for iron and steel (set switch to 0) or the NEMS-generated PPI for metals and metal products (set switch to 1)	--	--	--	--
Util_Max	TInp_CLUSER_SCrv	Util_Max	Upper capacity utilization amount used to trigger additions to productive capacity	Supply region	Fraction	--	EIA specification
Util_Mid	TInp_CLUSER_SCrv	Util_Mid	Mid-level capacity utilization amount used to trigger additions to productive capacity	Supply region	Fraction	--	EIA specification

[18] Variable also listed in CPS.mdb in table ***TImp_CLUser_Singular_Data_Inputs***, but this table currently not read by AIMMS code.

Table 1.B-2. User-specified inputs required by the CPS (cont.)

AIMMS name	CPS.mdb table	Data field name	Description	Specification level	Units	Variable used in equations	Source or EIA survey
Util_Min	TInp_CLUSER_SCrv	Util_Min	Lower capacity utilization amount used to trigger additions to productive capacity	Supply region	Fraction	--	EIA specification
Util_Max_Adj	TInp_CLUSER_SCrv	Util_Max_Adj	Factor used to increase surface productive capacity when capacity utilization ≥UTIL_MAX	Supply region	Fraction	--	EIA specification
Util_Mid_Adj	TInp_CLUSER_SCrv	Util_Mid_Adj	Factor used to increase surface productive capacity when capacity utilization ≥UTIL_MAX but UTIL_MID	Supply region	Fraction	--	EIA specification
Util_Min_Adj	TInp_CLUSER_SCrv	Util_Min_Adj	Factor used to retire surface productive capacity when capacity utilization ≤UTIL_MIN	Supply region	Fraction	--	EIA specification

Inputs provided by other NEMS components. Table 1.B-3 identifies inputs obtained from other NEMS components and indicates the variable name, the units for the input, and the level of detail at which the input must be specified. Electricity prices are obtained from the Electricity Market Module, industrial distillate fuel prices are obtained from the Liquid Fuels Market Module, and the real rate of interest on AA public utility bonds is obtained from the Macroeconomic Activity Module.

Table 1.B-3. CPS inputs provided by other NEMS modules and submodules

CPS/AIMMS variable name	Description	Specification level	Units	Variable used in equations	NEMS module/ submodule[19]
MPBLK_PELIN	Average price of electricity in the industrial sector	Supply region/ year	1987 Dollars/ MMBtu	--	EMM
MPBLK_PDSIN	Average price of distillate in the industrial sector	National/year	1987 Dollars/MMBtu	--	LFMM
MC_RLRMCORPPUAA	Real rate on AA-rated public utility bonds	National	Percent	--	MAM
MACOUT_MC_JPGDP or mc_jpgdp	Chained price index gross domestic product	National	Index 1987 = 1.000	multiple	Macro

[19] See list of acronyms on page xiii.

Model outputs

The primary outputs from the CPS are step-function supply curves provided to the LP. In addition to all the parameters needed to generate the supply curves by step, the CPS.mdb input database provides the CDS with coal quality data that include estimates for heat, sulfur, and mercury content and for carbon dioxide emission factors. Table 1.B-4 below lists outputs of the supply curves that are calculated for each forecast year. See Appendix 1.A for more detail on the supply curves and Appendix 1.C for estimation methodology.

Table 1.B-4. CPS model outputs

AIMMS variable name	Table in CoalOutput.XLS	Description	Units	Variable used in equations
SC_PRICE87	USCoalSupplyCurves	Minemouth coal price associated with each CPS supply curve step provided to the CDS	1987 dollars/ton	$P_{i,j,k,z,t}$
SC_PRICE_BYDollars	USCoalSupplyCurves	Minemouth coal price associated with each CPS supply curve step provided to the CDS	Base-year dollars/ton	$P_{i,j,k,z,t}$
SC_QUAN	USCoalSupplyCurves	Length of each CPS supply curve step provided to the CDS	Million tons	$Q_{i,j,k,z,t}$
Btu	HeatContent	Average Btu content for each CPS supply curve step provided to the CDS	Million Btu/ton	--
Sulfur	(old CPS output currently unavailable)	Average sulfur content for each CPS supply curve step provided to the CDS	Lbs. sulfur /Million Btu	--
Mercury	(old CPS output currently unavailable)	Average mercury content for each CPS supply curve step provided to the CDS	Lbs. mercury /Trillion Btu	--
Carbon	(old CPS output currently unavailable)	Average carbon dioxide emission factor for each CPS supply curve step provided to the CDS	Lbs. carbon /Million Btu	--

Endogenous variables

Endogenous variables to the model are included in Table 1.B-5, which includes the variable name used in the AIMMS version of the CPS, a description of the variable, the variable's units, and the corresponding variable name used in the report in Appendix 1.A and Appendix 1.C.

Table 1.B-6 lists sources for the base year inputs into the CPS. These inputs are converted to the appropriate units and year dollars as the data used to estimate the supply curves, primarily input by CPS region. The base year for AEO2020 was 2018.

Table 1.B-7 includes a list of variables that were instrumented in the supply curve econometric specifications because they are correlated with the regression error term. Variables like the heat content and sulfur content of coal are also used for units conversion and coal rank or grade classification.

Table 1.B-5. Key endogenous variables

CPS AIMMS variable name	Description	Units	Variable used in equations
FY_TPH	Labor productivity for NEMS forecast year t	Tons/miner hour	$TPH_{i,j,t}$
MINE_FUEL	Hybrid fuel price (average of industrial electricity and distillate prices) for NEMS forecast year t	1992 dollars/ Million Btu	$PFUEL_{i,t}$
D_FUEL	National average diesel fuel prices for NEMS forecast year t (from MPBLK_PDSIN)	1992 dollars /Million Btu	--
FY_WAGE	Average coal industry wage by supply region i for NEMS forecast year t	1992 dollars/ year	$WAGE_{i,t}$
Usr_Cst_Capital	User-cost of mining equipment for NEMS forecast year t	Constant-dollar index (1992 dollars)	$PCSTCAP_t$
P_OPER_OTH	Cost index representing operating costs other than wages and fuel for NEMS forecast year t	Constant-dollar index (1992 dollars)	--
CALK	CPS calibration constant	--	$Cal\_Factor_{i,j,k}$
Mult	Multiplier for non-production terms in the CPS coal-pricing equation	--	$K_{i,j,k,t}$
QTARG_CMM	Target quantities for years t > 1, used to build step-function curves with 11 steps	Million tons	$Q_{i,j,k,t}$
SC_PRICE	Prices for each of the steps on the 11-step supply curves input to the CDS	1992 dollars/ton	$P_{i,j,k,z,t}$
SC_QUAN	Quantities for each of the steps on the 11-step supply curves input to the CDS	Million tons	$Q_{i,j,k,z,t}$
LAG_PRI	Minemouth price of coal by supply curve in year t-1	1992 dollars/ton	$MMP_{i,j,k,t-1}$
LAG_PROD	Coal production by supply curve in year t-1	Million tons	$Q_{i,j,k,t-1}$
FY_PROD_CAP	Coal productive capacity by supply curve in year t	Million tons	$PRODCAP_{i,j,k,t}$

Table 1.B-6. Data sources for base year supply variables

Variable	Description	Units	Sources
$BYP_{i,j,BY}$ {BY_MMP}	Average annual minemouth price of coal by CPS supply region and mine type	1992 dollars per short ton	U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*
$PRODCAP_{i,j,k,BY}$ {BY_PROD_CAP}	Annual coal productive capacity by region and mine type	Million short tons	U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*
$CAPUTIL_{i,j,BY}$ {BY_CAP_UTIL}	Average annual capacity utilization at coal mines by region and mine type	Percent	U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*
$TPH_{i,j,BY}$ {BY_TPH}	Average annual labor productivity by region and mine type	Short tons per miner hour	U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*; and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, *Quarterly Mine Employment and Coal Production Report*.
$WAGE_{i,BY}$ {BY_WAGE}	Average annual coal industry wage by region	1992 dollars per miner hour	U.S. Department of Labor, Bureau of Labor Statistics, Quarterly Census of Employment and Wages, NAICS 2121 Coal Mining, Average Annual Pay by State, Series IDs: Alabama: ENU010005052121; Colorado: ENU080005052121; and other states.
$PCSTCAP_{j,BY}$ {Usr_Cst_Capital}	Annualized user cost of mining equipment (national level)	Constant-dollar index (1992 dollars)	PPI for Mining Machinery and Equipment: U.S. Department of Labor, Bureau of Labor Statistics, Series ID: PCU333131333131; PPI for Construction Machinery: U.S. Department of Labor, Bureau of Labor Statistics, Series ID: PCU333120333120; and Yield on Utility Bonds: Global Insight.
$BYElecPrice_{i,j,BY}$ {BY_ELEC_PRICE}	Weighted average annual price of electricity in the industrial sector[20]	1992 dollars per million Btu[21]	U.S. Energy Information Administration, *Electric Power Annual*, Source Form EIA-861, *Revenue and Retail Sales by State and Sector*. EIA Electricity Detail State Data
$OTH\_OPER_{i,j,BY}$ {P_OPER_OTH}	A constant-dollar index representing mine operating costs other than wages and fuel requirements	Constant-dollar index (1992 dollars)	PPI for Iron and Steel: U.S. Department of Labor, Bureau of Labor Statistics, Series ID: WPU101; PPI for Explosives: U.S. Department of Labor, Bureau of Labor Statistics, Series ID: WPU067902.

[20] Average electric power price by coal supply region is computed for the base year by aggregating industrial sector "Revenue from Retail Sales of Electricity by State by Sector by Provider (EIA-861)" and "Retail Sales of Electricity by State by Sector by Provider (EIA-861)" for coal mining states to create average electricity price paid by coal mines.
[21] Conversion factor 1 **kWh** = **3412 Btu.**

Table 1.B-7. Data sources for instrumented variables excluded from the supply equation

Data item	Description	Units	Sources
Total coal-fired electricity generation	Annual coal-fired net electricity generation	Billion kilowatthours	U.S. Energy Information Administration, *Annual Energy Review,* DOE/EIA-0384, Table 8.2a. Interactive data browser
Natural gas share of total U.S. electricity generation	Share of total U.S. electricity generation accounted for by generation at natural gas-fired power plants	Fraction	U.S. Energy Information Administration, *Annual Energy Review,* DOE/EIA-0384(2011), Table 8.2a. Interactive data browser
Industrial coal consumption	Annual industrial coal consumption (steam and coking)	Million short tons	U.S. Energy Information Administration, *Annual Energy Review,* DOE/EIA-0384, Table 7.3. Interactive data browser
World oil price	Refiner acquisition cost of crude oil: imported	1992 dollars per barrel	U.S. Energy Information Administration, *Petroleum Marketing Annual,* DOE/EIA-0487, Table 1. Interactive data browser
Price of natural gas	Annual average delivered price of natural gas for electricity generation by state (aggregated to CPS supply region)	1992 dollars per million Btu	U.S. Energy Information Administration, *Electric Power Monthly,* DOE/EIA-0226, Table 4.13.B. EPM table
Heat content of coal	Average annual heat content of coal for receipts at electric power sector plants by CPS supply region and mine type	Million Btu per short ton	Federal Energy Regulatory Commission, FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; U.S. Energy Information Administration (EIA), Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*; and U.S. Energy Information Administration, Form EIA-923, *Power Plant Operations Report*
Sulfur content of coal	Average annual sulfur content of coal for receipts at electric power sector plants by CPS supply region and mine type	Pounds of sulfur per million Btu	Federal Energy Regulatory Commission, FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; U.S. Energy Information Administration (EIA), Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*; and U.S. Energy Information Administration, Form EIA-923, *Power Plant Operations Report*
Ash content of coal	Average annual ash content of coal for receipts at electric power sector plants by CPS supply region and mine type	Percent by weight	Federal Energy Regulatory Commission, FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; U.S. Energy Information Administration (EIA), Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*; and U.S. Energy Information Administration, Form EIA-923, *Power Plant Operations Report*

Table 1.B-7. Data sources for instrumented variables excluded from the supply equation (cont.)

Data item	Description	Units	Sources
Exports	Annual exports of U.S. coal	Million short tons	U.S. Energy Information Administration, *Monthly Energy Review*, Exports from Table 6.1 or Interactive data browser
Rest of U.S. coal production	Total U.S. production minus production for the current supply region observation[22]	Million short tons	U.S. Energy Information Administration, Form EIA-7A, *Coal Production and Preparation Report*
Coal inventories	Coal stocks at the beginning of the year for U.S. electric power sector	Million short tons	U.S. Energy Information Administration, *Electric Power Monthly,* DOE/EIA-0226, Table 3.1 (shifted one year because these stocks are beginning-of-year stocks instead of end-of-year stocks)
Days of coal supply at electric power plants	Year-end electric power sector coal inventories divided by average daily coal consumption[23]	Days	U.S. Energy Information Administration, *Electric Power Monthly,* DOE/EIA-0226, Electric Power Sector consumption (EU+IPP) Table 2.1 (also uses coal inventories—above)

[22] The econometric formulation software creates a variable that is unique for each supply region and instrumented to reduce multicollinearity. *Rest of U.S. production* or *other production* is equal to *total U.S. production* less the supply region production where the regional production Q_i^S is the independent variable and regional coal price P_i^S is the dependent variable of the regression that forms the coal supply curves as (P_i^S, Q_i^S) pairs.

[23] The software creates the instrument variable:
Days of coal supply = (beginning-of-year coal stocks / average daily coal consumption) for U.S. electric industry.
series days_sup = (boy_stk/(elec_sec_con/365))

Appendix 1.C. Data Quality and Estimation

Development of the CPS Regression Model

The two-stage least squares regression technique was used to estimate the relationship between the minemouth price of coal and the corresponding levels of capacity utilization at mines, productive capacity, labor productivity, wages, fuel costs, other mine operating costs, and a term representing the annual user cost of mining machinery and equipment. In the first stage of the estimation, the endogenous explanatory variables are regressed on the exogenous and predetermined variables. The product of this estimation is predicted values of the endogenous explanatory variables that are uncorrelated with the error term. In turn, these predicted values are employed in the second stage of the technique to estimate the relationship between the dependent endogenous variable and the independent variables. The first stage (reduced form) equations are used only to obtain the predicted values for the endogenous explanatory variables included in the second stage, removing the effects on minemouth prices caused by shifts in the demand function.

The structural equation for the coal-pricing model was specified in log linear (constant elasticity) form. In this specification, the values for all variables (except the constant term) are transformed by taking their natural logarithm. The coal pricing regression model was developed using a combination of cross-sectional and time series data. The model includes annual-level data for thirteen supply regions [24] and two mine types (surface and underground) for the years 1992 through 2015. In all, 432 observations are included (18 observations per year [13 surface and five underground] for each of the 24 years represented in the historical data series).

All data are pooled into a single regression equation. In addition to the overall constant term for the model, intercept dummy variables were included for most of the supply regions. Dummy variables were used for the productivity and productive capacity variables to allow slope coefficients to vary across regions and mine types. The Durbin-Watson test for first-order positive autocorrelation indicated that the hypothesis of no autocorrelation should be rejected. As a consequence, a correction for serial correlation was incorporated. In addition, a formal test indicated that the hypothesis of homoscedasticity (the assumption that the errors in the regression equation have a common variance) should be rejected, and, as a result, a weighted regression technique was employed to obtain more efficient parameter estimates.

The two-stage least squares (2SLS) regression equation for the pricing equation was estimated using the LSQ (general nonlinear least squares multi equation estimator) procedure in EViews. The form of the CPS regression equation and the associated regression statistics are presented below and in Table 1.C-1. The sources for the various historical data series used in the regression model are shown in Tables 1.C-2 and 1.C-3.

Indicative of the high R^2 statistic (see Table 1.C-1), the predicted and actual minemouth prices closely corresponded with each other. The calculation for the adjusted R^2 statistic is provided in Table 1.C-1. As

[24] Data for coal mines in the states of Alaska, Arkansas, Iowa, Missouri, Kansas, Oklahoma, Washington, and Wisconsin were not included in the regression estimation even though the model has two supply regions for those states. The average mine price of coal in those two regions are withheld from EIA publications to avoid disclosure of individual company data.

indicated in this report, all of the statistics related to the residuals using the 2SLS regression technique are calculated in EViews with the same formulas used for ordinary least squares (OLS). A summary of the calculations used for generating the R^2 and adjusted R^2 statistics is provided below.

Computation of R^2 with a constant term:

$$R^2 = 1 - \left[\sum e_t^2 / \sum (y_t - \bar{y})^2\right] \qquad (1.C\text{-}1)$$

where

$$e_t = y_t - \hat{y}_t$$

and

$$\hat{y}_t = X_t b$$

Or

$$R^2 = 1 - [SSR / SST]$$

where

$$SSR = \sum e_t^2$$

$$SST = \sum (y_t - \bar{y})^2$$

The adjusted R^2 or $\bar{R}^2$ with a constant term is calculated as follows:

$$\bar{R}^2 = 1 - [SSR / (T - K)] / [SST / (T - 1)] \qquad (1.C\text{-}2)$$

In the above equations,

e_t	residuals
y_t	observed values of the dependent variable
$\bar{y}$	mean of the observed values of y_t
$\hat{y}_t$	predicted values of the dependent variable
X_t	vector of independent variables
b	estimated regression coefficients
SSR	sum of squared residuals
SST	total sum of squares
T	number of observations in the sample
K	number of independent variables

Based on the regression results shown in Table 1.C-1, the equation used for predicting future levels of minemouth coal prices by region, mine type, and coal type is

$$\begin{aligned}
\ln P_{i,j,k,t} = {} & \ln CAL_FACTOR_{i,j,k,t} + \ln C_{i,j,k,t} + (\beta_3 + \beta_{j,4} + PRODCAPADJ) * \ln PRODCAP_{i,j,k,t} \\
& + \beta_5 \ln CAPUTIL_{i,j,k,t} + ((\beta_6 + TPHADJi,j,k) + \beta_{i,7} + \beta_{j,8} + \beta_{i,j,9}) * \ln TPH_{i,j,t} + (\beta_{10} + \beta_{j,11}) * \ln WAGE_{i,t} \\
& + \beta_{12} \ln PCSTCAP_{j,t} + \beta_{13} * \ln PFUEL_{i,t} + \beta_{14} * \ln OTH_OPER_{i,j,t} + rho * \ln P_{i,j,k,t-1} \\
& + (-rho * (\beta_3 + \beta_{j,4} + PRODCAPADJ)) * PRODCAP_{i,j,k,t-1} + (-rho * \beta_5 * CU_FY_SC) * \ln CAPUTIL_{i,j,k,t-1} \\
& + (-rho * (\beta_6 + TPHADJ_{i,j,k}) + \beta_{i,7} + \beta_{j,8} + \beta_{i,j,9}) * \ln TPH_{i,j,t-1} + (-rho * (\beta_{10} + \beta_{j,11})) * \ln WAGE_{i,t-1} \\
& + (-rho * \beta_{12}) \ln PCSTCAP_{j,t-1} + (-rho * \beta_{13}) \ln PFUEL_{i,t-1} + (-rho * \beta_{14})] \ln OTH_OPER_{i,j,t-1}
\end{aligned} \quad (1.C\text{-}3)$$

First Term in Equation 1.C3 ($CAL\_FACTOR_{i,j,k,t}$)

$CAL\_FACTOR_{i,j,k,t}$ is a constant added to the regression equation for each supply region i, mine type j, and coal type k in each year t to calibrate the model to current price levels. For each AEO, prices were calibrated to the (preliminary) average annual minemouth coal prices for the latest historical year that data were available for, which for AEO2019 was 2017 and for AEO2020 was 2018.

Second Term in Equation 1.C-3 ($C_{i,j,k,t}$)

$$\begin{aligned}
\ln C_{i,j,k,t} = {} & (A + \beta_1 + \beta_{i,2}) * (1-rho) + TPHADJ_{i,j,k} * (1-rho) * \ln TPH_{i,j,t=1} \\
& + [\beta_5 - (\beta_5 * CU_FY_SC)] * (-rho) * \ln CAPUTIL_HIST_{i,j} \\
& + (\beta_3 + \beta_{j,4} + PRODCAPADJ_{i,k,j}) * (1-rho) * \ln PROD_CAP_ADJ_{i,j,k} + (-rho) * \ln [PRI_ADJ_{i,j,k} \\
& + PRODCAPADJ_{I,k,j} * (1-rho) * \ln PRODCAP_{i,j,t-1}
\end{aligned} \quad (1.C\text{-}4)$$

The first term in equation 1.C-4 $(A + \beta_1 + \beta_{i,2}) * (1-rho)$ is the intercept for the model, where *A* is an overall constant for the model, β_1 represents a specific constant for each mine type in the model, and the term $\beta_{i,2}$ represents the regional specific constants for the model.

The second term in equation 1.C-4 $TPHADJ_{i,j,k} * (1-rho) * \ln TPH_{i,j,t-1}$ represents an adjustment to the intercept term for the coal-pricing equation to account for user-specified changes to the estimated coefficient for the overall productivity term β_5. The term $TPHADJ_{i,j,k}$ was set equal to zero reflecting the assumption that the estimated relationship between coal mining productivity and minemouth coal prices estimated for the historical period will continue to hold over the forecast horizon.

The third term in equation 1.C-4 $[\beta_5 - (\beta_5 * CU\_FY\_SC)] * (-rho) * \ln CAPUTIL\_HIST_{i,j}$ represents a required adjustment to the intercept term for the coal-pricing equation to account for changes in the parameter estimate (β_5) for the capacity utilization term. The coefficient for the capacity utilization term is revised endogenously within the Coal Market Module on the basis of how much the projected levels of capacity utilization vary from the representative historical levels of capacity utilization. This feature was added to the CPS to reflect the premise that coal mining costs will increase substantially as the average capacity utilization of coal mines approaches 100%. The term CU_FY_SC is equal to $(CAPUTIL_{i,j,k,t-1} / CAPUTIL\_HIST_{i,j,k})^{\eta}$. In this equation, $CAPUTIL_{i,j,k,t-1}$ is the projected level of capacity utilization for a specific supply curve in year t-1, $CAPUTIL\_HIST_{i,j,k}$ is the representative historical rate of capacity utilization for this same CPS supply curve, and the term η is a user-specified term. For AEO2020, the user-specified term η was set equal to 3.0.

The fourth term in equation 1.C-4 ($\beta_3 + \beta_{j,4}$+ $PRODCAPADJ_{i,k,j}$) * (1-rho) * ln $PROD\_CAP\_ADJ_{i,j,k}$ is used to adjust intercept for the model to account for the fact that the levels of productive capacity used to estimate the coal-pricing equation were specified by region and mine type, while the model is implemented in NEMS by region, mine type, and coal type (unique combination of heat and sulfur content). $PROD\_CAP\_ADJ_{i,j,k}$ is a user-specified input calculated by dividing base-year (2014) productive capacity for supply region i and mine type j by the estimated base-year (2014) productive capacity for supply region i, mine type j, and coal type k. The latter of these two productive capacity numbers represents data for a specific supply curve, thus the additional coal type dimension for this term.

The fifth term in equation 1.C-4 (-rho) * ln [$PRI\_ADJ_{i,j,k}$ is used to adjust the intercept for the model to account for the fact that the minemouth coal prices used to estimate the coal-pricing equation were specified by region and mine type, while the model is implemented in NEMS by region, mine type, and coal type (unique combination of heat and sulfur content). PRI_ADJ is a user-specified input calculated by dividing the average base-year (2014) minemouth coal price for supply region i and mine type j by the estimated average base-year (2014) minemouth coal price for supply region i, mine type j, and coal type k. The latter of these two prices represents data for a specific CPS supply curve, thus the additional coal type dimension for this term.

The sixth term in equation 1.C-4 $PRODCAPADJ_{ikj}$ * (1-rho) * ln $PRODCAP_{i,j,t=1}$represents a required adjustment to the intercept term for the coal-pricing equation to account for user-specified changes to the estimated coefficient for the overall productive capacity term β_3. For AEO2020, PCAPCADJ was set equal to -0.200, which reflects the assumption that the estimated relationship between coal mining productive capacity and minemouth coal prices will be more substantial than estimated in the regression analysis.

Remaining Terms in Equation 1.C-4

$P_{i,j,k,t}$	average annual minemouth price of coal in constant 1992 dollars for supply region i, mine type j, coal type k in year t
A	overall constant term for the model
$PRODCAP_{i,j,k,t}$	annual productive capacity of coal mines for supply region i, mine type j, and coal type k in year t
$CAPUTIL_{i,j,k,t}$	average annual capacity utilization (the ratio of annual production to annual productive capacity) of coal mines for supply region i, mine type j, and coal type k in year t (modeled as a percentage)
$TPH_{i,j,t}$	average annual coal mine labor productivity in tons per miner hour for supply region i, and mine type j in year t
$WAGE_{i,t}$	average annual wage for coal miners in year t

$PCSTCAP_{j,t}$	index representing the annualized user cost of mining equipment for mine type j in year t; the index is adjusted to constant 1992 dollars
$PFUEL_{i,t}$	a weighted average of the annual price of electricity in the industrial sector and the U.S. price of No. 2 diesel fuel (excluding taxes) to end users for supply region i in year t
$OTH\_OPER_{i,j,t}$	constant-dollar index representing mine operating costs other than wages and fuel requirements specified by supply region i, and mine type j in year t; examples of other operating costs include items such as replacement parts for equipment, roof bolts, and explosives.

Regression Coefficients

A overall constant for the model {RCoe_Ocont}
$\beta_{j,1}$ is the coefficient for mine type j {RCoe_MTypeCont}
$\beta_{i,2}$ is the coefficient for supply region i {RCoe_SRegCont}
β_3 for the productive capacity term {RCoe_ProdCap}
$\beta_{j,4}$ for the productive capacity term by mine type j {RCoe_MTypeProdCap}
β_5 for the capacity utilization term {RCoe_Util}
β_6 for the labor productivity term {RCoe_TPH}
$\beta_{i,7}$ for the labor productivity term by supply region i {RCoe_SRegTPH}
$\beta_{j,8}$ for the labor productivity term by mine type j {RCoe_MTypeTPH}
$\beta_{i,j,9}$ for the labor productivity term by supply region i and mine type j {RCoe_SRegMTypeTPH}
β_{10} for the labor cost term {RCoe_Wage}
$\beta_{j,11}$ for the labor cost term by mine type j {RCoe_MTypeWage}
β_{12} for the user cost of capital term {RCoe_UserCstCap}
β_{13} for the fuel price term {RCoe_Fuel}
β_{14} for the other mine operating costs term {Rcoe_POperOth}
$\beta_{i,j,15}$ is the coefficient for special combinations of mine type and supply region {RCoe_SRegMTCont}
$\beta_{j,16}$ for the fuel price term by mine type {RCoe_MTypeFuel}
$\beta_{i,j,17}$ for the capacity utilization term for special combinations of mine type and supply region {RCoe_MTypeUtil}
rho for the first-order autocorrelation term {RCoe_Rho}

Table 1.C-1. Regression statistics for the coal-pricing model

Regression coefficient	Variable	Parameter estimate	Standard error	t- Statistic
A	Overall Constant	-6.532	1.530	-4.269**
$\beta_{j=1,2}$	DUM_MINE_TYPE (Underground)	-0.220	0.032	-6.959**
$\beta_{i=3,2}$	DUM_REG_3 (Southern Appalachia (SA))	0.505	0.086	5.844**
$\beta_{i=6,2}$	DUM_REG_6 (Gulf Lignite (GL))	-2.369	0.897	-2.640**
$\beta_{i=7,2}$	DUM_REG_7 (Dakota Lignite (DL))	-1.048	0.328	-3.197**
$\beta_{i=8,2}$	DUM_REG_8 (Western Montana (WM))	-2.683	0.694	-3.868**
$\beta_{i=9,2}$	DUM_REG_9 (Wyoming, Northern PRB (NW))	0.026	0.571	0.045
$\beta_{i=10,2}$	DUM_REG_{10} (Wyoming, Southern PRB (SW))	-0.502	0.581	-0.863
$\beta_{i=11,2}$	DUM_REG_{11} (Western Wyoming (WW))	0.651	0.508	1.105
$\beta_{i=12,2}$	DUM_REG_{12} (Rocky Mountain (RM))	0.329	0.087	3.765**
$\beta_{i=13,2}$	DUM_REG_{13} (Arizona/New Mexico (ZN))	0.234	0.076	3.093**
β_3	ln PRODCAP	0.234[a]	0.027[a]	8.818**
β_5	ln CAPUTIL	0.095	0.082	1.160
β_6	ln TPH	-0.629	0.058	-10.896*
$\beta_{i=6,7}$	GL*ln TPH	0.930	0.408	2.280*
$\beta_{i=7,7}$	DL*ln TPH	0.274	0.124	2.212*
$\beta_{i=8,7}$	WM*ln TPH	0.848	0.235	3.612**
$\beta_{i=9,7}$	NW*ln TPH	-0.148	0.169	-0.876
$\beta_{i=10,7}$	SW*ln TPH	0.029	0.159	0.180
$\beta_{i=11,7}$	WW*ln TPH	-0.157	0.245	-0.640

Table 1.C-1. Regression statistics for the coal-pricing model (cont.)

Regression coefficient	Variable	Parameter estimate	Standard error	t- Statistic
$\beta_{i=1,j=1,9}$	NA * DUM_ MINE_TYPE (Underground) * ln TPH	0.056	0.027	2.073*
$\beta_{i=3,j=1,9}$	SA * DUM_ MINE_TYPE (Underground) * ln TPH	-0.095	0.123	0.770
$\beta_{i=12,j=1,9}$	RM * DUM_ MINE_TYPE (Underground) * ln TPH	-0.108	0.045	-2.387*
β_{10}	ln WAGE	0.802	0.161	4.984**
β_{12}	ln PCSTCAP	-0.039	0.031	-1.252
β_{13}	ln PFUEL	0.154	0.028	5.426**
β_{14}	ln OTH_OPER	0.085	0.063	1.352
Rho	Autocorrelation Parameter (Rho)	0.670	0.040	16.553
	Adjusted R Squared	0.997		
	Durbin-Watson Statistic	2.034		
	Number of Observations	391[c]		

NA = Not available. *Significant at 1%. ** Significant at 5%.

[a] In subsequent AEO projections, some coefficients have been adjusted by the coal team, from the originally estimated values. For example, the coefficient for the productive capacity term was adjusted upward to 0.405, reflecting the assumption that the estimated relationship between coal mining productive capacity and minemouth coal prices will be more substantial than estimated in the regression analysis.

[b] An intercept dummy for 2009 was included in estimating the model. Other years were tested, but they were not statistically significant.

[c] The combined use of a weighted regression technique and lagged variables results in the dropping of the first two observations for each group of data (combination of region and mine type). The model includes annual-level data for 13 CPS supply regions and two mine types (surface and underground) for the years 1978 through 2009, excluding data for the years 1986–1991. In all, 391 observations are included (17 observations per year for each of the 23 years represented in the final estimation).

Notes: The endogenous explanatory variables in the regression are PRODCAP, CAPUTIL, TPH, WAGE, PCSTCAP, PFUEL, and OTH_OPER. Instruments excluded from the supply equation are lagged coal-fired electricity generation, lagged natural gas share of total electricity generation, lagged days of supply at electric power sector plants, lagged industrial coal consumption, lagged exports, lagged coal inventories at electric power sector plants, lagged mine price of coal, lagged productive capacity, lagged capacity utilization, lagged mine productivity, lagged fuel price, lagged coal industry wage, lagged index of other mine operating costs, the world oil price, the price of natural gas to the electric power sector, and the average heat, sulfur, and ash content for coal received at electric power sector plants.

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Appendix 1.E CPS Abstract

Model name: Coal Production Submodule

Model abbreviation: CPS

Description: Produces supply-price relationships for 14 coal producing regions, nine coal types (unique combinations of thermal grade and sulfur content), and two mine types (underground and surface) and addresses the relationship between the minemouth price of coal and corresponding levels of capacity utilization at coal mines, annual productive capacity, labor productivity, wages, fuel costs, other mine operating costs, and a term representing the annual user cost of mining machinery and equipment. In the CPS, coal types are defined as unique combinations of thermal and sulfur content. This definition differs slightly from the NEMS Coal Distribution Submodule, where coal types are defined as unique combinations of thermal content, sulfur content, and mine type.

Purpose of the model: The purpose of the model is to produce annual domestic coal supply curves for the mid-term (to 2050) for the Coal Distribution Submodule of the Coal Market Module of NEMS.

Model update information: December 2019

Part of another model?: Yes, part of the

- Coal Market Module
- National Energy Modeling System

Model interface: The model interfaces with the following models:

- Domestic Coal Distribution Submodule
- Electricity Market Module
- Macroeconomic Activity Module
- Liquid Fuels Market Module

Official model representative:

Office: Electricity, Coal, Nuclear, and Renewables Analysis
Team: Coal and Uranium Analysis
Model Contact: David Fritsch
Telephone: (202) 587-6538
Email: David.Fritsch@eia.gov

Documentation:

- U.S. Energy Information Administration, Model Documentation: Coal Market Module 2020) (Washington, DC, April 2020).

Archive media and installation manual: Availability of the National Energy Modeling System (NEMS) Archive.

Energy system described by the model: Estimated coal supply at various FOB mine costs.

Coverage:

- Geographic: Supply curves for 14 geographic regions
- Time Unit/Frequency: 2009 through 2050
- Products: Nine coal types (unique combinations of thermal and sulfur content) and two mine types (underground and surface)
- Economic Sectors: Coal producers and importers

Modeling features:

- **Model structure:** The CPS employs a regression model to estimate price-supply relationships for underground and surface coal mines by region and coal type, using projected levels of capacity utilization at coal mines, annual productive capacity, productivity, miner wages, capital costs of mining equipment, fuel prices, and other variable mine supply costs.
- **Modeling technique:** Three main steps are involved in the construction of coal supply curves:
- Calibrate the regression model to base-year production and price levels by region, mine type (underground and surface), and coal type
- Convert the regression equation into supply curves
- Construct step-function supply curves for input to the DCDS
- **Model interfaces:** Electricity Market Module, Macroeconomic, Liquid Fuels Market Module
- **Input data:** Base-year values for U.S. coal production, capacity utilization, productive capacity, productivity, and prices. Base-year electricity prices and wages. Heat, sulfur, and mercury content averages and carbon emission factors by supply curve. Projections of labor productivity and wages as well as the PPIs for mining machinery and equipment, iron and steel, and explosives.

  Data sources: Please refer to Tables 1.B-6 and 1.B-7 of U.S. Energy Information Administration, Model Documentation: Coal Market Module 2020 (Washington, DC, April 2020) for list of input variables and data sources.

Computing environment: See *Integrating Module of the National Energy Modeling System*

Independent expert reviews conducted:

- Barbaro, Ralph and Schwartz, Seth. *Review of the Annual Energy Outlook 2003 Reference Case Forecast*, prepared for the U.S. Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., June 2003).
- Eyster, Jerry and Gaalaas, Trygve. Independent Expert Review of the Annual Energy Outlook 2003 Projections of Coal Production, Distribution, and Prices for the National Energy Modeling System's Appalachian, Interior, and Western Supply Regions, prepared for the U.S. Energy Information Administration (Washington, DC: PA Consulting Group, June 2003).

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- Suboleski, Stanley C., *Report Findings and Recommendations, Coal Production Submodule Review of Component Design Report*, prepared for the U.S. Energy Information Administration (Washington, DC, August 1992).
- Kolstad, Charles D., *Report of Findings and Recommendations on EIA's Component Design Report Coal Production Submodule*, prepared for the U.S. Energy Information Administration (Washington, DC, July 23, 1992).

Status of evaluation efforts conducted by model sponsor: The Coal Production Submodule (CPS) was developed for the National Energy Modeling System (NEMS) during the 1992–1993 period and revised in subsequent years. The version described in this abstract was used in support of the *Annual Energy Outlook 2020*.

Independent expert reviews of the Coal Market Module's (CMM) *Annual Energy Outlook 2002* and *Annual Energy Outlook 2003* coal forecasts were conducted in August 2002 and June 2003, respectively, by Energy Ventures Analysis, Inc. (EVA) and the PA Consulting Group.

Last update: The CPS is updated annually for use in support of each year's *Annual Energy Outlook*. The version described in this abstract was updated in April 2020.

2. Domestic Coal Distribution Submodule (DCDS)

Introduction

This section of the report presents the objectives of the approach used in modeling domestic coal distribution and provides information on the model formulation and application. Section 2 is intended as a reference document for model analysts, users, and the public, and it conforms to the requirements specified in Public Law 93-275, Section 57(B)(1) as amended by Public Law 94-385, Section 57.b.2.

Model summary

The Domestic Coal Distribution Submodule (DCDS) simulates optimal coal distribution between 14 U.S. coal supply regions and 16 domestic demand regions. Figure A on page *ix* of this document illustrates that the DCDS is the central part of the coal model. The DCDS consists of a linear program with constraints representing environmental, technical, and service/reliability constraints on delivered coal price minimization by consumers. Coal supply curves are derived from the CPS price equation formula described in Section 1, while projected coal demand is received from the Residential,[25] Commercial,[26] Industrial, Liquid Fuels (for CTL), and Electricity Market components of NEMS. In addition, coal export demand is provided by the International Coal Distribution Submodule (ICDS) described in Section 3 (Figure 2.1). The AIMMS software environment integrates the three submodules and solves the complex linear optimization.

Organization

This section describes the modeling approach used in the domestic portion of the Domestic Coal Distribution Submodule (DCDS) as a procedure within the AIMMS modeling framework. Within this section, the following are provided:

- The model purpose and scope, including its classification structures (including the coal typology adopted, model supply and demand regions, and demand sectors and subsectors), model inputs and outputs, and relationship to other NEMS modules and parts of the Coal Market Module
- The model rationale, including the theoretical approach, assumptions, major constraints, and other key features
- The structure of the model, including an outline of the DCDS computational sequence and input/output flows

This section has six appendixes:

- A detailed mathematical description of the model (Appendix 2.A)
- An inventory of input data, variable and parameter definitions, model output, and their location in files or reports (Appendix 2.B)

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[25] Although the residential coal demand sector is still represented in NEMS, EIA stopped reporting data for residential coal demand at the end of 2007 and, therefore, NEMS projects zero residential coal demand from 2008 onward.

[26] While the commercial sector is still referenced in the CMM source code, this sector is referred to as the commercial and institutional sector in the standard set of *Annual Energy Outlook* reporting tables. The definition for a commercial coal user is a retail or wholesale business or a facility housing such a business that uses coal for heating, raising steam, or generating electricity. An institutional coal user is defined as a private, state, or federal facility such as a prison, nursing home, military base, university, or hospital that uses coal for heating, raising steam, or generating electricity.

- A discussion of data quality and estimation for model inputs (Appendix 2.C)
- A bibliography of technical references for the model structure and the economic systems modeled (Appendix 2.D)

Model Purpose and Scope

Model objectives

The purpose of the Coal Market Model (CMM) is to provide annual forecasts (through 2050) of coal production and distribution within the United States. Coal supply in the CMM is modeled using a typology of 12 coal types (discrete categories of heat and sulfur content), 14 supply regions, and 16 demand regions. Exogenously generated coal demands within the demand regions are subdivided into five economic sectors and 52 economic subsectors. Coal transportation is modeled using sector-specific arrays of interregional transportation prices. Demands are met by supplies that represent the lowest delivered cost on a dollar-per-million-Btu basis. The distribution of coal is constrained by environmental, technical, and service/reliability factors characteristic of domestic coal markets.

As stated in the NEMS planning documents,[27] an important design objective in modeling domestic coal distribution is to provide a simple platform that can be rapidly adapted to model policy problems, not all of which may be currently foreseeable.

Classification plan

The CMM contains major structural elements that define the geographic and technical scale of its simulation of coal distribution. First is the typology that represents the significant variation in the heat and sulfur content of coal. The geographic categorizations of coal supply and demand comprise two more. The classification of demand into economic subsectors constitutes the fourth classification element. Each is discussed in turn below.

Coal typology

The coal typology contains three sulfur categories, four thermal grades of coal, and two mining types (surface and underground) to produce the framework shown in Table 1.1 in Section 1. By applying this typology to coal reserves in the 14 supply regions, the model defines 41 different coal supply sources. In the AIMMS CMM framework, these 41 supply sources have also been associated with the set parameter **SCRV1** to provide for easier ordering and reference to the 41 unique supply curves.

Coal supply and demand

The DCDS seeks to match the 41 supply sources with the many demand sinks in the demand requirements passed from the other NEMS modules. In addition to coal supply region, the CMM distinguishes coal quality, mine prices, and access to domestic markets as critical elements in

[27] U.S. Energy Information Administration: EIA Working Group, "Requirements for a National Energy Modeling System" (July 2, 1990), pp. 7, 14, 15. Office of Integrated Analysis and Forecasting: "Draft System Design for The National Energy Modeling System" (January 16, 1991), pp. 3,11; "Working Paper: Requirements for a National Energy System (Draft)" (November 22, 1991), pp. 8, 17; "Working Paper: Requirements for A National Energy Modeling System" (December 12, 1991), pp. 7, 15, 17; "Development Plan for The NEMS" (February 10, 1992), pp. 8, 50, 51. National Research Council, Committee on the National Energy Modeling System, Energy Engineering Board, Commission on Engineering and Technical Systems, "The National Energy Modeling System" (Washington, DC, January 1992), p. 58.

formulating the transportation problem. The four supply regions east of the Mississippi River contain 24 of the 41 coal supply sources used in the *Annual Energy Outlook* (Table 1.1 in Section 1). The eight supply regions west of the Mississippi River contain the remaining 17 coal sources. Production from each supply source (and the associated heat, sulfur, and ash content) for the historical base year is shown in Table 2.1.

Coal demand regions

The 16 CMM domestic demand regions (Figure 2.1) represent the nine census divisions, four of which have been divided to represent distinct sub-markets with special characteristics (Table 2.2). The South Atlantic Census Division has been partitioned to create a special market region for Georgia and Florida, which have low-cost access to western supply regions via the Mississippi River system and the Gulf of Mexico. Ohio is given separate region status because of its proximity to North Appalachian coal (from Ohio) and its greater distance from the East Interior and western coalfields. Similarly, Alabama and Mississippi are separated from the other East South Central states (Kentucky and Tennessee) because of their access to South Appalachian coal and because most coal consumption in Kentucky and Tennessee is supplied from the Central Appalachian and East Interior regions. The Mountain Census Division is subdivided to create a separate demand region for Idaho, Montana, and Wyoming, in which utilities are more highly dependent on coal from the Northern Great Plains. Within the Mountain Census Division, Colorado, Utah, and Nevada are also separated from Arizona and New Mexico to better represent transportation costs. The coal demand regions can easily be aggregated into census divisions for reporting purposes.

Table 2.1. Production, heat content, sulfur, mercury, and carbon dioxide (CO2) emission factors

Coal supply region	States	Coal rank and sulfur level	Mine type	2018 production (million short tons)	2018 heat content (million British thermal units per short ton)	2018 sulfur content (pounds per million British thermal units)	Mercury content (pounds per trillion British thermal units)	CO2 (pounds per million British thermal units)
Northern Appalachia	Pennsylvania, Ohio, Maryland, and West Virginia (North)	Metallurgical	Underground	17.8	28.71	0.76	N/A	204.7
		Mid-sulfur bituminous	All	16.6	24.45	1.65	12.68	204.7
		High-sulfur bituminous	All	69.7	25.35	2.61	12.19	204.7
		Waste coal (gob and culm)	All	10.2	13.40	3.89	53.85	204.7
Central Appalachia	Kentucky (East), West Virginia	Metallurgical	Underground	45.9	28.69	0.42	N/A	206.4
		Low-sulfur bituminous	All	14.7	25.73	0.51	5.02	206.4
		Mid-sulfur bituminous	All	17.9	24.53	0.92	8.58	206.4
Southern Appalachia	Alabama and Tennessee	Metallurgical	Underground	15.6	28.69	0.51	N/A	204.7
		Low-sulfur bituminous	All	0.7	25.55	0.59	3.87	204.7
		Mid-sulfur bituminous	All	1.9	23.47	1.38	9.65	204.7
East Interior	Illinois, Indiana, Kentucky (West),	Mid-sulfur bituminous	All	27.9	22.39	1.93	7.35	203.1
		High-sulfur bituminous	All	78.5	23.08	2.54	7.51	203.1
		Mid-sulfur lignite	Surface	3.0	10.64	0.93	25.30	216.5
West Interior	Iowa, Missouri, Kansas, Arkansas, Oklahoma, and Texas	High-sulfur bituminous	Surface	0.8	23.49	1.05	10.45	202.8
Gulf Lignite	Texas and Louisiana	Mid-sulfur lignite	Surface	22.7	13.28	1.05	11.56	212.6
		High-sulfur lignite	Surface	6.3	11.79	3.72	15.28	212.6
Dakota Lignite	North Dakota and Montana	Mid-sulfur lignite	Surface	30.4	13.88	1.20	7.76	219.3
Western Montana	Montana	Low-sulfur bituminous	Underground	0.2	20.63	0.44	3.86	215.5

Table 2.1. Production, heat content, sulfur, mercury, and carbon dioxide (CO2) emission factors (cont.)

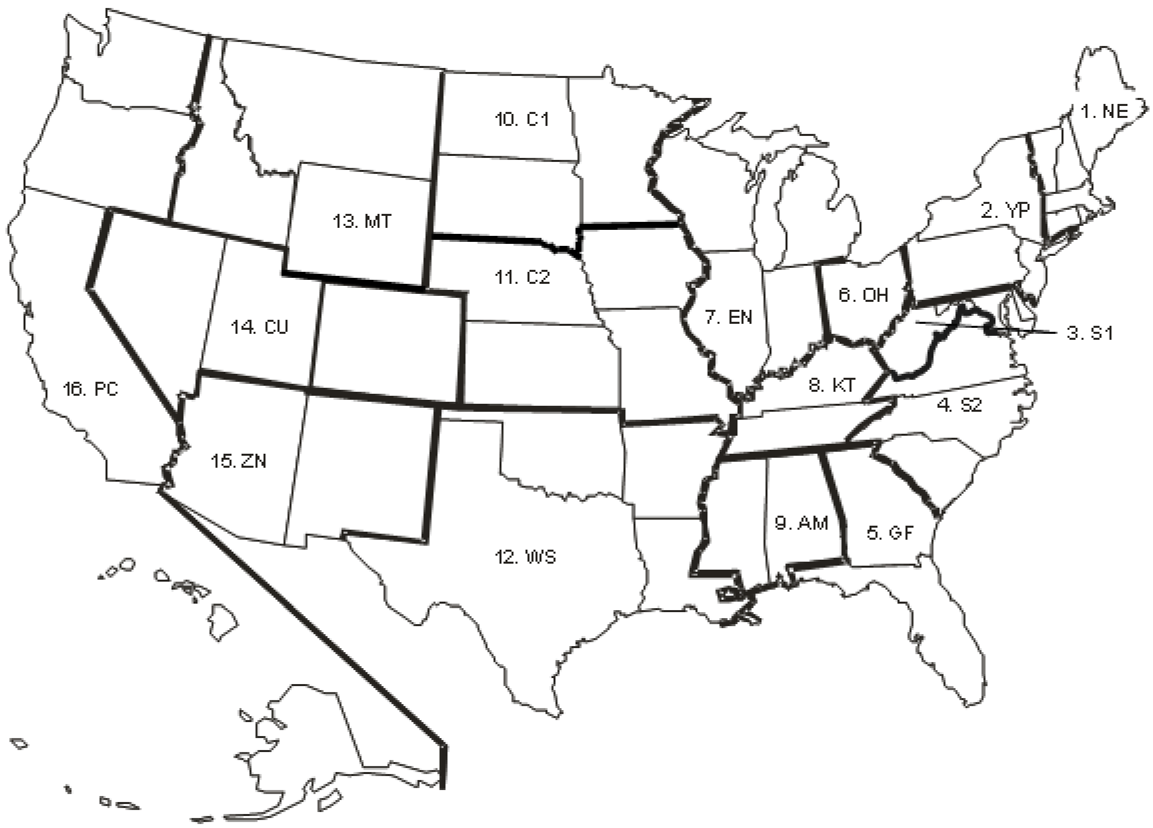
Coal supply region	States	Coal rank and sulfur level	Mine type	2018 production (million short tons)	2018 heat content (million British thermal units per short ton)	2018 sulfur content (pounds per million British thermal units)	Mercury content (pounds per trillion British thermal units)	CO2 (pounds per million British thermal units)
Western Montana (cont)	Montana	Low-sulfur subbituminous	Surface	17.2	18.32	0.37	7.52	215.5
		Mid-sulfur subbituminous	Surface	10.8	17.01	0.78	6.00	215.5
Wyoming, Northern PRB	Wyoming (Northern Powder River Basin [PRB])	Low-sulfur subbituminous	Surface	99.9	16.83	0.37	8.17	214.3
		Mid-sulfur subbituminous	Surface	2.2	16.29	0.64	11.87	214.3
Wyoming, Southern PRB	Wyoming (Southern Powder River Basin)	Low-sulfur subbituminous	Surface	186.8	17.64	0.26	7.37	214.3
Wyoming	Wyoming (non-Powder River Basin)	Low-sulfur bituminous	Underground	2.3	18.42	0.64	2.19	214.3
		Low-sulfur bituminous	Surface	4.0	19.47	0.56	1.90	214.3
		Mid-sulfur subbituminous	Surface	4.5	19.16	0.76	4.35	214.3
Rocky Mountain	Colorado and Utah	Metallurgical	Surface	0.1	28.69	0.43	N/A	209.6
		Low-sulfur bituminous	Underground	22.9	22.55	0.40	5.35	209.6
		Low-sulfur subbituminous	Surface	3.8	20.31	0.58	2.04	212.8
Southwest	Arizona and New Mexico	Low-sulfur bituminous	Surface	6.6	21.49	0.55	6.00	207.1
		Mid-sulfur subbituminous	Surface	9.1	18.32	1.08	13.98	209.2
		Mid-sulfur bituminous	Underground	3.0	19.73	0.68	7.18	207.1
Northwest	Washington and Alaska	Low-sulfur subbituminous	Surface	0.6	15.25	0.19	5.69	216.1

N/A = not available

[1] No production of this coal type in this region after 2013. Displayed values are from 2013.

Sources: U.S. Energy Information Administration, Form EIA-3, *Quarterly Survey of Industrial, Commercial & Institutional Coal Users*; Form EIA-7A, *Annual Survey of Coal Production and Preparation*; and Form EIA-923, *Power Plant Operations Report*. U.S. Department of Commerce, U.S. Census Bureau, *Monthly Report EM-545*. U.S. Environmental Protection Agency, Emission Standards Division, Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort (Research Triangle Park, NC, 1999). U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2011), Table A-37

Figure 2.1. CMM—domestic coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Table 2.2. CMM—domestic coal demand regions

Region	Census division name	Census division number code	States included
1. NE	New England	1	CT, MA, ME, NH, RI, VT
2. YP	Middle Atlantic	2	NY, PA, NJ
3. S1	South Atlantic	5	WV, MD, DC, DE
4. S2	South Atlantic	5	VA, NC, SC
5. GF	South Atlantic	5	GA, FL
6. OH	East North Central	3	OH
7. EN	East North Central	3	IN, IL, MI, WI
8. KT	East South Central	6	KY, TN
9. AM	East South Central	6	AL, MS
10. C1	West North Central	4	ND, SD, MN
11. C2	West North Central	4	IA, NE, MO, KS
12. WS	West South Central	7	TX, LA, OK, AR
13. MT	Mountain	8	MT, WY, ID
14. CU	Mountain	8	CO, UT, NV
15. ZN	Mountain	8	AZ, NM
16. PC	Pacific	9	AK, HI, WA, OR, CA

Coal demand sectors and subsectors

In the CMM, domestic coal demands are further divided into six major sectors and 49 subsectors, part or all of which may be used in each demand region in each forecast year. The six major coal demand sectors are electricity generation, industrial steam, industrial coking, industrial coal-to-liquids (CTL), residential/commercial, and exports. Electricity generation includes generation from utilities, independent power producers, and combined-heat-and-power facilities whose main purpose is the sale of electricity and represents about 80% of coal demand. The industrial steam sector includes other combined-heat-and-power facilities as well as industrial consumers of steam from coal. The industrial coking sector includes metallurgical and by-product coke ovens. The CTL sector includes facilities where coal is converted to liquid petroleum products. The residential and commercial sectors together represent less than 1% of coal demand, so they are modeled together in order to more closely model distribution patterns. Coal export demand is solved for by the ICDS (see Section 3).

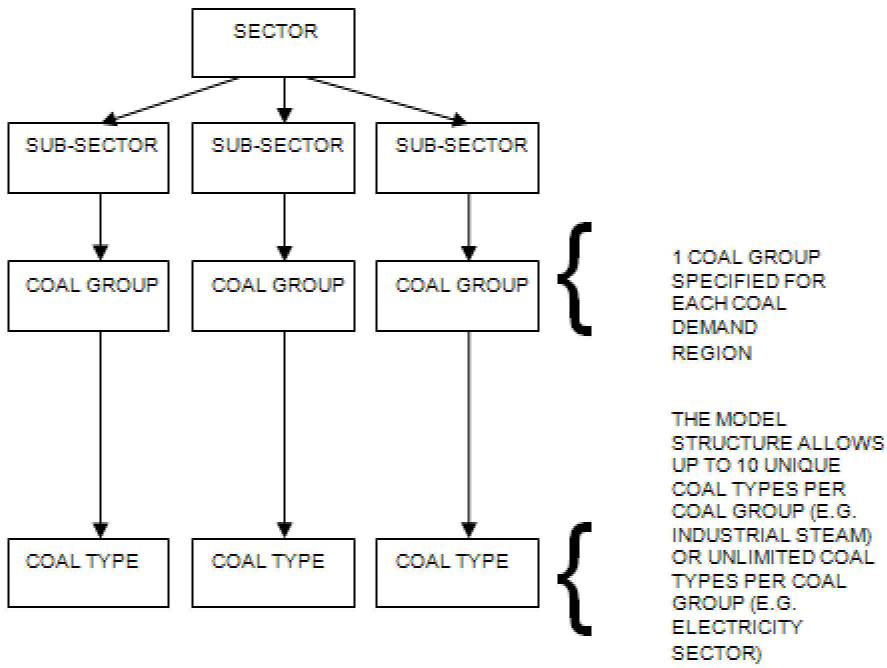
Coals of different types and quality, geographic availability, and prices tend to be associated with satisfying demands of particular sectors. These coals may not necessarily represent the least expensive option for a sector when factors such as quality or type are not considered, however. If minimization of costs alone is used to determine which coals satisfy a sector’s coal demand, many historical and forecast flows would not be accurately depicted in the model. The CMM determines the mix of coals used to satisfy demand based on minimization of cost within a linear program (LP). One option to handle these examples of seemingly uneconomical coal choices is to include many constraints within the LP specifying which coals are available for consumption by certain sectors, while making others unavailable. The addition of such constraints, however, would increase the model structure's complexity. To avoid this result, subsectors are defined for each economic sector. For the non-electricity sectors, consumption by the subsectors is allocated based mainly on historical distribution patterns. The subsectoral detail is shown in Table 2.3.

Table 2.3. Domestic CMM demand structure—sectors and subsectors

	Sector	Number of demand subsectors	Subsector codes	AIMMS {SubsectorFlag}
1.	Residential/commercial	2	R1-R2	-1
2.	Industrial steam	3	I1-I3	-2
3.	Industrial metallurgical	2	C1-C2	-3
4.	Industrial coal-to-liquids	1	L1	-4
5.	Exports	6	X1-X6	-5
6.	Electricity generation	38	15-52	-6
	Total number of subsectors	52		

For all of the subsectors, a *coal group* is defined for each demand region. Each of these coal groups references a particular set of coal types. An example of a coal type is medium-sulfur, surface-mined, bituminous coal from Northern Appalachia. Some of the coal groups allow unlimited choices of coal types while others are considerably more restrictive. For example, for the coking coal subsectors, only metallurgical grade coal is permitted. In general, the electricity sector is allowed to use coal from any of the non-metallurgical grade coal supply sources represented on the supply curves modeled in the CMM. (The electricity sector is further constrained in other ways, for example, sulfur limitations in the model structure. For more information, see "Constraints Limiting the Theoretical Approach" and "Environmental Constraints" in the discussion of the Model Rationale below.) A general schematic of the sectoral structure present in the coal model is displayed in Figure 2.3.

Figure 2.2. General schematic of sectoral structure



The electricity sector is divided into 38 subsectors, each representing a particular plant configuration generally describing the type of emission control technology employed at a group of plants (see Table 2.5). In the AIMMS code, the subsector parameter is {SubSector}, in which first 14 spots are used by Sectors 1 to 5 in Table 2.3. Power subsectors codes are the values in Table 2.5 plus 14, in other words, 15 through 52. Coal demand projections are sent from the electricity model in this level of detail, so the CMM does not need to disaggregate the demands into subsectors itself.

In a mercury-constrained scenario, once a mercury control technology is chosen, the model does not allow a subsequent retrofit decision to be made to *undo* the previous choice. Since pilot tests indicate that there are no mercury removal benefits, selective non-catalytic reduction systems (SNCRs) in combination with flue gas desulfurization equipment are not represented in the model as a mercury control option. Also, a plant without scrubbers is allowed to upgrade to only wet flue gas desulfurization equipment within the model structure (as opposed to dry flue gas desulfurization equipment). Existing plants may be upgraded with a carbon capture and sequestration retrofit option, but this option becomes economical only under certain scenarios where carbon emissions are regulated or taxed. Almost all plants are assumed to comply with the Mercury and Air Toxics Standards (MATS) by using a combination of a scrubber and Activated Carbon Injection (ACI) to control mercury. See Table 2.5 for a brief description of the plant configurations modeled. A complete discussion of the rules impacting coal plants can be found under “Legislation and regulations” in the most current AEO Coal Market Model Assumptions.

The industrial steam sector is divided into three subsectors (I1-I3). Although the subsectors in the industrial sector are less formalized than in the electricity sector, the basic premise is the same. As in the electricity sector, technical requirements of certain facilities limit the types of coal that may be used. For example, *stoker* industrial steam coals (I1) are shipped to older industrial boilers that require—for technical reasons—coal fuels with relatively low ash and high thermal energy content. Industrial pulverized coal boilers (I2) can accept lower-quality coals in terms of ash and Btu content. In addition, there are a wide variety of other specialized technologies including, for example, coal-fired, circulating fluidized-bed steam boilers (CFB), Portland cement kilns, and anthracite coals used as a sewage filtration medium.

The industrial coking sector is also divided into two subsectors (C1-C2). This sub-division of demand allows the CMM to better match historical consumption patterns for each demand region, to the specific premium coal “coking” supply curves that may transport to each subsectors. For instance, 80% of the coking demand for the Middle Atlantic region may be satisfied by the first subsector specifying coal group C1. The remaining 20% of the coking demand for the Middle Atlantic region may be satisfied by the second subsector specifying coal group C2.

Because the CTL sector has no historical flows, the CTL sector does not require subsectors in order to represent consumption. Each new CTL facility is assumed to have a capacity of 48,000 barrels per day of liquid fuels and is located in areas where existing refineries are present. The CTL market is not limited to specific coals but instead chooses its fuel based on minimization of costs. The Liquid Fuels Market Module (LFMM) sends demands to the CMM according to its five LFMM regions. The CMM assigns coal demand regions to each of these LFMM regions. For the regions LFMM1, LFMM2, LFMM3, and LFMM5, 100% of the CTL demand is mapped to the coal demand regions YP, EN, WS, and PC, respectively. LFMM4’s CTL demand is allocated equally to the CW and MT coal demand regions.

CTL facilities are modeled in the LFMM as indirect liquefaction *co-co* facilities, meaning they produce both liquid fuels (of which 72% is assumed to be diesel and 28% is naphtha) and electricity. Each modeled plant is assumed to produce 832 MW of electricity (295 MW for the grid and 537 MW for the conversion process) and is capable of producing 48,000 barrels of liquids per day. For additional information about the representation of CTL in NEMS, see the “Liquid Fuels Market Module” chapter in *Assumptions for the AEO2020*. Coal-biomass-to-liquids (CBTL) facilities were not modeled for AEO2020.

The six subsectors (X1-X6) used for export coals are split between metallurgical and steam coal and for the most part match to coal exports from the East, Gulf, and West Coasts. U.S. coal exports tend to be among the more expensive in international markets, even on a dollar-per-million-Btu basis, but they are sought because of the overall high levels of international coal demand in recent years, their high quality, their reliable availability, and their historical role as a method of balancing foreign trade accounts. The United States is an important exporter of premium coking coals (X1-X3), where the model allocates premium coking coals from U.S. supply regions or domestic markets (C1-C2). The other export subsectors (X4-X6) are for steam coals, which require special coal quality definitions that are different from domestic steam coals. The input file ***clintlusexport.txt*** sets minimum {ExportLowerBound} and maximum {ExportUpperBound} levels by subsector and coal demand region.

In summary, the DCDS contains two residential/commercial subsectors, three industrial steam and two domestic coking coal subsectors, one coal-to-liquid sector, three export metallurgical and three export steam subsectors, and 38 electricity subsectors, making 52 in all.

Relationship to other models

The DCDS relates to other NEMS modules as the primary iterating unit of the Coal Market Module, receiving demands from other non-coal modules and sending delivered coal prices, Btu contents, and tonnages framed in interregional coal distribution patterns specific to the individual NEMS economic sectors (see Figure A on page *ix*). This information is stored for other NEMS modules via the {Copy_Global} procedure in the AIMMS code. When the CMM's programming code (written in AIMMS) is opened, these data variables are automatically loaded into the coal model. Within the CMM, the domestic distribution component interacts with other parts of the CMM. In the first iteration of each annual forecast, the DCDS receives coal supply curve information from the Coal Production Submodule (CPS).

Price and quantity output from the CMM's simulation of domestic coal production, distribution, and exports by economic sector is sent to the NEMS Integrating Module. These outputs include (1) minemouth, transportation, and delivered prices; (2) regional/sectoral coal supplies in trillion Btu and millions of tons by coal heat and sulfur content categories; and (3) energy conversion factors (million Btu per short ton) and sulfur values (pounds of sulfur per million Btu). The CMM uses its own set of 16 domestic demand regions but aggregates all final outputs to the NEMS Integrating framework into the nine census divisions, which are a superset of the CMM's domestic demand regions.

Both the CMM and the EMM have input files that are defined at the unique plant unit level and then aggregated to the plant type level. Coal contracts, coal diversity constraints, transportation rates, and coal supply curves are represented in both models. The CMM also passes transportation rates and a simplified representation of the relevant coal supply curves to the LFMM for the purpose of coal-to-liquids (CTL) modeling. The detail shared between the three models stems from a goal of improving overall NEMS convergence and convergence speed.

Input requirements from NEMS

The CMM obtains electricity sector coal demand by forecast year and estimates of future coal demand in subsequent years from the EMM for each of the 16 CDS demand regions and 38 electricity subsectors.

The CMM receives annual U.S. coal export demands from the ICDS. These demands represent premium metallurgical demand and bituminous and subbituminous steam coal demands. Export demands are also disaggregated but only to the eight domestic demand regions of the CMM that contain ports of exit. This regional structure allows the CMM to forecast domestic mining and transportation costs to terminals in different regions of the United States and for exports to overseas markets in northern and southern Europe, South America, the Pacific Rim of Asia, and Canada.

Residential/commercial, industrial steam, and coking coal demands, specified for each of the nine census divisions, are sent from the Residential, Commercial, and Industrial Demand modules, respectively. Coal, once an important transportation fuel, is now restricted to use in a handful of steam engines pulling excursion rides. Therefore, there is no transportation demand sector in the CMM.

The CTL and CBTL (XTL) sectors represent technologies that could become commercially viable when low-sulfur distillate prices are high. Demands for XTL are specified by the LFMM's five demand regions. The relationship between the LFMM demand regions and the CMM demand regions is shown below in

Table 2.4. The modeling of XTL is simplified by only allowing certain coal demand regions to participate in the XTL sector. For AEO2020, CBTL is not modeled.

Table 2.4. LFMM demand region composition for the CTL and CBTL sectors

LFMM demand region	Coal demand regions
I	YP
II	EN
III	WS
IV	CW,MT
V	PC

The transition from census divisions and LFMM regions to the more detailed domestic DCDS demand regions is accomplished using static demand shares specific to the residential/commercial, industrial steam, industrial metallurgical, and industrial coal-to-liquids sectors. These shares are updated as required and are found in the table {tInp_clshare_CensusDivision}. Subsector fractional splits are provided by table {tInp_clshare_FRADI}. The demand for U.S. coal exports is received from the ICDS and is disaggregated into the domestic DCDS demand regions according to static shares found in the ICDS.

DCDS input tables are now provided to the AIMMS model through the **CMM.mdb** database file. Tables in **CMM.mdb** include transportation rates and coal contracts files that includes regional and sectoral indices and labels, as well as parameters used to calibrate minemouth prices and transportation rates. A number of old input files (among them clparam.txt, clcont.txt, clrates.txt, clexdem.txt, clshare.txt, and clnode.txt) are not used by the AIMMS model.

Output requirements for other NEMS components

The DCDS provides detailed input information to the EMM, including coal contracts, coal diversity information (subbituminous and lignite coal constraints), transportation rates, and coal supply curves. The EMM uses this information to develop expectations about future coal prices and coal availability in order to make improved projections of coal planning decisions.

Table 2.5. Electricity subsectors

		Sector characteristics			
Sector code		Particulate control/ general classification	SO2 control equipment	NOx control equipment	Additional controls
1.	B1	Bag house	NA	Any	NA
2.	B2	Bag house	NA	Any	CCS
3.	B3	Bag house	Wet scrubber	NA	NA
4.	B4	Bag house	Wet scrubber	NA	CCS
5.	B5	Bag house	Wet scrubber	Selective Catalytic Reduction	NA
6.	B6	Bag house	Wet scrubber	Selective Catalytic Reduction	CCS
7.	B7	Bag house	Dry scrubber	Any	NA
8.	B8	Bag house	Dry scrubber	Any	CCS
9.	C1	Cold side ESP	NA	Any	NA
10.	C2	Cold side ESP	NA	Any	FF
11.	C3	Cold side ESP	NA	Any	CCS
12.	C4	Cold side ESP	Wet scrubber	NA	NA
13.	C5	Cold side ESP	Wet scrubber	NA	FF
14.	C6	Cold side ESP	Wet scrubber	NA	CCS
15.	C7	Cold side ESP	Wet scrubber	Selective Catalytic Reduction	NA
16.	C8	Cold side ESP	Wet scrubber	Selective Catalytic Reduction	FF
17.	C9	Cold side ESP	Wet scrubber	Selective Catalytic Reduction	CCS
18.	CX	Cold side ESP	Dry scrubber	NA	NA
19.	CY	Cold side ESP	Dry scrubber	NA	FF
20	CZ	Cold side ESP	Dry scrubber	Selective Catalytic Reduction	CCS
21	H1	Hot Side ESP/Other/None	NA	Any	NA
22	H2	Hot Side ESP/Other/None	NA	Any	FF
23	H3	Hot Side ESP/Other/None	NA	Any	CCS
24	H4	Hot Side ESP/Other/None	Wet scrubber	NA	NA
25	H5	Hot Side ESP/Other/None	Wet scrubber	NA	FF
26	H6	Hot Side ESP/Other/None	Wet scrubber	NA	CCS
27	H7	Hot Side ESP/Other/None	Wet scrubber	Selective Catalytic Reduction	NA
28	H8	Hot Side ESP/Other/None	Wet scrubber	Selective Catalytic Reduction	FF
29	H9	Hot Side ESP/Other/None	Wet scrubber	Selective Catalytic Reduction	CCS
30	HA	Hot Side ESP/Other/None	Dry scrubber	Any	NA
31	HB	Hot Side ESP/Other/None	Dry scrubber	Any	FF
32	HC	Hot Side ESP/Other/None	Dry scrubber	Any	CCS

Table 2.5. Electricity subsectors (cont.)

			Sector characteristics		
Sector code		Particulate control/general classification	SO2 control equipment	NOx control equipment	Additional controls
33	PC	New Pulverized Coal	Wet scrubber	Selective Catalytic Reduction	FF
34*	OC	Other New Coal	NA	NA	NA
35	IG	New Integrated Gasification Combined Cycle (IGCC)	Acid gas removal system (pre-combustion)	Selective Catalytic Reduction	NA
36*	I2	IGCC with Natural Gas Co-firing	NA	NA	NA
37	PQ	Advanced Coal with Partial (30%) Sequestration	Wet scrubber	Selective Catalytic Reduction	FF, CCS
38	IS	Advance Coal with Full (90%) Sequestration	Wet scrubber	Selective Catalytic Reduction	FF, CCS

ESP = Electrostatic Precipitator

FF = Fabric Filter

CCS = Carbon Capture and Sequestration

NA = Not Applicable

##* = Currently inactive plant technology in the EMM

Ultimately, the CMM still projects the least-cost delivered prices for each coal type in each CMM demand region to the EMM. These prices allow the EMM to determine the comparative advantage of coal in relation to that of other fuels, and these prices are used for the EMM's dispatching decisions. After receiving the EMM demands, the CMM projects the least-cost available coal supplies that will satisfy the demands and reports the resulting distribution pattern, production tonnages and minemouth, transport, and delivered prices to NEMS for the electricity generation sector, after aggregating the output to the census division level. The CMM provides delivered prices and volumes for coal supplied to the residential, commercial, and industrial sectors by census division. Prices and volumes are reported by regional origin and Btu/sulfur content. These values are reported to the residential, commercial, and industrial models via the NEMS Integrating Module. The DCDS component of the CMM can provide export coal quantities and f.a.s. port-of-exit prices by export supply region and coal sulfur/Btu content.[28]

The CMM also provides detailed input information to the LFMM, including transportation rates and coal supply curves. The LFMM uses this information to develop expectations about future coal prices and coal availability, allowing the LFMM to determine the economic feasibility of constructing a coal-to-liquids facility by estimating delivered coal prices for specific quantities of coal. In scenarios where allowance prices are modeled (for more information, see section entitled "Environmental Constraints"), allowance prices for SO2 and mercury are sent to the LFMM and are considered in the overall cost of the

[28] F.a.s. prices, literally, *free alongside ship*, mean that these prices include all charges incurred in U.S. territory except loading onboard marine transport. This meaning is generally observed even when, as in the case of some exports to Mexico and Canada, they do not literally leave by water transport.

coal fuel supplied. Emissions from CTL facilities are assumed to be identical to those for IGCC. Additional details of coal-to-liquids modeling are provided in the LFMM Documentation.

DCDS output CMM falls into two categories:

- Outputs produced specifically for the NEMS system, characteristically in aggregate form and presented in tables that span the forecast period. These reports are primarily designed to meet the output requirements of the *Annual Energy Outlook* and its Supplement.
- Detailed reports produced in a set for a single forecast year.[29] These reports provide detail on sectoral demands received, regional and national coal distribution patterns, transportation costs, and reporting of regional and supply curve-specific production. Any or all of these reports can be run for any year in the model forecast horizon. These reports are designed to meet requirements for detailed output on special topics and for diagnostic and calibration purposes.

[29] This type of single year report is not currently available in the AIMMS version of the CMM. Extensive design of AIMMS reports is planned for the AEO2021 version of the CMM. AIMMS reports will include reports for both CPS and DCDS outputs.

Model Rationale

Theoretical approach

Each year, coal is transported from mines to consumers via thousands of individual transportation routes. Subject to certain constraints peculiar to its industrial organization, the behavior of the coal industry is demand-driven and highly competitive. Coal transportation, while far from perfectly competitive in all cases, is a competitive industry when viewed at the national scale. Given this overall picture, it is appropriate to model coal distribution with the central assumption that markets are dominated by the power of consumers acting to minimize the cost of coal supplies. Since the late 1950s, coal supply and distribution has been modeled with this central assumption, using linear programming, heuristic solution algorithms, or both to determine the least-cost pattern of supply to meet national demand.

The CMM employs a linear program to determine the least-cost set of supplies to meet overall national coal demand. The detailed pattern of coal production, transportation, and consumption is simplified in the CMM as consisting of about 200 annual demands (the exact number depends on the forecast year and scenario modeled) satisfied from up to 41 coal supply curves.

Constraints limiting the theoretical approach

The picture of a highly competitive coal mining industry serving consumers with significant market power is correct but substantially incomplete. It fails to show powerful constraints on consumer minimization of delivered coal costs that transform the observed behavior of the industry. These major constraints can be categorized as follows:

- Environmental constraints
- Technological constraints
- Transportation constraints

The deregulation of electricity generation and the increasing uncertainty about the long-term environmental acceptability of coal combustion have combined to remove some of the constraints imposed on coal modeling by long-term contracts and other *security of supply* agreements that tended to reduce the role of cost minimization in domestic coal markets. Environmental regulation and technological inflexibility combine to restrict the types of coal that can be used economically to meet many coal demands, thus reducing the consumer's range of choice. Supply reliability and local limits on transportation competition combine to restrict where, in what quantity, and for how long a technically and environmentally acceptable coal may be available. The synergistic action of these constraints produces a pattern of coal distribution that differs from unconstrained delivered cost minimization.

Coal transportation constraints are discussed within the context of the Model Structure below.

Environmental constraints

The CMM is capable of modeling compliance with emissions limits established by the Clean Air Act Amendments of 1990 (CAAA90), including the Cross-State Air Pollution Rule (CSAPR) and the Mercury Air Toxics Standard (MATS). The role of modeling these environmental constraints is largely performed by the Electricity Market Module (EMM). Typically, there are three ways in which emission constraints may be met: fuel switching, purchasing emissions allowances, and scrubber and other technology retrofits. The provisions of the combined regulations (CSAPR and MATS) are such that most compliance decisions are technology retrofits and in some cases retirement decisions projected by the EMM. The CMM responds accordingly with projected coal quantities to supply the electricity markets.

The CMM is formulated as a linear programming problem, which models supply source decisions in conjunction with simultaneously satisfying the emission requirements. Electricity demand, in Btu, originates from the EMM and is specified by plant unit. The CMM provides coal prices, sulfur content, mercury content, and SO2 and mercury allowance prices (if applicable). Hence, fuel switching between coal types needed to reach compliance is determined by the CMM.

In the case of mercury, MATS is modeled by requiring all plants over 25 megawatts to reduce their uncontrolled mercury emissions by 90%. This 90% reduction represents an approximation of the more specific limits set forth under MATS. Retrofit decisions in the EMM are the primary means of compliance for MATS.

Activated carbon injection (ACI) during the coal combustion process may also be used on an incremental basis to achieve various levels of mercury emission reductions. This use of ACI is represented in the coal model to further reduce emissions. The cost of removing mercury using activated carbon is added to the transportation cost and is included in the coal model's LP objective function. Each cost represents the amount spent on activated carbon to remove one ton of mercury and corresponds to a particular coal generation plant configuration, coal demand region, and mercury reduction quantity range. The amount of mercury removed using activated carbon is added to the mercury cap within the mercury constraint row. This adjustment to the mercury constraint row allows the CMM greater flexibility and accuracy in meeting the coal demands.

The mercury (Hg) content data for coal by supply region and coal type, in units of pounds of Hg per trillion Btu, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency (EPA) in its 1999 Information Collection Request (ICR). Data input to the CMM were calculated as weighted averages specified by supply region, coal rank, and sulfur category.

The CMM supplies the Electricity Fuel Dispatch (EFD) Submodule, a submodule of the EMM, with coal prices, average sulfur and mercury content for these 38 coal subsectors, and the penalty costs. Using these inputs, the EFD determines the appropriate mix of fuel demands based on regulatory and technological costs.

The CMM provides additional information to the Electricity Capacity Planning (ECP) Submodule, another submodule of the EMM, regarding contracts, subbituminous and lignite coal market share limitations, transportation rates (and supply curves), and other miscellaneous output. These data provide the ECP with improved expectations of coal prices and coal availability in the forecast years. The ECP submodule uses this information as well as output from other supply submodules to project capital decisions for the electricity markets. In addition to modeling new generation capacity required, the ECP submodule determines whether to retire coal units or to retrofit existing coal generation units with sulfur dioxide scrubbers. The ECP also estimates sulfur dioxide emissions and computes SO2 allowance prices.

Emissions from coal-to-liquids facilities, which are assumed to generate electricity that is sold to the grid as well as liquid products, are also subject to the restrictions of CSAPR and MATS. When applicable, the LFMM adds the cost of allowances to its fuel costs when making its CTL planning decisions. The emissions of CTL plants, similar to IGCC, are low relative to other coal technologies, as a result of the removal of 99% of potential sulfur dioxide and 95% of potential mercury emissions. The EMM and the CMM account for the emissions from the coal-to-liquids facilities when evaluating overall compliance with these regulations.

In the other subsectors that do not involve electric power generation, domestic environmental and technical constraints (with their foreign market equivalents for coal exports) combine to restrict choices. These constraints are modeled using the coal groups. In the industrial and residential/commercial sectors, demand is received from other NEMS components in aggregated form and is subdivided into sulfur categories.

Technological constraints

Technological constraints restrict the suitability of coals in different end uses. Coal deposits are chemically and physically heterogeneous; end-use technologies are engineered for optimal performance using coals of limited chemical and physical variability. The use of coals with suboptimal characteristics carries with it penalties in operating efficiency, maintenance cost, and system reliability. Such penalties range from the economically trivial to the prohibitive and must be balanced against any savings from the use of less expensive coal.

Precise modeling of the technological constraints on coal cost minimization would require an enormously detailed model, using large quantities of engineering data that are not in the public domain. A simplified approach is adequate for most public policy analyses and is mandated by data availability constraints. Technological constraints on coal choice are simply addressed in the CMM by subdividing sectoral demands into subsector detail representing the more important end-use technologies, and by then restricting supplies to these subsectors from one or more of the CMM coal types using the *coal group* definitions. For the electricity sector, the *coal groups* have been relaxed to allow the coal model greater flexibility in projecting quantities to satisfy the demands.

It is sometimes necessary to restrict regional demands to specific coal sources. In the case of demands for lignite, gob, or anthracite culm, which contains the lowest heat content per ton of the coals modeled in the CMM, transportation over any significant distance creates the double risk of significant Btu loss and spontaneous combustion. In the CMM, such demands can be restricted to demand regions conterminous with the appropriate supply regions.

Again, the advent of deregulation and the increasing importance of electricity generation costs have produced a willingness to overlook some of the less threatening types of damage that can occur from using coals that differ from a boiler's design specification. Many plants have learned that, with relatively minor investments, newer plants can be easily transferred from bituminous to subbituminous coal. The transportation rate model structure accounts for an increase in expenses when subbituminous coal is used beyond historical levels (see "Transportation Cost Constraints" below).

Technical constraints are also represented in the model for certain electricity subsectors and demand regions by modeling diversity constraints for lignite and subbituminous coals. The diversity constraints establish bounds for use of these types of coals. The bounds are established for particular electricity subsector/demand region combinations based on historical patterns of use of lignite and subbituminous coals. Over the forecast, these bounds become considerably less restrictive for subbituminous coals and have all but disappeared for all sectors by 2025. The lignite diversity constraints either allow plant units within an electricity subsector unlimited use of lignite coal or prevent lignite coal from being used at all.

Model Structure

Key computations and equations

The CMM uses a linear programming (LP) formulation to find minimum-cost coal supplies to meet domestic sectoral coal demands received from the Electricity Market Module, the Residential, Commercial, and Industrial Demand modules, and international demand. The linear program for the domestic component of the CMM selects the coal supply sources for all coal demands in each domestic demand region, subject to the constraint that all demands are met.

The LP model provides the required outputs to the pricing equation and to other modules of the NEMS. The initial matrix and objective function are inputs with most of the parameters in the model changing in the forecast period. For example, the objective function represents the cost of delivering coal from supply regions to demand regions, and its coefficients include minemouth prices, transportation rates, and coal demands specified by heat and sulfur content, all of which may vary. Similarly, coefficients in the constraint matrix, which include the electricity coal contracts, also change within the forecast horizon. Appendix 2.B provides mathematical descriptions of the objective function and equations of the constraint matrix and mathematical descriptions of the equations that derive the revised coefficients for the LP model. Appendix 2.C describes model inputs, parameter estimates, and model output. Appendix 2.D describes data quality and estimation.

Transportation rate methodology

A transportation network is defined in the DCDS as a set of transportation prices connecting coal supply sources with coal demand regions by subsector. In principle, there could be up to 34,112 possible coal transportation routes to connect the 16 demand regions with each of the 41 supply curves for each of the 52 subsectors within the six major economic sectors (electric power generation, industrial steam generation, domestic metallurgical production, residential/commercial consumption, coal-to-liquids, and exports). In practice, the number of useable routes is substantially less because many of the origin/destination possibilities represent routes that are economically impractical now and in the foreseeable future.

Coal transportation rates are set to dummy values to prohibit their use where there can be neither supply nor demand, which allows for easy modification of the rates should technological change or economic development produce possibilities where none now exist. For example, Alaska produces coal for its own consumption and export, but it has never *imported* coal from the contiguous states or overseas. Its only feasible coal transportation connection in the DCDS is with the Pacific Northwest region, since estimates of transport costs cannot be made for routes that have never been used and where required infrastructure does not exist. Similarly, metallurgical coal demand is typically limited to certain industrial customers in particular demand regions, and lignite coals are typically consumed within the same demand region where the mining occurs because their low heat content makes transport relatively cost prohibitive.

Base-year coal transportation rates for each of these routes are estimated exogenously and escalated based on regional transportation indices. Base-year historical transportation rates for each relevant coal transportation route are input to the model via text files (clrateselec.txt & clratesnonelec.txt). The base year historical rates are prepared by subtracting minemouth prices, derived from the annual sales and revenue data reported by respondents on the Form EIA-7A, *Annual Survey of Coal Production and Preparation*, from sector-specific delivered prices from the Form EIA-3, *Quarterly Survey of Non-Electric Sector Coal Data*, from the Form EM-545 for coal exports, and from the Form EIA-923, *Power Plant Operations Report*, for the electricity sector. Because coal-to-liquids (CTL) facilities do not currently exist, CTL transportation rates are based on historical transportation rates to the electricity sector for similar movements.

For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical, base year average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier may also be used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use.

Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (East and West) transportation indices. The indices are measures of the change in average transportation rates, on a tonnage basis, that occurs between successive years for rail and multimode coal shipments. An East index is used for coal originating from eastern supply regions, and a West index is used for coal originating from western supply regions. The indices are calculated econometrically as a function of railroad productivity, the user cost of capital of railroad equipment (East only), investment (West only), diesel fuel price (East only), and the western share of national coal demand (West only). Although the indices are derived from railroad information, they are universally applied to all coal transportation rates within the CMM. See Appendix 2.C for more information regarding the methodology used to derive the transportation rate indexes. For the transportation rate indexes used in AEO2020, please see the AEO assumptions.

For the case of increased shipping distances, the second-tier transportation rate is calculated by assuming a geographic centroid for the relevant demand region, estimating an approximate distance, and where possible using ton-mile data from the FERC Form 580, *Interrogatory on Fuel and Energy Purchase Practices*, to calculate a new dollars-per-ton transportation rate. For subbituminous coals, $0.10 per million Btu (2000 dollars) is assumed to be, on average, representative of the added difficulty of using subbituminous coal.[30] These difficulties include slagging/fouling problems, impacts on heat rates, and other operation costs. For subbituminous coals, the second-tier rate is simply the first-tier rate plus this adder of $0.10 per million Btu. For certain supply/demand region pairs, the second-tier rate may include both the $0.10 per million Btu adjustment as well as a geographic adder.

Domestic transportation rates in the CMM vary significantly between the same supply and demand regions for different economic sectors. This difference is explained by the following factors:

[30] $0.10/MMBtu, the estimated cost of switching to subbituminous coal, was derived by Energy Ventures Analysis, Inc., and recommended for use in the CMM as part of an Independent Expert Review of the *Annual Energy Outlook 2002*'s Powder River Basin production and transportation rates (Barbaro and Schwartz 2002).

- Both supply and demand regions may be geographically extensive, but the particular sectoral or subsectoral demands may be focused in different portions of the demand region, while the different types of coal used to meet these demands may be produced in different parts of the supply region.
- Different coal end-uses require coal supplies that must be delivered within a narrow range of particle sizes. Special loading and transportation methods must be used to control breakage for these end uses. Special handling means higher transportation rates, especially for metallurgical, industrial, and residential/commercial coals.
- Different categories of end-use consumers tend to use different size coal shipments, with different annual volumes. As with most bulk commodity transport categories, rates charged tend to vary inversely with both typical shipment size and typical annual volumes.
- Since the Staggers Rail Act of 1980, Class I railroads (defined by the Surface Transportation Board as those line haul freight railroads whose adjusted annual operating revenues for three consecutive years exceed 250 million dollars) have been free to make coal transportation contracts that differ in contract terms of service and in the sharing of capital cost between carrier and shipper. Where previously the carrier assumed the expense of providing locomotive power, rolling stock, operating labor and supplies, right-of-way maintenance, and routing and scheduling, more recent *unit train* contracts reflect the use of dedicated locomotive power, rolling stock, and labor operating trains on an invariant schedule. Often, the shipper wholly or partly finances these dedicated components of the total contract service. In such cases, the actual costs and services represented by the contract may cover no more than right-of-way maintenance, routing, and scheduling. Particular interregional routes may vary widely in the proportion of total coal carriage represented by newer cost-sharing and older tariff-based contracts.

Appendix 2.A. Detailed Mathematical Description of the Model

The CMM model is specified as a Linear Program (LP) in which the total costs of coal supply, including production, transportation, and the cost of satisfying environmental constraints, are minimized. The CMM receives production costs iteratively from the CPS pricing equation. These production costs are limited in scope to the neighborhood of the solution. The iterative relationship between the pricing equation and the LP allows non-linear supply curve information calculated in the CPS to be approximated by a linear form in the CMM. Costs of transportation from supply to demand regions are added to the production costs. The costs of limiting sulfur dioxide emissions and other pollutants for certain scenarios (in other words, mercury and carbon dioxide) can be modeled in the cost minimization LP. Based on these total costs, the model calculates the optimum pattern of supply required to satisfy demand.

Mathematical formulation

This appendix provides the user with more detail on the complex linear programming framework in the Coal Market Module. The linear program structure diagram in Figure 2.A-1 provides a revised version of the LP as it exists in the AIMMS implementation of the CMM. The diagram on pages 78 and 79 should be opened in two page layout or printed side by side. The user may want to refer back to the ***Model Rationale*** section in Chapter 2 (page 69) to understand variable definitions and the types of constraints incorporated into the DCDS linear program.

The block diagram format depicts the matrix as made up of sub-matrices or blocks of similar variables, equations, and coefficients. The first column in the diagram contains descriptions of the rows of equations in the model. The subsequent columns define sets of variables for the production and transportation of coal. Other columns are necessary to represent contracts, coal diversity constraints, and constraints on SO2, mercury, and carbon dioxide.

Contracts represent binding agreements between coal suppliers and generators. Coal diversity constraints represent technical constraints limiting the use of certain types of coal within particular plant types in certain demand regions. These constraints are currently limited to the use of subbituminous and lignite coals. Environmental constraints represent caps that may be present in certain scenarios. The columns referencing activated carbon define certain specialized activities in which activated carbon may be used by power generators to reduce emissions of mercury. The activated carbon features are only used in scenarios where a mercury regulation is in place, such as when modeling the effects of the Mercury Air Toxics Standard (MATS).

The various rows of the matrix include the objective function, demand, production, contracts, diversity, sulfur, mercury, carbon, and activated carbon rows. The objective function row, which is considered a free row, is set up as a linear programming cost minimization problem. Other free rows, used to collect information from the model solution, are present in the LP structure but are not depicted in the diagram below. The diagram no longer contains the Fortran Mask coding, but instead it contains the identifiers used in the AIMMS version. In some instances, the indexes (or sets) are included with the variable or constraint identifiers, but in most instances the indexes have been omitted. The diagram also includes the corresponding equation numbers with detailed descriptions from pages 82 to 87. The column labeled *Row Type* shows the equations to be maximums, minimums, or equalities. Each block within the table is shown with representative coefficients for that block. These coefficients are applied to the quantities (typically in trillion Btu) specified by their column intersections. The last column labeled *RHS* contains symbols that represent physical limitations such as supply capacities, demands, or minimum flows.

The version of the CMM currently in use has been built in the AIMMS program structure. Figure 2.A-2 lists the AIMMS variable identifier names with their indices (in other words, sets) in parenthesis (), and Figure 2.A-3 similarly lists the model constraints. These tables also contain the variables and constraints used in the DCDS formulation discussed in this appendix and those discussed in Appendix 3.A for the International Coal Distribution Submodule (ICDS).

The mathematical formulations in this document were prepared as descriptions for the original coding of the Coal Market Model (CMM) in Fortran. With the movement of the CMM code to the AIMMS platform, we have attempted to add AIMMS variable names in brown text with brackets {AIMMS variable} as a helpful reference for future users of the coal model.

Figure 2.A-1. DCDS linear program structure diagram

Domestic Coal Distribution Submodule Block Diagram

		Equation	PRODUCTION		TRANSPORTATION VECTORS: 1ST TIER				TRANSPORTATION VECTORS: 1ST TIER W/ ACTIV CARBON						
	Dcoumentaion Varriable		$Qp_{i,r,s,t,u}$		$Q1_{ti,j,p,r,t,u,v=1}$				$Q1_{ti,j,p,r,t,u,v=2}$				$UI_{i,j,m,t,v,z}$		
	AIMMS Identifier		ProductionVolumeSteps (SReg,Sulf,Mtyp,Rank,Scrv1Step,cyr)	ProductionVolume	ElectricityTransportAC (nsteps=1,SReg,Sulf,Mtyp,Rank, DReg,pt2,cyr)				ElectricityTransportAC (nsteps=2,SReg,Sulf,Mtyp,Rank, DReg,pt2,cyr)				ImportsElectricity	ImportsIndustrial	ImportsCoking
COAL RANK					BIT	SUB	LIG	OTHER	BIT	SUB	LIG	OTHER	BIT		Premium
Coal Rank (AIMMS)					1B	2S	3L	5G	1B	2S	3L	5G	1B		4P
SECTOR					ELEC.	ELEC.	ELEC.	ELEC.	ELEC.	ELEC.	ELEC.	ELEC.	ELEC.	IND	Coke
Objective	ObjTotalCost	(2.A-1)	+P		$+t_{E1}$	$+t_{E1}$	$+t_{E1}$	$+t_{E1}$	$+t_{E1+AC}$	$+t_{E1+AC}$	$+t_{E1+AC}$	$+t_{E1+AC}$	$+t_{Eitc}$	$+t_{Citc}$	$+t_{Eitc}$
Demand:															
Demand Requirements: Electricty	DomesticElectricityDemandRequirement	(2.A-4)			+1	+1	+1	+1	+1	+1	+1	+1	+1		
Industrial	IndustrialDemandRequirement	(2.A-4)												+1	
Coking Sector	CokingDemandRequirement	(2.A-4)													+1
Residential/Commercial	ResidentialDemandRequirement	(2.A-4)													
Coal to Liquids	LiquidsDemandRequirement	(2.A-4)													
Contracts:															
Concracted Minimums	ContractsScrubbed	(2.A-5)													
	ContractsUnscrubbed	(2.A-5)													
Supply Balance	ProductionTransportBalance	(2.A-2)		-1	+1	+1	+1	+1	+1	+1	+1	+1			
	SupplyCurveStepBalance	(2.A-2)	+1	-1											
Productive Capacity	ProductionCapacityLimit	(2.A-3)	+1												
Diversity Rows:															
Subbituminous:	SubbituminousDiversity	(2.A-6)				+1				+1					
Lignite:	LigniteDiversity	(2.A-6)					+1				+1				
Elec Tier Balance	MakeSureSecondTierGetsFirstTierPrice				+1	+1	+1	+1	+1	+1	+1	+1			
	BalanceScrubUnscrubTier1				-1	-1	-1	-1	-1	-1	-1	-1			
	BalanceScrubUnscrubTier2														
Transportation Rate Tier Limit	TransportationBoundUnScrubbed	(2.A-7)													
	TransportationBoundScrubbed	(2.A-7)													
Sulfur Dioxide	SulfpenConstraint (indexed by 1 and 2)	(2.A-9)			+s	+s	+s	+s	+s	+s	+s	+s	+s		
	SULFPNConstraint	(2.A-8)													
	MVSO2	(2.A-10)													
	SulfurVariability														
Mercury: MERCP01	Mercp02	(2.A-11)			+m*mef	+m*mef	+m*mef	+m*mef	+m*mef	+m*mef	+m*mef	+m*mef	+m*mef		
Activated Carbon	Acixxxxy2	(2.A-12)							+a	+a	+a	+a	+a		
Carbon Constraint	Carbonxx	(2.A-13)			+c	+c	+c	+c	+c	+c	+c	+c	+c		

Inactive variables and constraints

AIMMS Identifier	
Qdutzr	D_E = coal demand for electricity sector
IndustrialDemand	D_I = coal demand for industrial sector - steam coal
CokingDemand	D_C = coal demand for coking plants - metalurgical coal
ResidCommDemand	D_R = coal demand for residential, commercial, and institutional - steam coal
LiquidDemand	D_L = coal demand for coal to liquids
Trate1Ind	t_{I0} = Transportation cost rate w/ surcharge - industrial sector *
Trate1Coke	t_{C0} = Transportation cost rate w/ surcharge - coking sector *
Trate1Resid	t_{R0} = Transportation cost rate w/ surcharge - residential, commercial, institutional sector *
Trate1Liqu	t_{L0} = Transportation cost rate w/ surcharge - coal to liquid fuels *
Trate1Exp	t_{X0} = Transportation cost rate w/ surcharge - coal exports from US *
Trate2wSurchBtu	t_{E1} = Transportation cost rate - electric power 1st tier w/surcharge *
Trate2wSurchBtu	t_{E1+AC} = Transportation cost rate - electric power 1st tier w/Surcharge plus cost of activated carbon
tier2_adj	t_{E2} = Incremental cost rate of 2nd tier transportation cost above 1st Tier - electric power
InlandImportTranspRateBtu('E',nUS	t_{Eitc} = Inland transport cost w/o surcharge - electricity sector imported coal
InlandImportTranspRateBtu('I',nUS	t_{Iitc} = Inland transport cost w/o surcharge - industrial sector imported coal
InlandImportTranspRateBtu('C',nUS	t_{Citc} = Inland transport cost w/o surcharge - coking sector imported coal
Copy_emm_mef	mef = mercury emmissions factor by plant type

* Note: t1 rate also includes East/West cost escalators.

Figure 2.A-2. DCDS linear program structure (continued from opposite page)

Domestic Coal Distribution Submodule Block Diagram (cont)

TRANSPORTATION VECTORS							2ND TIER			CONTRACT ESCAPE VECTORS		CAIR SULFUR REGIONAL TRANSFER		CSAPR SULFUR REGIONAL TRANSFER			Mercury Escape vector	ACTIV. CARBON VECTOR	CARBON EMISSION VECTOR	Row Type	RHS
		$Q0_{ti,j,k,r,t,u}$					$Q2_{ti,j,k,r,t,u}$			SCRUBBED	UNSCRUB.						H	A_v	C		
ElectricityTransportUnscrubbed	ElectricityTransportScrubbed	LiquidsTransport	IndustrialTransport	CokingTransport	ResidentialTransport	ExportsTransport2	ElectricityTransport2Unscrubbed	ElectricityTransport2Scrubbed	ElectricityTransport2	ContractEscape1	ContractEscape2	MVso2outCAIR12	MVso2outCAIR21	MVso2out	MVslr	EscapeProductiveCapacity	Mercev	acixss1y	carbonx		
				Premium																	
				4P																	
ELEC.	ELEC.	CTL	IND	Coke	R/C	EXP	2ND TIER ELEC.			ELEC.	ELEC.	ELEC.	ELEC.	ELEC.	ELEC.		ELEC.	ELEC.	ELEC.		
		$+t_{L0}$	$+t_{I0}$	$+t_{C0}$	$+t_{R0}$	$+t_{x0}$	$+t_{E2}$	$+t_{E2}$		+999	+999					+999		+v	+EMETAX	--	MIN
																				EQ	D_E
			+1																	EQ	D_I
				+1																EQ	D_C
					+1															EQ	D_R
		+1																		EQ	D_L
	+1									-1										GE	B_1
+1											-1									GE	B_2
		+1	+1	+1	+1	+1														EQ	0
																				EQ	0
																-1				LE	PCAP
																				LE	B_3
																				LE	B_4
									-1											LE	0
+1	+1																			EQ	0
							+1	+1	-1											EQ	0
+1							-1													LE	T_{UnS}
	+1							-1												LE	T_{SCB}
												$+st_{12}$	$-st_{21}$							LE	S
+s														-1	+1					LE	S_r
															1					LE	S_{trade}
														+1	-1					EQ	0
																	-1			LE	M
																		-10		LE	0
																			-1	EQ	0

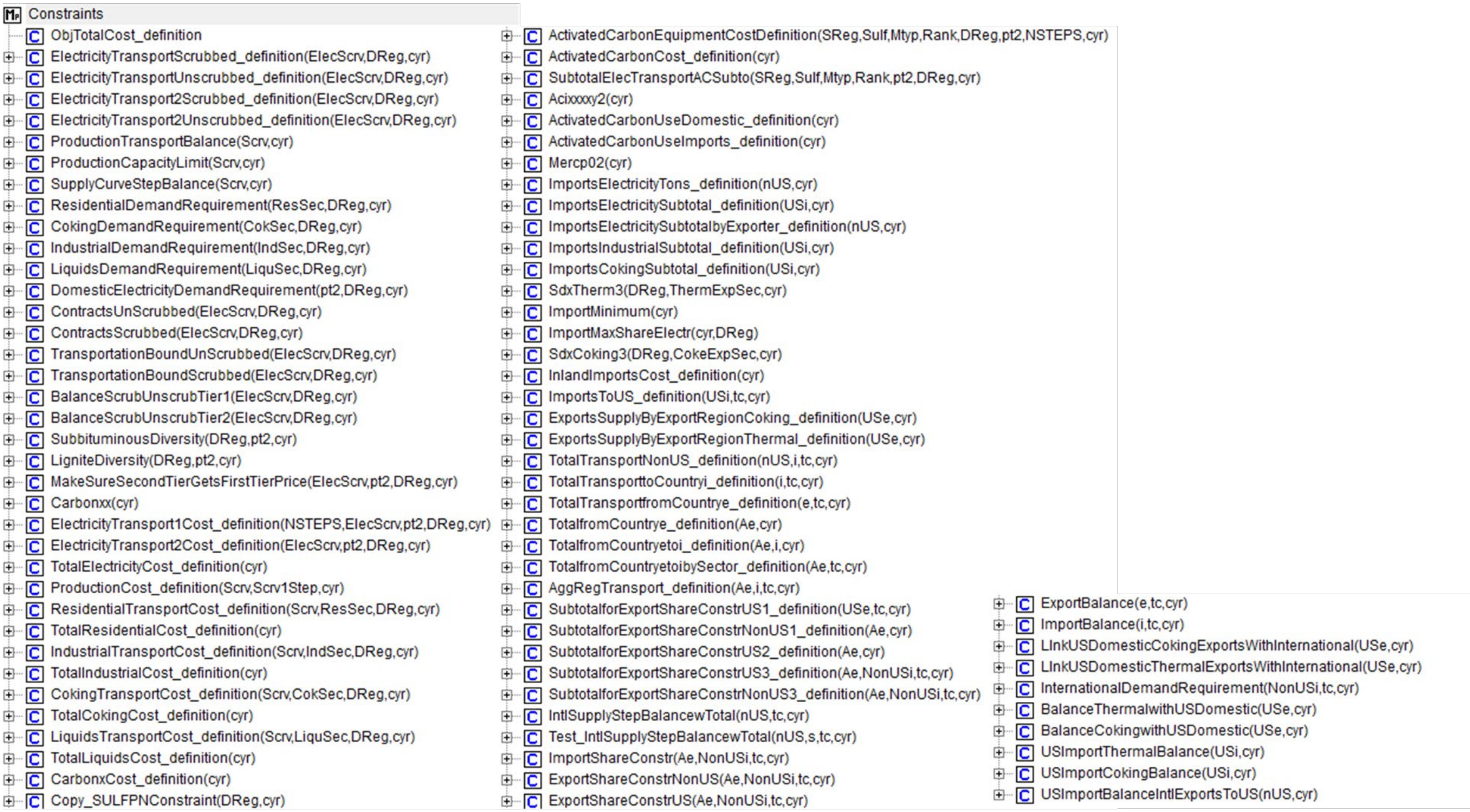
Inactive variables and constraints

AIMMS Identifier	
aci_qac	a = tons of activated carbon per trillion btu (by coal rank and plant type)
SC_2_PRICE87	P = production price by supply curve step $P_{i,r,s,t,u}$
FY_PROD_CAP3	PCAP = Productive capacity limit for supply curve
Sulfur2	s = SO2 content lbs per Million Btu (by coal supply region)
so2_shr_alw_grp12	st_{12} = relative value of trading SO2 allowances btw group 1 and group 2
so2_shr_alw_grp21	st_{21} = relative value of trading SO2 allowances btw group 2 and group 1
Copy8c_CdyrsScrubbed	B_1 = scrubbed contracts for electricity sector
Copy9c_CdyrsUnscrubbed	B_2 = unscrubbed contracts for electricity sector
Sdvconct	B_3 = subbitumous coal bound
Ldvconct	B_4 = lignite coal bound
emrfsa	S = SO2 emissinons limits
Tso2_lim_by_clrg	S_r = Regional SO2 limits to approximate Cross State Air Pollution Rule
Tso2_vr4_by_clrg	S_{trade} = sulfur trade limits between coal regions
EMEL_QHG	M = mercury cap (lbs of mercury)
coalemm_p_ac_sc	v = dollars per lb of activated carbon
carbon	c = carbon content (lbs CO2/million Btu)
Mercury2, InternationalMercuryU	m = mercury content (lbs per Trillion Btu)
EMISSION_EMETAX ('1')	EMETAX = tax on carbon emissions

Figure 2.A-2. AIMMS linear program variables

- Variables
  - ObjTotalCost
  - ProductionVolume(Scrv,cyr)
  - ProductionVolumeSteps(SReg,Sulf,Mtyp,Rank,Scrv1Step,cyr)
  - ResidentialTransport(SReg,Sulf,Mtyp,Rank,ResSec,DReg,cyr)
  - IndustrialTransport(SReg,Sulf,Mtyp,Rank,IndSec,DReg,cyr)
  - CokingTransport(SReg,Sulf,Mtyp,Rank,CokSec,DReg,cyr)
  - LiquidsTransport(SReg,Sulf,Mtyp,Rank,LiquSec,DReg,cyr)
  - ExportsTransport2(Scrv,ExpSec,USe,DReg,cyr)
  - ElectricityTransportScrubbed(ElecScrv,DReg,cyr)
  - ElectricityTransport2(ElecScrv,pt2,DReg,cyr)
  - ElectricityTransportUnscrubbed(ElecScrv,DReg,cyr)
  - ElectricityTransport2Scrubbed(ElecScrv,DReg,cyr)
  - ElectricityTransport2Unscrubbed(ElecScrv,DReg,cyr)
  - ElectricityTransport1Cost(NSTEPS,ElecScrv,pt2,DReg,cyr)
  - ElectricityTransport2Cost(ElecScrv,pt2,DReg,cyr)
  - TotalElectricityCost(cyr)
  - ProductionCost(Scrv,Scrv1Step,cyr)
  - ResidentialTransportCost(Scrv,ResSec,DReg,cyr)
  - TotalResidentialCost(cyr)
  - IndustrialTransportCost(Scrv,IndSec,DReg,cyr)
  - TotalIndustrialCost(cyr)
  - CokingTransportCost(Scrv,CokSec,DReg,cyr)
  - TotalCokingCost(cyr)
  - LiquidsTransportCost(Scrv,LiquSec,DReg,cyr)
  - TotalLiquidsCost(cyr)
  - ExportsTransportCost(Scrv,ExpSec,USe,DReg,cyr)
  - ContractEscape1(ElecScrv,DReg,cyr)
  - ContractEscape2(ElecScrv,DReg,cyr)
  - CarbonxCost(cyr)
  - Carbonx(cyr)
  - MVso2outCAIR12(cyr)
  - MVso2outCAIR21(cyr)
  - ActivatedCarbonEquipmentCost(SReg,Sulf,Mtyp,Rank,DReg,pt2,NSTEPS,cyr)
  - ElectricityTransportAC(NSTEPS,SReg,Sulf,Mtyp,Rank,DReg,pt2,cyr)
  - ElectricityTransportACSubtotal(SReg,Sulf,Mtyp,Rank,pt2,DReg,cyr)
  - ActivatedCarbonCost(cyr)
  - Mercev
  - acixss1y(cyr)
  - ActivatedCarbonUseDomestic(cyr)
  - ActivatedCarbonUseImports(cyr)
  - ImportsElectricity(NSTEPS,nUS,USi,DReg,pt2,cyr)
  - ImportsElectricityTons(nUS,cyr)
  - ImportsIndustrial(IndSec,DReg,nUS,USi,cyr)
  - ImportsCoking(CokSec,DReg,nUS,USi,cyr)
  - ImportsElectricitySubtotal(USi,cyr)
  - ImportsElectricitySubtotalbyExporter(nUS,cyr)
  - ImportsIndustrialSubtotal(USi,cyr)
  - ImportsCokingSubtotal(USi,cyr)
  - UxThermal(DReg,ThermExpSec,USe,cyr)
  - UxCoking(DReg,CokeExpSec,USe,cyr)
  - InlandImportsCost(cyr)
  - ImportsToUS(USi,tc,cyr)
  - ExportsSupplyByExportRegionCoking(USe,cyr)
  - ExportsSupplyByExportRegionThermal(USe,cyr)
  - Transport(nUS,i,s,tc,cyr)
  - ExpSupply(nUS,s,tc,cyr)
  - TotalTransportNonUS(nUS,i,tc,cyr)
  - TotalTransportUS(USe,NonUSi,tc,cyr)
  - TotalTransporttoCountryi(i,tc,cyr)
  - TotalTransportfromCountrye(e,tc,cyr)
  - TotalfromCountrye(Ae,cyr)
  - TotalfromCountryetoi(Ae,i,cyr)
  - TotalfromCountryetoibySector(Ae,tc,cyr)
  - AggRegTransport(Ae,i,tc,cyr)
  - SubtotalforExportShareConstrUS1(USe,tc,cyr)
  - SubtotalforExportShareConstrNonUS1(Ae,cyr)
  - SubtotalforExportShareConstrUS2(Ae,cyr)
  - SubtotalforExportShareConstrUS3(Ae,NonUSi,tc,cyr)
  - SubtotalforExportShareConstrNonUS3(Ae,NonUSi,tc,cyr)

Figure 2.A-2. AIMMS linear program constraints



Objective function

The objective function shown in equation 2.A-1 is a simplification of the LP used to minimize delivered costs of transporting coal from supply regions to demand regions. The objective function below defines the costs being minimized by the CMM. The costs include production, transportation, activated carbon (mercury scenarios), costs associated with a mercury cap (specific mercury scenarios), carbon (carbon scenarios), and escape vector. The transport solution for the individual demand sectors may be subject to different constraints, but all coal transport costs are generally in the form of *Quantity Transported * Price of Transportation*.

Activated carbon costs are relevant in mercury scenarios where activated carbon is injected during the coal combustion process in order to achieve various levels of mercury emissions reduction. In certain scenarios where a mercury allowance price is constrained, a mercury cap cost is included in the LP objective function. The presence of a volume in the mercury cap cost column indicates that the allowance price calculated by the coal LP is higher than the mercury cap. The cost associated with carbon emissions is relevant only in carbon scenarios. This cost is included in the objective function to allow the coal model's regional distributions to be influenced when carbon limits are present.

Escape vectors are a mechanism to allow the model to ignore a constraint by paying a large penalty. Escape vectors are a useful tool in identifying errors in assumptions or conflicting constraints and do not represent the true cost associated with coal deliveries. Iteratively, the escape vectors assist in gently pushing the model towards a feasible solution. When a feasible solution is obtained, the escape vectors are no longer active.

The objective function is defined as follows:

$$\Sigma_{i,r,t,u,s}\,[Qp_{i,r,s,t,u} * P_{i,r,s,t,u}] + \Sigma_{i,j,p,r,t,u,v}\,[Q1t_{\,i,j,p,r,t,u,v} * T_{i,j,p,r,t,u,v}] + \Sigma_{i,j,k,p,r,t,u}\,[Q2t_{\,i,j,k,r,t,u} * T_{i,j,k,r,t,u}] + \Sigma_{i,j,k,r,t,u}\,[Q0t_{\,i,j,k,r,t,u} * T_{i,j,k,r,t,u}] + \Sigma_{v}\,[A_v * x_v] + [H * y] + [C * z] + [SK * 10] + \text{escape vector costs} \qquad (2.A\text{-}1)$$

where the indexes are defined as follows:

Index Definitions

Index Symbol	Description
(h)	Coal supply region groups (Appalachia, Interior, West)
(i)	Coal supply region {Sreg}
(j)	Coal demand region {Dreg}
(k)	Demand subsector {SubSec}
(p)	Plant configuration (index p is a subset of index k) {pt2}
(r)	Coal rank {Rank}
(s)	Supply curve step {Scrv1Step}
(t)	Mine type {Mtyp}
(u)	Sulfur level {Sulf}
(v)	Activated carbon supply curve step {nsteps}
(w)	Scrubbed/unscrubbed by electricity plant type (p) (See Table 2.5 SO2 control column) {ecp_scrub_Scrubbed}

where the columns are defined as follows:

Column definitions

Column Notation	Description
$Qp_{i,r,s,t,u}$	Quantity of coal from step s of the supply curve produced from coal supply region i, of sulfur level u, mine type t, and rank r. Block Diagram Column: {ProductionVolumeSteps}
$Q1t_{i,j,p,r,t,u,v}$	Total quantity of coal transported from all steps of coal supply region i to coal demand region j, of sulfur level u, rank r, and mine type t, for the electricity plant type p, and activated carbon step v (if relevant to scenario). This quantity is moving at the adjusted Tier 1 rate for the electricity sector. Block Diagram Columns: {ElectricityTransportAC}
$Q2t_{i,j,k,r,t,u}$	Total quantity of coal transported at second-tier transportation rate from all steps of coal supply region i to coal demand region j, of sulfur level u, rank r, and mine type t, for the demand subsector k for the electricity sector. This quantity is moving at the adjusted Tier 2 rate for the electricity sector. Block Diagram Columns: {ElectricityTransport2Unscrubbed, ElectricityTransport2Scrubbed, ElectricityTransport2}
$Q0t_{i,j,k,r,t,u}$	Total quantity of coal transported from all steps of coal supply region i to coal demand region j, of sulfur level u, rank r, and mine type t, for the demand subsector k for the non-electricity sectors. This quantity is moving at the adjusted rate for the non-electricity sector. Block Diagram Columns: {ResidentialTransport, IndustrialTransport, CokingTransport, ExportsTransport2, LiquidsTransport}
A_v	Total quantity of activated carbon from activated carbon supply curve step v. Block Diagram Column: {acixss1y}
H	Quantity of mercury getting mercury cap price (only relevant for specific mercury scenarios) Block Diagram Column: {Mercev}
C	Quantity of carbon emitted from coal Block Diagram Column: {Carbonx}
SK	Volume of coal inventory changes in the Appalachia, Interior, and West region groups, for STEO years only. {AppalachiaStocks, InteriorStocks, WestStocks }

And the incremental costs assigned to the column vectors are defined as:

P	=	Production or minemouth price {SC_2_PRICE87}
T	=	Transportation price (plus cost of activated carbon, if relevant to scenario) {Trate1Resid, Trate1Ind, Trate1Coke, Trate1Liqu, Trate1Exp, tier2adj}
x	=	Cost of activated carbon {COALEMM_P_AC_SC}
y	=	Mercury allowance price cap {EMEL_QHG}
z	=	Carbon tax {EMISSION_EMETAX}

The escape vector costs correspond to the costs associated with the columns: {ContractEscape1}, {ContractEscape2 }, and {EscapeProductiveCapacity }. These costs are high so that they are chosen only as a last resort in order to keep the model feasible. By assisting in maintaining feasibility in early model runs, the linear supply curves can be moved along the supply functions in search of an optimal, minimum cost solution that is feasible without the escape vectors.

Row constraints

The rows interact with the columns present in the objective function to define the feasible region of the LP and are defined below.

SUPPLY BALANCE

EQUATIONS: For specific i,r,t, and u: $\Sigma_{j,k,v}\ Qt_{i,j,k,r,t,u,v} - \Sigma_s Qp_{i,r,s,t,u} = 0$ (2.A-2)

DEFINITION: Balance the coal produced from each supply region with the coal transported.

CORRESPONDING ROW IN BLOCK DIAGRAM: Supply Balance {ProductionTransportBalance, SupplyCurveStepBalance}

PRODUCTIVE CAPACITY LIMIT

CONSTRAINTS: For specific i,r,t, and u: $\Sigma_s Qp_{i,r,s,t,u} \leq PCAP_{i,r,t,u}$ (2.A-3)

DEFINITION: Prevents coal production by supply curve from exceeding its productive capacity limit (PCAP).

CORRESPONDING ROW IN BLOCK DIAGRAM: Production Capacity {ProductionCapacityLimit}

DEMAND BALANCE

EQUATIONS: For specific j and k: $\Sigma_{i,r,t,u,v} Qt_{i,j,k,r,t,u,v} = D_{j,k}$ (2.A-4)

DEFINITION: Balance the coal transported with the coal demanded by coal demand region and subsector.

CORRESPONDING ROWS IN BLOCK DIAGRAM: **Demand** {DomesticElectricityDemandRequirement}, {IndustrialDemandRequirement, CokingDemandRequirement, ResidentialDemandRequirement, LiquidsDemandRequirement}

CONTRACT FLOWS

CONSTRAINTS:

For specific i, j, r, t, u: $\Sigma_{p,v,w}Qt_{i,j,p,r,t,u,v,w}$ – escape vector quantity $\geq B_{i,j,r,t,u,w}$, (2.A-5)

where *B* equals contract quantity and *w* indicates whether plant type p is scrubbed or unscrubbed.

DEFINITION: Require minimum quantities of coal, *B*, of a specific coal quality from particular supply regions to satisfy electricity contracts from particular demand regions for scrubbed and unscrubbed plants.

CORRESPONDING ROWS IN BLOCK DIAGRAM: Contract Minimums {ContractsScrubbed} and {ContractsUnscrubbed)

DIVERSITY REQUIREMENTS

CONSTRAINTS:

For a specific j, p, and r (subbituminous or lignite only), where *B* equals subbituminous or lignite coal limit: $\Sigma_{i,t,u,}\ Qt_{i,j,p,r,t,u} \leq B_{j,p,r}$ (2.A-6)

DEFINITION: Limits the amount of subbituminous and lignite coal used to satisfy demand in certain electricity demand subsectors and regions.

CORRESPONDING ROWS IN BLOCK DIAGRAM: (SubbituminousDiversity} and {LigniteDiversity}

TRANSPORTATION RATE RESTRICTIONS

CONSTRAINTS: $\Sigma_p(Qt_{i,j,p,r,t,u} - Qt2_{i,j,p,r,t,u}) \leq T_{i,j,r,t,u}$ (2.A-7)

DEFINITION: Limits the amount of coal that may be transported at rates applicable to historical flow levels for the electricity sector for a specific i, j, p, r, u, and t, where *T* is the amount of coal capable of being transported at the current rates (first-tier rates). Additional transportation flows are assumed to require additional cost (second-tier rates) in order to expand coal deliveries in these regions.

CORRESPONDING ROW IN BLOCK DIAGRAM: (TransportationBoundUnsrubbed, TransportationBoundScrubbed}

SULFUR DIOXIDE EMISSION RESTRICTIONS CONSTRAINTS:

sulfur dioxide emissions from imports $+ \Sigma_{i,j,p,r,t,u}\ [s_{i,r,t,u} * Qt_{i,j,p,r,t,u}] \leq S$ (2.A-8)

DEFINITION: For relevant years, restrict the sulfur levels of coal in the electricity sector such that the sulfur dioxide emissions limit is met, where *s* equals the sulfur dioxide content of the coal and *S* equals the emissions limit. For more detail on sulfur dioxide emissions from imports, see "3. International Coal Distribution Submodule"

CORRESPONDING ROW IN BLOCK DIAGRAM: {CAIR constraint: SulfpenConstraint (indexed by 1 and 2)

SULFUR DIOXIDE EMISSION REGIONAL LIMITS CONSTRAINTS (for CSAPR):

sulfur dioxide emissions from imports $+ \Sigma_{i,j,p,r,t,u}$ $[s_{i,r,t,u} * Qt_{i,j,p,r,t,u}]$ -/+ $MVS(DR1)(DR2) \leq Sr$ (2.A-9)

DEFINITION: For relevant years, restrict the sulfur levels of coal in the electricity sector such that the sulfur dioxide emissions limit is met regionally, where *s* equals the sulfur dioxide content of the coal and *Sr* equals the regional emissions limit. A negative MVSO2(DR1)(DR2) represents the amount of sulfur dioxide emissions produced in demand region 1 (DR1) that can be credited to demand region 2 (DR2). A positive MVSO2(DR1)(DR2) represents the amount of sulfur dioxide emissions that, though produced in demand region 2 (DR2), can be credited to DEMAND region 1 (DR1).

Active for CSAPR, when {mx_so2}=1

CORRESPONDING ROW IN BLOCK DIAGRAM: {SULFPNConstraint, MVso2out, Mvsin}

SULFUR DIOXIDE REGIONAL TRADE (for CSAPR)

sulfur dioxide emissions from imports $+ \Sigma_{i,j,p,r,t,u}$ $[s_{i,r,t,u} * Qt_{i,j,p,r,t,u}] \leq$ Strade (2.A-10)

DEFINITION: For relevant years, restrict the trade of sulfur allowances, where *s trade* equals the maximum amount of sulfur dioxide emissions that can be credited to a different region other than where the emissions were produced.

CORRESPONDING ROW IN BLOCK DIAGRAM: {CASPR constraint: MVSO2}

MERCURY EMISSION RESTRICTIONS CONSTRAINTS:

$\Sigma_{i,j,k,r,t,u}$ $[m_{i,r,t,u} * Qt_{i,j,k,r,t,u}] - H -$ escape vector quantity $\leq M$ (2.A-11)

DEFINITION: Limits the quantity of mercury present in coal (adjusted with the plant removal rate and use of activated carbon) to be less than or equal to the coal mercury emissions limit, *M*. Coefficient $m_{i,r,t,u}$ is the mercury content of coal. Some mercury scenarios cap the compliance costs. In these scenarios, additional *allowances* are available at the allowance cap. *H* is the volume of additional allowances purchased at the cap price. Escape vectors are not active in the final solution but allow feasibility to be maintained in early iterations.

CORRESPONDING ROW IN BLOCK DIAGRAM: {Mercp02}

ACTIVATED CARBON SUPPLY CURVE CONSTRAINTS:

$\Sigma_{i,j,p,r,t,u,v}$ $[a_{p,v} * Qt_{i,j,p,r,t,u,v}] - 10 * \Sigma_v A_v \leq 0$ (2.A-12)

DEFINITION: Balances the activated carbon used in association with the electricity sector transportation vectors with the activated carbon supply curves. Coefficient $a_{p,v}$ represents tons of activated carbon per trillion Btu for plant configuration p and activated supply curve step v. A_v represents the total quantity of activated carbon from activated carbon supply curve step v.

CORRESPONDING ROW IN BLOCK DIAGRAM: {Acixxxxy2}

CARBON TAX CONSTRAINTS:

$\Sigma_{i,j,p,r,t,u}$ $[c_{i,j,p,r,t,u} * Qt_{i,j,p,r,t,u}] - C \leq 0$ (2.A-13)

DEFINITION: Balances the carbon emissions, *C*, associated with the electricity sector transportation vectors with the carbon emissions being *paid for* with the carbon penalty price. The coefficient $c_{i,j,p,r,t,u}$ represents the carbon content of coal.

CORRESPONDING ROW IN BLOCK DIAGRAM: {Carbonxx}

STEO CONSTRAINTS PRODUCTION

EQUATIONS: For regional production groups h,r,t, and u: $L_h \leq \Sigma_s Qp_{h,r,s,t,u} \leq U_h$ (2.A-14)

DEFINITION: Constrain the coal produced by supply group to be within tolerance intervals of production targets set from *Short-Term Energy Outlook*. Only active in the (STEO) early projection years.

NOT IN BLOCK DIAGRAM: {STEOAppalachiaLower, STEOAppalachiaUpper, STEOInteriorLower, STEOInteriorUpper, STEOWestLower, STEOWestUpper}

Where

L_h	Lower bound for *Short-Term Energy Outlook* (STEO) regional production {STEOAppalachiaLower, STEOInteriorLower, STEOWestLower }
U_h	Upper bound for *Short-Term Energy Outlook* (STEO) regional production {STEOAppalachiaUpper, STEOInteriorUpper, STEOWestUpper}

STEO CONSTRAINTS DEMAND

EQUATIONS: For specific sector d: $L_d \leq \Sigma_{i,r,t,u,} Qt_{i,j,k,r,t,u,v} \leq U_d$ (2.A-15)

DEFINITION: Balance the coal transported to each sector with the coal demanded in the national STEO target for the year. Only active in the (STEO) early projection years.

NOT IN BLOCK DIAGRAM: {STEOElecTonsLower, STEOElecTonsUpper, STEOCokeTonsStocks, STEOIndustrialTonsStocks, STEOWasteCoalLower, STEOWasteCoalLower, ElecPriceSTEO }

Where

DT_d	STEO Demand target by Sector {ElecTonsSTEO, WasteCoalSTEO, CokeTonsSTEO, IndustrialTonsSTEO,CokingExpSTEO, SteamExpSTEO, ElecPriceSTEO}

$L_d = DT_d$ *(1- Tolerance)*SideTolerance Lower bound for STEO demand by Sector d

$U_d = DT_d$ *(1+ Tolerance)*SideTolerance Upper bound for STEO demand by Sector d

ELECTRICITY TIER 1 UNSCRUBBED AND SCRUBBED BALANCE

EQUATIONS: For electricity plants using Tier 1 rates $\Sigma_{i,j,p,r,t,u,w,} Q1t_{i,j,p,r,t,u,v,w} = Q1t_{i,j,p,r,t,u,v}$ (2.A-16)

DEFINITION: Balance the coal transported at the Tier 1 rate for scrubbed and unscrubbed (w).

CORRESPONDING ROW IN BLOCK DIAGRAM: {BalanceScrubUnscrubTier1}

Output Variables

$X_{i,j,k,r,t,u,v}$ = Quantity of coal rank r, sulfur level u, and mine type t that is transported from coal supply region i to coal import region j for coal demand subsector k and activated carbon step v (if relevant to the scenario).

k=1 {ResidentialTransportTrills}
k=2 {IndustrialTransportTrills}
k=3 {CokingTransportTrills}
k=4 {LiquidsTransportTrills}
k=5 {ExportsTransportTrills2a}
k=6 {ElectricityACTrills}

$U_{j,k,t}$= Finalized (solution) delivered price (minemouth plus transportation cost) of coal from mine type t to demand sector k in demand region j. This variable is the final optimized value from the DCDS. (note: the model solves by coal demand regions but delivered prices are passed out to the other models via the restart file in U.S. Census regions. See Table 2.A-1 for available price and quantity parameters in AIMMS.)

Table 2.A-1. Solution results and output parameters for the domestic coal distribution submodule

AIMMS parameter	Description	Restart file variable
Price	Solution price of coal by supply area (1987$)	
MPBLK_PCLCM_D	Coal volume transported to Residential & Commercial sector by coal demand region (TBtu)	
MPBLK_PCLIN_D	Coal volume transported to Industrial sector by coal demand region (TBtu)	
MPBLK_PMCIN_D	Coal volume transported to Coking sector by coal demand region (TBtu)	
MPBLK_PCLSN_D	Coal volume transported to CTL sector by coal demand region (TBtu)	
MPBLK_PCLEL_D	Coal volume transported to Electricity sector by coal demand region (TBtu)	
MPBLK_PCLCM_C	Residential and Commercial sector solution mine cost plus transport cost by coal demand region (1987$)	
MPBLK_PCLIN_C	Industrial sector solution mine cost plus transport cost by coal demand region (1987$)	
MPBLK_PMCIN_C	Coking sector mine solution cost plus transport cost by coal demand region (1987$)	
MPBLK_PCLSN_C	Liquids (CTL) sector solution mine cost plus transport cost by coal demand region (1987$)	
MPBLK_PCLEL_C	Electricity sector solution mine cost plus transport cost by coal demand region (1987$)	
MPBLK_PCLCM_A	Commercial sector coal price by census region (1987$/MMBtu)	MPBLK PCLCM
MPBLK_PCLIN_A	Industrial sector coal price by census region (1987$/MMBtu)	MPBLK PCLIN
MPBLK_PMCIN_A	Metallurgical/coking sector coal price by census region (1987$/MMBtu)	MPBLK PMCIN
MPBLK_PCLSN_A	CTL sectore coal price by census region (1987$/MMBtu)	MPBLK PCLSN
MPBLK_PCLEL_A	Electricity sector coal price by census region (1987$/MMBtu)	MPBLK PCLEL
COALOUT_CQDBFT	Coal conversion factor for consumption by sector and census region	COALOUT CQDBFT
COALOUT_CPDBFT	Coal conversion factor for prices by sector and census region	COALOUT CPDBFT

Table 2.B-1. Row and column structure for the domestic component of the Coal Market Module

Identifier in diagram	Row or column	Activity represented
{acixss1y}	Column	Volume of activated carbon (in lbs.) injected to reduce mercury emissions; column bounds on this vector are present specifying how much activated carbon is available at each step.
{Acixxxxy2}	Row	Assigns activated carbon requirement (lbs. of activated carbon per trillion Btu) for each activated carbon step in transportation column.
{ElectricityTransportAC}	Column	Volume of coal transported in association with the use of activated carbon for particular activated carbon supply curve step {nsteps}, from supply region {Sreg}, sulfur level {Sulf}, mine type {Mtyp}, to demand region {Dreg} for plant type {SubSec} of coal type {Rank}.
ElectricityTransportAC}	Column	Transportation at first-tier rate for electricity sector from supply region {Sreg}, sulfur level {Sulf}, mine type {Mtyp}, coal rank {Rank} to demand region {Dreg} for plant type {SubSec} of coal type {Rank}.
{EscapeUnscrubTransportationBound}	Column	Escape vector allowing contracts to be ignored for supply region {Sreg} to demand region {Dreg} of coal type {Rank} for the unscrubbed electricity subsectors, if infeasibility is encountered. Not active in final solution.
{ContractsUnscrubbed)	Row	Contract constraint from supply region {Sreg} to demand region {Dreg} of coal type {Rank} for the unscrubbed electricity subsectors.
{Carbonx}	Column	Assigns carbon tax to coal in carbon scenario and influences patterns of coal use in electricity sector.
{Carbonxx}	Row	Assigns carbon content to electricity sector transportation rates.
{DomesticElectricityDemandRequirement}	Row	Electric power coal demand from demand region {Dreg} for electric plant type {SubSec}.
{IndustrialDemandRequirement, CokingDemandRequirement, ResidentialDemandRequirement, LiquidsDemandRequirement}	Row	Coal demand from demand region {Dreg} for demand subsector {SubSec}.
{LigniteEscape}	Column	Escape column vector for lignite diversity constraint for demand region {Dreg} and electricity plant type {SubSec}. Not active in final solution.
{SubbitEscape}	Column	Escape column vector for subbituminous diversity constraint for demand region {Dreg} and electricity plant type {SubSec}. Not active in final solution.
{LigniteDiversity}	Row	Coal diversity constraint for lignite coal, demand region {Dreg}, electricity subsector {SubSec}.
{SubbituminousDiversity}	Row	Coal diversity constraint for subbituminous coal, demand region {Dreg}, electricity subsector {SubSec}.

Table 2.B-1. Row and column structure for the domestic component of the Coal Market Module (cont.)

Identifier in diagram	Row or column	Activity represented
{EscapeScrubTransportationBound}	Column	Escape vector allowing contracts to be ignored for supply region {Sreg} to demand region {Dreg} of coal type {Rank} for the scrubbed electricity subsectors if infeasibility encountered. Not active in final solution.
{ContractsScrubbed}	Row	Contract constraint from supply region {Sreg} to demand region {Dreg} of coal type {Rank} for the scrubbed electricity subsectors.
{Mercev}	Column	Provides upper bound for mercury allowance price.
{Mercpo2}	Row	Mercury penalty constraint for electricity sector (mercury scenarios only).
{Morehggx}	Column	Escape vector allowing more mercury to be emitted if tight mercury constraint causes infeasibility. Not active in final solution.
{MVso2out}	Column	Specifies sulfur dioxide emissions trade from demand region 1 to demand region 2.
{MVSO2}	Row	Specifies the overall limits to trade in sulfur dioxide emissions by the destination region (where the emissions are transferred to).
{ProductionVolumeSteps}	Column	Coal production in supply region {Sreg}, sulfur level {Sulf}, mine type {Mtyp}, and step (S).
{ProductionTransportBalance}	Row	Coal production in supply region {Sreg} of sulfur level {Sulf}, mine type {Mtyp}, and coal type {Rank}.
{SulfpenConstraint}	Row	Sulfur penalty constraint for electricity sector.
{so2_shr_by_clreg}	Row	Specifies regional sulfur dioxide limit by demand region.
{ElectricityTransport2Unscrubbed, ElectricityTransport2Scrubbed}	Column	For electricity sector, the volume transported at second-tier rate (rate required to expand coal flows into this region) and, for non-electricity sectors, total transportation volume from supply region {Sreg}, sulfur level {Sulf}, mine type {Mtyp}, rank {Rank}, to demand region {Dreg}, subsector {SubSec}, of coal type {Rank}.
{ProductionCapacityLimit}	Row	Coal production capacity limit for supply region {Sreg} of sulfur level {Sulf}, mine type {Mtyp}, and coal type {Rank}.
{ResidentialTransport}	Column	For the residential, commercial, and institutional sectors, the volume transported using the rate t_{Ro}.
{IndustrialTransport}	Column	For the industrial sector, the volume transported using the rate t_{Io}. Transported volume is primarily steam coal.
{CokingTransport}	Column	For the coking sector, the volume transported using the rate t_{Co}. Transported volume is metallurgical coal used to make coke for use in blast furnaces.
{LiquidsTransport}	Column	For the coal to liquids sector, the volume transported using the rate t_{Lo}. Only active in cases with demand requirements from the LFMM.
{ExportsTransport2}	Column	For U.S. exports, the volume transported using the rate t_{Xo}. Transported volume is could be either steam or coking coal.

where

{DReg} **U.S. DEMAND REGIONS (see Figure 2.1 and Table 2.2 for states in named region)**

01NE	New England
02YP	Middle Atlantic
03S1	South Atlantic 1
04S2	South Atlantic 2
05GF	Georgia and Florida
06OH	Ohio
07EN	East North Central
08KT	Kentucky and Tennessee
09AM	Alabama and Mississippi
10C1	West North Central 1
11C2	West North Central 2
12WS	West South Central
13MT	Mountain
14CU	Colorado, Utah, and Nevada
15ZN	Arizona and New Mexico
16PC	Pacific

{SReg} **SUPPLY REGIONS**

01NA	PENNSYLVANIA, OHIO, MARYLAND, WEST VIRGINIA (NORTH)
02CA	WEST VIRGINIA (SOUTH), KENTUCKY (EAST), VIRGINIA, TENNESSEE (NORTH)
03SA	ALABAMA, TENNESSEE (SOUTH)
04EI	ILLINOIS, INDIANA, KENTUCKY (WEST), MISSISSIPPI
05WI	IOWA, MISSOURI, KANSAS, OKLAHOMA, ARKANSAS, TEXAS (BITUMINOUS)
06GL	TEXAS (LIGNITE), LOUISIANA
07DL	NORTH DAKOTA, MONTANA (LIGNITE)
08WM	WESTERN MONTANA (SUBBITUMINOUS)
09NW	WYOMING, NORTHERN POWDER RIVER BASIN (SUBBITUMINOUS)
10SW	WYOMING, SOUTHERN POWDER RIVER BASIN (SUBBITUMINOUS)
11WW	WESTERN WYOMING (SUBBITUMINOUS)
12RM	COLORADO, UTAH
13ZN	ARIZONA, NEW MEXICO
14AW	WASHINGTON, ALASKA

{CensDiv}	**CENSUS REGION**
01NEW	NEW ENGLAND
02MAT	MIDDLE ATLANTIC
03ENC	EAST NORTH CENTRAL
04WNC	WEST NORTH CENTRAL
05SAT	SOUTH ATLANTIC
06ESC	EAST SOUTH CENTRAL
07WSC	WEST SOUTH CENTRAL
08MTN	MOUNTAIN
09PAC	PACIFIC
10CAL	CALIFORNIA

{Rank} **COAL RANK**

1B	Bituminous
2S	Subbituminous
3L	Lignite
4P	Premium
5G	GOB and Culm

{Sulf} **SULFUR GRADE**

1C	Low:	≤ 1.2 lbs. SO_2 per million Btu
2M	Medium:	> 1.2 lbs. ≤3.33 lbs. SO_2 per million Btu
3H	High:	>3.33 lbs. SO_2 per million Btu

{MTyp}**MINE TYPE**

1S	Surface Mining
2D	Underground Mining

{Scrv1Step} **STEPS**

1 … 11

{SubSec}	**SUBSECTOR**
1	RESID/COM - R1= RESIDENTIAL/COMMERCIAL DEMAND
2	RESID/COM - R2
3	IND STEAM 1 - I1 = Stoker Fired Industrial Steam Coal Demand
4	IND STEAM 2 - I2 = Pulverized Coal Industrial Steam Coal
5	IND STEAM 3 - I3 = Other Industrial Steam Coal Demand
6	COKING 1 – M1
7	COKING 2 - M2
8	COAL-TO-LIQUIDS - L1
9	METALLURGICAL 1 EXPORT - X1
10	METALLURGICAL 2 EXPORT - X2
11	METALLURGICAL 3 EXPORT - X3
12	STEAM 1 EXPORT - X4
13	STEAM 2 EXPORT - X5
14	STEAM 3 EXPORT - X6
15	ELECTRICITY – B1
16	ELECTRICITY – B2
17	ELECTRICITY – B3
18	ELECTRICITY – B4
19	ELECTRICITY – B5
20	ELECTRICITY – B6
21	ELECTRICITY – B7
22	ELECTRICITY – B8
23	ELECTRICITY – C1
24	ELECTRICITY – C2
25	ELECTRICITY – C3
26	ELECTRICITY - C4
27	ELECTRICITY - C5
28	ELECTRICITY - C6
29	ELECTRICITY - C7
30	ELECTRICITY - C8
31	ELECTRICITY - C9
32	ELECTRICITY - CX
33	ELECTRICITY - CY
34	ELECTRICITY - CZ
35	ELECTRICITY - H1
36	ELECTRICITY - H2
37	ELECTRICITY - H3
38	ELECTRICITY - H4
39	ELECTRICITY - H5
40	ELECTRICITY - H6
41	ELECTRICITY - H7
42	ELECTRICITY - H8
43	ELECTRICITY - H9
44	ELECTRICITY - HA
45	ELECTRICITY - HB
46	ELECTRICITY - HC
47	ELECTRICITY - PC
48	ELECTRICITY - OC
49	ELECTRICITY - IG
50	ELECTRICITY - I2
51	ELECTRICITY - RQ
52	ELECTRICITY - IS

PT **PLANT TYPE**

See SUBSECTORS #15-52 above or Table 2.5 for more details

{ACSteps} **ACTIVATED CARBON SUPPLY CURVE STEPS**

1 … 8

{PADD} **LIQUID FUELS MARKET MODULE REGIONS**

01PADD	REGION 1
02PADD	REGION 2
03PADD	REGION 3
04PADD	REGION 4
05PADD	REGION 5
06PADD	REGION 6
07PADD	REGION 7
07PADD	REGION 8

C **COAL GROUPS**

1	Premium and Bituminous
2	Subbituminous
3	Lignite
" "	None

Appendix 2.B. Inventory of Input Data, Parameter Estimates, and Model Outputs

Input: Data requirements

Input to the domestic component of the CMM is read from input data files and database tables. These files and their contents are listed below. File names and tables are listed in ***bold_italics***.

Census Shares. This table ***tInp_clshare_CensusDivision*** in file *CMM.mdb* contains rational numbers used to create demand shares that distribute demands received at the census division level of aggregation over the 16 DCDS coal demand regions. The table contains elements for the standard nine census regions plus a placeholder to separate out California as a separate region and three of the major sectors: residential/commercial (R), industrial steam (I), and metallurgical coal (C). The tables ***tInp_clshare_PADD*** and ***Map_PADD_DReg*** provide a mapping from the nine Liquid Fuels Market Mode (LFMM) regions to coal demand regions for the coal to liquids sector (L).

Coal Stocks. The input table ***tInp_clshare_STOCKS*** lists historical stock changes. "Stock adjustments by coal demand region for electricity sector" enables the modeler to designate the coal demand regions where the stock adjustments are apportioned. For instance, if 720 trillion Btu are input for the stock calculation in year t, 50% could be allocated to the S2 coal demand region, 20% to C2, 20% to WS, 10% to MT, 10% to CU, and 10% to ZN. These percentages do not need to sum to 100. This approach was adopted in the AIMMS code to replicate what was required in Fortran CMM, but the approach appears to have been replaced by the AIMMS STEO *(Short-Term Energy Outlook)* benchmarking routine.

Subsector Splits. In the old Fortran version of the model, these parameters were input as regional subsector shares that summed to 1 for each nonutility demand sector. Data from ***tInp_clshare_FRADI*** are still input this way, but the data now appears in different rows in this database table. The fraction (FRADI) represents the share of demand for each subsector designated to a particular demand region. So for a coal demand region, (Dreg) 01NE FRADJ for R1+R2 =1.0, I1+I2+I3=1.0, etc. The same is true for all the other coal demand regions. For the industrial coking sector, it is possible for both C1 and C2 shares to be set to zero in regions where coking coal is not demanded. This table has 128 records (16 Dreg *multiplied by* 8 SubSec).

Transportation Rates. The coal transportation rates used in the DCDS are input in 1987 dollars per ton from two files, ***clratesnonelec.txt*** and ***clrateselec.txt***. The base rates for each non-electricity economic subsector in the model have a one-tier rate structure, while the base rate for the electricity sector has a two-tier structure. Each line in the input files represents a possible supply curve and demand region pair in the model. The files contain index values, which allow the model to map rate paths from supply curve Scrv(SReg, Sulf, Mtyp, Rank) to demand region {Dreg} and subsector {SubSec}. Transport paths that are unavailable have been coded with a rate of 999.99 (or $1,000 per ton), making them effectively unusable, compared to usable paths that typically have base rates between $1 and $50 per ton. The file ***clratesnonelec.txt*** contains the {Trate1}, which is the unadjusted base rate for the non-electricity sectors. The file ***clrateselec.txt*** contains the base, first-tier transport rates for the electricity sector, {Trate2} and the second-tier rate {Trate3}. For the electricity sector rates, the second electricity sector rate {Trate3} is always greater than or equal to the first rate{Trate2}.

Table 2.B-1. Parameter and variable list for DCDS

AIMMS variable	Input file	Database table/query	Description
Sec	cmm.mdb	(multiple)	Major demand sector (R,I,C,L)
CensDiv	cmm.mdb	(multiple)	Census division
Dreg	cmm.mdb	(multiple)	Coal demand region
MNUMCR=11	cmm.mdb	(multiple)	Census regions (9 + CA + U.S.)
Sreg		(multiple)	Coal supply region
Map_DReg_MNUMCR	cmm.mdb	Inp_CensusDivMap8	Map Dreg to census region
Map_Mnumcr_CensDiv	cmm2.mdb	Census Division Mapping	Mnumcr to census region
CensDivShare	cmm.mdb	tInp_clshare_CensusDivision	Share factors from CensDiv to Dreg
PADD	cmm.mdb	tInp_clshare_PADD	LFMM region
PMMDivShare	cmm.mdb	tInp_clshare_PADD	Share factors for LFMM region to Dreg
Map_PADD_DReg	cmm.mdb	Map_PADD_DReg	Index map for PADD to Dreg
USImpShare	cmm.mdb	USImpShare	Limit on coal imports by region
Stockbase	cmm.mdb	tInp_clshare_STOCKS	Base of coal stockpiles (Btu)
Stockshare	cmm.mdb	tInp_clshare_STOCKS	Stockpile share allocation
SubSec	cmm.mdb	tInp_clshare_FRADI, tInp_clparam_CoalGroupFlags2	Sub Sector (R1-R2,I1-I3,C1-C2,L1)
FRADI	cmm.mdb	tInp_clshare_FRADI	Fraction for allocating demands to resid/comm, industrial, metallurgical, and coal to liquids sectors
Trate1	clratesnonelec.txt		Base rates for non-electricity sectors (1987$/ton)
Trate2	clrateselec.txt		Base rate for electric power tier 1 transport (1987$/ton)
Trate3	clrateselec.txt		Base rate for electric power tier 2 transport (1987$/ton)
Pu_id	cmm.mdb	(multiple)	Unique power plant ID code (pid-uid)
TBTU	cmm.mdb	TotalBtusforPlant	Historical plant-unit consumption (Trillion Btu)
Plant_C_Prof	cmm.mdb	Contracts	Contract profile number
Plant_BaseYear_Btu	cmm.mdb	Contracts	Contracted annual quantity (TBtu)
Plant_T_Prof	cmm.mdb	Contracts	Corresponding transportation profile number
yr	cmm.mdb	(multiple)	Year
nsteps	Cmm2.mdb	Mercury_allowed	Steps for mercury activated carbon
allowed	Cmm2.mdb	Mercury_allowed	Active steps (value =1)
APONROAD_PDSTRHWY	Restart file		Adjusted price, distillate, transportation sector, on-road by census region (1987$/MMBtu)

Table 2.B-1. Parameter and variable list for DCDS (continued)

AIMMS variable	Input file	Database table/query	Description
{cnum}	cmm.mdb	tlnp_clcont1_contrProf	Contract profile number
ContractProfile	cmm.mdb	tlnp_clcont1_contrProf	Contract profile share (0.80)
TranspProfileNumber {tnum}	cmm.mdb	tlnp_clcont2_TranspProf	Transportation profile (1 or 2)
TranspProfile	cmm.mdb	tlnp_clcont2_TranspProf	Transportation profile value
SubDivProfileNumber {snum}	cmm.mdb	tlnp_clcont3_SubDivProf	Subbit profile number
SubDivProfile	cmm.mdb	tlnp_clcont3_SubDivProf	Subbituminous profile share
LigDivProfileNumber {lnum}	cmm.mdb	tlnp_clcont4_LigDivProf	lignite profile number
LigDivProfile	Cmm.mdb	tlnp_clcont4_LigDivProf	Lignite profile share
Plant_S_Prof	Cmm.mdb	ContractsSubbit	Pu_id to subbit profile number
Plant_L_Prof	Cmm.mdb	ContractsLig	Pu_id to lignite profile number
ImpSec	Cmm2.mdb	clintlsurcharge	Import sector
nUS	Cmm2.mdb	clintlsurcharge	Non-U.S. exporting regions
USi	Cmm2.mdb	(multiple)	U.S. importing regions
DistanceSurcharge	cldistance.txt		Distance (miles) from Sreg to Dreg
Pinlandtr	Cmm2.mdb	clintlsurcharge	Imports surcharge
DistanceSurcharge	Cldistance.txt		Distance from Sreg to Dreg in miles
TonsPCar	Cltoncar.txt		Tons per car by Sreg
Trigger	Cltoncar.txt		Diesel price to trigger surcharge (nominal $/gal) by Sreg
Trig_Incr	Cltoncar.txt		Price per gallon increase for surcharge
ChargePermile_car	Cltoncar.txt		Dollar per carload mile charge
Miners	cmm.mdb	tlnp_clparam_NumberMiners	Number of miners by Sreg (base year)
Tonrailmile	Cltonrailmile.txt	[not in use]	Distance from Sreg to Dreg in miles by major sector (E,I,C)
CoalGroupFlag	cmm.mdb	tlnp_clparam_CoalGroupFlags2	Unique combinations of Sreg, Sulf, Mtyp, Rank, Dreg. and Subsec
Railwage	cmm.mdb	tlnp_clparam_Escalator	AAR Rail Wage Index (not used)
Tr_prod_e	cmm.mdb	tlnp_clparam_Escalator	Transport Rate Productivity East (Ton-Miles/Employee)
Tr_prod_w	cmm.mdb	tlnp_clparam_Escalator	Transport Rate Productivity West (Ton-Miles/Employee)
Dist_w	cmm.mdb	tlnp_clparam_Escalator	Initial Investment value (read in but replaced by calc for investment adder)

Table 2.B-1. Parameter and variable list for DCDS (continued)

AIMMS variable	Input file	Database table/query	Description
Contrdur_e	cmm.mdb	tInp_clparam_Escalator	Contract duration for east (not used)
Contrdur_w	cmm.mdb	tInp_clparam_Escalator	Contract duration for west (not used)
PPIrail_actual	cmm.mdb	tInp_clparam_Escalator	Producer Price Index for Railroad Equip (Used in East)
Distance	cmm.mdb	tInp_clparam_EscalatorDistance	Distance from western supply regions {SReg} to all demand regions {Dreg}
steoyr	clflags.txt		Years to benchmark
steoflagW	clflags.txt		Benchmark flag by year for waste coal
SteoFlagET	clflags.txt		Benchmark flag by year for electricity consumption
SteoFlagC	clflags.txt		Benchmark flag by year for coking
steoflagI	clflags.txt		Benchmark flag by year for industrial
steoflagRT	clflags.txt		Benchmark flag by year for residential
steoflagIMP	clflags.txt		Benchmark flag by year for imports
steoflagExports	clflags.txt		Benchmark flag by year for exports
steoflagSTOCKS	clflags.txt		Benchmark flag by year for stocks
Bsrzr_util_a	clflags.txt		Utilization target by year for electricity prices
Tolerance	clflags.txt		Tolerance value for STEO benchmarking (Currently 2%)
EMMBENCH	emmbench.txt		Choice for side case tolerance adjustment
TolAdjBench1	clflags.txt		Multiplier for tolerance: EMMBECH=1 (Value of 1.0 = 2% tolerance)
TolAdjBench2	clflags.txt		Multiplier for tolerance: EMMBECH=2 (Value of 1.5 = 3% tolerance)
TolAdjBench3	clflags.txt		Multiplier for tolerance: EMMBECH=3 (Value of 3.0 = 6% tolerance)
AppalachiaLimit	clsteo.txt		STEO Target for Appalachia
InteriorLimit	clsteo.txt		STEO Target for Interior
WestLimit	clsteo.txt		STEO Target for West
ElecPriceSTEO	clsteo.txt		STEO Target for Electricity Price
ElecTonsSTEO	clsteo.txt		STEO Target for Electricity Sector
WasteCoalSTEO	clsteo.txt		STEO Target for Waste Coal
CokeTonsSTEO	clsteo.txt		STEO Target for Coking Sector
IndustrialTonsSTEO	clsteo.txt		STEO Target for Industrial Sector
CokingExpSTEO	clsteo.txt		STEO Target for Coking Exports
SteamExpSTEO	clsteo.txt		STEO Target for Steam Exports
ImportsSTEO	clsteo.txt		STEO Target for Imports

Fuel Surcharges. The following information is provided separately for domestic production and imports: a flag to turn the surcharge on or off, average distances by supply region and coal demand region, tons per carload by supply and demand region, trigger prices at which the surcharge becomes effective by supply and demand region, the incremental increase in the trigger price at which a higher surcharge is applied, and the cost per mile per car by supply region and coal demand region. (See additional discussion in section 2.C on page 117)

- The ***cldistance.txt*** file contains transport distance {DistanceSurcharge} in miles from supply region {Sreg} to demand region {Dreg} by tier for domestic production.
- The file ***Cltoncar.txt*** provides the tons per car {TonsPCar}, diesel trigger price {Trigger}, price threshold {Trig_Incr}, and incremental carload mile charge {ChargePermile_car} to calculate a surcharge on a per ton basis.
- A similar calculation will use data from ***clintlsurcharge, clintldistance,*** and ***clintlinland*** tables from CMM2.mdb to set surcharges for imported coal.

Coal Contracts. A framework for modeling coal transportation contracts was developed in the CMM for the previous Fortran versions of the CDS and has been carried forward into the current AIMMS DCDS. This framework includes a list of historical contract paths for power plants sourced from various coal supply regions. The ***Contracts*** table in CMM.mdb contains plant-unit ID code {pu_id}, supply region , sulfur grade {Sulf}, mine type {Mtyp}, coal rank {Rank}, demand region {Dreg}, contracted quantity {Plant_BaseYear_Btu}, and lookup codes identifying the corresponding contract profile number {cnum}, lignite profile number {lnum}, and transportation profile number {tnum}.

The ***tInp_clcont1_contrProf*** table lists 496 *contract profile* indices {cnum}, with corresponding contract profiles {ContractProfile}, one for each year of the forecast. The contract profiles extend through 2050. These profiles determine whether minimum flows of a particular supply region's coal will be maintained or decline over the forecast horizon.

A transportation rate profile is assigned for each plant in the electricity sector from the ***tInp_clcont2_TranspProf*** table. This profile determines when the second rate takes effect. There are two options (1 or 2) for a transportation rate profile. (In AEO2020 all the contracts have transport profile set as 1.) For domestic production only, transportation profiles determine whether a plant will always get the first-tier transportation rate or whether it will be assigned a second-tier transportation rate as well. The second-tier rate will become effective only if modeled volumes exceed historical flows. If the second-tier rate takes effect, it is applied to only the volume in excess of this shipment level. (By default, all new plants are subject to the second-tier rate for their coal shipments.)

For domestic production only, the transportation profile section is accompanied by the *subbituminous diversity profiles* and then the *lignite diversity profiles* from tables ***tInp_clcont3_SubDivProf*** and ***tInp_clcont4_LigDivProf***. These tables determine what proportion of a plant's consumption can be composed of subbituminous coal and lignite coal, respectively. Historical consumption by plant is available from the ***TotalBtusforPlant*** table. A subbituminous diversity profile is established for new or unidentified coal units by demand region. Unidentified coal units are those units that may be present in the electricity model's plant input file but are not listed in the contracts file. New and unidentified plants are allowed unlimited use of subbituminous coal.

For both domestic production and imports, contracts are specified by coal type, supply region, demand region, and whether the units have flue gas desulfurization equipment. Units with flue gas desulfurization equipment are referred to as *scrubbed*. The process for determining the level of contracts for a given forecast year involves a series of calculations that use the contracts data. First, the historical proportion of consumption satisfied at the entire plant unit by each coal type/supply region combination is calculated for each plant unit. Second, a profile percentage indicating the proportion of the historical quantity still under contract in the current forecast year is multiplied by the share calculated in the first step. Third, the resulting calculated minimum contract share is multiplied by the demand (specified by plant unit) received from the electricity model. Finally, this information is aggregated by coal type, supply region, demand region, and whether the units specified in the contract have flue gas desulfurization equipment.

As the forecast year changes, this minimum flow is subject to change as the contract profiles and electricity demand change. For domestic production, the resulting calculated minimum flow is the right-hand side of the F(SR)(DR)XI row in the LP for the scrubbed sector or the C(SR)(DI(C) row for the unscrubbed sector. (See Chapter 2 Figure 2.A-1. DCDS Linear Program Structure) For imports, the resulting calculated minimum flow is the right-hand side of the {ContractsScrubbed} row in the LP for the scrubbed sector or the {ContractsUnscrubbed} row for the unscrubbed sector. (Additional information on imports is available in Chapter 3 Figure 3.A-1. ICDS Linear Program Structure – International Component in Appendix 3.B.)

The following depicts a hypothetical situation in which a demand region is composed of just two scrubbed plant units.

Example	Source of data, if applicable	Scrubbed Plant Unit 1	Scrubbed Plant Unit 2	Total
Step 1. Calculation of supply curve historical share				
Historical consumption of supply “u”ve "X" @ unit (trillion Btu):		100	80	
Historical total plant unit consumption (all supply curves, trillion Btu):	{TBTU}	150	200	
Calculated share:		100/150=0.67	80/200=0.40	
Step 2: Apply profile percentage				
Profile for forecast year, T:	{ContractProfile}	0.80	0.50	
Adjusted share for forecast year, T:		0.67*0.80=0.53	0.40*0.50=0.20	
Step 3. Calculation of minimum flow for each unit				
Electricity demand for plant unit for forecast year, T (trillion Btu):	electricity model	170	210	
Minimum flow by plant unit for forecast year, T (trillion Btu):		170*0.53=90	210*0.20=42	
Step 4. Total contract value, specified by scrubbed/unscrubbed categorization, demand region, and supply curve (trillion Btu)				90+42=132

The contract, or minimum flow, in this hypothetical example, used in the LP for this forecast year, demand region, scrubbed sector, and supply curve *X* combination, is 132 trillion Btu (or 90 plus 42).

For the diversity profiles for domestic coal production, the process is similar, but the level of aggregation (Step 4) is different. Here, the diversity profiles are specified by plant type (Table 2.4) and demand region. The resulting value becomes the right-hand side for the rows {SubbituminousDiversity} for subbituminous and {LigniteDiversity} for lignite coals.

Again, for the transportation profiles for domestic coal production, the process is similar, but the information is aggregated based on supply region, demand region, plant type, and coal type. For those transportation profiles indicating a second-tier rate, the calculated value becomes the right-hand side for the row {BalanceScrubUnscrubTier1} and represents the bound on the first-tier transportation rate. In other words, any production from supply curve *X* transported to demand region *Y* for plant type *Z* in excess of this *bound* must get the more expensive second-tier rate.

Coal Parameters. This section includes other parameters used by the CMM for the AEO2020 projection.

Table ***tInp_clparam_NumberMiners*** is total number of miners by region in the base year from which subsequent coal mine employment for the forecast years is calculated.

Table ***tInp_clparam_CoalGroupFlags2*** provides groupings into unique combinations of supply region, sulfur category, mine type, coal grade, and coal demand region {Sreg, Sulf, Mtyp, Rank, Dreg} and Subsec for the purposes of calculating rates and transport cost for the nonutility sectors. The subsector {SubSec} index is two-letter alphabetic labels for the 53 economic subsectors in the DCDS as described in Table 2.3 and Table 2.4.

Table ***tInp_clparam_Escalator*** from CMM.mdb provides the transportation escalator inputs for the variables {Railwage, Tr_prod_e, Tr_prod_w, Dist_w, Contrdur_e, Contrdur_w, PPIrail_actual} listed in Table 2.B-1 above. These variables are used in conjunction with the transportation escalator equation parameters, which have been hard coded into the AIMMS code. The current values for AEO2020 are listed in Table 2.B-2 below. See **Appendix 2.C** for a more complete discussion of the east and west transportation rate escalators. Table ***tInp_clparam_EscalatorDistance*** contains average distance {Distance} for western-sourced coal supply regions to all demand regions (this data input is currently not used by the CMM.

Table 2.B-2. Parameters inside AIMMS code

AIMMS variable	Parameter value	Description
Inv_p_tm	0.0530	+/- cents per corresponding +/- ton-miles
Inv_yr	2006	investment dollar base year
Invbase	1.54	investment for base year (same format as econometric equation)
Invdol	93166	investment for base year (billion 1987 dollars)
Basket	0.0003	+/- 'basket of rail goods' purchased per +/- ton-miles
Cap_p_tm	.0030	+/- cents of capital expenditures per corresponding +/- ton-miles
Cap_yr	2007	base year for capital expenditures
Capbase	4734	capital expenditures (national) in base year (billion 1987 dollars)
PPI_yr	2017	PPI rail equipment (national) base year; first year of calculation for escalator
Cof1	0.632603	West intercept
Cof2	0.434937	coefficient for investment term for West formulation
Cof3	-0.111765	productivity coefficient (West formulation) billion ton-miles/employee
Cof4	-0.264830	western share of national production coefficient (West formulation)
Cof5	1.59107	East intercept
Cof6	-0.124193	east productivity coefficient (billion ton-miles per employee)
Cof7	0.0	diesel coefficient (East)
Cof8	0.361206	rho for East
Cof9	0.013095	coefficient for coal of capital railroad equipment (East formulation)
Cof10	0.547600	rho for West

Historical Coal Data. Multiple tables are read from CMM2.mdb to input historical overwrite information. A list of historical value fields is provided in Table 2.B-3 below. Historical information for AEO2020 includes data for years 1998–2018. Some input tables like ***Historical_Imports*** have data for forecast years and are used as constraints to U.S. import levels.

Table 2.B-3. Historical coal data

AIMMS variable	Input file	Database table/query	Description
yr	Cmm2.mdb	(multiple)	Year
NSREGN	Cmm2.mdb	(multiple)	Supply region
M2	Cmm2.mdb	(multiple)	Mine type
M3	Cmm2.mdb	(multiple)	Sulfur
M4	Cmm2.mdb	(multiple)	Rank
ImportsMinimumElectricity	Cmm2.mdb	Historical_imports	Minimum U.S. imports (tons)
ImportsMaximumElectricity	Cmm2.mdb	Historical_imports	Maximum U.S. imports (tons)
hclprd	Cmm2.mdb	Historical_production	Historical coal production (million tons)
hclmmpr1	Cmm2.mdb	Historical_minemouth	Historical minemouth price ($/ton)
hclprdbt	Cmm2.mdb	Historical_East_West	Historical production trillion Btu (m3=1:East, 2:West, 3:Total U.S.
hwcdistst	Cmm2.mdb	Historical_wastecoal_Miscell	Historical waste coal (Mst)
hwcprodbtu	Cmm2.mdb	Historical_wastecoal_Miscell	Historical waste coal (trillion Btu)
hclexptn	Cmm2.mdb	Historical_wastecoal_Miscell	Historical coal exports (Mst)
hclexpbt	Cmm2.mdb	Historical_wastecoal_Miscell	Historical coal exports (trillion Btu)
hclimptn	Cmm2.mdb	Historical_wastecoal_Miscell	Historical coal imports (Mst)
hclimpbt	Cmm2.mdb	Historical_wastecoal_Miscell	Historical coal imports (trillion Btu)
hclmmtn1	Cmm2.mdb	Historical_wastecoal_Miscell	Historical coal minemouth prices (nominal $/ton)
hclmmbt1	Cmm2.mdb	Historical_wastecoal_Miscell	Historical coal minemouth prices (nominal $/MMBtu
hcltrtmrrc	Cmm2.mdb	Historical_East_West_Rail	Historical rail coal shipments (m2=1:East, m2:West
hcldist	Cmm2.mdb	Historical_distribution_by_supplyregion	Historical coal distribution by supply region (Mst)
hclcon	Cmm2.mdb	Historical_sectoral	Historical coal consumption by major sector(R,I,C,X,E) (Mst)
hcldprtn1	Cmm2.mdb	Historical_sectoral	Historical coal price by major sector(R,I,C,X,E) ($ per ton)
hcldprbt1	Cmm2.mdb	Historical_sectoral	Historical coal price by major sector (R,I,C,X,E) ($/MMBtu)
tc	Cmm2.mdb	Historical_worldtrade	tc=1(thermal)2(coking)
M4	Cmm2.mdb	Historical_worldtrade	m4=Europe, Asia, other, total
M11 / ae	Cmm2.mdb	Historical_worldtrade	m11=Australia, etc. aggregate export regions (ae)
hclworld	Cmm2.mdb	Historical_worldtrade	World coal trade by M4, ae, tc, yr
map_m11_Ae	Cmm2.mdb	Historical_Map_M11_Ae	Mapping to historical country/region data to ae regions
map_m4_importregion	Cmm2.mdb	Historical_Map_M4_ImportRegion	Mapping to historical country/region data to M4 regions
i	Cmm2.mdb	Historical_Map_M4_ImportRegion	International import region/country

STEO Benchmarking. EIA produces a *Short-Term Energy Outlook* (STEO) to project energy trends over the next 18 to 30 months. The AEO projection can be benchmarked to the latest STEO projection. The files ***clflags.txt, clsteo.txt,*** and ***EMMBENCH.txt*** provide inputs to the CMM to benchmark the near years to the STEO projection. The CMM hits the benchmark targets by setting constraints in the STEO years {Steoyr} for coal production, coal transport by sector, coal stocks, and the end use price of coal to the electricity sector. This process is done by specifying a tolerance {Tolerance} interval (currently +/– 2 %) around the benchmark targets. The tolerances are allowed to be looser in the alternate sensitivity cases. The CMM has three levels of tolerance specified by variables {TolAdjBench1, TolAdjBench2, TolAdjBench3} and selected by case through {EMMBENCH} passed from the Electric Market Module (EMM). As an example the benchmark multipliers {TolAdjBench1, TolAdjBench2, TolAdjBench3} were set at 1.0, 3.0, and 5.0 for 2019, 2020, and 2021, respectively. These factors are multiplied by the base tolerance, so side cases would have tolerances of 0.02 * 1.0 = 2%, 0.02 * 3.0 = 6%, or 0.02 * 5 = 10%, depending on which side tolerance is chosen in the EMMBENCH.txt file.

The benchmarking routines create an upper and lower constraint to the production and transport solutions. These constraints are active only in the STEO years and are inactive from the remaining years of the forecast. Hitting the target price for the electric power sector may require adjusting the variable {Bsrzr_util_a} found in ***clflags.txt.*** Manual benchmarking steps should be undertaken only after historical year updates of production and transportation rates for all sectors. These manual benchmarking steps would include updating any active contracts for the transport of coal and any adjustment to the East and West rate escalators.

The benchmarking method implemented in the AIMMS version of the CMM is as follows:

1. Before benchmarking, primary CMM data updates should be completed.
2. Ideally, allow the Electricity Market Model (EMM) to make a first attempt at determining coal generation numbers.
3. Apply regional production coal constraints that allow flexibility to reach STEO goal within 2%.
4. Apply total electricity coal tons constraint, if necessary.
5. Update imports, steam coal exports, and coking coal exports using in ***clsteo.txt***.
6. Continue to adjust coal transportation rates to achieve calibrated coal price to the power sector but perform test in AIMMS Windows environment.
7. Apply waste coal constraint.
8. Test with EMM in integrated environment, and repeat #5, if necessary.

The benchmarking procedure was modified for AEO2019 to add an automatic scaling factor to adjust exports of steam and coking coal to match the STEO exports within tolerances. These factors {ExportMultScaleSteam} and {ExportMultScaleCoke} are calculated only during the STEO years in the first iteration of the model. The scale factors work by adjusting the bounds on U.S. exports through the parameters {CokingUpperBound, CokingLowerBound, ThermalUpperBound, ThermalLowerBound}. See the diagram in Figure 3.A-1. *ICDS linear program structure* and equations 3.A-15 and 3.A-16 in Chapter 3 of this document for more information on the U.S. export constraints.

Model Output

The Domestic Coal Distribution Submodule (DCDS) provides annual forecasts of U.S. coal quantities transported to the demand sectors and the cost of moving coal. The key output from the DCDS is the LP solution of the least cost movement of coal for each sector(in trillion Btu). Listed in Table 2.B-4 are separate output tables by sector, which can be combined to form the total domestic transport solution. Most of the tables report transport flows by supply curve {Scrv1}, supply region {Sreg}, sulfur category {Sulf} mine type {Mtyp}, coal grade {rank}, demand region {Dreg}, and forecast year {yr}. Average heat rate values are applied to convert output from trillion Btu to short tons for report-writing purposes.

Table 2.B-4. Outputs from DCDS

Output in CoalOutput.xls	AIMMS variable	Description	Units
Residential	ResidentialTransportTrills	Residential/Commercial Sector Transported Volume	Trillion Btu
Industrial	IndustrialTransportTrills	Industrial Sector Transported Volume	Trillion Btu
Coking	CokingTransportTrills	Coking or Metallurgical Coal Transported Volume	Trillion Btu
Exports	ExportsTransportTrills2a	Coal Exports	Trillion Btu
Liquids	LiquidsTransportTrills	Coal Transported for Liquids	Trillion Btu
ElectrictyACTrills	ElectricityTransportACSubtotalTrill	Power Sector Transported Volume	Trillion Btu
ElectrictyT1Rate	Trate2wS^{ur}ch	Tier 1 transportation rate	1987$ per Ton
ElectricityTier2TotalCost	ElectricityTransport2CostScrvYr	Tier 2 electricity total transport cost	1987$ per Ton
RevisedRate	Trate1RevisedBase	Non-electricity sector revised transportation rates	1987$ per Ton
Surcharge	SurcharT1	Surcharge for Tier 1 transport	1987$ per Ton
HeatContent	Btu	Heat content by supply curve	million Btu/short ton
TransMultiplier	FinalWest	Transportation rate multiplier for west	Numeric ratio
TransMultiplier	FinalEast	Transportation rate multiplier for west	Numeric ratio
MinePrice	PriceByYr	Minemouth Price	1987$ per MMBtu
ImportsSubtotal	ImportsElectricitySubtotalReport	Total U.S. coal imports for electricity sector	Trillion Btu
ImportsSubtotal	ImportsIndustrialSubtotalReport	Total U.S. coal imports for industrial sector	Trillion Btu
ImportsSubtotal	ImportsCokingSubtotalReport	Total U.S. coal imports for coking sector	Trillion Btu
USCoalSupplyCurves	SC_QUAN	US supply curve quantities by supply step	Trillion Btu
USCoalSupplyCurves	SC_PRICE87	US supply curve prices by supply step	1987 dollars
USCoalSupplyCurves	SC_PRICE_BYDollars	US supply curve prices by supply step	2018 dollars

Output: NEMS Tables

Prices and quantities projected by the CMM appear throughout the NEMS tables. However, the bulk of the DCDS output is reported in seven NEMS tables dedicated entirely to coal. These reports can be found using the interactive table viewer. These reports are organized to show selected NEMS coal quantities and prices for each year in the forecast period.

"*Coal Supply, Disposition, and Prices*" shows the following:

- Production east and west of the Mississippi River and for the Appalachian, Interior, and Western regions, and the national total in millions of short tons.
- Imports, exports, and net imports, plus total coal supply in millions of short tons.
- Sector consumption for the residential/commercial, industrial steam, industrial coking, and electricity sectors plus total domestic consumption in millions of short tons.
- Annual discrepancy (including the annual stock change).
- Average minemouth price in dollars per ton (the dollar year is provided).
- Sectoral delivered prices in dollars per ton for the industrial steam, industrial coking, and electricity sectors, and the weighted average for these three sectors.
- Average free-alongside-ship price for exports, in other words, the dollar-per-ton value of exports at their point of departure from the United States.

"*Coal Production and Minemouth Prices By Region*" provides annual summaries of national distribution, aggregated supply regions, plus subtotals for five subregions: Appalachia, Interior, Western, East of the Mississippi River, and West of the Mississippi River. In the lower half of the table, minemouth prices are shown in dollars per ton for the same regions and subregions.

"*Coal Production by Region and Type*" lists production in millions of short tons per forecast year by supply region by coal rank and sulfur level.

"*Coal Minemouth Prices by Region and Type*" lists minemouth prices for each forecast year by supply region by coal rank and sulfur level.

In addition, three tables in the table viewer show international seaborne coal trade projections for coal by international supply regions to the Europe/Mediterranean region, Asia, and the Americas for the steam coal trade, metallurgical coal trade, and total coal trade.

"*Total Energy Supply, Disposition, and Price Summary*" reports national coal production, consumption, and exports in quadrillion Btu, along with the minemouth price of coal in dollars per ton.

"*Energy Consumption by Sector and Source*" lists annual energy consumption for the residential, commercial, industrial (both industrial steam and coking consumption are shown), and the electric power sectors in quadrillion Btu, along with delivered coal prices for these same sectors in dollars per million Btu.

"*Conversion Factors*" shows Btu conversion rates for coal production (east and west of the Mississippi River and the national average) and for coal consumed in the domestic NEMS sectors (residential/commercial, industrial, coking, and electricity sectors).

Appendix 2.C. Data Quality and Estimation

Development of the DCDS transportation index

Projected coal transportation costs, both first- and second-tier rates, are modified over the forecast horizon by two regional (East and West) transportation indices. The indices, calculated econometrically, are measures of the change in average transportation rates, on a tonnage basis, that occurs between successive years for coal shipments. The methodology used to formulate these indices was first developed for *AEO2009*. The East index is used for coal originating from eastern supply regions, while a West index is used for coal originating from western supply regions. The East index is a function of railroad productivity, the user cost of capital for railroad equipment, and the national average diesel fuel price. The user cost of capital for railroad equipment is calculated from the producer price index for railroad equipment, projected to remain flat in real terms, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10% per year), less any capital gain associated with the worth of the equipment. The West index is a function of railroad productivity, gross capital expenditures for Class I railroads, and the western share of national coal consumption. The indices are universally applied to all domestic coal transportation movements within the CMM. In the AEO2020 Reference case, eastern coal transportation rates are 2.2% lower in 2050, and western rates are projected to be 5.5% lower in 2050 compared with 2018[31].

Background

Transportation rates can be expected to change over time as market conditions change. Historically, the majority of transportation agreements involved contracts that extended over many years. Despite the length of these contracts, escalator clauses were typically employed allowing rates to change in accordance with changing market conditions. In addition, shorter contracts, which have become more prevalent, provide an opportunity for both parties involved to renegotiate their positions more frequently. The transportation indexing methodology used in AEO2020 is needed within the DCDS to simulate the changes that may occur in real coal transportation rates over the forecast horizon.

Before the *Annual Energy Outlook 1997* (AEO1997), transportation indexing factors were derived from index data published by the Association of American Railroads. Beginning in AEO1997 and extending through AEO2004, an indexing methodology based on the producer price index (PPI) for the transportation of coal via rail was used. The PPI for coal transportation tracks the national average change in prices received by railroads for the transportation of coal. A statistical regression model was fitted to the PPI for coal rail transportation. The independent variables used in the formulation were intended to account for the input costs that would affect transportation rates over time and, in the AEO1997 formulation, included the following: trend (as a proxy for productivity), the price of No. 2 distillate fuel to the industrial sector, the PPI for transportation equipment, and the national average wage rate. (For more information on this formulation, see "Forecasting Annual Energy Outlook Coal Transportation Rates" by Jim Watkins in *Issues in Midterm Analysis and Forecasting,* 1997.) For

[31] See Table 2 in the Coal Market Model, Assumptions to AEO2020.

AEO2004, the PPI for rail transportation equipment was substituted for the PPI for transportation equipment as one of the independent variables. The PPI for rail transportation equipment was also converted to the user cost of capital of transportation equipment for use in the regression. In addition, for AEO2004, the average rail wage replaced the national average wage rate in the econometric formulation.

For AEO2005, the methodology used to derive the transportation index was again revised. The principal goals of the development of a revised transportation escalator for AEO2005 were a statistically significant regression that included East and West regional differentiation and an improved representation of productivity. Although the factors that affect costs in the East and West are largely the same, there is evidence suggesting the weights of these factors on transportation costs differ for these two regions. For instance, western coal traffic tends to be associated with longer hauls than eastern traffic. Hence, the effect of distance on the change in average transportation cost for western traffic is assumed to be more influential. In addition to the incorporation of a regional component, an improved representation of productivity was also an objective. In previous formulations of the transportation index, a time trend served as a proxy for productivity. A time trend is not amenable to the development of sensitivity cases in which productivity falls or increases; therefore an alternative was sought.

The methodology was revised for the AEO2009 because the FERC 580 survey, the basis for the AEO2005 methodology, only includes a sample of coal shipments to electric utilities. As deregulation lowered the number of utilities nationwide, this sample size dropped even more. Therefore, an update of the historical information for the dependent variable in the regression model (transportation rate), distance, and contract information, all previously derived from the FERC Form 580, would not represent all coal shipments. The revised AEO2009 methodology combines the historical FERC Form 580 information through 1999 (supplemented with information from the Surface Transportation Board's Carload Waybill Sample) with the average transportation rates inferred from the FERC Form 423, Form EIA-423, and Form EIA-7A surveys for the years 2000 through 2005 to approximate the dependent variable of the equation. The current escalation methodology uses data through 2006.

Theoretical approach

The general intent of the transportation index is to account for the variables that are correlated with or impact non-inflationary changes in average coal transportation rates over time. The approach taken to develop a revised formulation included a review of the factors contributing to historical changes in transportation rates, the development of a list of potential predictive variables, and the actual development of a regression model.

Although coal is transported by rail, barge, truck, and conveyor, the most frequently used form of transportation for coal is rail. In 1980, 59% of coal was transported by rail alone. In 2012, rail carried 70% of all domestic coal shipments. Currently, all modes of coal transportation are aggregated within the DCDS. In addition, limited data resources are available for the less dominant modes of coal transport. For these reasons, the regression is formulated with a railroad focus.

The Staggers Act of 1980 partially deregulated the railroad industry, allowing greater flexibility in the prices charged to rail customers. From 1980 through the 1990s, competitive pressures between rail companies inspired productivity improvements both related to and independent of the consolidation of the rail industry and the reduction of redundancies in the rail network. As the rail industry consolidated, many jobs were eliminated and replaced with investments in capital equipment. Unit trains, as long as 110 railcars and dedicated to the servicing of a single destination, contributed to improvements in average train speed and fuel economy. Larger, more powerful locomotives and the use of lighter aluminum rail cars, rather than cars made entirely of steel, have also had a beneficial impact on productivity. Bigger rail cars, capable of holding 100 tons each, longer train sets, and double tracking are also among the improvements cited by the rail industry.

The Clean Air Act Amendments of 1990 (CAAA90) imposed sulfur dioxide emissions limits on the electric power industry. As a result, more low-sulfur western coal was being used and shipped to locations much farther away than previously thought practical. This coal, lower in thermal content than typical eastern bituminous coals, previously was regarded as too high in moisture content and too volatile to transport long distances. Also, transportation rates from western supply regions became increasingly competitive to help western coal penetrate eastern markets. Lower, competitively-priced transportation rates, coupled with low western minemouth prices and lower sulfur content, made many generators interested in at least trying western subbituminous coal. An increase in the share of western coal required to satisfy national coal demand is assumed to be negatively correlated with transportation rates.

The railroad industry is capital-intensive and requires investments in the purchase and servicing of equipment such as freight cars, land, inventory, and structures such as tracks. Without investments in capital structure, many productivity improvements would not have occurred in the historical period. For this reason, some representation of investment was deemed to be a necessary for the current formulation. For the East regression, the PPI for rail transportation equipment was transformed into a user cost of capital for rail equipment by accounting for the interest rate, depreciation, and any capital gain or loss associated with the investment. Unlike productivity, which is expected to push prices downward, with all other variables held constant, an increase in the user cost of capital tends to increase transportation rates. For the West, the same term did not prove significantly. Instead, gross capital expenditures for Class I railroads was used as a proxy for western railroad investments.

While diesel fuel historically has represented a fairly small share, 9%,[32] of railroad operating costs and fixed charges, high fuel costs in recent years are assumed to have an increasing influence on overall transportation costs. The diesel fuel price is included as an explanatory variable for the eastern formulation for 2001 through 2006. Diesel fuel prices did not appear to be significant for the western formulation and do not have an effect on the formula for the east in years before 2001.

For the dependent variable, calculated prices from the Coal Transportation Rate Database (CTRDB) were used to develop the index for the historical period from 1980 to 1999. These data were based on the FERC Form 580 in combination with supplemental data from the Surface Transportation Board's Carload Waybill Sample. Multimode shipments were included with rail since rail travel is frequently a component of multimode shipments. For the period 2000 through 2006, average transportation rates were inferred

[32] Association of American Railroads, *AAR Railroad Cost Indexes* (September 2003), p. 4.

from the FERC Form 423 and the Form EIA-423 surveys and EIA's Form EIA-7A. The 423 surveys provide delivered price information for the electricity sector, and minemouth prices are obtained from the Form EIA-7A survey. The difference between the delivered prices and minemouth price is assumed to be the transportation rate. The resulting data series was merged with the CTRDB data by rebasing both series to their respective 1999 values (indexed to 1.00).

The regression analysis relies on the following explanatory variables: productivity, user cost of capital of railroad equipment (east), investment dollars (west), diesel fuel price (east), and western share of national coal demand (west). These variables were chosen because of their ability to explain variability in the dependent variable during the historical time period, their availability, the ability to develop reasonable estimates of their future values for NEMS, and their ability to generate a statistically reasonable regression.

Equation specification

EAST INDEX = f(PRODUCTIVITY, USER COST OF CAPITAL OF RAILROAD EQUIPMENT, DIESEL FUEL PRICE)

and

WEST INDEX = f(PRODUCTIVITY, INVESTMENT DOLLARS, WESTERN SHARE OF NATIONAL COAL DEMAND)

Variables:

EAST and WEST INDEX, the dependent variables, are the values of the transportation price index in year t for coal originating east of the Mississippi River and west of the Mississippi River, respectively. For the historical data series (1980 through 1999), this value is calculated from the yearly average transportation rates (dollars per ton) calculated from the CTRDB for rail and multimode shipments of coal originating from eastern supply sources for the East index and from western supply sources for the West index. The CTRDB nominal dollars per ton is subsequently divided by the chain-weighted implicit gross domestic product (GDP) deflator to convert the rate to real 1987 dollars.

The CTRDB represents only a subset of the electric power industry. The CTRDB is mainly based on the FERC 580 Form, *Interrogatory on Fuel and Energy Purchase Practices*, which collects information from jurisdictional utilities (investor-owned utilities that sell electric power at wholesale prices to other utilities) owning at least one power plant of 50 MW or more. The FERC Form 580 collects coal shipment information and transportation costs related to contract shipments between coal utilities and coal producers and brokers of one year or greater in duration on a biannual basis. This database is also supplemented with data from the Surface Transportation Board's Carload Waybill Sample.

For 1998 through 2006, transportation rate data were imputed using the difference between the delivered price of coal to the electricity sector from FERC Form 423 and EIA's Form EIA-423 and the minemouth prices from the Form EIA-7A. This methodology was not used for earlier years because of the unavailability of data before 1998. For this series, data were rebased so that 1999 equals 1.00 and then merged with the CTRB data for the years 1999 through 2006.

PRODUCTIVITY is defined as billion ton-miles per employee per year for Class I railroads. This variable has not been converted to an index. The ton-miles and employee information is derived from data collected by the Association of American Railroads (AAR) and annual reports from the four largest major freight railroads and represents productivity for these railroads' entire freight traffic, not just coal.

Ton-miles per employee is calculated by multiplying the total revenue tons by the average length of haul for all freight shipments divided by the number of railroad employees for Class I railroads. Class I railroads are defined by the Surface Transportation Board as those line haul freight railroads whose adjusted annual operating revenues for three consecutive years exceed 250 million dollars.[33] This definition has changed over time as the revenue criteria have changed and railroads have entered and exited the railroad industry. Class I railroads generate most of the revenue and move most of the freight in the rail industry. In performing the calculation, East tons and average haul are calculated from shipments originating in the East while West tons and average haul are calculated from shipments originating in the West. In calculating the number of Eastern employees, the following railroad companies were included in the historical series: CSX Transportation, Norfolk Southern, Consolidated Rail, Illinois Central, and Florida East Coast Railway Company. In calculating the number of Western employees, the following railroad companies were included in the historical series: Union Pacific, Burlington Northern & Santa Fe, Southern Pacific, Atchison, Topeka & Santa Fe, Chicago & North Western, Grand Trunk Corporation, Soo Line Railroad, and Kansas City.

USER COST OF CAPITAL OF RAILROAD EQUIPMENT (UCC) is calculated from the producer price index (PPI) for railroad equipment. The PPI is obtained from the Bureau of Labor Statistics series WPS144. The user cost of capital, intended to capture the true cost of purchasing transportation equipment, accounts for the opportunity cost of money used to purchase the equipment, depreciation occurring as a result of use of the equipment (assumed at 10%), less any capital gain associated with the worth of the equipment. The formula to convert the PPI to a user cost of capital is the following:

$$UCC_t = (r_t - \delta - (p_t - p_{t-1})/p_{t-1}) * p_t \qquad \{costcap\}$$

where

r_t is a proxy for the real rate of interest, where r_t = ((AA Utility Bond Rate$_t$ + greenhouse gas risk premium)/100) – [GDP Deflator$_t$ – GDP Deflator$_{t-1}$)/GDP Deflator$_{t-1}$]; {realrate, MACOUT_MC_RMCORPPUAA, EMISSION_EXTRARISK, MACOUT_MC_JPGDP}

δ is the rate of depreciation on railroad equipment, assumed (value is specified directly in the AIMMS code, not as a parameter input to the CMM) to equal 10% per year; and

p_t is the PPI for railroad equipment (1982=1), adjusted to constant 1987 dollars using the GDP deflator for year t.{PPIraileq}

[33] Surface Transportation Boardwebsite at https://www.stb.gov/stb/faqs.html.

In the projections, the PPI for railroad equipment is estimated from the year-over-year change in railroad capital expenditures, based on railroad ton-mile growth, and uses a three year moving average. {PPIraileq2}

The three terms represented in the annual user cost of railroad equipment are defined as follows:

rp_t is the opportunity cost of having funds tied up in railroad equipment in year t;

δp_t is the compensation to the railroad company for depreciation in year t; and

$((p_t - p_{t-1})/ p_{t-1}))\, p_t$ is the capital gain on railroad equipment (in a period of declining capital prices, this term will take on a negative value, increasing the user cost of capital for year t).

INVESTMENT was originally calculated from the gross capital expenditures of Class I railroads in a given year, sourced from the *U.S. Census Bureau Statistical Abstract*. These gross capital expenditures include expenditures on equipment, roadway, and structures. Historical expenditures are entered through 2006 and held flat thereafter in the projections. This data is input as an AIMMS variable {dist_w} but not used. Instead, investment {invtemp} is calculated as {INVDOL} + {investadder}, where the investment adder is computed from the change in ton-miles from the previous two years multiplied by $0.053 per ton-mile and added to an initial investment level {INVDOL} of $93,166 Billion (1987$).

WESTERN SHARE OF NATIONAL TOTAL COAL PRODUCTION is the total proportion of coal produced that is supplied from west of the Mississippi River. This rising share since 1980 was correlated with declining transportation rates through and including 2005 as the West sought to increase its market share. This variable is assumed to be correlated with changes in transportation rates in the projection period.

RHO: In conducting the regression for the East and West index, the Durbin-Watson statistic indicated autocorrelation was present. Autocorrelation indicates that some portion of the error term is capable of being forecast but is not represented by the independent variables in the equation. A correction for autocorrelation, rho, was incorporated into the equations in TSP 4.5 with the AR1 option for first-order correlation.

Using ordinary least squares (OLS) regression and correcting for autocorrelation, the following equations were derived:

{FinalEast} $\text{EAST INDEX} = [\text{EAST INDEX}_{t-1}{}^{rho_e} + (A_E * (1 - rho_e)) + (B1 * \text{productivity}_t) - (B1 * rho_e * \text{productivity}_{t-1}) + (B2 * \text{uccrequ}_t) - (B2 * rho_e * \text{uccrequ}_{t-1}) + (B3 * \text{DUM05} * \text{diesel fuel price}_t) - (B3 * rho_e * \text{DUM05} * \text{diesel fuel price}_{t-1})] / \text{EAST INDEX}_O$

where
A_E = constant term {Cof5}
B1 = the regression coefficient for productivity {cof6}
B2 = the regression coefficient for the user cost of capital {Cof9}
B3 = the regression coefficient for the diesel fuel price {Cof7}
DUM05 = 1 if year > 2000, else 0 {dum}

rho_e= correction for autocorrelation {Cof8}
Productivity East (Ton-Miles/Employee) {Tr_prod_e}
uccrequ = user cost of capital for railroad equipment {CostCap}
diesel fuel price {MPBLK_PDSIN(11)} –National Diesel Fuel Price to Industrial sector
EAST $INDEX_O$ = the value of EAST INDEX in the base year {EastEscalator(CPSBaseYr)}

A semi-log linear specification was used to develop the West econometric formula.

{FinalWest} WEST $INDEX_t$ = [$WestEscalator_t$ / $WestEscalator_O$]

and $WestEscalator_t$ = $\exp(A_W * (1 - rho_w) + (B5*invest_t) - (B5*rho_w* invest_{t-1}) + (B4*productivity_t) - (B4 * rho_w *productivity_{t-1}) + (B6*wshnatl_t) - (B6*rho_w*wshnatl_{t-1})]$

Where
A_W = constant term {Cof1}
B5 = the regression coefficient for investment {Cof2}
B4 = the regression coefficient for productivity {Cof3}
B6 = the regression coefficient for the western share of national coal demand {Cof4}
rho_w = correction for autocorrelation {Cof10}
Productivity West (Ton-Miles/Employee) {Tr_prod_w}
wshnatl = western share of national coal demand for 1981 to 2005 {COALOUT_WESTSUP}
invest = Class I railroad investment dollar index {invest2}
$WestEscalator_O$ = the value of WEST INDEX in the base year {WestEscalator(CPSBaseYr)}

Table 2.C-1. Statistical regression results

	EAST INDEX	WEST INDEX
Method of estimation:	Ordinary Least Squares	Ordinary Least Squares
Number of observations:	27 (years 1980–2006)	26 (years 1981–2006)
Mean of dependent variable:	1.29086	0.262376
Standard deviation of dep. var.:	.216717	0.335155
Sum of squared residuals:	.131569	0.045453
Variance of residuals:	0.598043^{-02}	0.216443^{-02}
Standard error of regression:	0.077333	0.0465223
R^2:	0.892330	0.984019
Adjusted R^2:	0.872753	0.980975
Rho:	0.361206	0.547600
Durbin-Watson:	1.77288	1.85383
Schwarz B.I.C.:	-29.710825.3577	-37.9701
Log likelihood:	37.856133.5973	46.1153

EAST INDEX

Variable	Estimated coefficient	Standard error	t-statistic	P-value
Constant	1.59107	0..120371	13.2180	[0.000]
Productivity	-0.124193	.013626	-9.11410	[0.000]
User cost of capital for rail equipment	0.011394	0.486063^{-02}	2.34421	[0.019]
Diesel fuel price	0.077039	0.010463^{-02}	7.36320	[0.000]
Rho	0.361206	0.203607	1.77403	[0.076]

WEST INDEX

Variable	Estimated coefficient	Standard error	t-statistic	P-value
Constant	0.632603	0.132541	4.77287	[0.000]
Productivity	-0.111765	0.010056	-11.1148	[0.000]
Western share of national coal demand for years less than 2006	-0.264830	0.087420	-3.02939	[0.002]
Investment	0.434937	0.154393	2.81707	[0.005]
Rho	0.547600	0.232696	2.35329	[0.019]

Table 2.C-2. Data sources for transportation variables

Variable	Units	Historical data	Forecasted data
Transportation Rate	No units (index)	1980–1999: Derived from U.S. Energy Information Administration, Coal Transportation Rate Database (CTRDB); 2000–2006: imputed from difference between delivered prices on FERC/EIA Form 423 and minemouth prices from Form EIA-7A	Forecasted endogenously from econometric equation.
Productivity	Billion Freight Ton-Miles/Employee	Derived from data from the Association of American Railroads and Class I Railroads' Annual 10-K Reports	Projected to remain flat from 2012 levels.
User Cost of Capital for Rail Equipment	No units (index)	Derived from the PPI for rail equipment from Bureau of Labor Statistics (Series WPS144).	PPI for rail equipment is assumed to change proportionately with year-over-year changes in national coal ton-miles. Each forecast year uses a three-year rolling average of the PPI.
Gross Capital Expenditures for Class I railroads	Million Dollars	U.S. Census Bureau, *Census Bureau Statistical Abstract,* (Washington, DC, various editions), website http://www.census.gov/compendia/statab/	Changes proportionately with year-over-year change in national coal ton-miles (estimated by model).
Western share of national coal demand	Percentage	U.S. Energy Information Administration, *Annual Energy Review 2007*, (Washington, DC, June 2007), Table 3.3, website http://www.eia.doe.gov/emeu/aer/pdf/aer.pdf	Linked to model output.
Diesel Price	Dollars per million Btu	U.S. Energy Information Administration, *Annual Energy Review 2007*, (Washington, DC, June 2007), Table 3.3, website http://www.eia.doe.gov/emeu/aer/pdf/aer.pdf	The coefficient is changed to zero to avoid double-counting the effects of the fuel surcharge discussed below.

Table 2.C-3. Historical data used to calculate East index

Year	Productivity (East ton-miles/East employees)	UCC rail equipment	Diesel fuel price (nominal dollars per MMBtu)	Transportation rate (1987 dollars, 1999=1.00)	GDP deflator
1980	1.75	12.63	5.90	1.43	0.74
1981	1.82	21.39	7.17	1.58	0.81
1982	1.82	25.11	6.79	1.58	0.86
1983	2.24	24.54	5.96	1.61	0.89
1984	2.48	24.53	5.93	1.62	0.92
1985	2.52	21.81	5.69	1.48	0.95
1986	2.63	20.35	3.45	1.49	0.97
1987	3.11	21.30	3.97	1.45	1.00
1988	3.40	18.26	3.61	1.47	1.03
1989	3.54	14.44	4.22	1.39	1.07
1990	3.94	16.62	5.23	1.37	1.11
1991	4.09	16.99	4.67	1.34	1.15
1992	4.32	18.13	4.46	1.20	1.18
1993	4.66	16.80	4.34	1.24	1.21
1994	5.07	15.75	3.99	1.12	1.23
1995	5.35	14.44	4.04	1.14	1.26
1996	5.68	16.89	4.91	1.14	1.28
1997	6.07	19.96	4.63	1.14	1.30
1998	6.20	17.08	3.56	1.05	1.32
1999	6.04	17.54	4.21	1.00	1.34
2000	6.59	17.54	6.74	0.99	1.37
2001	6.94	17.27	6.07	1.24	1.40
2002	7.47	16.48	5.49	1.15	1.42
2003	7.78	14.37	6.81	0.91	1.45
2004	8.52	10.14	8.96	0.96	1.50
2005	8.35	4.40	12.88	1.29	1.54
2006	8.34	10.96	15.11	1.51	1.59

Table 2.C-4. Historical data used to calculate West index

Year	Productivity (West ton-miles/West employees)	Investment (1987 dollars, 1981= 1.00)	Western share of national coal demand	Transportation rate (1987 dollars, 1999=1.00)	GDP deflator
1981	2.50	1.00	0.24	1.89	0.81
1982	2.57	0.97	0.24	1.96	0.86
1983	2.98	0.93	0.24	1.96	0.89
1984	3.31	1.19	0.24	2.15	0.92
1985	3.32	1.15	0.29	2.04	0.95
1986	3.64	1.13	0.23	2.13	0.97
1987	4.41	1.12	0.24	1.94	1.00
1988	4.88	1.12	0.26	1.73	1.03
1989	5.18	1.11	0.26	1.65	1.07
1990	5.47	1.06	0.30	1.57	1.11
1991	5.78	1.06	0.32	1.34	1.15
1992	6.21	1.04	0.31	1.33	1.18
1993	6.54	1.04	0.36	1.25	1.21
1994	7.20	1.05	0.36	1.19	1.23
1995	8.03	1.07	0.39	1.17	1.26
1996	8.64	1.15	0.37	1.10	1.28
1997	8.58	1.18	0.36	1.09	1.30
1998	8.71	1.24	0.38	1.02	1.32
1999	9.43	1.30	0.42	1.00	1.34
2000	10.11	1.30	0.42	0.92	1.37
2001	10.72	1.31	0.43	0.87	1.40
2002	11.00	1.30	0.44	0.87	1.42
2003	11.49	1.39	0.45	0.83	1.45
2004	11.94	1.42	0.48	0.83	1.50
2005	11.71	1.53	0.51	0.89	1.54
2006	11.97	1.54	0.53	0.97	1.59

For the projection period, the explanatory variables are assumed to have varying impacts on the calculation of the indexes. For both the East and West indexes, investment is assumed to occur in response to changes to coal demand. Overall US coal demand is measured by the change in coal ton-miles, as calculated by the model. If national ton-miles increase, the terms representing investment (for both the East and the West) are assumed to increase. Likewise, if ton-miles decrease, investment may decline. This assumption is derived partly from the assertion by railroads that they will be hesitant to make investments in capacity unless the demand is already present. Industry documents indicate that capital programs are correlated with the revenue received. Changes in ton-miles are naturally correlated with changes in revenue. In addition, other analysis has concluded that transportation investment is more sensitive to business cycles than other businesses. An increase in ton-miles encourages investments to expand capacity and alleviate congestion, and a decline in ton-miles will similarly discourage investments.

Historically, cost savings derived from improvements in productivity have been accompanied by declining transportation rates. For both the East and the West, any related financial savings as a result of productivity improvements through 2050 are assumed to be retained by the railroads and are not passed on to shippers in the form of lower transportation rates. For that reason, productivity is held flat for the projection period for both regions. For the East, for the projection period, diesel fuel is removed from the equation in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program.

Fuel Surcharge

Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. Although the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, has recommended that the railroads agree to develop some consistencies across their disparate programs and has likewise recommended closely linking the charges to actual fuel use. The STB has cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.

The effects of a fuel surcharge program were incorporated into the projected coal transportation rates for the first time in AEO2007, based on BNSF Railway Company's mileage-based program for all regions. The current methodology is based on BNSF Railway Company's mileage-based program for western coal sources, and for the East the methodology is based on CSX Transportation's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon for the West and $2.00 per gallon for the East. For the West, for every $0.06 per gallon increase to more than $1.25, a $0.01 per carload mile is charged, and for the East, for every $0.04 per gallon increase to more than $2.00, a $.01 per gallon fee is assessed. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a predetermined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate.

The base year transportation rates are already assumed to include an assessed fuel surcharge. The model calculates the fuel surcharges for the base year and subtracts it from the corresponding base year transportation rate. These modified lower base-year transportation rates are used in subsequent forecast years, and the fuel surcharges and transportation escalators for a specific forecast year are applied to these lower rates.

Data Sources

EIA maintains a number of annual surveys of coal production and distribution, and it has access to data from several surveys collected for the Federal Energy Regulatory Commission (FERC) that report the fuel purchase and delivery practices of the nation's electricity sector. Other information comes from Census Bureau forms that report coal imports and exports. Data from the Association of American Railroads, the Surface Transportation Board, the Mine Safety and Health Administration, and state agency reports of mining activity supplement these sources.

- Form EIA-3, Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Users, surveys heat, sulfur, and ash content of coal receipts delivered to industrial steam, commercial, and institutional coal consumers by consumption location and state of origin.
- Form EIA-5, *Quarterly Coal Consumption and Quality Report, Coke Plants*, surveys volatility, sulfur, and ash content of coal receipts delivered to coke plants by consumption location and state of origin.
- Form EIA-7A, *Coal Production and Preparation Report*, covers coal producers and coal preparation plants and reports production, minemouth prices, coal seams mined, labor productivity, employment, stocks, and recoverable reserves at mines.
- Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*, covers electric nonutility plants with capacity of 50 MW or more and reports delivered cost, receipts, ash, Btu, sulfur, and sources. Beginning in 2008, coal receipts data previously collected on the Form EIA-423 and FERC Form 423 are now collected by EIA on Form EIA-923.
- FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, covers electric utility plants with capacity of 50 MW or more and reports delivered cost, receipts, ash, Btu, sulfur (*As Received* basis), and sources. Beginning in 2008, coal receipts data previously collected on the Form EIA-423 and FERC Form 423 are now collected by EIA on Form EIA-923.
- Form EIA-923, *Power Plant Operations Report*, collects information from regulated and unregulated electric power plants in the United States. Data collected include electric power generation, energy source consumption, end of reporting period fossil fuel stocks, and quality and cost of fossil fuel receipts.
- FERC Form 580, *Interrogatory on Fuel and Energy Purchase Practices*, was a biennial survey of investor-owned utilities that sell electricity in interstate markets and have a capacity of more than 50 MW. This survey covers contractual base tonnage, tonnage shipped, ash, Btu, sulfur and moisture (*As Received* basis), minemouth price, freight charges, coal source and destination, shipping modes, transshipments (if any), and distances.
- Form EM 545 from the U.S. Census Bureau records coal exports by rank, value, and tonnage from each port district. The Census Bureau's Form IM 145 reports imports by rank, value, tonnage, and port district.
- The Carload Waybill Sample, administered by the Surface Transportation Board, contains confidential information on a sample of waybills from those railroads that terminate at least 4,500 cars per year. The data collected includes origin, destination, tons, commodity type, revenue, and distance information. This information has been used to supplement EIA's CTRDB database.

Data gaps

The resources that are available to support the NEMS CPS and CDS include a series of databases derived from a variety of surveys that are valuable for their national scope and census-like coverage. However, as shown in Table 2.C-5, no data from mines are routinely collected on the quality of coal produced at the mine or the minemouth price for coals of different quality levels. The Form EIA-923, which has replaced the FERC Form 423 and the Form EIA-423, now asks for mine origin information in addition to coal quality information. By doing this, it is possible in some instances to infer some coal quality information for particular mines when the respondents have specific knowledge of their coal supplier. The Form EIA-923 together with the Forms EIA-3 and EIA-5 (which provide state origin information) provide some coal quality data that assist in assigning coal quality information to coal supply regions.

Although EIA publishes data identifying the tonnage of exported coal mined in each state, and the U.S. Department of Commerce collects data on the tonnage exported (by port district), no data are available to identify the tonnage from each mining state that is exported at each port of exit. Coals consumed by surveyed sectors (electricity, industrial, commercial/institutional, and coke plants) are known to differ in quality from coals delivered to currently unsurveyed sectors (residential, export metallurgical, and export steam). The Form EIA-7A requests information about export quantities. Where the coal quality characteristics of the mine can be inferred from information gathered on the Form EIA-923, some coal quality characteristics for exports can be likewise deduced. Consumption in the un-surveyed sectors currently accounts for a small percentage of production.

The difference between delivered costs as shown on the Forms EIA-923, EIA-3, EIA-5, and EM 545 and minemouth costs as shown on Form EIA-7A in the most recent available historical year is used to estimate transportation rates. (Although commodity cost and delivered cost are available on the Form EIA-923, transportation rates are not currently calculated from that form alone as a result of insufficient or incomplete information from the respondents.) This method allows estimation of different rates from each supply curve to each sector in each demand region, but it can do little to provide transportation rates for routes that have not been used, even if data for more remote historical years were used. More than half the routes indicated by the CDS supply and demand region classification structures have not been used for coal transport in significant quantities in recent years. In the version of the CDS documented here, rates for these routes have been synthesized using available data on tariff rates and analytical judgment, while others that are unlikely to be used are given dummy values that prevent their use.

The general availability of coal-related data that were used to build and calibrate the DCDS for the *Annual Energy Outlook 2020* is summarized in Table 2.C-5.

Table 2.C-5. Survey sources used to develop CMM inputs

	Electricity	Industrial	Coking	Commercial[1] /industrial	Export	Import	Mine
Prices:							
Minemouth prices							EIA-7A
Delivered prices	EIA-923	EIA-3	EIA-5	EIA-3	EM 545[2]	EIA 3,5,923	
Transportation:							
Transportation mode	EIA-923	EIA-3	EIA-5	EIA-3			
Origin	EIA-923	EIA-3	EIA-5	EIA-3	EIA-7A	IM 145[2]	EIA-7A
Destination	EIA-923	EIA-3	EIA-5	EIA-3	EM 545[2]	EIA 3,5,923	
Tonnage:							
Production	EIA-923	EIA-3	EIA-5	EIA-3	EIA-7A		EIA-7A
Receipts	EIA-923	EIA-3	EIA-5	EIA-3		EIA 3,5,923 and IM 145[2]	
Distribution	EIA-923	EIA-3	EIA-5	EIA-3	EM 545[2]	EIA 3,5,923 and IM 145[2]	
Consumption	EIA-923	EIA-3	EIA-5	EIA-3			
Contact information	EIA-923	EIA-3	EIA-5	EIA-3		EIA-923	
Quality:							
Rank	EIA-923	EIA-3	EIA-5	EIA-3	EM 545[2]	EIA 3,5,923	EIA-7A
Heat content	EIA-923	EIA-3	EIA-5	EIA-3		EIA 3,5,923	
Sulfur content	EIA-923	EIA-3	EIA-5	EIA-3		EIA 3,5,923	
Ash content	EIA-923	EIA-3	EIA-5	EIA-3		EIA 3,5,923	
Mercury content	EIA-923	EIA-3	EIA-5	EIA-3		EIA 3,5,923	
Volatile matter			EIA-5				

Notes:

[1] *Commercial/institutional* replaces *residential/commercial* and excludes residential information.

[2] The EM 645 and the IM 145 are reports from the U.S. Census Bureau.

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Appendix 2.E DCDS Submodule Abstract

Model name: Domestic Coal Distribution Submodule

Model abbreviation: DCDS

Description: United States coal production, national coal transportation industries

Purpose: Forecasts of annual coal supply and distribution to domestic markets

Model update information: December 2019

Part of another model:

- Coal Market Module
- National Energy Modeling System

Model interface: The model interfaces with the following models: within the Coal Market Module, the DCDS interfaces with the Coal Production Submodule (CPS) and the International Coal Distribution Submodule (ICDS). Within NEMS, the DCDS receives projected industrial steam and metallurgical coal demands from the NEMS Industrial Demand Module, coal-to-liquids demands from the NEMS Liquid Fuels Market Module, residential demands from the NEMS Residential Demand Module, commercial demands from the NEMS Commercial Demand Module, and electricity sector demands from the NEMS Electricity Market Module. The DCDS also receives macro-economic variables from the NEMS Macro-Economic Activity Module.

Official model representative:

Office: Electricity, Coal, Nuclear, and Renewables Analysis
Team: Coal and Uranium Analysis
Model Contact: David Fritsch
Telephone: (202) 587-6538
Email: David.Fritsch@eia.gov

Documentation:

- U.S. Energy Information Administration, Model Documentation: Coal Market Module 2020) (Washington, DC, April 2020).

Information on obtaining NEMS: Availability of the National Energy Modeling System (NEMS) Archive.

Energy system described by the model: Coal demand distribution at various demand regions by demand.

Coverage:

- Geographic: United States (excluding Puerto Rico and the U.S. Virgin Islands).

- Time Unit/Frequency: 2003 through 2040 (with structure available through 2050)
- Basic Products Involved: Bituminous, subbituminous, and lignite coals in steam and metallurgical coal markets.
- Economic Sectors: Forecasts coal supply to two residential/commercial, three industrial, two domestic metallurgical, one coal-to-liquids, six export, and 35 electricity subsectors to 16 domestic demand regions.

Special features:

- All data on demands are exogenous to the DCDS.
- Supply curves (there are 41 supply sources) depicting the U.S. coal reserve base are exogenous to the DCDS and are reported in the DCDS from 14 coal supply regions.
- The DCDS currently contains no descriptive detail on coal transportation by different modes and routes. Transportation modeling consists only of sector-specific rates between regions represented on demand and supply curves that are adjusted annually for factor input cost changes.
- The DCDS output includes tables of aggregated output for the NEMS system and approximately six annual reports providing greater regional and sectoral detail on demands, production distribution patterns, and rates charged.
- Coal imports are calculated endogenously based on interaction with the ICDS.
- The DCDS reports minemouth, transport, and delivered prices, coal shipment origins and destinations (by region and economic subsector), and coal Btu and sulfur levels.

Modeling features:

- **Structure:** The DCDS uses 41 coal supply sources representing 12 types of coal produced in 14 supply regions and two mine types. Coal shipment costs to consumers are represented by transportation rates specific to NEMS sector and supply curve/demand region pair, based on historical differences between minemouth and delivered prices for such coal movements. In principle there are up to 31,360 such rates for any forecast year; in practice there are fewer because many rates are economically infeasible and because a unique transportation rate is not derived for each of the 35 electricity sectors. Coal supplies are delivered to up to 49 demand subsectors in each of the 16 demand regions. A single model solution represents a single year, but up to 36 consecutive years (2015–2050) may be run in an iterative fashion. Currently, the NEMS system provides demand input for the 1990–2050 period.
- **Modeling technique:** The model uses a linear program that minimizes the estimated delivered cost to all demand sectors.

- **Model interfaces:** The NEMS residential, commercial, and industrial models provide estimates of coal demand for those sectors, the NEMS Liquid Fuels Market Module provides demands for the coal-to-liquids sector, and the NEMS Electricity Market Module provides demands for the electricity generation sectors. The DCDS provides the NEMS with coal production estimates, Btu conversion factors, and estimated minemouth, transportation. and delivered costs for coal supplies to meet the demands. The DCDS interfaces with the ICDS to receive projected coal export demands. The DCDS interfaces with the CMM's Coal Production Submodule (CPS) to receive supply curves that specify the minemouth price in relation to the quantity demanded. In turn, the CPS receives production quantities from the CDS that are used to revise its prices, if necessary, for subsequent iterations.
- Input Data:
    - Physical:
        - Demand shares by sector and region: (1) residential/commercial (trillion Btu); (2) industrial steam coal (trillion Btu); (3) industrial metallurgical coal (trillion Btu); (4) industrial coal-to-liquids (trillion Btu); (5) import supplies (millions of short tons).
        - Coal contracts for electricity sector: (1) coal demand regions; (2) supply regions; (3) coal quality (Btu and sulfur content); (4) contract historical volumes (trillion Btu); (5) contract profiles for each forecast year.
        - Coal quality data for supply curves: (1) million Btu per short ton; (2) lbs. sulfur per million Btu; (3) lbs. of mercury per trillion Btu; (4) lbs. of carbon dioxide emitted per million Btu.
        - Coal quality specifications for regional subsectoral demands in electricity generation and other sectors.
    - Economic:
        - Supply curves relating minemouth prices to cumulative production levels.
        - Transportation rates: (1) 1987 dollars per short ton; (2) specified by subsector, differ by sector; (3) differ also by supply curve and demand region pair.
        - Transportation rate escalation factors: (1) endogenous; (2) regional (eastern and western railroads); (3) based on estimates of railroad productivity, the producer price index for rail equipment, contract duration, and distance (for western railroads only); (4) used to escalate and de-escalate transportation rates by forecast year.
        - Minemouth price adjustments: (1) can be made by supply region and forecast year; (2) currently used only by forecast year; (3) used to adjust for productivity change.
        - Transportation rate adjustments (not used in AEO2020): Adjustments can be applied by demand sector and demand region to calibrate rates in the model and are derived from an offline program that subtracts base-year minemouth costs from delivered costs reported in Forms EIA-3 and EIA-5, and EIA-923 to produce transport rates, calculate the ratio between the modeled rate and the rate from survey forms, and preserve the ratio as a model parameter.

Data sources:

- Form EIA-3, Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Users
- Form EIA-5, Quarterly Coal Consumption and Quality Report, Coke Plants
- Form EIA-7A, Coal Production and Preparation Report
- FERC Form 423, Monthly Report of Cost and Quality of Fuels for Electric Plants
- Form EIA-423, Monthly Cost and Quality of Fuels for Electric Plants Report
- Form EIA-923, Power Plant Operations Report
- FERC Form 580, Interrogatory on Fuel and Energy Purchase Practices
- U.S. Department of Commerce, Form EM-545, U.S. Exports of Domestic and Foreign Merchandise
- U.S. Department of Commerce, Form IM-145, *U.S. General Imports*
- Association of American Railroads, AAR Railroad Cost Indices (Washington, DC, quarterly)
- Rand McNally and Co., Handy Railroad Atlas of the United States (Chicago, IL, 1988)
- Caplan, Abby, et al., eds., 1996-1997 Fieldston Coal Transportation Manual (Washington, DC, 1996)

Output data:

- Physical: Forecasts of annual coal supply tonnages (and trillion Btu) by economic sector and subsector, coal supply region, coal Btu, coal sulfur content, coal mercury content, and demand region.
- Economic: Forecasts of annual minemouth, transportation, and delivered coal prices by coal type, economic sector, coal demand, and supply regions.

Computing environment: See Integrating Module of the NEMS

Independent expert reviews conducted:

Independent expert reviews were conducted for the Component Design Report, which was reviewed by Dr. Charles Kolstad of the University of Illinois and Dr. Stanley Suboleski of the Pennsylvania State University during 1992 and 1993.

An independent expert review was conducted in 2002 by PA Consulting Group and Energy Ventures Analysis, Inc. The focus of the review was on forecast levels of production supplied from the Powder River Basin and transportation rates. Some of the recommendations were incorporated into the *Annual Energy Outlook 2003*. As a result of the review, some transportation rates were re-estimated, a two-tier transportation rate structure was introduced, and two coal demand regions were redefined. The coal demand regions that were redefined included MT and ZN. Previously, Nevada, Colorado, and Utah were included in MT; the change included adding these states to ZN.

In 2003, PA Consulting Group and Energy Ventures Analysis, Inc. were asked to review the entire coal forecast of the *Annual Energy Outlook 2003*. Based on their recommendations, an additional coal demand region, CU, was added for the *Annual Energy Outlook 2004*, which includes Colorado, Utah, and Nevada.

Status of evaluation efforts conducted by model sponsor: No formal evaluation efforts other than the above reviews have been made at the date of this writing.

Last update: The DCDS is updated annually for use in support of each year's *Annual Energy Outlook*. The version described in this abstract was updated in January 2018.

3. International Coal Distribution Submodule (ICDS)

Introduction

The purpose of Section 3 of the Coal Market Module documentation is to define the objectives and basic approach used to forecast international coal trade in the International Coal Distribution Submodule (ICDS) and to provide information on the model formulation and application. It is intended as a reference document for model analysts, users, and the public. The report conforms to requirements specified in Public Law 93-275, Section 57(B)(1) (as amended by Public Law 94-385, Section 57.b.2).

Model summary

The ICDS projects coal trade flows from 17 coal-exporting regions (5 of which are in the United States) to 20 importing regions (4 of which are in the United States) for two coal types—steam and metallurgical. The model consists of exports, imports, trade, and transportation components. The major coal exporting countries represented include the United States, Australia, South Africa, Canada, Indonesia, China, Colombia, Venezuela, Poland, the countries of Eurasia (primarily Russia), and Vietnam. The structure of the international component of the ICDS endogenously models U.S. imports. The U.S. import algorithm is integrated with the domestic DCDS discussed in Chapter 2. All components of the Coal Market Module (CMM) are modeled within the AIMMS software framework.

Organization

This section of the report describes the modeling approach used in the international component of the CDS used to project international coal trade. Subsequent sections of this report describe the following:

- The model objective, input and output, and relationship to other models
- The theoretical approach and assumptions
- The model structure, including key computations and equations

An inventory of model inputs and outputs, detailed mathematical specifications, bibliography, and model abstract are included in the appendixes.

Model Purpose and Scope

Model objectives

The objective of the international component of the ICDS is to provide annual forecasts of world coal trade flows through 2050.

Coal exports in the ICDS are modeled using two coal types: steam and metallurgical. Steam coal is used primarily for electricity generation but is also used in the industrial, commercial, and residential sectors for the production of steam and direct heat. Metallurgical coal is used to produce coal coke, which in turn is used as a fuel and as a reducing agent for the smelting of iron ore in blast furnaces. There are 17 geographic export regions (Table 3.1), including 5 U.S. export regions, 2 Canadian export regions, and 10 additional major coal exporting countries/regions. The five U.S. coal export regions in the CMM (Figure 3.1) include the Northern Interior, the East Coast, the Gulf Coast, the Southwest and West, and the Non-Contiguous United States. These regions represent aggregations of ports of exit through which exported coal passes on its way from domestic export regions to foreign consumers. For instance, the Northern Interior includes 12 ports of exit including locations ranging from Boston, Massachusetts, to Great Falls, Montana. The Non-Contiguous U.S. region is represented by only two ports of exit, Anchorage and Seward, Alaska. These domestic port districts are identified in Table 3.1.

The metallurgical and steam sectors define the international coal import sectors. There are 20 coal import regions represented in the CMM (Table 3.2). The coal import regions for the United States are the same as the coal export regions, except that the U.S. Southwest and West is excluded. Canada is split into two coal import regions, Eastern and Interior. The remaining 14 coal import regions are represented as either individual countries or groups of two or more countries.

The U.S. share of world coal markets is defined as a linear optimization problem and is solved simultaneously with the domestic coal forecast.

Four key user-specified inputs are required. They include coal import requirements, coal export curves, transportation costs, and constraints (Figure 3.2). The primary outputs are annual world coal trade flows.

Relationship to other modules

The model generates regional forecasts for U.S. coal exports. These international U.S. export requirements are integrated with the DCDS so that sufficient production is allocated to U.S. exports. The ICDS also projects U.S. imports required to satisfy coal demand in the United States, as projected by the industrial and electricity models.

Table 3.1. ICDS coal export regions

Abbreviations	Export regions	Domestic port districts
UI	1 U.S. Northern Interior (I)	Boston, MA
		Portland, ME
		St. Albans, VT
		Buffalo, NY
		Ogdensburg, NY
		New York, NY
		Philadelphia, PA
		Detroit, MI
		Cleveland, OH
		Duluth, MN
		Pembina, ND
		Great Falls, MT
UE	2 U.S. East Coast (E)	Baltimore, MD
		Norfolk, VA
		Charleston, SC
		Savannah, GA
		Miami, FL
		San Juan, PR
		US Virgin Islands
		Tampa, FL
UG	3 U.S. Gulf Coast (G)	Mobile, AL
		New Orleans, LA
		Houston-Galveston, TX
		Laredo, TX
		El Paso, TX
UW	4 U.S. Southwest and West (W)	Nogales, AZ
		San Diego, CA
		Los Angeles, CA
		San Francisco, CA
		Stockton, CA
		Richmond, CA
		Portland, OR
		Seattle, WA
UA	5 U.S. Non-Contiguous (A)	Anchorage, AK
		Seward, AK
AU	6 Australia	NA
NW	7 Canada, Western	NA
NI	8 Canada, Interior	NA

Table 3.1. ICDS coal export regions (cont.)

Abbreviations	Export regions	Domestic port districts
SF	9 Southern Africa[1]	NA
PO	10 Poland	NA
RE	11 Eurasia[2] (exports to Europe)	NA
RA	12 Eurasia[2] (exports to Asia)	NA
HI	13 China	NA
CL	14 Colombia	NA
IN	15 Indonesia	NA
VZ	16 Venezuela	NA
VT	17 Vietnam	NA

[1]Southern Africa includes South Africa, Mozambique, and Botswana.

[2]Eurasia includes Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

Figure 3.1. U.S. export and import regions used in the CDS

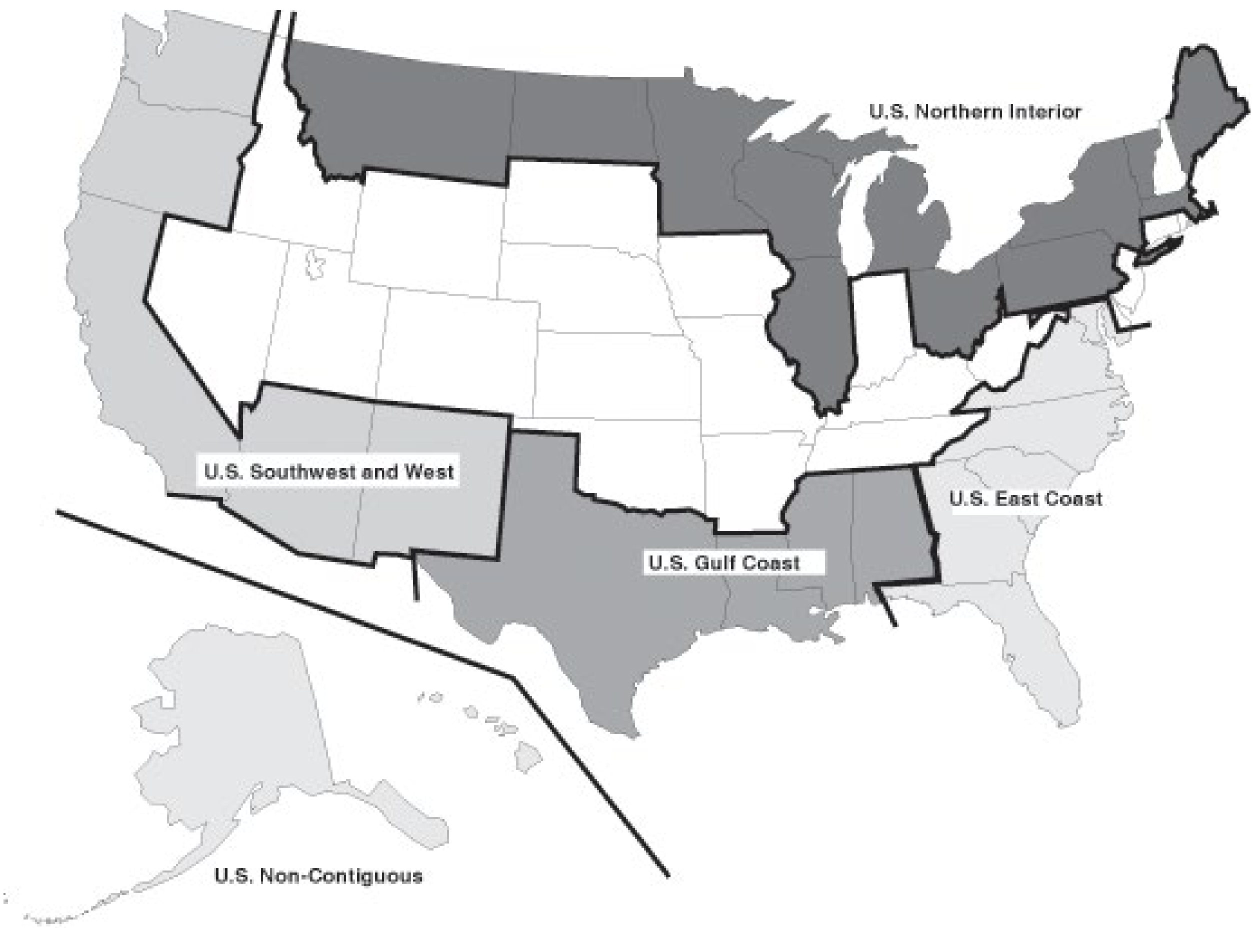


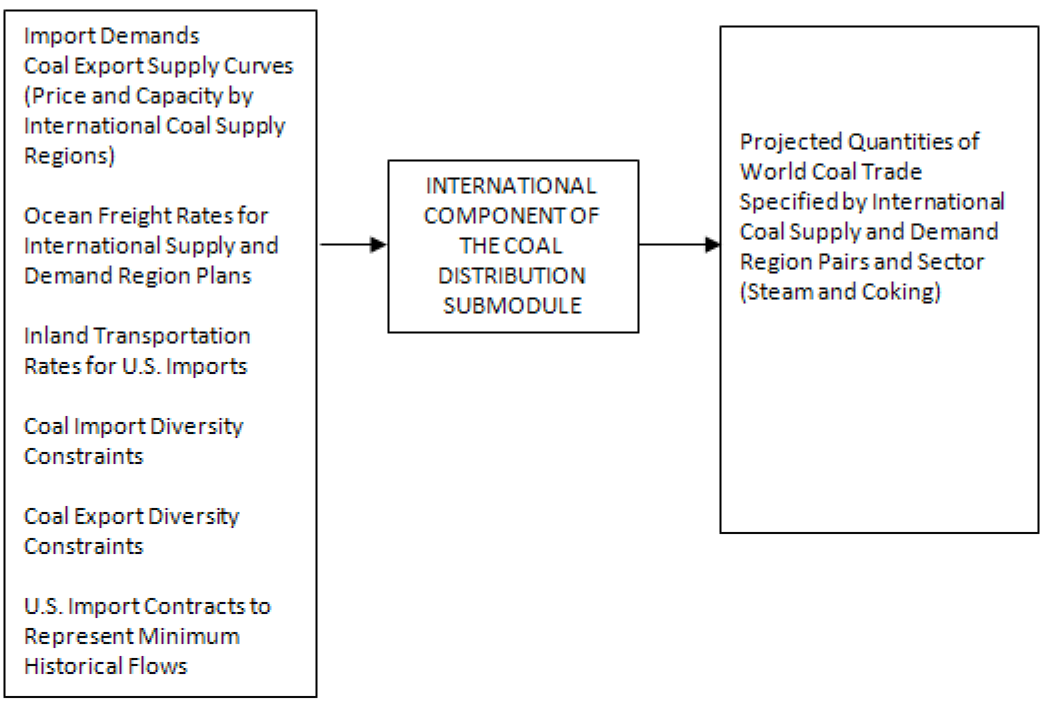
Table 3.2. ICDS coal import regions

Abbreviations	Import regions	Countries
UE	1 U.S. East Coast (E)	NA
UG	2 U.S. Gulf Coast (G)	NA
UI	3 U.S. Northern Interior (I)	NA
UN	4 U.S. Non-Contiguous (N)	NA
NE	5 Canada, Eastern	NA
NI	6 Canada, Interior	NA
SC	7 Scandinavia	Denmark
		Finland
		Norway
		Sweden
BT	8 United Kingdom/Ireland	NA
GY	9 Germany/Austria/Poland	NA
OW	10 Other NW Europe	Belgium
		France
		Luxembourg
		Netherlands
PS	11 Iberia	Portugal
		Spain
TL	12 Italy	NA
RM	13 Med./E. Europe	Algeria
		Bulgaria
		Croatia
		Egypt
		Greece
		Israel
		Malta
		Morocco
		Romania
		Tunisia
		Turkey
MX	14 Mexico	NA
LA	15 South America	Argentina
		Brazil
		Chile
		Peru
		Puerto Rico

Table 3.2. CDS coal import regions (cont.)

Abbreviations	Import regions	Countries
JA	16 Japan	NA
EA	17 East Asia	North Korea
		South Korea
		Taiwan
CH	18 China/Hong Kong	NA
AS	19 ASEAN	Malaysia
		Philippines
		Thailand
		Vietnam
IN	20 Indian sub/S. Asia	Bangladesh
		India
		Iran
		Pakistan
		Sri Lanka

Figure 3.2. International component inputs/outputs



Model rationale

Theoretical approach

The core of the ICDS is a linear programming optimization model. This LP model finds the pattern of coal production and trade flows that minimizes the production and transportation costs of meeting a set of regional net import requirements. The basic underlying assumption regarding the modeling of international coal trade in the ICDS is that the international coal market is essentially a perfectly competitive market. The key conditions of a perfect market are that there are no real significant barriers to entry and exit on the export side, there are a large number of buyers and sellers, and no single buyer or seller controls enough of the market so as to be able to exert pricing power.

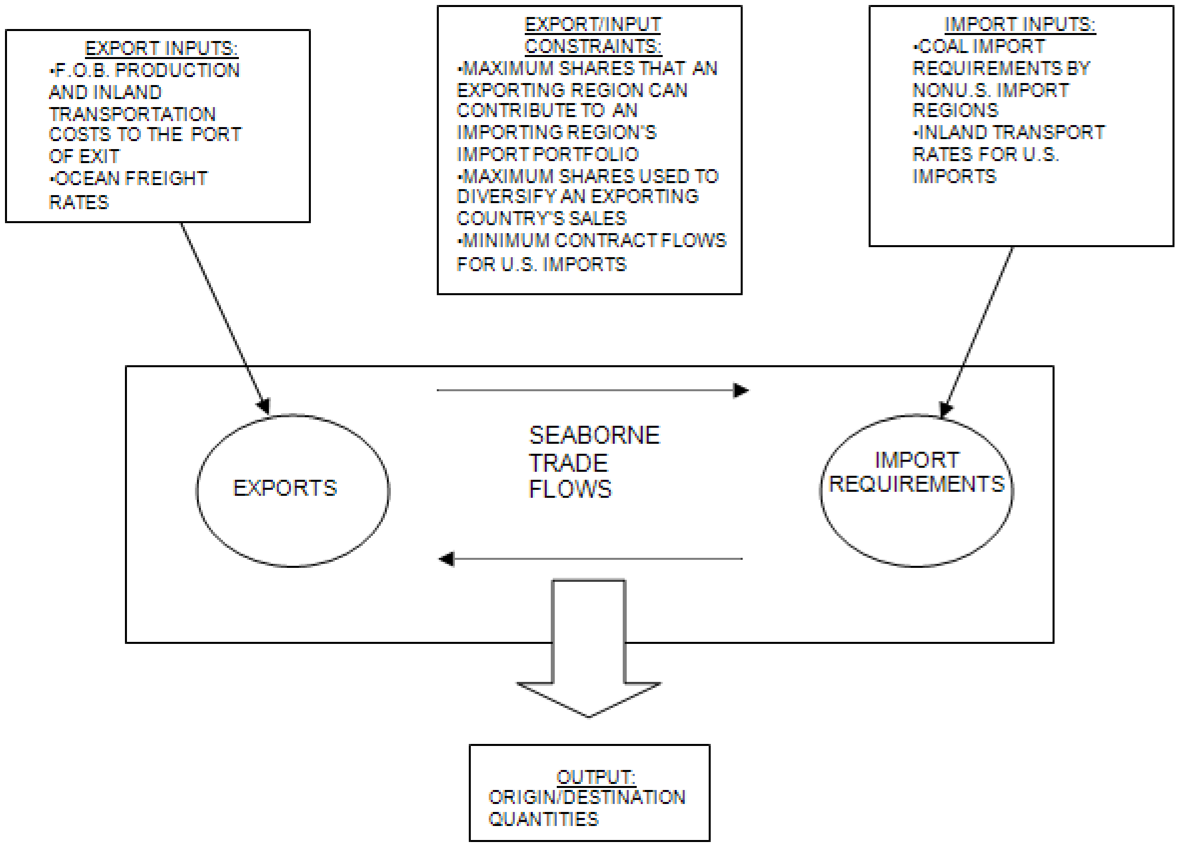
Although a perfectly competitive market is the basic underlying assumption used for modeling international coal trade in the CMM, the model solution is subject to a number of key constraints:

- Export capacity of export regions.
- Maximum share that any importing region can take from one exporting region. Coal buyers (importing regions) will tend to spread their purchases among several suppliers in order to reduce the impact of supply disruption, even though this action will add to their purchase costs.
- Maximum share that any exporting region will sell to one importing region. Coal producers (exporting regions) will choose not to rely on any one buyer and will diversify their sales.
- Sulfur dioxide emission limits for U.S. imports. U.S. coal imports are subject to SO2 emission regulations as set forth under CAAA90 and Clean Air Interstate Rule or Cross-State Air Pollution Rule (CSAPR). This constraint is modeled by intersecting emissions from thermal imports in the electricity sector with the sulfur dioxide emissions constraint in the domestic component of the ICDS.
- Mercury emission limits for U.S. coal imports. In scenarios where mercury emissions are restricted, imports are subject to the same limits as U.S. coal. When relevant, this contraint is modeled by intersecting emissions from thermal imports in the electricity sector with the mercury row constraint of the ICDS. Imports are subject to EPA's Mercury Air Toxics Standard to regulate hazardous air pollutants.
- Minimum (*contract*) flows for U.S. imports. These minimum flows are based on coal receipts data for existing U.S. power plants collected on the Form EIA-923, *Power Plant Operations Report*.

Model structure

The ICDS is specified as part of an LP that satisfies import requirements at all points at the minimum overall *world* coal cost plus transportation cost (Figure 3.3). The optimal pattern of supply is derived from the LP model output.

Figure 3.3. Overview of the international component of the ICDS



The geographical representation of the *world* is a set of coal export regions (Table 3.1) and coal import regions (Table 3.2). Each coal export region is able to supply coal based on the region's export supply curve that determines the quantity of coal available for export at a given cost. The cost associated with each quantity of coal available for export includes (1) mining costs; (2) representative coal preparation costs, which vary according to export region, coal type, and end-use market; and (3) inland transportation costs (before export). Coal import requirements for all regions except the United States are taken as fixed inputs to the CDS model. For the United States, import requirements are derived endogenously; that is, they are determined by the model. Diversity constraints limit the portion of a region's imports by sector that can be met by each of the individual export regions. If used, subbituminous constraints can limit the amount of subbituminous coal that a specific region can import. Each import region may also be restricted to a certain level of sulfur dioxide (SO2) emissions. Importing countries may be constrained by a maximum expectation of high sulfur coal as a share of their total imports. In scenarios where emissions limits for SO2, mercury, or carbon dioxide are specified for the United States, imports are also subject to those constraints. Minimum contract constraints for U.S. imports may also be specified. The linear program minimizes the costs associated with exporting coal from one region to an importing region while considering the constraints described above.

Appendix 3.A. Detailed Mathematical Description of the Model

The international component of the ICDS is specified as part of the overall CMM. The LP satisfies import requirements at the minimum overall *world* coal cost plus transportation cost. The optimal pattern of supply is derived from the LP model output.

The geographical representation of the *world* is a set of coal export regions and coal import regions. Each coal export region is able to supply coal based on the region's export supply curve that determines the quantity of coal available for export at a given cost. The cost associated with each quantity of coal available for export is inclusive of (1) mining costs; (2) representative coal preparation costs, which vary according to export region, coal type, and end-use market; and (3) inland transportation costs. For U.S. imports, an additional U.S. inland transportation rate is specified. This rate represents the cost of moving the imported coal from its port of entry to its point of consumption. Coal import requirements for all regions except the United States are taken as fixed inputs to the ICDS model. Starting in AEO2006, the ICDS allows U.S. import requirements to be endogenously determined based on competition with other U.S. domestic coal supply regions and to be satisfied at the minimum overall cost.

The model can account for limits on total SO2 emissions by coal import region through the incorporation of a model constraint. A restriction regarding the maximum permissible sulfur content of coal shipments to an import region, as well as restrictions on total coal shipments by coal import region/coal export region pairs, can be accounted for in the model as flow constraints, but it is not currently used. In addition, changes in U.S. policies regarding emission limits for SO2 and mercury and their impacts on U.S. coal imports can be represented. Minimum flow (*contract*) constraints are available in the model structure for coal imports to the U.S. electricity sector, but they are not currently used.

Mathematical formulation

This appendix provides the user with more detail on the complex linear program framework that is the Coal Market Module. The linear program structure diagram in Figure 3.A-1 provides a simplified version of the LP as it was originally designed for the CMM and coded in Fortran. This diagram, although from a previous version of the CMM, is still useful in helping the user understand the structure of the LP. The user should refer back to the ***Model Rationale*** section in Chapter 3 to understand variable definitions and the types of constraints incorporated into the ICDS linear program.

The block diagram format depicts the matrix as made up of sub-matrices or blocks of similar variables, equations, and coefficients. The first column contains the description of the sets of equations and the equation number as defined later in this section. Subsequent columns define sets of variables for the international production for seaborne export, transportation, U.S. import, and U.S. and Non-U.S. export of coal. The row equations can be maximums, minimums, or equalities. Each block within the table is shown with representative coefficients for that block, most typically either a (+/-) 1.0. The last table column, labeled *RHS (*an abbreviation for right-hand side), contains symbols that represent the constraint limit.

Figure 3.A-2 lists the AIMMS variable names with their indices (in other words, sets) in parenthesis(), and Figure 3.A-3 similarly lists the model constraints. These tables contain the variables and constraints used in the ICDS formulation discussed in this appendix and those discussed in Appendix 2.A for the Domestic Coal Distribution Submodule (DCDS).

The mathematical formulations in this document were prepared as descriptions for the original coding of the Coal Market Module (CMM) in Fortran. With the movement of the CMM code to the AIMMS platform we have attempted to add AIMMS variable names in brown text with brackets {AIMMS variable} as a helpful reference for future users of the coal model.

Figure 3.A-1. ICDS linear program structure

			INTERNATIONAL PRODUCTION FOR SEABORNE EXPORTS		TRANSPORTATION VECTORS																					
			NON-U.S. COAL SUPPLY		U.S. IMPORTS INLAND TRANSPORTATION						U.S. EXPORTS INLAND (PRIOR TO EXPORT) TRANSPORTATION			U.S. EXPORTS TRANSPORT INTERNATIONAL FREIGHT RATES				NON-U.S. TRANSPORT INTERNATIONAL FREIGHT RATES		U.S. AND NON-U.S. Transport Sumation Variables			U.S.			
			$PX_{i,s,t}$		$UI_{i,j,m,t,v,z}$			U.S. Imports Sector Subtotals of Transport			(cost also shown in DCDS)			$TX_{i,j,t}$ (US)				$TX_{i,j,t}$ (non-US)		$IMP_{j,t}$	$EXP_{i,t}$		$UX_{k,z}$			
	AIMMS Identifier		ExpSupply (nUS,s,tc,cyr)		ImportsElectricity	ImportsIndustrial	ImportsCoking	ImportsElectricitySubtotal	ImportsIndustrialSubtotal	ImportsCokingSubtotal	ExportsTransport2	ExportsSupplybyExportRegionCoking	ExportsSupplybyExportRegionThermal	TotalTransportUS	(USe,NonUSi,tc,cyr)	ImportsToUS		TotalTransportNonUS (nUS,i,tc) or Transport (nUS,i,s,tc,cyr)		TotalTransporttoCountryi	TotalTransportfromCountrye	AggRegTransport	UXThermal	UXCoking		
		Equation / Sector:	Thermal	Metallurgical	Electricity	Industrial	Metallurgical	Electricity	Industrial	Metallurgical	All	CokingSupplyCurves	ThermalSupplyCurves	Thermal	Metallurgical	Thermal	Metallurgical	Thermal	Metallurgical	Import Quantity	Export Quantity	Transport Quantity	Thermal	Metallurgical		RHS
		International Sector{tc} =	2	1										2	1	2	1	2	1							
Objective	ObjTotalCost	(3.A-1)	$+P_{i,s,t}$	$+P_{i,s,t}$	$+TI_E$	$+TI_I$	$+TI_C$				$+t_{x0}$			$+F_{i,j,t}$	$+F_{i,j,t}$			$+F_{i,j,t}$	$+F_{i,j,t}$							MIN
	WORLD TRADE STRUCTURE																									
Non-U.S. Production/Shipping Balance	IntlSupplyStepBalancewTotal	(3.A-4)	+1	+1														-1	-1						EQ	0
	Test_IntlSupplyStepBalancewTotal	(3.A-4)	+1	+1														-1	-1						EQ	0
U.S. Supply Balance (U.S. exports):	LInkUSDomesticCokingExportsWithInternational	(3.A-8)									-1				+1										EQ	0
	LInkUSDomesticThermalExportsWithInternational										-1			+1											EQ	0
Non-U.S. Supply (Transported) Balance:	ExportBalance	(3.A-8)												+1	+1			+1	+1		-1				EQ	0
U.S. and Non-U.S. Demand Balance:	ImportBalance	(3.A-6)												+1	+1			+1	+1	-1					EQ	0
Transport Total for All International Import Regions	TotalTransportfromCountryi (definition)	$IMP_{j,t}$												+1	+1			+1	+1	-1					EQ	0
Transport Total for All International Export Regions	TotalTransportfromCountrye (definition)	$EXP_{i,t}$												+1	+1			+1	+1		-1				EQ	0
Non-U.S. Import Demand	InternationalDemandRequirement	(3.A-5) Mettalurgical and Thermal												+1	+1			+1	+1						EQ	D
International Quanty Transported	AggRegTransport (definition)	TXi,j,t												+1	+1			+1	+1			-1			EQ	0
U.S. and Non-U.S. Import Diversity Constraint:	ImportShareConstr	(3.A-7)																				+1			LE	D*IC
Export Diversity Constraint:	ExportShareConstrNonUS	(3.A-9) Non-U.S.:																			-EC	+1 (nonUs)			LE	0
	ExportShareConstrUS	U.S.:												+1	+1						-EC				LE	0
	U.S. IMPORTS AND EXPORTS STRUCTURE ONLY																									
U.S. Import Demand Rows:	DomesticElectricityDemandRequirement	(3.A-2) Electricity:			+1																				EQ	D_E
	IndustrialDemandRequirement	Industrial:				+1																			EQ	D_I
	CokingDemandRequirement	Metallurgical:					+1																		EQ	D_C
U.S. Inland Transportation and International Freight (to U.S.) Balance Rows:	USImportThermalBalance USi only	(3.A-3) Thermal:						-1	-1									+1							EQ	0
	USImportCokingBalance USi only	Metallurgical:								-1									+1						EQ	0
	USImportsBalanceIntlExportsToUS USi only				-1	-1	-1											+1	+1						EQ	0
US Imports Totals	ImportstoUS (definition)	tc=1								+1							-1								EQ	0
	ImportstoUS (definition)	tc=2						+1	+1							-1									EQ	0
US Exports Totals	ExportsSupplyByExportRegionThermal (definition)	rank<> 4P									+1		-1												EQ	0
	ExportsSupplyByExportRegionCoking (definition)	rank = 4P									+1	-1													EQ	0
U.S. Export Supply Balance:	SdxTherm3	(3.A-10)									-1												+1		EQ	0
	SdxCoking3										-1													+1	EQ	0
U.S. Export Demand Balance:	BalanceCokingwithUSDomestic	(3.A-11) tc=1										-1									+1				EQ	0
	BalanceThermalwithUSDomestic	tc=2											-1								+1				EQ	0
Historical Flow Constraints:	ElectricityImportMinimum	(3.A-12)			$+1/u_i$																				GE	T_{Min_E}
	IndustrialImportMinimum					$+1/u_i$																			GE	T_{Min_I}
	CokingImportMinimum						$+1/u_i$																		GE	T_{Min_C}
	ElectricityImportMaximum	(3.A-13)			$+1/u_i$																				LE	T_{Max_E}
	IndustrialImportMaximum					$+1/u_i$																			LE	T_{Max_I}
	CokingImportMaximum						$+1/u_i$																		LE	T_{Max_C}
	U.S. IMPORTS AND EXPORT CONSTRAINTS ACTIVE ONLY IN STEO YEARS																									
Short Term Outlook Targets	STEOImportsLower	(3.A-14)			$+1/u_i$	$+1/u_i$	$+1/u_i$																		GE	$STIM_L$
	STEOImportsUpper				$+1/u_i$	$+1/u_i$	$+1/u_i$																		LE	$STIM_U$
	STEOCokeExportsLower	(3.A-15) Scrv In CokingSupplyCurves									$+1/u_{sc}$														GE	$STEXC_L$
	STEOCokeExportsUpper	Scrv In CokingSupplyCurves									$+1/u_{sc}$														LE	$STEXC_U$
	STEOSteamExportsLower	(3.A-16) Scrv in ThermalSupplyCurves									$+1/u_{sc}$														GE	$STEXS_L$
	STEOSteamExportsUpper	Scrv in ThermalSupplyCurves									$+1/u_{sc}$														LE	$STEXS_U$

AIMMS Identifier	*Symbol in Diagram Defined*
MtceToBtu	U_{TCE} : 27.78 Metric Ton Coal Equivalent per million Btu
InternationalDemand	D : demand (from clintldemand.txt input file)
Qdutzr	DE : coal demand for electricity sector
IndustrialDemand	DI : coal demand for industrial sector - steam coal
CokingDemand	DC : coal demand for coking plants - metalurgical coal
InternationalExportMaxShare	EC : exporter share constraint (from clexportlimits.txt input file)
InternationalImportMaxShare	IC : importer share constraint (from climportlimits.txt input file)
ImportTonsLower	$STIM_L$: US Imports lower bound (million short tons)
ImportTonsUpper	$STIM_U$: US Imports upper bound (million short tons)
CokeExpTonsLower	$STEXC_L$: US Coking Exports lower bound (million short tons)
CokeExpTonsUpper	$STEXC_U$: US Coking Exports lower bound (million short tons)
SteamExpTonsLower	$STEXS_L$: US Steam Exports lower bound (million short tons)
SteamExpTonsUpper	$STEXS_U$: US Steam Exports lower bound (million short tons)

AIMMS Identifier	*Symbol in Diagram Defined*
InlandImportTranspRateBtu('E',nUS,DReg,USi)	TI_E : Inland transport cost w/o surcharge - electricity sector imported coal
InlandImportTranspRateBtu('I',nUS,DReg,USi)	TI_I : Inland transport cost w/o surcharge - industrial sector imported coal
InlandImportTranspRateBtu('C',nUS,DReg,USi)	TI_C : Inland transport cost w/o surcharge - coking sector imported coal
Trate1Exp	t_{X0} : Transportation cost rate w/ surcharge - coal exports from US
InternationalUnitTransport	$F_{i,j,t}$: Cost of freight transportation for coal from export region i to coal import region j for international coal sector t.
InternationalFOBScalintBtu	$P_{i,s,t}$: Cost from step s of the export supply curve for coal from non-U.S. export region i for international coal sector t.
Btu2	u_{sc} : Heat content b coal supply curve .
InternationalHeatContent	u_i : International Heat content from export region i for coal type metalurgial(1) or thermal coal (2).
ImportsMinimumElectricity	T_{MIN_E} : minimum for U.S. imports for electricty (million short tons)
ImportsMinimumIndustrial	T_{MIN_I} : minimum for U.S. imports for electricty (million short tons)
ImportsMinimumCoking	T_{MIN_C} : minimum for U.S. imports for electricty (million short tons)

Figure 3.A-2. AIMMS linear program variables

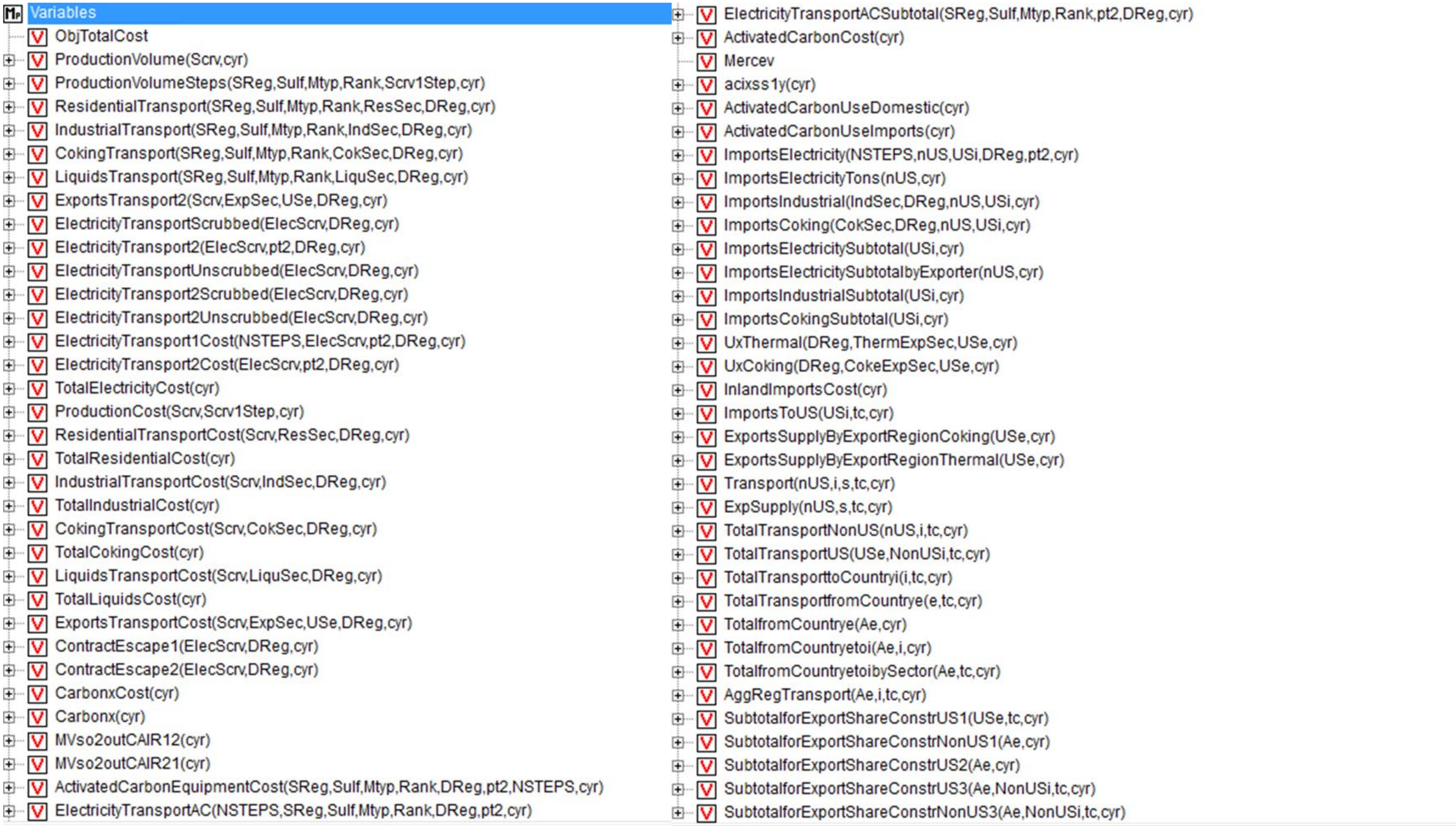
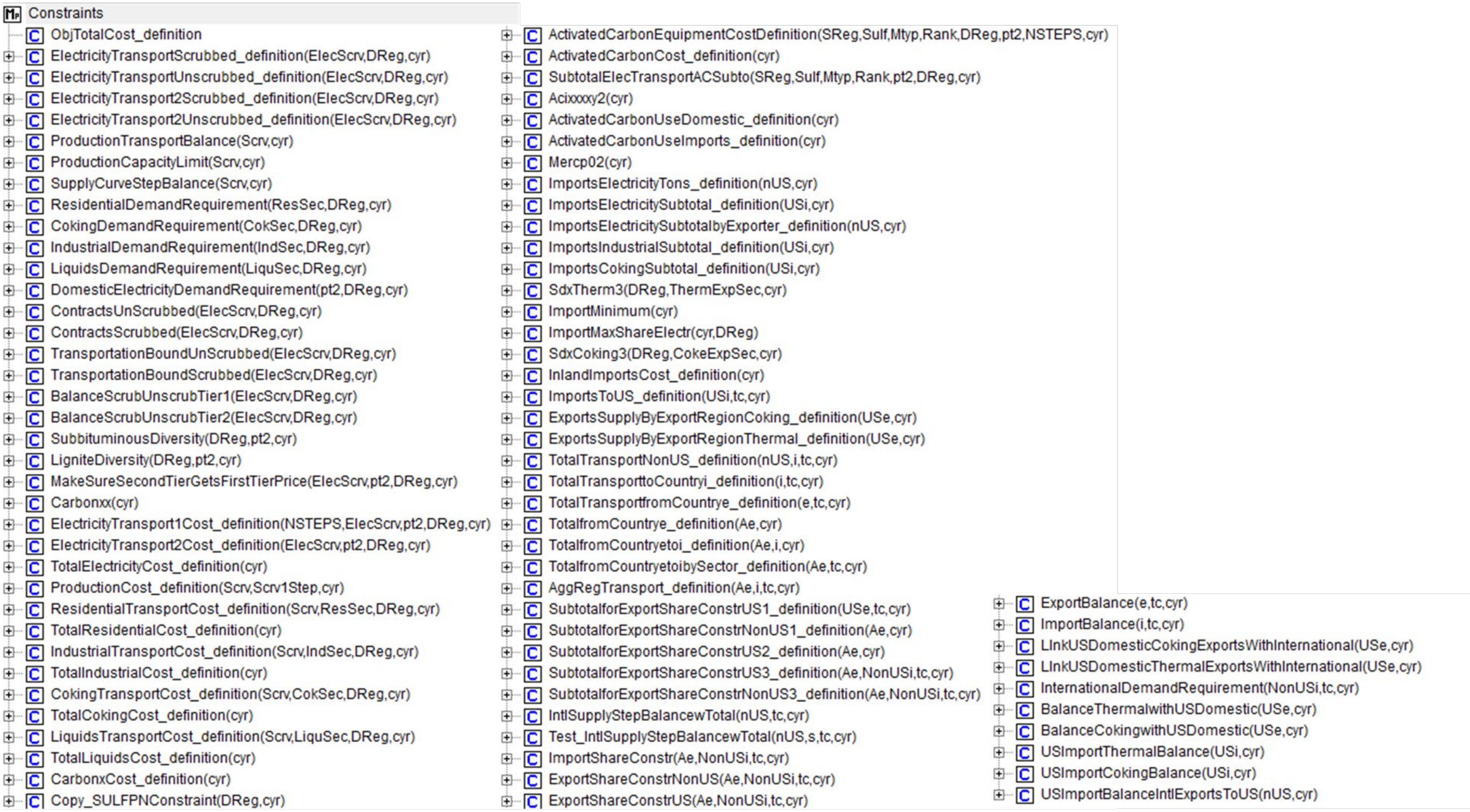


Figure 3.A-3. AIMMS linear program constraints



Objective function

The objective function to be minimized represents delivered costs (in other words, minemouth production, preparation, and inland transportation costs plus freight transportation costs) for moving coal from international export regions to international import regions and has been defined as

$$\Sigma_{i,s,t}\ PX_{i,s,t} * P_{i,s,t} + \Sigma_{i,j,t}\ TX_{i,j,t} * F_{i,j,t} + \Sigma_{i,j,m,t,v,z}\ UI_{i,j.m,t,v,z} * TI_{i,j,m,t,v,z} \qquad (3.A\text{-}1)$$

For the United States, the objective function is linked to the DCDS's objective function primarily through the row constraints (3.A-4), (3.A-6), and (3.A-8) described below. The U.S. production costs and inland transportation costs for U.S. domestically produced coal (for exports and domestic consumption) are not shown in (3.A-1) because they are accounted for in the DCDS model, which is documented in Chapter 2. The mercury price cap, mercury escape vector, activated carbon vector, and carbon emission vectors are also not represented in (3.A-1) for the same reason.

The index definitions for the objective function, the rows, and the columns are defined below.

Index definitions

Index Symbol	Description
(i)	International supply regions for coal exports. {e}
(j)	International import regions. {i}
(k)	U.S. coal export subsectors (correspond to U.S. export sectors in domestic component of DCDS). {CokeExpSec, ThermExpSec}
(m)	U.S. domestic subsector, either plant type for the electricity sector or sector number for the industrial and metallurgical sectors. {Subsec}
(s)	Step on coal export supply curve for non-U.S. international export regions. {s}
(t)	International coal sector (thermal or coking). {tc}
(u)	U.S. export supply curve representing one of eight possible U.S. coal types (different combinations of rank, mining method, and sulfur content) in combination with 1 of 16 possible export regions.
(v)	Activated carbon supply curve step. {NSTEPS}
(z)	U.S. coal export subregions and U.S. coal import subregions. These subregions are equivalent to the demand regions in the domestic portion of the DCDS and include: NE, YP, SA, GF, OH, EN, KT, AM, CW, WS, CU, MT, ZN, and PC. {Dreg}

Column definitions

Column notation	Description
$PX_{i,s,t}$	Quantity of coal from step s of export supply curve in non-U.S. export region i for international sector t. {ExpSupply}
$EXP_{i,t}$	Sum of coal exported from U.S. or non-U.S. international export region i. { {TotalTransportfromCountrye}
$IMP_{j,t}$	Sum of coal imported for international coal sector t to international import region j (U.S. or non-U.S.). {TotalTransporttoCountryi}
$TX_{i,j,t}$	Quantity of coal transported from U.S. or non-U.S. export region i to import region j for international sector t. {TotalTransportUS}, {TotalTransportNonUS}
$TXS_{i,j,s,t}$	Quantity of coal transported from non-U.S. export region i to import region j for international sector t and international supply curve step s. {TransportUS }
$UI_{i,j.m,t,v,z}$	Quantity of coal imported into the United States from international supply region i to coal international import region j, for U.S. domestic subsector m, for activated carbon supply curve step v, for international coal sector t, and U.S. domestic coal import region z. {ImportsElectricity}, {ImportsIndustrial}, {ImportsCoking}
$UX_{k,z}$	Quantity of coal exported for U.S. export subsector k from U.S. coal export sub-region z. {UxThermal, UxCoking}
$Qt_{k,u,z}$	Quantity of coal from U.S. export supply curve u transported to U.S. coal export subregion z and U.S. export subsector k. {ExportsTransport2}

And the incremental costs assigned to the column vectors are defined as

$P_{i,s,t}$ Cost from step s of the export supply curve for coal from non-U.S. export region i for international coal sector t. {InternationalFOBScalintBtu}

$F_{i,j,t}$ Cost of freight transportation for coal from export region i to coal import region j for international coal sector t. This cost includes the freight costs for U.S.-sourced exports. {InternationalUnitTransportBtuNonUS}

$TI_{i,j,m,t,v,z}$ Cost of inland transportation (within United States) for imported coal to the U.S. from export region i to coal international import region j, for U.S. domestic subsector m, for activated carbon supply curve step v, for international coal sector t, and U.S. domestic coal import region z. {InlandImportTranspRateBtu}

Row constraints

The rows interact with the columns to define the feasible region of the LP and are defined below:

U.S. IMPORTS STRUCTURE ONLY

U.S. IMPORT

EQUATIONS: non-imported coal + $\Sigma_{i,v}$ $UI_{i,j.m,t,v,z} = D_{j,m,t,z}$ (3.A-2)

where $D_{j,m,t,z}$ represents the U.S. coal imports for coal import region j, U.S. subsector m, for international coal sector t, and for U.S. domestic coal demand region z.

DEFINITION: Specifies the level of coal imports by import region j that must be satisfied for domestic coal subsector m.

CORRESPONDING ROWS IN BLOCK DIAGRAM: {DomesticElectricityDemandRequirement}, {IndustrialDemandRequirement} and {CokingDemandRequirement}

BALANCE OF U.S. INLAND TRANSPORTATION AND INTERNATIONAL FREIGHT TO U.S.

EQUATIONS: $TX_{i,j,t} - \Sigma_{m,v,z} UI_{i,j.m,t,v,z} = 0$ (3.A-3)

DEFINITION: For j equal to U.S. importing regions, the row balances coal freighted to U.S. international import region j from international (non-U.S.) export region i for international sector t (thermal or coking).

CORRESPONDING ROWS IN BLOCK DIAGRAM: {USImportThermalBalance}, and {USImportCokingBalance}

WORLD COAL TRADE ROWS

NON-U.S. PRODUCTION/SHIPPING BALANCE

EQUATIONS: $\Sigma_s PX_{i,s,t} - \Sigma_j TX_{i,j,t} = 0$ or $PX_{i,s,t} - \Sigma_j TXS_{i,j,s,t} = 0$ (3.A-4)

DEFINITION: Balance of coal produced in international (non-U.S.) export region i with the coal shipped from export region i for international sector t (thermal or coking).

CORRESPONDING ROWS IN BLOCK DIAGRAM: {IntlSupplyStepBalancewTotal} or {Test_IntlSupplyStepBalancewTotal}

NON-U.S. IMPORT

EQUATIONS: $\Sigma_i TX_{i,j,t} = D_{j,t}$ (3.A-5)

where $D_{j,t}$ represents the coal imports for import region j for international coal sector t.

DEFINITION: Specifies the level of coal import requirement by import region j that must be satisfied for international coal sector t (thermal or coking).

CORRESPONDING ROWS IN BLOCK DIAGRAM: {InternationalDemandRequirement}

U.S. AND NON-U.S. FREIGHT/IMPORT BALANCE

EQUATIONS: $\Sigma_i TX_{i,j,t} - IMP_{j,t} = 0$ (3.A-6)

DEFINITION: Balance of total coal imported to international import regions j with quantity freighted to

import region j for international sector t.
CORRESPONDING ROWS IN BLOCK DIAGRAM: {ImportBalance}

U.S. AND NON-U.S. IMPORT CONSTRAINTS:
EQUATIONS: $TX_{i,j,t} - IC_{i,j,t} * IMP_{j,t} < 0$ (3.A-7)
DEFINITION: Import constraint specifying that only a certain share of imports for an import region j can come from export region i. $IC_{i,j,t}$ is the proportion of coal imports flowing to international import region j that can come from export region i for international coal sector t.
CORRESPONDING ROWS IN BLOCK DIAGRAM: {ImportShareConstr}

U.S. AND NON-U.S. PRODUCTION/EXPORT BALANCE
EQUATIONS: $a\Sigma_s PX_{i,s,t} + b\Sigma_{k,z} UX_{k,z} - EXP_{i,t} = 0,$ (3.A-8)
where a = 0 and b = 1, for U.S.; a = 1 and b = 0 for non-U.S.; and where k is a subset of t.
DEFINITION: Balance of coal produced for export from international export region i with total exported from i for international sector t.
CORRESPONDING ROWS IN BLOCK DIAGRAM: {LInkUSDomesticCokingExportsWithInternational, LInkUSDomesticThermalExportsWithInternationa}and {ExportBalance}

U.S. AND NON-U.S. EXPORT CONSTRAINT
EQUATIONS: $TX_{i,j,t} - EC_{i,j,t} * EXP_i < 0$ (3.A-9)
DEFINITION: Export constraint limiting the amount of export coal from an international export region i that can be shipped to a particular import region j. $EC_{i,j,t}$ is the proportion of coal exports flowing from international export region i that can be shipped to import region j for international coal sector t.
CORRESPONDING ROWS IN BLOCK DIAGRAM: {ExportShareConstrUS, ExportShareConstrNonUS}

U.S. EXPORT SUPPLY BALANCE
EQUATIONS: $\Sigma_{k,z} UX_{k,z} - \Sigma_j TX_{i,j,t} = 0,$ (3.A-10)
where z is a subset of i and k is a subset of t.
DEFINITION: Balance of total U.S. coal transported overseas with U.S. coal exported. The U.S. export requirement is bounded. The bounds assumed are based on historical levels of exports.
CORRESPONDING ROWS IN BLOCK DIAGRAM: {SdxTherm3, SdxCoking3}

U.S. EXPORT DEMAND BALANCE
EQUATIONS: $\Sigma_u Qt_{k,u,z} - UX_{k,z} = 0$ (3.A-11)
DEFINITION: Balance of coal transported within United States from U.S. coal supply curves to meet export requirements from U.S. export subregions z and U.S. export subsectors k. The U.S. export requirements are bounded. The bounds are based on historical levels of exports.
CORRESPONDING ROWS IN BLOCK DIAGRAM: {BalanceCokingwithUSDomestic and BalanceThermalwithUSDomestic}

HISTORICAL FLOW CONSTRAINTS:

MINIMUM IMPORT EQUATION: $\Sigma_{i,j,m,t,v,z}\, UI_{i,j.m,t,v,z} \geq T_{MIN}$ (3.A-12)

DEFINITION: Sets minimum value (T_1) for all U.S. imports.

CORRESPONDING ROWS IN BLOCK DIAGRAM: { ElectricityImportMinimum, IndustrialImportMinimum, CokingImportMinimum}

MAXIMUM IMPORT EQUATION: $\Sigma_{i,j,m,t,v,z}\, UI_{i,j.m,t,v,z} \leq T_{MAX}$ (3.A-13)

DEFINITION: Sets maximum value (T_2) for all U.S. imports.

CORRESPONDING ROWS IN BLOCK DIAGRAM: { ElectricityImportMaximum, IndustrialImportMaximum, CokingImportMaximum}

STEO CONSTRAINTS FOR US IMPORTS

EQUATIONS: For coal imports i,j,m,t, and v: $STIM_L \leq \Sigma_{i,m,t,v}\, UI_{i.m,t,v} \leq STIM_U$ (3.A-14)

DEFINITION: Constrains the coal imports for the total U.S. to be within tolerance intervals of total imports targets set from the *Short-Term Energy Outlook*. Only active in the (STEO) early projection years. {STEOImportsLower, STEOImportsUpper}

STEO CONSTRAINTS FOR U.S. EXPORTS

EQUATIONS: For coal exports k,t,u, and z: $STEXC_L \leq \Sigma_u\, Qt_{k,t,u,z} \leq STEX_U$ (3.A-15)

DEFINITION: Constrain the coking coal exports for international coal sector t=1 from U.S. export subregions z and U.S. export subsectors k for the total United States to be within tolerance intervals of total imports targets set from the *Short-Term Energy Outlook*. Only active in the (STEO) early projection years. {STEOCokeExportsLower, STEOCokeExportsUpper}

EQUATIONS: For coal exports k,t,u, and z: $STEXS_L \leq \Sigma_u\, Qt_{k,t,u,z} \leq STEXS_U$ (3.A-16)

DEFINITION: Constrain the steam coal exports for international coal sector t=2 from U.S. export subregions z and U.S. export subsectors k for the total United States to be within tolerance intervals of total imports targets set from the *Short-Term Energy Outlook*. Only active in the (STEO) early projection years. {STEOSteamExportsLower, STEOSteamExportsUpper}

Row and column structure of the International Coal Distribution Submodule of the CMM

Each column and row of the linear programming matrix is assigned a name identifying the activity or constraint that it represents.

Table 3.A-2. Row and column structure of the International Coal Distribution Submodule

Identifier in diagram	Row or column	Activity represented
{ImportBalance}	Row	Imports balance row for international import region {i} for international coal sector {tc}.
{ExportBalance}	Row	Export balance row for export region {e}.
{LInkUSDomesticCokingExportsWithInternational, LInkUSDomesticThermalExportsWithInternationa}	Row	Balance row for U.S. exports.
{IndustrialDemandRequirement}	Row	Coal demand from demand region {Dreg} for industrial sector, I, and sector number{ThermExpSec}.
{CokingDemandRequirement}	Row	Coal demand from demand region {Dreg} for metallurgical sector, M, and sector number {CokeExpSec}
{DomesticElectricityDemandRequirement}	Row	Coal demand from demand region {Dreg} for electricity plant types {SubSec}.
{BalanceCokingwithUSDomestic and {BalanceThermalwithUSDomestic}	Row	Export balance row for U.S. export subregion {USe} of U.S. export subsector {USe}.
{InternationalDemandRequirement}	Row	International demand requirement for import region {i} for coking coal (tc=1) and thermal (tc=2).
{TotalTransportfromCountrye}	Column	Sum of exports from export region {e}.
{TotalTransporttoCountryi}	Column	Sum of imports from import region {i} for international coal sector {tc}.
{ImportMaximum}	Row	Sets maximum level for total imports for a specified year.
{ImportMinimum}	Row	Sets minimum level for total imports for a specified year.
{Morehgxx}	Column	Escape vector allowing more mercury to be emitted if tight mercury constraint causes infeasibility. Not active in final solution.
{ImportsIndustrial}	Column	U.S. import volume transported within the United States for use in the industrial steam sector.
{SubtotalImportsCoking}, {ImportsCoking}	Column	U.S. import volume transported within the United States for use in the metallurgical sector.
{ExpSupply}	Column	Supply of exports for non-U.S. international export region {e} for international coal sector {tc} and supply curve step {s}.

Table 3.A-2. Row and column structure of the International Coal Distribution Submodule (cont.)

Identifier In diagram	Row or column	Activity represented
{SdxTherm3, SdxCoking3}	Row	Row balancing the sum of coal transported from the export subsectors {USe} from the international U.S. export region {USe} with the total exported from the U.S. export region {USe}.
{IntlSupplyStepBalancewTotal}	Row	Row balancing the supply of coal exports from international export region {e} to international import region {i} for coking coal.
{Test_IntlSupplyStepBalancewTotal}	Row	Row balancing the supply of coal exports from international export region {e} to international import region {i} for thermal coal.
{USImportCokingBalance}	Row	Row balancing the quantity of imported coking coal transported inland from U.S. port (UP) from international export region {e} to that freighted to the port from international export region {e}.
{USImportThermalBalance},	Row	Row balancing the quantity of imported thermal coal transported inland from U.S. port (UP) from international export region {e} to that freighted to the port from international export region {e}.
{ExportsTransport2}	Column	U.S. export volume transported internally from U.S. export regions where coal is produced {Sreg} to U.S. export subregions {USe} for U.S. export subsectors for coal type (CT).
{TotalTransportfromCountrye and TotalTransportUS}	Column	U.S. export transportation volume from U.S. export subregion {Dreg}, to international import region {i}, for U.S. export subsector {USe}, for international export sector {tc}.
{TotalTransportNonUS}	Column	Export volume transported from non-U.S. export region {e} to international import region {i} for international export sector {tc}.
{UxThermal, UxCoking}	Column	Export volume for U.S. export subregion {USe} and U.S. export subsector {USe}. Export volume must lie between an upper and lower bound derived from historical volumes.
{ExportShareConstrUS, ExportShareConstrNonUS}	Row	Diversity export constraint on international export region {e} to import region {i} for international export sector {tc}.
{ImportShareConstr}	Row	Diversity import constraint on import region {i} for international export sector {tc} from export region {e}.

Categories and Regional Groupings

{Dreg} U.S. EXPORT SUBREGIONS AND/OR U.S. IMPORT REGIONS

NE	CONNECTICUT, MASSACHUSETTS, MAINE, NEW HAMPSHIRE, RHODE ISLAND, VERMONT
YP	NEW YORK, PENNSYLVANIA, NEW JERSEY
S1	WEST VIRGINIA, DELAWARE, DISTRICT OF COLUMBIA, MARYLAND
S2	VIRGINIA, NORTH CAROLINA, SOUTH CAROLINA
GF	GEORGIA, FLORIDA
OH	OHIO
EN	ILLINOIS, INDIANA, MICHIGAN, WISCONSIN
KT	KENTUCKY, TENNESSEE
AM	ALABAMA, MISSISSIPPI
C1	NORTH DAKOTA, SOUTH DAKOTA, MINNESOTA
C2	IOWA, NEBRASKA, MISSOURI, KANSAS
WS	TEXAS, OKLAHOMA, ARKANSAS, LOUISIANA
MT	MONTANA, WYOMING, IDAHO
CU	COLORADO, UTAH, NEVADA
ZN	ARIZONA, NEW MEXICO
PC	ALASKA, HAWAII, WASHINGTON, OREGON, CALIFORNIA

{i} INTERNATIONAL IMPORT REGIONS

Non U.S. International Import Regions {NonUSi}

NE	East Coast Canada
NI	Interior Canada
SC	Scandinavia
BT	United Kingdom, Ireland
GY	Germany, Austria, Poland
OW	Other Northern Europe
PS	Iberian Peninsula
TL	Italy (thermal and coking)
RM	E. Europe and Mediterranean
MX	Mexico
LA	South America
JA	Japan
EA	East Asia
CH	China, Hong Kong
AS	ASEAN
IN	Indian Subcontinent, S. Asia

U.S. International Import Regions {USi}

UE	U.S. Eastern
UG	U.S. Gulf
UI	U.S. Interior
UN	U.S. Noncontiguous

{tc} INTERNATIONAL COAL SECTORS

C	Coking = 1
T	Thermal = 2

{e} INTERNATIONAL EXPORT REGIONS

Non U.S. International Export Regions {nUS}

NA		Canada (alternate for Canada)
NW	or W	West Coast Canada
NI	or N	Interior Canada (thermal only)
CL	or C	Colombia (thermal only)
VZ	or Z	Venezuela (thermal only)
PO	or P	Poland
RE	or E	Eurasia (exports to Europe)
RA	or R	Eurasia (exports to Asia)
SF	or S	Southern Africa
IN	or I	Indonesia
HI	or H	China
AU	or A	Australia
VT	or T	Vietnam

U.S. International Export Regions {USe}

UG	U.S. Gulf
UI	U.S. Interior
UN	U.S. Noncontiguous
UW	U.S. West Coast
UE	U.S. East Coast
US	U.S.
UA	U.S. All

Aggregate Export Regions {Ae}

1 AU	Australia	[AU]
2 US	United States	[UG, UI, UW, UE, UA]
3 SF	Southern Africa	[SF]
4 RS	Eurasia	[RE, RA]
5 PO	Poland	[PO]
6 NA	Canada	[NI, NW]
7 HI	China	[HI]
8 SA	South America	[CL, VZ]
9 VT	Vietnam	[VT]
10 IN	Indonesia	[IN]

{s} INTERNATIONAL EXPORT SUPPLY CURVE STEPS

1	Step 1
2	Step 1
3	Step 3
4	Step 4
5	Step 5
6	Step 6
7	Step 7
8	Step 8
9	Step 9
10	Step 10

PT **PLANT TYPE** (see DCDS page 89)

{Subsec} **U.S. IMPORT SUBSECTOR NUMBERS**

I1 – I3 FOR INDUSTRIAL IMPORTS
C1 – C2 FOR METALLURGICAL IMPORTS

{Sreg}	**U.S. COAL SUPPLY REGIONS**
01NA	PENNSYLVANIA, OHIO, MARYLAND, WEST VIRGINIA (NORTH)
02CA	WEST VIRGINIA (SOUTH), KENTUCKY (EAST), VIRGINIA, TENNESSEE (NORTH)
03SA	ALABAMA, TENNESSEE (SOUTH)
04EI	ILLINOIS, INDIANA, KENTUCKY (WEST), MISSISSIPPI
05WI	IOWA, MISSOURI, KANSAS, OKLAHOMA, ARKANSAS, TEXAS (BITUMINOUS)
06GL	TEXAS (LIGNITE), LOUISIANA
07DL	NORTH DAKOTA, MONTANA (LIGNITE)
08WM	WESTERN MONTANA (BITUMINOUS AND SUBBITUMINOUS)
09NW	WYOMING, NORTHERN POWDER RIVER BASIN (SUBBITUMINOUS)
10SW	WYOMING, SOUTHERN POWDER RIVER BASIN (SUBBITUMINOUS)
11WW	WESTERN WYOMING (SUBBITUMINOUS)
12RM	COLORADO, UTAH
13ZN	ARIZONA, NEW MEXICO
14AW	WASHINGTON, ALASKA

UP **U.S. PORT REGION**

G	U.S. Gulf
I	U.S. Interior
N	U.S. Noncontiguous
E	U.S. East Coast

{ExpSec}	**U.S. EXPORT SECTORS**
X1	Metallurgical Export 1
X2	Metallurgical Export 2
X3	Metallurgical Export 3
X4	Steam 1 Export
X5	Steam 2 Export
X6	Steam 3 Export

CT **U.S. DOMESTIC COAL TYPE** (CT's pairing with a U.S. supply region designates the supply curve and rank.)

1 LOW SULFUR AND UNDERGROUND MINING METHOD
2 MEDIUM SULFUR AND UNDERGROUND MINING METHOD
3 HIGH SULFUR AND UNDERGROUND MINING METHOD
4 LOW SULFUR AND SURFACE MINING METHOD
5 MEDIUM SULFUR AND SURFACE MINING METHOD
6 HIGH SULFUR AND SURFACE MINING METHOD
7 METALLURGICAL COAL
8 WASTE COAL OR MISSISSIPPI LIGNITE

Appendix 3.B. Inventory of Input Data, Parameter Estimates, and Model Outputs

Model inputs

The inputs required by the ICDS are divided into two main groups: user-specified inputs and inputs provided by other NEMS components. The required user-specified inputs are listed in Table 3.B-1. In addition to identifying each input, this table indicates the variable name used to refer to the input in this report, the units for the input, and the level of detail at which the input needs to be specified.

The user-specified inputs to ICDS are contained in various input files. These files and their contents are listed below.

International Supply Curves. The file ***clintsupply.txt*** contains the step-function coal export supply curves for all non-U.S. export regions. The file contains indices in columns for international export region {nUS}, supply step {s}, coal sector {tc}, and year {yr} along with two parameters for the curves {InternationalFOB, InternationalSupply}. The file ***clintquality.txt*** contains additional detail by export region and coal sector. These parameters for average heat, sulfur, mercury, and CO2 content are assumed to be unchanging over the forecast. The seven parameters for the curves are as follows:

1) InternationalFOB, the export FOB price of coal (minemouth price plus inland transportation cost) in 1992 dollars per metric ton for the indexed region, step, sector, and year;
2) InternationalSupply, the estimated coal export supply in million metric tons for the indexed region, step, sector, and year;
3) InternationalHeatContent, the heat content in million Btu per short ton;
4) InternationalSO2Unit, the sulfur content in percent sulfur by weight in lbs. per million Btu;
5) InternationalMercuryUnit, the mercury content in pounds per trillion Btu;
6) InternationalCO2Unit, the carbon dioxide content in pounds of carbon dioxide per million Btu; and
7) InternationalScaleFactor, a scalar that permits the user to adjust the international coal export supply curves over time at rates that vary from the price path for U.S. export coal.

Some additional calculations are required to convert inputted data to units consistent with the linear program. They include converting metric tons to short tons, using the internal NEMS price deflators to convert to 1987 dollars, and representing coal price curves on a $/MMBtu basis.

International Coal Demand. The file ***clintdem.txt*** contains the non-U.S. coal import requirements (variable: InternationalDemand) by ICDS import region {NonUSi} and sector {tc} for the years 1990 through 2050 in million metric tons of coal. Before the import requirements are used in the LP, they are converted to trillion Btu by the following calculation: DEMAND * 27.78 million Btu per metric ton of coal equivalent.

International Transport Cost. In AEO2020 and forward, the file ***clfreight.txt*** is no longer being used. The change in methodology is discussed in Appendix 3.C. The international transport cost for each {e} to {i} arc is now computed inside the ICDS based on additional tables ***tInp_IntlVesselCosts***, ***tInp_MarineFuels***, and ***tInp_MfuelDiffs*** from CMM2.mdb along with a new input files ***cloceandist.txt*** indexed by international export region {e}, international import region {i} and coal sector {tc} and assumed vessel class[34] {vclass} which contains the variables {IntlNauticalMiles} and {VesselLadingT} for every possible transport arc. The tables from CMM2 are indexed by forecast year and have variables for vessel hiring cost {DailyHireCost} and marine transportation fuel costs {BunkerIFO380_USGulf, DieselMGO_USGulf}, which will change over the projection.

International transport also requires inland transportation rates, which are read from CMM2.mdb tables ***clintlsurcharg, clintldistance, and clintlinland***, in 1987 dollars per short ton, for U.S. imports. These rates represent the transportation cost from the initial import entry to the U.S. coal import region and are specified by the electricity, industrial, and metallurgical sectors.

Minimum and Maximum U.S. Import Levels
The old Fortran file ***clexfrt.txt*** also included optional switches to set minimum and maximum import levels. If a switch was equal to *1*, the minimum/maximum constraint was in use for industrial steam and coking coal imports into the United States. The current AIMMS format lacks the ability to lock in minimum or maximum industrial imports by sector {tc}. The table ***USImport_Shares*** read in from CMM.mdb contains a parameter {USImpShare} indexed by demand region {Dreg} to limit the share of coal imports meeting the domestic power sector demand requirement.

Export Limits. The ***clexportlimts.txt*** file sets aggregate region {Ae} export limits, where a parameter {InternationalExportMaxShare} is the percentage of each export region capacity that can be supplied to any single import region. Currently, the export max share is set to 65% for all the aggregate export regions. Aggregate export regional groupings are defined in the file ***claggexportmap.txt.*** The coal export regions available in the CMM are defined in the table ***tInp_InternationalExportReg,*** read in from CMM.mdb, which also defines the Non U.S. International Export Regions {nUS} and U.S. International Export Regions {USe}. Export region definitions and groups can be found on page 138.

The ***clintlusexport.txt*** file inputs lower bounds {ExportLowerBound} and upper bounds {ExportUpperBound} by demand region {Dreg}, export region {USe}, export sector {ExpSec}, coal sector {tc}, and year {yr} of the projection. These bounds are in the same units (trillion Btu) as the CMM transport solution.

Import Limits. The ***climportlimts.txt*** file sets the coal import diversity constraints {InternationalImportMaxShare}, specified as a percentage of the total coal international import demand requirement by region {i} and sector {tc}, that can be supplied by the specified aggregate export region {Ae}. The constraints limit the portion of an import region's import requirement by sector that can be met by each of the individual export regions. For example, an input of 40 for the AE=US, i=JA, tc=1 indicates that only 40% of Japan's annual imports of thermal coal can be met by U.S. coal suppliers.

Transport Paths. The ***clfeasibleout.txt*** file by aggregate export region {Ae} and international import region {i} sets the paths available to the ICDS LP to transport coal. Most international paths are available, but intra country paths are not available because movements of coal transported with the United States are modeled in the DCDS transport structure.

[34] Vessel class for each transport arc was chosen based on historical annual volumes transported, size of predominant port loading or unloading capacity, and whether or not the route distance included movement through the Panama or Suez canals.

Table 3.B-1. User-specified inputs

ICDS variable	Description	Specification level[a]	Input units
InternationalSupply	Coal export capacity	Coal export region/coal sector/export supply curve step/forecast year	Million metric tons
InternationalHeatContent	Btu conversion assignment for coal export supply curve	Coal export region/coal sector/export supply curve step	Million Btu per short ton of coal
InternationalDemand	Coal import requirement (Non-U.S.)	Coal import region/coal demand sector/forecast year	Million metric tons of coal equivalent
InternationalExportMaxShare	Exporter diversity constraints	Coal export region/coal import region	Percentage
InternationalFOB	Coal export prices (FOB port of exit)	Coal export region/coal sector/export supply curve step/forecast year	1992 dollars per metric ton
InternationalUnitTransport (replaced in AEO2020)	Ocean freight rates	Coal export region/coal import region/coal sector/coal demand sector	1992 dollars per metric ton
IntlNauticalMiles	Estimated nautical miles from coal export region {e} to coal import region {i}	Coal export region/coal import region/coal type/vessel class	Nautical miles
VesselLadingT	Assumed average ship capacity for each {e} to {i} arc	Coal export region/coal import region/coal type/vessel class	Lading tons (Metric)
InternationalMercuryUnit	Mercury content assignment for coal export supply curve	Coal export region/coal type	Pounds of Hg per trillion Btu
InternationalImportMaxShare	Importer diversity constraints	Coal export region/coal import region	Percentage
InternationalCO2Unit	Carbon dioxide content assignment for coal export supply curve	Coal export region/coal type	Pounds of CO_2 per million Btu
InternationalScaleFactor	Price adjustment factor for non-U.S. export supply curves	Coal export region/coal type/export supply curve step/forecast year	Scalar
InternationalSO2Unit	Sulfur content assignment for coal export supply curve	Coal export region/coal type	1,000 metric tons of SO_2 emissions per TCE (metric ton of coal equivalent)
USImpShare	Maximum share for imported coal	Demand region	Fraction
ExportLowerBound	Lower bounds for U.S. exports	Demand region/demand sector/export sector/U.S. export region/forecast year	Trillion Btu
ExportUpperBound	Upper bounds for U.S. exports	Demand region/demand sector/export sector/U.S. export region/forecast year	Trillion Btu

[a]For example, inputs specified at the coal export region/coal sector/forecast year level require separate values for each export region, coal type, and forecast year.

Table 3.B-1. User-specified inputs (continued)

AIMMS variable	Input file	Database table/query	Description
ImpSec	Cmm2.mdb	clintlsurcharge	Import sector
nUS	Cmm2.mdb	clintlsurcharge	Non-U.S. exporting regions
USi	Cmm2.mdb	(multiple)	U.S. importing regions
PInlandtr	Cmm2.mdb	clintlsurcharge	Imports surcharge
DistanceSurchargeImport	Cmm2.mdb	clintldistance	Inland distance for imports surcharge
TonsPCar_Imp	Cmm2.mdb	clintlinland	Tons per car for imports
Trigger_Imp	Cmm2.mdb	clintlinland	Trigger flag
Trig_Incr_Imp	Cmm2.mdb	clintlinland	Incremental trigger
ChargePerMile_Car_Imp	Cmm2.mdb	clintlinland	Charge per car mile
OFBaseYr	AIMMS code	(AEO2020=2018)	Base-year dollars for ocean freight equations and cost inputs
VesselClass	Cmm2.mdb	tInp_IntlVesselCosts	Dry bulk vessel class—Panamax or Cape size
DailyHireCost	Cmm2.mdb	tInp_IntlVesselCosts	Annual average daily hire cost by vessel class—real $ per day
PortCostPer_mTon	Cmm2.mdb	tInp_IntlVesselCosts	Assumed port cost in real $ per metric ton
PortDays	Cmm2.mdb	tInp_IntlVesselCosts	Number of days in port per trip to load and unload the ship
BunkerFuelUseSea	Cmm2.mdb	tInp_IntlVesselCosts	Fuel use of bunker fuel/IFO380 (resid 88% and distillate 12%) while in sea transit—units metric tons per day
DieselFuelUseSea	Cmm2.mdb	tInp_IntlVesselCosts	Fuel use of MGO/diesel fuel while in sea transit—units metric tons per day
DieselFuelUseSea	Cmm2.mdb	tInp_IntlVesselCosts	Fuel use of MGO/diesel fuel while in sea transit—units metric tons per day
DieselFuelUsePort	Cmm2.mdb	tInp_IntlVesselCosts	Fuel use of MGO/diesel fuel while in port—units metric tons per day
SailingSpeedKn	Cmm2.mdb	tInp_IntlVesselCosts	Vessel sailing speed in knots per day
BunkerIFO380_USGulf	Cmm2.mdb	tInp_MarineFuels	Bunker fuel IFO380 prices by year for U.S. Gulf Coast (2018$ per metric ton)
DieselMGO_USGulf	Cmm2.mdb	tInp_MarineFuels	Diesel MGO prices by year for U.S. Gulf Coast (2018$ per metric ton)
BunkerIFO_RgnDiff	Cmm2.mdb	tInp_MFuelDiffs	Differential from U.S. Gulf to export region in U.S. dollars per metric ton for bunker IFO fuel (2018$ per metric ton)
DieselMGO_RgnDiff	Cmm2.mdb	tInp_MFuelDiffs	Differential from U.S. Gulf to export region in U.S. dollars per metric ton for diesel MGO fuel (2018$ per metric ton)

Model Outputs

The International Coal Distribution Submodule (ICDS) provides annual forecasts of U.S. coal exports and imports to the domestic distribution area of the NEMS Coal Market Module. The key international projection output from the CDS, listed in Table 3.B-2, is world coal trade flows by coal export region/coal import region/coal type/coal demand sector (in trillion Btu). Conversion factors convert output from trillion Btu to short tons for report-writing purposes.

Table 3.B-2. Outputs from ICDS

Output in CoalOutput.xls	AIMMS variable	Specification level[a]	Units
InternationalTrade	TotalTransportNonUS	Coal export region{nUS}, coal import region{i}, coal sector{tc} forecast year{yr}	Trillion Btu
ImportsElec	ImportsElectricityTonsDetail2	Coal imports to U.S. electric power sector by Non-U.S. International Export region {nUS}	Million tons
ImportsElec	ImportsElectricityTrillsDetail2	Coal imports to U.S. electric power sector by Non-U.S. International Export region {nUS}	Trillion Btu
ExportsFromUS	OutputExportFromUSTrils	Coal exports from the United States by Non-U.S. International Import regions {NonUSi}	Trillion Btu
ExportsFromUS	OutputTonsTransportUSbyImporterCoking	Coking coal exports from the United States by Non-U.S. International Import regions {NonUSi}	Million tons
ExportsFromUS	OutputTonsTransportUSbyImporterThermal	Thermal coal exports from the United States by Non-U.S. International Import regions {NonUSi}	Million tons

Appendix 3.C. Data Quality and Estimation

Non-U.S. coal import requirements are import volumes specified by CMM international coal import region and demand sector (coking and thermal). Annual import requirements are assumed to be equal to domestic coal demand less domestic supply (domestic production minus exports). In the CMM, non-U.S. coal import requirements by region and international import sector are an exogenous input and are typically specified at five-year intervals. Published information such as announced and planned additions/retirements of coal-fired generating plants, coke plants, and coal mining capacity are used to adjust the annual input data for coal import requirements.

Coking coal requirements represent the consumption of coal at coke plants to produce coal coke. Coal coke is used primarily as a fuel and as a reducing agent in smelting iron ore in a blast furnace. Coal coke is also consumed at foundries and in the production of sinter. Thermal coal demands correspond to coal consumed for electricity generation, industrial applications (excluding the use of coking coal at coke plants), space heating in the commercial and residential sectors, and for the production of coal-based synthetic gas and liquids. The direct use of coal at blast furnaces for the manufacture of pig iron is also categorized as thermal coal demand.

Coal export supply inputs are potential export supplies specified on a tranche-by-tranche (steps on supply curve) basis in the clexsup.txt input file to enable users to build up a stepped supply curve. Up to 10 tranches are allowed for the major price-sensitive suppliers. Coal qualities (sulfur, mercury, carbon dioxide, and Btu content) cannot vary between tranches.

With each update of the AEO, the export FOB price of coal (InternationalFOB) for the international base year is updated on the basis of available data on average annual prices for coal exports and imports as reported by EIA, the International Energy Agency, South Africa's Department of Minerals and Energy, and other statistical agencies and organizations. For international export supply regions and coal types where data for average annual coal export prices are either limited or unavailable, prices are updated on the basis of changes in reported prices for other coal export regions. Further adjustments are made to calibrate the model to base-year trade flows.

The InternationalFOB and InternationalSupply variables together represent the supply curves for each of the modeled supply regions. For the base year, the paired variables represent estimates of current coal supply potential, while future year projections account for known capacity plans and capacity potential, both in regard to mine capacity expansions (for exported coal), reserves, and inland transportation upgrades and in regard to port capacity upgrades or limitations. Limited availability and consistent sources of reliable international data make updating these assumptions difficult. The update of these curves ultimately requires some judgment on the part of the modeler. In general, the slopes of these supply curves are assumed to be similar to those of the U.S. supply curves. The InternationalScaleFactor variable allows productivity assumptions to differ from those of the United States for the various supply curves. Assumptions about the elasticity of coal export supply for each exporting country determine the prices associated with steps on the supply curves representing new mine capacity.

International ocean freight shipping cost projections represent the seaborne cost of shipping between each export origin (e) to import destination (i) pair represented in the ICDS. The methodology for calculating the projections was redesigned in AEO2020 based on analysis by Hellerworx, Inc., to allow for endogenous changes in fuel prices and to account for exogenous assumptions for vessel operating and port costs, shipping distances, vessel speed, and days in port based on the size of the vessel (Panamax or Cape). The ICDS computes port usage fees, vessel rates, and fuel costs for days in port and vessel rates and fuel costs for days to compute the total cost of transport for every active {e} to {i} arc.

The algorithm for calculating the shipping cost in dollars per metric ton ($/mt) for each origin-destination pair in the international network, estimated in **real 1992 dollars** to match the other data in the CMM, are specified for each origin-destination pair ***(e** to **i)***, coal type (***tc),*** and vessel class (***vc***) by year (***yr)***.

The first step is to define the days at sea between each origin-destination pair based on the mileage and vessel sailing speed, and the fuel costs based on the export region, as follows:

$$Days\ at\ Sea_{e,i,tc,vc,yr} = \frac{Intl\ Nautical\ Miles_{e,i,tc}}{(Sailing\ Speed\ Kn_{vc,yr} * 24\ hours)}$$

$$Diesel\ fuel\ cost_{e,yr} = (Diesel\ Price_{yr} + Diesel\ Differntial_{e})$$

$$Bunker\ fuel\ cost_{e,yr} = (Bunker\ Price_{yr} + Bunker\ Differntial_{e})$$

The transportation rates are broken into costs while at port and costs while at sea in $/mt. Port costs (**PC**) consist of port usage fees to cover dock space and loading and unloading costs, as well as vessel hire and diesel fuel costs while at port, for the vessel size used on the trade route, as follows:

- **Port Usage Cost (PUC)**: Based on the cost per metric ton input parameter (AEO2020 = $2.00/ton in 2018$).
- **Port Vessel Cost (PVC)**: Based on the daily vessel hire rate times the days in port divided by the vessel type's voyage lading in metric tons.

- $PVC_{e,i,tc,yr} = \frac{Daily\ Hire\ Rate_{vc,yr} * Days\ in\ Port_{vc,yr}}{(\text{Voyage}\ Lading\ mt_{e,i,tc,vc} * 1000)}$

- **Port Fuel Cost (PFC)**: Based on the daily diesel fuel consumption rate while in port times the days in port and the cost of diesel fuel at the region of origin divided in metric tons.

$$PFC_{e,i,tc,yr} = \frac{Diesel\ Fuel\ Use\ in\ port_{vc,yr} * Days\ in\ Port_{vc,yr} * Diesel\ fuel\ cost_{e,yr}}{(\text{Voyage}\ Lading\ mt_{e,i,tc,vc} * 1000)}$$

The at-sea costs (**ASC**) consist of the costs for vessel hire and the costs for both bunker and diesel fuels, for the vessel size used on the trade route, as follows:

- **At-Sea Vessel Cost (ASVC)**: Based on the daily vessel hire rate times the days at sea divided by the vessel type's voyage lading in metric tons.

$$ASLC_{e,i,tc,yr} = \frac{Daily\ Hire\ Rate_{vc,yr} * Days\ at\ Sea_{e,i,tc,vc,yr}}{(\text{Voyage}\ Lading\ mt_{e,i,tc,vc} * 1000)}$$

- **At-Sea Fuel Cost (ASFC)**: Based on the rate of bunker fuel and diesel fuel consumption while at sea times the number of days at sea and the associated fuel price at the region of origin divided by the vessel type's voyage lading in metric tons.

$$ASFC_{e,i,tc,yr} = \frac{Bunker\ Fuel\ Use\ at\ Sea_{vc,yr} * Days\ at\ Sea_{e,i,tc,vc,yr} * Bunker\ fuel\ cost_{e,yr}}{(\text{Voyage}\ Lading\ mt_{e,i,tc,vc} * 1000)} + \frac{Diesel\ Fuel\ Use\ at\ Sea_{vc,yr} * Days\ at\ Sea_{e,i,tc,vc,yr} * Diesel\ fuel\ cost_{e,yr}}{(\text{Voyage}\ Lading\ mt_{e,i,tc,vc} * 1000)}$$

The resulting **Unit Transport Cost (UTC)** is the sum of total Port Costs (PC) and total At-Sea Costs:

$$UTC = PC + \text{ASC}$$

Or $IntlUnitTransCost_{e,i,tc,yr} = PUC + \text{PVC} + \text{PFC} + \text{ASVC} + \text{ASFC}$

An example of ocean freight cost calculations by vessel type is provided in Figure 3.C-1.

U.S. import inland transportation rates {Pinlandtr} for origin (port of entry) and destination (domestic coal demand regions) pairs are estimated using information about domestic shipping rates for comparable distances.

Figure 3.C-1. Example of ocean freight cost by vessel type

Parameters	Units	Panamax	Cape Size
Days at Sea	**Days**	**10.8**	**10.8**
Voyage Distance (Example) (F - by Route)	Nautical Miles	3,500	3,500
Daily Distance Traveled	Nautical Miles	324.0	324.0
Average Speed (F)	Knots	13.5	13.5
Hours Per Day (F)	Hours	24	24
Daily Hire Rate (A: User)	**$ Per Day**	**$ 13,000**	**$ 20,000**
Fuel Oil Assumptions			
Bunker Fuel Consumption Per Day at Sea (F)	Metric Tons/Day	33	54
Bunker Fuel Oil Cost (A: NEMS)	$ Per Metric Ton	$ 400	$ 400
Marine Fuel Consumption Per Day at Sea (F)	Metric Tons/Day	1	2
Marine Fuel Oil Cost (A:NEMS)	$ Per Metric Ton	$ 600	$ 600
Marine Fuel Consumption Per Day in Port (F)	Metric Tons/Day	4	4
Port Cost Assumptions			
Port Fees Per Delivery (F)	$ Per Metric Ton	$ 2.00	$ 2.00
Lading Tonnes (F)	Metric Tons	74,000	150,000
Days in Port (F)	Days	5.00	8.80

(F) = Fixed Parameter Value; (A: User) = Annual, User-Specified Values; (A: NEMS) = Annual Values from Other NEMS Module

	Units	Panamax	Cape Size
Total Cost at Sea	**$ Per Coal Delivery**	**$ 514,506**	**$ 959,466**
Cost Per Thousand Tonne-Miles	*$ Per Tonne-Mile*	*$ 1.99*	*$ 1.83*
Cost Per Metric Ton	*$ Per Metric Ton*	*$ 6.95*	*$ 6.40*
Total Cost at Sea	**$ Per Coal Delivery**	**$ 289,506**	**$ 462,346**
Cost Per Thousand Tonne-Miles	*$ Per Tonne-Mile*	*$ 1.12*	*$ 0.88*
Cost Per Metric Ton	*$ Per Metric Ton*	*$ 3.91*	*$ 3.08*
Bunker Fuel Cost at Sea	**$ Per Coal Delivery**	**$ 142,593**	**$ 233,333**
380 CST High Sulfur Heavy Fuel Oil	Metric Tons	356	583
Bunker Fuel Consumption Per Day at Sea	Metric Tons/Day	33	54
Days at Sea	Days	10.8	10.8
Bunker Fuel Oil Cost	$ Per Metric Ton	$ 400	$ 400
Marine Fuel Cost at Sea	**$ Per Coal Delivery**	**$ 6,481**	**$ 12,963**
Marine Gas Oil (MGO)-DIESEL	Metric Tons	11	22
Marine Fuel Consumption Per Day at Sea	Metric Tons/Day	1	2
Days at Sea	Days	10.80	10.80
Marine Fuel Oil Cost	$ Per Metric Ton	$ 600	$ 600
Vessel Hire Costs at Sea	**$ Per Coal Delivery**	**$ 140,432**	**$ 216,049**
Daily Hire Rate	$ Per Day	$ 13,000	$ 20,000
Days at Sea	Days	10.8	10.8
Total Cost in Port	**$ Per Coal Delivery**	**$ 225,000**	**$ 497,120**
Cost Per Thousand Tonne-Miles	*$ Per Tonne-Mile*	*$ 0.87*	*$ 0.95*
Cost Per Metric Ton	*$ Per Metric Ton*	*$ 3.04*	*$ 3.31*
Marine Fuel Cost in Port	**$ Per Coal Delivery**	**$ 12,000**	**$ 21,120**
Marine Gas Oil (MGO)-DIESEL	Metric Tons	20	35
Marine Fuel Consumption Per Day in Port	Metric Tons/Day	4	4
Days in Port	Days	5.00	8.80
Marine Fuel Oil Cost	$ Per Metric Ton	$ 600	$ 600
Total Port Costs	**$ Per Coal Delivery**	**$ 148,000**	**$ 300,000**
Port Fees Per Delivery	$ Per Metric Ton	$ 2.00	$ 2.00
Lading Tonnes	Metric Tons	74,000	150,000
Vessel Hire Costs in Port	**$ Per Coal Delivery**	**$ 65,000**	**$ 176,000**
Daily Hire Rate	$ Per Day	$ 13,000	$ 20,000
Days in Port	Days	5.00	8.80

Appendix 3.D. Bibliography

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Appendix 3.E ICDS Submodule Abstract

Model name: International Coal Distribution Submodule (ICDS)

Model abbreviation: ICDS

Description: The ICDS projects coal trade flows from 17 coal-exporting regions (5 of which are in the United States) to 20 importing regions (4 of which are in the United States) for three coal types—premium bituminous, low-sulfur bituminous, and subbituminous. The model consists of exports, imports, trade flows, and transportation components. The major coal exporting countries represented include the following: the United States, Australia, South Africa, Canada, Indonesia, China, Colombia, Venezuela, Poland, Vietnam, and the countries of Eurasia. The DCDS determines the optimal level of coal imports used to satisfy U.S. coal demand for the industrial and electricity sectors.

Purpose: Forecast international coal trade. Provide U.S. coal export and import forecasts to the Domestic Coal Distribution Submodule (DCDS).

Model update information: June 2020

Part of another model:

- Coal Market Module
- National Energy Modeling System

Model interface: The model can interface with the following models:

- Domestic Coal Distribution Submodule (DCDS)

Official model representative:

Office: Electricity, Coal, Nuclear, and Renewables Analysis
Team: Coal and Uranium Analysis
Model Contact: David Fritsch
Telephone: (202) 587-6538
Email: David.Fritsch@eia.gov

Documentation:

- U.S. Energy Information Administration, Model Documentation: Coal Market Module 2020) (Washington, DC, May 2020).

Information on obtaining NEMS: Availability of the National Energy Modeling System (NEMS) Archive.

Coverage:

- Geographic: 17 export regions (5 of which are in the United States) and 20 import regions (4 of which are in the United States).

- Time Unit/Frequency: Each run represents a single forecast year. Model can be run for any forecast year for which input data are available.
- Products: Coking, low-sulfur bituminous coal, and subbituminous coal.
- Economic Sectors: Coking and steam.

Modeling features:

- **Model structure:** Satisfies coal import requirements at the lowest cost given specified export supply curves and transportation.
- **Modeling technique:** The model is a Linear Program (LP), which satisfies import requirements at all points at the minimum overall *world* coal cost plus transportation cost and is embedded within the Coal Market Module.
- **Special features:** The model is designed for the analysis of legislation concerned with air emissions.

Data sources:

Non-DOE sources

SSY Consultancy and Research, IHS Connect Global Coal , International Energy Agency. Published trade and business journal articles, including Platts: International Coal Report, Energy Publishing: Coal Americas, Financial Times: International Coal Report, McCloskey Coal Report, and World Coal. These sources are used in the estimation of the following inputs to the ICDS:

— Coal Import Requirements (Non-U.S.)
— Coal Export Supply Curves
— Diversity Constraints
— Sulfur Emission Constraints
— Subbituminous and High-Sulfur Coal Constraints

DOE sources

— U.S. import inland transportation rates are imputed from similar-distanced origin/destination pairs found in the domestic component of the CDS.
— Coal minimum historical flows (*contracts*) for electricity sector: (1) coal import regions; (2) international export regions; (3) contract historical volumes (trillion Btu); (4) contract profiles for each forecast year.

Computing environment: See Integrating Module of the National Energy Modeling System

Independent expert reviews conducted:

- Kolstad, Charles D., "Report of Findings and Recommendations on EIA's Component Design Report Coal Export Submodule," prepared for the U.S. Energy Information Administration (Washington, DC, April 9, 1993).

Status of evaluation efforts conducted by model sponsor: The ICDS is a submodel of the Coal Market Module developed for the National Energy Modeling System (NEMS) during the 1992–1993 period and revised in 1994. In 2005, the ICDS was revised to include endogenous representation of U.S. imports. For AEO2020, the ICDS was revised to incorporate an endogenous representation of seaborne coal transportation rates. No subsequent evaluation effort has been made as of the date of this writing.