Model Documentation

Coal Market Module

of the National Energy Modeling System

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Contents

Figures

Appendices

Part II—Coal Export Submodule Model Documentation

Tables

Figures

Appendices

Part III—Coal Distribution Submodule Model Documentation

Tables

Figures

Appendices

Executive Summary

Purpose of this Report

This report documents the objectives and the conceptual and methodological approach used in the development of the National Energy Modeling System's (NEMS) Coal Market Module (CMM) used to develop the *Annual Energy Outlook 1995 (AEO95)*. This report catalogues and describes the assumptions, methodology, estimation techniques, and source code of CMM's three submodules. These are the Coal Production Submodule (CPS), the Coal Export Submodule (CES), and the Coal Distribution Submodule (CDS).

This document has three purposes. It is a reference document providing a description of CMM for model analysts and the public. It meets the legal requirement of the 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 the continuity in model development by providing documentation from which energy analysts can undertake model enhancements, data updates, and parameter refinements as future goals to improve the quality of the module.

Module Summary

CMM provides annual forecasts of prices, production, and consumption of coal for NEMS. In general, the CDS integrates the supply inputs from the CPS to satisfy demands for coal from exogenous demand models. The CES forecasts annual world coal trade flows from major supply to major demand regions and provides annual forecasts of U.S. coal exports and imports for input to the NEMS Coal Distribution Submodule. Specifically, the CDS receives minemouth prices produced by the CPS, demand and other exogenous inputs from other NEMS components, including the CES, and provides delivered coal prices and quantities to the NEMS economic sectors and regions.

Archival Media

Archived as part of the National Energy Modeling System production runs.

Model Contact

Information on individual submodules may be obtained from each submodule Model Contact.

Coal Production Submodule

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 four major steps for any given forecast year. First, CPS projects coal production capacity by mine type, and coal type for each year of the forecast period. Second, the CDS estimates the relationship between capacity utilization of mines and marginal costs to produce capacity utilization-marginal costs curves by region and mining method. Then the projected capacity, in conjunction with the capacity utilization-marginal costs curves, are used to construct generic short-run supply curves. These curves reflect only the relationship between the level of production and marginal costs. Finally, to reflect the effects of reserve depletion, changes in labor productivity, changes in real-labor and fuel costs on the marginal costs, a vertical adjustment is made to the short-run curves along the y-axis.

Coal Export Submodule

The CES provides annual forecasts of U.S. coal exports and imports in the context of world coal trade for input to NEMS. The CES uses 16 coal export regions (including 5 U.S. export regions) and 20 coal import regions (including 4 U.S. import regions) to forecast steam and metallurgical coal flows which are computed by minimizing total delivered cost by a constrained Linear Program (LP) model. The constraints on the LP model are: maximum deliveries from any one export region; sulfur dioxide limits; and international coal supply curves.

Coal Distribution Submodule

The CDS determines the least cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector in each demand region by heuristic algorithm which compares alternative sources. The transportation costs are assumed to change over time across all regions and demand sectors. These rates are escalated over time in response to changes in labor, material and fuel cost trends. The CDS uses the available data on existing utility coal contracts (tonnage, duration, coal type, and origin and destination of shipments) to represent coal shipments under contract. These contracts are honored through their expiration date.

Organization of this Report

The next three sections of this report give the specifics of the CPS, CES, and the CDS respectively. Each section will detail each submodule's objectives, assumptions, mathematical structure, primary input and output variables, and its relationship within CMM and other modules of the NEMS integrating system.

The Appendices of each submodule's section will provide supporting documentation for the CMM files currently residing on the EIA mainframe. Each Appendix A lists and defines the CMM input data, parameter estimates, forecast variables, and model outputs. A table referencing the equations in which each variable appears is also provided in Appendix A. Each Appendix B contains a mathematical description of the computational algorithms used in the respective submodule of CMM, including model equations and variable transformations. Each Appendix C is a bibliography of reference materials used in the development process. Appendix D consists of model abstracts, and Appendix E discusses data quality and estimation methods.

Part I—Coal Production Submodule Model Documentation

1. Introduction

Statement of Purpose

This chapter documents the objectives and the conceptual and methodological approach used in the development of the Coal Production Submodule (CPS). It provides a description of the CPS for model analysts and the public. The chapter describes the assumptions, methodology, estimation techniques, and source code of the CPS. 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 in this chapter addresses the important coal supply-related issues of capacity utilization, lead-time constraints, future technological developments, and reserve depletion. The effect of capacity utilization on mining costs is captured through region/mining method regression analysis which relates utilization to price. The model defines capacity utilization/marginal cost curves and converts them into supply curves through capacity projections developed separately. The capacity projections limit the coal supply available in a given year to reflect the lead time required to open new mines. Supply curves are adjusted vertically to reflect technology change and reserve depletion effects. Reserve depletion is captured using exogenous depletion functions generated by the Resource Allocation and Mine Costing (RAMC) Model. The cost impact of technological development is captured by estimating its effect on labor productivity. The regression equations, together with exogenous productivity forecasts, estimate the percentage change in cost due to productivity changes and changes in labor costs and fuel prices.

The CPS generates a different set of supply curves for the NEMS' Coal Market Module (CMM) for each year in the forecast period. The construction of these curves involves four major steps for any given forecast year. First, the CPS projects coal production capacity by region, mine type, and coal type for each year of the forecast period. Second, the CPS estimates marginal costs as a function of capacity utilization of mines and other determinants of cost to produce capacity utilization/marginal cost curves by region and mine type. Next, generic short-run supply curves are constructed using projected capacity in conjunction with the capacity utilization/marginal cost curves. Finally, the short-run supply curves are adjusted to reflect mid- and long-term effects of reserve depletion, changes in labor productivity, and changes in real labor and fuel costs.

Model Archival Citation and Model Contact

The version of the CPS documented in this report is that archived in March 1995.

Name: Coal Production Submodule
Acronym: CPS
Archive Package: CPS95 (Available through National Technical Information Service)
Model Contact: Michael Mellish, Department of Energy, EI-822, Washington, DC 20585 (202)586-2136

Report Organization

This report describes the modeling approach used in the Coal Production Submodule. Subsequent sections of this report describe:

- The model objectives, input and output, and relationship to other models (Chapter 2)
- The theoretical approach, assumptions, and other approaches (Chapter 3)
- The model structure, including key computations and equations (Chapter 4).

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

2. Model Purpose and Scope

Model Objectives

The objective of the CPS is to develop mid-term (to 2010) annual domestic coal supply curves for the Coal Distribution Submodule (CDS) of the Coal Market Module (CMM) of the National Energy Modeling System (NEMS). The supply curves relate annual production to the marginal cost of supplying coal. Separate supply curves are developed for each mine type (surface or underground), coal type, and supply region. The method for developing the supply curves limits the forecast horizon to 30 years. Modifications to the method will be required for longer term forecasts (i.e., forecasts beyond 2010).

The model is part of a larger integrated National Energy Modeling System (NEMS). The NEMS is a comprehensive, policy-oriented modeling system with which existing situations and alternative futures for the U.S. energy system can be described. NEMS objective is to delineate the energy, economic, and environmental consequences of alternative energy policies by providing forecasts of alternative mid- and long-term energy futures using a unified system of models. Each production, conversion, transportation, and consumption sector is implemented as a module in the NEMS, and supply and demand equilibration among these sectors is achieved through an integrating framework. Annual forecasts are provided through a 20-year horizon. NEMS is capable of providing forecasts of energy-related activities in the United States at the national and regional level. Moreover, the NEMS will provide comprehensive, integrated forecasts for the *Annual Energy Outlook*.

Coal Typology

The model's coal typology includes four thermal and four 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 four sulfur grades were selected to correspond to emissions limitations specified in the Clean Air Act Amendments of 1990.

The coal typology potentially yields 32 possible sulfur/thermal grade/mining method categories or coal types. The coal categories used by the model are displayed in Figure 1. Thermal grades are in million Btu per ton and sulfur grades are in pounds of sulfur per million Btu. Included in the figure are isolines for 1 and 2 percent (by weight) coal sulfur levels. The boundaries between thermal grades of coal represent points at which inter-substitution of different coals is technically and economically constrained. Similarly, the boundaries between sulfur grades represent points where intersubstitution is limited by regulation.

Figure 1. Heat and Sulfur Content Categorization of Coal in the CPS

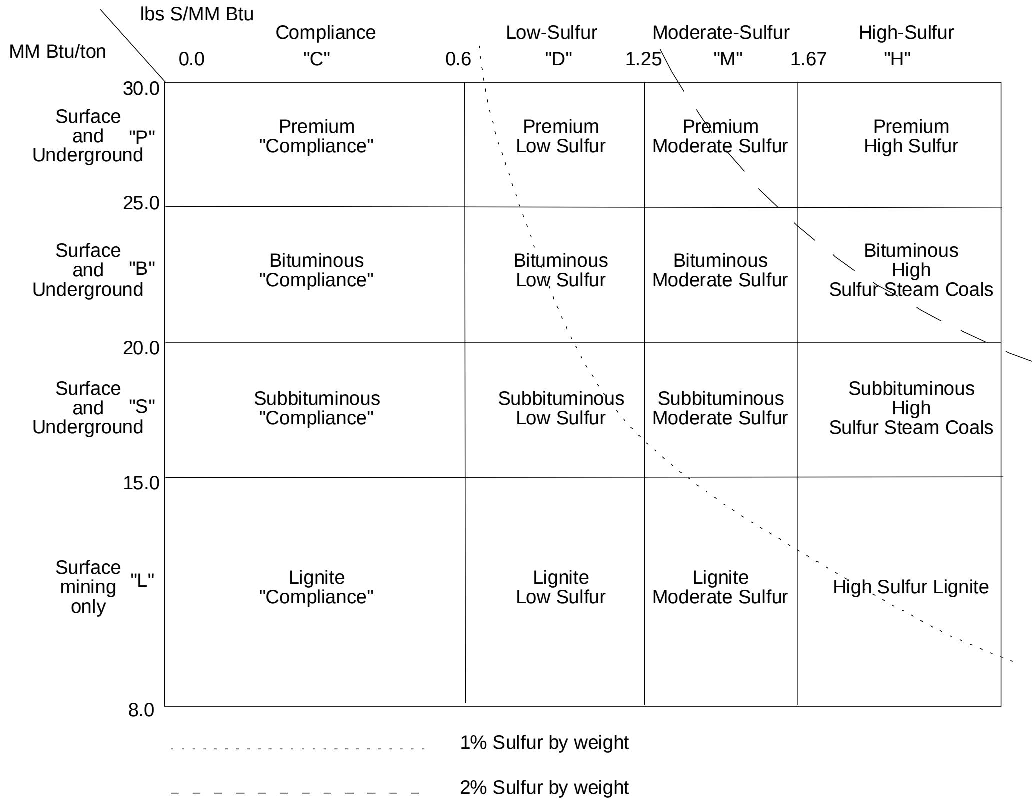


Table 1. Coal Supply Regions for the CPS

Region	Definition
1	Pennsylvania, Maryland, and Ohio
2	West Virginia (north)
3	West Virginia (south)
4	Kentucky (east)
5	Virginia and Tennessee
6	Alabama
7	Kentucky (west)
8	Illinois and Indiana
9	Arkansas, Iowa, Kansas, Missouri, and Oklahoma
10	Texas and Louisiana
11	North Dakota, South Dakota, and Montana
12	Wyoming (east)
13	Wyoming (west)
14	Arizona, New Mexico, Colorado, and Utah
15	Washington, Oregon, and California
16	Alaska

Coal Supply Regions

Sixteen coal supply regions are represented in the model. The coal regions are listed in Table 1 and shown in Figure 2. The coal supply regions represented include States and regions in which prospective changes in coal use are likely to have the greatest market impacts.

Model Inputs and Outputs

Model input requirements are grouped into three categories, as follows:

- User-specified inputs
- Inputs provided by other NEMS modules and submodules
- Inputs provided by the Resource Allocation and Mine Costing (RAMC) Model.

User-specified inputs include base year coal production, total coal shipments to industrial users prior to the base year, total coal exports prior to the base year, labor productivity, and labor cost escalation factors. Inputs obtained from other NEMS modules include fuel prices, total projected coal-fired power plant capacity, coal production in the forecast year, coal shipments to power plants, coal shipments to industrial users, and coal exports. RAMC inputs include a file containing estimates of annual reductions in existing mine capacity caused by mine retirements and a file containing reserve depletion curves. Appendix A includes a complete list of input variables and specification levels.

The primary outputs of the model are annual coal supply curves. Annual supply curves (price/production schedules) are provided for each supply region, mining method, and coal type. Other output quantities also are provided in the form of printed reports. These reports include surge capacity, labor productivity values, and the results of intermediate calculations performed by the model.

Relationship to Other Modules

The model generates regional mid-term (to 2010) coal supply curves. A distinct set of supply curves is determined for each forecast year. The supply curves are required by the CDS submodule of the CMM. The information flow between the model and other NEMS modules (or submodules) is shown in Figure 3. Information obtained from other NEMS modules is as follows:

- Diesel fuel prices from the Petroleum Market Module (PMM) by census region in year t + 2
- Labor costs for the nonmanufacturing sector from the Macroeconomic Activity Module (MAM) by census region in year t + 2.

Figure 2. CPS Coal Supply Regions

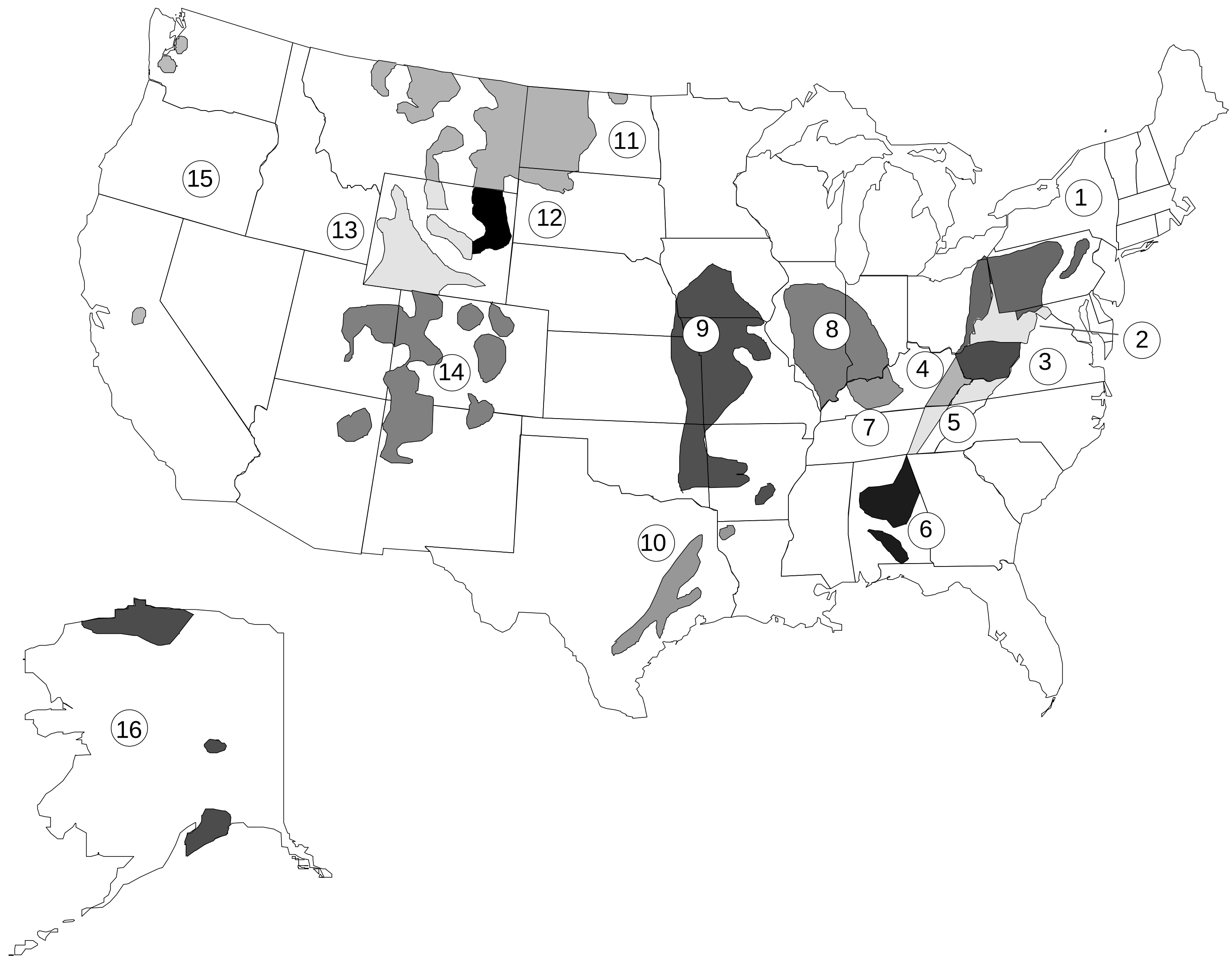
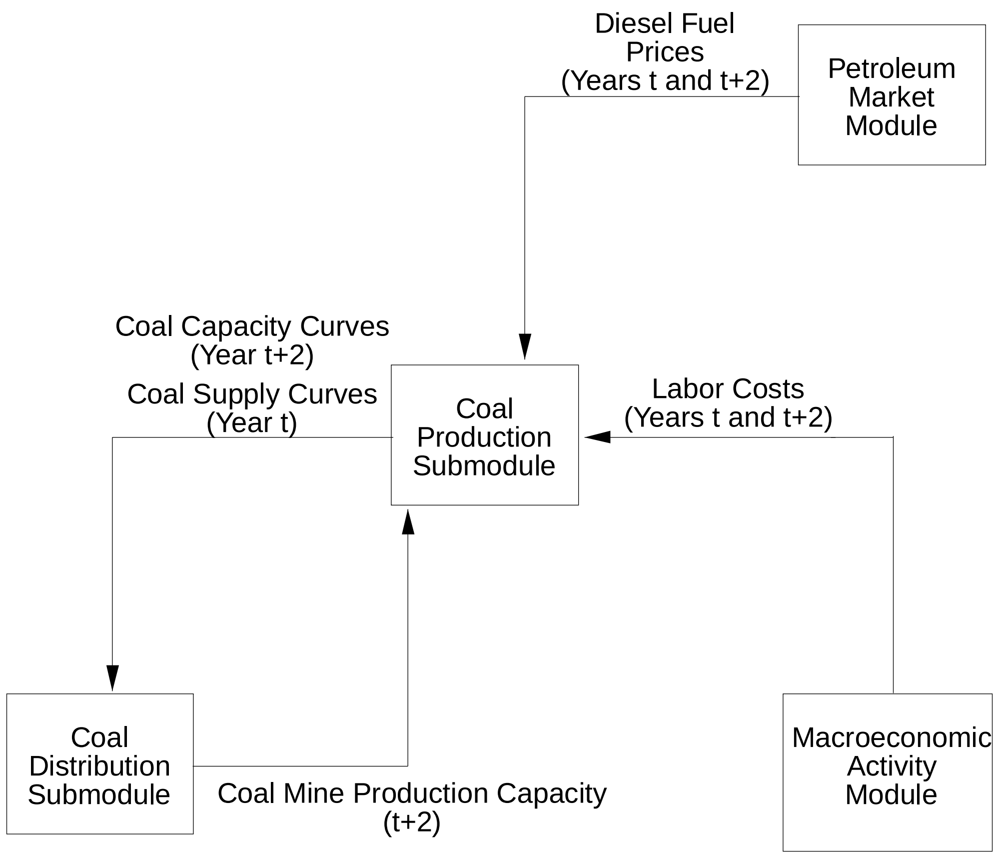


Figure 3. Information Flow Between the CPS and Other Modules



3. Model Rationale

Theoretical Approach

The purpose of the CPS is to construct a distinct set of coal supply curves for each forecast year in the NEMS. The model constructs the supply curves in four separate steps. First, regional coal production capacity is projected by mine type and coal type. Next, the relationship between mine capacity utilization and marginal cost is estimated and regional capacity utilization/marginal cost curves are developed for each mining method. Then, generic short-run supply curves are constructed that reflect the relationship between production level and marginal cost. Finally, the short-run supply curves are adjusted to reflect effects on marginal cost of reserve depletion, labor productivity changes, and changes in real labor and fuel costs.

The EIA currently uses the Resource Allocation and Mine Costing Model (RAMC) for mid-term forecasting. The RAMC is an accounting and engineering model that generates domestic coal supply curves used by other energy models.[1,2] The RAMC performs an ancillary role in the NEMS by providing exogenously to the CPS information to estimate the impact on mining costs of reserve depletion. The RAMC also provides input for piecewise linear capacity curves used to project regional coal production capacity.

As indicated above, the CPS focuses on other factors affecting mine costs in addition to reserve depletion effects. These factors include capacity utilization,[3] lead time constraints for opening new mines, labor productivity, and real labor and fuel costs. Some factors, such as reserve depletion and labor productivity, have important mid- and long-term effects on mining costs. Other factors, such as capacity utilization and lead time constraints, are more important in the short and mid-term. By addressing other substantive factors in addition to reserve depletion effects, the model de-emphasizes the significance of reserve depletion in determining mid-term mining costs.[4]

Underlying Rationale

Since NEMS produces annual forecasts, the supply curves generated by the model represent the cost and availability of coal in each forecast year. In each year, the potential production represented by the supply curves is constrained by the total mine capacity existing at the beginning of the year. New mines may open during the year to meet anticipated or unanticipated demand; however, the number of new mines opened will be limited by the lead time required to open a mine.[5]

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[1]With the exception of adjusting the supply curves to reflect retirement of existing mine capacity, RAMC curves remain static over time.

[2]Coal supply curves developed by the RAMC are used in the Coal Supply and Transportation Model (CSTM), the National Coal Model (NCM), and the International Coal Trade Model (ICTM).

[3]Capacity utilization is production (or output) measured relative to total capacity; i.e., capacity utilization equals annual production (in tons) divided by estimated annual productive capacity (in tons). Productive capacity is defined as the output associated with the minimum of the short-run average total cost curve.

[4]Reserve depletion is influenced strongly by current estimates of the coal Demonstrated Reserve Base (DRB). Because the DRB is inherently uncertain, reducing the effect of reserve depletion on estimated mining costs by adding other factors affecting cost represents a significant enhancement to current supply curve generation procedures.

[5]The lead time required to open a mine varies by mine type, seam access method, mine size, and other site-specific factors. On average, construction and development lead times range from 6 months for small surface and underground drift operations to 7 years for large underground shaft or slope mines. Also, at least one additional year may be needed prior to construction to obtain mining permits. See Science Applications International Corporation, "Enhancement of Short-Term Coal Supply Modeling Capabilities: Final Report Volume I" (unpublished report prepared for the Energy Information Administration, March 1989), pp. 33-34.

Capacity utilization is production or output measured relative to total capacity. In the short term, with mine capacity essentially fixed, variations in production translate into variations in capacity utilization, and different levels of capacity utilization typically imply different mining costs per unit of output. Thus, the relationship between capacity utilization and costs can be embodied directly in a supply curve.

Capacity Utilization/Marginal Cost Curves

Background Discussion and Theoretical Foundation. Lead time requirements force mine operators to determine the additional new mine capacity required in year t and to begin prior to year t the mine permit, construction, and development processes for the new capacity. If the coal demand anticipated in year t significantly exceeds or falls short of actual demand, the percentage of mine capacity utilized in that year will vary from 100 percent. For example, between 1979 and 1986, EIA data indicate that capacity utilization was less than 100 percent for the U.S. coal industry as a whole—- ranging from a low of 86 percent in 1979 to a high of 93 percent in 1986.[6]

The excess capacity that characterized the coal industry during the 1980's was not necessarily due solely to differences between expected and realized coal demand. Some of the excess capacity may have been structural in nature. Coal mines (particularly large coal mines) generally produce for long periods of time. Mine lives of 30 to 50 years are not uncommon. In many cases, a coal operator may open a mine whose design capacity exceeds the current coal demand, with an expectation that demand will grow sufficiently to match the design capacity. Widespread use of long-term contracts may encourage this practice: in general, a large mine will not be opened until a long-term contract has been signed for at least some portion of the mine's future production. Because large mines are very capital-intensive, long-term contracts not only reduce the risk of opening a large mining operation, but evidence of a long-term commitment may be needed to secure adequate financing.

Long-term contracts typically do not specify purchase of a specific annual quantity of coal but provide instead a commitment to purchase coal within a predetermined range. Although a mine's capacity must be sufficient to meet the maximum amount required by the buyer, actual purchases often are less. Moreover, the maximum contracted quantity may be less than the mine's actual production capacity. Consequently, a mine operator will try to sell excess capacity through short-term contracts or on the spot market. As demand increases over time, the producer's ability to sell excess capacity generally improves. Thus, excess capacity initially available at new operations tends to decrease over time. However, since new mines constantly are being opened to replace retired operations as well as to meet new demands, the excess capacity associated with new operations tends to mitigate changes in the industry's capacity utilization and prevent the coal industry from reaching full capacity utilization even under tight market conditions.

Despite the inherent structural component of excess capacity that existed in the coal industry during the 1980's, excess capacity also was affected significantly by the difference between expected and realized demands. This was true particularly in the western coal region, where, during the 1970's, previously subeconomic reserves of lower rank, low-sulfur coal were developed rapidly in response to: (1) substantial oil price increases; (2) new regulations controlling electric power plant sulfur-dioxide emissions; (3) the Carter Administration's National Energy Policy, which emphasized the use of coal in meeting the nation's future energy needs; (4) an optimistic outlook for the development of coal-based synthetic fuels based on data from experiments and demonstration plants throughout the country; and (5) decreased reliance on natural gas for electricity generation, that resulted from state and federal actions aimed at curtailing its use in industrial

[6]Energy Information Administration, *Coal Production 1986,* DOE/EIA-0118(86) (Washington, DC, January 1988) and prior issues.

applications.[7] High expectations of continued growth in demand for western coal resulted in a significant amount of excess capacity in the western coal industry by the late 1970's. An evaluation of the western coal mining industry suggested that actual 1979 production represented only 71 percent of original pre-production planned capacity for a sample of surface mines in Arizona, Colorado, Montana, New Mexico, North Dakota, and Wyoming.[8]

Excess capacity affects mining costs. When capacity exceeds demand, coal operators respond by idling the least productive, highest cost mines and/or mine sections. Operations remaining in production are characterized by higher productivity and lower costs. And as a result of the mine operator's response, there is an almost immediate improvement in productivity and mine costs.

Mine productivity may be improved further (and costs reduced) through technological and managerial developments that are related indirectly to excess capacity. Historically, technological change has been a persistent factor in reducing coal mining costs. The diffusion of new technology and improved operating methods into the coal industry has occurred in both expanding and contracting market conditions. Excess capacity conditions may force operators to hasten efforts to introduce new technology and improved management procedures, particularly if excess capacity persists, or is expected to persist, over a long time period.

The relationship between productivity and coal mine capacity utilization is shown in Figure 4, which depicts marginal and average product curves for a representative mine. As capacity utilization declines, the level of employment declines as workers are laid off; likewise, the level of employment increases with increased capacity utilization. During this process, the marginal product of labor initially increases and then decreases with rising employment levels.

The marginal product of labor measures the incremental change in output due to an incremental change in labor, with all other factor inputs fixed. Output rises initially as labor is increased incrementally. At some point, the rate of increase associated with additional labor begins to fall. This is the point of diminishing marginal returns to labor. After this point, incremental additions to labor causes the average product of labor to decrease so that employing additional labor may be counterproductive. Consequently, a mine will prefer to employ at the level where the average product of labor peaks, L_1 in Figure 4, since each incremental increase in labor up to L_1 increases the average output per worker and each increment of labor beyond L_1 lowers the average output per worker.

The relationship between labor productivity and employment level is defined by the portion of the average product curve to the right of L_1, where labor productivity is related inversely to employment level. If the mine is operating, the employment level will be at least equal to L_1. Employment levels greater than L_1 occur when the mine is underutilized. Consequently, a decline in capacity utilization leads to a reduction in employment level and a corresponding improvement in labor productivity. As illustrated in Figure 4, if the employment level declines from L_3 to L_2 the output per worker rises from $AP_L^{'}$ to $AP_L^{''}$. Also, the marginal product of labor increases as employment level declines. As a result, marginal and average costs are reduced.

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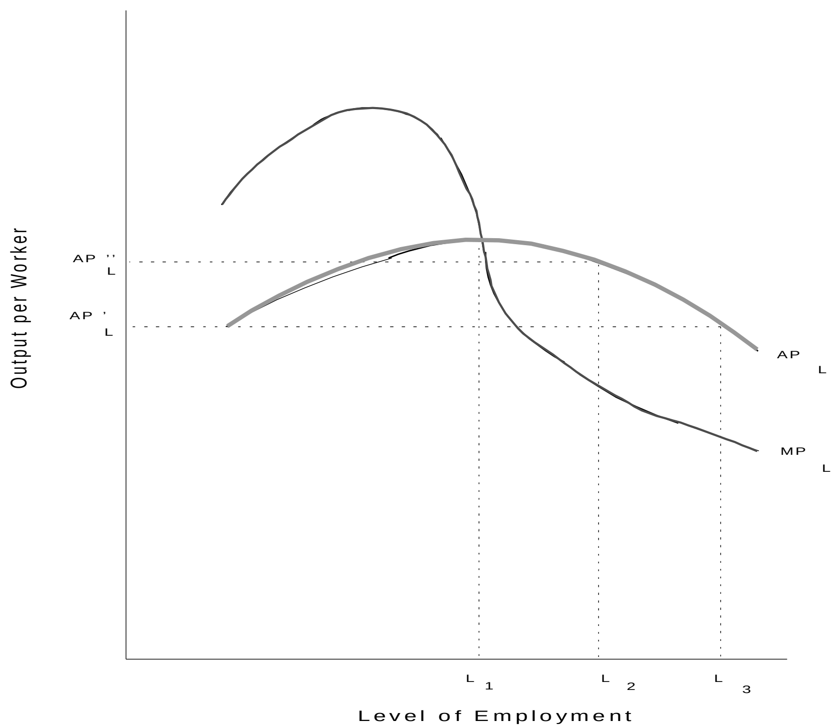
[7]Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 1992), p. 12; and Bill Bryans, "Coal Mining in Twentieth Century Wyoming: A Brief History," *Journal of the West* 21, no.4 (1982), pp. 24-35.

[8]Albert J. Herhal and Scott G. Britton, "Economic Evaluation of the Western Coal Mining Industry," prepared for the Office of Policy and Evaluation, U.S. Department of Interior (May 1981).

Figure 4. Marginal and Average Products for Representative Mine



AP_L = Output per Worker (Average Product of Labor)
MP_L = Marginal Product of Labor

Figure 5. Cost as a Function of Capacity Utilization

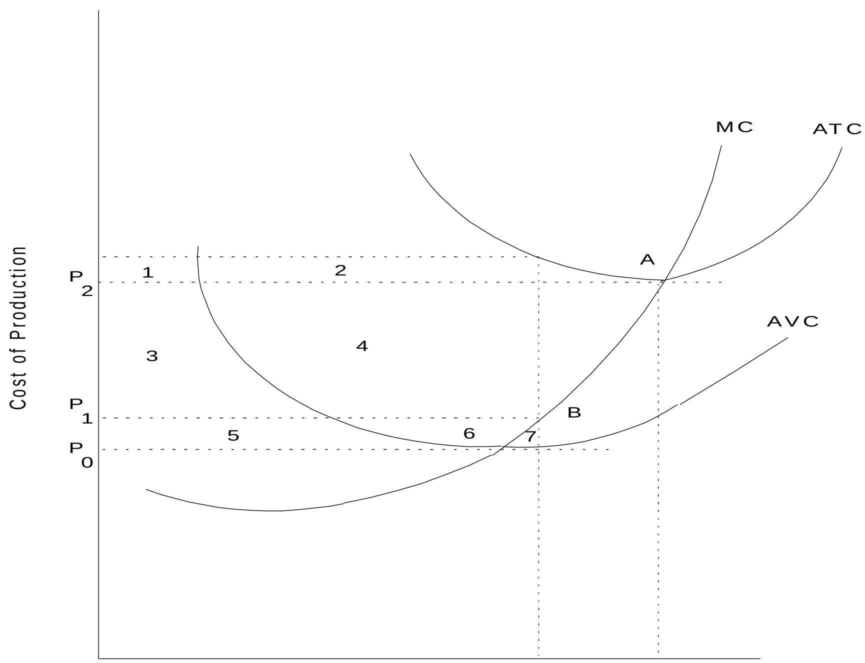


Figure 5 illustrates for a typical mine the relationship between price, marginal cost, average cost, and capacity utilization. A mine will design its operation to minimize average total costs. Hence, the point at which total average costs are minimized (point A) corresponds to 100 percent of the planned production or capacity. At this point, marginal cost equals total average cost. In a competitive market, the mine will maximize profits at the point at which the market price (P_2) of each unit of production is equal to the marginal cost of production. Therefore, the mine operates at full capacity only when price equals P_2. For example, if the market price were lower than P_2, say P_1, the mine would operate at point B and produce at less than 100 percent capacity. At B, price is less than average total cost and the mine does not recover its full cost of production. Under this condition, the mine's loss is defined as the sum of areas 1,2, 3, and 4. However, at B the mine minimizes its loss; otherwise, losses would equal the sum of areas 1, 2, 3, 4, 5, 6, and 7 (total fixed costs) if the mine were to shut down completely. Thus, in the short run, it is in the firm's interest to produce at B despite negative economic profits.[9] However, if the price were less than P_0 (the price corresponding to the minimum average variable cost), the firm will minimize loss by "idling" the mine (assuming zero idling costs).[10]

Each mine's supply curve is defined as the portion of the marginal cost curve lying above the average variable cost curve. The industry supply curve is obtained by aggregating over all mines the individual marginal cost curves. Figure 6 illustrates for the mining industry the relationship between marginal cost and capacity utilization, where point A represents 100 percent industry capacity utilization. As the figure suggests, a decline in utilization is associated with a lower marginal cost of production.

As discussed above, individual mine operations may choose to "idle" a mine when price declines below the mine's average variable cost. Thus, declining coal prices may induce mines with higher average variable costs to cease production. As marginal higher cost mines idle (and temporarily "exit" the industry), the industry's marginal and average costs decrease. Thus, as the industry adjusts to declining prices, a larger fraction of the industry's "design" capacity corresponds to idle mines.

Capacity Utilization/Marginal Cost Curves for the CPS. In the CPS, capacity utilization/marginal cost curves are developed from regression models where minemouth price is the dependent variable and capacity utilization, labor productivity, real labor costs, and real diesel fuel costs are the explanatory variables. As discussed above, in a competitive market the mine will maximize profit (or minimize loss) by setting its output rate so that minemouth price equals marginal cost. Since historical data on marginal mining costs are unavailable, the minemouth price is used as a proxy for marginal cost because mines will maximize profits by producing up to the point where marginal cost equals price. It is assumed that the bulk of reported minemouth prices approximates closely the actual marginal cost of mining.

Although it is assumed that coal industry behavior reflects the characteristics of a competitive market, there are a number of factors that may cause the industry to deviate from a true competitive market structure. One major factor is the dependency of coal producers on long-term contracts with electric utilities. The characteristics of long-term contracts that affect coal price formation include: (1) long-term contracts typically are designed to reflect full cost recovery of producers; and (2) long-term contracts act to insulate producers from short-term price fluctuations. Other mechanisms for coal market transactions include the spot market, short-term contracts, medium term contracts, and long-term contracts with short-term price re-openers.[11] The minemouth price represents an average of these market transactions, and each distinct market transaction typically carries a different level of pricing.[12] Thus, the average minemouth price may not conform precisely to marginal production costs associated with variations in factors of a relatively short-term nature such as capacity utilization and labor productivity. These costs are more likely reflected in spot market prices than in contract prices because the spot market for coal includes all market transactions in a purely competitive market. However, historically, movements in coal contract prices have tracked consistently movements in spot market prices so that the trend in the composite minemouth price approximates a competitive market. For this

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[9]The analysis here is static rather than dynamic. In a dynamic analysis, along the lines of Hotelling, the shut-down decision in the current period would be based on the future time path of prices, in addition to the relationship between the current price and average variable costs. Given the assumptions underlying a dynamic analysis (e.g., that there is no uncertainty regarding either the size of the reserve base or the future costs of extraction), it is believed that the static approach describes better the realities of the coal industry. Harold Hotelling, "Economics of Exhaustible Resources," *Journal of Political Economy* (April 1931), pp. 137-175.

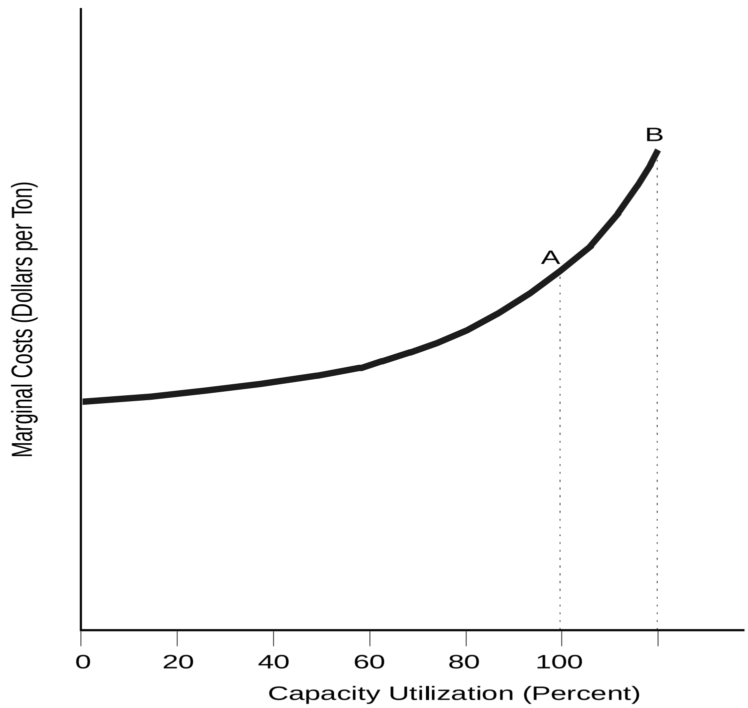
[10]An idle mine is defined as a mine that currently is not producing coal, but is still open (i.e., access to the seam has not been permanently sealed) and has all the necessary equipment (though not the workforce) required to produce coal. Since the workforce required to bring an idle mine back into production generally can be hired within a short time period (a few months at most), these mines represent a part of the total capacity available in any given year.

[11]Separate data on average minemouth prices of coal for the spot and contract markets are not available.

[12]During the past several years, the average delivered price of utility coal under contract has been higher than coal sold on the spot market. Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1991*, DOE/EIA-0191(91) (Washington, DC, August 1992) and prior issues.

reason, it is believed that reasonably representative relationships between the marginal cost of mining and the explanatory variables can be captured through reported minemouth prices.[13]

Figure 6. Industry Marginal Costs vs. Capacity Utilization



Surge Capacity and Capacity Expansion. As suggested by Figures 5 and 6, in the short-run a mine can produce in excess of 100 percent capacity. This "surge" capacity represents production that is greater than the nominal design capacity (the capacity at which under normal conditions the mine is designed to operate). As discussed above, the mine's design capacity corresponds to the point at which the marginal cost equals the average total cost (Point A in Figure 5). Average total costs are minimized at this point, and the mine operator will plan to operate at this point in the long run. However, production can be increased beyond design capacity, at the expense of higher marginal and average costs. Therefore, if demand exists, and if the price of coal is high enough to justify higher marginal costs, the mine will produce beyond its design capacity. In practical terms, this additional production might be obtained by adding a third production shift to a mine normally scheduled to produce coal only two shifts per day. Alternatively, a mine scheduled to produce coal three shifts per day might work Saturdays, Sundays, and/or holidays to increase output. The additional output realized by expanding the production schedule may come at the expense of higher labor costs (due to higher wage rates paid for work performed on weekends and holidays) and reduced productivity (due, e.g., to the hiring of less experienced workers and reductions in the amount of time available for preventive maintenance). However, as long as prices are sufficient to cover the higher costs, it is likely that the mine operator will continue to produce to the maximum level technically feasible using the existing equipment fleet. This

[13]To the extent that average minemouth price reflects market transactions other than the spot market, the regression coefficients may tend to be smaller because coal sold under contract is less responsive than the spot market to changes in capacity utilization, labor productivity, and factor input costs.

maximum production level corresponds to the mine's surge capacity. In Figure 6, the total design capacity of the industry corresponds to A, and the total surge capacity corresponds to B.

Surge capacity typically is utilized only over short periods. If demand continues to exceed design capacity over a longer period, the operator will respond by adding to the mine's equipment fleet (thereby increasing its design capacity) and/or opening new mines. However, within a single forecast year, the number of operators who can increase the design capacity of their existing operations, and the extent to which the capacity can be increased, will be limited by mine design and engineering considerations. Likewise, lead time constraints will limit new mine capacity additions. For a single year, lead times will limit the number of large mines opened to mines currently under construction prior to the beginning of the year.[14] Since these mines are planned based on expected demands, they do not represent a source of capacity for meeting additional unforeseen demands.

Small mine operators that have obtained necessary mining permits will be able to initiate and complete construction activities within the year, but may not reach full production levels until roughly mid-summer even if construction begins in January. Prior to passage of the Surface Mining Control and Reclamation Act (SMCRA) in 1977, small mine operators were able to respond rapidly to unexpected demand increases by opening new operations; however, the permitting and bonding requirements created by SMCRA have reduced the small operator's ability to respond rapidly to capacity shortfalls. Nonetheless, since some mine operators may obtain mining permits for more properties than they actually expect to develop, a limited amount of additional capacity above the amount provided by existing mines could be added to the supply curve by opening small operations. In addition, a small amount of production could be added to the curve by expanding the capacity of some existing operations. However, it is unlikely that this limited amount of additional capacity potentially available from existing mines and small new mines will be opened unless operators believe that the unexpectedly high demand level will continue sufficiently to justify the capital expenditures. Finally, the portion of the supply curve lying to the right of the design capacity point is expected to be utilized by the CDS only on rare occasions. For these reasons, the model assumes that the amount of available coal supply over and above design capacity is limited to that provided by the surge capacity of existing operations.

Adjustments to Coal Mine Capacity

The preceding discussion focused on short-term issues that determine cost and availability of coal supply within a single NEMS forecast year. The assumption underlying short-term cost and availability is that industry capacity is fixed; i.e., that new mines will not be opened. This assumption is sufficient for estimating coal supply for a single year. However, since the NEMS forecast horizon is 25 years, the model must be able to adjust industry capacity each year as mines open and close. To estimate annual production capacity, the CPS and CDS make use of projected coal demands from the Electric Market Module, the demand modules, and the Coal Export Submodule. Mine capacity is projected by the model for each year of the forecast period. The annual capacity projections are used to move the position of the design capacity point to the right on the coal supply curve (point A on Figure 6).[15] Thus, although the supply curve will remain fixed in length *within* a forecast year, it will become longer from one forecast year to the next to reflect new mine openings and the increase in available capacity. The variables included in the capacity model are discussed separately below.

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[14]Based on information presented in the report "Economic Evaluation of the Western Coal Mining Industry" (by Albert J. Herhal and Scott G. Britton), construction times (exclusive of development) range from approximately 1.25 to 3 years for large ($\geq$500,000 ton-per-year) operations.

[15]Historical data were obtained for the industrial and export sectors from the EIA-6 data base. Export demand includes all overseas shipments and shipments to Canada and Mexico. Industrial demand includes domestic shipments of U.S. coal to both the coking and industrial steam coal sectors. Only national levels are included in the model.

Coal Demand. The decision to open a new mine is a long-run decision based on expected changes in coal demand. Because of the lead time required to open a mine, the coal industry must make capacity expansion decisions prior to year that the additional capacity will be required. Consequently, projections of coal demand in year *t* for year *t+x* are used by the CPS and CDS to determine coal mine capacity requirements in year *t+x*.[16] Projections of coal demand are obtained from the Electricity Market Module, the Coal Export Submodule, and the demand modules. The CDS solves for the least cost sources of mine capacity by supply region, coal type, and mining method for year *t+x* using the projections of coal demand in year *t* for year *t+x* and coal mine capacity curves from the CPS. Coal mine capacity estimates for year *t+x*, as determined by the CDS, are provided to the CPS.

Reserve Depletion

Mining costs vary significantly and depend, in part, on the geological characteristics of the reserves. Coal mine operators generally mine lower cost reserves prior to higher cost reserves to minimize production costs. Costs tend to rise as reserves are depleted and operators are forced to develop less attractive coal deposits. Technology development and other factors, however, may mitigate the effect of reserve depletion on mining costs. The model considers these effects in estimating mining costs. However, the effects of reserve depletion and other factors are considered separately to capture interrelationships that may exist among factors affecting mine costs. To capture depletion effects, the model uses exogenous reserve depletion functions obtained from the RAMC to adjust the supply curves over time.

Technology Change/Labor Productivity and Factor Input Costs

New technology developments tend to be evolutionary rather than revolutionary in nature in the coal industry. The introduction of longwall mining into the United States in the mid-1960's provides the most recent example of an entirely new mining system penetrating the market. One must return to the late 1940's, and the development of continuous mining, to find a technological change comparable in scope to the introduction of longwall mining. Furthermore, these new technologies have increased their market shares gradually over time. For example, the percentage of total underground production from continuous mining increased from 2 percent in 1951 to 31 percent in 1961. By 1971, the share of continuous mining coal production was 55 percent, and in 1990, continuous mining accounted for 64 percent of total underground production.[17] The percentage of total underground production mined by longwalls rose from less than 1 percent in 1966 to 4 percent in 1976. Recent estimates suggest that longwall mining contributed approximately 16 to 20 percent of total underground production in 1982, and estimates by the EIA suggest that longwalls accounted for 29 percent of total underground production in 1990.[18] For surface mines, the size and capacity of the various types of equipment used (including shovels, draglines, front-end loaders, and trucks) has gradually but steadily increased over time.

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, and the effect on productivity and cost also

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[16] The model currently uses projections of coal demand in year *t* for year *t+x*.

[17] 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).

[18] Energy Information Administration, *Coal Data: A Reference*, DOE/EIA-0064(90) (Washington, DC, November 1991), p. 10; and Paul C. Merritt, "Longwalls Having Their Ups and Downs," *Coal*, MacLean Hunter (February 1992), pp. 26-27.

has been gradual.[19] The gradual introduction of new technology development is expected to continue during the NEMS forecasting horizon. Potential technology developments in underground mining during the next 10 years are as follows:[20]

- A continuation in the trend toward increased continuous miner mining and loading rates
- Introduction of equipment with self-diagnostic capabilities
- Automation of longwalls
- Increased depth of cutting drums on longwall shearers
- Continued penetration of improved longwall and continuous mining technology
- Increased utilization of conveyor belt monitoring systems, and extension of monitoring systems to the production equipment
- Introduction of pillaring shields (currently in use at only two mines)
- Increased utilization of continuous haulage systems in thick seams
- Application of longwall mining to above-drainage seams
- Increased utilization of continuous mining supersections.

Potential improvements in surface mining technology include the increased utilization of on-board 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 (e.g., larger bucket sizes for draglines and loading shovels and larger trucks for overburden and coal haulage).

Technological developments during the NEMS time horizon are expected to consist of incremental improvements to existing technology rather than the introduction of new technologies. Because of the complexity in representing explicitly in the model the cost impact of each potential technology improvement, the effect of incremental technology change is captured indirectly through its estimated net effect on labor productivity. Since technology developments in the mining industry reduce costs primarily by impacting productivity, exogenous estimates of labor productivity that reflect the estimated net effect of technological improvement are provided to the model in each forecast year. Separate estimates are input to the model for each region and mining method. The cost effect of the labor productivity change for each succeeding year is determined using the regional regression models for surface and underground mine marginal costs. In each forecast year, the regression model for each region, mining method, and coal type determines the change in cost due to the change in labor productivity, as well as the factor cost inputs, between the base year and the forecast year. This calculation is based on exogenous productivity forecasts together with forecasts of the various factor input costs. After adjusting the supply curve's position to reflect reserve depletion, the supply curve is shifted up or down by an amount equal to the estimated cost change. The costs of factor inputs to

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[19]Perhaps the most notable exception has been the dramatic, on-going rise in longwall productivity, following rapidly on the heels of 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.

[20]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).

mining operations captured by the model include real labor costs and real diesel fuel prices over the forecast period.

A Comparison of the CPS to Other Coal Supply Analysis Models

During the development of the CPS, three alternative mid-term coal supply analysis approaches were reviewed. These approaches are embodied in the following models: the EIA's RAMC, the coal supply module of ICF Inc.'s Coal and Electric Utilities Model (CEUM), and the coal supply portion of the Data Resources, Inc. (DRI)/Zimmerman Model. These approaches are outlined in this section. In addition, since the RAMC will supply reserve depletion information to the CPS, the manner in which the other coal supply modules estimate the effects of reserve depletion is compared with that of the RAMC. Also, the supply analysis methodologies used in the RAMC, the CEUM, and the DRI/Zimmerman model are compared with those to be incorporated into the CPS.

Resource Allocation and Mine Costing Model

The RAMC generates coal supply curves that are used as input to other EIA models—most notably the CSTM. The CSTM uses RAMC supply curves, in conjunction with its coal transportation network, to determine least cost supplies of coal by supply region for a given set of coal demands by demand sector and region. The RAMC supply curves formerly were used as an exogenous input to EIA's Intermediate Future Forecasting System (IFFS), which produces energy forecasts for EIA's *Annual Energy Outlook*. RAMC supply curves also have been used as input for stand-alone model runs of the CSTM to analyze coal-related issues such as proposed changes in State severance taxes and the potential impact of proposed coal slurry pipelines. The RAMC is included in NEMS, but is maintained and operated off-line rather than being incorporated and executed as part of an integrated submodule of NEMS. The RAMC supplies reserve depletion and production capacity-related information as an exogenous input to the CPS.

The RAMC uses a model mine approach to construct mid-term coal supply curves. The model incorporates 32 supply regions and 30 coal types (combinations of 5 heat content categories and 6 sulfur content categories). With the exception of reducing existing mine steps to reflect the retirement of older mines, the RAMC supply curves remain static over time. New mines are opened only when production from existing mines cannot meet a specified level of demand. The RAMC assumes all mines operate at full capacity utilization under a presumption that coal demand balances production capacity in the long-term.[21] The RAMC adjusts mining costs for projected or assumed changes in the real costs of capital, labor, and power and supplies through the incorporation of separate escalation factors for each of these categories. Adjustments of these escalators are reflected in the calculation of annual levelized costs in the RAMC and can be made only at the national level.

ICF's Coal and Electric Utilities Model

The CEUM is used to analyze coal-related policy issues. It is a successor to the National Coal Model developed by ICF, Inc. for the Federal Energy Administration in 1976.[22] Among the many analyses the CEUM

[21]This assumption may be unrealistic, as discussed above. However, unlike the RAMC, the CPS does not assume that mines operate at full utilization at all times.

[22]ICF, Inc., *The National Coal Model: Description and Documentation*, prepared for the Federal Energy Administration (Washington, DC, October 1976); and Resource Dynamics Corporation, *A Review of Coal Supply Models*, prepared for Assistant Secretary of Fossil Energy, U.S. Department of Energy (Washington, DC, October 1982), p. V-6.

has been used for are western coal development, Federal coal leasing, and acid rain mitigation proposals (including analyses of various legislative proposals leading to the enactment of the Clean Air Act Amendments of 1990 for the Environmental Protection Agency).

The coal supply module of the CEUM uses a model mine approach to produce mid-term coal supply curves. The model incorporates 40 supply regions and 50 coal types (combinations of 7 heat/volatility level categories and 7 sulfur content categories, plus 1 anthracite category).[23] The effects of depletion, changes in labor productivity, and changes in real costs of factor inputs on mining costs are estimated over the forecast period.

The coal supply module of the CEUM and the RAMC share common origins, since both are modified versions of the coal supply model incorporated into the 1976 version of the National Coal Model. However, the current versions of the models use somewhat different methods for deriving annual levelized mining costs. Most revisions to these models involved the addition of more detailed model mines which better reflect variations in coal geology and coal mining techniques. In addition, longwall model mines have been added to reflect the growing importance of longwall technology in the U.S. coal mining industry.

The ICF model and database modifications that differ from RAMC are: (1) the incorporation of mine start-up (i.e., development) and shut-down productivity and production levels into the model's mine costing equations; (2) the incorporation of intertemporal rents into the algorithm used to calculate a minimum acceptable selling price;[24] and (3) the inclusion of additional non-DRB reserves (primarily inferred) into the modeling reserve base.

DRI/Zimmerman Model

The DRI/Zimmerman coal model is used to develop mid-term forecasts for DRI Inc.'s coal analysis and forecasting service.[25] In the DRI coal supply module, reserves are allocated to mine cost categories (defined primarily by seam thickness for underground mines and by overburden ratio for surface mines), in contrast to being allocated to coal mines.[26] As a result, the horizontal axis of DRI supply curves reflects the total amount of recoverable coal reserves instead of potential annual production. Long-run marginal costs, which determine the height of each step, are the sum of annual levelized capital costs and current year mine operating costs.[27] Thus, if labor, materials, and supply costs do not increase in real terms over the forecast period, the DRI mine costs are equivalent to an annual levelized cost. On each supply curve, all reserves in the lowest cost category for a particular region and coal type combination are produced before any reserves in the next highest cost category. To limit the amount of new production that can come on-line in a given forecast year, maximum annual percentage increases/decreases in coal production are input by supply region. Intertemporal adjustments to mine costs are made to reflect the impact of expected changes in labor productivity.[28] The model incorporates 10 supply regions and 6 coal types (sulfur content categories).

The primary difference between the DRI model and the RAMC is that in the DRI model all reserves in the lowest cost category for a particular region and coal type are produced before any reserves in the next highest cost category. In contrast, on a RAMC supply curve, where the horizontal axis represents potential annual

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[23]ICF, Inc., *Documentation of the ICF Coal and Electric Utilities Model: Coal Supply Curves Used in the 1987 EPA Interim Base Case*, prepared for the U.S. Environmental Protection Agency (Washington, DC, September 1989).

[24]Intertemporal rents are based upon the economic theory of depletable resources.

[25]Resource Dynamics Corporation, *A Review of Coal Supply Models*, p. VII-1.

[26]Benjamin Lev, ed., *Energy Models and Studies* (Amsterdam: North Holland Publishing Company, 1983), Richard L. Gordon, *The Evolution of Coal Market Models and Coal Policy Analysis*, p. 73.

[27]Resource Dynamics Corporation, *A Review of Coal Supply Models*, p. VII-52.

[28]King Lin, Data Resources International, Inc., Personal Conversation, March 18, 1992.

production, coal of various costs is produced at the same time.[29] Thus, in the RAMC, the producer with the highest mining costs, as determined by the annual level of coal demand, is treated as the price leader. Producers with lower mining costs on the same supply curve earn economic rents.

All else being equal, depletion effects have less influence on minemouth price under the DRI approach because (1) no producers earn economic rents and (2) reserves are not allocated to mines (thus assuring that lower-cost reserves are completely exhausted before higher cost reserves are developed). A criticism of the DRI methodology is that, since there are no unused committed reserves, price rises will continue to be forecast during a period of declining coal demand.[30] This is because the DRI methodology assumes that all lowest cost reserves (i.e., the lowest step on the supply curve) are mined before the next higher cost reserves. Thus, even during periods of declining coal demand, all reserves in a cost category can be depleted and production would proceed to the next highest cost category of reserves, with the result being higher price forecasts. However, this criticism is not without exceptions since: (1) retirement of existing production capacity in the RAMC model shortens supply curves and, therefore, can result in the condition of rising price forecasts during periods of decreasing coal demand; and (2) both productivity increases and declining wages result in downward adjustments of supply curves in the current version of the DRI/Zimmerman model, which can more than offset estimated price impacts of reserve depletion.

Comparison of the NEMS Model with the RAMC and the Coal Supply Modules of the CEUM and the DRI/Zimmerman Model

The NEMS model does not incorporate explicitly the RAMC modeling methodology to develop supply curves. Rather, the CPS constructs supply curves using projected coal production capacity by region and coal type in conjunction with regression equations that relate capacity utilization to marginal costs. Coal production capacity projections, however, are determined primarily from projected coal demands from other NEMS modules and piecewise linear capacity curves developed through the RAMC methodology. An initial upward adjustment to the supply curves is made on the basis of reserve depletion information from the RAMC. Additional adjustments are made to capture the effects on mining costs of labor productivity changes and changes in real operating costs.

In addition to incorporating the RAMC reserve depletion effects, the CPS includes enhanced capabilities to: (1) adjust minemouth cost estimates for projected changes in labor productivity, wage rates, and fuel costs; (2) limit the amount of new production capacity that can come on-line in any given year (incorporating the real-world reality of lead-time constraints); and (3) analyze the impacts on the coal industry of variations from full coal mine capacity utilization.

Both the CPS and the ICF model account for depletion effects, labor productivity change, and changes in real operating costs over the forecast period. However, unlike the ICF model, which incorporates projected or assumed changes in labor productivity and real operating costs into its calculation of an annual levelized cost,[31] the CPS makes annual adjustments to the supply curves. The CPS does not include detailed reserve allocation and mine costing algorithms, since the primary purpose of these algorithms is to estimate the relationship between reserve depletion and mining costs (which the CPS captures as an exogenous input from the RAMC). Also, the regional and coal type classification of the CPS is less detailed than the 40 supply regions and 50 coal types classification of the ICF model. By eliminating the need to use detailed reserve allocation and mine costing algorithms (as included in the ICF model) the CPS algorithm substantially reduces solution time requirements and meets the NEMS requirement to minimize total module execution time.

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[29]Steps on a RAMC supply curve are ordered from lowest production cost to highest production cost.

[30]Resource Dynamics Corporation, *A Review of Coal Supply Models*, p. VII-54.

[31]ICF, Inc., *Documentation of the ICF Coal and Electric Utilities Model: Coal Supply Curves Used in the 1987 EPA Interim Base Case*; and Dan Klein, ICF, Inc., Personal Conversation, April 6, 1992.

Also, in contrast to the ICF model, the CPS limits the amount of new production capacity brought on-line in any given forecast year and models variations from full coal-mine capacity utilization that, for example, result from uncertainty in future demand. However, it should be noted that the productivity and production profile for new mines incorporated into ICF's mine costing equations also address, to a more limited extent, mine lead-time constraints, since new mines in the ICF model come on-line at less than full production capacity.

The CPS and the DRI model both estimate depletion effects, changes in labor productivity, changes in the real costs of factor inputs on mining costs, and make annual adjustments to the supply curves over the forecast period. The CPS also limits the amount of new production capacity that can come on-line in a given year. In contrast to the DRI model, which determines the limits exogenously, limits on new mine capacity additions in the CPS for a given forecast year are a function of current and previous year forecast results from other NEMS modules. Also, as discussed above, unlike the DRI model, the CPS reduces execution time by capturing exogenously the relationship between reserve depletion and mining rather than including detailed reserve allocation and mine costing algorithms.

Finally, although the ICF and DRI models address some of the key CPS issues, the fact that the models are proprietary, not fully documented, not coded to NEMS standards, and not publicly available make them inappropriate for use within the NEMS.

4. Model Structure

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

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

- Step 1: Project coal production capacity by region, mine type, and coal type for each forecast year

- Step 2: Estimate the relationship between the mine's capacity utilization and the marginal cost and develop capacity utilization/marginal cost curves by region and mining method

- Step 3: Construct generic short-run supply curves (i.e., curves that reflect only the relationship between level of production and marginal costs) using projected capacity and the capacity utilization/marginal cost curves

- Step 4: Adjust the vertical position of each annual short-run supply curve to reflect the effects on marginal cost of reserve depletion, labor productivity changes, and changes in real labor and fuel costs.

Step 1: Production Capacity Forecasts

As discussed in Chapter 3, the capacity of existing operations constrains the quantity of coal available during each year of the forecast period. The CPS recognizes this critical constraint by building the supply curve on the basis of a projection of the design capacity of existing operations.

In Step 1, coal mine capacity totals for each unique combination of supply region, mining method,and coal type are estimated empirically using information obtained from other NEMS modules.[32] Coal mine capacity projections are based on information provided by the EMM concerning future coal-fired power plant fuel requirements and information provided by other NEMS modules concerning future industrial, commercial, residential, and export sector coal demands. The long-term coal-fired power plant capacity requirements projected by the EMM reflect changes in power plant capacity due to capacity additions and requirements, as well as expected shifts in demand by coal quality (due, for example, to the 1990 Clean Air Act Amendments). Projected utility coal-fired power plant capacity requirements (represented as equivalent coal demand) together with projected demands from other sectors and piecewise linear capacity/supply curves form the basis for distribution by the CDS of projected coal capacity requirements.

The capacity projection methodology is summarized briefly as follows:

- projected coal-fired power plant, nonutility, and export sector demands are provided to the CDS through the NEMS modules

[32] The function of the capacity projection methodology is determine in year t the coal production capacity required in year $t + x$, where x represents the lead time required to bring a mine to meaningful production levels. Currently, the lead time requirement is set equal to 2 years.

- RAMC supply curves (representing the marginal cost of new capacity) adjusted for the effects of labor productivity changes and changes in real labor and costs are converted to piecewise linear curves and passed to the CDS

- least-cost coal production capacities required to meet projected coal demands are determined by the CDS using the current CDS solution algorithm

- projected coal capacities are aggregated by the CPS to CPS supply region, coal type, and mine type and adjusted for excess capacity.

Projecting Utility, Nonutility, and Export Coal Demand

Projections of utility coal demands currently are obtained directly from EMM forecasts of coal-fired power plant requirements. The EMM has a 6-year capacity expansion projection horizon. Since, the current version of the CPS assumes a 2-year lead time to bring mines to meaningful production levels, estimates of coal demand are obtained only for the second year of the 6-year EMM capacity expansion projection horizon. The EMM provides coal demand to the CDS by coal rank, sulfur content, and coal demand region.[33]

Nonutility and export sector coal demands represent a small share of total coal demand.[34] Conceptually, projections of nonutility and export sector demand can be obtained using information provided by the NEMS modules. For example, if coal producers partially adjust capacity in each year to move toward a desired capacity level, incremental capacity requirements can be approximated by a simple extrapolation model which projects nonutility and export sector demand as a function of current and historical demand levels.[35] The CPS emulates this extrapolation method by obtaining from the NEMS information concerning future expectations of nonutility and export sector coal demands. These expected demands are combined with the projected utility coal demands to obtain total coal demands in the projected year.[36]

Developing Capacity/Supply Curves from the RAMC

The RAMC supply curves estimate the marginal cost of new coal production. In contrast to the marginal cost curves used in the CPS, embedded in the development of the RAMC supply curves is an assumption that mines operate at full capacity. Consequently, the set of RAMC-generated supply curves represents the marginal cost of new coal production capacity. An adjusted set of RAMC supply curves is passed to the CDS to determine the least-cost distribution of new coal production capacity in response to projected coal demands.

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[33]Alternatively, coal demand can be obtained from projected capacity planning decisions estimated by the EMM. The EMM projects coal-fired power plant capacity expansion in each of 6 years following the forecast year *t*, estimates of future utility coal requirements can be obtained by converting the capacity projections to coal demand using long-term capacity utilization and heat rates associated with the coal-fired power plants, as follows: $(D_{d,g})_i = k*(C_{d,g})_i*(CF_d)_i*(HR_d)_i$, where $D_{d,g}$ is utility demand for coal type g in demand region d, $C_{d,g}$ is projected coal-fired power plant capacity for coal type g in demand region d, CF_d is long-term capacity utilization for coal-fired power plants in demand region d, HR_d is long-term heat rate for coal-fired power plants in demand region d, and i equals the projected year and k is a constant. Coal demand estimates for the *1995 AEO* were obtained directly from EMM forecast to provide a more stable solution. The alternative coal demand projection methodology can be implemented as a future enhancement.

[34]In 1990, nonutility consumption was approximately 11.2 percent of total coal production and exports were 10.3 percent. By 2010, nonutility consumption is expected to decrease to nearly 9 percent of total coal production and exports are expected to increase to about 17 percent, See Energy Information Administration, *Annual Energy Outlook 1993*, DOE/EIA-0383(93) (Washington, DC, January 1993).

[35]An example of an exponentially weighted extrapolation model for projecting demand is as follows: $D^p_{t+1} = \alpha D^a_t + (1 - \alpha)D^p_t$, where D^p is projected demand and D^a is actual demand. By taking the difference between projected demand in year *t + 1* and actual demand in year *t*, the incremental projected demand reduces to the following form: $\Delta D^p_{t+1} = \mu D^a_t + (1 - \alpha)D^p_t$, where μ and α represent adjustment factors.

[36]Currently, future expectations of nonutility demand are obtained from the NEMS restart file.

The long-term annual RAMC capacity curves are adjusted to capture the effects of changes in labor productivity and changes in factor input costs and fuel prices. For each projected year, changes from base year values are computed based on projected changes in productivity, factor input costs, and fuel prices. The capacity curves are shifted vertically to reflect the incremental changes to mining costs. The capacity curves are adjusted further to account for the retirement of existing capacity. The adjusted RAMC capacity curves are converted to piecewise linear segments and passed to the CDS.

Aggregating to CPS Supply Regions and Adjusting for Excess Capacity

The CDS determines the least-cost distribution of projected capacity based on projected coal demands and the piecewise linear capacity curves. This procedure is discussed in Part III - Coal Distribution Submodule Documentation. The projected capacities are passed to the CPS.

A disaggregated set of projected capacities is passed to the CPS by the CDS. The CDS projects capacity by supply region, demand region, coal type, and demand sector. The capacities must be aggregated to CPS supply regions, coal types, and mine types. The CPS searches through the set of projected capacities to identify and aggregate capacities corresponding to each CPS region, coal type, and mine type. When appropriate, the projected least-cost capacities (required to meet demand and replace capacity lost when existing mines are retired) are reduced to account for excess capacity existing in the prior year. Excess capacity is determined by comparing the capacity in a supply region by coal type and mine type in the prior year to the corresponding shipments from the supply region projected for year $t + 2$.

Step 2: Development of Capacity Utilization/Marginal Cost Curves

In Step 2, a set of regression equations estimates the relationship between capacity utilization and marginal cost. These regression models estimate marginal costs as a function of capacity utilization, labor productivity, labor costs, and diesel fuel costs. A distinct capacity utilization/marginal cost curve is developed for each mining method. In this step, estimates by coal type are not determined since mining costs are not significantly dependent on coal type.

Two distinct marginal cost regression models were estimated: one for underground mines and one for surface mines. Because capacity utilization and productivity are both functions of price, regression of these variables onto price using an ordinary least squares approach would yield biased coefficient estimates. Thus, in order to obtain consistent, unbiased estimates of marginal cost, a two-stage least-squares methodology was used in which the estimated values of productivity and capacity utilization were used as input variables in the second stage.

In the CPS, supply curves essentially are developed by retaining capacity utilization as a variable in the marginal cost models, while holding the values of the other independent variables constant. Each marginal cost model is used as the basis of the supply curves for all coal supply regions and coal types within a mining method. The end portion of each capacity utilization/marginal cost curve, as shown in Figure 6, corresponds to surge capacity. Because comprehensive data on mine capacity and prices are lacking for the most recent period of shortfalls in U.S. coal production capacity—the years 1973 through 1975—engineering estimates for surge capacity were used instead of a regression model. The CPS has the capability of estimating surge capacity and the prices associated with that capacity on a regional basis.

The general form of the regression model for estimating marginal costs of production at underground mines in each supply region is as follows:

$$MMP_u = EXP[a(1/LP_u) + b(CU_u) + c(DFP)^{1/2} + d(LC_u) - e(D_1) - f(D_2) - g(D_3)]$$

where

MMP_u	=	marginal cost of production at underground mines for supply region
LP_u	=	predicted average labor productivity at underground mines in supply region
CU_u	=	predicted average capacity utilization of underground mines in supply region
DFP	=	average annual U.S. diesel fuel prices
LC_u	=	escalation index for labor costs for underground mines in supply region
D_1	=	dummy variable for Alabama coal supply region
D_2	=	dummy variable for western Kentucky coal supply region
D_3	=	dummy variable for Illinois-Indiana coal supply region

and a, b, c, d, e, f, and g are regression coefficients.

The general form of the regression model for estimating marginal costs of production at surface mines in each supply region is as follows:

$$MMP_s = [a(1/LP_s)^2 + b(CU_s)^6 + c(DFP) + d(D_1) + e(D_2) + f(D_3) + g(D_4)]^{1/2}$$

where

MMP_s	=	marginal cost of production at surface mines for supply region
LP_s	=	predicted average labor productivity at surface mines in supply region
CU_s	=	predicted average capacity utilization of surface mines in supply region
DFP	=	average annual U.S. diesel fuel prices
D_1	=	dummy variable for West Virginia coal supply region
D_2	=	dummy variable for Alabama coal supply region
D_3	=	dummy variable for western Kentucky coal supply region
D_4	=	dummy variable for Illinois-Indiana coal supply region

and a, b, c, d, e, f, and g are regression coefficients.

Regression results for the marginal cost models are provided in Appendix E.

The role of other independent variables in the construction of the CPS coal supply curves is discussed in the following subsections. For the purpose of the present discussion, they may be viewed as constants.

Step 3: Construction of Generic Marginal Cost/Capacity Utilization Supply Curves

In Step 3, the capacity utilization/marginal cost curves are converted to supply curves using the mine capacity forecasts estimated in Step 1. This is accomplished by converting from a percentage utilization to a production basis.

Using the capacity utilization/marginal cost functions in conjunction with the endogenous capacity projection, the CPS constructs a supply curve (i.e., production/price relationship) for each region, mining method, and mine type. This is accomplished by converting the x-axis on each capacity utilization/marginal cost curve from a percentage utilization to a tonnage output basis. For any given point on the x-axis, capacity utilization is converted into a corresponding production level as follows:

$$P_{i,j,k,t} = (U_{i,j}/100)(C_{i,j,k,t})$$

where

$P_{i,j,k,t}$	=	corresponding production for region i, mining method j, coal type k and year t (tons)
$U_{i,j}$	=	capacity utilization for region i and mining method j (percent)
$C_{i,j,k,t}$	=	projected capacity for region i, mining method j, and coal type k, in year t (tons)

Figure 7. Coal Supply Curve (Design Capacity of 80 x 10^6 TPY)

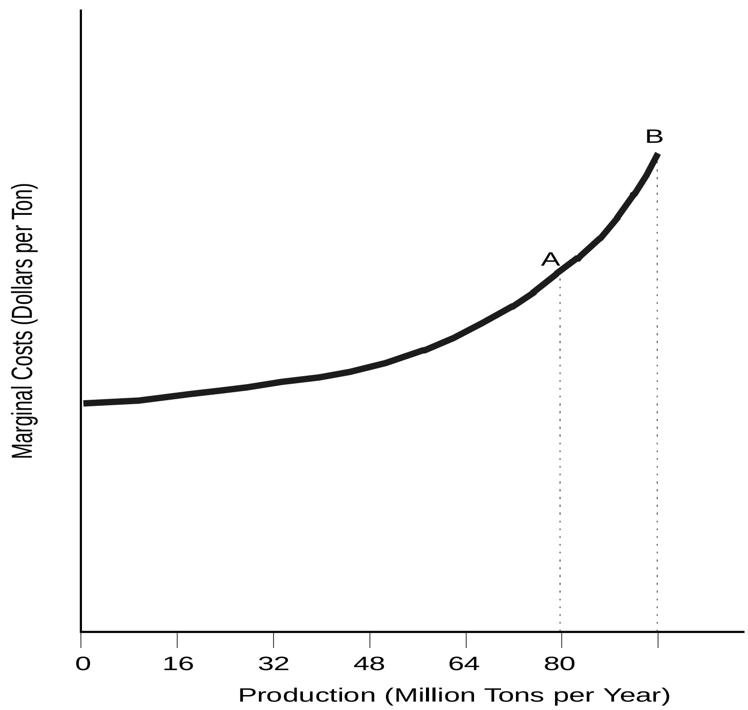


Figure 7 presents a supply curve constructed on the basis of the capacity utilization/marginal cost curve shown in Figure 6, and a projected capacity of 80 million tons. A comparison of Figure 7 with Figure 6 indicates that the two curves are the same, except that the percentage utilization values on the x-axis have been replaced with the corresponding production values derived in Step 1.

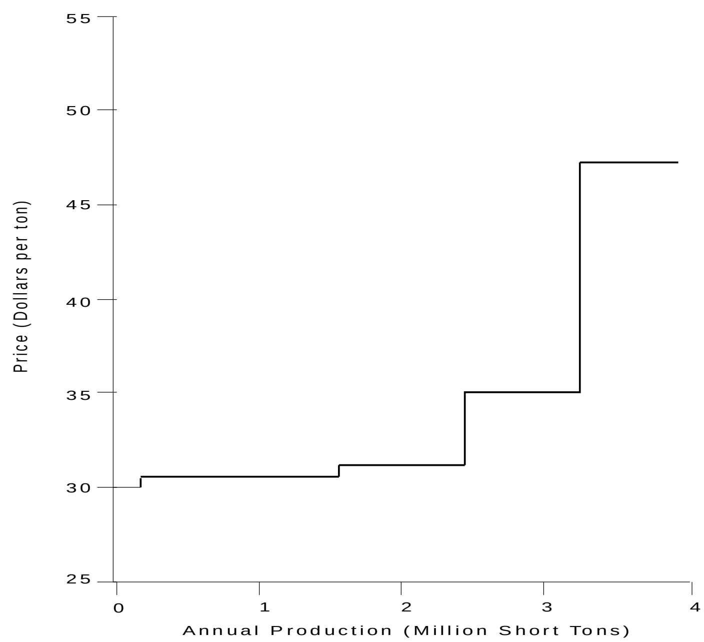
Once the x-axis has been converted from a percentage utilization to a tonnage output basis, the CPS performs one additional step to complete the construction of the supply curve. Based on the values of the other independent variables included in the regression model, in conjunction with information from an exogenous reserve depletion function, the submodule adjusts the position of the supply curve relative to the y-axis to reflect projected geological, technological, and other conditions in the forecast year. This adjustment, and the rationale behind it, is discussed in the following subsection.

Step 4: Reserve Depletion, Technological Change/Labor Productivity, and Costs of Factor Inputs

Capacity utilization can have a significant effect on short-term costs and, as discussed above, on mid-term costs. Other factors, such as technology change and reserve depletion, also can affect costs. But these effects occur primarily in the mid- and long-term. In Step 4, the effects of reserve depletion and changes in labor productivity and real factor input costs are captured through vertical adjustments to the supply curve. Supply curve adjustments due to changes in labor productivity changes and real labor and fuel costs are estimated endogenously. Supply curve adjustments associated with reserve depletion effects are estimated from exogenous RAMC-based reserve depletion functions. The procedures used by the CPS to capture in mine costs the effects of reserve depletion, technological change/labor productivity, and factor input costs are discussed in this subsection.

Using the RAMC to Estimate Reserve Depletion in the CPS

Figure 8. Sample RAMC Coal Supply Curve



The RAMC generates long-term annual coal supply curves. As discussed in Chapter 3, the RAMC and NEMS regions and coal types are not equivalent. Thus, a RAMC post-processing program is used to aggregate RAMC supply curves to the regions and coal types used by the CPS. The post-processing program is maintained off-line, rather than included in the CPS. A typical aggregated RAMC supply curve is shown in Figure 8. The upward sloping supply curve captures the shift from lower cost to higher cost reserves as reserves are depleted. This relationship between mining costs and reserve depletion is used to generate a reserve depletion function that is applied to CPS supply curves (relating marginal cost to capacity utilization) to adjust the supply curves over time to account for reserve depletion. The procedure is discussed below.

The CPS initially determines a base year[37] marginal cost for each region, mining method, and coal type using the CPS marginal cost regression equations. In the base year calculation, capacity utilization in the CPS marginal cost equations is set equal to 100 percent to maintain consistency with the RAMC supply curves (which reflect mine costs for mines operating at full capacity). Also, base year values for labor productivity, labor cost, and diesel fuel cost are used so that the effect of reserve depletion will be captured exclusive of the effects of these factors.

[37]The base year is 1990 for the AEO95 forecast.

Next, for each region, mining method, and coal type, the endogenous capacity forecast from the CPS is plotted on the corresponding RAMC curve. For example, consider the curve shown in Figure 8. Suppose that, for a given forecast year, capacity is projected to be 3 million tons. Based on Figure 8, when production reaches 3 million tons per year, the RAMC cost estimate for production from the marginal mine, operating at full capacity, is $35 per ton.

Finally, a vertical adjustment for shifting the CPS supply curve is computed as the difference between the two marginal cost estimates. Thus, the initial CPS supply curve is shifted upward such that, at the production point representing full capacity utilization—e.g., 3 million tons per year in Figure 8--marginal costs are higher by the amount of the computed difference. The slope of the curve remains constant; it is assumed that only the position of the supply curve with respect to the vertical axis is affected by reserve depletion.

This procedure is repeated for each year of the forecast period. Thus, increases in projected capacity over time will shift the supply curve upward. Alternatively, if capacity declines (e.g., in response to excess capacity), the supply curve will shift downward. Just as mine operators tend to open mines in lower-cost reserves before developing higher-cost reserves, they also tend to close mines in higher-cost reserves before they shut down mines in lower-cost coal. Returning, for example, to Figure 8, if capacity were to drop from 2 million to 1 million tons per year, the high-cost mines represented by the third step on the curve would be closed, while a portion of the mines on the second step (up to the 1 million ton-per-year production point) would remain open.

The RAMC-based reserve depletion functions remain essentially static with respect to time. In converting the reserve quantities contained in each reserve block into the annual production quantities defining the length of each step, the RAMC assumes that the life of the new mines will be 30 years. Since the assumed mine life exceeds the NEMS' mid-term 25-year forecasting horizon, none of the new mines will fully deplete their reserves, and all will be able to produce at full capacity throughout the forecast period. For this reason, the length of new mine steps remain constant throughout the forecast period. However, the length of the first (existing) mine step must be reduced to reflect the retirement of existing mines, since these mines represent a wide mix of operations at various stages in their lives. The existing RAMC post-processing program produces a "decrement" file containing estimates of the reduction in existing mine production capacity by supply region, coal type, and mining method for each year of a 25-year period. The estimates are developed using mine-level data on recoverable reserves and production capacity from the EIA-7A database to estimate the remaining life of each mine. In each forecast year, the relevant capacity reduction estimates are used by the CPS to adjust the lengths of the existing mine steps.

Treatment of Technology Change/Labor Productivity and Costs of Factor Inputs in the CPS

Labor productivity is used in the CPS to capture 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 marginal cost regression model developed for the CPS, increases in labor productivity translate into lower mining costs on a per-ton basis. Using this approach, exogenous estimates of labor productivity are provided to the CPS for each year of the forecast period. Separate estimates are developed as inputs to the submodule for each region and mining method.

In the CPS, the cost effect of changes in labor productivity, from one forecast year to the next, is determined using the marginal cost regression models for surface and underground mines. These models include labor productivity, real labor costs, and real fuel costs, as well as capacity utilization, as independent variables. In each forecast year, the projected values of labor productivity, real labor cost, and real diesel fuel cost variables are used to calculate the change in costs due to changes in these factors between the base year and the forecast year. This calculation is made using the exogenous productivity forecasts along with forecasts of the factor input costs. Following adjustment of the supply curve's position to reflect reserve depletion, the supply curve is shifted vertically by an amount equal to the calculated cost change (since changes in wages and fuel prices have a direct effect on mining costs).

Part II—Coal Export Submodule Model Documentation

1. Introduction

Statement of Purpose

The purpose of this report is to define the objectives of the modeling approach used in the Coal Export Submodule (CES), to describe the basic approach, and to provide information on the model formulation and application. The report is intended as a reference document for the 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 CES projects coal trade flows from 16 coal-exporting regions (5 of which are U.S.) to 20 importing regions (4 of which are U.S.) for 4 coal types—coking, high- and low-sulfur thermal coal, and subbituminous. The model consists of supply, demand, trade and transportation constraint components. The major coal producing countries (United States, Australia, South Africa, Canada, and Poland) are represented, as well as countries that could become major coal exporters (Colombia, Venezuela, and China).

Model Archival Citation and Model Contact

The version of the CES documented in this report is that archived in March 1995

Name: Coal Export Submodule
Acronym: CES
Archive Package: CES95 (Available through National Technical Information Service.)
Model Contact: Melinda Hobbs, Department of Energy, EI-822, Washington DC 20585 (202) 586-0012

Report Organization

This report describes the modeling approach used in the Coal Export Submodule. Subsequent sections of this report describe:

- The model objective, input and output, and relationship to other models (Chapter 2)
- The theoretical approach, assumptions, and other approaches (Chapter 3)
- The model structure, including key computations and equations (Chapter 4).

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

2. Model Purpose and Scope

Model Objectives

The objective of the CES is to provide annual forecasts (through 2010) of world coal trade flows. Coal supply in the CES is modeled through the incorporation of 4 coal types (Table 2) (unique combination of heat and sulfur content) and 16 geographic supply regions (Table 3 and Figure 9). On the demand side, 2 coal demand sectors (Table 4) are modeled for 20 importing demand regions (Table 5 and Figure 9). The CES also provides annual U.S. coal export forecasts to the Coal Market Module (CMM) of the National Energy Modeling System (NEMS).

Four key user-specified inputs are required. They include coal import demands, coal supply curves, transportation costs, and constraints. The primary outputs are annual world coal trade flows.

Relationship to Other Modules

The model generates regional forecasts for U.S. coal exports for use in the CMM. These export demands are passed to the CDS which solves and returns the price to the CES.

Figure 9. U.S. Coal Export and Import Regions

CES Coal Export/Import Region	Corresponding NEMS CDS Demand Regions
U.S. East Coast	3, 5, 6, and 7
U.S. Gulf Coast	8, 13, 16, and 17
U.S. Southwest and West	23
U.S. Northern Interior	1, 2, 9, 10, 11, 14, and 18
U.S. Non-Contiguous	22

Table 2. CES Coal Supply Types

Coal Supply Type	**Heat Content** (mmBtu/short ton)	**Sulfur Content** (lbs./mmBtu)	**Corresponding NEMS CPS/CDS Coal Types**
Premium Bituminous	≥25	<0.60	PC
Low-Sulfur Bituminous	≥20 but <25	<0.60	BC
High-Sulfur Bituminous	≥20	≥0.60 but <1.67	PD, PM, BD and BM
Subbituminous	≥15 but <20	<0.60	SC

Table 3. CES Coal Export Regions

1	U.S. East Coast
2	U.S. Gulf Coast
3	U.S. Southwest and West
4	U.S. Northern Interior
5	U.S. Non-Contiguous
6	Australia
7	Canada, Western
8	Canada, Interior
9	South Africa
10	Poland
11	CIS (Europe)
12	CIS (Asia)
13	China
14	Colombia
15	Indonesia
16	Venezuela

Table 4. CES Coal Demand Sectors

Demand Sector	Acceptable CES Coal Types
Coking	Premium Bituminous
Steam	Premium Bituminous Low-Sulfur Bituminous High-Sulfur Bituminous Subbituminous

Table 5. CES Coal Import Regions

1	U.S. East Coast	U.S. East Coast
2	U.S. Gulf Coast	U.S. Gulf Coast
3	U.S. Northern Interior	U.S. Northern Interior
4	U.S. Non-Contiguous	U.S. Non-Contiguous
5	Canada, Eastern	Canada, Eastern
6	Canada, Interior	Canada, Interior
7	Scandinavia	Denmark
		Finland
		Norway
		Sweden
8	UK/Ireland	Ireland
		United Kingdom
9	Germany	Austria
		Germany
10	Other NW Europe	Belgium
		France
		Luxembourg
		Netherlands
11	Iberia	Portugal
		Spain
12	Italy	Italy
13	Med./E Europe	Algeria
		Bulgaria
		Croatia
		Egypt
		Greece
		Israel
		Malta
		Morocco
		Romania
		Tunisia
		Turkey
14	Mexico	Mexico
15	South America	Argentina
		Brazil
		Chile
16	Japan	Japan
17	East Asia	North Korea
		South Korea
		Taiwan
18	China/Hong Kong	China
		Hong Kong
19	ASEAN	Malaysia
		Philippines
		Thailand
20	Indian sub/S Asia	Bangladesh
		India
		Iran
		Pakistan
		Sri Lanka

3. Model Rationale

Theoretical Approach

The core of the CES is a linear programming optimization model. This LP finds the pattern of coal production and trade flows that minimizes the production and transportation costs of meeting a pre-specified set of regional net import demands. It does this subject to a number of constraints:

- Export capacity of supply regions
- Maximum share that any importing region can take from one supply region
- Maximum share that any exporting region will sell to one importing region
- Maximum shares of both high sulfur and subbituminous coal which each importing region can take
- Maximum sulfur emission associated with imports for each importing region.

Fundamental Assumptions

The key assumptions underlying the CES are:

- The coal market is competitive: In other words, no large suppliers or grouping of producers are able to influence the price through adjusting their output. This means suppliers gain no producer surplus. Producers' decisions on how much and who they supply to are driven by their costs, and prices are set by their perceptions of what the market can bear. In this situation the buyer gains the full consumer surplus.

- The market is always in a sustainable equilibrium, as suppliers adjust their capacities to exactly match demand. This implies that there are no barriers to entry and exit.

- The world is a comparatively static one, and there are no linkages between periods: so the results of period t are not influenced by those in period t-1, or any other past time periods.

- 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 will add to their purchase costs. Similarly, producers will choose not to rely on any one buyer, and will diversify their sales.

- Coking coal is treated as homogeneous: This is a heroic, but a necessary assumption. There are too many important quality parameters (fluidity, swell, expansion characteristics, volatility, ash, phosphorus, and sulfur) and complex synergies to make a differentiated coal model workable.

- Suppliers sell at the same FOB price irrespective of who they are supplying. In practice, suppliers often fix different prices depending on which market they are selling into and whether the coal is being sold on long term or short term basis.

- While subbituminous coal is included, importing regions will not wish to rely on this unconventional type of coal for more that a certain portion of their needs. Use of subbituminous coal is, therefore, constrained by the capacity of coal-fired plants that can burn it and the extent that it can be substituted/blended.

- SO_2 emission regulations are modeled in two ways. First, the share of thermal coal imports that can be satisfied by high sulfur coal can be set for each thermal coal buyer. Second, in order to capture the effect of bubble emission caps, an SO_2 emission allowance associated with using imported coal can be set for each region. Emissions are calculated on the basis of fuel sulfur levels and the share of imports used in facilities which remove (or neutralize) sulfur.

Alternative Approaches and Reasons for Selection

A number of alternative approaches to modeling international coal trade incorporate other features, such as dynamic linkages, the ability of major buyers and sellers to influence pricing and the effects of contracts in locking in supply patterns. None of these are based on linear programming procedures.

The two most notable models are EIA's own International Coal Trade Model (ICTM) and Resource Economics Corporation's World Coal Trade Expert System (WOCTES).

The *ICTM*, a linear optimization model and database, was designed to provide a methodology for forecasting and analyzing the unique role of the United States in world coal trade.[45] The model projects world coal trade flows from 20 coal exporting regions of the world to 9 demand regions for 3 types of coal (metallurgical, low-sulfur steam, and high-sulfur steam). The objective function at the heart of the ICTM solution algorithm maximizes total producer and consumer surplus for coal traded internationally, subject to a system of linear constraints that describe the physical, technical, and contractual relationships among the individual trade activities represented.[46] Questions have been raised in the planning for the National Energy Modeling System (NEMS) over the need for an approach with such a broad scope and whether a simpler solution algorithm in NEMS might be more desirable.[47]

WOCTES is the most powerful PC-based model for examining international thermal coal trade. The model has the capability to handle 20 supply regions and 20 demand regions. Up to four coal types can be included, with coals defined by their heat content. The WOCTES model is a spatial equilibrium methodology (which uses an advanced complementary algorithm) to determine trade patterns and prices. Coal importers look at prices offered by all suppliers, and choose the best supplier. It is assumed that suppliers price the coal as high as they can without driving customers away.

WOCTES allows the modeling of noncompetitive market behavior, but is invariably used in the competitive market mode by its major users. The EIA, the only user of the ICTM, has produced all its long term forecasts since 1985 on the assumption that no suppliers or buyers exert market influence. Similarly, the major users of WOCTES, (which include the United Kingdom's PowerGen and National Power, Australia's ABARE, and the EC Commission) all generate forecasts using constrained, competitive market description.

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[45]See Energy Information Administration, *International Coal Trade Model: Executive Summary*, DOE/EIA-0444(EX) (Washington, DC, May 1984) for a description of the ICTM model itself and the underlying supply and ocean transportation models.

[46]For a complete discussion of the ICTM solution see the following reports: Energy Information Administration: *Description of the International Coal Trade Model*, DOE/EI/11815-1 (Washington, DC, September 1982); *Mathematical Structure of the International Coal Trade Model*, DOE/NBB-0025 (Washington, DC, September 1982); *International Coal Trade Model, Version 2, Preliminary Description*, by William Orchard-Hayes (Washington, DC, June 10, 1985; *International Coal Trade Model— Version 2 (ICTM-2) User's Guide* (Washington, DC, March 1987); and The George Washington University, Department of Operations Research, *Oligopoly Theories and the International Coal Trade Model*, GWU/IMSE/Serial T-494/84, by James E. Falk and Garth P. McCormick (Washington, DC, July 1984).

[47]National Research Council, *The National Energy Modeling System* (Washington, DC, January 1992), p. 58.

It is possible to examine the impacts of producers' power, using a competitive market model (such as the CES) by restricting the supply of one or more major suppliers. This will give an indication of the impact on prices and trade patterns. It doesn't however, throw any light on what happens to the suppliers' profits as the model still assumes producers' supply at cost.

In terms of coal qualities and market segmentation, WOCTES is too restrictive, as it is designed to only analyze the thermal coal market. It also assumes that coal buyers are indifferent between coal types. The ICTM does differentiate between coking and thermal coal, with import demand being similarly differentiated. Demand is specified separately for each coal type with no possibility of cross-supply. This is also too restrictive, because in practice, thermal coal users are able to use coking coals.

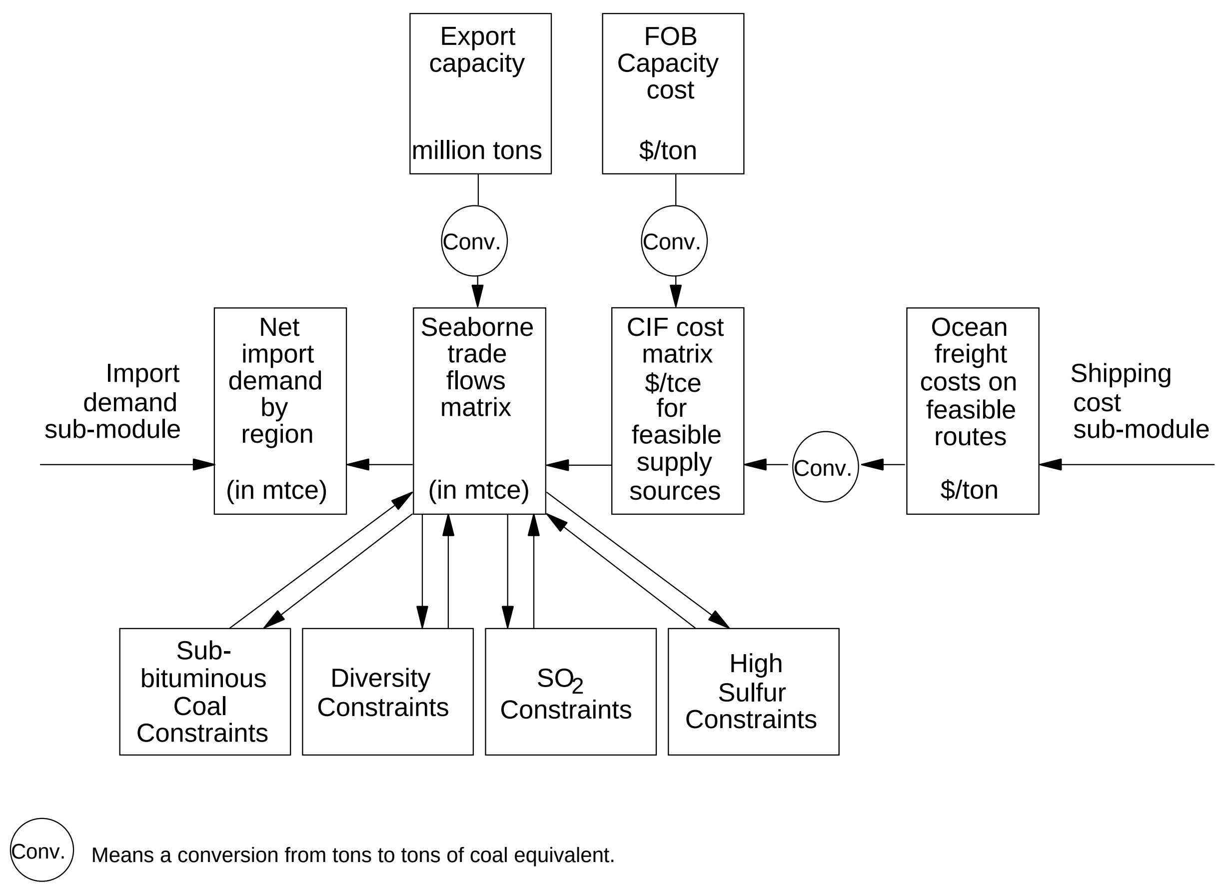
The CES incorporates this linkage between the market segments. This is done by allowing suppliers of coking coal to ship to thermal coal buyers. Suppliers of the different thermal coal grades are not, of course, allowed to ship to coking coal buyers. In order to capture the effects of reduced coal washing costs in producing thermal coal as opposed to coking coals, CES takes a washery credit off the cost of shipping "coking coal" to thermal coal buyers.

Neither the ICTM nor WOCTES allow the model user to analyze the impact of tightening SO_2 emission regulations: the CES does. This is an input factor in CES which allows the model user to specify both maximum shares of high sulfur coal that each region can import as well as average sulfur levels. The latter is generated from a sulfur emission cap associated with the use of imports and is expressed in thousands of tons of SO_2. While these emission caps are clearly very different from the bubble emission caps which most European countries have adopted, they do provide a way of representing different approaches to SO_2 emission regulation on imported coal in various regions. Furthermore, they allow the user to explore the impact of tightening emissions standards on the exports of coal with different sulfur contents.

4. Model Structure

The CES model is specified as a Linear Program (LP), which satisfies demands at all points at the minimum overall "world" coal cost plus transportation cost (Figure 10). From the output of the model it is possible to determine an optimum pattern of supply.

Figure 10. Overview of the CES System



The geographical representation of the "world" is a set of coal export regions and coal import regions. Each coal export region has a quantity of coal available for export, in which this amount available is price dependent. 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. This model is driven by fixed (input) coal demands that must be satisfied at the minimum overall cost.

Main Subroutines

The functions of the subroutines in the Coal Export Submodule (CES) are described below.

CEX Main controlling subroutine for the CES.

Purpose: CEX is the driver subroutine for the CES. It uses a FORTRAN code controlling structure, NEMS integrating model common variables, and CES intemal variables to set up and process the CES LP and to update NEMS variables based on an optimal LP solution.

Equations: None.

CRMATRIX Create CES LP Matrix.

Purpose: Creates the rows and columns for the CES matrix for the first iteration in the first NEMS year. Allocates computer memory and calls the OML subroutine WFOPT to obtain an optimal solution.

Equations: Converts input supply in metric tons to metric tons of coal equivalent:

UBND = CAPYR*CV/12.6

where

CAPYR = coal capacity on each supply step
CV = Btu conversion for each supply step

The factor 12.6 is Btu/lb in a metric ton of coal equivalent.

Converts costs from 1992 dollars to 1987 dollars in metric tons of coal equivalent:

FLOWCOST = ((FREIGHT*FOBYR*12.6)/CV)/1.208

where

FREIGHT = shipping cost
FOBYR = cost of coal on each supply step

The factor 1.208 is the GNP deflator.

TSTRET Transfer CES solution values to the Coal Distribution Submodule (CDS)

Purpose: Supplies coal import and export quantities and prices to the CDS.

Equations: Converts million metric tons of coal equivalent to trillion Btu's to pass to the CDS submodule using 27.7782 as the conversion factor.

RDMATRIX Reads data from flat files for matrix coefficients of CES.

Purpose: Reads freight rates, export capacities, demands, diversity shares,conversion factors, and sulfur content for each coal type.

Equations: None.

REVISE Revise CES matrix coefficients and optimize

Purpose: Retrieves coal quantities and prices determined by the latest iteration of the CDS. Revises the CES and obtains a new optimal solution.

Equations: Converts input supply in metric tons to metric tons of coal equivalent:

UBND = CAPYR*CV/12.6

where

CAPYR = coal capacity on each supply step
CV = Btu conversion for each supply step

The factor 12.6 is Btu/lb in a metric ton of coal equivalent.

Converts costs from 1992 dollars to 1987 dollars in metric tons of coal equivalent:

FLOWCOST = ((FREIGHT*FOBYR*12.6)/CV)/1.208

where

FREIGHT = shipping cost
FOBYR = cost of coal on each supply step

The factor 1.208 is the GNP deflator.

CEXRPT Produce reports for the CES

Purpose: Extracts solution values for quantities and prices from the optimal CES solution and produces formatted reports.

Equations: Converts million metric tons of coal equivalent to million short tons using 13.888 as the conversion factor.

Part III—Coal Distribution Submodule Model Documentation

1. Introduction

Statement of Purpose

The purpose of this section is to define the objectives of the modeling approach used in the Coal Distribution Submodule (CDS), to describe the basic approach, and to provide information on the model formulation and application. The report is intended as a reference document for model analysts, users, and the public. The report 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 CDS forecasts coal distribution from 16 United States coal supply regions to 23 domestic demand regions. The model consists of a two part solution algorithm with constraints representing environmental, technical and service/reliability constraints on delivered coal price minimization by consumers. Coal supply curves are input from the CPS, another submodule of the Coal Market Module, while coal demands are received from the Residential, Commercial, Industrial and Electric Power components of NEMS, with export demands being provided by the Coal Export Submodule, another component of the NEMS Coal Market Module.

Model Archival Citation and Model Contact

The version of the CDS documented in this report is that archived in March 1995.

Name: Coal Distribution Submodule
Acronym: CDS
Archive Package: CDS95 (Available through the National Technical Information Service).
Model Contact: Richard Newcombe, Department of Energy, EI-822, Washington, DC 20585
(202) 586-2415

Report Organization

This section describes the modeling approach used in the Coal Export Submodule. Subsequent sections of this report describe:

- The model purpose and scope, its classification structures (including the coal typology adopted, model supply and demand regions and demand sectors and sub-sectors), model inputs and outputs, and relationship to other NEMS modules and Coal Market Module submodules (Chapter 2)

- The theoretical approach, assumptions, major constraints, and other key features (Chapter 3)

- The structure of the model, including an outline of the CDS computational sequence and input/output flows; a listing of the key computations and equations in the CDS (Chapter 4).

Six appendices to the text of this section contain:

- A listing of input data, variable and parameter definitions, model output, and its location in reports (Appendix A)

- A detailed mathematical description of the model (Appendix B)

- A bibliography of technical references for the model structure and the economic systems modeled (Appendix C)

- A model abstract (Appendix D)

- A discussion of data quality and estimation for model inputs (Appendix E).

- A description of CDS program availability (Appendix F).

2. Model Purpose and Scope

Model Objectives

The purpose of the CDS is to provide annual forecasts (through 2010) of coal production and distribution within the United States. Coal supply in the CDS is modeled using a typology of 28 coal types (discrete categories of heat and sulfur content), 16 supply regions and 23 demand regions. Exogenously generated coal demands within the demand regions are subdivided into 5 economic sectors and 23 economic sub-sectors. Coal transportation is modeled using sector-specific arrays of interregional transportation prices. Demands are met by supplies representing the least dollar per million Btu delivered cost. The distribution of coal is constrained by environmental, technical, and service/reliability factors characteristic of domestic coal markets.

The design of the CDS was guided by NEMS planning documents that influenced the functions to be included and the content of the sub-module's classification structures.[49] Comments by the National Research Council's Committee on the National Energy Modeling System determined the general design philosophy: "The current EIA model is extremely detailed, far more so than would be appropriate for NEMS. One priority for NEMS development would be a greater simplification of this model to use in general forecasting and analysis. The simple model would then be used in NEMS. Detailed analyses of coal issues should probably be conducted outside the NEMS."[50]

EIA may not have the resources to maintain both a dedicated NEMS model (the simple model), and a detailed model to be used for exogenous analyses. Past policy studies emphasized possible shifts in coal demand, supply, and distribution that were significant at the national level. Classification structures in the CDS are therefore simpler than those in previous EIA coal distribution models. However, models used to analyze impacts of national policy initiatives are often required to provide regional and technical detail. The CDS is designed to have the capacity to address the effects of issues related to coal mining, transportation, and the environment together with associated tax, regulatory, and social impacts at the State and sub-state level for important coal producing States.

An important design objective for the CDS was to provide a simple modelling platform that can be rapidly adapted to model policy problems, not all of which may be currently foreseeable. Incorporation of particular theoretical points-of-view that transcend the fundamental characteristics of the systems modeled was deliberately avoided. The general design strategy for the CDS can be summarized as follows:

- Start with EIA's coal distribution model from the IFFS modeling system, the Coal Supply and Transportation Model (CSTM)

- Reduce classification detail to the minimum needed to simulate present and potentially important supply and demand patterns and transport routes

- At the same time, minimize the computational complexity of model functions, thus reducing maintenance requirements and scenario turnaround time while making the model easier to understand

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[49]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.

[50]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 1972), p. 58.

- Design model structure to make maximum use of the limited existing EIA data resources as model input and calibration factors (to enhance the transparency of model operation and maximize the consistency of output with EIA data sources).

Classification Plan

The CDS contains four 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 regionalization 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

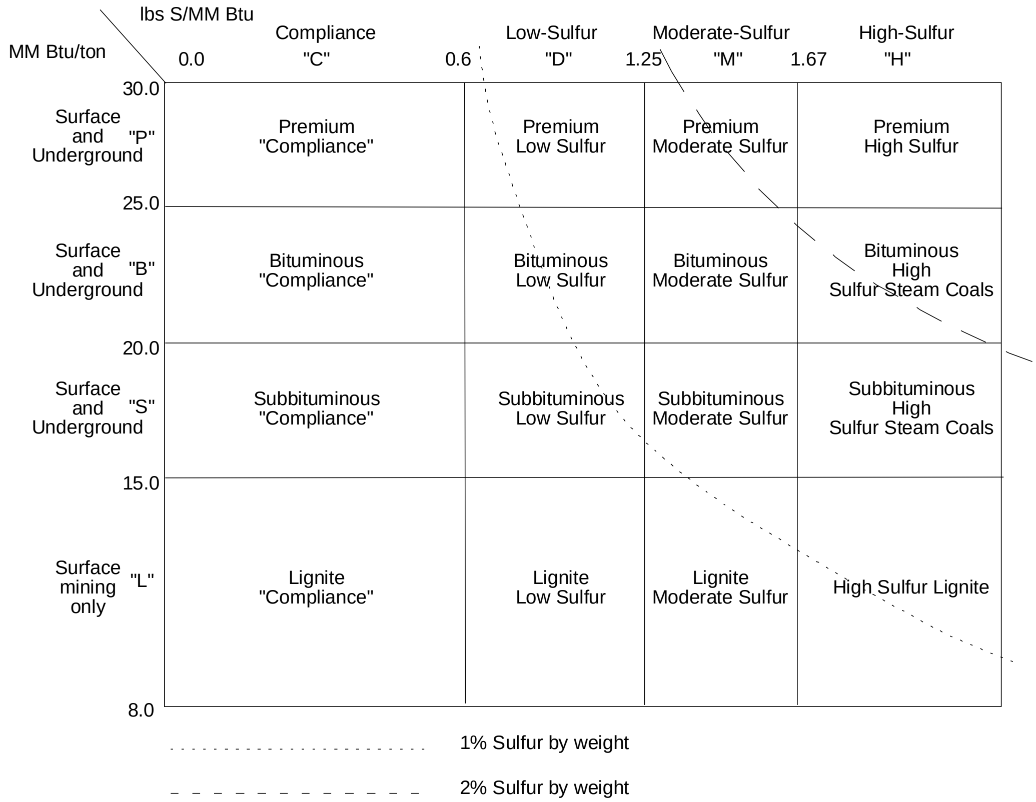
The CDS coal typology contains 4 sulfur and 4 thermal grades of coal with surface and underground mining to produce a 32-type framework. Since lignite is not mined by underground methods, this categorization is reduced to the 28 coal types shown in Figure 11. In this figure, thermal rank categories are shown in million Btu per short ton, while the sulfur categories are shown in pounds of sulfur per million Btu. This figure also contains isolines for coal sulfur levels of 1 and 2 percent sulfur by weight. Thermal rank categories separate coals with limited substitution potential in current end use technologies. The sulfur categories represent boundaries across which substitution is regulatorily limited. When this typology is applied to coal reserves in the 16 supply regions (see below) 202 supply curves result.

Coal Supply and Demand Regions

The 16 coal supply regions selected for the CDS provide 2 regions each for the three most important coal mining States (Wyoming, West Virginia, and Kentucky). This level of detail is justified by marked differences in available coal quality and typical mining costs in all three States, and by substantial differences in transportation costs between the subregions in Kentucky and Wyoming (Figure 12, Table 6). The typical sulfur content of coal produced also differs between the subregions in Kentucky and West Virginia. Most topical coal policy studies have required model comparisons of policy impacts involving sub-regions of these three States. These three States accounted for 51 percent of the coal mined in the United States during the 1989 - 1991 period.

The remaining coal mining States have been aggregated into 10 supply regions based on their relative location, importance to national production, typical coal quality, and transportation access. The supply region structure also provides an equal amount of regional detail to eastern and western coalfields. These regions have been chosen to facilitate studies of competition between major coal carrying railroads as well as competition between competing transport modes. Some smaller producing areas have been given supply region status due to their isolation from national markets and unusual transportation costs (the Pacific Northwest, Alaska); or because of their unique production costs and/or status as an independent sub-market for locally produced coal (Alabama).

Figure 11. CDS Coal Typology



The CDS demand regions are also the product of multiple requirements. The CDS must provide delivered coal cost and quality to the EMM for its use in formulating coal demand in the electric power generation sector. Currently the domestic electric utility market share of total U.S. coal receipts exceeds 75 percent; the CDS demand regions were therefore defined to provide a close approximation of the EMM's North American Electricity Reliability Council (NERC) regions. Regional boundaries also were defined to avoid splitting states, and to provide single state demand regions for states which are major or potential coal producers, or are important because of the size or special nature of their energy demands.

The CDS must also provide delivered costs, quantity and quality data for *all* economic sectors to the NEMS integrating module by Census division. This is achieved by defining a CDS demand region for each geographic entity representing a unique combination of Census division and NERC region identities. There are 29 such geographical entities, but 6 were merged into other regions since they contained insignificant demand potential. The CDS must also report tidewater costs, quality, and tonnages for coal exports. This is accomplished in the CES by aggregating the CDS Demand Regions that contain U.S. ports-of-exit into the 5 CES supply regions for U.S. coal: Great Lakes, Atlantic, Gulf of Mexico, Pacific, and Alaska (Table 7, Figure 13).

Figure 12. CDS Coal Supply Regions

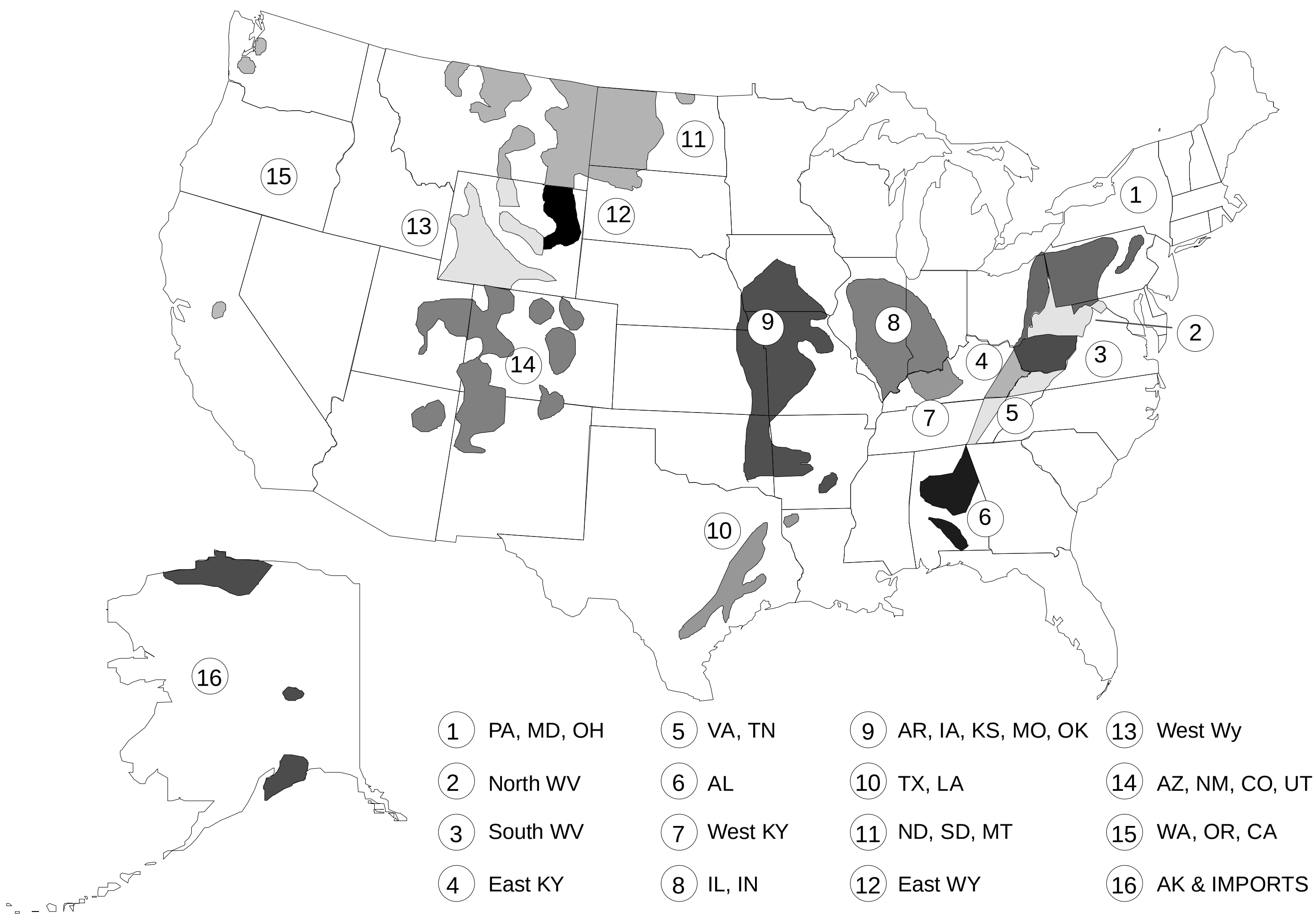


Table 6. CDS Coal Supply Regions, 1992, 1993, and 1994 Production
(Million Short Tons)

Region	Content	Production 1992	1993	1994	Average (Percent)
North Appalachia					
1 PO	PA, MD, OH	102.7	91.9	101.1	9.9
2 NV	North WV	50.0	33.8	46.5	4.3
South Appalachia					
3 SV	South WV	112.2	96.7	110.4	10.7
4 EK	East KY	119.4	120.2	122.2	12.2
5 VT	VA, TN	46.5	42.4	42.2	4.4
6 AL	AL	25.8	24.8	23.1	2.5
Interior					
7 WK	West KY	41.7	36.1	36.5	3.8
8 II	IL, IN	90.3	70.4	85.3	8.3
9 WI	AR, IA, KS, MO, OK	5.3	3.0	2.7	0.4
10 TL	TX, LA	58.3	57.7	58.3	5.9
North Great Plains					
11 MD	ND, SD, MT	70.6	67.9	75.3	7.2
12 EW	East WY	168.3	191.9	210.4	19.2
13 WW	West WY	21.9	18.3	21.0	2.1
Other West					
14 OW	AZ, NM, CO, UT	77.6	84.2	89.1	8.4
15 PC	WA, OR, CA	5.4	4.7	4.9	0.5
Noncontiguous					
16 NC	AK	1.5	1.6	1.5	0.1
United States	Total	997.5	945.4	1030.5	100.0

Coal Demand Sectors and Subsectors

The CDS treats coal demand in five economic sectors and 23 subsectors (Table 8). The broad NEMS demand sectors are: Residential, Commercial, Industrial, Export, Synfuels and Electricity. The need for an expanded list of subsectors in the CDS stems from technical and regulatory requirements for different types of coals with different geographical availability and prices; it is the economic and geographic expression of the chemical heterogeneity of coal and the engineering requirements of specialized end-use technologies. A less detailed sectoral structure would severely impair the CDS's ability to correctly model the sources and delivered prices of coal supplied to the broader NEMS sectors, since such demands are often supplied by different types of coals from a half-dozen or more supply regions.

Table 7. NEMS Coal Distribution Module Demand Regions: 1993 Coal Consumption and Exports (Million Short Tons)

CDS Region		Census Region	States Included	Consumption and Exports Millions of short tons
1	NE	New England	ME, NH, VT, MA, CT, RI	6.52
2	NY	Middle Atlantic	NY	11.98
3	PJ	Middle Atlantic	PA, NJ	58.70
4	WV	South Atlantic	WV	32.05
5	DV	South Atlantic	MD, DE, DC	20.12
6	SA	South Atlantic	VA, NC, SC	90.17
7	GA	South Atlantic	GA	27.08
8	FL	South Atlantic	FL, PR, USVI	26.43
9	MI	East North Central	MI	32.83
10	OI	East North Central	OH, IN	127.16
11	IW	East North Central	IL, WI	59.03
12	KY	East South Central	KY	39.10
13	ES	East South Central	AL, MS, TN	71.19
14	MP	West North Central	MN, ND, SD, NE, IA	80.31
15	MK	West North Central	MO, KS	40.77
16	SP	West South Central	OK, AR, LA	53.69
17	TX	West South Central	TX	97.02
18	MT	Mountain	MT	9.25
19	WY	Mountain	WY	26.08
20	SW	Mountain	CO, AZ, NM	51.07
21	UN	Mountain	UT, ID, NV	24.18
22	PC	Pacific	WA, OR, AK, HI	9.81
23	CA	Pacific	CA	5.81
	Total			1000.35

The subsectoral detail in the residential, commercial and industrial sectors stems primarily from technical requirements of end-use technologies, and is thus specific to the CDS. Because residential and commercial coal consumption, taken together, constitute less than 1 percent of total demand, they are treated as a single composite demand sector in NEMS coal modeling. Industrial demands are, on the other hand, treated as two groups of demands, those for steam coal and those for metallurgical coals.

Industrial steam coal demand is further subdivided into three sub-sectors in the CDS. "Stoker" industrial steam coals are shipped to older industrial boilers, generally exempt from seriously constraining emissions regulation, but which require—for technical reasons—coal fuels with relatively low ash and high thermal energy content. "PVC," or pulverized coal boilers can accept lower quality coals in terms of ash and Btu content, but are—on the average—newer and larger than "stoker" boilers, and are thus often subject to regulatory restrictions on sulfur oxide emissions. "Other Technology" industrial demands represent a wide range of specialized technologies ranging from new coal-fired fluidized-bed steam boilers through Portland cement kilns to anthracite coals used as a sewage filtration medium. This last group of demands is heterogeneous but quantitatively smaller than the other industrial steam sub-sectors in most demand regions, and is distinguished in order to permit analytical focus on the "Stoker" and "PVC" sub-sectors. The use of three subsectors also allows a more detailed representation of industrial steam coal distribution patterns, which are as complex as the pattern of electricity coal demand and supply.

Table 8. Demand Sectors in the NEMS Coal Distribution Module

Number	Sector Name
1	Residential/Commercial
2	Industrial, Stoker
3	Industrial, Pulverized Coal Boiler
4	Industrial, Other
5	Premium Coking
6	Blending Coking
7	Export Premium
8	Export Low Sulfur Steam
9	Export High Sulfur Steam
10	Utility Bituminous, Compliance Sulfur
11	Utility Bituminous, Low-Medium Sulfur
12	Utility Bituminous, High-Medium Sulfur
13	Utility Bituminous, High Sulfur
14	Utility Subbituminous, Compliance Sulfur
15	Utility Subbituminous, Low-Medium Sulfur
16	Utility Subbituminous, High-Medium Sulfur
17	Utility Subbituminous, High Sulfur
18	Utility Lignite, Compliance Sulfur
19	Utility Lignite, Low-Medium Sulfur
20	Utility Lignite, High-Medium Sulfur
21	Utility Lignite, High Sulfur
22	Existing Electric Utility Contracts
23	Synfuels from Coal

Industrial coking demand is simulated in two subsectors in the CDS. These represent, respectively, premium coking coals (modeled as low and medium volatile bituminous coals with a sulfur content of less than 1.25 percent, and high volatile bituminous blendstocks. Low and medium volatile bituminous coal supplies are found only on the eastern side of Appalachian coalfields and in limited areas of the Rocky Mountain states, while high volatile bituminous coals with suitable characteristics for coke blends are widely distributed. If only a single subsector were used, the model would be unable to simulate the willingness of cokemakers to pay higher prices for premium coking coals.

The CDS contains a single, currently unused subsector reserved for synthetic fuel production. Synthetic fuel processes are insensitive to coal sulfur content (since desulfurization is a part of the conversion process), but highly sensitive to coal rank. They are also sensitive to fuel costs, waste disposal costs, process water availability, and product transport costs. Capital costs and fuel costs are such that no unsubsidized commercial scale coal synfuel plant is likely to be built without contractually guaranteed markets and coal supplies. It is, therefore, efficient to treat synfuel coal supplies, when operationalized in NEMS, as predetermined contractual links between supply sources and demand locations. This practice eliminates the need to provide further sectoral detail dedicated to synthetic fuel feedstocks.

The three subsectors used for export coals are established in much the same way as the industrial sectors. American coal exports tend to be among the most expensive in international markets, even on a $/million Btu basis, but are bought because of their high quality, reliable availability, and historical role as a method of balancing foreign trade accounts. The United States is a major world source in the declining market for premium coking coals (which have the same characteristics as premium coking coals in domestic markets). The other export subsectors are for low and high sulfur steam coals, which require special coal quality definitions different from domestic steam coals.

Disaggregation of electricity demand into subsectors is required by the EMM's treatment of electricity coal demand, which reflects both technical and regulatory requirements that must be economically balanced in that model to realistically portray coal demand in response to emission requirements and the relative economics of different coal and noncoal fuels. Electricity coal demand is partitioned into demand for bituminous, subbituminous, and lignite coals. For technical reasons, substantial safety risks, losses in combustion efficiency and boiler derating are associated with the use of coals with ranks other than that for which a boiler was originally designed. Within these three coal rank categories, separate sub-sectors are established in the CDS for each of the four coal sulfur levels modeled. To the 12 electricity demand subsectors thus defined, one more must be added to handle existing electric utility contracts.

In summary, the CDS contains a single residential/commercial sector, 3 industrial steam coal demand sectors, 2 domestic coking coal sectors, 3 export sectors, a synfuel sector, an electric utility contract sector and 12 noncontract electricity demand sectors, making 23 in all.

Relationship to Other NEMS Modules

The CDS relates to other NEMS components as the primary iterating unit of the Coal Market Module, receiving demands from other noncoal modules and sending delivered coal costs, Btu contents, and tonnages framed in inter-regional coal distribution patterns specific to the individual NEMS economic sectors. Within the Coal Market Module (CMM), the CDS interacts with other CMM components in two ways. First, in the first iteration of each annual forecast, the CDS receives piecewise-linear capacity curves from the CPS and coal demand projections from other NEMS modules. The CDS projects a regional distribution of future capacity requirements based on the projection of future demands. The future estimates of coal capacity are transferred to the CPS. Second, the CDS receives supply curves from the CPS and coal export demands from the CES, while sending export supply quantities and port-of-exit prices to the CES. Price and quantity output describing 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 thermal energy content and sulfur content categories; (3) energy conversion factors (million Btu per short ton) and sulfur values (lbs Sulfur per million Btu) plus delivered coal prices at all destinations for all coal supply curves for which the Electricity Market Module has established demands. This last category of output is provided to the Electricity Market Module during its integrated iteration with the CMM. The CDS relates to other CMM components (and the Electricity Market Module, when operating in the integrated mode) using its own set of 23 domestic demand regions, but aggregates all final outputs to the NEMS integrating model into the 9 Census Divisions, which are a superset of the CDS demand regions.

CDS Input Requirements from NEMS

The CDS obtains electricity sector coal demand by forecast year and estimates of future coal demand in subsequent years from the Electricity Market Module (EMM) for each of the 23 CDS demand regions. The electric power demands are disaggregated into the 23 CDS demand region set in 12 coal rank and sulfur categories by the Electricity Market Module (EMM). The CDS receives annual U.S. coal export demands from CMM's Coal Export Submodule (CES). These demands represent premium metallurgical demand, and low and high sulfur steam coal demands. Export demands are also disaggregated, but only to the 18 CDS demand regions that contain ports-of-exit. This regional structure will allow the CDS to forecast domestic mining and transportation costs to terminals in different regions of the U.S., 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 received 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 sector in the CDS.

Coal supply curves enabling the CDS to compute minemouth prices are received from the Coal Production Submodule (CPS). Minemouth prices for each supply curve are also strongly influenced by estimates of coal production capacity generated by the CPS. The CDS solutions determine actual production quantities and supply sources in the Coal Market Module, and this data is used in the CPS to decrement the supply curves by the amount of coal reserves depleted through mining each year. This procedure prevents the CDS from repeatedly "mining" the lowest cost coal represented by the left-most segments of each supply curve. As coal is "produced" in the CDS, reserves are exhausted, and new demand must be met by opening new mines. Separate piecewise-linear capacity curves also are passed by the CPS to the CDS during the first iteration of each forecast year. The CDS solutions determine the projected regional distribution of future coal mine capacity requirements based on expectations of future utility and nonutility demands.

The transition from Census divisions to the more detailed CDS demand regions is accomplished using static demand shares specific to the Residential/Commercial, Industrial Steam and Industrial Metallurgical sectors. These shares are updated annually and are found in the CDS input files. The demand for U.S. coal exports is received from the CES and is disaggregated into the CDS demand region set by static shares found in the CES. Coal demands by coal rank and sulfur type are received from the EMM and are disaggregated into the CDS demand region set by shares located in the EMM.

Other CDS inputs include transportation rates and electric utility coal contracts (both discussed in Chapter 3), a parameters file which includes regional and sectoral indices and labels, as well as parameters used to calibrate minemouth prices and transportation rates. The parameter input file also contains the parameters that are used to define "coal groups"—groups of coal types that limit the coal Btu and sulfur categories that may be used to satisfy demand in different subsectors. The parameter input file also serves to store the Btu and sulfur values that define the quality of coal on each supply curve, and the import supply file.

The supply of coal imports to the United States for each forecast year is prepared as an input file to the CDS. Coal imports are not priced in the CDS due to the substantial and varying uncertainties associated with import dependence (the magnitude of which is usually seen as varying significantly with the particular national import source). If domestic coal market prices were the primary standard by which the acceptability of imports were judged, coal imports would be at a substantially higher level than they have currently reached or are forecast to reach. This exogenous import forecast is specified by economic sector and subtracted from sectoral demand totals in each relevant demand region prior to the operation of the Coal Distribution Submodule's solution algorithm.

CDS Output Requirements for Other NEMS Components

The CDS provides the least cost delivered prices for each coal type in each CDS region to the EMM. These prices allow the EMM to determine the comparative advantage of coal in relation to that of other fuels. The CDS, after receiving these demands, supplies them with the least cost available coal supplies 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.

Similarly, the CDS 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 quantities are reported to the residential, commercial and industrial models via the NEMS integrating module. The CDS can provide export coal quantities and f.a.s. port-of-exit prices by export supply region and coal sulfur/Btu content to the CES.[51] The CDS will not compute overseas delivered prices for coal exports and, therefore, does not require additional demand regions to represent foreign destinations.

Finally, the CDS provides projections of coal mine capacity requirements for each coal type on each CDS region. The least-cost coal production capacities needed to meet projected demands are provided to the CPS by CDS region, mine type, and coal type.

The CDS output falls into two categories:

- Outputs produced specifically for the NEMS system, characteristically in aggregate form and presented in tables that span the 20-year 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. These reports comprise a set of 43 single-year reports detailing sectoral demands received, regional and national coal distribution patterns, transportation costs, and detailed reporting of regional and supply curves-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.

A more detailed discussion of CDS output reports is provided in Appendix A.

[51] F.a.s. prices, literally, "free alongside ship", mean that these prices include all charges incurred in U.S. territory except loading on board 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.

3. Model Rationale

Theoretical Approach

The rationale for the CDS is derived directly from fundamental characteristics of domestic coal markets. Coal production occurs in over 250 counties in 27 States. Coal deposits are widespread, occurring in 39 of the 50 States; it is the Nation's most abundant nonrenewable fuel resource. The coal supply industry, while currently involved in a phase of consolidation, still has nearly 3,000 mines controlled by 1,000 parent companies.

Coal demand occurs in over 600 counties in 49 States; domestic coal consumption takes place at over 1,600 identifiable locations, and is dominated by the coal consumption of over 200 electric power utilities at over 400 different locations - about 80 percent of U.S. coal demand. Each year, coal is transported from mines to consumers over at least 10,000 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 is transported by most of the Nation's major railroads, over the inland waterway system by barge and towboat, along the coasts and over the Great Lakes by collier, and overland by truck, pipeline, and conveyer. 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 1950's, coal supply and distribution has been modeled with this central assumption, using linear programming and/or heuristic solution algorithms that determine the least cost pattern of supply to meet national demand.

The CDS is a partial equilibrium model that employs an exact shortest path algorithm to determine the least cost source of supply for each sectoral/regional demand, and a heuristic equilibrium algorithm to determine the least cost combination of supply sources to meet overall national coal demand. The enormously detailed historical pattern of coal production, transportation, and consumption is simplified in the CDS as consisting of between 600 and 800 annual demands (the exact number depends on the forecast year and scenario modeled) satisfied from up to 202 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 constraints can be categorized:

- Environmental constraints
- Technological constraints
- Transportation constraints
- Reliability constraints.

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 severely 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 which, at first analysis, shows little similarity to unconstrained delivered cost minimization. The CDS's approach to modeling these constraints cannot be judged without comprehension of these constraints.

Environmental Constraints in the CDS

The simplest constraints on coal markets, from the modeler's perspective, are due to environmental regulations. Historically, these constraints have imposed regulatory limits on the sulfur oxide emissions from coal consumption. Currently, interest is focused on the electricity generation industry's response to the Clean Air Act Amendments of 1990 (CAAA) as they unfold for Phase I (1995) and Phase II (2000). The CDS coal typology provides four categories of coal sulfur content that are matched to the regulatory requirements of CAAA Phase I and Phase II. The CDS incorporates environmental constraints on coal use by limiting acceptable coal supplies to those within appropriate sulfur categories. Most of the 16 supply regions in the CDS contain coals with a variety of sulfur contents; however, the range of choice is restricted by these limits.

These restrictions are applied using slightly different methods for the electric power generation sectors and the nonelectric power sectors. In the former, demand is subdivided into 12 subsectors, each of which represents demand for a particular coal rank/sulfur level category. In each model iteration, the CDS supplies the EMM with least cost delivered price for coal in each subsector, and the Electricity Market Module (EMM) determines the appropriate mix of demands based on regulatory and technological costs. In the EMM, these calculations are a sub-part of the problem of determining the most economical electric power generation technology and fuel from the entire range of fossil, nuclear, and renewable fuel technologies.

In the nonelectric power generation subsectors, a blend of domestic environmental and technical constraints (with their foreign market equivalents for coal exports) combine to restrict choices. For coal export markets, different sulfur categories of demand are determined in the Coal Export Submodule, and transmitted to the CDS for determination of least cost supply sources. In the domestic, industrial, and residential/commercial sectors, demand is received from other NEMS components in aggregated form and is subdivided into sulfur categories within the CDS using a concept referred to as "coal groups." Each of these "coal groups" specifies one or more of the members of the CMM coal typology that may be used to fill the specified demand, depending on its subsectoral and regional identity. In the industrial sector, for example, demand is specified in each CDS demand region as belonging to one of five subsectors: premium metallurgical coal, blending metallurgical coal, industrial steam coal for stoker boilers, steam coal for pulverized coal boilers, and coal for all other industrial applications.

Technological Constraints in the CDS

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 sub-optimal 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.

Every element found in nature exists in coal.[52] The chemical and physical content of coal reserves varies widely from place to place, and from seam to seam, at any given location. The important qualitative

[52]Valkovic, Vlado, *Trace Elements in Coal* (Boca Raton, FL: CRC Press, 1983).

differences between characteristics of different coal beds in different coalfields can be altered by selective mining (to exclude undesirable ash minerals), coal preparation (to further enhance the quality of coal products) and blending of different coals. The degree of qualitative improvement that is economically feasible varies widely from seam to seam and from mine to mine, even where identical beneficiation methods are identically applied. Given the essentially atomistic nature of the coal industry and the physical and chemical diversity of coal products available, the decisionmaking cost associated with continuous attempts to optimize the delivered cost of coal with acceptable chemical, physical, and environmental/regulatory characteristics can be significant.

Precise modeling of the technological and environmental 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. It is, however, important that the CDS should preserve a flexible method for modeling these constraints, for it is likely that environmental concerns related to coal consumption may extend beyond sulfur and carbon oxide emissions to include, for example, heavy metal emissions (gaseous emissions from combustion and leachates from ash disposal). Technological constraints on coal choice are simply addressed in the CDS by subdividing sectoral demands into subsectoral detail representing the more important end-use technologies, and by then restricting supplies to these subsectors to one or more of the CMM coal types using the "coal group" definitions.

It is sometimes necessary to restrict regional demands to specific coal sources. In the case of demands for lignite, 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 as lignite oxidizes rapidly upon exposure to air. Additionally, lignite oxidation is accompanied by crumbling, so that handling and open-air storage produces a high proportion of unusable dust. For these reasons, lignite must be consumed at the minemouth.[53] In the CDS, lignite demands are restricted to demand regions coterminous with lignite supply regions. In other cases, the use of "coal groups" is not restrictive enough to solely determine coal supply sources.

Transportation Cost Constraints

Minimization of delivered coal costs may be constrained by the market power of railroads, the dominant transport mode. Railroad rates for coal have historically reflected substantial market power in many regions; they still may in most of the northeastern United States and in areas throughout the Nation where alternative coal sources and/or multiple common carriers are lacking. Coal consumption facilities have a typical economic life of from 25 to 50 years; once built they are immovable; the resulting price inelasticity of demand often enables a coal carrier to extract economic rents.

Nationwide, shipping costs for contract deliveries to electric utilities represented 29 percent of delivered costs in 1984 and only 25 percent in 1987, but amounted to 40 percent of delivered costs to utilities in the South in 1987, and half of delivered costs in the West.[54] In some current cases, transport costs have exceeded 80 percent of delivered costs.[55] Railroads, which carry 55-60 percent of all coal, historically evolved with the

[53]Exceptions exist where small quantities are mined for nonfuel use or transported in air-tight containers. Some Arkansas and California lignites have been mined as a source of montan wax, an ingredient in shoe polish.

[54]Energy Information Administration, *Trends in Contract Coal Transportation, 1979-1987,* DOE/EIA-0549 (Washington, DC, September 1991), p. ix.

[55]In 1990 Georgia Power purchased over 1.5 million short tons of Wyoming coal at a delivered cost of $26.48 per short ton, of which the reported minemouth cost at the Caballo Rojo mine in Wyoming was $4.00 per short ton, or 15.1 percent.

coal industry, since railroads were the major consumers of coal from the mid-19th to the mid-20th century.[56] Coal-hauling railroads have a century of experience in coal shipment. Their knowledge of regional variation in coal quality and the economic geography of reserves and market areas is unsurpassed. At sites close to navigable water, competition may be enhanced by barge or intermodal transportation routes. Truck competition can be an important local factor in and adjacent to major mining regions, but truck transportation is not usually feasible beyond a limit that varies regionally from 70 to 200 miles.[57,58]

In 1989, coal provided 40 percent of all rail tonnage and 23 percent of all railroad revenues; since not all railroads serve coal-producing and consuming regions, the importance of coal to those that do is even greater than these statistics suggest.[59] Since the Railroad Revitalization and Regulatory Reform Act of 1976 (the "4R" act) and the Staggers Rail Act of 1980, average real dollar rail rates for coal have declined; however, evidence suggests that railroads still have and use market power over coal.[60,61] Standard authorities on transport economics, as well as the Interstate Commerce Commission, define rail ratemaking practice as charging "what the traffic will bear" between the minimum set by variable costs and the regulatory maximum.[62,63] The presence of two competing carriers does not guarantee that rates will be set at either carrier's marginal costs, for they may act as a noncolluding duopoly to earn rents above the higher-cost carrier's marginal cost, optimizing the allocation of rail capacity over time, all commodities, and all revenues.[64] Railroads with market power need not ship coal at minimum cost: "Studies of actual coal rail rates show these routes to be neither the shortest, nor the fastest, nor the most energy efficient, nor the cheapest paths from origin to destination."[65] When, in an application of a detailed freight network equilibrium model, computed costs were compared to *contractual rates* in 25 cases, rates varied from 99 to 280 percent of calculated costs, with 75 percent of the cases showing rate/cost ratios in the 116- to 166-percent range.[66] Under the Staggers Act, the regulated maximum rate that can be charged is 180 percent of fully allocated variable cost as defined by ICC Rail Form A.[67]

Coal distribution modeling mandates recognition that coal transportation rates only approach marginal costs of service in the presence of intermodal competition. Further, as suggested above, the difference between cost and price can be significant, not merely on a route-specific basis, but at the national level. Because coal transportation rates may not be determined by either costs or distance, estimation of route-specific transport

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[56]The railroad share of total contract coal traffic was 59 percent in 1990: Energy Information Administration, *Coal Distribution, January-December 1990*, DOE/EIA-0125(90/4Q) (Washington, DC, April 1991), Table 17, p. 25.

[57]The upper limit of 200 miles is documented in *Coal Week*, January 13, 1992, p. 7. column 2.

[58]Factors other than distance and freight volume also affect truck rates. See Richard Beilock, Peter Garrod and Walter Miklius, "Freight Charge Variations in Truck Transport Markets: Price Discrimination or Competitive Pricing?" *American Journal of Agricultural Economics*, vol. 68, No. 2, May 1986, pp. 226-236.

[59]Energy Information Administration, *Trends in Contract Coal Transportation 1979-1987*, DOE/EIA-0549 (Washington, DC, September 1991), p. 3.

[60]For the post-1976 decline in rail rates for coal: United States General Accounting Office, *Railroad Regulation, Economic and Financial Impacts of the Staggers Rail Act of 1980*, GAO/RCED-90-80 (Washington, DC, May 1990), and Energy Information Administration, *Trends in Contract Coal Transportation, 1979-1987*, DOE/EIA-0549 (Washington, DC, September 1991), p. ix.

[61]For evidence of persistent exercise of rail market power over coal freight rates: Dunbar, Frederick C. and Joyce S. Mehring, "Coal Rail Prices During Deregulation: A Hedonic Price Analysis", *Logistics and Transportation Review*, vol. 26, No.1, 1990, pp. 17-18.

[62]See, for example: D. Philip Locklin, *Economics of Transportation* (Homewood, IL: Richard D. Irwin, Inc., 1972) p. 160.

[63]U.S. Senate, Committee on Energy and Natural Resources, Committee on Commerce, Science, and Transportation, *National Energy Transportation, Volume 1, Current System and Movements*, Committee Print Publication No. 95-15 (Washington, DC, May 1977), pp. 73-74.

[64]Wolak, Frank A. and Charles D. Kolstad, "Measuring Relative Market Power in The Western U.S. Coal Market Using Shapley Values", *Resources and Energy*, 10 (1988), pp. 293-314.

[65]Bronzini, Michael S., "Network Routing and Costing Systems for Coal Transportation," *Proceedings of Coal Transportation and Costing Seminar, October 15, 1984*, The Argonne National Laboratory for the Electric Power Research Institute and the U.S. Department of Energy, (Kansas City, MO, July 1985), pp. 155.

[66]Bronzini, Michael S., *op. cit.*, pp 149-176.

[67]49 U.S.C., Section 10709, (a),(d)(2),(E); Section 10705 (m)(1).

rates (i.e., when required for topical analyses) will be done exogenously. Since thousands of transport routes may be in use in any year, endogenous estimation of a reasonably complete set of route-specific costs would impose unacceptable model execution times and maintenance burdens.

In the CDS, transportation rates are portrayed at the interregional level of detail by subtracting historical average minemouth prices from historical average delivered prices. For each of five major economic sectors (electric power generation, industrial steam generation, domestic metallurgical production, residential/commercial consumption, and exports) a set of transportation prices connects the 23 demand regions with each of the 16 supply regions. In principle, there are thus 23*16*5=1840 coal transportation routes and associated prices in the model. In practice, the number of useable routes is substantially less, since many of the origin/destination possibilities represent routes that are economically impractical now and in the foreseeable future.

Where no coal traffic exists or is foreseen, the model contains dummy prices to prevent their use. An example is Alaska, which is connected to the lower 48 States only by water and unpaved road. While Alaska has a coal dock used to export coal, the State contains no facilities for unloading coal from ship to shore. Alaska produces coal for its own consumption and export, but has never "imported" coal from the contiguous States or overseas. Its only feasible coal transportation connection in the CDS is with the Pacific Northwest region. No other approach is reasonable in such cases, since estimates of transport costs cannot be made for routes that have never been used and where required infrastructure does not exist. A different type of example is provided by the metallurgical coal sector. Here not all the model's supply regions contain coal reserves suitable for making metallurgical coke in current technologies. Similarly, not all demand regions still contain coking coal demands. Where there can be neither supply nor demand, coal transportation rates are set to dummy values to prohibit their use. This method is efficient, since it is easy to modify should technological change or economic development produce possibilities where none now exist.

Transportation rates in the CDS vary significantly between the same supply and demand region for different economic sectors. This variance is explained by the following factors:

- 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 Act of 1980, class I railroads 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 these dedicated components of the total contract service are wholly or partly financed by the shipper. 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.

Reliability and Service Constraints in the CDS

The need for reliable fuel supplies constrains the consumer's ability to minimize its delivered cost. While the general quantitative and qualitative characteristics of coal reserves are better known than for most mineral resources, they may vary unforeseeably in ways that strongly affect extraction costs at individual mines. All coal demands contain both elastic and inelastic components; it is impossible for coal consumers to precisely foresee the quantity of coal they will require, even in the short term. Coal is generally the least expensive fossil fuel, but its price can be very volatile in the short- and mid-terms. For many consumers, the price of coal supplies is a small fraction of total business costs and is less important than security of supply. Coal consumers prefer to supply the price-inelastic component of their demand with risk-minimizing supply strategies: long-term supply contracts, multiple sources, and stockpiles. The coal consumer's interest in obtaining coal at the lowest possible delivered cost is thus a sub-part of a broader strategy to minimize the long term, overall cost of coal dependence.

Coal demand is derived from the demand for final products to which coal is a factor input, e.g., electricity, steel, cement, and food products. Short-run demand varies, reflecting business cycles unrelated to mining costs. Because coal-dependent facilities represent large capital investments with productive lifetimes of 40 years or more, coal demand shows substantial price inelasticity at the individual facility level in the long term, and at the national level in the mid term.[68] Because coal is ultimately a substitute for other, more convenient fuels, long-term demand is price elastic when the long term is defined to be a period in which new capital investments take place (or new facilities are constructed). To maintain coal's market share, its price must remain less than or equal to the cost of alternative fuels, after factoring in all technical and environmental externalities. Coal markets thus display concurrent responses to short term demand fluctuations and mid-term price inelasticity. Thus, coal consumers experience demand divided between invariant "base load" and highly variable "peak load" components. The relative importance of these components varies among economic sectors, industries, and regions. Coal supply strategies are conditioned by these differences and by the characteristics of the coal supply and distribution industries.

While the coal mining industry has become more concentrated in recent years, by the standards applied in industrial economics, coal production is not a concentrated industry. The largest coal producer accounted for less than 9 percent of national production in 1991, and a dozen were required to produce 40 percent of the national total.[69] Coal mining has low barriers to entry, and substantial barriers to exit. Brief periods of high prices bring rapid expansion of mining capacity; long periods of stable and declining prices yield excess capacity and fierce competition during which mines continue to produce, so long as price exceeds variable cost and some contribution to fixed costs can be made. Mining costs, even in well known coal fields, vary acre by acre.[70] Coal producers have only incomplete knowledge of the mining cost and quality of coal of the reserves they own.[71] Mining firms thus face both geological and market uncertainties.

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[68]Richard T. Newcombe, "Mineral Industry Demands and General Market Equilibrium", Chapter 2.7, *Economics of The Mineral Industries*, 3rd ed., American Institute of Mining, Metallurgical and Petroleum Engineers, Inc. (New York, 1976); Wolak, Frank A. and Charles D. Kolstad, "Measuring Relative Market Power in the Western U.S. Coal Market Using Shapley Values," *Resources and Energy*, 10 (1988), pp. 297, fn 3.

[69]Energy Information Administration, *The Changing Structure of U.S. Coal Industry: An Update*, DOE/EIA-0513 (93), July 1993, Table A3, p. 37.

[70]Illinois State Geological Survey and the U.S. Department of the Interior, U.S. Bureau of Mines, *Engineering Study of Structural Geologic Features of The Herrin (No. 6) Coal and Associated Rock in Illinois, Volume 2, Detailed Report, NTIS PB-219462* (Washington, DC, June 1979).

[71]Richard Gordon, *Coal Industry Problems, Final Report, EA 1746, Project 1009-4,* Pennsylvania State University, prepared for the Electric Power Research Institute (Palo Alto, CA, June, 1979), pp. 2-43, 2-44.

Thus, both consumers and producers are motivated to reduce substantial uncertainties using multiple sources and/or clients, long-term contracts, and stockpiles. Optimal coal consumption and production strategies, therefore, emphasize long-term relationships rather than short-term delivered coal cost minimization, for they must provide security of supply.[72] In the residential, commercial, and industrial demand sectors, delivered coal costs are a smaller portion of total operating costs than for utilities, and reliability and adequacy of supply become much more important criteria than minimized delivered price.

Multi-year contracts serve producers, carriers, and consumers in several ways. For all parties, they reduce market uncertainties. For consumers, they can greatly reduce the decisionmaking costs associated with assuring reasonably priced supplies, and can assure both the needed quality and quantity of supply. For producers, they can greatly reduce the cost and risks of marketing. Contracts are central to the successful operation of modern coal markets; 75 to 95 percent of all coal sold to all economic sectors is produced under contract (the percentage varies with market conditions). No significant increment of mining capacity is likely to be constructed without a contract for at least 80 percent of its potential production for a time period sufficient to ensure amortization of invested capital.

Because short-term demand is variable, coal consumers require that producers under contract must be able to increase or decrease the quantity supplied by 5 to 50 percent around the base tonnage.[73] Coal shipments are routinely tested by independent laboratories to ensure that their physical and chemical parameters are within contractual limits. Special clauses in contracts may specify price penalties for violation of coal quality, quantity or schedule terms, and may also divide any benefits or disincentives due to changing costs between the producer and consumer. Fixed-price contracts were once common, but these have been replaced by "evergreen" contracts in which prices are adjusted annually to follow market trends.

While new contract prices reflect the sum of fixed and variable costs, and may include special service charges, spot market coal may be sold at any price that is at least equal to variable costs. Consumers commonly purchase 5 to 25 percent of their coal needs in the open or "spot" market. By doing so, consumers gain information on production and transport costs that can be used to adjust existing contracts and identify potential suppliers. Buyer's markets prevail in most years, so spot market prices are usually below both average and new contract prices. If regulatory change or unforeseen demand increases occur, a period of mining or transport capacity shortage may ensue, with spot market prices leading new contract prices to record levels. Such periods occurred in World Wars I and II, and from 1973 through 1978.

Because of their overwhelming importance in stabilizing short- to mid-term coal markets, the inclusion of contracts in coal distribution models can enhance the simulation.[74] Spot markets for coal are unstable and coal models without contract simulation tend to be equally unstable if they are otherwise true to the systems they model. Coal contracts embody important information about coal quality and reliability of supply, information for which real world coal consumers have historically demonstrated their willingness to pay a premium above the spot market price because their experience has shown that, in the long run, they save money by so doing.

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[72]"Security of supply" can be defined as the right amount of coal with the right physical and chemical specifications delivered at the right time over the right term at a reasonable cost. A major eastern utility has described its coal procurement objective as provision of an "adequate, economical, and reliable" supply, of which 82 percent is obtained under contract. (Resource Dynamics Corporation, *Coal Market Decision-Making: Description and Modeling Implications, Final Report to the Maxima Corporation for the Energy Information Administration* (McLean, VA, June 1984), p. 14).

[73]Utility contracts usually require the producer to provide up to plus or minus 20 percent of a base quantity. Industrial contracts must provide for supplies to meet short-term demand shifts at facilities with smaller, or even no stockpiles. It is not uncommon for industrial contracts to specify an optional tonnage of plus or minus 25 percent. In the electric utility sector, the consumer usually makes the transportation contract. In the industrial sector, the mining firm is often responsible for coal transportation, whether under contract or not.

[74]At any given time, 75 to 95 percent of all coal produced in the United States is shipped under the provisions of multi-year contracts. This applies to coal shipped not only in the electric power generation sector, where contracts tend to be the longest and control the largest tonnage per contract, but also in the industrial, metallurgical and export sectors.

In the CDS, electric power utilities' existing coal contracts are included to link supply and demand in the historical pattern rather than that determined by annual delivered price minimization.[75] The average length of such contracts is about 21 years and, on the average, those in the model tend to be about half over in the CDS forecast period's base year, 1990.[76] This means that the amount of contract influence on electric power coal distribution declines year-by-year through the forecast period and is minimal after the year 2005. These contracts make an important contribution to the CDS' portrayal of the geographic pattern of coal distribution in the first 5 to 10 years of the forecast period.

The CDS does not use historical contract prices. Instead, minemouth, transportation and delivered price are assigned to contracts by the same process used to meet other demands. The model does use the contract duration, regions of origin, destination, the maximum contract volume, and the coal type indicated by the contract to create a required distribution of a particular coal type from the specified supply region to the specified demand region for the indicated number of years. These contracts remain in effect only so long as the EMM, which determines the electric utility coal demand used in the CMM, calculates that the demand pattern is cost efficient. Should the demand received from the EMM decline below the maximum contract volume, it is only honored to the extent of that demand. Should the demand for the coal under a contract decline to zero, the contract is no longer honored in the CMM. Since most supply regions contain both surface and underground mine supply curves for each coal type in the region, the CMM will assign demands under contract to be filled by the least cost combination of supplies from these surface and underground coal types. In summary, the current use of contracts in the CMM restricts only the supply region from which contractual supplies must come, and this restriction is only enforced on the quantity of demand for the specified coal type that is received from the EMM. Contracted supplies cannot exceed the maximum tonnage indicated by the contract. These procedures minimize the potential for serious delivered price distortions due to the contracts.

It may seem from this discussion that existing contracts used in the CDS are irrelevant to the computed distribution patterns. In fact, these contracts have a powerful effect on distribution, but the method of modeling them has a less dramatic effect on **delivered** coal prices. The EMM determines electricity coal demands by selecting the most cost effective combination of different coals and other fuels based on **delivered** prices.

However, the assignment of such coal demands by existing contracts to specified regions still allows a demand to be met by the most economical coal within a region (subject to regulatory and technical constraints). Thus there is still intra-regional price competition at the minemouth price level. Fixing the supply region for a demand is likely to cause the demand to be met by a non least-cost source, but in practice the **delivered** price difference is not always enough to cause the EMM to reduce the affected demand.

This is so in the CDS because transportation costs are calculated as the difference between historical minemouth and delivered costs, thus efficiently capturing the historical pattern of economic rents gained by common carriers. This pattern of rents has the effect at a given demand region of moving delivered coal prices from competing supply regions toward equality. Coal transportation prices are thus not independent of the distribution pattern imposed by existing contracts. It may be that total coal demand in NEMS is somewhat

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[75]The data available to EIA on existing electric utility contracts (from the FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," and from the FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants") are detailed and extensive, but do not provide universal coverage, even for the electric utility sector. EIA collects no data on contracts in the industrial or export sectors. Moreover, the vitally important data on transportation contracts (route mileage, tonnage, transport mode, origins, destinations and service prices contained in the FERC Form 580 are a wasting resource, since price as well as other information is largely proprietary in new railroad transport contracts, and no other objective source of such data is available.

[76]Energy Information Administration, *Trends In Contract Coal Transportation, 1979—1987,* DOE/EIA-0549 (Washington, DC, September 1991), p. ix.

smaller than it would be without these existing contracts, but this is as likely to be true in the industries being simulated as it is in the model.

Some economists might argue that simulation of contracts in a long-term model is inappropriate since it might distort demand and supply patterns away from the long-term least cost solution. The current use of contracts in the CDS escapes this criticism since most of the contracts expire by 2000. However, it can be argued that it is incorrect to exclude contracts, since they represent fuel choice considerations beyond short term delivered cost minimization, providing a more realistic portrayal of consumers' actual decision processes. Economic theory does not require that fuel choice decisions be restricted to short term delivered cost minimization. There are, however, four appropriate limitations on the use of coal contracts in the model: (1) contracts should not bind a higher percentage of model coal demand than they do in reality; (2) contracts should be subject to economic re-evaluation so that, if savings greater than the unexpired value of the contract can be realized by "buying out" the contract, the model has the capability to do this; (3) the model must be able to abrogate contracts in cases of regulatory force majeure (Phase I and Phase II of the Clean Air Act have not been found judicially to be force majeure as of this date); and, (4) the price of contract coal should follow, but not necessarily equal, market levels.

The current method of using available contract data is efficient in that it improves the model's ability to portray coal distribution plausibly and provides a partial stabilizing influence without requiring the use of detailed engineering and coal quality data (which, in any case, is not in the public domain). This "black box" approach allows the above improvements in model performance while reducing the volume of calculations that must be performed by the model's solution algorithm and, therefore, helps increase the model's execution speed.

Comparison of the CDS to Other Coal Distribution Models

In the 1970's and early 1980's, high world oil prices and the stagnation of the U.S. nuclear power industry produced coal price increases and rapid growth in western low sulfur coal mining regions. Coal supply modelers focused on how consumers and producers would meet joint challenges posed by increasing demand and regulatory stringency. Entering the decade of the 1980's, the emphasis shifted toward detailed modeling of coal transportation costs and capabilities. It was realized that national policies emphasizing increasing coal use were dependent on a financially troubled national rail network adapting to significant deregulatory initiatives. Ensuing years have demonstrated that, while controversy over railroad freight rates for coal has not evaporated, average rail rates for coal have declined. Railroads have responded to deregulation with rate innovations, improved factor input productivity, and enhanced financial viability, while continuing to charge "what the market will bear" subject to the remaining regulatory limitations.

Since the early 1980's, developments in coal supply modeling have shown a selective focus. Models have been adapted to explore the potential market shares of steam coal imports into the United States and to examine the capability of U.S. coal producers to maintain or expand their market share in rapidly growing international steam coal markets. At the close of the 1980's, renewed interest in emissions from coal combustion and State analyses of the revenue potential from coal severance taxes created a demand for detailed model output describing impacts at the State or sub-State regional level. The trend toward greater regional detail was accelerated by the perception that the last remaining obstacle to accurate modeling of distribution patterns lay in more detailed simulation of transportation costs. Concurrently, coal supply models extended their forecast horizons from 10 to 25 years.

The Evolution of Coal Distribution Models

Stimulated by increased interest in energy supply and distribution costs associated with events subsequent to the Arab oil embargo of September 1973, rapid development of new modeling techniques took place. The models most relevant to development of the NEMS CDS are programming and spatial equilibrium models developed on the foundation of James Henderson's study of coal industry efficiency.[77]

These models include regionalized linear programming models that differentiate coal products by mining method (surface versus underground) and by distinguishing multiple levels of Btu and sulfur content, but did not recognize that other coal quality parameters such as ash fusion temperatures, ash quantity, grindability, and base/acid ratios are equally important in defining coal markets. Coal blending at the demand point was incorporated.[78] Quadratic programming models based on the work of Takayama and Judge developed more sophisticated objective functions, incorporating maximization of producers' and consumers' surpluses.[79] This methodology was applied to the spatial distribution of Appalachian coal.[80]

Recursive programming models were adapted to model decisions over time in which subsequent solutions depended on the results of earlier executions. Feedback equations were employed to simulate constrained optimization including adaptation to current conditions. This approach is well suited to modeling decisions under "adaptive price expectations" where the feedback may come from preliminary executions for time period 2 and affect final decisions in time period 1. Of course, such a methodology imposes execution time penalties that are of concern in a large, integrated system such as NEMS. An early application was used to explain the historical adoption of improved mining technologies and their effects on the coal mining industry.[81]

Programming models have been adapted to simulation of markets characterized by imperfect competition. An early and representative example is the work performed on the Project Independence Evaluation System (PIES) at EIA to model regulated gas prices and tariff adjustments/oil entitlements.[82]

The development of large scale integrated modeling systems such as the PIES, the Midterm Energy Forecasting System (MEFS), IFFS, and NEMS has meant that the sharp edges of individual modeling approaches are blurred by the characteristics of the integrated system. System sub-models act both as components of the integrated modeling system and as stand-alone models that must be quickly adaptable to analyses of, for example, the impacts of proposed legislation at the State or sub-State region level. Modeling systems with central integrating models (e.g.,"MAIN" in IFFS) allow the freedom to join econometric demand components with structural/engineering supply components. All the above systems have been the responsibility of EIA and/or its predecessor agencies. The EIA integrated systems are paralleled by similar systems in other environments, such as the Hudson-Jorgenson system and the Brookhaven Integrated Energy/Economy Modeling System.[83,84]

PIES consisted of a linear programming integrating model that computed an equilibrium solution for demands generated by an econometric demand model with supplies generated by a programming model. Equilibrium

[77]James M. Henderson, *The Efficiency of The Coal Industry, An Application of Linear Programming* (Cambridge, MA: Harvard University Press, 1958).

[78]Libbin, J.J. and X.X. Boehle, "Programming Model of East-West Coal Shipments," *American Journal of Agricultural Economics*, Vol. 27, 1977.

[79]Takayama, T., and G. Judge, *Spatial and Temporal Price and Allocation Models* (Amsterdam: North-Holland, 1971).

[80]Labys, W.C. and Yang, C.W., "A Quadratic Programming Model of The Appalachian Steam Coal Market," *Energy Economics*, Vol. 2, pp. 86-95.

[81]Day, R.H. and W.K. Tabb, 1972, *A Dynamic Microeconomic Model of The U.S. Coal Mining Industry*, SSRI Research Paper (Madison, WI: University of Wisconsin, 1972).

[82]Murphy, F.H., *The Structure and Solution of The Project Independence Evaluation System*, Energy Information Administration (Washington, DC, 1980); Murphy, F.H., R.C. Sanders, S.H. Shaw and R.L. Thrasher, "Modeling Natural Gas Regulatory Proposals Using the Project Independence Evaluation System," *Operations Research*, Vol. 29, pp. 876-902.

[83]Hudson, E.A. and D.W. Jorgenson, "U.S. Energy Policy and Economic Growth, 1975-2000," *Bell Journal of Economics and Management Science*, Vol. 5, pp. 461-514.

[84]Groncki, P.J. and W. Marcuse, "The Brookhaven Integrated Energy/Economy Modeling System and Its Use in Conservation Policy Analysis," *Energy Modeling Studies and Conservation*, ECE, ed., prepared for the United Nations, (NY: Pergamon Press, 1980), pp. 535-556.

output from the integrating model was input to a macroeconomic model, an environmental impact model, and an international model.[85]

Most models of coal supply and distribution fall into two categories. The first is a series of models largely developed by ICF, Inc., for EIA, but also marketed to other clients. The EIA representative of this "family" of models is the National Coal Model (NCM), which has had various capabilities in its two decades of existence. The other coal supply model "family" of the 1970's was designed by Martin Zimmermann and subsequently incorporated into the DRI, Inc., modeling system as the central analytical tool of the DRI Coal Service. Both the NCM and DRI models are linear programming models that treat coal transportation costs as an interregionally specific markup over minemouth costs.

Both the DRI model and the NCM can operate independently (with exogenously supplied demands) or as part of an integrated system. The NCM contains a utility capacity planning and dispatch submodel that receives electricity demand, and allocates this demand among coal, oil, gas, and nuclear generation capacity according to relative cost. The NCM disaggregates coal demand, using technical and sectoral environmental constraints, testing the economic efficiency of low-sulfur coals against high-sulfur coals that require scrubbing.[86]

The DRI and NCM models can be contrasted in several regards. First the NCM, in all its versions, has had a more detailed classification scheme. The NCM has had from 40 to 60 coal types; the DRI-Zimmermann model has 36. Both models' supply curves are in the form of step functions, but the NCM has over 400 while the DRI-Zimmermann model has 35. The NCM has 31 supply regions while the DRI-Zimmermann model has 6. The NCM has 44 demand regions while the DRI-Zimmermann model has, in various versions, either 13 or 18. Interregional supply-demand links in the NCM total about 1,000, while different versions of the DRI-Zimmermann model have either 78 or 108. A version of the NCM, as modified for recent use by the U.S. Environmental Protection Agency, contains hundreds of demand and supply centroids, and over 2,000 interregional coal shipment routes.[87] Each of these routes is represented by a detailed description of the carriers, link mileages, locomotive horsepower, and other cost related factors. These, in turn allow detailed engineering cost estimates for each route. Such an accounting model approach to coal transportation allows very precise estimates of costs, but as discussed above, coal transportation rates may not be determined by costs. Thus, in spite of the extreme detail input to this model, it may underestimate delivered coal costs.

As linear programming models were adapted to model coal distribution, it became increasingly apparent that available data on such costs, when combined with accurate minemouth costs, did not necessarily produce plausible coal distribution patterns. A logical strategy in resolving this dilemma was to increase the number of supply and demand regions to allow the model to capture idiosyncratic rail rates to very localized regions. This method achieved a measure of success, at least in capturing historical patterns, as the number of demand regions began to approach the number of coal using electric power utilities (approximately 200). At this level of detail it is possible to synthesize reasonably plausible rates that accurately portray past coal distribution. Even at this level of detail, the rate differences between routes with neighboring origins and destinations may be quite large, and due to the lack of coal transportation cost data for many regions, such a rate system is

[85]Energy Information Administration, *Documentation of the Project Independence Evaluation System* (Washington, DC, 1979).

[86]Description of the NCM is taken from: ICF, Inc, *The National Coal Model: Description and Documentation, Final Report* (Washington, DC, October 1976; Energy Information Administration, *Mathematical Structure and Computer Implementation of The National Coal Model*, DOE/EI/10128-2 (Washington, DC, January 1982); Energy Information Administration, *National Coal Model (NCM), Users Manual* (Washington, DC, January 1982). Description of the Zimmermann-DRI model is taken from: Zimmermann, M.B., "Modeling Depletion in a Mineral Industry: The Case of Coal," *Bell Journal of Economics*, Vol. 8, No. 4 (Spring, 1977), pp. 41-65; Zimmermann, M.B., "Estimating a Policy Model of U.S. Coal Supply," *Advances in the Economics of Energy and Resources*, Vol. 2. (New York: JAI Press, 1979), pp. 59-92; Pennsylvania State University, "Zimmermann Coal Model," *Economic Analysis of Coal Supply: An Assessment of Existing Studies*, Volume 3, Final Report, EPRI EA-496, Project 335-3 (Palo Alto, CA: the Electric Power Research Institute, June 1979); Data Resources, Inc., Coal Service Documentation (Lexington, MA, March 1981).

[87]ICF Resources, Inc., *Documentation of the ICF Coal and Electric Utilities Model: Coal Transportation Network used in the 1987 EPA Interim Base Case*, the U.S. Environmental Protection Agency (Washington, DC, September 1989).

difficult to document other than through reliance on "analytical judgment." It is also obviously true that maintaining a system of rates involving routes between up to 100 supply regions and 200 demand regions has an impact on scenario turnaround time. Models containing this level of detail are simply too cumbersome for a system like NEMS.

Another primary difference between the NCM and the DRI models is in the treatment of resource depletion. In both models, minemouth costs are developed by supply curves relating annualized production of recoverable reserves to mining costs that rise with progressive depletion. Each has its own approach to estimation of supply curves. The NCM is empirical, using curves developed by the RAMC from the Demonstrated Reserve Base, the Coal Analysis Files, and mine costing models. For the DRI-Zimmermann model, the supply curves were originally developed from the assumption that coal reserves were log-normally distributed by seam thickness and/or overburden ratio, the two primary determinants of reserve-related mining costs in both models. The hypothesis of log normal reserve distribution by seam thickness has never been proved, and there is evidence that it is descriptively incorrect.

Until the early 1980's, coal transportation costs were simply added onto the demand sensitive minemouth costs determined by the supply curves, as a "mark up" and were not treated as sensitive to transport mode capacity utilization. The general flowering of energy modeling techniques in the 1970's did not produce a significant development in coal transportation modeling until the end of the decade.

Freight Network Equilibrium Models

The central concept of the freight network equilibrium model is a straightforward application of the shortest path algorithm in a network model as developed in introductory management science and operations research texts.[88] The early 1980's saw rapid development and application of the technique in response to contemporary concern that the national rail network might not be able to transport expected coal tonnages at reasonable costs. As subsequent events have shown, railroads have provided the required capacity while reducing real dollar average transportation costs per ton-mile.[89]

The distinguishing feature of freight network models is a network composed of connecting links, each independently costed. These models develop route transportation costs by finding the optimal path through the network for each origin/destination pair. Since links have independent cost functions, networks can represent multimodal routes with loading, transloading, and unloading options. Optimal routes can be defined as those with the lowest costs, or as those generating maximum revenues. Link costing functions can range from flat fees through volume-sensitive capacity utilization functions to complete engineering cost models, depending on the functions of the model in question.

Very large networks may be used to describe mode-specific transportation capacities for the entire United States. Applications to coal supply modeling generally use simplified networks of up to a few thousand links. The time required to execute a freight network model increases rapidly as a function of network size and complexity. Since the network links connect actual places, they represent actual distances and freight capacities in geographic space, and have the computational properties associated with true geographic scale. In such networks, rates may be constructed by multiplying the sum of a "base rate" and a volume sensitive capacity utilization function by function of link distance. The source of such base rates may be the error term in a linear regression predicting rates from distance.

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[88]See, for example, Wagner, Harvey M., "Network Models," Chapter 6 in *Principles of Management Science with Applications to Executive Decisions* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1970).

[89]United States General Accounting Office, *Railroad Regulation, Economic and Financial Impacts of the Staggers Rail Act of 1980, GAO/RCED-90-80* (Washington, DC, May 1990).

Freight network models often contain an equilibrium algorithm, which is required by the use of volume-sensitive capacity utilization functions to price transportation across links. Since the solution begins with estimated volumes, flows through the network will not reach equilibrium unless actual flows equal estimated flows. Since freight prices vary with volume shipped, estimated and actual flows are unlikely to be equal. Successive iterations may not converge to an equilibrium assignment of volumes on different routes. Heuristic algorithms were adopted to shift small percentages of route volume toward more optimal routes until equilibrium is attained. The combination of exact shortest path and heuristic equilibrium assignment algorithms provides a powerful method of processing very large quantities of transportation detail. Given a sufficiently detailed method of estimating link-specific costs, such models can provide accurate estimates of the route specific variable costs incurred by coal carriers.[90] Freight network models have been widely used to study regional rate responses to increasing system capacity utilization.

The ability to model transportation costs at a link-specific level of detail does not come without drawbacks, however. Freight network models depend heavily on detailed input describing freight flows, rates, and exact routes.[91] Coal distribution networks have been developed with from 269 to over 18,000 links; the bigger the network, the more difficult and expensive it is to maintain, and the greater the model's execution time requirements. In smaller networks, scale problems such as the "centroid problem" inevitably emerge. This problem emerges as the number of origins and destinations decreases, and the accuracy and stability of interregional tonnage-weighted distances diminishes. If a node is not the true volume- and tonnage-weighted center of the region it represents, the use of actual ton-mile rates will produce inaccurate route prices. True centroids constantly shift in a freight network, just as the population center of the United States has been hopping in a southwesterly direction across the midwestern United States after each decennial census in this century. This means that simple networks require painstaking annual adjustments if reasonable rates are to be maintained. In the real world, an individual link may have widely different ton-mile rates as a component of different contractual movements priced at "what the market will bear." Simplified networks also reduce the ability to model competition on parallel routes between the same origin and destination.

A strength of freight network models is their ability to provide detail about comparative route geography and link-specific economics. However, this detail has few applications in national energy policy analyses as addressed by the NEMS. It *is* useful to be able to model coal transportation competition on a carrier/route basis. The CDS is designed to produce (through an exogenous accessory program that is not operational for the *Annual Energy Outlook 1995*) route and mode specific transportation detail that can be adapted to studies of carrier competition. However, the current depiction of transportation consists entirely of rates determined by subtracting average minemouth costs generated in the CDS from historical delivered costs as collected on Forms EIA-3A, -5A, and FERC Form 423. Thus the model remains compact and speedy, and the rates generated are based on the only set of available data that can provide universal coverage of recent historical coal transportation rates.

Modeling Coal Supply Under Imperfect Competition

Over the last decade, a number of papers have explored imperfect competition in domestic and international coal markets. These studies are relevant to the design of the CDS because of several issues they present.

The first of these issues is methodological. The lack of a strong relationship between the marginal costs of coal transportation and the prices charged; the geographically idiosyncratic pattern of transportation rates reflecting different types of service, modes, and the local market power of common carriers; the lack of credible evidence that rates are strongly related to distance shipped all combine to suggest a very highly

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[90]Vyas, A.D., "Overview of Coal Movement and Review of Transportation Methodologies," *Proceedings of Coal Transportation Costing and Modeling Seminar, October 15, 1984* (Kansas City, MO: Argonne National Laboratory, July 1985), p. 7.

[91]Vyas, A.D., "Overview of Coal Movement and Review of Transportation Methodologies," p. 7.

detailed portrayal of coal transportation. The NEMS system cannot support coal transportation simulation at this scale, and it is questionable whether such a system could be adequately supported by factual data to meet EIA documentation standards. Still, the CDS must avoid "corner solutions" that distort interregional flows and prices. Finally, evidence suggests that without inclusion of more detail than the NEMS system can tolerate, it can not be shown that, in the short-term (year-by-year) coal distribution is significantly determined by delivered cost minimization. The inclusion of existing contracts through the mid-term is of vital importance to the modeling of a plausible distribution.

The problem of scale representation can be illustrated by coal shipments to Ohio, one of two States included in CDS Demand Region 10 (Ohio and Indiana). Coal can be delivered to all parts of the State by truck and rail, but many coal consumers are located along the northern and southern edges of the State, adjacent to Lake Erie and the Ohio River, respectively. The least cost solution to Ohio's coal supply needs, when the State is modeled as a point demand, is to ship all supplies via either Great Lakes vessel or river barge, which is a serious distortion of actual practice. In most large coal distribution models, this problem is addressed by subdividing Ohio into two or more demand regions. In the CDS, there is one demand region for Ohio and Indiana combined. For most analyses, the use of average transportation rates to these two State regions is adequate, but if the CDS is to be used for studies of intercarrier or intermodal competition, an endogenous method of constraining competition is clearly required.

Two methods have been developed to address analogous problems in modeling international coal trade, where noncost minimizing patterns of supply and demand are common. One is to disaggregate demand into shares "dedicated" to particular suppliers.[92] The second approach is the specification of finite elasticities of substitution for products from different supply sources.[93] Other studies of imperfect competition have focused on the power of western coal-producing State governments and the railroads serving mines in these States to extract economic rents. Kolstad and Wolak examined the ability of the Wyoming and Montana governments to extract rents from coal through severance taxes. Assuming Nash-Cournot conditions, and using reaction-function equilibria with the tax rate, rather than the production level, as the decision variable, optimal severance tax levels of 27 percent for Montana and 33 percent for Wyoming were found (both higher than current tax levels).[94] These authors also tested the ability of the two rail carriers providing transportation eastward from Montana and Wyoming to capture rents.[95] The methodology required is computationally intensive, and is inappropriate for a national scale, multi-purpose model that must meet NEMS performance requirements.

Wolak and Kolstad have also explored the modeling of steam coal supply to Japan as a mixed strategy considering both the expected cost of coal from different suppliers against the expected cost variability inferred for these suppliers from their recent trade histories.[96] This method directly addresses the uncertainty associated with long-term minemouth and coal transportation costs, but it requires the computation of covariance matrices for historical price variation for each demand to be met. This is too great a computational burden for a NEMS model with classification structures as extensive as those in the CDS (200 supply curves and 600-800 sectoral/regional demands).

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[92]Abbey, David S. and Charles D. Kolstad, "The Structure of International Steam Coal Markets", *Natural Resources Journal*, 23 (1983), pp. 859-891; Charles D. Kolstad, David S. Abbey and Robert L. Bivins, *Modelling International Steam-Coal Trade, LA-9661-MS, UC-98F* (Los Alamos, NM: Los Alamos National Laboratory, January 1983), p. 12.

[93]P.S. Armington, *A Theory of Demand for Products Distinguished by Place of Production*, International Monetary Fund Staff Papers, 16 (1) (March 1969), pp. 159-176; T. J. Grennes, P.R. Johnson, and M. Thursby, *The Economics of World Grain Trade* (New York: Praeger, 1978).

[94]Kolstad, Charles D. and Frank A. Wolak, Jr., "Competition in Interregional Taxation: The Case of Western Coal," *Journal of Political Economy*, Vol. 91, No. 3 (1983), pp. 443-460.

[95]Wolak, Frank A. and Charles D. Kolstad, "Measuring Relative Market Power in The Western U.S. Coal Market Using Shapley Values," *Resources and Energy*, 10 (1988), pp. 293-314.

[96]Frank A. Wolak and Charles D. Kolstad, " A Model of Homogeneous Input Demand Under Price Uncertainty," *The American Economic Review*, Vol. 81, No. 3 (June 1991), pp. 514-538.

Summary Comparison of the CDS and Other Coal Distribution Models

Coal distribution models have evolved as approaches to solving fundamental problems encountered as attempts have been made to apply the models to a broader and broader array of topics associated with the coal supply and distribution industries. These models have faced the endless challenge of successfully addressing an endlessly growing range of purposes, while under great pressure to remain compact, transparent, easy to maintain, and quick to execute. As discussed above, these problems can be summarized:

- Coal distribution, on a year-by-year basis, and at the required level of regional and sectoral detail can not be shown to be determined by the delivered cost of coal. Yet, in the long run, historic data show that it undoubtedly is. It has been argued that this is due to the short- and mid-term price inelasticity of demand for coal, and the concurrent existence of localized market power in the coal transportation industry. It has further been argued that the primary symptom and descriptor of coal markets' adaptation to this fact is the dominance of such markets by long-term coal supply and transportation contracts.

- Historically, coal distribution models have attempted to resolve this problem by including greater and greater levels of regional and sectoral detail, accompanied by highly detailed attempts to portray coal transportation rates. These attempts have expanded the detail in most coal models beyond levels appropriate for a NEMS component and, often, past the point where the transportation rate structure can be shown to have an explicitly factual basis.

- Important technological constraints on the operation of different end-use technologies with sub-optimal coals are known to strongly constrain attempts to minimize delivered prices. Unfortunately, the available documentation of such issues focuses on engineering issues rather than cost impacts, and so can only be incorporated into models in a general way. Again, precise modeling of such constraints would both require data that are not available and a level of detail in modeling that is inappropriate for the coal components of NEMS. Most coal distribution models, including NEMS, have been forced to use an extremely simplified coal typology. Perhaps for this reason, explicit recognition of these constraints is rare in coal distribution model literature, although common in the combustion engineering literature.

- Many issues referred to coal distribution models involve environmental or transportation issues that rest on plausible modeling of the above constraints; at the same time, data needed to provide detailed modeling of such issues are not available.

In this framework, it is questionable whether highly detailed approaches to coal distribution modeling can be rationalized as cost-efficient. One approach would be to construct a model that used a simplified classification structure (six to twelve supply and demand regions with a similar number of coal types and economic sectors) and treat demands as imputed contracts, fixed for 20 years, allowing price competition to determine the distribution of only the marginal component of total demand represented by expired contracts plus demand growth. A highly efficient, transparent, and simple model would result. However, such a model would not "fit" into an integrated system such as NEMS where year-specific outputs are closely scrutinized, where annual solutions are produced by the integrated iteration of many models, and where State level reporting of potential policy impacts is required.

The CDS has been constructed to compromise the need for speed and simplicity with the need for detailed output, while maintaining the capability for adaptation to much more detailed studies. The current CDS is the core component of such a model, but its current use of contract data is restricted to available data on electric utility industry long-term contracts. The CDS imputes no contracts for the nonutility sectors (precisely where demand is least sensitive to annual delivered price fluctuation), and imputes no electric utility contracts after existing ones expire. Moreover, by the standards of most of the larger linear programming coal distribution models that have evolved in the last two decades, the treatment of coal transportation in the CDS is extremely simple and heavily reliant on analytical judgement to set rates for the nonelectric utility sectors that are (1) plausible, based on survey data describing average sectoral delivered prices, and (2) that will effect a plausible geographic pattern of coal distribution. The current methodologies are, however, adequate to produce regionally aggregated forecasts such as those required for the *Annual Energy Outlook*.

As the NEMS system develops, the CDS must be developed to enhance its use of long-term demand/supply assignments based on price and other data that transcends annual delivered cost minimization, e.g., contracts could be imputed on the basis of a combination of annual prices and long-term supply curve slopes. Such a methodology should be adequate to determine supply/demand relationships in the less price sensitive nonelectricity generation economic sectors, provided that imputed contracts are limited in duration to the 5- or 10-year lengths typical of these sectors in the "real world." Benefits of such an approach include: (1) faster model execution, since the number of demands that must be solved in each iteration is reduced in proportion to the inverse of average imputed contract length; (2) more plausible output as the model begins to encompass technological and reliability constraints as major decision factors in coal choice decisions; (3) more stable behavior, a factor of interest in a model which must act as a component of a large integrated system.

The methods reviewed above for addressing coal transportation cost issues due to imperfect competition were developed for study of particular problems at a level that required simple classification structures. The CDS must develop a methodology adaptable to many studies at a national scale. It can not be assumed that all such study topics are foreseeable. It is, therefore, probable that the most efficient approach to use in the CDS, as it is further developed to provide more detailed coal transportation modeling, will be to provide exogenous year-specific maximum shares for a set of detailed, multi-modal routes that can be adjusted as required to explore scenarios associated with mode- and carrier-specific competition in the model. Detailed description of transportation routes and modes can be accomplished outside the CDS solution algorithm processes to maintain model speed. The use of shares is more transparent and easier to maintain than the development of mode-specific elasticities. It is questionable whether modal or carrier-specific elasticities can be provided with adequate factual basis, but it is probable that available data surveys can support the concept of shares. The use of year-specific shares provides a transparent method of exploring what are, in effect, alternative hypotheses about intermodal or intercarrier price elasticities of demand. Finally, it is possible to construct the entire mechanism descriptive of routes and shares outside the CDS itself, and use it to develop rate input for the CDS at a level of detail appropriate to the study at hand. Thus, any detailed description of routes and shares need not encumber the NEMS system when it is in use to develop forecasts, such as the *Annual Energy Outlook*, that do not require this detail.

4. Model Structure

The CDS forecasts the quantities of coal needed to meet regionally and sectorally specified coal demands. It provides the Btu and sulfur content of all coal delivered to meet each demand. The CDS also provides annual forecasts of minemouth and delivered coal prices by sector and region. Marginal delivered coal prices by demand sector and sulfur content are provided to the EMM to be used in formulating regional and sector-specific electricity demands for coal. Additionally, the CDS projects the regional distribution of coal mine capacity requirements by sector, region, mine type, and coal type based on future utility and nonutility coal demand. Transportation costs can be summarized independently by coal supply region, coal rank and sulfur content, and by transportation mode for regional or sectoral transportation analysis.

The model code of the CDS that performs these tasks is simple in structure, consisting of ten subroutines, eight sources of input and five output files. The interaction of these components is outlined below and in the accompanying flowcharts.

CDS Computational Sequence and Input/Output Flow

The controlling submodule in the Coal Distribution Submodule code is called "CDS".[97] The functions of subroutine "CDS" are shown in Figure 14, which also provides a partial overview of the operations of the CDS code as a whole. "CDS" controls four other subroutines:

- "CMAPSR" disaggregates demands from the regional and sectoral structure used throughout the NEMS system into the more detailed structure used within the Coal Market Module. "CMAPSR" is described in more detail in the discussion of Figure 15. During the first iteration of each forecast year, "CMAPSR" obtains from the NEMS restart file future expectations of nonutility demands and calls subroutine "CMAPP" to obtain, from the NEMS restart file, future projections of utility coal demand. The projected demands also are decomposed into the structure used within the Coal Market Module and are used to project coal mine capacity requirements in subsequent years.

- "CLTRAN" controls the CDS solution algorithm and contains one of the two portions of the CDS solution algorithm. The first portion of the solution process is a shortest path algorithm contained in the "SWEEP" subroutine called by CLTRAN, while the second portion of the process, a heuristic equilibrium assignment algorithm, is contained within "CLTRAN". During the first iteration of each forecast year, "CLTRAN" obtains piecewise-linear capacity curves from the CPS. The CDS solution algorithm projects future coal mine capacity requirements based on expectations of future utility and nonutility demands. "CLTRAN" writes projected capacity by sector, region, coal type, and mine type to the common block name "CDSCPSP".

- "CPSHR" maps output coal prices as they are transmitted to NEMS and to the EMM in particular when the CMM and EMM are operating in a fully integrated mode. "CPSHR" writes nonelectric utility coal price output to the common block name "PQ", and delivered coal prices, sulfur and Btu assignments for coals assigned to electric utility demands to the common block name "COALOUT". "CPSHR" writes prices, sulfur, and Btu content for coal meeting utility demands to a physical file named "CLCDS". "CPSHR" also writes diagnostic output to the physical file "CLDEBUG". As the name implies, "CLDEBUG" contains output describing the iteration-by-iteration output of the CDS that is used in resolving problems that arise in the operation of the CMM and/or other NEMS models with which it interacts.

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[97] To avoid confusion in the following discussion, subroutine and file names are always written in quotation marks, e.g., "CLTRAN", "COALOUT".

Figure 14. Calling Order for CDS Subroutines—Overview

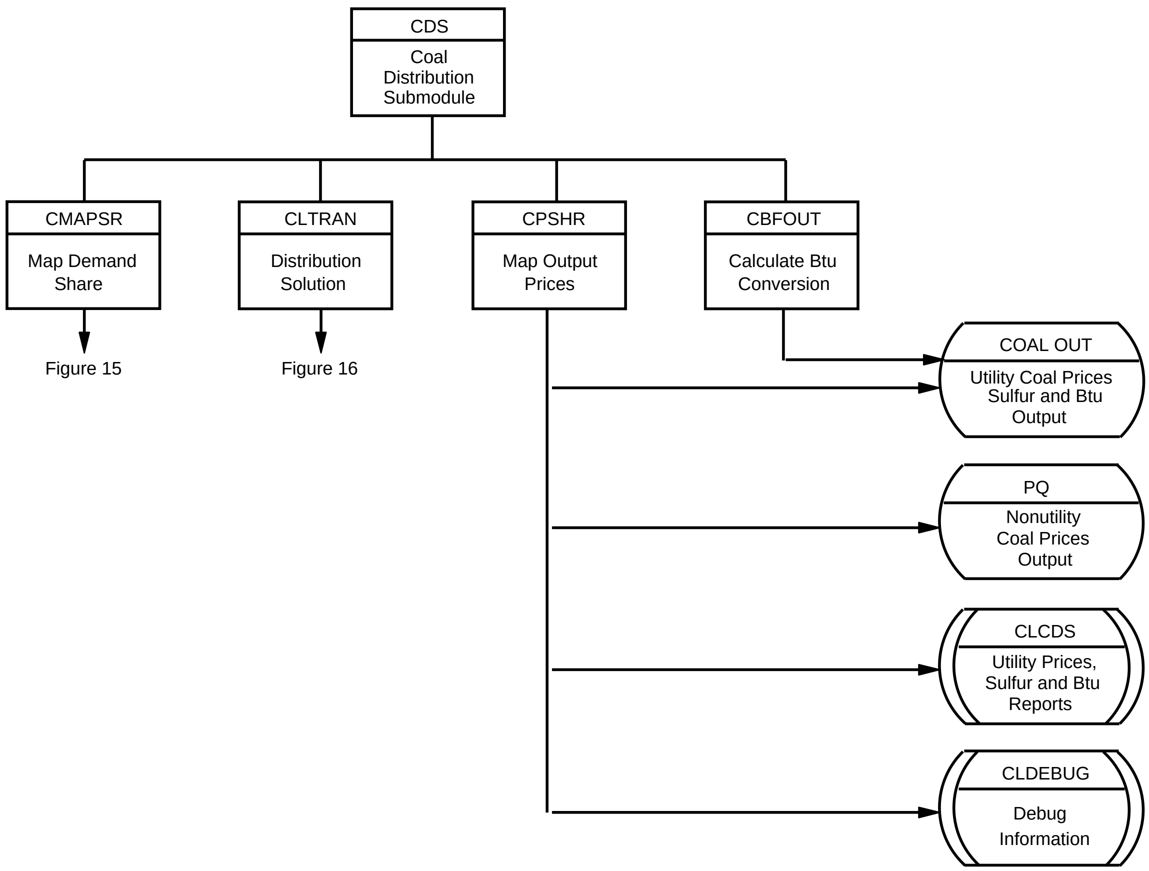
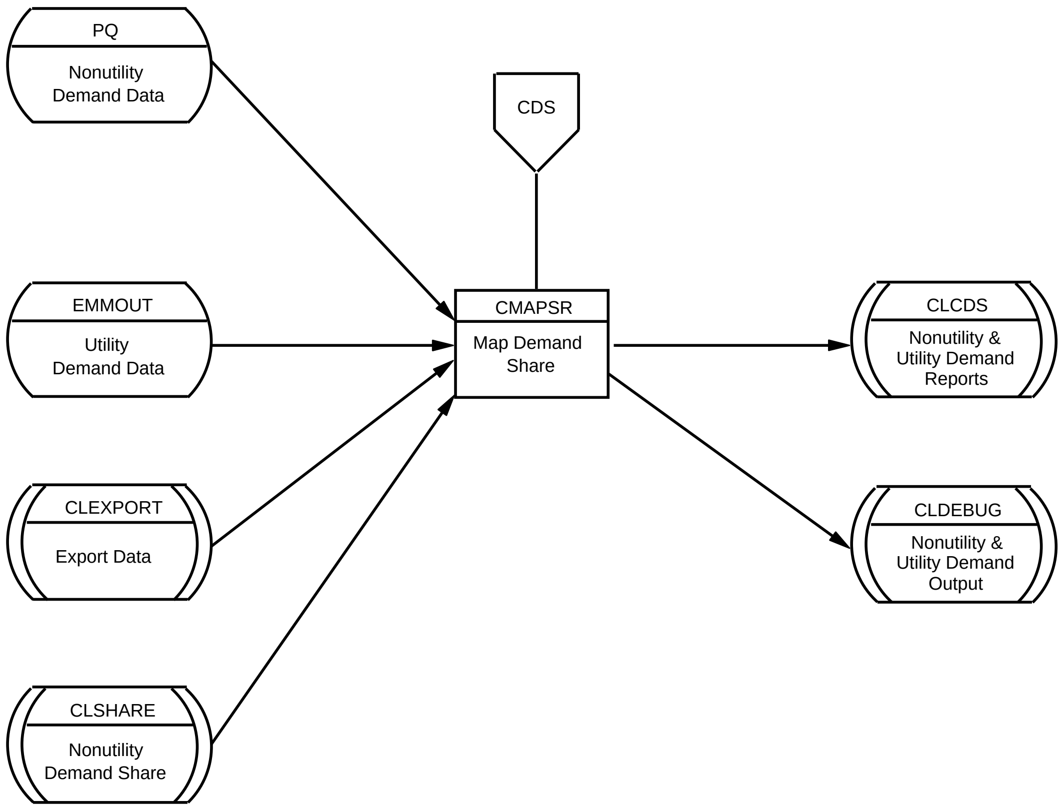


Figure 15.   Functions of Subroutine "CMAPSR"



- Subroutine "CBFOUT" calculates Btu conversion factors, an important process since the Coal Market Module mimics actual industry behavior in modeling the mining and shipping of coal in short tons, but demands are met in terms of least delivered cost per million Btu. This conversion is conceptually important since production, transportation, and delivery data are required to be reported in both physical units and trillion Btu. The conversions accomplished in "CBFOUT" are reported to the common block name "COALOUT".

The subroutine "CDS" calls the above subroutines in the same order in which they are discussed above, and this order is honored in Figure 14, if that figure is read from left to right. However, the functions performed by subroutines "CMAPSR" and "CLTRAN" are too numerous and complex to show in a single figure. As shown in Figure 14, the processing functions of these two subroutines are each displayed in a dedicated figure: those for "CMAPSR" in Figure 15. The operations outlined in Figures 15 and 16 are discussed below.

Figure 15 displays the functions of subroutine "CMAPSR". This subroutine creates the regionally and sectorally distinct demands for which the CDS solves. It does not, however, prioritize these demands, nor does it perform the important step of modifying the demands to reflect the constraints imposed by existing electric utility coal contracts. Both these processes are accomplished by subroutine "CLTRAN", which is described in association with the discussion of Figure 16. "CMAPSR" reads common block names "PQ" (which contains the nonelectric utility coal demands) and "EMMOUT" which contains the electric utility demands. The demand for coal exports is read by "CMAPSR" from the common block "CDSCES" (which contains data passed by the coal export submodule). The demand shares used to disaggregate demands from the NEMS demand regions (the 9 Census divisions) to the 23 CDS demand regions are read from the physical file "CLSHARE".

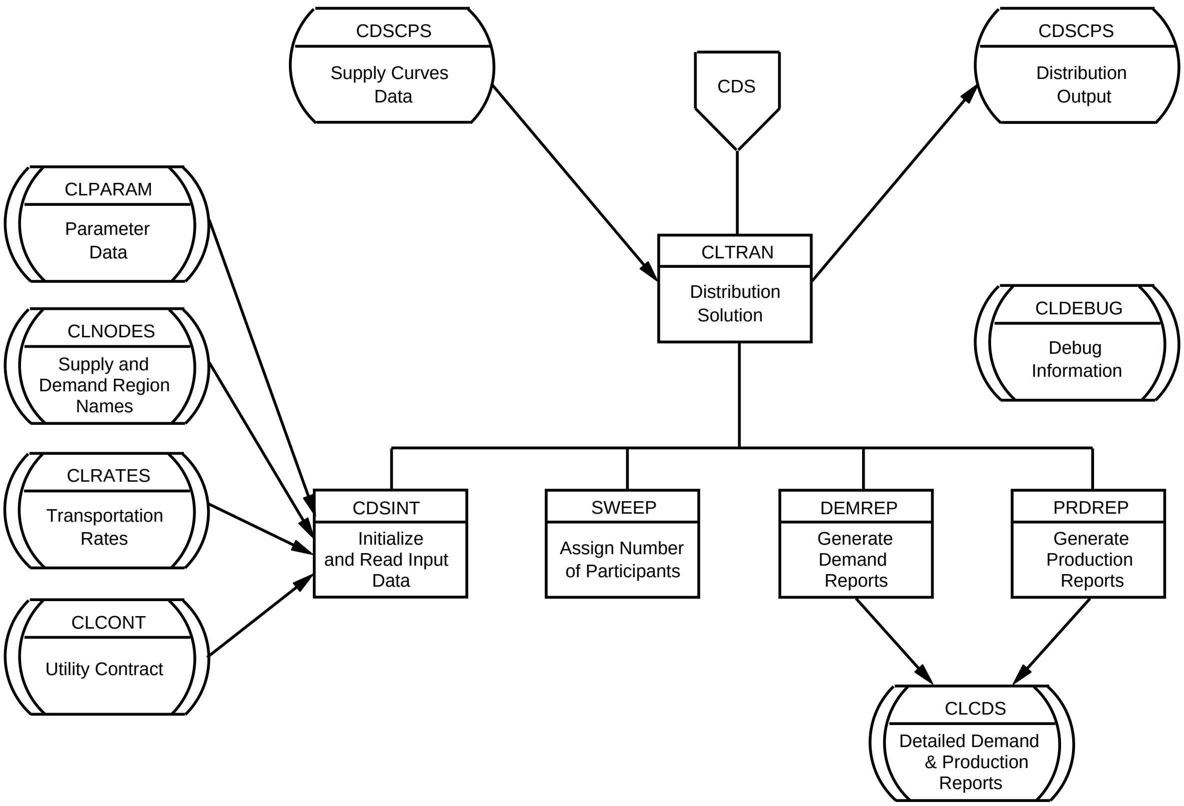
During the first iteration of each forecast year *t*, "CMAPSR" obtains from the NEMS restart file for projected year *t + 2* expected nonutility demands and calls subroutine "CMAPP" to obtain utility demands projected by the Electric Market Module by CDS regions. The nonutility demands are disaggregated to the regionally and sectorally distinct demands.

"CMAPSR" writes output describing the demands it has calculated from the input common block names and physical files described above. Nonutility and utility demand reports, plus a utility demand summary report are written to the physical file "CLCDS". These reports appear at the head of the year-specific detailed CDS output that consists of approximately 15 reports available for each forecast period year. "CMAPSR" also reports to the "CLDEBUG" physical file, as shown in Figure 15. Using these reports it is possible to determine exactly what demands the CDS has solved for in a given forecast year, since this output is written before the CDS solution algorithm is called by the "CDS" subroutine.

The subroutine "CLTRAN" controls the order in which regionally and sectorally disaggregated demands are solved in the solution algorithm by calling subroutine "CDSINT" which functions to initialize all arrays and read input data from four physical files. These input units are:

- "CLPARAM" which contains parameters that order the assignment of demands, assign coal type labels and sectoral names, and provide important adjustments to minemouth and transportation prices, as well as constraining the types of coal that can be used to fill demands in different economic sectors and regions. (The contents of "CLPARAM" and other physical input files are described in greater detail in Appendix A of Part III of this report.)

Figure 16. Functions of Subroutine "CLTRAN"



- "CLNODES" currently contains only supply and demand region name labels.

- "CLRATES" contains a large matrix of transportation rates defined by economic subsector, coal supply, and demand regions. These rates are specified in 1987 dollars, are adjusted to provide rates in the dollar year used in any run, as well as adjustments specific to the economic sector and forecast years. These last two adjustments are accomplished by parameters found in "CLPARAM" that are discussed in Appendix A.

- "CLCONT" contains data defining aggregated existing electric utility coal contracts that are assigned to constrain the selection of coal sources by the CDS solution algorithm. The nature of this input and its use is also discussed in Appendix A.

Once these physical units have been read, subroutine "CLTRAN" can formulate a complete demand list, and also has the information required to assign transportation costs based on the coal origin and destination, and the type of demand being supplied. However, in order to calculate the delivered prices for candidate coal supplies to meet these demands, "CLTRAN" must obtain information defining the minemouth costs of coal from the CPS. These values are read from the common block name "CDSCPS" by "CLTRAN". "CLTRAN" can then call subroutine "SWEEP" which determines the least-cost coal supply sources using a shortest path algorithm. In effect, the use of the shortest path algorithm in "SWEEP" assigns a preliminary list of supply sources, or "participants" for each demand in demand list. Since the process of assignment does not guarantee an equilibrium solution, the equilibrium assignment algorithm embedded in "CLTRAN" must be used iteratively with the shortest path algorithm in "SWEEP" to obtain an equilibrium solution. The heuristic rules and coefficients defining the manner in which these two solution algorithm components iterate are discussed in detail in Appendix B of this report. When internal CDS convergence criteria have been satisfied, "CLTRAN" writes output describing the coal distribution solution to common block name "CDSCPSP". "CLTRAN" also calls two subroutines that write the bulk of the year-specific detailed reports, that provide the bulk of written CDS output:

- Subroutine "DEMREP" generates coal demand reports that describe demand, transportation, and distribution of coal from supply to demand region by economic sector, with fully adjusted transport rate data provided in both $/ton and $/MMBtu. One of these year-specific reports, the "Detailed Supply and Price Report," provides a full description of coal type, demand quantity, individual participants, and minemouth, transportation, and delivered costs for an entire run, in the order of the 23 CDS demand regions. This is the most detailed report currently available from the CDS, and generally requires 30 to 50 pages per forecast year (divided into 23 regional subreports). Reports generated by "DEMREP" are written to the physical file "CLCDS".

- Following the production of the demand reports, subroutine "PRDREP" generates coal production reports that describe the quantities of coal produced by coal type from each coal supply curve in each supply region. Accompanying production quantities in millions of tons are associated minemouth prices. The definition for each coal type that is assigned to individual coal supply curves defines a sulfur and Btu category, but values of sulfur and Btu that are specific to each supply curve (and which are taken from the FERC Form 423) are also available, and are used by both the CDS and the EMM to calculate precise $/MMBtu prices and sulfur contents (in lbs sulfur per MMBtu). The coal production reports are written on physical file "CLCDS".

"CLTRAN" also writes diagnostic output directly to the physical file "CLDEBUG".

"CLTRAN" is executed twice during the first iteration of each forecast year *t*. In the first pass, "CLTRAN" obtains from the common block "CDSCPSP" the piecewise-linear capacity curves developed by the CPS. The capacity curves, combined with the disaggregated nonutility and utility demands expected in projected year $t + 2$, are processed by the CDS algorithm to obtain projections of coal mine capacity requirements in *projected* year *t + 2*. The projected capacities are output to the common block "CDSCPSD". In the second pass, regional and sector demands are reinitialized to the *current* demand values for the forecast year *t*, and the "CLTRAN" solution algorithm is executed as discussed above.

Key Computations and Equations in the CDS

The CDS FORTRAN code is over 5000 lines in length. Any attempt to summarize it in a few key equations is likely to seem at least partially arbitrary. Those included in this section have been selected based on experience gained in over 10 years of documenting and explaining the model's predecessor, the Coal Supply and Transportation Model (CSTM). The solution algorithm of the CDS is essentially identical to that of the CSTM; the heuristic component of this algorithm was a focus of interest in the CSTM, and its key components (described in greater detail in Appendix B of this section of the report) are identified and described and located below. Equations responsible for minemouth price and transportation rate formation are also identified and located, as are equations for the total tons of coal required to meet a given demand, and the equation for the total delivered price of coal to meet a demand. A pair of equations that endogenously specify subsectoral demand shares for domestic premium metallurgical and blending metallurgical subsectors are also listed below since they contain coefficients that would otherwise be difficult to locate.

One pair of equations that is not central to the operation of the CDS solution algorithm is included in this list because it establishes a subdivision of total domestic metallurgical demand into a "premium" metallurgical subsector and a "blending" metallurgical coal subsector. These equations are the only cases in the CDS code where subsectoral demands are established by coefficients embedded in the code, rather than by demand share arrays read from the "CLSHARE" physical file, and they are located for the reviewer's convenience. Both are found in subroutine "CLTRAN" between 6 and 12 lines after FORTRAN statement 310:

"Premium" metallurgical demand = 14 percent of total metallurgical coal demand.

YDL(J) = QDMT1R(K)*0.14

"Blending" metallurgical demand = 86 percent of total metallurgical coal demand.

YDL(J) = QDMT1R(K)*0.86

These statements currently occur near line number 3954.

Some of the most important of these key equations are those that calculate the reference price of coal on a given supply curve. There are two variations of this equation, one for deep and one for surface mines. Both are located in subroutine "CLTRAN" closely following FORTRAN statement 1015. First the equation determines whether a deep mine curve or surface mine curve is being priced (coal types numbered 1 through 16 are deep mine curves). Then the code determines the minemouth price from the first and third segments of the supply curve:

```
 IF (ISVC (I)  .LE. 16) THEN
  PSRNG (I) = (COFA (IJ) + (COFB (IJ)* EXP(COFC(IJ,1)*VSCUR(I) [deep mine equation]
          **(COFX(IJ,1))))) * CSDISC (ISVR (I), IYEAR-1)
 ELSE
  PSRNG(I) = (COFA (IJ) + (COFB (IJ) + COFC (IJ,1)*VSCUR(I)
          **COFX(IJ,1))**0.5) * CSDISC (ISVR (I), IYEAR-1)[surface mine equation]
 END IF
ELSE
  PSRNG(I) = (BSV (IJ)* VSCUR(I) + ASV(IJ)) * CSDISC(ISVR(I),IYEAR-1)[1st and 3rd segment]
END IF
```

These statements currently occur after line 4232.

Another important equation is the calculation of the fully adjusted transportation rate for a candidate coal supply. This is found in "CLTRAN" following FORTRAN statement 1500 at or near line 4317:

```
RS = ODTRATE(L,LY,M)*BSRZR(M,LY)*BTR(CURIYR)
```

This equation is very simple since the basic rate, ODTRATE, is read from an input file, and modified to approximate the actual difference between minemouth and delivered prices in the base year by the variable BSRZR, and escalated for transport cost factor input inflation by the year-specific parameter BTR.

Another group of important equations controls the interaction of the shortest path and equilibrium assignment subparts of the CDS solution algorithm. Readers may wish to familiarize themselves with Appendix B, which provides a mathematical description of the solution algorithm and its operation prior to attempting to comprehend the portion of the code in which this group of equations is found.

The equation defining the number of CDS iterations between successive iterations of the "SWEEP" subroutine, which contains the shortest path algorithm is located in "CLTRAN" following FORTRAN statement 1100 on or about line 4290:

```
ITST = 60-IC*5
```

The number of "CLTRAN" iterations between "SWEEP" iterations is constrained to have a minimum value of 15 on the next code line.

```
IF (ITST .LT.15) ITST = 15
```

The ratio of the highest participant delivered price to the lowest participant delivered price for a given demand determines whether the CDS convergence criteria has been met. The test begins shortly after "CLTRAN" FORTRAN statement 1510 at or about line 4338.

```
ZZ=ZH/ZL
IF (ZZ .LT. RATIO) GO TO 1511
RATIO = ZZ
```

When the convergence test is not met, a series of conditional tests is applied to control the amount of participants' coal supplies that must be shifted to lower cost participants. These proportions have been determined through experience with the current model, the CDS, and its predecessor, the CSTM, which incorporated a solution algorithm with the same basic structure. These begin, as indicated above, at "CLTRAN" FORTRAN statement 1511, and can be enumerated as follows (readers may wish to refer to Appendix B, and, more specifically, Table B-1 for a better understanding of the functions of these equations).

Current high priced participant or low priced participant matches previous participant:

```
IF (JH.NE.JTPH(J) .AND. JL .NE. JTPL(J)) SDL (J) = SDL(J)=*1.01
```

"CLTRAN", after FORTRAN statement 1511, at or about line 4353-4353.

Both current high priced participant and current low priced participant match previous participant:

```
IF (JH .EQ. JTPH(J) .AND. JL .EQ. JTPL(J)) SDL(J)=SDL(J)*1.5
```

"CLTRAN", after FORTRAN statement 1511, at or about line 4354.

Previous high priced participant is current low priced participant <u>or</u> previous low priced participant is current high priced participant:

IF (JL .NE. JTPH(J) .AND. JH .NE. JTPL(J)) SDL(J) = SDL(J)*0.95

"CLTRAN", at FORTRAN statement 1515, at or about line 4357.

Previous high priced participant is current low priced participant <u>and</u> previous low priced participant is current high priced participant:

IF (JL .EQ. JTPH(J) .AND. JH .NE. JTPL(J)) SDL(J) = SDL(J)*0.5

"CLTRAN", after FORTRAN statement 1515, at or about line 4359.

Both current high priced participant and current low priced participant are different from both previous high and low priced participants: in this case no equation is required since there is no required change in the fraction of the participant supply volume, i.e., this is the default setting for the algorithm.

A maximum value of SDL(J), set at 0.10 is set in "CLTRAN" following FORTRAN statement 1511, at or about line 4355:

IF (SDL(J) .GT. 0.10) SDL(J) = 0.10

The default setting of SDL(J), 0.05, is determined in "CLTRAN" between FORTRAN statements 355 and 377, and is repeated in four conditional IF statements tied to the above conditions (at or about current code lines 4028, 4039, 4051 and 4061).

SDL(J)=0.05

Another pair of equations in the same section of "CLTRAN" discussed above where the four conditions and their associated participation shifts (located between FORTRAN statements 1511 and 1525) defines the tonnages of coal actually supplied by the high and low cost participants in any demand job. The first defines the tonnage assigned to the high cost participant, while the second defines the tonnage assigned to the low cost participant:

```
1525   TIJL(JH,J) = TIJL(JH,J) - (DTJL(JH,J) * SDL(J))
       TIJL(JL,J) = TIJL(JL,J) - (DTJL(JL,J) * SDL(J))
```

Still another pair of equations determines the Btu conversion used to convert demand in trillion Btu to tons of coal. In general, the method simply applies the million Btu per ton assigned to the supply curve in question, which is an input received from the Coal Production Submodule. However, in the case of metallurgical coals, an arbitrary assignment of 26.80 million Btu per ton is used. The reasoning behind this technique is that EIA collects no data defining the actual Btu per ton for metallurgical coals (energy content is not, in any case, a significant determinant of the economic quality of metallurgical coals, which are priced based on other criteria). For many years, EIA's Office of Coal, Nuclear, Electric, and Alternate Fuels has estimated the Btu content of bituminous metallurgical coals at 26.80 million Btu per ton in the *Annual Energy Review*. The CDS uses this estimate to convert demands in the three affected subsectors: "Premium" and "Blending" domestic metallurgical coals and "Premium" export coals (which represent metallurgical exports). The equations in question are found in subroutine "SWEEP" between FORTRAN statements 1210 and 1215, at or about lines

5260 - 5264. The metallurgical sectors are identified by their numerical indices of 5,6 and 7 in the list of 23 subsectors in the CDS.

```
IF( M .GE. THAN 5 .AND. M .LE. 7) THEN
X=QDL(J)/26.8
ELSE
X=QDL(J)/RSBTU(I)
END IF
```

One further equation may be of interest. The equation determining the total delivered price, 'P', is necessarily found in both "SWEEP" and "CLTRAN". In "SWEEP" it is found between FORTRAN statements 1210 and 1215 immediately following the statement of the transportation price equation, at or about lines 5270 and 5271:

```
UFO = ODTRATE(L,LY,M) * BSRZR(M,LY)*BTR(CURIYR) [fully adjusted transport rate]
P = (UFO + PSRNG(I)) * X [final price]
```

Note that the presence of the Btu conversion factor, 'X', as a multiplier indicates that the final delivered price is here being converted from the $/million Btu version used in the solution algorithm to the $/ton version printed in most of the CMM output reports.

An equivalent version of the same equation is found in "CLTRAN" shortly before FORTRAN statement 1803 (at or about line 4480). In this case, however, the final delivered price is stated in $/million Btu:

```
TOT = ODTRATE(L,LY,M)*BSRZR(M,LY)*BTR(CURIYR)+PSRNG(I)
```

And again in "CLTRAN" between FORTRAN statements 1705 and 1710:

```
UFO = (ODTRATE(L,LY,M)*BSRZR(M,LY)*BTR(CURIYR)+PSRNG(I))
```

Multiple versions of the total price equation occur because, in the cases cited above, the "SWEEP" algorithm must use the total delivered price to determine the least cost participants (example 1), and "CLTRAN" must use the same price in testing whether delivered price equivalence among participants to a given demand job is sufficient to meet the CDS convergence criteria (example 3). In the second case, the code section containing the total delivered price is calculating the total value of coal exports as the product of quantity exported times delivered price at the port-of-exit.

CDS Transportation Rate Methodology

The choice of methods in modeling transportation is strongly influenced by the need to find a method that can be easily maintained (because rapid scenario turnaround time is a design requirement), but that can provide detailed, route-specific descriptions of competition for coal transportation. Moreover, the pattern of delivered prices produced in the model for historical years must not disagree with delivered price data published by EIA, and the methodology adopted must not slow the model's execution time when operating in integration with the entire NEMS modeling system. Coal transportation rates are known to vary by the route-specific degree of competition, as well as by the value of the coal transported (or, as it sometimes phrased, by the end use sector to which it is transported), and by the annual volume transported. The variation in rates by its value or by the end use sector to which it is transported need not be interpreted as discriminatory pricing by the carriers involved, since different types and degrees of care in handling may be required depending on the end-use technology involved. As examples, the distribution of delivered coal by size categories and moisture content are critical variables for many end-use technologies, and most coal must be chemically protected against freezing during the winter in northerly regions.

In order to understand the methodology adopted, it is necessary to understand the data sources available and the constraints imposed by the limitations of those sources. An important constraint is that the model's sectoral and regional delivered prices for coal in historical years should not contradict EIA's published data for those years. Where rates are generated from sample data, or any source that is not a census or survey of the total relevant population, the representativeness of the sample must be statistically demonstrated.

EIA's available sources can be broken into three categories: those providing data on delivered coal prices by economic sector and state, those providing data on minemouth coal prices by state, and those providing data on rates by origin, transport mode(s), and destination.

The first category is the richest. EIA conducts annual surveys of delivered coal prices by in the domestic industrial steam and coking coal consuming sectors. Coal receipts, consumption, changes in stocks (all in short tons), and coal expenditures are reported by about 900 industrial coal consumers on Form EIA 3, "Quarterly Coal Consumption Report - Manufacturing Plants." The same data is reported by approximately three dozen consumers of coking coal on the Form EIA 5, "Coke Plant Report". The price of coal delivered to over 400 coal fired electric power plants is provided by the Form FERC 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants", which also provides the source and quality (Btu, ash and sulfur content) of the coal received. The last domestic price for coal exports at the port-of-exit is recorded on the Form EM-545, a Census Bureau form that records coking and steam coal exports by coal rank, tonnage and value.

Data from all these sources can be used to compute tonnage-weighted average delivered prices for coal in each of the CDS' 23 demand regions. Similarly, tonnage weighted average minemouth price data from the Form EIA 7A, "Coal Production Report" is used to provide average minemouth prices for each coal supply region. Thus, for each demand sector in each demand region, and for each contributing supply region, the difference between minemouth and delivered coal prices can be calculated by subtraction. Because there are many combinations of combinations of economic sector and region on the demand side, and of coal type and region on the supply side, the variance around the average price values within each supply/demand group tends to be relatively small.

The only alternative source for transportation rates that is available to EIA at the current time is the Form FERC 580, "Interrogatory on Fuel and Energy Purchase Practices." This form is a biennial survey of investor-owned utilities selling electricity in interstate markets and having generation capacity in excess of 50 MW. This form provides coverage of minemouth prices, freight charges,, coal sources and destinations (by plant), shipping modes, transshipment charges (if any) and distances covered. While this coverage is excellent in principle, the FERC 580 provides little useable information for a number of reasons. First, the limitation to investor owned utilities means that a number of significant coal using utilities, most notably the Tennessee Valley Authority, are not covered. Second, the biennial coverage means that the most recent available information is usually at least two years out of date, a serious disadvantage when the rapidity of rate change in recent years is considered. Third, much of the most interesting data is withheld as proprietary, including almost all rate information on transportation contracts that are not tariff based, i.e. the more recent post-Staggers Act contracts that are of most interest in modeling. The FERC 580 is thus not a census or universal survey, and the rate data it contains is an arbitrary sample of national rates containing little or no useable data for many supply/demand region pairs although in other cases it may provide rate data for over half of all electric utility coal traffic. Finally, the FERC 580 provides no data whatever for the industrial steam or export steam sectors, and can provide no useful rates for shipments in the domestic and export coking coal sectors where origins and destinations, coal handling requirements, and typical shipment and contract volumes are quite different from those in steam coal consumption sectors. Give the large percentage of Form FERC 580 data that is withheld as proprietary, the most productive use of the form is its description of the geography for a fairly large proportion of the routes used in the electric utility sector. However, this data has not yet been exploited by the CDS since the NEMS did not provide coal route and transport mode description in the Annual Energy Outlook 1994.

Given that base year transportation differentials can be calculated accurately from EIA and FERC survey data, two practical problems remain to be solved. First, the model must have a method for adjusting transportation prices so that delivered prices remain correct in the historical years as changes in demand shift the burden of supply across supply regions and supply curves. Second, the transportation rates used must be adjusted throughout the forecast period to account for escalation/de-escalation due to changes in factor input costs.

The need for the first adjustment stems from the CMM's place as a component in a system of models, with demands being generated by other models. In the case of electric power demands for coal (over 80 percent of total demand) the total quantity and distribution pattern of the demand received is a function not only of the coal prices received by the electric power model, but of the prices of alternative fuels, and constraints of existing contracts in the CDS. As, say natural gas prices, or general macroeconomic assumptions are shifted, demands shift from one supply curve to another, and - since minemouth price is a function of quantity demanded - delivered prices tend to rise and fall proportionately, violating historical values for regional/sectoral prices in historical years. A parameter in the params input file named "BSRZR" is used to adjust transportation rates so that the combination of minemouth and transportation rates is close if not identical to the historical delivered price. As the demand received shifts coal sources to different supply regions and supply curves, the transportation rate multipliers in the parameter "BSRZR" lose their ability to produce the historical delivered prices, and must be recomputed to produce transport rates that equal the historical delivered prices minus the minemouth prices produced in that model run. This is accomplished by an off-line program named "BSRZR.FOR.TEST".

The second adjustment, escalation/de-escalation throughout the forecast period, is accomplished by another parameter, "BTR". This parameter has the form of a year-specific vector with a single rate multiplier for every year in the forecast period. Usually, the most recent year for which historical data is available has the multiplier 1.0000 and all other years are calculated with reference to that base; the base year may be other than the most recent historical year in cases when that year appears economically abnormal. The annual values of "BTR" are computed off-line based on a composite cost index that includes projected values of the $/gallon diesel fuel price and changes in a variety of costs including labor, materials and supplies, equipment rentals, purchased services, depreciation, interest, taxes and other expenses. The basis for this composite rate escalator is a series of railroad related cost indices obtained from the Association of American Railroads.

The assumption underlying this escalator is that changes in transport rates **over time** will reflect changes in transportation costs over time. This assumption is to be distinguished from the assumption that inter-regional or inter-route differences in rates, **at a given time** will reflect inter-regional or inter-route differences in costs. As explained elsewhere in this documentation, the bulk of informed opinion denies that the single year pattern of rates, especially railroad rates, is strongly cost related in the absence of inter-carrier competition. However, this method of rate escalation assumes that the general pattern of relative prices will be escalated at geographically uniform rate nationally, although that rate may differ from year to year. The pattern itself is that demonstrated by the reported structure of minemouth and delivered prices in the base year.

Appendix A

Inventory of Input Data, Parameter Estimates, and Model Outputs

Input: Data Requirements

Input to the CDS is read from six input data files. These files and their contents are listed below.

6005PRJ.COAL.CLRATES.<scenario>.<datekey>. This file contains the basic coal transportation rates used in the CDS. The input data are in 1987 dollars, organized as subsets of 23 rates (one for each economic subsector in the model). These subsets are indexed into 368 groups representing the possible supply and demand region pairs in the model. At the left hand side of the file, the regional two letter abbreviations are shown, with the supply region on the left and the demand region immediately to the right. Rates are differentiated only for the major sectors, so that in each subset of 23, a residential/commercial rate is followed by 3 industrial subsector rates, 2 metallurgical subsector rates, 3 export subsector rates, 12 electric utility sector rates and a synthetic fuel sector rate. Where supply/demand region pairs are economically very unlikely (i.e., there is no historical record or current prospect of coal moving between these two regions), dummy rates of 999.99 are entered.

6005PRJ.COAL.CLSHARE.<scenario>.<datekey>. This file contains rational numbers used to create demand shares that distribute demands received at the Census division level of aggregation over the 23 CDS demand regions. The shares are organized in 10 columns representing the 9 Census divisions plus a 10th column reserved in case it is decided to model California as a separate region. The CDS demand regions are represented by the rows. The first 23 rows contain rational numbers used to disaggregate residential/commercial demands. The second 23 rows contain the shares for industrial demands. The third set of 23 rows contain the shares for metallurgical demands.

This set of 69 rows is immediately followed by an array representing supplies of imported coal in millions of tons. This input is indexed by Census division, CDS demand region, and by the sector to which the demand pertains (i.e., "1"= Electric Utility imports, "2"= Industrial imports, and "3"= Metallurgical imports). Each indexed group contains 26 numbers, one for each year in the model's forecast horizon.

Following this array is one with 23 rows and 3 columns of rational numbers. These assign industrial demands to the three industrial subsectors in the CDS for each CDS demand region.

The next array is the FERC Form 423 electric utility demand for 1990 indexed by number (and alphabetic code) to the 23 CDS demand regions and the 13 National Electric Reliability Council Regions. The 12 rows represent the 12 CDS coal types used for electric utility demands (from left to right these are PC+BC, PD+BD, PM+BM, PH+BH, SC, SD, SM, SH, LC, LD, LM, and LH). This array is repeated twice with slightly varying numerical entries, and these repetitions represent the same data for 1991 and 1992. These arrays have been used in test runs of the CMM and to calibrate the model to historical demand patterns.

6005PRJ.COAL.CLEXPOR.<scenario>.<datekey>. This file contains the export demands received from the Coal Export Submodule. Each group of demands contains 26 numbers representing annual demands for coal exports in trillion Btu. These groups have three indices at the left. From left to right these indices are (1) the CDS demand region, (2) the economic subsector to which they pertain ("7"= premium exports, "8"= high sulfur steam coal exports and "9" = low-sulfur steam coal exports), and (3) the CDS coal group from which supplies may be drawn. (The organization of "coal groups" is explained below in the discussion of the "CLPARAMS" input file.)

6005PRJ.COAL.CLCONT.<scenario>.<datekey>. This file contains data describing existing electric utility coal contracts. The information is organized similarly to the above inputs in groups of 26 numbers, each of which expresses the sum of contract demands specific to a supply region, demand region, and coal type for a given year. On inspection it will be seen that these demands (they are expressed in trillion Btu) decline to zero before the 26th year. These contract demands are indexed, from left to right, by line number, cds demand region, coal type, and supply region.

6005PRJ.COAL.CLNODES.<scenario>.<datekey>. This file contains labels for coal distribution origins and destinations, that is, two-letter and full alphabetic designations for the supply and demand regions in the model.

6005PRJ.COAL.CLPARAMS.<scenario>.<datekey>. This file contains 11 arrays and vectors. They are described and identified in the order of their appearance. The first array is named "COAL" and contains labels for the CMM coal types.

The next array is a parameter named "BSRZR" that is used to adjust transportation rates by demand region and economic sector. These adjustment factors are indexed at the left by CDS demand region number. Each indexed group of 23 represents the array of subsectors in the CDS, beginning with the Residential/Commercial subsector and terminating with the synthetic fuel subsector. "BSRZR" is produced by an off-line program that uses historical delivered prices and minemouth prices generated by the CPS to determine the transportation rate adjustment that will provide the correct delivered price in the base year of the forecast period (1990 in the *Annual Energy Outlook 1994*).

"BSRZR" is followed by "Sector", a column vector of alphabetic labels for the 23 economic subsectors in the CDS. "Sector", in turn, is followed by a pair of row vectors, "IFED" and "ISEC". "IFED" assigns the 23 CDS demand regions to the 9 Census divisions, while "ISEC" assigns the 23 CDS economic subsectors to the 6 NEMS economic sectors (Residential/Commercial, Industrial steam, Industrial metallurgical, Exports, Electric Utility, and Synthetic fuels).

These vectors are followed by an array defining a parameter named "KCNUR", which is indexed with the demand region numbers and their two-letter alphabetic abbreviations. "KCNUR" assigns coal groups to residential/commercial, industrial steam, and metallurgical coal economic subsectors which are represented, in that order, by the first six columns of integers. These values are followed by three columns of rational numbers, the demand shares by region for the three industrial subsectors. (The identical set of shares is found in the CLSHARES input file and is described above.)

"KCNUR" is followed by a pair of vectors defining transportation cost escalation trends during the 26-year forecast horizon. These are named "BTR" and "BTW" and represent, respectively, rail and water transportation cost escalators. Since the current version of the CPS does not distinguish between coal transportation modes, only the first vector, "BTR", is in use.

"BTR" and "BTW" are followed by another parameter, "CSDISC", which is used to adjust minemouth prices to reflect regional labor productivity changes during the forecast period. "CSDISC" is indexed by the two-letter alphabetic code abbreviations for the 16 CMM coal supply regions, with each group containing a value for each of the 26 forecast horizon years.

"CSDISC" is followed by another parameter used to assign coal groups to the 12 electric utility sectors assigned to demands by coal type. This parameter, "KCUR", is indexed by demand region, but the coal group assignments do not vary among the regions. The first 12 coal groups defined are always assigned to these economic subsectors, so that the "KCUR" array is simply the integers 1 through 12 repeated 23 times.

The parameter "ICSET" follows "KCUR", and it is used to define the 30 coal groups currently in use. "ICSET" is indexed by the number of the coal group being defined, and lists the numbers of the coal types assigned to each group. The identity of the coal types in the coal group can be obtained by referring to the first array in the CLPARAMS file, "COAL", which lists the names of the coal types. By starting at the upper left hand corner of "COAL", and counting across the row and to the right, then starting at the left hand side of the second row and counting to the right, etc., 32 coal types are identified. The integer numbers defining coal groups in "ICSET" are identical to these numbers. Coal groups serve to limit competition between coal types in the model and are used to represent the technical and regulatory limitations on substitution of different coals in the different economic sectors and demand regions.

The last parameter in the CLPARAMS file, a row vector named "ISUL" assigns the 4 sulfur levels to the 32 coal types.

Listing of Parameters and Variables in the CDS

Table A-1. Parameter List for CDS (source: CDS)

NCOALTYP=32	Number of coal types
NCSET=22	Number of coal sets available
NCUTSET=12	Number of coal utility sets
NFYRS=26	Number of forecasted years
NINTJOBS=600	Maximum number of intermediate demand jobs
NMAXCTRK=600	Maximum number of contracts
NMAXCURV=300	Maximum number of supply curves
NMAXDJOB=900	Maximum number of demand jobs
NMAXEXPT=40	Maximum number of export demands
NMAXPART=20	Maximum number of participants per demand job
NMAXSTEP=4000	Maximum number of curve steps
NSREG=16	Number of coal supply regions
NTOTDREG=23	Total number of demand regions
NTOTSECT=23	Total number of demand sectors
NUTSEC=12	Number of utility sectors

Table A-2. Variables for Common Block CDSCOM1 (source: CDS)	
CPSBF	Total minemouth price in 1987 $/ton
CQEXP	Total export demand in trillion Btu
CQSBFB	Coal production by CDS supply regions in million Btu
CQSBFT	Conversion factor for coal production in million Btu/ton
CSIMP	Coal imports (sector 1=utility, 2=industrial)
PDIN1R	Industrial delivered price in 1987 $/million Btu
PDMT1R	Metallurgical coal delivered price in 1987 $/million Btu
PDRC1R	Residential/commercial delivered price in 1987 $/million Btu
PDUTZR	Utility delivered price by utility sector in 1987 $/million Btu
QDIN1R	Industrial demand in trillion Btu
QDMT1R	Metallurgical coal demand in trillion Btu
QDRC1R	Residential/commercial demand in trillion Btu
QDUTZR	Utility demand by utility sector in trillion Btu
BTUTZR	Btu conversion factor for utility sectors in million Btu/ton
SOUTZR	SO_2 content for utility sectors in lb/million Btu
IMPBTU	Import total in trillion Btu by census divisions
IMPTON	Import total in million tons by census divisions
IMPBTUC	Import total in trillion Btu by CDS demand regions
IMPTONC	Import total in million tons by CDS demand regions
TONN	Import tonnage in million tons
EDYRS	Export demand in trillion Btu
IEDR	Demand region index for export sector
IEDZ	Demand sector index for export sector
IEDC	Coal set index for export sector

Table A-3. Variables for Common Block CDSCOM2 (source: CDS)	
RSBTU(NMAXCURV)	Btu content in million Btu/ton
RSULF(NMAXCURV)	Sulfur content in lb/million Btu
VSCUR(NMAXCURV)	Production by supply region/coal type
PSRNG(NMAXCURV)	Minemouth price in 1987 $/ton
USV(NMAXSTEP)	Upper limit before step invoked
BSV(NMAXSTEP)	Slope of supply curve segment
ASV(NMAXSTEP)	Y-Intercept for supply step
DSYRS(NMAXCURV,NFYRS)	Depletion amount by supply region/coal type/years
PD40(NTOTSECT,NDREG)	Coal price for all demand sectors in 1987 $/million Btu
BT40(NTOTSECT,NDREG)	Coal Btu conversion factors for all demand sectors
SO40(NTOTSECT,NDREG)	Coal SO_2 content for utility sectors in lb/million Btu
QDL(NMAXDJOB)	Coal demand per demand job in trillion Btu
SDL(NMAXDJOB)	Shift factors for QDL (see immediately above)
DTJL(NMAXPART,NMAXDJOB)	Coal demand requirement by coal type in million tons
TIJL(NMAXPART,NMAXDJOB)	Coal assigned by coal type in million tons
YDL(NINTJOBS)	Intermediate demand list used for merge in trillion Btu
CDYRS(NMAXCTRK,NFYRS)	Utility contract demand in trillion Btu
EDYRS(NMAXEXPT,NFYRS)	Export demand in trillion Btu
BSRZR(NTOTSECT,NDREG)	Rail route multipliers
BTR(NFYRS)	Network rail rate multiplier
BTW(NFYRS)	Network water rate multiplier
XC(NCSET)	Contract demand in trillion Btu
XT(NCSET)	Utility demand in trillion Btu

Table A-3. Variables for Common Block CDSCOM2 (Continued)	
XCH(NCSET)	Sum of contract demand indexed by coal set (trillion Btu)
XTH(NCSET)	Sum of utility demand indexed by coal set (trillion Btu)
IMPBTU(10,3,NFYRS)	Import Btu quantity totals in trillion Btu
CSDISC(NSREG,NFYRS)	Productivity adjustment factors
FRADI(3,NDREG)	Fraction for three industrial sectors
QIND(2,NDREG)	Industrial demand (1=exist, 2=new)
IMPTON(10,3,NFYRS)	Import tonnage totals in million tons
TONN(10,3,NFYRS)	Import tonnage in million tons
NODES(5,600)	Node names
SECTOR(3,NTOTSECT)	Sector name
TITLE(20)	First title
TITLE2(20)	Second title
COAL(NCOALTYP)	Coal type code
SUPRGN(NSREG)	Supply region
DEMRGN(NTOTDREG)	Demand region
ISVR(NMAXCURV)	Supply region index
ISVC(NMAXCURV)	Coal type index
KSVND(NMAXCURV)	Pointer to last active supply step
KCLR(NMAXCURV)	Linked-list pointers to supply curves by coal type
MCLR(NCOALTYP)	Top of the list for KCLR
IDLR(NMAXDJOB)	Index of demand region by demand job
IDLZ(NMAXDJOB)	Index of demand sector by demand job
IDLC(NMAXDJOB)	Index of coal sets (groups) by demand job
IDLCNT(NMAXDJOB)	Contract line number
JTPH(NMAXDJOB)	Index of highest cost route
MTJ(NMAXDJOB)	Number of routes for job
KXT(NMAXPART,NMAXDJOB)	Pointer to active route for demand job
ISTJ(NMAXPART,NMAXDJOB)	Index of supply region by route and demand job
ICSET(NCSET,NCOALTYP)	Coal set indices
JTPL(NMAXDJOB)	Index of lowest cost route
ICSR(NMAXDJOB)	Contract supply region
KCNUR(6,NDREG)	Indices of coal sets for nonutility demands
IYLR(NINTJOBS)	Index of intermediate demand list region
IYLZ(NINTJOBS)	Index of intermediate demand list sector
IYLC(NINTJOBS)	Index of intermediate demand list coal set

Table A-3. Variables for Common Block CDSCOM2 (Continued)	
ICD(NMAXCTRK)	Contracted demand region
MDLZ(NMAXCTRK)	Index of contract sector
ICS(NMAXCTRK)	Index of supply region for contract
ICC(NMAXCTRK)	Index of coal set for contract
IEDR(NMAXEXPT)	Demand region index for export sector
IEDZ(NMAXEXPT)	Demand sector index for export sector
IEDC(NMAXEXPT)	Coal set index for export sector
KCUR(NUTSEC,NDREG)	Indices of coal sets for utility demands
ISUL(NCOALTYP)	Coal type sulfur
IFED(NTOTDREG)	Converts CDS demand region index to census division index
ISEC(NTOTSECT)	Converts demand sector index to IFFS sector index
NDRX	Number of demand regions
NNCSET	Number of coal sets

Table A-4. Variables for Common Blocks for CPS/CDS (sources: CPS and CDS)	
CDS_RECORDS	Number of records in the file for the CDS
CDS_SR	Numeric region code used in CDS file
CDS_DR	Numeric demand region code (CDS file)
CDS_CT	Numeric coal type code (CDS file)
CDS_DS	Numeric demand sector code (CDS file)
CPS_NCUR	Number of supply curves for CPS
CPS_REG(300)	Numeric region codes for CPS
CPS_CTYPE(300)	CDS numeric codes for coal types
CDS_QTY	Coal shipments in million tons
CPS_YINT1(300)	Y-Intercept for the first segment of the supply curve
CPS_SLOPE1(300)	Slope for the first segment of the supply curve
CPS_PEND1(300)	Production at the end point of the first segment of the supply curve
CPS_SURCAP(300)	Production at the endpoint of the second segment of the supply curve
CPS_RINTER2(300)	Constant in the supply curve
CPS_RMULT(300)	Coefficient in the supply curve
CPS_NMCUTIL(300,3)	Exponent1 in the supply curve
CPS_MCUTILX(300,3)	Exponent2 in the supply curve
CPS_YINT3(300)	Y-Intercept for the third segment of the supply curve
CPS_SLOPE3(300)	Slope of the third segment of the supply curve
CPS_PEND3(300)	Production at the end point of the supply curve
CPS_LPROD(300)	Labor productivity
CPS_BTU(300)	Average Btu content for the supply curve in million Btu/ton
CPS_SULFUR(300)	Average sulfur content for the supply curve in lb/million Btu
P_RECORDS	Number of records in capacity file for the CDS
P_SR(2000)	Numeric supply region code for capacity used in the CDS
P_DR(2000)	Numeric demand region code for capacity (CDS file)
P_CT(2000)	Numeric coal type code for capacity (CDS file)
P_DS(2000)	Numeric demand sector code for capacity (CDS file)
P_QTY(2000)	Coal capacity in million tons
P_ISVR(300)	Supply region index for capacity
P_ISVC(300)	Coal type index for capacity
P_KSVND(300)	Pointer to last active capacity step
PWL_CURV	Total number of capacity curves
PWL_REC	Total number of capacity curve steps

Table A-4. Variables for Common Blocks for CPS/CDS (Continued)	
P_USV(4000)	Upper limit of capacity before step invoked
P_BSV(4000)	Slope of capacity curve segment
P_ASV(4000)	Y-intercept for capacity step
P_BTU(300)	Average Btu content for capacity curve in million Btu/ton
P_SULFUR(300)	Average sulfur content for capacity curve in lb/million Btu
FIRSTFLG	Flag to control sequence of capacity calculations

Table A-5. Variables for Common Block CDSSHR (source: CDS)	
CDSIN(NDREG,MNUMCR)	Industrial sector share factors
CRSIN(2,MNUMCR)	Industrial type fractions (1=existing, 2=new)
CDSRC(NDREG,MNUMCR)	Residential/commercial sector share factors
CDSMC(NDREG,MNUMCR)	Metallurgical coal sector share factors
CDSUT(NDREG,12)	Utility sector share factors
NERC(NDREG)	NERC index

Table A-6. Variables for Common Block CDSFMGR (sources: CPS and CDS)	
IUNIT	Unit for WRITE statement
IUNITDB	Unit to WRITE to the debug file
IUNITDS	Unit to WRITE to the CDS file
FILE_MGR	File manager

Table A-7. Variables for Coal Module Output Common Block (source: CDS)	
COTN_TM(MNUMCR,MNUMYR)	1 Coal transportation ton-miles
COPRCLQ(MNUMCR,MNUMYR)	2 Supply of coal liquids
COPRCLG(MNUMCR,MNUMYR)	3 Supply of coal gases
COIM(MNUMXR,MNCLTYPE,MNUMYR)	4 Coal exports
COIMP(MNUMXR,MNCLTYPE,MNUMYR)	5 Coal export prices
COCCLQ(MNUMCR,MNUMYR)	6 Delivered costs of coal liquids
COCCLG(MNUMCR,MNUMYR)	7 Delivered costs of coal gases
COSUPC(MNUMXR,MNCLTYPE,MNUMYR)	8 Coal supply curves
COELPRC(MNUMNR,MNUMYR)	9 Utility coal price
CLSYNGPR(17,MNUMYR)	10 Coal synthetic natural gas price
CLSYNGQN(17,MNUMYR)	11 Coal synthetic natural gas quantity
CQSBB(3,MNUMYR)	12 Coal production (East,West Miss,U.S.) in trillion Btu
CQSBT(3,MNUMYR)	13 Coal Btu conversion factor for production in million Btu/ton
CPSB(3,MNUMYR)	14 Coal minemouth price in 1987 $/ton
CQDBFT(MNUMCR,6,MNUMYR)	15 Coal conversion factor for Consumption in million Btu/ton
CQDBFB(MNUMCR,6,MNUMYR)	16 Coal consumption in trillion Btu
CELNR(NDREG,MNUMYR)	VLS bituminous coal price by CDS regions in 1987 $/million Btu
PBDELNR(NDREG,MNUMYR)	LS bituminous coal price by CDS regions in 1987 $/million Btu
PBMELNR(NDREG,MNUMYR)	MS bituminous coal price by CDS regions in 1987 $/million Btu
PBHELNR(NDREG,MNUMYR)	HS bituminous coal price by CDS regions in 1987 $/million Btu
PSCELNR(NDREG,MNUMYR)	VLS subbituminous coal price by CDS regions in 1987 $/million Btu
PSDELNR(NDREG,MNUMYR)	LS subbituminous coal price by CDS regions in 1987 $/million Btu
PSMELNR(NDREG,MNUMYR)	MS subbituminous coal price by CDS regions in 1987 $/million Btu
PSHELNR(NDREG,MNUMYR)	HS subbituminous coal price by CDS regions in 1987 $/million Btu
PLCELNR(NDREG,MNUMYR)	VLS lignite coal price by CDS regions in 1987 $/million Btu
PLDELNR(NDREG,MNUMYR)	LS lignite coal price by CDS regions in 1987 $/million Btu

Table A-7. Variables for Coal Module Output Common Block (Continued)

PLMELNR(NDREG,MNUMYR)	MS lignite coal price by CDS regions in 1987 $/million Btu
PLHELNR(NDREG,MNUMYR)	HS lignite coal price by CDS regions in 1987 $/million Btu
BBCELNR(NDREG,MNUMYR)	VLS bituminous coal Btu factor by CDS regions in million Btu/ton
BBDELNR(NDREG,MNUMYR)	LS bituminous coal Btu factor by CDS regions in million Btu/ton
BBMELNR(NDREG,MNUMYR)	MS bituminous coal Btu factor by CDS regions in million Btu/ton
BBHELNR(NDREG,MNUMYR)	HS bituminous coal Btu factor by CDS regions in million Btu/ton
BSCELNR(NDREG,MNUMYR)	VLS subbituminous coal Btu factor by CDS regions in million Btu/ton
BSDELNR(NDREG,MNUMYR)	LS subbituminous coal Btu factor by CDS regions in million Btu/ton
BSMELNR(NDREG,MNUMYR)	MS subbituminous coal Btu factor by CDS regions in million Btu/ton
BSHELNR(NDREG,MNUMYR)	HS subbituminous coal Btu factor by CDS regions in million Btu/ton
BLCELNR(NDREG,MNUMYR)	VLS lignite coal Btu factor by CDS regions in million Btu/ton
BLDELNR(NDREG,MNUMYR)	LS lignite coal Btu factor by CDS regions in millio n Btu/ton
BLMELNR(NDREG,MNUMYR)	MS lignite coal Btu factor by CDS regions in million Btu/ton
BLHELNR(NDREG,MNUMYR)	HS lignite coal Btu factor by CDS regions in million Btu/ton
SBCELNR(NDREG,MNUMYR)	VLS bituminous coal sulfur factor by CDS regions in lb/million Btu
SBDELNR(NDREG,MNUMYR)	LS bituminous coal sulfur factor by CDS regions in lb/million Btu
SBMELNR(NDREG,MNUMYR)	MS bituminous coal sulfur factor by CDS regions in lb/million Btu
SBHELNR(NDREG,MNUMYR)	HS bituminous coal sulfur factor by CDS regions in lb/million Btu
SSCELNR(NDREG,MNUMYR)	VLS subbituminous coal sulfur content by CDS regions in lb/million Btu
SSDELNR(NDREG,MNUMYR)	LS subbituminous coal sulfur content CDS regions in lb/million Btu
SSMELNR(NDREG,MNUMYR)	MS subbituminous coal sulfur content by CDS regions in lb/million Btu

Table A-7. Variables for Coal Module Output Common Block (Continued)

SSHELNR(NDREG,MNUMYR)	HS subbituminous coal sulfur content by CDS regions in lb/million Btu
SLCELNR(NDREG,MNUMYR)	VLS lignite coal sulfur content by CDS regions in lb/million Btu
SLDELNR(NDREG,MNUMYR)	LS lignite coal sulfur content by CDS regions in lb/million Btu
SLMELNR(NDREG,MNUMYR)	MS lignite coal sulfur content by CDS regions in lb/million Btu
SLHELNR(NDREG,MNUMYR)	HS lignite coal sulfur content by CDS regions in lb/million Btu

Table A-8. Variables for Coal Module Report Common Block (sources: CDS and CES)	
US	Total number of export demands
EXPQTY(MAXDEMD,MNUMYR)	Demand in trillion Btu
EXPCST(MAXDEMD,MNUMYR)	Cost in dollars per million Btu
CDRE(MAXDEMD)	Demand region index
CDSE(MAXDEMD)	Demand sector index
CDGR(MAXDEMD)	Demand coal group index

Output and Composition of Reports

Current output from the CDS falls into three categories:

- From CDS generated data, the NEMS system currently generates four reports in the NEMS table array (Tables 10, 71, 72, and 79).

- An output file (&6005PRJ.@.COAL.CLCDS.<scenario>.<datekey>) that currently contains 17 year-specific detailed reports. These reports are intended for use in model diagnosis, calibration and to provide detailed output for special studies. This group of tables is still under development and is planned to total 31 reports when complete. Only those currently operational are reviewed in this appendix. For diagnostic purposes, the reports in this file may be generated for each iteration of the CDS.

- A second file contains output showing the performance of the CDS fortran code and is used for diagnostic purposes (&6005PRJ.@.COAL.CLDEBUG.<scenario>.<datekey>.

NEMS Tables from the CDS

Prices and quantities produced by the CDS occur throughout the NEMS tables. However, the bulk of CDS output is reported in four NEMS tables dedicated entirely to coal: Tables 10, 71, 72 and 79. These reports are organized to show selected NEMS coal quantities and prices for each year in the forecast period. Table 10, "Coal Supply, Disposition, and Prices" shows:

- Production east and west of the Mississippi River 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 electric utility sectors plus total domestic consumption in millions of short tons

- Annual discrepancy (including the annual stock change, which in coal can exceed 25 million tons per year)

- 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 electric utility sectors, and the weighted average for these three sectors

- Average free-alongside-ship price for exports, i.e., the dollar-per-ton value of exports at their point of departure from the United States.

Table 71, "Domestic Coal Supply, Disposition and Prices by Case," occurs in a national version (where it repeats the consumption, delivered price and discrepancy numbers for the domestic coal consuming sectors that are shown in Table 10) and in nine regional versions for the Census divisions. In addition to sectoral consumption and prices, this table shows the regional origin of coal consumed in the Census division for six aggregated supply regions: Northern and Southern Appalachia, the Interior, the Northern Great Plains, Other West and Non-Contiguous. Imports are also shown for each Census division, so that the total of domestic and import supply adds to total coal supply. Neither the national nor Census division versions of Table 71 show exports.

Table 72, "Coal Production and Minemouth Prices By Region," provides annual summaries of national distribution from the same aggregated supply regions used in Table 71, 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 subtotals

Table 79, "NEMS Regional Coal Production," provides a detailed report of regional production (Appalachia, Interior, and Western Production) by coal rank (Bituminous, Subbituminous, Lignite) and sulfur level (low, medium, and high). This report allows the reader to track production shifts throughout the forecast period, summarizing the response of the Coal Market Module to shifts in demand as a result of the Clean Air Act Amendments of 1990.

Other outputs from the Coal Distribution Submodule occur in a number of NEMS tables. National coal production, consumption, and exports are reported in quadrillion Btu in NEMS Table 1, as is the minemouth price of coal in dollars per ton (Table 10). Annual energy consumption for the Residential, Commercial, Industrial (both industrial steam and coking consumption are shown) and the Electric Utility sector in quadrillion Btu are shown in NEMS Table 2. Table 3 gives delivered coal prices for these same sectors in dollars per million Btu. NEMS Table 96 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 Electric Utility).

Single Year Detailed Reports from the CDS

These detailed reports begin with three summaries of the demands received by the CDS for each sub-sector and region. These demands, shown in trillions of Btu, are indexed to both the CDS region and Census Division in which they occur by region number. These summaries are divided into a single-page report for the non-electric utility sectors, a single-page report for the 12 electricity sub-sectors that represent different coal Btu and sulfur coal categories, and a single-page report summarizing electric utility demands by region, coal rank category, and coal sulfur level.

The nonutility demand report is structured as follows, reading the columns from left to right:

- Census division index number, repeated to allow separate indexing of each CDS demand region in each Census division, with subtotals for each Census division; the CDS demand region index number

- Residential/Commercial demands, by region

- Demands for the each of the three industrial demand subsectors are listed in three columns; then the total industrial demand is listed in a fourth; the fifth column for industrial demand contains the import supplies that have been subtracted from industrial demand

- Demands for the two metallurgical subsectors are listed with the subtotal for both subsectors and the import supplies that are subtracted from metallurgical demand

- Export demands for the three export subsectors and the subtotal for all export demands

- Total of all nonutility demand.

The Nonutility Demand Report is immediately followed by the Utility Demand Report, again indexed by Census division and CDS demand region with subtotals by Census division. Here the columns represent demands in each of the 12 electric power utility sectors that are keyed to individual coal types. (The Electricity Market Module does not distinguish between coals of "P" and "B" Btu content, so that all such demands are listed as "B" coal demand.) In comparing the demands in this report with the supplies provided (which can be traced in the Detailed Supply and Price Report discussed below), it should be noted that electric power demands for, say, "BM" coal can be met by lower sulfur coals if it is less expensive to do so.

The Utility Demand Report is followed by the Utility Summary Demand Report, which provides demand totals by region for bituminous, subbituminous and lignite coals, and for low, medium, and high sulfur coals. Only coals of "C" or "Compliance" sulfur level—less than or equal to 0.6 lbs sulfur per million Btu—are reported as low sulfur coals. Similarly, only coals of "H" or "High" sulfur content—greater than 1.67 lbs sulfur per million Btu—are treated as high sulfur coal. The remaining two sulfur categories, "D" and "M" are reported as medium sulfur coal.

The next report, the CDS Detailed Supply and Price Report, describes each demand met by the model in the year described and shows each participant that contributes to the supply for every demand. It shows the coal shipped to each demand by each participant in millions of short tons. The demands are shown in millions of short tons and trillion Btu. This report also contains the adjusted minemouth price for each participant, the origin of the coal shipped, the type of coal shipped, and the associated transportation rate. Average prices and total quantities are provided for the major sectors in each demand region. This report is 35 to 50 pages in length, depending on the year and scenario reported.

Following the Detailed Supply and Price Report, coal distribution is shown in a series of spreadsheets where rows represent demand regions and columns supply regions. Each of these reports is three and one-half pages in length and reports, for each supply/demand region pair, the tonnage shipped and the minemouth, transport, and delivered prices in dollars per million Btu. Currently, these reports are operational for the industrial, export, and utility sectors and for total coal distribution.

These reports are currently followed by a spreadsheet "Total Transportation Report." As currently formatted, this report shows only the tonnage shipped and the transport rate in dollars per ton. It is planned to modify this report to show the rates charged for transport between the regions for each major sector. All rates in this report will be reported in dollars per ton.

The distribution spreadsheets are followed by three single-page regional summary production reports. The first shows regional production and minemouth price (in millions of short tons and dollars per ton, respectively) by mine type. The second shows the same items by coal rank, while the third shows them by coal sulfur level.

These summary reports are followed by the Detailed Coal Production Report, showing the production, minemouth price, total energy content and Btu conversion factor for all supply curves used in the reported year. The report is formatted to show the sulfur and ash levels also, but these have not been programmed into the report at this date. This report, which is five and one-half pages long, is also formatted as a spreadsheet, with the coal types shown as rows and the supply regions as columns.

The Detailed Production Report is followed by the Census Division Report, which shows sectoral statistics by Census division and for the Nation. The statistics reported are production in millions of tons, demand in trillion Btu, and the sectoral average Btu conversion factor. The minemouth, transportation, and delivered prices are shown in dollars per ton, and the delivered price is also shown in dollars per million Btu. No prices are shown for imported coal since it is not priced in the model.

Three more summary reports follow the Census Division Report. These show the dollar-per-million-Btu delivered price, Btu conversion factor, and sulfur content of coal shipped to the utility subsectors. These reports are primarily of interest in diagnosing problems between the CMM and EMM, since, in effect, they provide a concise summary of data reported more extensively in other reports. These reports have the same format as the Utility Demand Report described above.

Appendix B

Detailed Mathematical Description of the Model

Introduction

The general objectives for CDS design have been overall simplicity and flexibility. These have been approached through adoption of simple classification structures and avoidance of detail which does not support modeling of policy issues. Functional capabilities may be added to meet emerging NEMS requirements without exceeding NEMS execution time requirements. The solution method used in the coal distribution model of the IFFS system, the Coal Supply and Transportation Model (CSTM) has been retained in the CDS because:

- It is fast enough to meet NEMS execution time requirements even after addition of new model functions for NEMS; the advantages of using, for example, one of the newer, very fast linear programming algorithms might not be fully realized given the size of the problem addressed by the CDS with its simplified classification structures.

- The CDS receives nonlinear input (most notably, capacity utilization—sensitive supply curves from the CPS), and this input cannot be linearized without significant expense and delay.

- The operating properties of the existing algorithm are well understood: it performs without "corner" solutions, converges reliably, and has few operational problems.

- In its current form it is sufficiently stable to allow use of its most detailed output in topical studies. While this will provide more detail than most NEMS uses require, such capability obviates the need to maintain and operate a more detailed model.

General Approach

The problem addressed by the CDS is to find the combination of delivered prices of coal and the matrix of coal shipments, or distribution, that will satisfy at minimum cost a fixed set of coal demands, given minemouth price functions (supply curves), transportation costs, and predetermined contract and coal group assignments. The minimum cost solution implies a pattern of coal supply, or production, coming from each of the coal supply regions by coal type. This production, in turn, determines the minemouth price of coal through the supply curves. Transportation costs are assumed fixed during a given year, but are adjusted exogenously over the forecast horizon using transport cost escalation adjustments. The solution algorithm is heuristic, and is specified in the following sections.

To clarify discussion of the CDS solution algorithm it is helpful to introduce two terms: "demand job" and "participant." A "demand job" is a demand specific to an economic sector in a particular demand region, for example, the demand for premium coking coal in western Pennsylvania. The CDS satisfies such a demand job by developing the least-delivered-cost combination of coal sources, where each source is represented by a minemouth price (from a supply curve) and a transport cost (from a shipment route). For example, total costs for the demand job might be minimized by selecting one or more coal source/route combinations from both Northern and Central Appalachia. Each such individual "shipment" combining a particular supply curve with a particular coal transport route is a "participant." A demand job is allowed up to 20 such participants in the current CSTM. More than one source/route combination may be needed because all minemouth prices vary directly with tonnage produced since all supply curves are upward sloping and continuous, but their rate of increase varies with the slope of each individual supply curve. Thus, even where transport costs are identical, the costs of different coals mined in the same supply region and delivered to the same demand region may vary significantly.

The CDS approaches the problem of simulating coal distribution by seeking to reach an equilibrium of delivered prices for all participants in each demand job. The formal conditions for completion of the CDS solution are that the delivered prices of each participant in a demand job be equal and that no delivered price can be lowered by shifting sources of supply or transport modes. These conditions are formally equivalent to minimizing the total delivered cost of coal.[98]

The subparts of the CDS solution method include both heuristic and exact algorithms. The objective of the solution method is to meet the formal conditions for completion within a prescribed tolerance. The solution algorithm is a decomposition approach in the style of Dantzig-Wolfe insofar as it consists of: (1) a master problem of balancing supply and demand on, and recosting of, existing routes, and (2) subproblems of finding least-cost solutions given prices supplied by the master problem.[99] Each subproblem is solved rigorously, since the shortest-path algorithm finds the least-cost participants, given the fixed prices supplied by shifting and recosting in the master problem. The master problem is solved heuristically, using rules for shifting route participation that have proved efficient in reaching convergence over a decade of use in the Coal Supply and Transportation Model. Since the sum of a route's transportation and minemouth costs is increasing and continuous as quantity demanded increases, it is to be expected that shifting participation in small increments will eventually reach equilibrium. The combination of a shortest path algorithm with an equilibrium assignment algorithm is a technique developed for freight network equilibrium models in the 1970's.[100]

Variable Definitions

S	=	a set of supply sources, where each source is a type of coal produced in a supply region.
F_i	=	million Btu/short ton of coal from source i.
$P_{i(\cdot)}$	=	supply curve for source $i \epsilon S$. The units for the supply curve are million Btu produced and \$/million Btu minemouth prices.[101]
D	=	a set of demand jobs, where each job is an amount of coal Btu that must be satisfied (for the purpose of this discussion it is assumed that all coal types may satisfy all demands).[102]

[98]Energy Information Administration, *Coal Supply and Transportation Model: Model Description and Data Documentation*, DOE/EIA-0401 (August 1983), Appendix D.

[99]See, for example, Donald P. Gayver and Gerald I. Thompson, *Programming and Probability Models in Operations Research* (Wadsworth, 1973), Section 5.3.

[100]Bronzini, Michael S., "Evolution of a Multimodal Freight Transportation Network Model," *Proceedings - Twenty First Annual Meeting, Transportation Research Forum*, Vol. XXI, Number 1 (Philadelphia, PA, 1980), pp. 475-485.

[101]The minemouth price for coal produced by source i is the sum of a nonlinear, continuous, and increasing function of reserve depletion and a nonlinear, continuous, and unbounded function of mine capacity utilization at source i. For a detailed discussion of the formulation of the minemouth prices used in the NEMS Coal Market Module, the reader should refer to the documentation for the Coal Production Submodule.

[102]This is not actually the case. Constraints exogenous to the solution algorithm ensure that specific demands can be met only by suitable coals. Methodology employed to simulate the limited intersubstitution potential of different coals is discussed in Chapter 3.

R_{ij} = a set of transport routes connecting supply source i to demand job j. Each member $k \in R_{ij}$ denotes a route from a supply region to a demand region using a specific transport mode.

T_{ijm} = a transport cost associated with a route connecting supply source i with demand job j by transport mode m.

Q_{ijm} = the amount of coal shipped from source i to demand job j via transport mode m, in millions of Btu. Similarly, Q_i is the amount produced at source $i \in S$, and Q_j is the amount of coal mined at source i and demanded for job j; q is the continuous form of the quantity variable introduced for purposes of integration.

Since a demand job may be satisfied by coal drawn from more than one supply source and such coal may be shipped by more than one transport mode from single or multiple sources, and since more than one demand job may draw coal from a given supply source and/or use a specific transport route and mode, the volume shipped, in tons, may be written as V_{ijm} where:

$$V_{ijm} = \sum_{i \in S} \sum_{j \in D} \sum_{m \in R_{ij}} (Q_{ijm}/F_i) \qquad (1)$$

Mathematical Specification and Objective Function

In the CDS, the market is assumed to operate in such a way that:

- Each demand job activates a new participant only if the delivered price in $/million Btu for that participant is lower than the prices for all other participants.

- The CDS continues to iterate until the delivered price of coal for all participants in a job is equal (within prescribed tolerance limits described later in this section).

Representing the final equilibrium price on demand job j by E_j, these conditions may be expressed mathematically, as follows:

$$[P_i(Q_i)+T_{ijm}(V_{ijm}/F_i)]-E_j \geq 0 \qquad (i \in S,\ j \in D,\ m \in R_{ij}) \qquad (2)$$

$$\{[P_i(Q_i)+T_{ijm}(V_{ijm}/F_i)]-E_j\}Q_{ijm} = 0 \qquad (i \in S,\ j \in D,\ m \in R_{ij}) \qquad (3)$$

The objective function for the CDS can now be written as:

Minimize:

$$Z = \{\sum_{i \in S} \int_0^{Q_i} P_i(q)dq \sum_{i \in S} \sum_{j \in D} Q_{ij} + \sum_{i \in S} \sum_{j \in D} \sum_{m \in R_{ij}} T_{ijm}\} Q_{ijm} \geq 0 \tag{4}$$

Subject to:

$$\sum_{i \in S} \sum_{m \in R_{ij}} Q_{ijm} = Q_j \qquad j \in D \tag{5}$$

(The quantity demanded equals the quantity mined and shipped),

$$\sum_{j \in D} \sum_{m \in R_{ij}} Q_{ijm} = Q_j \qquad i \in S \tag{6}$$

(The quantity mined equals the quantity shipped and demanded),

$$\sum_{m \in R_{ij}} Q_{ijm} = Q_{ij} \qquad i \in S,\ j \in D \tag{7}$$

(The quantity shipped equals the quantity mined and demanded).

The equivalence of this price equilibrium approach to the optimization approach can be shown. First it can be shown that price equilibrium is a necessary condition for equation (4). Associate the Lagrangean multipliers π_j, ψ_j, and ω_{ij} with constraints (5),(6), and (7) respectively. The necessary conditions associated with the variables Q_i, Q_{ij}, and Q_{ijm} are then as follows:

$$Q_i\ :\ P_i(Q_i)+\psi_i = 0 \tag{8}$$

$$Q_{ij}\ :\ \omega_{ij} = 0 \tag{9}$$

$$Q_{ijm}\ :\ T_{ijm}(V_{ijm})-\pi_j-\psi_i-\omega_{ij} \geq 0 \tag{10}$$

$$(T_{ijm}(V_{ijm}) - \pi_j - \psi_i - \omega_{ij})Q_{ijm} = 0 \tag{11}$$

Using (8) and (9) to eliminate ψ_j and ω_{ij} in (10) and (11), conditions (10) and (11) are seen to be equivalent to the mathematical statement of price equilibrium given in (2) and (3) above.

This solution is not unique. A solution exists because the supply curves are unbounded; their convexity guarantees that that solution is unique. The objective of the CDS is to find a set of production levels and volumes on transportation routes that satisfy (2) through (6) above. The discussion above shows that the price equilibrium approach of the CDS is equivalent to minimizing total system cost, and, therefore, the solution is a global optimum and equivalent to a linear programming solution of the same problem. A linear program would execute the "participation shift" that makes the greatest contribution to attaining the global minimum cost solution (i.e., over all demand jobs), then make the shift with the second greatest contribution, and so on.

In the CDS's participation shifting algorithm, all demand jobs' delivered costs are concurrently reduced until further improvements are impossible.[103]

Solution Technique

The overall flow of the CDS algorithm is shown in Figure B-1; the main parts are summarized below

- *Costing Calculations*. Minemouth prices for each coal supply curve are computed at the prevailing production levels. For the first iteration, these prices are effectively the y-intercept of the coal supply curves. Transportation costs are given.

- *Shortest Path Algorithm and Least Cost Participant Identification.* This algorithm determines the least cost supply source for each participant given prevailing production volumes. Transportation costs to a given demand region from all supply regions are added to each minemouth price for each coal type that meets the given demand group. The lowest value for a demand job is found. The result is the least cost participant for each demand job. The process is repeated for all demand jobs. In the first iteration, the demand job receives all of its supply from the least cost supplier. In subsequent iterations a portion of the demand is shifted from the highest cost to the lowest cost supplier.

- *Equilibrium Assignment Algorithm*. For each demand job, the lowest and the highest cost active coal sources and routes are identified and compared, and a "shift ratio" is calculated for each demand job. The shift ratio is the price of the highest cost participant divided by the price of the lowest cost participant in the demand job. The CDS retains the maximum shift ratio over all demand jobs. When the maximum ratio is greater than some predetermined value (say 1.01), then a new set of costs and participant shifting is computed. If the ratio is less than that value, then the model has reached convergence for that iteration.

The overall solution method has two pathways embedded in it. The recosting and shifting pathway is a heuristic procedure for moving small amounts of coal on each demand job in the direction of delivered price equilibrium. The shortest path algorithm is an exact solution to finding the least cost source/route for each demand region. In discussing the overall method, some additional notation will be required.

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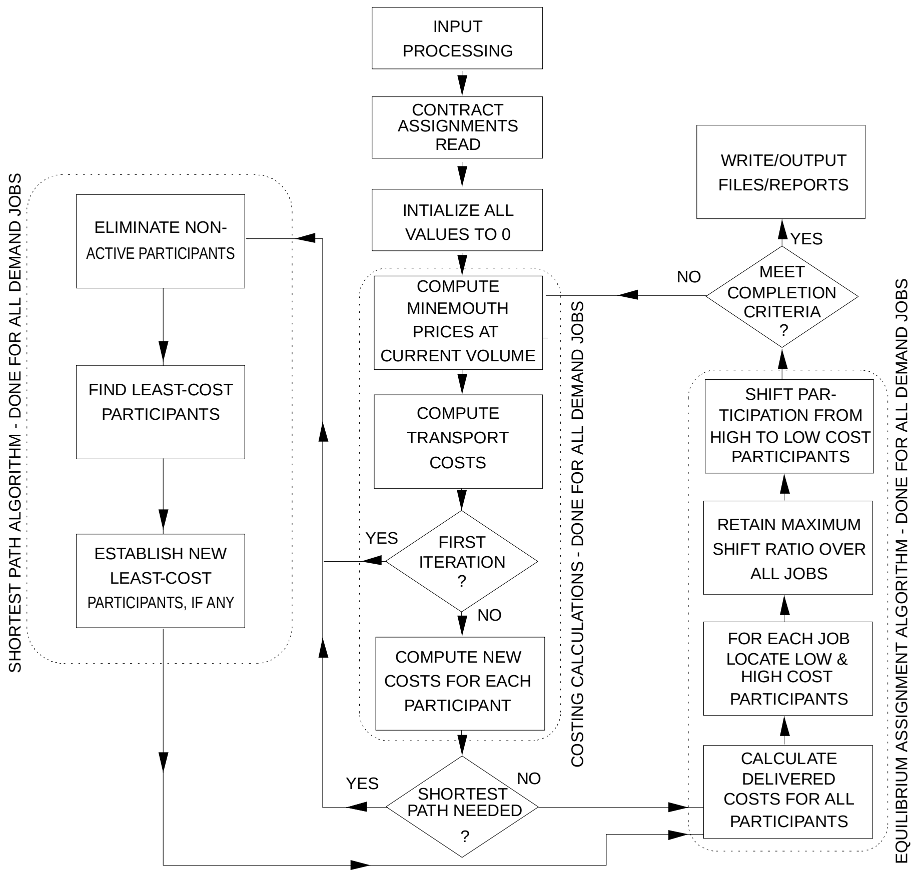
[103]The above discussion has been adapted to the CDS solution algorithm from Energy Information Administration, *Coal Supply and Transportation Model, Model Description and Data Documentation*," Appendix D., Theoretical Basis of the CSTM Algorithm" (Washington, DC, August 1983), pp. 173-176. See also: LeBlanc, L.J., E.K. Morlok and W.P. Pierskalla, "An Efficient Approach to Solving the Network Equilibrium Traffic Assignment Problem," *Transportation Research,* Volume 9 (1975), pp. 309-318 and Eash, R. W., B.N. Janson and D.E. Boyce, "Equilibrium Trip Assignment: Advantages and Implications for Practice," *Transportation Research Record*, #728 (Washington, DC, 1979), Passenger Travel Forecasting Transportation Research Board, NAS/NRC Commission on Sociotechnical Systems, pp. 1-8. As discussed elsewhere, coal carriers enjoy route-specific market power over delivered coal prices. The CDS must be able to model such power where it is significant, but can not assume its ubiquity. Since there are thousands of routes in use annually, endogenous route-specific modelling is not practical given NEMS performance and maintenance requirements. The CDS therefore treats transport costs using input base-year data escalated through the forecast period using exogenously prepared escalators for carrier- or route-specific analyses. The default option employs base year average mode-specific inter-regional costs computed as the difference between minemouth and delivered costs as determined on annual surveys such as the Forms EIA-3A, -5A and -7A, and the FERC Form 423, escalated using standard cost factors. Equation (4) implies that coal consumers are monopsonists with respect to coal producers, but not with respect to coal transporters. This monopsony power is limited by imperfect foresight in estimating mid-term demand (as in the two World Wars and the mid-1970s), by demand inelasticity due to technical limits on coal intersubstitution and by regulatory changes. Consumers may choose to limit the use of monopsony power through contract terms or other policies in order to reduce their decisionmaking costs (by ensuring more reliable service).

Figure B-1. CDS Solution Algorithm: Overall Flow



Notation

i	=	Coal source, a supply region
j	=	Demand region
k	=	Coal type
l	=	Coal group
m	=	Transport mode
n	=	Demand sector

"Coal Type" refers to a range of coal quality defined by coal heat content and sulfur content limits; "coal group" is a list of one or more "coal types" that may be used to satisfy a given demand. Individual supply curves each represent the quantity of a specific coal type available in a given coal supply region. Coal types are grouped to represent engineering and regulatory limitations on the inter-substitution of different coals. The coal groups may be modified periodically to reflect either changes in technological constraints or changes in EIA information concerning the regional market shares of different technologies. Such changes do not, however, affect the way in which coal groups are used in the model.

Input Variables

D_{jln} = Coal demand in demand region j for coal group l and demand sector n (a demand job). The coal group specifies a list of acceptable coal types. In general, this specification will define the maximum sulfur content and minimum Btu content required to meet that demand. More than one coal type may meet the requirements of a given coal group. Since supply regions usually contain both surface and deep mine supply curves for a given coal type, a region often has two sources of the same coal type, with different minemouth prices at any level of demand.

$f(S_{ik})$ = Coal supply function relating the price of coal type k in supply region i to supply, or production, of that coal.

T_{ijmn} = Transportation cost from supply region i to demand region j and demand sector n by transportation mode m.

C_{ijlmn} = Specified contract quantity of coal group l from supply region i to demand region j and demand sector n by transportation mode m. The coal contracts in the CDS are existing electric utility contracts, as determined from the descriptions of coal origins, destinations, coal quality and quantity, and contract expiration dates as described on FERC Forms 423 and 580. After these contracts expire, the pattern of coal supply to meet demand is determined by delivered cost minimization as constrained by the coal groups.

M_{ik} = Minemouth price of coal type k in supply region i.

Output Variables

P_{ijkmn} = delivered price of coal of type k from supply region i to demand region j and demand sector n by transportation mode m.

S_{ik} = supply of coal type k in supply region i (the quantity of coal on a supply curve).

Q_{ijkmn} = shipments of coal type k from supply region i to demand region j and demand sector n by transportation mode m (a participant).

Other Variables Used

LC_{jln} = price of the least cost supply/transport source of coal of group l to demand region j and demand sector n

$\triangle_{jln}$ = quantity of demand moved from the highest cost supplier to the lowest cost supplier during the participant-shifting algorithm

F = a set of fractions used in the participant-shifting algorithm to compute $\triangle_{jln}$

R_{jln} = the ratio of the price of the highest cost supplier to the lowest cost supplier, computed during the CDS convergence test

Step 1: Cost Calculations

The first step in the CDS solution algorithm is to compute the matrix of all delivered prices of coal of a given type from each supply region to each demand region and sector by each transportation mode:

$$P_{ijkmn} = M_{ik} + T_{ijmn}$$

where

$$M_{ik} = f(S_{ik})$$

Minemouth prices are a function of the quantity supplied. In the first iteration, the minemouth price is calculated assuming a zero volume of supply for all producers (i.e., the minemouth price is the y-intercept of the supply function). In subsequent iterations, if a positive supply of coal type k from that region is required, the price is an increasing function of supply. Transportation costs are fixed within a given year.

During the first iteration, contracts must also be matched with demand. Demand must match the contract in terms of demand region, demand sector, and coal group. Since each contract has a price associated with it from the costing calculations, the algorithm determines the least cost contract to meet matching demand. Under the simplifying assumption that there is only one contract that meets each demand.

$$Q_{ij,k\in l,mn} = C_{ijlmn} \text{ for each matching demand where } C_{ijlmn} \leq D_{jln} \text{ for all i and m}$$

$$Q_{ij,k\in l,mn} = D_{jln} \text{ for each matching demand where } C_{ijlmn} > D_{jln} \text{ for all i and m}$$

When the costing calculations are complete, a test is applied to determine which of the two solution method pathways to use next.

Step 2: Test for Use of Shortest Path Algorithm

Since the shortest path algorithm requires more computer time than the recosting of supply sources and transportation routes, it is performed only for selected iterations. Use of the shortest path is forced on the first iteration of each model run, since the participation shifting algorithm (which is required for convergence), depends on the presence of costed participants created by the shortest path algorithm. The number of model iterations between subsequent executions of the shortest path algorithm is determined each time the algorithm is executed as:

$$ITST \quad = \quad 60 - (5 * IC)$$

where *IC* is the total number of new least cost participants generated by the last execution of the shortest path algorithm. A minimum value for *ITST* is determined (it is currently set at 15) so that participation shifting and recosting will move the CDS toward equilibrium before the shortest path algorithm determines if new least cost participants have arisen. If no new participants have been created (*IC* = 0), the number of iterations before the next computation of the shortest path algorithm is 60. This formula proved to be efficient in the Coal Supply and Transportation Model; it will be modified as dictated by experience with the CDS.

Step 3: Shortest Path Algorithm

The shortest path algorithm is initialized prior to the introduction of coal demand. The values used to compute initial minemouth prices are the y-intercepts of the coal supply curves.

Route- and mode-specific transport prices for a zero volume of coal supply are known based on the cost calculations in Step 1. Now the algorithm finds the least cost participant, or source/transport mode combination, that will meet each demand for a given coal group in a given demand region and sector.

$$LC_{jln} \quad = \quad \min_{i,k\epsilon l,m} (P_{ijkmn})$$

The least cost coal is found by examining each coal supply/transport mode combination that has a coal type matching the coal types in the coal group.

Step 4: Determining Shipment Quantities

The CDS now assigns the shipments of coal from each least cost participant to the given demand. For non-contract demands (and unfulfilled demand in the case where a matching contract is less than the given demand requirement), quantities are computed for each least cost participant. In the first iteration,

$$Q_{ij,k\epsilon l,mn} = \quad D_{jln}$$

for the least cost participant. In the second and subsequent iterations, if there is more than one participant (i.e., if new least cost participants are found in Step 3) a portion of demand is shifted from the highest cost to the lowest cost participant.

$$\triangle_{jln} \quad = \quad D_{jln} \bullet F$$

The highest cost participant decreases its shipments by $\triangle$, and the lowest cost participant increases its shipments by $\triangle$, thus bringing delivered prices closer together. F is a set of "rule-of-thumb" fractions based on changes in the participant set for each demand job. The members of F will be determined by experimentation; the current set in the CSTM is given in Table B-1.

Table B-1. CSTM Participation Shifting Rules for Determining Fraction of Demand to be Shifted from High-Cost to Low-Cost Coal Participants

Test Used	Description of Condition	Change in Fraction Shifted[a]
$JH = JTPH_j$ or $JL = JTPL_j$, but not both	Current high route or current low route matches previous	$SDLJ=SDLJ*1.01$
$JH = JTPL_j$ and $JL = JTPH_j$	Both current high route and current low route match previous	$SDL_J=SDL_J*1.5$
$JH = JTPL_j$ or $JL = JTPH_j$ but not both	Previous high route is current low route, or previous low route is current high route	$SDL_J=SDL_J*0.95$
$JH = JTPL_j$ and $JL = JTPH_j$,	Previous high route is current low route, or previous low route is current high route	$SDL_J=SDL_J*0.5$
All tests above are failed	Current low route and current high route are both different from both previous high and low routes	No change in fraction

Note: Variable definitions

JH = current high-cost route on job
JL = current low-cost route on job
$JTPH_J$ = previous high-cost route
$JTPL_J$ = previous low-cost route
SDL_J = fraction to be shifted from current high-cost route to current low-cost route

[a] SDL_J has a maximum value of 0.1.

After participant-shifting is completed, a test for convergence is performed. The ratio of the price of the highest cost participant to the price of the lowest cost participant for each demand job is formed.

$$R_{jln} = P^{\text{high cost}}_{ij,k\in l,mn} \,/\, P^{\text{low cost}}_{ij,k\in l,mn}$$

The maximum ratio over all demand jobs is found.

$$RATIO = \max_{jln} (R_{jln})$$

If RATIO is greater than the predetermined convergence criterion, then the algorithm moves to Step 2 to find a new set of least cost participants. If RATIO is equal to or less than the convergence criterion, then the iteration is complete, and the solution is in equilibrium. For the *Annual Energy Outlook 1995*, the value of RATIO is compared to 1.02. If RATIO is less than 1.02 for four successive iterations, the solution is assumed complete. Otherwise, the model proceeds to the next iteration. Experimentation will be performed with the CDS for the model developer's report to determine the most appropriate convergence criterion and iteration minimum.

Step 5: Computation of Coal Supply

If convergence has not yet occurred, the model now computes supplies of coal of type k from each supply region i, given the shipments assigned in Step 4.

$$S_{ik} = \sum_{j} \sum_{n} \sum_{m} Q_{ijkmn}$$

Next the model returns to Step 1 to compute a new matrix of delivered prices P using the new supply requirements determined in this step.

Appendix C

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Appendix D

CDS Model Abstract

Model Name: Coal Distribution Submodule

Model Acronym: CDS

Description: United States coal production, national and international coal transportation industries.

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

Model Update Information: December 1994

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 CDS interfaces with the Coal Export Submodule and the Coal Production Submodule. Within NEMS, the CDS receives Industrial steam and metallurgical coal demands from the NEMS Industrial Demand 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 CDS also receives macro-economic variables from the NEMS Macro-Economic Activity Module.

Official Model Representative:

Office: Integrated Analysis and Forecasting

Division: Energy Supply and Conversion

Branch: Coal, Uranium and Renewable Fuels Analysis

Model Contact: Richard Newcombe

Telephone: (202) 586-2415

Documentation:

- Energy Information Administration, *Model Documentation, NEMS Coal Distribution Submodule*, December 1993.

- Energy Information Administration, "Component Design Report, Coal Distribution," Revised Draft - 1/19/93.

- Energy Information Administration, *Overview of the Coal Market Module of The National Energy Modeling System*, April 1992.

Archive Media and Installation Manual: CDS95 - *Annual Energy Outlook 1995*.

Energy System Described by the Model: Coal demand distribution at various demand regions by demand sector.

Coverage

Geographic: United States, including Hawaii, Puerto Rico, and the U.S. Virgin Islands.

Time unit/Frequency: Annual forecasts for 1990-2015 period (26 years).

Basic products involved: Bituminous, subbituminous and lignite coals in steam and metallurgical coal markets.

Economic Sectors: Forecasts coal supply to 1 Residential/Commercial, 3 Industrial, 2 domestic metallurgical, 3 Export, and 13 Electric Utility subsectors (a synthetic fuel subsector is present but not operational in the CDS) to 23 domestic demand regions.

Special Features

- All demands are exogenous to the CDS.
- Supply curves (there are 202) depicting coal reserve base are exogenous to CDS and are reported in the CDS from 16 coal supply regions.
- CDS currently contains no descriptive detail on coal transportation by different modes and routes. Transportation modeling consists only of sector-specific rates between demand and supply regions that are adjusted annually for factor input cost changes.
- CDS output includes tables of aggregated output for NEMS system and approximately 20 single-year reports providing greater regional and sectoral detail on demands, production distribution patterns, and rates charged.
- Coal imports are treated as a static input that is subtracted from demand before solving the CDS. Imports are reported to NEMS and detailed in some single-year reports.
- CDS reports minemouth, transport and delivered prices, coal shipment origins and destinations (by region and economic sub-sector), coal Btu and sulfur levels.

Modeling Features

- **Structure:** The CDS uses 202 coal supply curves representing 28 types of coal produced in 16 supply regions. Coal shipments to consumers are represented by transportation rates specific to NEMS sector and supply/demand region pair, based on historical differences between minemouth and delivered prices for such coal movements. In principle there are 1,840 such rates for any forecast year; in practice there are less since many rates are economically infeasible. Coal supplies are delivered to up to 22 demand sectors in each of the 23 demand regions. A 23rd demand sector for synthetic fuel demands exist in the CDS classification structures, but is not currently used. A single model run represents a single year, but up to 26 consecutive years (1990-2015) may be run in an iterative fashion. Currently the NEMS system provides demand input for a 20-year period (1990-2010).
- **Modeling Technique:** The model develops a disaggregated demand list from the NEMS demand models and conversion models for the residential/commercial, industry and electric utility sectors, and from the NEMS Coal Market Module's Coal Export Submodule (q.v.) for export coal demands.

This list contains between 600 and 800 demands—referred to as "demand jobs"—depending on the forecast year and scenario. Least cost coal source/route combinations (minemouth costs plus transportation costs) from each supply region to each demand region for each demand job are identified by a shortest path algorithm. An heuristic equilibrium assignment algorithm is used to shift fractions of demand toward lower cost source/route combinations—called "participants." The second algorithm is required because mining costs vary directly as a function of volume mined. The CDS iterates the shortest path algorithm after recosting the participants and repeats the heuristic "participation shifting" algorithm until convergence criteria for the equality of delivered costs across participants in each demand job are met.

- **Model Interfaces:**

  — The NEMS residential, commercial, and industrial models provide demands for those sectors, while the NEMS Electricity Market Module provides demands for the electricity generation sectors. The Coal Export Submodule of the NEMS Coal Market Module provides demand for the coal export sector. The CDS provides coal production, Btu conversion factors, minemouth, transportation and delivered costs for coal supplies to meet these demands to the NEMS system.

  — The CDS interfaces with the Coal Market Module's Coal Export Submodule to receive coal export demands.

  — The CDS interfaces with the Coal Market Module's Coal Production Submodule 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 determine mine capacity utilization percentages for each supply curve and to decrement the coal reserve base (to prevent remining of reserves already depleted in a previous iteration).

- **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) import supplies (millions of short tons)

  —— *Coal supply/transportation contracts:* (1) coal supply regions; (2) coal demand regions; (3) coal quality (Btu and sulfur content); (4) contract annual volumes (trillion Btu); (5) contract expiration dates (forecast year)

  —— *Coal quality data for supply curves:* (1) million Btu per short ton; (2) lbs. sulfur 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 and demand region pair

—— *Transportation rate escalation factors:* (1) exogenous; (2) based on estimates of factor input costs (labor, fuel, etc.); (3) 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:* (1) can be used by demand sector and demand region; (2) derived from off-line program that subtracts base year minemouth costs from delivered costs reported in Forms EIA-3 and -5, and FERC Form 423 to produce transport rate, calculates ratio between model rate and rate from forms, preserve ratio as model parameter; (3) used to calibrate rates in model

— **Ecological:** none

- **Data Sources**
  - Form EIA-3, "Quarterly Coal Consumption Report, Manufacturing Plants"
  - Form EIA-5, "Coke Plant Report - Quarterly"
  - Form EIA-6, "Coal Distribution Report"
  - Form EIA-7A, "Coal Production Report"
  - FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"
  - FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices"
  - U.S. Department of Commerce, Form EM-522
  - U.S. Department of Commerce, Form IM-145
  - 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)
  - Lescoart, John E., ed., *1986-1987 Fieldston Coal Transportation Manual* (Washington, DC, 1986)

- **Output Data**

  — **Physical:** Forecasts of annual coal supply tonnages (and trillion Btu) by economic sector and subsector, coal supply region, coal Btu and sulfur 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

- **Language:** VS FORTRAN
- **Processor:** IBM VS FORTRAN compiler
- **Core Requirement:** Storage requirement is 932,764 k-bytes*sec
- **Estimated Cost to Run:** The Reference Case run for the *Annual Energy Outlook 1994* (AEO94B.D1221934) required 137.42 CPU seconds to complete for the 1990-2010 period (an average of 6.54 CPU seconds per forecast year). CPU charges totaled $19.73; I/O, $0.83; and printing for 10,850 lines, $11.83; for an estimated total charge of $31.90 ($1.52 per forecast year).
- **Storage:** 1800k bytes (900 tracks, 3350 disk)
- **Input/Output Mode:** Batch
- **Average Run Time:** 10 CPU seconds for a single year
- **Turnaround Time:** Class D job - 20 minutes to 1 hour
- **Average Compile Time:** 20 CPU seconds

Inhouse or Proprietary

Inhouse

Independent Expert Reviews Conducted:

The Coal Distribution Submodule of NEMS is a new model, first used for the *Annual Energy Outlook 1994*. The only independent Expert Review conducted to date was for the Component Design Report, which was reviewed by Dr. Charles Kolstad of the University of Illinois and by Dr. Stanley Suboleski of the Pennsylvania State University during 1992 and 1993.

Status of Evaluation Efforts Conducted by Model Sponsor

The Coal Distribution Submodule (CDS) is a new model, developed for the National Energy Modeling System (NEMS) during the 1992-1993 period and revised in 1994. The version described in this abstract is that intended for use in support of the *Annual Energy Outlook 1995*. No prior evaluation efforts have been made at the date of this writing.

Last Update

As a new model, planned for use in the *Annual Energy Outlook*, the CDS will be updated annually. The version described in this abstract was updated September 1994.

References:

The Coal Distribution Submodule is a new model, and this is the first documentation of that model. The only existing descriptive reference for this model is: Coal, Uranium and Renewable Fuels Analysis Branch, Energy Supply and Conversion Division, Office of Integrated Analysis and Forecasting, Energy Information Administration, **Component Design Report, Coal Distribution**, Revised Draft - 1/19/93.

Appendix E

Data Quality and Estimation

Data Sources

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

- Form EIA-3, "Quarterly Coal Consumption Report—Manufacturing Plants", covers 97 percent of coal receipts to industry (Form EIA-6, below): coal stocks, delivered prices, and consumption.

- Form EIA-5, "Coke Plant Report" covers 100 percent of coal receipts at coke plants: consumption, delivered prices, and stocks.

- Form EIA-6, "Coal Distribution Report" covers 99 percent of production (Form EIA-7A, below): distribution from mine to consumer by economic sector, transport mode, and tonnage.

- Form EIA-7A,"Coal Production Report" covers 5,000 coal producers and reports production, minemouth prices, coal seams mined, labor productivity, employment, stocks, and recoverable reserves at mines. A supplement in 1983 covered prices, Btu, ash, and sulfur content as sold to individual economic sectors; these data were collected on a "Dry" basis.[104]

- Form EIA-759, "Monthly Power Plant Report," covers 100 percent of electricity generating plants with 50 megawatts (MW) or more of capacity, reporting consumption and stocks.

- FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants" covers power plants with capacity of 50 MW or more and reports delivered cost, receipts, ash, Btu, sulfur ("As Received" basis), and sources.

- FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices", is a biennial survey of investor-owned utilities selling electricity in interstate markets and having capacity over 50 MW; coverage of 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 Census Bureau records coal exports by rank, value and tonnage from each port district. The Form IM 145 reports imports by rank, value, tonnage, and port district.

Nonsurvey sources describe coal reserves and their quality. EIA maintains a Demonstrated Reserve Base (DRB), updated annually, that contained 475.6 billion short tons of coal on January 1, 1992. Tables distributing these reserves by coal rank, State, and potential mining method are published annually.[105]

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[104]Energy Information Administration, *Coal Production 1984*, DOE/EIA-0118(84) (Washington, DC, November 1985), Appendix C.

[105]Energy Information Administration, *Coal Production 1990*, DOE/EIA-0118 (90) (Washington, DC, September 1991), pp. 69-73.

Estimates of Btu and sulfur content associated with reserve tonnages by State and coal rank have also been published.[106] Btu and sulfur content is linked with reserve tonnages by the Coal Analysis Files, which record over 53,000 sample analyses of coal shipments to government facilities. These are recorded on a "Dry" basis, but "As Received" moisture is also recorded, allowing comparison to data on FERC forms, above. These samples were taken from the 1940's to the present, and contain much old data for eastern anthracite and bituminous coals and little data for western subbituminous and lignite coals.

Data Gaps

The Coal Analysis Files and the Demonstrated Reserve Base provide the geological data underlying the supply curves used by the NEMS CDS. The association of minemouth costs with increments of coal reserves is the central function of the NEMS Coal Production Submodule (CPS). The CPS is documented under its own title.

The resources that are available to support the NEMS CPS and CDS include a series of databases that are valuable for their national scope and census-like coverage. However, as shown in Table E-1, no data are routinely collected on the quality of coal produced at the mine or the minemouth price for coals of different quality levels. While EIA publishes data identifying the tonnage of exported coal mined in each State and the Department of Commerce collects data on the tonnage exported (by port district), there are no data to identifying the tonnage from each mining State that is exported at each port of exit. Also, there are currently no data describing the minemouth price for coal delivered to any of the economic sectors modeled. The FERC Form 423 now provides the only coal quality data available, and it is restricted to the electric utility sector. Coals consumed by the electric power generation industry are historically lower in Btu content, higher in sulfur, and lower in ash than coals delivered to other consuming sectors. There is no source of coal quality or delivered price for coal delivered to the residential/commercial sector.

During FY 1994, it is expected that 1992 data from the new Forms EIA-3A and -5A will provide the quality, delivered price, and State of origin for coal delivered to the industrial steam and industrial metallurgical coal sectors. The availability of these data will represent a significant improvement over that currently available for these sectors.

Available data on coal transportation rates are restricted to the nonproprietary data collected on FERC Form 580. In addition to the withholding of proprietary data on the survey, its coverage is restricted to a portion of the electric utility sector that excludes both some of the largest and many of the smaller electricity generation utilities in the Nation. The difference between delivered costs as shown on the FERC Form 423, Forms EIA-3, EIA-5, and EM 522 and minemouth costs as shown on Form EIA-7A in the most recent available historical year is used to estimate transportation rates. The use of this method allows estimation of different rates for each sector in each demand region, but—even if data for more remote historical years were used—can do little to provide transportation rates for routes that have not been used. More than half the routes indicated by the CDS supply and demand region classification

[106]Energy Information Administration, *U. S. Coal Reserves: An Update By Heat and Sulfur Content*, DOE/EIA-0529(92) (Washington, DC, February 1993).

Table E-1. EIA Coal Supply Data Frame

	Demand: NEMS Economic Sectors						Supply	
Demand Sector	Electric Utility	Industrial Coking	Industrial Steam	Residential/ Commercial	Exports (f.o.b. piers)	Imports (f.o.b. piers)	Coal Products	Coal Reserves
Reserve Tonnage	--	--	--	--	--	--	--	DRB
Origin	FERC-580, 423	EIA-6[a]	EIA-6	EIA-6	EIA-6	IM-145	EIA-7A	DRB
Minemouth Price	EIA-7A (1983) FERC-580	EIA-7A (1983)	EIA-7A (1983)	EIA-7A (1983)	EIA-7A (1983)	NA	EIA-7A	--
Freight Charges	FERC-580	NA	NA	NA	NA	NA	--	--
Transport Mode (final)	FERC-580	EIA-6	EIA-6	EIA-6	NA	NA	--	--
Delivered Price	FERC-423	EIA-5	EIA-3	NA	EM-522[b]	IM-145	--	--
Destination	FERC-423, 580	EIA-5, 6	EIA-3, 6	EIA-6	EM-522	IM-145	--	--
Tonnage								
Tonnage (receipts)	FERC-423, EIA-6	EIA-5, 6	EIA-3, 6	EIA-6	EM-522	IM-145	EIA-7A	--
Tonnage (consumption)	EIA-759	EIA-5	EIA-3	EIA-6	--	--	--	--
Tonnage (stockpiles)	EIA-759	EIA-5	EIA-3	NA	--	--	EIA-7A, 6	--
Chemistry								
Moisture (as received)	FERC-580	NA	NA	NA	NA	NA	NA	Coal Analysis Files
Volatiles (as received)	NA	NA	NA	NA	NA	NA	NA	Coal Analysis Files
Fixed Carbon (as received)	NA	NA	NA	NA	NA	NA	NA	Coal Analysis Files
Ash (as received)	FERC-423, 580, 767	NA	NA	NA	NA	NA	EIA-7A (1983)	Coal Analysis Files
Btu/pound (as received)	FERC-423, 580, 767	NA	NA	NA	EM-522 (Rank)	IM-145 (Rank)	EIA-7A (1983)	Coal Analysis Files
Total Sulfur (as received)	FERC-423, 580, 767	NA	NA	NA	NA	NA	EIA-7A (1983)	Coal Analysis Files
Particulates	EIA-767	NA	NA	NA	--	--	--	--
SO_x	EIA-767	NA	NA	NA	--	--	--	--
NO_x	EIA-767	NA	NA	NA	--	--	--	--
CO_x	EIA-767	NA	NA	NA	--	--	--	--
Ash (tonnage)	EIA-767	NA	NA	NA	--	--	--	--

[a]EIA-6 lists export tonnage by mining state, but not by U.S. port-of-exit.
[b]EM-522 lists export tonnage by U.S. port-of-exit, but not by mining state.
NA = Not available.
DRB = Demonstrated reserve base.

structures have not been used for coal carriage in significant quantity in the last 50 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 to prevent their use.

The general availability of coal-related data that were used to build and calibrate the CDS for the *Annual Energy Outlook 1995* is summarized in Table E-1 which shows the entire EIA data frame as it has been available during the NEMS construction and calibration period.

Appendix F

CDS Program Availability

The source code for the CDS program is available in file CN6005.PRJ.NEMS.FORTRN.COAL.D0926941. This file is available in the program office.

Appendix A

Inventory of Input Data, Parameter Estimates, and Model Outputs

Model Inputs

Model inputs are classified into three categories: user-specified inputs, inputs provided by other NEMS components, and inputs provided by the RAMC.

User-Specified Inputs. User-specified inputs are listed in Table A-1. The table identifies each input, the variable name, the units for the input, and the level of detail at which the input must be specified. The required production inputs also are used as inputs to the RAMC, and the source for these inputs is the RAMC data library. Future levels of labor productivity are estimated by the EIA. For the *1995 AEO*, labor productivity estimates were derived by assuming that, in the first year of the forecast period, productivity increases at a rate equal to the average annual productivity increase over the recent past and that the initial rate of increase diminishes gradually over the remainder of the forecast period. The average heat and sulfur content values are estimated from data obtained from the FERC-423 database.

The inputs listed in Table A-1 are contained in a single "flat" file. The file is divided into four sections. Each section corresponds to one of four input specification levels: national, national/year, supply region/mining method/year, and supply region/mining method/coal type. Each section contains all input requirements for the level. For example, the region/mining method/coal type section of the file contains all of the production values. Less detailed sections appear toward the beginning of the file, while more detailed sections appear toward the end. For example, the first record in the file contains values for the national-level inputs (e.g., the exports), while the last section of the file contains production inputs.[38]

Inputs Provided by Other NEMS Components. Table A-2 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. Diesel fuel prices are obtained from the Petroleum Market Module, coal-fired power plant capacity is obtained from the EMM, and labor costs are obtained from the Macroeconomic Activity Module. Additional run control variable are obtained from the NEMS integrating Module. These variables include the base year, the forecast year, the current iteration, and a print control variable. All remaining inputs listed in Table A-2 are obtained from the Coal Distribution Submodule.

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[38] The indices used in the tables are defined as follows:

i	=	supply region
j	=	mining method (surface or underground)
k	=	coal type
t	=	year
by	=	base year
ny	=	NEMS reference year (for prices)
x1, x2,...xn	=	aggregate coal demand regions for CPS capacity model
c	=	coal demand region (CDS)
z	=	step on RAMC supply curve

Table A-1. User-Specified Inputs Required by the CPS

CPS Variable Name	Description	Specification Level	Units	Variable Used in this Report	Source(s)
RAMC_YEAR	Year basis for RAMC prices	National	--	--	RAMC Input file
NEMS_YEAR	NEMS reference year	National	--	REF	Set by user
DEF	Deflator	National	__	DEF	PGDP price deflator
M_SWITCH	Controls modeling approach used	National	--	--	Set by user
P_SWITCH	Controls output reports produced	National	--	--	Set by user
I_SWITCH	Controls inputs utilized	National	--	--	Set by user
RAMC_ESC	Escalator for RAMC prices	National	--	--	RAMC input file
MC_YEAR	Year basis for marginal cost models	National	--	--	Defined by data
MC_ESC	Escalator for marginal cost models	National	--	--	FGDP escalator
RAMC_ALT	Controls RAMC input	National	--	--	Set by user
WAGE	Real labor cost escalator (not used for 1994 *AEO*)	National/year	--	--	EIA projection
RG	Alphabetic supply region code	Supply region/ mine type	--	--	Model definition
MT	Alphabetic mine type code	Supply region/ mine type	--	--	Model definition
MC_INT	Marginal cost model intercept	Supply region/ mine type	--	a_j	Regression analysis
MC_WAGE	Marginal cost model coefficient (labor cost term)	Supply region/ mine type	--	d_j	Regression analysis
MC_PROD	Marginal cost model coefficient (productivity term)	Supply region/ mine type	--	c_j	Regression analysis
MC_PRODX	Marginal cost model exponent (productivity term)	Supply region/ mine type	--	--	Regression analysis

Table A-1. User-Specified Inputs Required by the CPS (Continued)

CPS Variable Name	Description	Specification Level	Units	Variable Used in this Report	Source(s)
MC_UTILX	Marginal cost model exponent (utilization term)	Supply region/ mine type	--	--	Regression analysis
MC_FUELX	Marginal cost model exponent (diesel fuel term)	Supply region/ mine type	--	--	Regression analysis
MC_WAGEX	Marginal cost model exponent (labor cost term)	Supply region/ mine type	--	--	Regression analysis
C_EX	Assigned coefficient (excess capacity term)	Supply region/ mine type	--	CEX	EIA estimate
N_EX	Assigned coefficient (excess capacity term)	Supply region/ mine type	--	N	EIA estimate
CAL_CAP	Capacity in first forecast year (as a fraction of base year capacity)	Supply region/ mine type	--	--	EIA *Coal Production 1991*
SF	Surge capacity scaling factor	Supply region/ mine type	--	$SF_{i,j}$	EIA estimate
L_PROD	Base year productivity	Supply region/ mine type	tons/manhour	$LP_{i,j,by}$	EIA *Coal Production 1990*
FR_PROD	Forecast year productivity (as a fraction of L_PROD)	Supply region/ mine type/year	--	$LP_{i,j,t}$	EIA projection
ADJ_FORE	Price adjustment variable (currently set to zero)	Supply region/ mine type/year	Dollars/ton	--	EIA estimate
SBAS_REGION	Alphabetic supply region code	Supply region	--	--	Model definition
NBAS	Number of production records	Supply region	--	--	File definition
CPROD_TYPE	Alphabetic coal type code	Supply region/ coal type	--	--	Model definition
B_PROD	Base year production	Supply region/ mine type/coal type	MMTons	$P_{i,j,k,by}$	EIA *Coal Production 1990*; FERC-423
BTU	Average heat content	Supply region/ coal type	MMBtu/ton	--	FERC-423
SULFUR	Average sulfur content	Supply region/ coal type	lbs/MMBtu	--	FERC-423

Table A-2. CPS Inputs Provided by Other NEMS Modules and Submodules

CPS Variable Name	Description	Specification Level	Units	Variable Used in this Report	NEMS Module/ Submodule
MC_NMFGWGRT	Wage rate (nonmanufacturing sector)	Census region/year	Dollars/hour	--	Macro-economic model
MC_PGDP	GDP deflator	Census region/year	--	--	Macro-economic model
PDSIN	Diesel fuel price	National/year	Dollars/ gallon	--	PMM
UADDCST	Projected coal-fired power plant capacity	CDS demand region/year	Megawatts	$PP_{xn,t}$	EMM
CDS_QTY	Coal shipments	CDS demand region/ demand sector/supply region/mine type/coal type	MMTons	$ES_{xy,i,j,k,t}$	CDS
CDS_RECORDS	Number of elements in array CDS_QTY	National	--	--	CDS
CDS_SR	CDS numeric supply region code	CDS demand region/ demand sector/supply region/mine type/coal type	--	--	CDS
CDS_DR	CDS numeric demand region code	CDS demand region/ demand sector/supply region/mine type/coal type	--	--	CDS
CDS_CT	CDS numeric mine type/ coal type code	CDS demand region/ demand sector/supply region/mine type/coal type	--	--	CDS
CDS_DS	CDS numeric demand sector code	CDS demand region/ demand sector/supply region/mine type/coal type	--	--	CDS
FIRSTFLG	Controls projected capacity calculation	National	--	--	CMM
P_QTY	Projected capacity	CDS demand region/ demand sector/supply region/mine type/coal type for projected capacity	MMTons	$C^{CDS}_{dr,ds,j,k,t}$	CDS
P_RECORDS	Number of elements in array P_QTY	National	--	--	CDS

CPS Variable Name	Description	Specification Level	Units	Variable Used in this Report	NEMS Module/ Submodule
MC_NMFGWGRT	Wage rate (nonmanufacturing sector)	Census region/year	Dollars/hour	--	Macro-economic model
P_SR	CDS numeric supply region code for projected capacity	CDS demand region/ demand sector/supply region/mine type/coal type for projected capacity	--	--	CDS
P_DR	CDS numeric demand region code for projected capacity	CDS demand region/ demand sector/supply region/mine type/coal type for projected capacity	--	--	CDS
P_CT	CDS numeric mine type/ coal type code for projected capacity	CDS demand region/ demand sector/supply region/mine type/coal type for projected capacity	--	--	CDS
P_DS	CDS numeric demand sector code for projected capacity	CDS demand region/ demand sector/supply region/mine type/coal type for capacity projection	--	--	CDS

The CPS provides the user with the option of obtaining the diesel fuel and labor cost data from input files as opposed to other NEMS components. This option may be exercised by setting to 0 the value of run control variable I_SWITCH (in the user input files). When I_SWITCH is set equal to 0, labor costs will be calculated using projected national-level labor cost escalators contained in the user input file. Diesel fuel prices projections (by NERC region) will be obtained from a separate flat file. When I_SWITCH is set equal to 1, the CPS will run in normal "integrated" mode, and will obtain the diesel fuel and labor cost data either from the above-listed NEMS modules or from the NEMS restart file.

Inputs Provided by the RAMC. The inputs obtained from the RAMC (or, more properly, the RAMC post-processing program) are required regardless of the modeling approach used. These inputs are contained in two separate files: the decrement file and the file containing the reserve depletion curves. The decrement file contains estimates of the reduction in existing mine capacity, due to mine retirements, in each year of a 25-year period. The capacity reduction estimates (represented by variable $R_{i,j,k,t}$ in Appendix B) are specified in millions of tons. Each set of estimates, for each region, mining method and coal type, are contained on two adjacent records. The first record identifies the region, mining method, and coal type, and contains the capacity reduction estimates for the first 15 years; the second record contains the estimates for the remaining 10 years. Table A-3 lists and describes all of the variables read from the decrement file.

Table A-3. Inputs Included in the RAMC Decrement Files

CPS Variable Name	Description	Units	Variable Used in this Report
SDEC_REGION	Alphabetic supply region code	--	--
DEC_C_TYPE	Alphabetic coal type code	--	--
M_TYPE	Alphabetic mine type code	--	--
DECR	Capacity to be retired	Million tons	$R_{i,j,k,t}$

In the file containing the RAMC curves, each record corresponds to a step on the curve; a separate curve is included in the file for each region, mining method, and coal type. The information provided for each step includes some details that are not required by the model (e.g., the size of the mines represented on the step); the data that *will* be read by the model include the codes identifying the region, mining method, coal type, and type of step (existing mine or new mine step), as well as the total capacity and price for the step. The variables read from the RAMC curves file are listed and described in Table A-4.

Table A-4. Inputs Included in the RAMC Curves Files

CPS Variable Name	Description	Units	Variable Used in this Report
SCUR_REGION	Alphabetic supply region code	--	--
N_RECORD	Number of file records for each region	--	--
C_TYPE	Alphabetic coal type code	--	--
CAP	Total capacity on the step	Million tons	--
PRICE	Price for the step	Dollars/ton	$PRAMC_{i,j,k,t}$
S_FRAC	Numeric mine type code	--	--

Model Outputs

The primary output from the model are the supply curves. The general form of equations representing supply curves for underground mines is as follows:

$$MC_{i,j,k,t} = IN^{**}_{i,j,k,t}+(M^{u*}_{i,t})EXP[(b^{u}_{i,k,t})(P_{i,j,k,t})^{x}] \tag{1}$$

The general form of the surface mine equation is as follows:

$$MC_{i,j,k,t} = IN^{**}_{i,j,k,t}+[M^{s*}_{i,t} + (b^{s*}_{i,k,t})(P_{i,j,k,t})^{x}]^{1/2} \tag{2}$$

Model output consists of the five constants: $IN^{**}_{i,j,k,t}$, $M^{*}_{i,j,t}$, $b^{u}_{i,k,t}$, $b^{s*}_{i,k,t}$, and x.[39] In addition, the surge capacity ($SC_{i,j,k,t}$)[40] is output along with the value of production ($P_{i,j,k,t}$) for which capacity utilization equals 50 percent. The 50-percent production value and the surge capacity define the beginning and end points of the second segment of the supply curve. In addition to the outputs defining the nonlinear second segment, the CPS provides the slope and the y-intercept of the first and third linear segments, along with the value of production at the end point of the third segment (set equal to 10 times the surge capacity). Separate values of the output variables defining the three segments are provided for each supply curve; i.e., for each region, mining method, and coal type. In addition, the surge capacity represents the end-point of the supply curve. The outputs include the values supplied as inputs to the model for the labor productivity ($LP_{i,j,t}$ in the preceding chapter), average Btu content, and average sulfur content variables. Separate labor productivity values, for the forecast year (year t), are provided for each region and mining method. The CPS output variables are listed in Table A-5.

[39]Three separate values of $b^{u}_{i,k,t}$, $b^{s*}_{i,k,t}$, and x are provided as output for each supply curve, for three separate production terms. However, the current regression models include only one production term. The values of $b^{u}_{i,k,t}$, $b^{s*}_{i,k,t}$, and x for the other two terms are set equal to 0, 0, and 1, respectively.

[40]Surge capacity is defined as the maximum quantity of coal a mine can produce with current labor and equipment in response to unexpected short-term increased demand that is above the nominal design production capacity.

In addition to the outputs above, which are passed to the CDS, the model produces a number of output reports presenting the results of some of the intermediate calculations performed by the submodule, as well as results of calculations performed specifically for the report. The latter calculations include the following:

$$U_{i,j,k,t-1} = (P_{i,j,k,t-1})(100)/C_{i,j,k,t-1} \tag{3}$$

for underground mines:

$$MC_{i,j,k,t} = IN^{**}_{i,j,k,t} + (M^{u*}_{i,j,t})EXP[(b^{u}_{i,j,k,t})(C_{i,j,k,t})] \tag{4}$$

for surface mines:

$$MC_{i,j,k,t} = IN^{**}_{i,j,k,t} + [M^{s*}_{i,t} + (b^{s*}_{i,k,t})(C_{i,j,k,t})^{6}]^{1/2} \tag{5}$$

For each region, mining method, and coal type, the output report includes the full capacity marginal cost ($MC_{i,j,k,t}$) and capacity utilization ($U_{i,j,k,t-1}$) values calculated for each forecast year. In addition, the following results of intermediate calculations (see preceding chapter) for each region, mining method, coal type and year are reported:

- Original and modified values of the coefficients in the equations for marginal costs (Equations 1 and 2)
- Projected total capacity
- Increase in price between the base year and the forecast year, due to reserve depletion (from the RAMC curves).

In addition, the output report includes the values of all user-specified inputs, as well as the values of inputs obtained from other NEMS components.

Table A-5. CPS Model Outputs

CPS Variable Name	Description	Units	Variable Used in this Report
CPS_YINT	Y-intercept for first supply curve segment	--	$Y_{i,j,k,t}\vert_{.5}$
CPS_SLOPE	Slope of first supply curve segment	--	$M_{i,j,k,t}\vert_{.5}$
CPS_PENDI	Production at end-point of first supply curve segment	Million tons	--
CPS_SURCAP	Production at end-point of second supply curve segment	Million tons	$SC_{i,j,k,t}$
CPS_RINTER2	Supply curve constant	--	$IN^{**}_{i,j,k,t}$
CPS_RMULT	Supply curve coefficient	--	$M^{u*}_{i,t}$ i $M^{s*}_{i,t}$
CPS_NMCUTIL	Supply curve exponent	--	$b^{u*}_{i,k,t}$ i $b^{s*}_{i,k,t}$
CPS_MCUTILX	Supply curve exponent	--	x
CPS_YINT3	Y-intercept for third supply curve segment	--	$Y_{i,j,k,t}\vert_{s}$
CPS_SLOPE3	Slope of third supply curve segment	--	$M_{i,j,k,t}\vert_{s}$
CPS_PEND3	Production at end-point of third supply curve segment	Million tons	--
CPS_LPROD	Labor productivity	Tons/person-hour	$LP_{i,j,t}$
CPS_BTU	Average Btu content for the supply curve	MMBtu per ton	--
CPS_SULFUR	Average sulfur content for the supply curve	lbs/MMBtu	--

Model Endogenous Variables

Variables endogenous to the model are included in Table A-6. Table A-6 includes the variable name used in the report, the corresponding variable name used in the CPS model, a description of the variable, and the variable's units.

Table A-6. CPS Endogenous Variables

CPS Variable Name	Description	Units	Variable Used in this Report
D_FUEL	Diesel fuel price index	--	Ft
SUR_CAP,L_P_END	Surge capacity	Million tons	$SC_{i,j,k,t}$
INTER1	Constant term for supply curve function, following initial calibration	--	$IN_{i,j,k}$
INTER2	Constant term for supply curve function, capturing depletion effects	--	$IN^{*}_{i,j,k,t}$
R_INTER2	Finalized multiplier for supply curve function	--	$IN^{**}_{i,j,t}$
MULT	Multiplier for supply curve function, prior to deflation	--	$M_{i,j,t}$
R_MULT	Finalized multiplier for supply curve function	--	$M^{*}_{i,j,t}$
N_MC_UTIL	Finalized coefficient for production term	--	$b^{*}_{i,j,k,t}$
UTILIZ	Capacity utilization	Fraction	$U_{i,j,k,t-1}$
P_CAP, PCAP_S	Projected mine capacity	Million tons	$C_{i,j,k,t}$
P_S_CAP	P_CAP (PCAP_S), in thousands of tons	Thousand tons	--
P_EXCAP	Excess capacity	Million tons	$EC_{i,j,k,t}$
A_PRICE	Adjusted year t price on step z of supply curve	Dollars/ton	$AP_{z,i,j,k,t}$
SLOPE	Slope of linear segment of supply function for utilization less than 50 percent	--	$m_{i,j,k,t}\vert_{.5}$
L_SLOPE	Slope of linear segment of supply function for production greater than surge capacity	--	$m_{i,j,k,t}\vert_{s}$
Y_INT	Y-intercept of linear segment of supply function for utilization less than 50 percent	--	$Y_{i,j,k,t}\vert_{.5}$
L_Y_INT	Y-intercept of linear segment of supply function for production greater than surge capacity	--	$Y_{i,j,k,t}\vert_{s}$

Table A-6. CPS Endogenous Variables (Continued)

CPS Variable Name	Description	Units	Variable Used in this Report
P_END	Production at 50 percent utilization	--	$P_{i,j,k,t}\|_{.5}$
A_CAP	Existing mine capacity, adjusted for mine retirements	Million tons	$EXC_{i,j,k,by}$
DEC_COUNT	Number of region/mine type/coal type combinations included in decrement file	--	--
S_NLAS	Number of mine type/coal type combinations with reserves and capacity, in forecast year	--	--
NLAS	Number of mine type/coal type combinations with reserves and capacity, in year prior to forecast year	--	--
L_CTYPE,S_CT	CDS numeric mine type/coal type code	--	--
NUM_RECS	Number of records in decrement file	--	--
FRAC_CODE	Mine type code	--	--
B_REGION	Alphabetic supply region code	--	--
B_C_TYPE	Alphabetic coal type code	--	--
F_INDEX	Diesel fuel price index in base year	--	--
UX_TERM	Value of utilization term when production = P_END	--	--
UX_SUM	Sum of UX_TERM for all utilization terms	--	--
UX	EXP(UX_SUM)	--	--
PRICE_50	Price on supply curve at P_END	Dollars/ton	--
L_CAP	Projected capacity in year prior to forecast year	--	--
B_S_FRAC	Numeric mine type code	--	--
PRINT_PRICE	Price on supply curve at 100 percent utilization	Dollars/ton	$MC_{i,j,k,t}$
DEPLET	Reserve depletion effect	Dollars/ton	--
UX_TERMS	Sum of utilization terms when production = capacity	--	--
UX2	EXP(UX_TERMS)	--	--
B_INDEX	Number assigned to first step on each RAMC curve	--	--

Table A-6. CPS Endogenous Variables (Continued)

CPS Variable Name	Description	Units	Variable Used in this Report
B_CAP	Base year coal industry capacity	--	--
B_PRICE	Base year coal price	--	--
U_TERM	Value of utilization term, at base year utilization levels	--	--
BASE_SUM	Sum of productivity, labor cost, and fuel cost terms in the base year	--	--
PFW_SUM	Sum of productivity, labor cost, and fuel cost terms	--	--
TEMP	Sum of U_TERM for all utilization terms	--	--
CAL_PRICE	Predicted price in base year, prior to model calibration	--	$MC_{i,j,k,by}$
DEC_CAP	P_CAP, adjusted for mine retirements	Million tons	--
SUM_CAP	Cumulative capacity on RAMC steps	Million tons	--
DEP_PRICE	Price at projected capacity level, from the RAMC curve	Dollars/ton	$PRAMC_{i,j,k,t}$
DEP_SUM	Sum of utilization terms, at 100 percent utilization	--	--
MC_NODEP	Predicted price at 100 percent utilization, in the forecast year, assuming no depletion effect	Dollars/ton	$MC_{i,j,k,t}$
DEP_CHANGE	Increase in MC_NODEP due to depletion	Dollars/ton	--
B_UTILIZ	Utilization in the base year	Fraction	--
MT_CODE	Alphabetic mine type code	--	--
NN	B_YEAR - NEMS_YEAR	--	--
REV_P	Adjusted price on RAMC capacity curve	Dollars/ton	$RP_{i,j,k,t}$
REV_CAP	Production capacity on RAMC capacity curve, adjusted for capacity retirements	Million tons	$E_{i,j,k,t}$
II	CDS_SR	--	--
JJ	CDS_DR	--	--
KK	CDS_CT	--	--
CT_CODE	Alphabetic coal type code	--	--

Table A-6. CPS Endogenous Variables (Continued)

CPS Variable Name	Description	Units	Variable Used in this Report
P_TERM	Calculated value of productivity term in marginal cost model	--	--
F_TERM	Calculated value of fuel cost term in marginal cost model	--	--
W_TERM	Calculated value of labor cost term in marginal cost model	--	--

Appendix B

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

- Step 1: Initial calibration of marginal cost regression equations
- Step 2: Calculation of projected capacity
- Step 3: Calculation of surge capacity
- Step 4: Retirement of existing mines on reserve depletion (RAMC) curves
- Step 5: Adjustment of regression equations for reserve depletion
- Step 6: Adjustment of regression equations for labor productivity, labor costs, and diesel fuel prices
- Step 7: Conversion of regression equations from utilization to production basis
- Step 8: Adjustment of marginal costs from base year to NEMS reference year dollars
- Step 9: Addition of linear segments to supply curves.

Figure B-1 is a flow chart of the model.

Figure B-1. CPS Flowchart

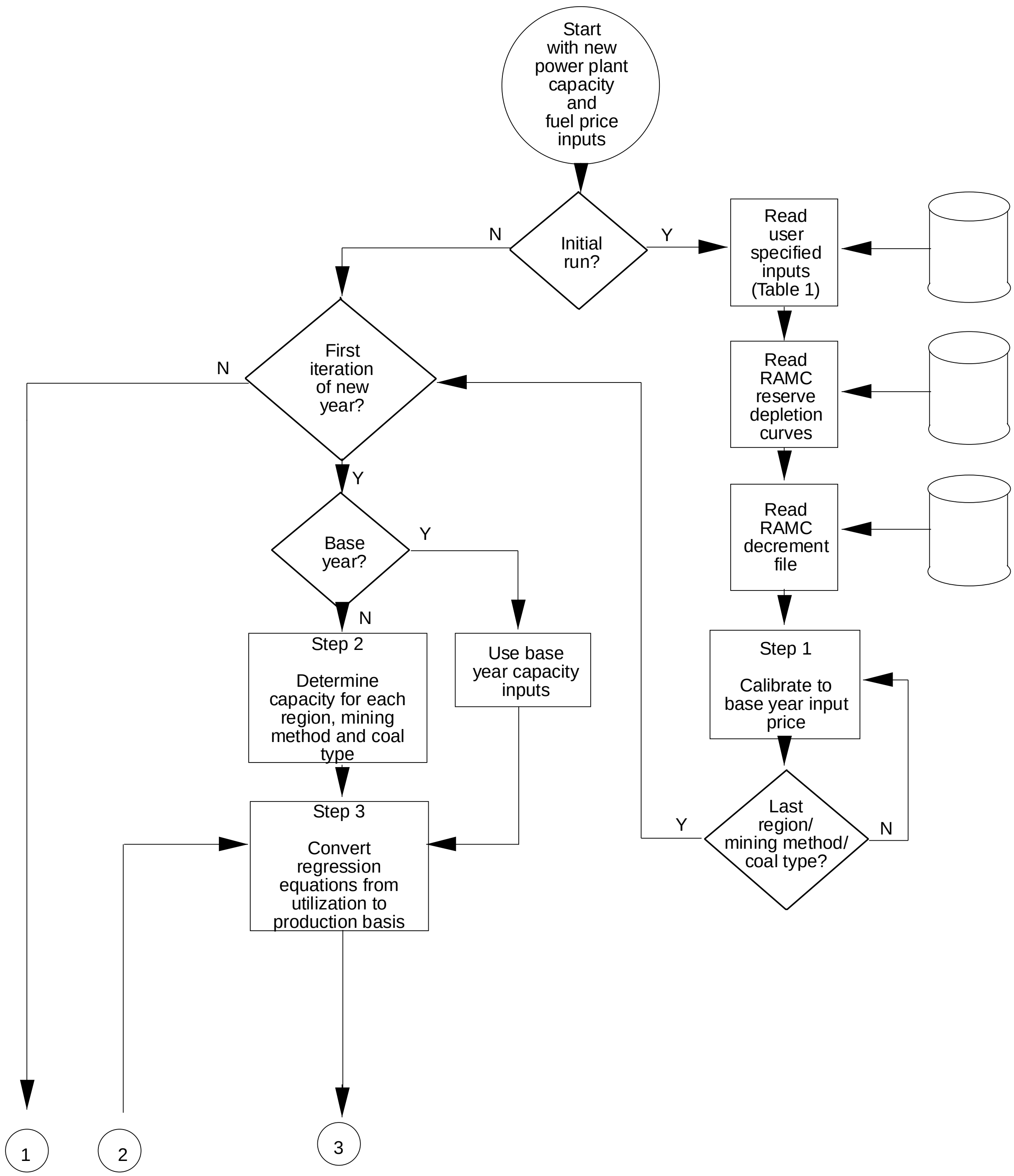
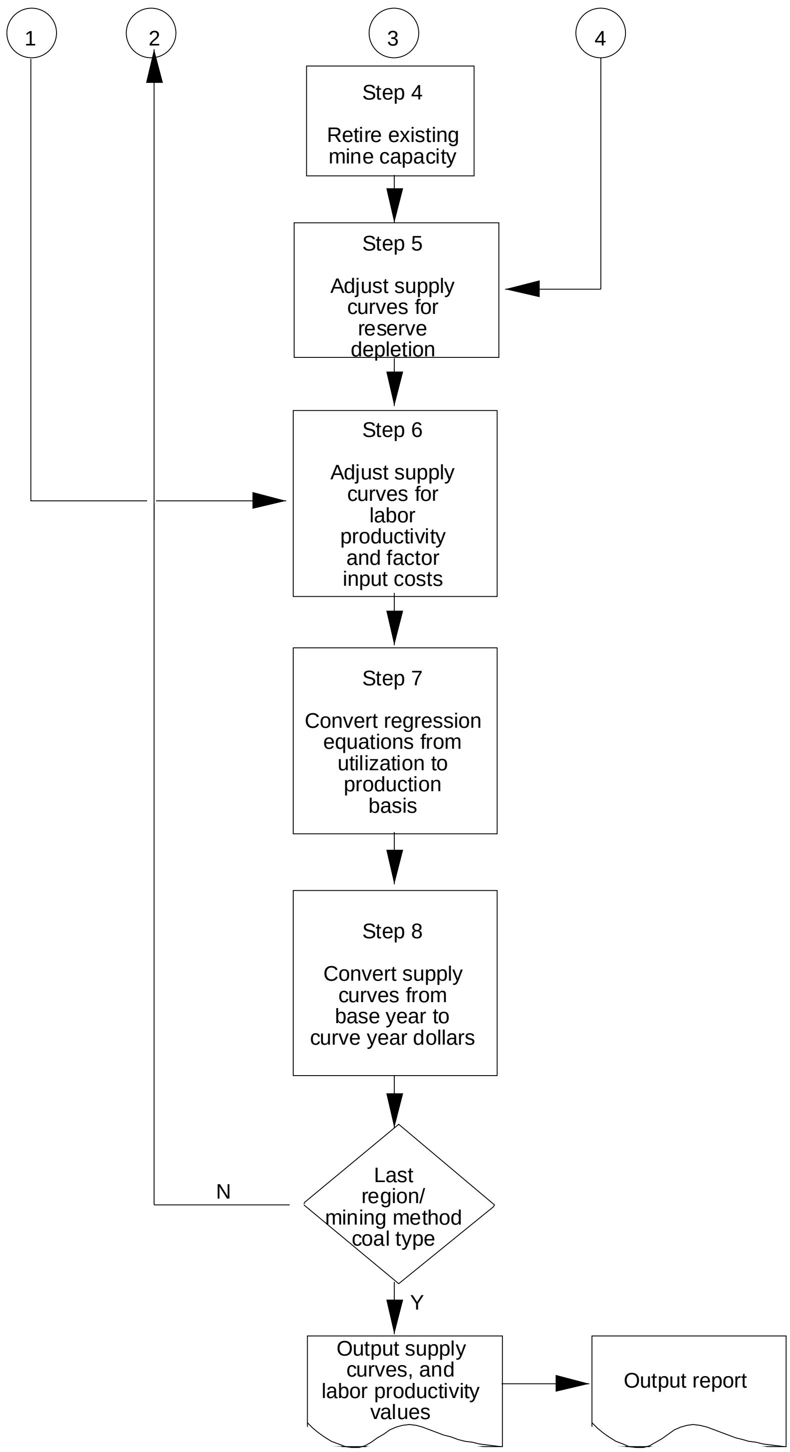


Figure B-1. CPS Flowchart (Continued)



Variable Definitions

The variables used in the model are defined as follows:

Indices

i	=	supply region
j	=	mining method (surface or underground)
k	=	coal type
t	=	year
by	=	base year
ny	=	NEMS reference year (for prices)
x1, x2,...xn	=	aggregate coal demand regions for CPS capacity model
c	=	coal demand region (CDS)
ds	=	coal supply region (CDS)
z	=	step on RAMC supply curve

Input Variables

$P_{i,j,k,t-1}$	=	production for region i, mining method j, and coal type k, in year t-1 (millions of tons)
$LP_{i,j,t}$	=	labor productivity for region i and mining method j, in year t (tons per miner hour)
LC_t	=	escalation index for labor costs in year t
F_t	=	fuel price in year t (dollars per gallon)
$PR_{i,j,k,by}$	=	base-year minemouth price (actual), in dollars per ton, for region i, mining method j, and coal type k, in the base year (from the existing mine step on the RAMC curve)
$R_{i,j,k,t}$	=	capacity retired, in region i, mining method j, and coal type k, in year t (millions of tons)
DEF	=	deflator (fraction)
BASE	=	base year
REF	=	NEMS reference year
$MMP_{z,i,j,k}$	=	computed RAMC minemouth price for step z of supply curve for region i, mining method j, and coal type k (dollars per ton)

Output Variables

$SC_{i,j,k,t}$	=	surge capacity for region i, mining method j, and coal type k, in year t (millions of tons)
$LP_{i,j,t}$	=	labor productivity for region i and mining method j, in year t (tons per miner hour)

$IN^{**}_{i,j,k,t}$ = finalized intercept for supply curve function, for region i, mining method j, coal type k, and year t

$M^{*}_{i,j,t}$ = finalized multiplier for supply curve function, for region i, mining method j, and year t

$b^{*}_{i,j,k,t}$ = finalized coefficient for production term, for region i, mining method j, coal type k, and year t

$AP^{*}_{z,i,j,k,t}$ = price in NEMS reference year dollars, for region i, mining method j, coal type k, step z, and year t (dollars per ton)

$MC_{i,j,k,t}|_{.5}$ = marginal costs on the linear supply segment for capacity utilization between 0 and 50 percent, for region i, mining method j, and coal type k, in year t (dollars per ton)

$MC_{i,j,k,t}|_{s}$ = marginal costs on the linear supply segment for production greater than surge capacity, for region i, mining method j, and coal type k, in year t (dollars per ton)

$m_{i,j,k,t}|_{.5}$ = slope of linear segment of supply function for production at capacity utilization between 0 and 50 percent, for region i, mining method j, coal type k, and year t (set equal to 0.01 $/mm tons); see description of Step 9.

$m_{i,j,k,t}|_{s}$ = slope of linear segment of supply function for production greater than surge capacity, for region i, mining method j, coal type k, and year t (set equal to 150 $/mm tons); see description of Step 9.

$IN^{**}_{i,j,k,t}|_{.5}$ = y-intercept of linear segment of supply function for production at capacity utilization between 0 and 50 percent, for region i, mining method j, coal type k, and year t

$IN^{**}_{i,j,k,t}|_{s}$ = y-intercept of linear segment of supply function for production greater than, for region i, mining method j, coal type k, and year t

$P_{i,j,k,t}|_{.5}$ = production at 50 percent capacity utilization, for region i, mining method j, coal type k, and year t

Other Variables Used in the Model

$C^{a}_{i,j,k,t}$ = unadjusted projected capacity for supply region i, mining method j, coal type k (millions of tons)

$C_{i,j,k,t}$ = projected capacity for region i, mining method j, and coal type k, adjusted for excess capacity (millions of tons)

$IN_{i,j,k}$ = intercept for region i, mining method j, and coal type k, following initial calibration

$IN^*_{i,j,k,t}$ = intercept, as modified for reserve depletion effects, for region i, mining method j, coal type k, and year t

$MC_{i,j,k,t}$ = marginal costs for supply region i, mining method j, and coal type k, in year t (dollars per ton)

$M_{i,j,t}$ = marginal cost model multiplier, for supply region i, mining method j, and year t

$EC_{i,j,k,t}$ = amount of excess (i.e., unused) capacity in forecast year t, for supply region i, mining method j, and coal type k (millions of tons)

$b^*_{i,j,k,t}$ = coefficient for production term, for region i, mining method j, coal type k, and year t

$SF_{i,j}$ = scaling factor for surge capacity, for region i and mining method j

$EXC_{i,j,k,by}$ = capacity of mines existing as of the base year, in region i, mining method j, and coal type k (millions of tons)

$PRAMC_{i,j,k,t}$ = minemouth price at full (100 percent) capacity utilization from the RAMC supply curve, in region i, mining method j, and coal type k, and year t (dollars per ton)

$PRAMC^c_{i,j,k,t}$ = minemouth price at full (100 percent) capacity utilization from the RAMC capacity curve, in region i, mining method j, and coal type k, and year t (dollars per ton)

$CC_{i,j,t}$ = change in costs between the base year and year t, for region i and mining method j (dollars per ton)

$AP_{z,i,j,k,t}$ = adjusted year t price on step z of supply curve for region i, mining method j, and coal type k (dollars per ton)

Step 1: Initial Calibration

Prior to the processing of inputs, the model calibrates the regression equations for marginal costs against current price levels. The regression equations take the following form:

For underground mines:

$$MC_{i,j,k,t} = EXP\{a_j + b_j(P_{i,j,k,t}/C_{i,j,k,t}) + (c_j/LP_{i,j,t}) + d_j(LC_t) + e_j(F_t)^{1/2}\} \qquad (6)$$

For surface mines:

$$MC_{i,j,k,t} = \{a_j + b_j(P_{i,j,k,t}/C_{i,j,k,t})^6 + [c_j/(LP_{i,j,t})^2] + e_j(F_t)^4\}^{1/2} \qquad (7)$$

where

a_j, b_j, c_j, d_j, e_j = regression coefficients

Capacity utilization is represented as production, expressed as a fraction of capacity in the equations. For calibration purposes, base year values of production ($P_{i,j,k,t}$), capacity ($C_{i,j,k,t}$), labor productivity ($LP_{i,j,t}$), and the two factor cost inputs (LC_t and F_t) are provided as model inputs. Using the base year values, the regression equation is solved for each CPS supply region, mining method, and coal type.

Intercepts are determined as the difference between the estimated marginal cost and the corresponding base year price (also provided as an input), as follows:

$$IN_{i,j,k} = (PR_{i,j,k,by} - MC_{i,j,k,by}) \tag{8}$$

Intercepts calculated using the equation above are added to each marginal cost equation (Equation 6 and Equation 7) to complete the calibration process.

Step 2: Determination of Capacity

The base year capacity values provided as input to the model are taken as the initial base year capacities for each supply region, mining method, and coal type. In each subsequent forecast year, capacity is projected by the following procedure.

Because of the lead time required to bring a mine to normal production levels, the CPS makes a decision to build new capacity prior to the year the capacity is needed. The CPS assumes a 2-year lead time constraint. Thus, in each forecast year t, the CPS interacts with the CDS to project capacity requirements in the year t + 2. The CPS passes to the CDS a set of piecewise linear capacity curves derived from RAMC capacity curves. The curves are adjusted to capture the effects of productivity changes, changes in real labor costs and real fuel costs, and capacity retirements. The adjustments are made to the RAMC capacity curves prior to their conversion to piecewise linear segments.

The adjustments for productivity changes and changes in real labor costs and real fuel costs is based on the CPS marginal cost curves evaluated at 100 percent capacity utilization. The adjustment is effected by first determining for the projected year t + 2 the marginal cost of production at full capacity utilization using values of labor productivity, labor costs, and fuel costs in the projected year. For underground mines, the marginal cost at full utilization reduces to:

$$MC^{100}_{i,j,k,t+2} = IN^{*}_{i,j,k} + EXP\{a_j + b_j + (c_j/LP_{i,j,t+2}) + d_j(LC_t) + e_j(F_{t+2})^{1/2}\} \tag{9}$$

For surface mines, the marginal cost at full utilization reduces to:

$$MC^{100}_{i,j,k,t+2} = IN^{*}_{i,j,k} + \{a_j + b_j + c_j/(LP_{i,j,t+2})^2 + e_j(F_{t+2})^4\}^{1/2} \tag{10}$$

Next, the marginal cost of production at full capacity utilization in the base year is calculated using base year values of labor productivity, labor costs, and fuel costs. An incremental cost adjustment is calculated as the difference between the projected year marginal cost and the base year marginal cost, as follows:

$$\Delta CP_{i,j,k,t+2} = MC^{100}_{i,j,k,t+2} - MC^{100}_{i,j,k,by} \tag{11}$$

The incremental cost adjustment is added to each new mine step on the RAMC capacity curve, as follows.

$$RP_{i,j,k,t+2} = PRAMC^{c}_{i,j,k,t+2} + \Delta CP \tag{12}$$

The RAMC capacity curves are adjusted further for retirement of existing capacity. The capacity retired through the projected year t + 2 is obtained from the RAMC "decrement file." For each projected year, the CPS determines remaining existing capacity by subtracting from the capacity existing in forecast year t the capacity to be retired by the projected year t + 2, as follows:

$$E_{i,j,k,t+2} = E_{i,j,k,t} - CR_{i,j,k,t+2} \tag{13}$$

The RAMC capacity curves are a series of steps where the height of each step represents the price of coal and the length of each step represents the amount of capacity available at each price. Each RAMC capacity curve is converted to a series of linear segments. The piecewise linear capacity curves slope upward and to the right, representing the assumption that the least-cost capacity will be developed first.

The piecewise linear capacity curves are passed to the CDS. The CDS passes back to the CPS projected capacity by supply region, CDS coal type/mine type, CDS demand region, and CDS demand sector. These capacities are aggregated by the CPS to CPS supply region, coal type, and mine type, as follows:

$$C^{a}_{i,j,k,t+2} = \sum_{c\in i}\sum_{ds\in i} C^{CDS}_{c,ds,j,k,t+2} \tag{14}$$

In order to ensure that projected capacity moves toward a long-term equilibrium value, the capacity projections are adjusted to capture the effect of excess capacity on capacity build decisions. Excess capacity is calculated as the difference between the prior year's regional capacity by coal type and mine type and the regional shipments (production) by coal type and mine type. Since regional shipments are passed by the CDS to the CPS by supply region, CDS demand region, CDS demand sector, and CDS coal type/mine type, the CPS first aggregates the shipments to CPS supply region, coal type, and mine type as follows:

$$P_{i,j,k,t-1} = \sum_{c\in i}\sum_{ds\in i} SHIP^{CDS}_{c,ds,j,k,t-1} \tag{15}$$

Excess capacity in the forecast year t is calculated as follows:

$$EC_{i,j,k,t} = C^{a}_{i,j,k,t-1} - P_{i,j,k,t-1} \tag{16}$$

The adjustment for excess capacity is as follows:

$$C_{i,j,k,t} = C^{a}_{i,j,k,t} - CEX_{i,j} * (EC_{i,j,k,t})^{N} \tag{17}$$

where CEX and N are coefficients specified by the user.[41]

Step 3: Calculation of Surge Capacity

Surge capacity is defined as the amount of coal a mine can produce, above and beyond the amount the mine is designed to produce under normal conditions using the existing equipment fleet. Surge capacity can be attained, for example, by adding an additional production shift or by expanding production operations to Saturdays, Sundays, and/or holidays. In the model, the surge capacity for each region, mining method, and coal type is calculated on the basis of projected design capacity ($C_{i,j,k,t}$), as follows:

$$SC_{i,j,k,t} = (SF_{i,j})(C_{i,j,k,t}) \tag{18}$$

The scaling factors, used in Equation 18 to estimate surge capacity on the basis of design capacity, are specified as an input to the model. Once calculated, surge capacity represents the maximum production attainable for a given region, mining method, and coal type, in forecast year t; thus, surge capacity defines the endpoint of the supply curve.

Step 4: Retirement of Existing Mines

The first step on the RAMC reserve depletion curves represents mines that presently exist. As noted above, the RAMC post-processor estimates the reduction in existing mine capacity for each year of the 25-year forecast period. The capacity reduction estimates, by region, mining method, and coal type, are output to a "decrement file." The model inputs the decrement file and the file containing the reserve depletion curves. In each forecast year, the model re-estimates existing mine capacity—i.e., the length of each existing mine step—using the following equation:

$$EXC_{i,j,k,t} = EXC_{i,j,k,by} - R_{i,j,k,t} \tag{19}$$

$EXC_{i,j,k,by}$ is obtained from the RAMC reserve depletion functions and $R_{i,j,k,t}$ is obtained from the decrement file.

Step 5: Reserve Depletion Adjustment

After the lengths of the existing mine steps are adjusted to reflect retirements, the model plots each capacity value calculated in Step 2 on the corresponding RAMC reserve depletion curve. The value on the y-axis corresponding to the capacity value represents the total estimated price (including the reserve depletion effect) at full (100 percent) capacity utilization, in the forecast year (year t). The comparable base year price at full capacity utilization is subtracted from the price obtained from the RAMC curve to determine the depletion

[41] The coefficients serve as a market adjustment mechanism. The model adjusts projected capacity requirements based on feedback from the CDS concerning the amount of available capacity actually used in the preceding year. Thus the coefficients provide an interface between the CPS and the CDS that moves the coal industry toward full or 100 percent capacity utilization - i.e., a state of equilibrium. In short, while the model is capable of modeling the coal industry under nonequilibrium conditions, the adjustment for excess capacity will ensure that coal forecasts approach the theoretical expectation that the market moves toward a long-term equilibrium.

effect. The base year price, at full capacity utilization, is computed by solving the marginal cost/capacity utilization equation. This equation, as calibrated in Step 1, is as follows:

For underground mines:

$$MC_{i,j,k,t} = IN_{i,j,k} + EXP\{a_j + b_j[(P_{i,j,k,t})/C_{i,j,k,t}] + (c_j/LP_{i,j,t}) + d_j(LC_t) + e_j(F_t)^x\} \tag{20}$$

For surface mines:

$$MC_{i,j,k,t} = IN_{i,j,k} + \{a_j + b_j(P_{i,j,k,t}/C_{i,j,k,t})^6 + [c_j/(LP_{i,j,t})^2] + e_j(F_t)^4\}^{1/2} \tag{21}$$

where

a_j, b_j, c_j, d_j, e_j = regression coefficients

In the equations above, the value of $P_{i,j,k,t}/C_{i,j,k,t}$ is set equal to 1 (i.e., capacity utilization = 100 percent), and the labor productivity, fuel cost, and labor cost variables are set equal to base year values. Capacity utilization is set equal to 100 percent because the RAMC reserve depletion curves represent costs for mines assumed to be producing at full (100 percent) capacity.[42] Labor productivity, labor costs, and fuel costs are held constant at base year values because, in Step 5, the effect of reserve depletion must be captured exclusive of any effects from other factors. The effects of changes in labor productivity, labor costs, and fuel costs are captured in Step 6.

The difference between the base year price estimate ($MC_{i,j,k,t}$) calculated using Equations 20 and 21 and the forecast year price obtained from the RAMC curve ($PRAMC_{i,j,k,t}$), represents the effect of reserve depletion on price; the supply curve must be shifted up by an amount equal to this difference. Shifting the supply curve is accomplished by adding the difference to the intercept $IN_{i,j,k}$, to yield a new intercept, as follows:

$$IN^*_{i,j,k} = IN_{i,j,k} + (PRAMC_{i,j,k,t}-MC_{i,j,k,t}) \tag{22}$$

In subsequent steps, the new intercept $IN^*_{i,j,k}$ replaces the original intercept $IN_{i,j,k}$ in the marginal cost equation.

[42]Generally, capacity utilization will not be 100 percent in the base year. The capacity utilization is set equal to 100 percent in the base year because the RAMC reserve depletion curves represent costs for mines assumed to be producing at 100 percent capacity. The marginal cost equations are adjusted in a calibration procedure for the actual base year capacity utilization, as discussed in Step 2.

Step 6: Adjustments for Labor Productivity, Labor Costs, and Fuel Prices

In addition to shifting the supply curves to reflect reserve depletion, the model adjusts the curves to reflect changes in labor productivity, real labor costs, and real fuel costs. The adjustment is accomplished by substituting the values of the labor productivity, labor cost, and fuel cost terms in the marginal cost equation using the projected (year t) values of the three factors, and simplifying the equation as follows:

For underground mines:

$$MC_{i,j,k,t} = IN^{*}_{i,j,k} + (M^{u}_{i,t})EXP\{b_j(P_{i,j,k,t}/C_{i,j,k,t})\} \quad (23)$$

where

$$M^{u}_{i,t} = EXP[a_j + (c_j/LP_{i,j,t}) + d_j(LC_t) + e_j(F_t)^{1/2}] \quad (24)$$

For surface mines:

$$MC_{i,j,k,t} = IN^{*}_{i,j,k} + [M^{s}_{i,t} + b_j(P_{i,j,k,t}/C_{i,j,k,t})^6]^{1/2} \quad (25)$$

where

$$M^{s}_{i,j,t} = \{a_j + [c_j/(LP_{i,j,t})^2] + e_j(F_t)^4\} \quad (26)$$

Since the variables $M^{u}_{i,t}$ and $M^{s}_{i,t}$ are calculated using the forecast year (year t) values of labor productivity, labor costs and fuel costs, Equations 23 through 26 capture the changes in productivity and factor costs between the base year and the forecast year.

Step 7: Conversion of Regression Equations from Utilization to Production Basis

After the marginal cost equations are adjusted to capture the reserve depletion effects, productivity changes, and factor cost changes, the model converts the equations from a capacity utilization to a production basis. This is accomplished by replacing the variable $C_{i,j,k,t}$ in Equations 23 through 26 with the corresponding projected capacity value and simplifying. The simplified version of Equations 23 through 26 are as follows:

For underground mines:

$$MC_{i,j,k,t} = IN^{*}_{i,j,k} + (M^{u}_{i,t})EXP[b^{u}_{i,k,t}(P_{i,j,k,t})] \quad (27)$$

where

$$b^{u}_{i,k,t} = b_j/C_{i,j,k,t} \quad (28)$$

For surface mines:

$$MC_{i,j,k,t} = IN^{*}_{i,j,k} + [M^{s}_{i,j,t} + b^{s}_{i,k,t}(P_{i,j,k,t})^6]^{1/2} \quad (29)$$

where

$$b^{s}_{i,k,t} = b_j/(C_{i,j,k,t})^6 \quad (30)$$

Step 8: Adjustment of Costs from Base Year to NEMS Reference Year Dollars

As a result of initial calibration (Step 1), marginal costs on the supply curves are in base year dollars. In some cases, it may be desirable to deflate (or inflate) the marginal costs from the base year to some other user-specified year. The model converts the supply curves from base year to NEMS reference year dollars by adjusting the values of the variable $IN^{*}_{i,j,k}$, $M^{u}_{i,t}$, $M^{s}_{i,t}$, in the marginal cost/production function as follows:

$$IN^{**}_{i,j,k,t} = IN^{*}_{i,j,k,t}/[(1 + DEF)^{(BASE - REF)}] \tag{31}$$

$$M^{u*}_{i,j,t} = M^{u}_{i,j,t}/[(1 + DEF)^{(BASE - REF)}] \tag{32}$$

$$M^{s*}_{i,j,t} = M^{s}_{i,j,t}/[(1 + DEF)^{(BASE - REF)}]^{2} \tag{33}$$

$$b^{s*}_{i,k,t} = b^{s}_{i,k,t}/[(1 + DEF)^{(BASE - REF)}]^{2} \tag{34}$$

If the user sets the NEMS reference year equal to the base year, the supply curves remain in base year dollars; otherwise, the supply curves are converted to the year specified as the NEMS reference year.

The adjusted constants calculated using the equations above can be inserted in Equations 27 and 30 to yield the following marginal cost/production functions:

For underground mines:

$$MC_{i,j,k,t} = IN^{**}_{i,j,k,t} + (M^{u*}_{i,j,t})EXP[(b^{u}_{i,j,k,t})(P_{i,j,k,t})] \tag{35}$$

For surface mines:

$$MC_{i,j,k,t} = IN^{**}_{i,j,k,t} + [M^{s*}_{i,j,t} + (b^{s*}_{i,j,k,t})(P_{i,j,k,t})^{6}]^{1/2} \tag{36}$$

Step 9: Addition of Linear Segments to Supply Curves

Equations 35 and 36 are limited to production values ranging from production corresponding to 50-percent-capacity utilization, to production corresponding to surge capacity. Linear segments are added to the curves described by Equations 35 and 36 for production that falls outside this range. A near-horizontal linear segment is assumed for production between 0 and 50 percent capacity utilization. A linear segment is used in this range to ensure a positive value for the y-intercept, which otherwise could be negative under Equations 35 and 36. Generally, projected production will be in a range that is greater than 50-percent-capacity utilization; hence, the use of an essentially horizontal linear segment for the production values below the 50-percent point represents an acceptable approximation to the curve.

For production values exceeding the surge capacity a steep-sloped linear segment is added to the marginal cost curves to constrain solutions to the operating portion of the supply curve. Conceptually, the physical end of the supply curve occurs at the point representing surge capacity. However, because the CDS solution algorithm permits searches along the supply curve to exceed the surge capacity, it is necessary to add a steep-sloped linear segment as a constraint. The segment prevents the CDS from providing solutions that exceed surge capacity. The linear segments are determined as follows:

For capacity utilization between 0 and 50 percent, a linear segment with a slope ($MC_{i,j,k,t}|_{.5}$) of 0.01 is assumed. In this range, the general form of the linear segment for both the underground and surface marginal cost/production functions is as follows:

$$MC_{i,j,k,t}|_{.5} = IN_{i,j,k,t}|_{.5} + (m_{i,j,k,t}|_{.5})(P_{i,j,k,t}) \quad (37)$$

where $IN_{i,j,k,t}|_{.5}$ is the y-intercept of first segment determined by solving equation 35 or 36 for the production value corresponding to the 50-percent point and subtracting the product of $m_{i,j,k,t}|_{.5}$ and $P_{i,j,k,t}|_{.5}$ from the result.

For capacity utilization greater than surge capacity, a linear segment with a slope of 150 is assumed. In this range, the general form of the linear segment for both the underground and surface marginal cost/production functions is as follows:

$$MC_{i,j,k,t}|_{s} = IN_{i,j,k,t}|_{s} + (m_{i,j,k,t}|_{s})(P_{i,j,k,t}) \quad (38)$$

where $IN_{i,j,k,t}|_{s}$ is the y-intercept of first segment determined by solving equation 35 or 36 for the production value equivalent to surge capacity and subtracting the product of $m_{i,j,k,t}|_{s}$ and the surge capacity from the result.

Equations 35 through 38 represent the finalized supply curves. The model passes the finalized curves for each region, mining method, and coal type to the CDS. The specific outputs provided by the model are described in Appendix A.

Location of Documented Equations in CPS Program

Table B-1 indicates the location within the CPS program of each model equation documented in the main text. The table indicates the number used to identify each equation in this report, a section of the program in which the equation appears, and the line number(s) on which the equation appears. The line numbers correspond to the version of the CPS used for the 1995 *AEO*. It should be noted that some equations are included in the text of this report solely for background information or to clarify material contained in the text. These equations do not appear in the CPS program and, therefore, are not included in the table.

Table B-1. Location of Documented Equations in the CPS Computer Code

Equation Number in Text	Section of Code	Line Number
4	Main Program	1308-1309
5	Main Program	1306-1307
6	Subroutine MODEL1	2080
7	Subroutine MODEL1	2079
8	Subroutine MODEL1	2081-2082
9	Subroutine SUPPLY	3345
10	Subroutine SUPPLY	3344
11	Subroutine SUPPLY	3359
12	Subroutine SUPPLY	3360
13	Subroutine SUPPLY	3386
14	Subroutine SUPPLY	3491-3506
15	Subroutine SUPPLY	3444-3454
16	Subroutine SUPPLY	3460
17	Subroutine SUPPLY	3538-3541
18	Subroutine SUPPLY	3585
19	Subroutine MODEL1	2148
20	Subroutine MODEL1	2208
21	Subroutine MODEL1	2207
22	Subroutine MODEL1	2217
24	Subroutine MODEL1	2246
26	Subroutine MODEL1	2245
28	Subroutine MODEL1	2268-2269
30	Subroutine MODEL1	2268-2269
31	Subroutine MODEL1	2297-2298
32	Subroutine MODEL1	2294-2295
33	Subroutine MODEL1	2292-2293
34	Subroutine MODEL1	2270-2271

Appendix C

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Appendix D

Model Abstract

Model Name: Coal Production Submodule

Model Acronym: CPS

Description: Produces supply-price relationships for 16 coal types and 16 producing regions, based on the EIA Demonstrated Reserve Base, capacity utilization, and changes in labor productivity and factor input costs. The model serves as a major component in the National Energy Modeling System (NEMS).

Purpose of the Model: The purpose of the model is to produce annual domestic coal supply curves for the mid-term (to 2015) for the Coal Distribution Submodule of the Coal Market Module of the NEMS.

Model Update Information: December 1994

Part of Another Model?: Yes, part of the:

- Coal Market Module
- National Energy Modeling System

Model Interface: The model interfaces with the following models:

- Coal Distribution Submodule
- Electricity Market Module
- Petroleum Market Module
- Macroeconomic Activity Module

Official Model Representative:

Office: Integrated Analysis and Forecasting

Division: Energy Supply and Conversion

Branch: Coal, Uranium and Renewable Fuels Analysis

Model Contact: Michael Mellish

Telephone: (202) 586-2136

Documentation:

- Energy Information Administration, *Coal Production Submodule Component Design Report* (draft), May 1992, revised January 1993.

- Energy Information Administration, *Model Documentation, Coal Market Module of the National Energy Modeling System*, Part I, March 1994.

Archive Media and Installation Manual: CPS95 - *Annual Energy Outlook 1995*

Energy System Described by the Model: Potential coal supply at various f.o.b. mine costs.

Coverage:

- **Geographic:** Supply curves for 16 geographic regions
- **Time Unit/Frequency:** 1990 through 2015
- **Product(s):** 16 coal types
- **Economic Sector(s):** Coal producers and importers.

Modeling Features:

- **Model Structure:** The CPS employs regression models to determine marginal costs for underground and surface coal mines.
- **Modeling Technique:** Four steps are involved in the construction of coal supply curves:
  - Project coal production capacity by region, mine type, and coal type
  - Estimate relationship between capacity utilization and marginal cost
  - Construct generic coal supply curves
  - Adjust supply curves for reserve depletion, labor productivity changes, and changes in real labor and fuel costs
- **Model Interfaces:** Coal Distribution Submodule, Electricity Market Module, Petroleum Market Module, and Macroeconomic Activity Module
- **Input Data:** Base year production, capacity, prices, productivity projections, heat and sulfur content averages, reserve depletion functions.
- **Data Sources:** DOE data sources: EIA-6 database, EIA-7A database, *Inventory of Power Plants in the United States* (various years), *Petroleum Marketing Annual 1990*, and the RAMC model and data library. Non-DOE data sources: FERC-423 database and the *Bureau of Labor Statistics Establishment Data: Employment, Hours, and Earnings.*

Computing Environment:

- **Language Used:** FORTRAN
- **Core Requirement:**
- **Estimated Cost to Run:**
- **Special Features:** None

Independent Expert Reviews Conducted:

- Suboleski, Stanley C., *Report Findings and Recommendations, Coal Production Submodule Review of Component Design Report*, prepared for the 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 Energy Information Administration (Washington, DC, July 23, 1992).

Status of Evaluation Efforts Conducted by Model Sponsor: The Coal Production Submodule (CPS) is a new model developed for the National Energy Modeling System (NEMS) during the 1992-1993 period and revised in 1994. The version described in this abstract was used in support of the *Annual Energy Outlook 1995*. No prior evaluation effort has been made as of the date of this writing.

References:

- Energy Information Administration, *Coal Production Submodule Component Design Report* (draft), May 1992, revised January 1993.

- Energy Information Administration, *Model Documentation, Coal Market Module of the National Energy Modeling System*, Part I, March 1994.

Appendix E

Data Quality and Estimation

Data Series Used in the Development of the Regression Models

Regression models for estimating surface and underground marginal costs of production were developed using a combination of cross-sectional and time series data. The cross-sectional data include annual level data for the 16 coal supply regions defined for NEMS, and the time series data include data from 1979 through 1986.[43]

The cross-sectional data included annual data for the 16 coal supply regions defined for NEMS, and the time series data included data for each of the coal supply regions for the years 1979 through 1986. Separate regression models by region and coal type were not developed due to the limited amount of available data (primarily the lack of capacity utilization data prior to 1979) and because mining costs are not dependent, to any significant degree, on coal type.

Historical data for developing the regression models were collected from a number of sources. Data on average minemouth prices and labor productivity were obtained from the EIA-7A database. Data on labor costs were obtained from the *Bureau of Labor Statistics Establishment Data: Employment, Hours, and Earnings*, which provides average weekly earnings for the bituminous coal and lignite industry for selected States that include Alabama, Illinois, Ohio, Pennsylvania, Utah, and West Virginia.[44] Data on diesel fuel prices were represented by refiner prices for no. 2 diesel fuel and were obtained from the EIA's *Petroleum Marketing Annual 1990*.

Data on capacity utilization were derived on the basis of annual production and daily capacity utilization data from the EIA-7A database. Capacity utilization was calculated using the following equation:

$$U = P(100)/C$$

where

U	=	capacity utilization (percent)
P	=	production (tons/year)
C	=	productive capacity (tons/year)

The production values used in the above equation were taken directly from the EIA-7A database. Capacity (C) was estimated on the basis of the daily capacity data contained in the same database. The daily capacity values were converted to annual capacity estimates based on assumptions concerning the standard work schedule at coal mines. Nonrespondents to the request for daily capacity data were identified and deleted; separate utilization estimates were developed by mine size category to enable correction for the fact that the nonrespondents tended to be small operations.

In an initial analyses, the value of productive capacity (C) excluded the capacity of idle mines. Since only those mines that produced coal in a given year are required to report on Form EIA-7A, daily capacity data for idle mines are unavailable. Subsequently, rough estimates of the capacity associated with idle mines were developed and added to the capacity of active mines to yield new values of productive capacity.

[43] EIA did not publish capacity utilization data during the 1987-1990 time period.

[44] Data on labor costs for these particular States were assumed to be representative of regional rates.

Two main steps were involved in the derivation of idle mine capacity. First, mines that were idle in a given year were identified on the basis of whether or not they appeared in the EIA-7A file in prior and subsequent years. Specifically, a mine that did not appear in the file in a given year x, but did appear in the file in both a previous year *and* a subsequent year, was assumed to be idle in year x. Next, the capacity of each idle mine was estimated based on data reported by the mine in prior and/or subsequent years. Specifically, the capacity of the mine was calculated for each year for which data were available for the mine; the three largest capacity values were then averaged together to yield the estimated capacity for the mine in the year(s) in which it was idle.

The regression models were estimated using single pooled cross-sectional data. The results of the regression analysis are presented below.

Regression Model for Estimating Marginal Costs of Production at Underground Mines

$$MMP_{i,t} = EXP[1.431(1/LP_{i,t}) + 0.972(CU_{i,t}) + 0.046(DFP_{i,t})^{1/2} + 0.5*10^{-4}(LC_{i,t}) - 0.137\,(D1_{i,t}) - 0.193(D2_{i,t}) - 0.268(D3_{i,t})] \quad (39)$$

where

$MMP_{i,t}$ = Average minemouth price of coal at underground mines by supply region i in year t (1982 dollars per ton)

$LP_{i,t}$ = Predicted average labor productivity (from stage 1 equation) at underground mines by supply region i in year t (tons per miner hour)

$CU_{i,t}$ = Predicted average capacity utilization (from stage 1 equation) of underground mines by supply region i in year t (fraction)

DFP_t = Average U.S. diesel fuel prices in year t (cents per gallon)

$LC_{i,t}$ = Labor costs for underground mines by supply region i in year t (average annual wages per miner in dollars)

$D1_{i,t}$ = Dummy variable for Alabama coal supply region

$D2_{i,t}$ = Dummy variable for western Kentucky coal supply region

$D3_{i,t}$ = Dummy variable for Illinois-Indiana coal supply region

The R-squared value for the model is 0.9988. The parameter estimates, standard errors and t-statistics for the model are provided in Table E-1.

Table E-1. Selected Statistics for the Marginal Cost Regression Model for Underground Mines

Variable	Parameter Estimate	Standard Error	t-Statistic
$1/LP_{i,t}$	1.431	0.1018	14.062
$CU_{i,t}$	0.972	0.1528	6.364
$(DFP_{i,t})^{1/2}$	0.046	0.0150	3.036
$LC_{i,t}$	$0.5*10^{-4}$	$0.5*10^{-5}$	10.188
$D1_{i,t}$	-0.137	0.0537	-2.548
$D2_{i,t}$	-0.193	0.0496	-3.888
$D3_{i,t}$	-0.268	0.0498	-5.386

Regression Model for Estimating Marginal Costs of Production at Surface Mines

$$MMP_{i,t} = [3230.151(1/LP_{i,t})^2 + 149.370(CU_{i,t})^6 + 6.7*10^{-7}(DFP_{i,t}) + 230.289(D1_{i,t}) + 844.413(D2_{i,t}) + 182.551(D3_{i,t}) + 163.288(D4_{i,t})]^{1/2} \quad (40)$$

where

$MMP_{i,t}$ = Average minemouth price of coal at surface mines by supply region i in year t (1982 dollars per ton)

$LP_{i,t}$ = Predicted average labor productivity (from stage 1 equation) at surface mines by supply region i in year t (tons per miner hour)

$CU_{i,t}$ = Predicted average capacity utilization (from stage 1 equation) of surface mines by supply region i in year t (fraction)

DFP_t = Average U.S. diesel fuel prices in year t (cents per gallon)

$D1_{i,t}$ = Dummy variable for West Virginia

$D2_{i,t}$ = Dummy variable for Alabama

$D3_{i,t}$ = Dummy variable for West Kentucky

$D4_{i,t}$ = Dummy variable for Illinois-Indiana

The R-squared value for the model is 0.9738. The parameter estimates, standard errors and t-statistics for the model are provided in Table E-2.

Table E-2. Selected Statistics for the Marginal Cost Regression Model for Surface Mines

Variable	Parameter Estimate	Standard Error	t-Statistic
$(1/LP_{i,t})^2$	3230.151	91.056	35.474
$(CU_{i,t})^6$	149.370	33.574	4.449
$DFP_{i,t}$	$6.7^{*}10^{-7}$	$2.2^{*}10^{-7}$	3.018
$D1_{i,t}$	230.289	37.111	6.205
$D2_{i,t}$	844.413	36.009	23.450
$D3_{i,t}$	182.551	35.047	5.209
$D4_{i,t}$	163.288	35.665	4.578

Appendix F

CPS Program Availability

The source code for the CPS program is available in file CN6005.PRJ.NEMS.FORTRN. COAL.D0926941. This file is available from the program office.