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THE ICF, INC. COAL AND ELECTRIC UTILITIES MODEL: AN ANALYSIS AND EVALUATION

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FINAL REPORT

by

Energy Model Analysis Program

M.I.T. Energy Laboratory Report No. MIT-EL 81-015

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

Energy Laboratory
Energy Model Analysis Program
Cambridge, Massachusetts 02139

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VOLUME I:

FINAL REPORT

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PREFACE

This report is one in a series of seven volumes presenting the results of an indepth review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). The Final Report (Volume I) provides a self-contained summary of the study objectives and results, with supporting papers and materials presented in Volumes II-VII.

The complete series includes:

Energy Model Analysis Program, "The ICF, Inc. Coal and Electric Utilities Model: An Analysis and Evaluation," M.I.T. Energy Laboratory Report No. MIT-EL 81-015, Cambridge, Massachusetts 02139, March 1980.

Volume I: Final Report

Volume II: Documentation and Verification of Model Implementation

Volume III: Coal Supply Issues: Mine Lifetime and Coal Royalties

Volume IV: The Coal Supply Cost Function

Volume V: Electric Utility Expansion and Operation

Volume VI: Other Evaluation Issues

Volume VII: Evaluation Strategies and Computational Results

Acknowledgments

Several individuals made significant contributions to the organization and content of this project. Dr. Richard Richels, the EPRI project manager, provided overall direction, coordinated the arrangements for supporting the participation of ICF, Inc., and provided many helpful comments and suggestions regarding the substance of the project. Professor Richard Gordon participated as a consultant to the project, attending project review meetings and providing important comments on draft reports and materials. Dr. George Lady, Director of the Office of Analysis Oversight and Access (OAOA) of the Energy Information Administration (EIA), U.S. Department of Energy organized and supported the evaluation of the documentation as a separate project and provided many useful insights and comments regarding the elements of effective documentation. At an early stage of the project, Dr. Phil Childress of OAOA provided useful insights and materials relating to EIA's efforts in using the model, and provided assistance in establishing our access to the model at the EIA computer center. Professor Martin Baughman, Dr. Tom Brown, and Dr. John Weyant provided useful comments on this report.

Most significantly, we acknowledge the contributions of Mr. Hoff Stauffer and Dr. Michael Wagner of ICF, Inc., in particular for their participation in project review meetings, and in responding to questions, draft reports, and materials. We especially want to acknowledge Dr. Wagner's assistance in providing instructions for model operations and use.

Finally, the editing of Mr. Peter Heron and report production work of Ms. Judy Behrens, Ms. Rosemary Dujsik, Ms. Penelope Klyce, Ms. Alice Sanderson, and Ms. Sue Thompson have contributed immeasurably to our efforts.

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Section 1

INTRODUCTION AND SUMMARY

1.1 BACKGROUND, OBJECTIVES, AND ORGANIZATION

The Electric Power Research Institute (EPRI) is sponsoring a series of evaluations of important energy policy and electric utility industry models by the MIT Energy Model Analysis Program (EMAP). The subject of this report, an evaluation of the ICF, Inc. Coal and Electric Utilities Model (CEUM), is the second study in the series.

The EMAP evaluation of the CEUM is especially appropriate as the second study. First, and most importantly, the model is being used by the Departments of Energy and Interior and the Environmental Protection Agency in major studies of the impacts of the Clean Air Act Amendments and energy policies affecting the coal and electric utility industries. Further, the coal production submodel of the CEUM is used by the Energy Information Administration as the coal supply component in its Mid-range Energy Market Model (MEMM) (formerly the PIES system) and so is a significant part of the analytical system used by EIA in its various energy analysis studies, in particular the EIA's Annual Report to Congress. Second, the environment in which the CEUM was developed and is applied differs greatly from that of the first model evaluated--the Baughman/Joskow Regionalized Electricity Model--and so offers a challenge to the guidelines developed in that study for organizing and conducting policy model evaluations.

The EMAP evaluation study of the CEUM was initiated in June 1978 and was conducted in three phases.[1] The first phase, completed in January 1979, involved an overview evaluation of the model. Materials considered included all model documentation and applications for the version of the model extant in September 1978. The report for phase 1 was reviewed by ICF and submitted to EPRI in March 1979. The substance of that report is incorporated in this Final Report and supporting volumes.

The second phase of the study involved an independent audit in which computational experiments designed by the EMAP group were executed by ICF. The design of these experiments was based both upon the analysis of phase one, and the need for the evaluation group to learn how to implement certain types of applications. Approximately one-third of the proposed audit runs were completed by ICF before this phase of the project was terminated and the third phase begun in June 1979. The materials used in the audit phase included model documentation and the September 1978 version of the model made available to ICF on the EIA computer system. Materials from the audit phase are incorporated in this final report as appropriate.

The final and most extensive phase of the project involved an in-depth evaluation of the model, in which the model was transferred to the EMAP group. This phase proved to be the most difficult and time-consuming, in large part because the CEUM was not designed or documented to be transferable, or to be operated by groups other than the original modelers at ICF. The decision to undertake such a difficult task was based upon a mutual desire by EPRI and the EMAP group to provide more computational evidence and analysis relating to the issues identified in the overview and audit phases of the study. The trade-off for increased depth and detail of analysis was, of course, the timeliness of this report.

Phase three was completed early in 1980, and the Final Report was prepared and submitted to EPRI in March 1980. Following review by EPRI and ICF, a joint decision was made to expend more effort on reviewing unresolved issues, including the organization of the Final Report. The evaluation group and ICF met twice during the late summer of 1980, resulting in a revised report submitted to EPRI in October 1980. The major result of this activity was extending Chapter 1 to include a complete summary of the project and results; substantial editing of the remainder of this Final Report; reorganization and editing of the supporting volumes; and correction of an EMAP misunderstanding regarding treatment of control technologies. The revised report was reviewed by EPRI, independent reviewers chosen by EPRI, and ICF, and review results transmitted to EMAP in July 1981. All these reviews have been carefully considered in revising the Final Report.

The modelers and analysts at ICF have been involved in all stages of the evaluation. They have participated in all project review meetings and commented upon all draft and preliminary materials. We acknowledge their comments and contributions as appropriate in the text of this report. Certain issues remain unresolved between the reviewers and ICF, issues which we summarize and discuss in Section 1.5.

The EMAP evaluation of the CEUM identifies key issues in model structure, implementation, application, and associated data, and presents evidence on how these issues affect model applicability and interpretation of results. For this reason the review is most useful to an analyst already familiar with the CEUM, the general class of policy problems for which it is intended, and the studies to which it has been applied.[2] For such an analyst this Final Report and supporting volumes provide considerable information to assist in conducting, interpreting, and evaluating CEUM applications. For analysts less familiar with the model and its intended applications, this review will considerably extend the existing model documentation.

To the fullest extent possible, the review attempts to provide constructive recommendations for improvements in modeling concepts, structure, and associated data. Most constructive are those recommendations which are relatively easy to implement, by modifying either the model or the procedures for application. Of equal importance, but perhaps less useful to the potential user of CEUM, is the identification and analysis of issues for which constructive recommendations were not possible, short of the traditional call for "further research." A secondary but very important contribution of the study is to extend model documentation, thereby increasing the accessibility of the CEUM to potential users and analysts.

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- coal resources (deep versus surface mined in 30 producing regions, 8 sulfur and 5 heat content categories, and 5 deep mine and 6 surface sizes),
- existing mining capacity in a base year,
- factor costs of production by coal type, the expected mine lifetime, and mining recovery factors, and
- industry plans for new mine openings,

the coal supply submodel determines the potential coal production and cost schedules for a specified case year.

The key behavioral assumption underlying these schedules is that a mine will be opened when the case-year market price equals or exceeds the present value of fixed and variable costs of production. The annuitized production costs are evaluated for a fixed mine lifetime, with constant annual rates of production equal to the mine's reserves scaled for recovery loss, and divided by the mine lifetime. The resulting supply schedules are step functions where step height is the present value of all annuitized costs for a given coal type; step length is the total availability of the coal type per annum; and the step segments are organized into ascending order of the annuitized costs of production.

Given the coal production and cost schedules and

- coal transport network and unit costs of transport,
- electricity demand and non-utility coal demand in 39 consuming regions,
- existing utility generating capacity (coal, oil, gas, nuclear, and hydro/geothermal),
- capital and operating costs for capacities and scrubber control technology,
- non-coal fuel costs,
- utility industry plans for capacity expansion, existing coal transportation links and capacities, and

- existing interregional electricity transmission links, and industry plans for bulk transfers,

the remainder of the CEUM is organized as a linear program, the objective of which is to minimize the costs of coal production and transport and electricity production and transmission. The LP portion of the CEUM determines

- equilibrium coal production and prices by coal type and producing region,
- coal transportation flows,
- coal and competing fuel procurement by utilities,
- electricity generation from coal and competing generating sources,
- new plant expansion and scrubber investments,
- interregional electricity transmission, and
- SO_2, NO_x, and total suspended particulate emissions,

while satisfying various constraints and, most importantly, emission regulations.

The model is solved for a specified case year (1985 in applications considered in this review). New problems may be constructed by updating data to reflect expected developments between the original and a new case year (e.g., electricity demand), and adding constraints to the original problem to ensure that capacities or flows created in the earlier period are available for operation or recognized in the new case year. In applications considered in this evaluation, 1985 results have been extended to 1990 and 1995.

1.3 EVALUATION OF THE CEUM

The CEUM evaluation project was organized into three phases, including

- an overview phase, in which model documentation, application studies, and other supporting materials were reviewed and used to identify and analyze issues concerning model concepts, structure, and associated data that might complicate model applications and interpretation of model-based results;

- an independent audit phase, in which computational experiments, designed by the evaluation group to provide information concerning issues identified in the overview's analysis, were implemented by ICF. In addition, some audit runs were intended to provide information to the evaluation group on how the modelers implemented certain types of changes and conducted certain model applications, information which could not be obtained from the available documentation; and

- an in-depth analysis phase, in which the model was transferred to the evaluation group, and computational experiments were designed and conducted to, in large part, help sharpen and resolve issues raised in the earlier phases of the study.

All phases of the study emphasized (i) evaluation of model documentation, (ii) verification of model implementation, including logic of implementation and correspondence of documentation with computer implementation, and (iii) analysis and evaluation of model concepts, structure, and associated data. Each of these activities was conducted with the objective of providing the user/analyst with information concerning the validity of the model in selected applications, and of facilitating interpretation and understanding of model-based studies. A secondary objective was to contribute to model documentation and descriptive materials, improving understanding and accessibility of the CEUM. We now turn to a summary of the major findings of the EMAP study.

1.3.1 Evaluation of Documentation and Descriptive Materials

Documentation of policy models must satisfy the requirements of several groups having very different needs and expectations. These groups include other modelers and model analysts such as the EMAP group; user/analysts who employ the model either in concert with the modelers or independently and who must interpret model-based results; nontechnical groups who use and are influenced by model-based policy research; and decision makers who must integrate model-based policy research with the interests and views of their constituencies. There currently is a very active discussion within the policy modeling community--in particular at EPRI and DOE/EIA--concerning documentation standards and guidelines to meet the needs of these various groups. For our present purposes we employ the documentation types and guidelines promulgated by the Energy Information Administration (EIA). The document types, descriptions, primary audience, and a summary of the evaluation of CEUM documentation in each category are presented in Table 1.

The reader will immediately note the unevenness in the ratings given each type of CEUM documentation. This is due to disparity between the objectives for documentation set by ICF and their sponsors, and those we feel are appropriate for a major policy model intended for studies of complex and controversial policy issues. The ICF documentation objectives for the CEUM may be summarized as follows.

- o The most important documentation objective is to describe the model and associated data in a format designed to facilitate general understanding by study clients;
- o Technical documentation of the scientific basis for the model, as contrasted with model description, is relatively less important since,
    - -- the model methodology and concepts are simple, straightforward, and widely understood, and
    - -- study clients do not require such technical documentation, and acquire what they do need in the course of working directly with the modelers in specific application projects;
- o Formal user/operator guides are not required since the model is intended for use by ICF analysts and operators, not for transfer to other groups.

As will be seen, the ICF documentation is consistent with these objectives. However, we believe the objectives are much too narrow, and do not do justice to the importance of the applications for which the model is intended, or to the needs of the technical community (including ourselves) being asked to evaluate and comment upon the model and model applications. The most serious problem is that so little information and technical analysis is available to rationalize and support the modeling concepts, approach, and methods of data analysis and extension employed by ICF. Presentation of such technical information and analysis should be the natural consequence of both scientific and problem-oriented policy modeling, and should be presented in the natural language of the discipline(s) involved to make peer review and analysis possible. This is indisputable in scientific research, and the same should be true for

Table 1

DOCUMENT TYPES AND DESCRIPTIONS, PRIMARY AUDIENCE, AND EVALUATION OF THE CEUM DOCUMENTATION

Document Type and Description	Primary Audience	Evaluation
Model Summary: nontechnical descriptions of the model and model applications	Nontechnical	Uniformly excellent discussions of study objectives and results; good descriptions of scenario data and methods of data development; good summary descriptions of model structure; poor or non-existent discussion of rationale and alternatives for key model concepts, and level of resolution required for intended applications.
Model Methodology: technical description of rationale, precedents, and comparative evaluations with alternative approaches	Modelers, Peers, Model users, other Analysts	Good descriptions of modeling approach, but not usually in the "natural language" for peers/other modelers. Very little technical discussion justifying model concepts, approach; almost no comparative discussion of alternative approaches.
Model Description: presentation of the model sufficient to describe its structure, associated data, and conditions for understanding and interpreting results	Analysts performing policy research	Consistently good description of associated data and results; relatively poor documentation of actual model implementation; almost no discussion of results in terms of limitations and approximations used in developing data at resolution required by the model.
Guide to Model Applications: nontechnical description of model, and model applications to support interpretation and use of model-based analyses	Nontechnical groups, analysts interpreting policy research	Does not exist
Users Guide: detailed description of operating procedures	User/operators	Does not exist

* The document types and descriptions are based upon the documentation guidelines promulgated by the Energy Information Administration.

Source: Lady (1978).

problem-oriented analysis models such as the CEUM. In these matters it is as important to be told why things were done--and what the alternatives were--as to be told what was done.

Thus, evaluation of CEUM documentation varies depending upon the perspective of its different potential users. In general what has been done is consistently well done, and should contribute significantly to a potential user's confidence in the professionalism of the modelers. What has not been done, however, is critically important to understanding the strengths and limitations of this particular approach. Reading the CEUM documentation will provide the potential user with little information on how the particular modeling approach and concepts are likely to influence model performance in particular applications. This is a serious deficiency, in part remedied by materials presented in this report.

We recommend that additional documentation relating to the technical formulation and implementation of the model be prepared, as well as a formal user/operator guide.[3]

1.3.2 Verification of Model Implementation

Efforts at verification concentrated primarily upon the coal supply submodel and associated data, and upon the data inputs to the LP portion of the model. Verification consisted of three steps, including comparison of documentation with computer code and data files, analysis of computer implementation, and independent reprogramming of one component of the coal supply submodel, the coal production costing routines.

A remarkable result of this effort was that only eight errors were uncovered in the implementation of the CEUM. The most serious error concerns a double counting of deep-cleaning costs for certain coal types introduced in an effort to account properly for cleaning of metallurgical coals. The effect of implementing the corrections results in some adjustments to the 1985 reference case with increasing effects in later years, especially in the distribution of coal production. A number of other issues were identified relating to nontransparent areas of the code where a user might be misled when trying to make changes, usually because that part of the code is subsequently overridden in another part of the program.

A one-day meeting was devoted to reviewing these errors and problems with ICF. At that time they concurred with all results from the verification analysis, except for our approach to correcting the problem with double counting of certain deep-cleaning costs.[4] Based upon this review, a corrected version of the model was implemented. Except where noted, the computational results reported in Chapter 3 of this report and in the various supporting volumes are based upon the corrected version of the model.

1.3.3 Results of CEUM Evaluation

The following material summarizes the results of this evaluation study of the CEUM. We first present some general comments to acquaint the analyst with certain issues of modeling approach, model structure, and associated data important in evaluating model applications and in interpreting model-based results. We then summarize several specific issues that are especially relevant in evaluating and interpreting the CEUM, and most of which lead to specific recommendations for model and associated data revisions and extensions. Next we summarize the implications of the evaluation for actual and/or potential model applications. In the final section, we outline several unresolved issues between ICF modelers and the EMAP reviewers.

Before beginning the summary, it is useful to preface the evaluation with a few words on model applications--especially so the reader will not be misled by the naturally questioning tone and style of the critical analysis and evaluation.[5] In our view the most logical and legitimate use of the CEUM is for analysis of the impacts of the Clean Air Act Amendments (CAAA)--the principal application of the model to date. Excepting the verification errors mentioned above, the various qualifications raised in this report as to the applicability of the model for CAAA analyses pertain to requirements for developing scenario data, data analysis, and checking consistency between such model data and model results. If not addressed by the analyst, these qualifications will, of course, compromise interpretation of model results.

General Comments

In presenting the CEUM, ICF emphasizes "...six key characteristics which enable [the CEUM] to perform sound public analysis with respect to coal." (ICF [1977], p. I-2) These six characteristics are:

- calculates equilibrium solutions for prices and quantitites for U.S. coal markets;
- has a high degree of resolution in coal types and supply and demand regions;
- is price-sensitive;
- is flexible in accommodating case-year and data changes;
- is understandable, being based upon engineering relations; and
- is usable, providing the analyst with extensive output at several levels of detail.

We employed these six characteristics as a convenient framework for some general remarks regarding model strengths and limitations.

Equilibrium Solutions. We note two important qualifications to the notion that the CEUM provides equilibrium solutions for coal market prices and quantities. First, the model does provide a cost-minimizing solution for prices and quantities of coal by type in producing and consuming regions, and for coal transportation flows and electricity transmission. The model formulation treats the coal and electric utility industries as competitive; if this were true, then the cost-minimizing solution would represent a competitive equilibrium. However, since the electric utility industry is a natural monopoly and is regulated, a cost-minimizing approach does not correspond to an equilibrium solution from the utility industries' point of view, although cost minimizing may be the objective of the regulator. To some extent, this is quibbling; the assumption of cost minimization is employed by most similar models--especially utility capacity planning and dispatch models--due to the great difficulty of accounting for the institutional and non-economic factors that influence technology choice decisions by U.S. electric utilities.[6]

Second, the analyst should bear in mind that the CEUM comprises only part of the energy system, so the costs being minimized are conditioned on various other energy form demands, supplies, and prices. The exogenous part of the system, which must be specified in order to use the CEUM, includes electricity demand, non-utility coal demand, and prices of other fuels used in electricity production--all at a considerable regional level of detail. Since the model determines the price of coal and the cost of electricity production, exogenously specifying electricity and nonutility coal demands implies that they are perfectly price inelastic, an extreme assumption that can be moderated only by post-application checking for plausibility of model-produced prices and costs against the exogenous demands.[7]

For the purposes for which the CEUM seems most appropriate, these points do not seem critical, but are important for a potential user to bear in mind when evaluating the usefulness of the model for his/her particular application, and--perhaps more importantly--for the analyst interpreting and presenting model-based results.

Resolution. As suggested by the brief model description in Section 1.2, the CEUM provides the analyst with considerable detail on coal types, production regions, and demand regions. A critical tension exists in the model between the level of detail required by the intended applications, and the measurement system providing data and information for model implementation and in support of model applications. In the analysis of the Clean Air Act Amendments, for example, detail on coal types (characterized by heat and sulfur content) must be combined with information on the cost and performance characteristics of control technologies in order to analyze the trade-off between coal types, investments in control technologies, and use of coal-based generation in electricity production. Because transport cost is an important part of the delivered cost of coal, regional detail by producing and consuming regions is required in order to distinguish this component of coal costs. Thus, although considerable, the level of detail of the CEUM is dictated in large part by the policy issues--in particular the CAAA analyses--for which it is intended.

But while the policy issues may require certain levels of detail, the measurement system providing data and information is another matter. Much of this evaluation is devoted to analysis and computational experiments concerning sensitivity of model results to alternative methods for resolving gaps in the underlying measurement and data system. Here we mention a few general issues relating the geographic, coal resource, utility equipment, and time resolution of the CEUM.

First, consider the geographic detail provided by the CEUM. The CEUM includes 30 coal-producing and 39 demand regions, connected by a coal transportation and electricity transmission system. The requirement for regional detail derives in large part from two sources: the need to represent coal transport costs in the delivered cost of coal, and the fact that sulfur emission regulations have a state component. While we have not developed any significant evidence as to whether these regional classifications are appropriate, we do note that the model documentation provides no analysis as to why this particular classification was chosen or what the consequences of--for example--aggregating regions would be on results, say at the Project Independence Evaluation System (PIES) or the national level of detail.

Our concern lies more with the demand than the production region classification.[8] First, since the model permits electricity transmission between demand regions, shouldn't the demand regions correspond to major utility service regions? There are over 2000 utilities in this country, and over 200 "major" utilities. Do 39 regions represent the appropriate level of detail to capture the relevant possibilities for transmission?

The geographic resolution of the CEUM and the reasons for this detail must be contrasted with the level of detail usually reported in applications of this model. In most applications of the CEUM, the level of reporting detail is the PIES coal production and demand regions, representing a considerable aggregation of the CEUM geographic resolution. When more detailed results are presented, such as in ICF [1978b], they are qualified as follows:

> It must be understood that no model is accurate at its lowest level of regional disaggregation. The ICF model is no exception. (ICF [1978b], p. 11)

Just as the model documentation does not provide much analysis and information as to why the specific geographic level of detail was chosen, so is there little or no clarification concerning the level of detail at which model results are plausible and reliable.

This "modeling aggregation theorem" should be interpreted with some caution by those using CEUM-based studies. First, to the extent it is true, it raises obvious questions concerning the applicability of the CEUM to policy issues requiring detail below the PIES region level. For example, studies of the effect of state depletion taxes upon coal production, or of state environmental policies may be beyond the scope of the model. Second, it might suggest that the user/analyst need not devote very much attention to the detailed results, relying primarily upon aggregated results.

In fact, neither of these conclusions is justified. For a carefully constructed and executed study, the CEUM is useful at the sub-PIES level of detail; likewise, confidence in aggregated results must be based upon analysis, interpretation, and understanding of the detailed results. The "theorem" is really a common-sense rule especially important for models such as the CEUM whose strength is that they can accommodate a great deal of very detailed data and information. The "cost" for the user is that the large amount of information and data to be provided requires a serious commitment on the analyst's part if he/she is truly to understand and interpret model results. This means that the analyst must analyze and interpret model results at the most detailed level (region, coal type, equipment type, etc.) in order for results to be plausible and understandable at more aggregate levels of detail.

Because we are sympathetic to this interpretation of the ICF "aggregation theorem," we are disappointed that more information and analysis is not provided regarding the appropriate geographic detail for, say, the analysis of the Clean Air Act Amendments, the principal application of the model to date. That regional disaggregation is required for analysis of environmental regulations at the state level and for more accurate estimation of transport costs seems quite reasonable, but what effect does this detail have on model results at, say, the PIES or national level of aggregation? In the CEUM documentation, little or no information is provided to the user/analyst on this point. An independent audit experiment was proposed for ICF, but could not be implemented; an experiment along these lines was also considered as part of the in-depth portion of the study, but was beyond the capability of the evaluation group without disproportionate commitment of time and resources. Thus, the effect disaggregation has upon results at the PIES level of detail and above remains speculative.

Next consider the model resolution for coal resources and associated characteristics (heat and sulfur content, geologic deposition). Several points should be kept in mind. First, the basic data relating to coal reserves are not very accurate for CEUM-size regions. The Bureau of Mines, the source of the data used, cautions potential users concerning use of the data as estimates of mineable reserves, and the ICF further cautions the user that:

> The fundamental data upon which the supply curves are based (i.e., the Bureau of Mines reserve data) do not warrant undue confidence in the high disaggregated estimates. (ICF [1978b], p. 11)

For near-term studies these cautions are probably less significant than in the longer term, when increasing portions of total coal supply come from new "frontier" coal resources. To the extent that uncertainty about the level and geographic distribution of coal resources contributes key uncertainties in policy analysis, improved estimates of the size of the resource base will be required. Some information is provided in this evaluation study relating to the effects upon model results of plausible changes in the expected size and geographic distribution of the United States coal resource base. The reader should keep in mind that since the Bureau of Mines is a key source for coal resource data, any coal supply model using this source will require the same cautions.

Perhaps a more important caution for the user is that coal resource data are not collected by the characteristics of geologic deposition (seam thickness, depth, overburden ratio) required by the model's procedure for evaluating costs of production. When the source data do not provide the resolution required by the model, ICF's procedure is to apply the uniform distribution to "estimate" the missing data. Their assertion is that when no other information is available, it is best to employ the simplest possible distribution rule. Thus, for example, in estimating the distribution of coal resources by seam thickness, ICF assumes that the total available resource is distributed uniformly between the minimum thickness reported by the Bureau of Mines (28 inches) and the maximum thickness so reported (72 inches).

Others claim to discern evidence supporting a more complicated distribution of coal seam thickness, namely the lognormal distribution (e.g., Zimmerman [1979]). However, this evidence is based on one coal-producing region and is not generally viewed as definitive.[9] In this review, an experiment was conducted to determine the significance of using one or the other distribution, with results suggesting that it is of some importance. However, the analysis is unconstructive in the sense that no new information could be developed to resolve the underlying question without new measurements and analysis of actual distributions. Thus the user must be satisfied that in any application no policy result depends critically upon the assumption of a uniform distribution for unclassified coal resources.

A third point relating to resolution is the complementarity between coal types considered in the model and the equipment utilizing this coal, both generating equipment and environmental control equipment. Here the user/analyst should note that in the version of the CEUM under consideration, the cost and efficiency characteristics of generating and control equipment are complementary with the model coal types, but the equipment choices are limited to one control technology--wet limestone scrubbers. This choice was justified on the basis of an independent, unpublished study, which also provided engineering estimates of the costs and efficiencies of the scrubber technology at different plant size and for different coal sulfur content levels.[10] Of course, adding control technologies to the CEUM is quite possible, dependant only on developing and incorporating the relevant data.

Finally there are several points to keep in mind concerning the time resolution of the CEUM. First, the "gain" from the static formulation is the ability to accommodate the considerable resolution of the model in a computationally feasible system. The "costs" are that dynamic features of the coal/utility industry investment and production process must be dealt with outside the model itself. First, the greater the time between the base and case years, the greater is the analyst's effort required to project the time path of those variables that are endogenous in the case year, since much of this data depends on analysis of industry plans and on out-of-model projections. Second, the static formulation means that decisions in the case year do not reflect information about future periods. For example, utility investment decisions do not reflect the firm's evaluation of possible changes in environmental regulations or, more importantly, technical developments in generating and control technologies. Likewise, decisions to produce coal in the case year do not reflect any information concerning producer expectations about the future price of coal.

The former problem is probably beyond the current state of the applied modeling art, for reasons mentioned above. The latter problem is of greater concern to us. For example, while the assumption that intertemporal rents are zero is a feature of all the coal supply models with which we are familiar, some evidence developed in this evaluation study suggests that this might not be a good assumption for U.S.

coal--especially when a detailed classification of coal types and production regions is employed. Further, in the CEUM the "myopic" formulation leads to a particular approach to modeling the mine opening decision, which treats mine lifetime as an exogenous variable independent of future prices, interest rates, and other economic variables influencing the producer.

We have mentioned various issues which the CEUM user must keep in mind regarding the geographic, coal reserve, utility equipment, and time resolution of the CEUM. In summary, the CEUM achieves its level of resolution through a combination of estimation methods applied to source data and a model specification sufficient to reduce the computational problem to one of static cost minimization. The trade-off between detail and computational burden of model applications dictates the static formulation. This imposes a cost upon the user to deal with certain of the inherently dynamic features of their problems outside the model. As we shall see, some extensions to the CEUM modeling system may help to mitigate these costs.

Price Sensitivity. The CEUM cost-minimizing solution for regional coal production and utilization by coal type is the most important characteristic of the model. Not only do we obtain cost-minimizing coal prices, conditional on the data and constraints of the problem being solved, but the LP formulation provides the user/analyst with information on the contribution of each one unit change in each constraint via the shadow prices associated with a solution.

A caution for the user, however, is to keep in mind which prices are not allowed to adjust. Most importantly, factor supply schedules are assumed to be infinitely elastic over the range of demands projected by the model. For certain types of input factors--e.g., utility capacity and transport and transmission systems--technical constraints on construction times and supply capacity are introduced, thus mitigating the infinite supply elasticity assumption, requiring the user to develop the information independently. But capital, labor, and materials for coal mining, and fuel inputs for electricity generation are treated as being infinitely available at the specified prices.

Perhaps more seriously, the model assumes that electricity demand and aggregate non-utility coal demand are perfectly price-inelastic. These are very restrictive assumptions, not supported by consideration of the literature or any independent analysis. To ensure that exogenous non-utility coal and electricity demands are consistant with model estimated electricity costs and coal prices, the user must perform a post-application check involving independent information on demand elasticities, and analysis of the relation between estimated costs of electricity generation and the regulated price of electricity.

Flexibility. The CEUM provides the user with considerable flexibility in the choice of time frame, model activities, and data to be used in a particular analysis. The CEUM LP framework is largely data driven, and so structure comes from data used in conditioning and constraining the problem (cost coefficients, resource constraints, capacity levels, etc.). It is in this sense that the CEUM should be viewed as a flexible system.

However, there are costs to this type of flexibility. First, the fact that much of the information conditioning a particular problem must be provided in the form of input data and constraints means that the user/analyst must devote considerable effort to pre-application data preparation and analysis. Of course much of this effort carries over from problem to problem, so the modelers and their long-term clients have built up data bases and experience which greatly reduces the effort required to prepare a new problem. But a new client/user would have to familiarize him/herself with this data base legacy in order to be convinced of its legitimacy and in order to be convincing in interpretation and analysis of applications based on its use. An analyst responsible for interpreting and appraising model applications also would have to make a similar effort. Thus the quasi-permanency of portions of the input data is only a partial off-set to the effort required in data analysis for any particular problem.

Second, much of the detail and resolution in the CEUM is possible because of simplifying assumptions which are untenable without post-application analysis and consistency checking between data and assumptions and model outputs. We have mentioned in the sections on Resolution and Price Sensitivity some of the consistency checks that are required in order to mitigate the effects of untenable simplifying assumptions. Such auxiliary analysis, and the possibility that certain parts of the application will require iterative solution, reduces the apparent flexibility of the CEUM.

One point concerning flexibility in preparation and analysis of model results should be noted. In the version of the model considered in this evaluation study, an excellent report generator was available, providing considerable flexibility in developing report formats and providing a capability for post-application arithmetic, thereby facilitating input-output data consistency evaluation and analysis.

Understandability. ICF emphasizes that the CEUM is based upon engineering relations that facilitate understanding, checking, and revising of components. They note that since so much of the data must be based on expert opinion and judgment, it is important to:

> ...break complex relationships into their component parts and then use the best estimate possible for each component. (ICF [1977], p. I-8)

Further, they argue that linear programming is the most appropriate methodolgy providing a convenient framework for a data-driven model in which many external constraints can be imposed. ICF contrasts this explicit "engineering components" approach to more heuristic approaches, as follows:

> The relevant variables in relationships are identified explicitly in terms that are understandable. The structural approach minimizes the use of statistics and general regression equations. It stresses the use of engineering relationships and disaggregated data. As a result, each data element, relationship or assumption can be subjected to review and comment by those experts familiar with that

> aspect of coal supply. Since the structural approach is data-driven, new data inputs can be accommodated without modifying the basic structure of the model. Thus, the structural approach allows for sensitivity analyses which identify the variables that really matter. Unfortunately, the data needs of the model are substantial. While much of the data that is needed is readily available, a significant portion is not. (ICF [1977], p. III-1)

We agree that an "engineering components" approach is appropriate, given the resolution of geography, coal type, and geologic deposition that ICF judges is required for the problems they wish to address with the model. But in the case of the CEUM the approach is largely dictated by the lack of real data and information required. As the above quote makes clear, and as the discussion of Chapter 3 will further demonstrate, much of the data required to calibrate and apply the CEUM simply is not available. This is why so much of the model documentation is given over to presenting the heuristics by which model data are generated.[11]

Of course, we would expect such "openness" in any modeling effort. But we would hope for more, in particular that the data required to calibrate and apply the model be independently measured, and not generated as part of the modeling effort. Further we would require that the data be sufficient to support evaluation of alternative hypotheses about appropriate model concepts and structure. Being informed as to how a particular concept--say the concept of the "model" mine--is calibrated is not sufficient to make the concept understandable and meaningful in a scientific sense. To accomplish that, we require an unambiguous linking of theory, measurement, and analysis. Much of the CEUM is simply not understandable in this sense.

It should be noted that these observations are not necessarily a criticism of the LP as a modeling approach, nor a comment as to whether or not the liberties taken in data generation can be justified. In fact we are inclined to the view that the issues--especially analysis of Clean Air Act Amendments--do require a level of detail exceeding that supported by current measurement systems and that the effects of data generation upon model results can be sufficiently understood so the model can legitimately discriminate among policy alternatives. Careful description of the data generation process is essential to such understanding and control, and this part of the documentation is generally excellent. Understanding the data generation procedures, however, should not be confused by the user with more fundamental scientific understanding of the process being modeled and analyzed. Thus, much of this review is devoted to analyzing model sensitivity to plausible changes in model data, and the effects of these changes upon the model's discriminating power.

Usability. By now it should be clear to the potential user that the CEUM should be used only in association with the ICF modelers. Even then, use of the model will be very expensive in terms of the analysts' time and resources necessary to develop a model data base that is understandable and plausible to the user, and in checking the various consistency loops mentioned above and in Chapter 3. For these reasons, the CEUM is probably most useful for those organizations having a continuing, as opposed to "one-shot," requirement for the general kind of analysis provided by this model and ICF.

ICF emphasizes that CEUM output report formats make the model results very usable by analysts. Not only are the existing reports and formats useful in terms of providing model output at a variety of aggregation levels, but also the report writer language in which the version of the model we evaluated is written makes generating new reports an almost trivial exercise. This is a very important and valuable feature of the model.

Specific Issues and Major Recommendations. Next we discuss some specific issues regarding CEUM structure and associated data, and present recommendations, mostly related to appropriate model use and interpretation. The most important issues considered in this evaluation study relate to the coal production and the electric utility submodels.

First, however, two points should be made concerning what the CEUM formulation is not intended to be. Most importantly, the CEUM formulation of the utility capacity planning and dispatch problem is not intended to be a substitute for the detailed capacity planning and dispatch models employed by utilities. The purpose of the CEUM formulation is to provide a sufficient framework by which utility coal demand and control technology investment may be jointly determined, consistent with emission regulations. The ICF view, with which we concur, is that this can be accomplished with a relatively aggregate representation of plant types and utility choice variables. The potential user evaluating the CEUM should concentrate upon satisfying him/herself that sufficient detail and representative utility behavior are present and adequate to the task of evaluating the trade-off between control technology investments and coal types, and between coal-based generation and alternative sources. This is the essential purpose of the model.

Related to this, the reader should not judge the CEUM on the basis of its likely forecasting capability or performance. At best, the CEUM might be characterized as a conditional forecasting system, assuming that the various behavioral factors that complicate or invalidate the assumption of cost-minimizing behavior by all agents in the system are satisfactorily dealt with via externally introduced constraints and data provided by the user/analyst. The purpose of the CEUM is policy analysis, not forecasting. For this purpose the "proper" use of the model--at least in our opinion--involves the user/analyst devoting considerable effort to developing both the input data--including constraints and conditioning information in the form of industry plans and expectations concerning future likely industry behavior--and to use these data to obtain a plausible and "interpretable" reference analysis for the case year(s) of interest. This effort is substantial and under present circumstances cannot be done efficiently without active interaction between ICF and the user.

We now turn to issues relating to the coal production submodel. Four issues are particularly important. These include the treatment of mine lifetime, reliability of the underlying coal reserve and resource data, the treatment of intertemporal rents in coal production costs, and the approach to evaluating coal production costs.

Perhaps the most serious problem in the coal supply submodel is the assumption of a uniform mine lifetime. Given reserves and recovery factors, mine lifetime is the key parameter in determining coal production. It affects supply in two important ways. First, for a given volume of reserves, the rate of extraction is inversely proportional to the mine lifetime. Second, it directly affects the cost of production through influence on capital investment. A longer mine lifetime means lower extraction costs due to lower annualized capital costs, with no attention to rewarding the owner for further delay in recovering his investment. Section 3.3.2 will demonstrate that model results are very sensitive to this parameter, so the issue is not simply "academic." To illustrate how mine lifetime might be endogenized, we have developed a conceptual "counter-model" that treats mine lifetime as an economic variable subject to control by the mine operator via decisions regarding rate of production from a fixed body of reserves. In this conceptual model the economic mine lifetime is seen to depend importantly upon such economic variables as the interest rate and the capital recoupment period--the latter depending on the price of coal.

There are three ways to deal with this problem. The issue is complicated by the fact that implementing some variant of the counter-model involves a dynamic formulation. Thus, to endogenize the mine lifetime as a function of the interest rate and capital recoupment period (for example) requires that investment decisions in the current period depend upon expectations about future coal prices. This is probably computationally infeasible without a significant reduction in the model resolution. An alternative to endogenizing the mine lifetime would be to develop an auxiliary model that could initially estimate the mine lifetime conditional on an expected future price of coal, then check the result when the full model has been solved for this price. Such an auxiliary model would "close the loop." As a third alternative, the user can simply keep in mind that he/she should check carefully the plausibility of the complementary relationship between inputs of interest rate and mine lifetime and the output coal price in the case year.

We recommend the second option, that an independent auxiliary model should be developed and applied in conjunction with the CEUM to "close the loop" between mine lifetime and coal price.

A second issue is the accuracy of coal reserve data and the information and procedures for distributing that source data to the geologic characteristic, and heat- and sulfur-content detail required by the CEUM. As noted above, the Bureau of Mines advises caution when attempting to translate their reserve data into estimates of recoverable reserves. Yet ICF not only uses the data in this way (after adjusting for such factors as deposition under highways, cities, and in unrecoverable situations), but further distributes the data by such geologic characteristics as seam depth and thickness. Where distribution is required, ICF always employs the uniform distribution, arguing that the simplest distribution scheme should be used when no additional information is available. Through several computational experiments we have shown that model results are very sensitive both to changes in the reserve data base and to changes in the assumption of the applicability of the uniform distribution. These results demonstrate the importance of ensuring that any policy results based on the model be insensitive to plausible changes in the reserve base and/or the distribution procedure. The studies reviewed in this report do not pay attention to this issue, so we recommend that users devote greater attention to a sensitivity analysis of the effect upon policy conclusions of plausible changes in the coal reserve base. The reader should note that any coal supply model must deal with these issues; they are not unique to the CEUM.

Another important issue concerns the treatment of intertemporal rents in the CEUM. The CEUM is formulated as a static model and so calculates those rents associated with a particular unit of coal production based upon the difference between its extraction cost and the cost of extraction for the marginal increment of coal being mined. This procedure provides no reward to the owner of the resource who delays extraction to some future period. The treatment of such intertemporal rents accruing to a depletable resource is naturally a dynamic issue, since the payment required by resource owners in the current period depends upon their expectations about future prices.

As with mine lifetime, it would be possible to treat intertemporal rents by making the current model dynamic. But again, given the current data resolution of the model, this is likely to be computationally infeasible. Alternatives would include developing an auxiliary model to be used in calculating the approximate intertemporal rent to be included in the static model and/or checking output results from the CEUM. In the CEUM and similar modeling efforts the importance of intertemporal rents has been considered minimal. This may be true, but our experiment reported in Section 3.3.2--calibrated with data from the CEUM data base--suggests that ICF and others may be underestimating the importance of this factor. We have not developed enough information in this study to support a strong recommendation for an auxiliary modeling effort. At minimum, we recommend that more analysis be devoted to this issue in order to determine the potential importance of this problem.

A final set of coal supply issues concerns the estimation of coal production costs in the CEUM. Production costs are based upon cost factors associated with two "typical" mines, a surface and an underground mine, complemented with cost adjustment parameters explicitly associated with changes from the characteristics (size, seam thickness, depth, overburden ratio) of the typical mine. In Section 3.3.2 we present results showing the sensitivity of results to these adjustment factors. Further, our analysis provides some disconcerting evidence regarding the behavior of the underlying engineering cost function implicit in the CEUM data. In particular, the curve has no minimum value for both deep and surface mines, a result difficult to interpret given the nature of coal production.

The typical mine costing data and the cost adjustment factors used in the CEUM were developed some time ago (1974-76) in studies relating to the FEA Project Independence project and subsequent coal supply modeling efforts. The sensitivity of model results to the data and methods used suggests that more data development and analysis work is required. We recommend that any organization considering use of the CEUM carefully review the assumptions and procedures of the "typical mine" approach and the data used to implement that approach. Even when this approach is considered acceptable, some new data development will still be required. We recommend careful consideration of either adopting the EPRI/NUS mine costing model and data or a new independent effort. In either case, and especially in the latter, the effort is not trivial.

We now turn to the electric utility submodel (EUS) of the CEUM. The essential elements of the EUS may be summarized as follows:

- Case year fixed electricity demand is distributed via a regional exogenously specified load duration curve characterized by four load segments (daily peak, seasonal peak, intermediate, and baseload);

- Base year plant types/capacities are distributed to these four segments, at a prespecified capacity factor;

- The aggregate generating capacity in the case year must be sufficient to satisfy demand in that year by each load segment; the model chooses the least-cost combination of plant types to satisfy the demand for that segment, building additional capacity as necessary, satisfying system constraints on expansion limits, required coal flows, and usage, plant characteristics, etc.;

- Of special importance is that for coal-burning plants, the relevant cost comparisons reflect investments in control technology versus coal types consistent with emission regulations;

- Finally, generation costs are compared across demand regions, permitting interregional transmission in place of new capacity additions when such transfers reduce costs of meeting baseload demand.

This abbreviated description of the electricity supply submodel (EUS) highlights three important issues that attracted our attention.

First, there is the issue of constraints on expansion plans generated by the model, and the trade-off between resolution in plant characteristics and computational complexity in the model. Second, there is the issue of the resolution of the load duration curve used in the model, the means by which this representation is parameterized, and the sensitivity of model results to plausible changes in this parameterization. Third, and closely related to the second issue, there is the manner by which peaking capacity expansion absorbs the "excess" demand of the system.

The first point is an important caution to the user of the CEUM. In all the applications of the CEUM considered in this evaluation study, the user has been required to fix the levels of new investment in all plant types in base and intermediate load, except for coal plants and oil and gas turbines to meet peak demand. In these applications the model chooses between coal types and between scrubbing versus cleaning coal. Further, while there may conceivably be as many coal plant types as there are coal types in the model, in fact in any particular region many of these coal types will not be economical, and so may be screened out of consideration by the user, thereby decreasing the model's computational burden. This is all quite reasonable, especially considering the difficulty in modeling the choice between nuclear and coal plants given the great uncertainty in regulatory process and ultimate costs. Further, even if modeling the coal/nuclear choice issue were not so difficult, it might be reasonable in a model intended to analyze the consequences of changes in environmental regulations and in coal industry development to "control" a particular nuclear expansion plan. However, the user must always keep in mind that such plausible assumptions are justified only by his/her hard work at developing reasonable expansion plans in the first place, and in checking the consistency of model outputs with these plans.

Along this same line, one interesting feature of the model that has not been much commented upon or used in the application studies that we have reviewed, is that existing plant capacity may serve any load segment of the load duration curve (LDC), and may be "retired" when it proves uneconomic to employ. Thus, while investment decisions reflect the expected physical life of the capacity, the economic life of existing capacity reflects the economic conditions in the case year. The static nature of the capacity planning process in this model complicates the interpretation of unused capacity in the case year as being economically retired, but such information should be of interest and use to the analyst. For example, in regions with a high proportion of oil and gas in existing capacity, analysis of the economic trade-off between replacing this high-variable-cost capacity with lower-cost capacity, especially coal, is an important policy issue.

A second issue of which the user should be aware is that the load duration curve (LDC) is represented in the CEUM by four points (four load segments) for each region. There are two questions here. First, are four points sufficient to approximate the LDC? Second, how are the representative LDCs for each region developed and projected?

As to the rationale for a four-point approximation to the regional LDC, the ICF documentation provides no information. In discussions with the modelers, they have noted that the original PIES formulation (closely related to the CEUM) employed only one point, while the FEA's National Coal Model (the CEUM's immediate ancestor) employed a three-point approximation. ICF asserts that going from one- to three- to four-point approximations had a "significant impact upon the results," but have provided no evidence on this point.

An heuristic argument can be made, however, in support of the four-point approximation. Just as in so many other instances with this model, resolution in the LDC is obtainable only with significant increases in computational burden. Adding more load segments would mean adding increased detail in plant types and characteristics. Such detail is most useful if the scrubber investment and operating costs are nonlinear with respect to the plant size and characteristics, but this is not the case, at least for the version of the model we considered. Thus, in an important sense the treatment of the scrubber cost function in the CEUM determines an important aggregation condition for load segments. Since scrubber costs are linearly related to plant size in the CEUM, employing two load segments to accommodate base and intermediate coal plants of implicit constant size does not seem unreasonable, unless there is some other consideration. The obvious "other consideration" is whether or not the four points chosen produce a plausible pattern of capacity expansion, and a plausible load factor for each region in the model. "Plausible" here would mean bearing some consistent relation with the historical patterns and/or with the expected behavior of the utilities in that region. Such evaluations are a critical contribution of the analyst, both in picking the points to approximate the region's LDC and in evaluating the expansion plan produced by the model.

Clearly the user's task may be reduced by providing an auxiliary (or in the jargon of utility analysts, a screening) model by which the LDC parameters may be generated consistent with a plausible load factor for that system. We strongly recommend that such an auxiliary model be explicitly provided as part of the CEUM. Such a model has two uses: to assist in developing input data for representing the LDCs for each region, and for post-application checking of the actual expansion plan's consistency with the capacity factors assumed for each plant type in each load segment. The reader should be aware that in discussing this point, ICF has indicated that such a model exists and is routinely employed in developing the input data for representing regional LDCs in the CEUM. This existing model, never referenced in any of the studies we reviewed, should be accorded a more prominent place in the CEUM documentation.

Next consider the basis for the representative LDCs. In the version of the CEUM considered in this study, each region's LDC is taken to be an historical LDC for one utility within that region. No evidence is provided that the utility chosen is "representative" for the region, or that an averaging of a region's utility LDCs was considered. There are two consequences of using an historical LDC for one utility as the starting point for projecting a future LDC for the region. First, it provides no information as to the quality of the representation even in the base period. The notion of a representative LDC clearly should be reflected in the definition of utility regions. A region with very different utilities in terms of their LDCs would only be an acceptable aggregation if the pattern were expected to persist into the future. Second, even supposing that a particular LDC was a good historical representation for the region, how does this help the user in projecting a case year LDC? The answer is, very little; its only use is to provide an estimate of the load factor for the region which might be used as a benchmark against which to evaluate case-year load factors for plausibility.

What should be done? First, more attention should be paid to developing and using historical data in representing the base year regional LDCs.[12] Since this data base is so important in evaluating the ultimate plausibility of model results, it seems worth some effort to develop in a usable form. Such data are readily available, at least for all large utilities, and should be analyzed and made available to a CEUM user/analyst. Second, the screening model used by the CEUM should be integrated with this data base, documented, and provided to the user of the CEUM, or at least be made transparent to him/her via augmented documentation of CEUM-based studies.

The third major issue of which the user should be aware concerns oil and gas turbine capacity in the CEUM. The issue arises in the following way. Small changes in the shape of the load duration curve--i.e., shifts between the daily, seasonal, intermediate, and baseload segments of the curve--are magnified for oil and gas turbines, which are the primary new source for the seasonal and daily peaking portions of the LDC. Because these are small units, small changes in the pattern of electricity demand can have large effects on the number of units required. A degree of freedom is provided to the system by leaving capacity additions for oil and gas turbines essentially unconstrained.

Several of the computational experiments in this study make clear how sensitive oil and gas turbine capacity is to changes in the distribution of demand between load segments, thereby underscoring the importance of this particular post-application consistency check. For example, a one-unit change in the least significant digit of the CEUM parameter characterizing daily peaking energy will cause a shift of 6 GW of turbine capacity--approximately 5 to 10 years of current planned expansion. The important point to note is that a plausible reference case or application requires that the load factor, the pattern of expansion versus capacity factors by load segment, and the peaking capacity requirements all be carefully checked for plausibility and for consistency with information on likely industry behavior. The problem is not so much a flaw in CEUM--we think the formulation seems a reasonable trade-off between computational efficiency and requirement for user pre- and post-application analysis and checking--but rather a warning to the potential user and the analyst concerned with interpreting CEUM-based studies.

In the more detailed material presented in Chapter 3 and the supporting volumes, several other points are made relating to model structure resolution and data inputs. In general, however, bearing in mind that the CEUM is not a substitute for the detailed expansion planning and dispatch models used by utilities and is not intended as a forecasting model, we believe that the electric utility submodel is adequate for the principal application of the model to date--analysis of amendments to the Clean Air Act.

One other issue relating to the non-utility demand for coal deserves mention here. As noted, the user is responsible for preparing an estimate of the aggregate non-utility demand for coal. The model then determines the cost-minimizing combination of coal types that satisfies this demand. Since the environmental regulations may also affect industrial coal use, any information available on permissible coal types must be included as constraints on the amounts of those particular coal types. The problem of trading off among durable equipment, fuel use, control technology, and coal type is transferred outside the model to the user. Thus, somewhat paradoxically, the problem that the model addresses for the utility sector is left to the user/analyst for non-utility coal use. The issue is mitigated somewhat by the fact that utility coal use is the biggest part of domestic coal consumption. But as coal increases its share in industrial fuel use, the issue will become increasingly important. Independent of the CEUM, ICF is developing an industrial coal use model. We have not evaluated that effort, but in commenting on this report ICF has informed us that the issue of fuel type/control technology/coal type trade-off evaluation has been considered. This modeling activity will contribute to "completing" this aspect of the CEUM, thereby reducing the data development requirements of the user/analyst.

For the reader's convenience we now summarize the major recommendations and suggestions regarding model and associated data extensions and model applications.

First, the CEUM documentation should be improved in the following ways:

- The technical documentation of the model should be improved, especially regarding the underlying analysis and rationale for key model concepts.

- A user's guide should be prepared that at minimum makes more formal and forceful the required data input and the consistency checks the user/analyst must provide, and of which anyone interpreting CEUM-based results must be aware.

- Documentation for auxiliary models used in developing CEUM data and/or in checking consistency of model input-output data should be provided, in particular for the screening model employed in developing load curve parameters and evaluating load factors.

Second, the verification errors identified in this study should be corrected.

Third, we cannot overemphasize the importance of the user's checking to ensure that plausible changes in input data, and especially in heuristic methods for data generation, do not significantly affect policy conclusions derived from model results. Areas of particular importance include the coal reserve and resource base; the distribution of that reserve base by geologic deposition and coal characteristics; cost factors in coal production, in transport, and in electricity production and control technology costs and efficiencies; the representation of the utility load duration curve; and the exogenously specified portion of utility industry expansion plans.

The following are our major recommendations regarding model and associated data extensions.

- Most importantly, the treatment of mine lifetime as independent of economic variables must be revised. We recommend that an auxiliary model relating mine lifetime to expectations about future coal prices and other economic variables be formulated and implemented. The model has two uses: (1) to assist the user in estimating an approximate value of the mine lifetime parameter, and (2) to assist in checking consistency between those variables determined by the CEUM--for example, coal prices--and the values assumed by the auxiliary model in estimating the input value of the mine lifetime parameters.

- o Preliminary evidence presented in this study suggests that intertemporal rents may be a more significant part of coal prices than assumed in the CEUM and other coal supply models. We recommend further analysis of this possibility, and that consideration be given to adopting the auxiliary model recommended above to provide estimates of the intertemporal rent component of the coal prices estimated by CEUM.

- o We recommend that the typical mine costing data used in the current version of the model be updated and extended to reflect the EPRI/NUS mine costing data.

- o We recommend that the current informal auxiliary model used by ICF to parameterize representative load duration curves by region be formally implemented, and used both to generate LDC parameterizations consistent with expected load factors and exogenously specified expansion plans, and for post-application input-output checking.

1.4 Recommendations Regarding CEUM Applications

We now turn to the task of reviewing the actual and potential applications of the CEUM in the context of our evaluation. There are two sources of information regarding model applications: actual studies and potential applications identified by the modelers. ICF's statement on model applications is summarized in the executive summary of ICF (1977), and includes:

- o Clean Air Act Amendments,
- o Western coal development,
- o Strip-mine reclamation requirements,
- o Energy Supply and Environmental Coordination Act conversion orders, and
- o Changes in coal depletion allowance and in investment tax credit.

The model is also thought to be useful for studying the impact of utility investment behavior upon coal production and non-government factors, including changes in non-coal fuel prices; changes in electricity and non-utility coal demand; supply constraints on labor, equipment, and transportation; and impact of new technologies on electricity generation and/or on fuels that compete directly with coal.

The three major studies conducted by ICF and considered in this evaluation include:[13]

- o An analysis for EPA of the Alternative New Source Performance Standards (ANSPS) following the 1977 Amendments to the Clean Air Act (ICF [1978a]);
- o Further analysis of ANSPS for EPA and DOE (ICF [1978c]);
- o An analysis of the demand for western coal, with a sensitivity analysis for 12 data and policy parameters (ICF [1978b]), including:
  - -- High (30 percent) and low (5 percent) severance tax for Western coal;
  - -- High and low electricity growth rates;
  - -- High and low oil prices per barrel;
  - -- Current and revised New Source Performance Standards;
    - -- Labor cost escalation above (2 percent) and below (0 percent) the base-case value of 1 percent;
    - -- A 50 percent increase in rail transport rates above base case; and
    - -- Allowance of combined-cycle oil plants.

From this brief survey it is apparent that, excepting studies of the effects of conversion orders and new technologies, the CEUM has been employed in all the application areas for which ICF believes the model is credible.

We now turn to a consideration of the CEUM in each of the policy analysis applications suggested by ICF.

<u>Clean Air Act Amendments</u>: The potential user should note that while this evaluation has identified and analyzed many issues that qualify the interpretation of model results, in fact the principal application of the model to date--analysis of the Clean Air Act Amendments--is, in our view, the most logical and legitimate use of the model. Excepting the verification errors reported above, the qualifications as to the

applicability of the model for such analyses pertain to requirements for data development, data analysis, and checking consistencies of model input data and model results. Some of this "checking" is substantial, resulting in a series of recommendations for auxiliary models as aids to the user/analyst. In our view, these issues must be addressed to avoid serious compromise in interpreting model results. However, in a carefully conceived and executed study, these issues can be greatly mitigated.

One important qualification should be kept in mind. We find it misleading to suggest, as ICF does, that the model could easily be specialized to a particular utility region, and that the modeling approach would be appropriate for such a micro-analysis. While the model might provide some of the broad control totals and parameters applicable to a particular utility, in its present form we do not believe it is useful for such an analysis. In the micro case, it would be necessary to consider the specific characteristics of the utility's capacity and load, demand projection procedures, and other much more highly resolved information when evaluating decisions related to capacity-type choices and capacity uses. Certainly the CEUM approach may be adopted for more micro-oriented problems, but the user should recognize that the CEUM was not designed with such applications in mind. Furthermore, adapting the model in this way would constitute, in effect, a new modeling effort.

<u>Western Coal Development</u>. The sensitivity of the model's East-West production decisions, as demonstrated in Section 3, complicates the use of the CEUM for analysis of Western coal development. Indeed, ICF says as much in the context of a sensitivity analysis of the CEUM base case considered in ICF [1978b]: Thus

> ...one of the policy implications of these analyses is that it is not possible to estimate western production levels with much accuracy, because of the inherent uncertainty in many of the key parameters. (ICF [1978b], p. 35)

It should be noted that the issues here would be difficult to handle with any modeling approach, and are not confined to the CEUM.

Strip-Mine Reclamation Requirements: The effect of strip-mine reclamation regulations is introduced into the CEUM via the coal production cost function, shifting the supply curve upward. The procedure is quite reasonable as a means of estimating increased costs of production. However, the regional distribution of coal production is sensitive to small (and plausible) changes in parameters and data, even at fairly aggregate levels--for example, East versus West--which complicates interpretation of model results at the most detailed regional level. Of course, this is true for other CEUM applications as well, but it seems especially important in calculating effects of changes in reclamation requirements, an application in which regional detail is especially important.

Energy Supply and Environmental Coordination Act Conversion Orders: The CEUM will be useful in analyzing the consequences of conversion orders, although a great deal of out-of-model data development and integration is required. Since the model data base does not include plant-level detail and since the model is not designed to make conversion decisions, analysis of plant conversion orders will require adjusting model data, including capacities (both generation and scrubber), capacity characteristics, and transmission and financial data to reflect the conversion order. Clearly a substantial analysis effort is required to set up this scenario, although once done, it should be possible to reflect it in a separate auxiliary model that can be used in revising and setting up the model data base.

Depletion Allowances and Investment Tax Credits: Finally, we find that the model is probably not very useful for analyzing changes in the coal depletion allowance and investment tax credits (ITC). Regarding depletion allowance and ITC for coal mining, the changes are introduced into the model via the production cost function. The same comment applies here as for strip-mine reclamation costs. Regarding the effect of changes in the ITC upon utilities, the model does not include the utilities' balance sheet on any procedure for calculating the capital change rate. This is all done outside the model. Further and more importantly, a change in the price of capital services for utilities (due to a change in ITC) has "no place to go" in the model, except to change components of the objective functions. But the effects of a change in ITC would be to induce investment in more capital-intensive generation, and to reduce the regulated price of electricity. Further, there is no demand response via price. Hence most of the effect of this change must be evaluated outside the model.

1.5 Unresolved Issues and ICF Comments

ICF representatives participated in all project review meetings and provided comments on draft materials at all stages of the project. This participation was supported contractually by EPRI and includes the preparation of comments on this report. In the text of this Final Report we have indicated, usually in footnotes, where ICF disagrees--with an indication of the nature of the disagreement--or has provided additional information of importance to the reader. Here we summarize the main unresolved issues between the review group and ICF. These include (i) the value of a "single model" evaluation in contrast to a comparative evaluation, and the appropriate audience for such an evaluation; (ii) the meaning and importance of technical documentation; and (iii) the model forecast variables and level of detail used in reporting computational experiments.

Single Model versus Comparative Evaluations: An issue of continuing concern to ICF has been that the EMAP review concentrated only on the CEUM, and did not contrast and compare that model with related models. From ICF's perspective, there are two important implications of this. First, there is the possibility of penalizing ICF if a reader misconstrues critical comments as applicable only to the CEUM, and not to related models. Second, there is a related question of the appropriate audience for a single model assessment. ICF feels such a review is only useful to themselves and to analysts already familiar with the model, related models, and the applications for which such models are intended. In their view, publication for a wider audience is likely to be unconstructive, resulting in potential misunderstanding of the relation between CEUM, related models, and the state of the modeling art.

We are sympathetic to ICF's concern that the reader understand the scope of a single model reveiw, such as we have conducted for the CEUM. In Section 1.1, we include an explicit caution to this effect. Beyond that, however, we disagree that "single model" evaluations are useful only to a fully prepared audience. Certainly independent review of documentation, comparison of documentation to actual implementation, and verificiation of implementation are elements of good practice in policy modeling, being elements of peer review. Such review provides analysts who may need to consider model-based results useful information on the modeling process. In fact, we believe that modelers and model sponsors should plan and budget for such independent review as part of the model development process since this would improve the timeliness and utility of such activities. Excepting technical documentation, we believe ICF basically agrees with this view.

The crux of disagreement appears to be with policy model validation, by which we generally mean the review of model structure, data, and predictive performance. For policy models such review must consider both scientific issues and the appropriateness of the model, given the policy issues for which it is intended. Thus, for example, model x might be much preferable to model y in a specific application, but the scientific foundations and data of both models are weak. A critical review of model x, due to the weak scientific foundations, might lead an incautious analyst to conclude that model y is preferable. According to ICF, comparative model reviews are the only way to deal with this problem. We disagree, believing that once the reader has been alerted to the "single model" nature of the review, he/she can be trusted to interpret and use the results accordingly. Certainly when the objective is to select between models for some specific study, comparative reviews are obviously essential.

<u>Documentation</u>: A second area where unresolved issues remain concerns the need for technical documentation. In the early stages of the review we concluded that the documentation of the CEUM was deficient in not providing technical discussions of why certain concepts, approaches, and data were employed. Caricaturing somewhat, our concern was that

documentation should inform both what was done and why it was done. We were also concerned that the CEUM documentation includes no user or operator guides. As noted above, our general guide for document types and content was the EIA documentation standards (Lady [1978]).

ICF strongly disagrees with this assessment. Regarding user and operator guides, they point out that the need for such documentation depends on whether or not analysts other than the modelers, ICF, will actually run the model. Since they intend that clients use the model only with their collaboration, such documentation is not required. Regarding technical documentation, ICF disputes the meaningfulness of the "what versus why" distinction. They point out that other reviewers, in particular Professor Richard Gordon, have praised the CEUM documentation, and that it was sufficient for a competitor essentially to replicate the CEUM. Finally they observe that even in this review we rate highly the descriptive documentation regarding modeling approach and data, and so regard as inconsistent our concerns about technical documentation.

In response to ICF's concerns we devoted more time and attention to understanding their documentation objectives and the environment for model applications, and believe our review reflects this additional effort and material. We note, and restate here, that ICF's application environment eliminates the need for formal user and operator guides, although obviously such documentation is required for internal management and control purposes. ICF has assured us that such internal materials exist and are used routinely. Regarding technical documentation, we remain convinced that inattention to rationalizing model approach and concepts is a serious limitation.

Reporting Detail for Model Forecast Variables: An important part of this review has been to conduct computational experiments evaluating the model performance and sensitivity to changes in concepts and data. In Section 3 and in the various supporting volumes--especially Volume VII--the results of these experiments are summarized and discussed. In general, detail is confined to national aggregates, and to coal producing regions. This contrasts with--and brackets--the level of detail emphasized by ICF in the studies we reviewed, that being PIES coal producing and electric utility regions. Further, we employ two aggregation procedures for two key model variables, coal production and prices, including (i) simple summation of quantities and quantity weighted summation of prices, and (ii) quantity (price) weighted averages of absolute percentage changes in producing region prices (quantities). The latter measure is unforgiving in that changes of opposite sign do not cancel.

ICF disputes both our use of national aggregates and our method of aggregating detailed coal production and prices. Regarding the first, they feel that such national aggregates conceal much of the information of interest to the serious analyst. For analysis purposes we would agree, but our purpose here is sensitivity analysis combined with compactness of presentation. Reporting changes in national aggregates for key model variables seems a satisfactory summary indicator of model response and sensitivity to changes in concept, parameters, or independent data.

Regarding the weighted absolute percentage change procedure for aggregating coal production and prices, ICF argues that such a measure is overwhelmed by mathematical programming noise and cannot be substantively interpreted. This issue relates to the point on appropriate regional resolution discussed in Section 1.3. The essential point of controversy is between ICF's view that model results are only meaningful and interpretable at a higher level of aggregation, which allows canceling out of "mathematical programming noise," and our view, which emphasizes the need for analysis and interpretation at the most detailed level in order to understand, interpret, and make credible aggregates of the detailed results. We believe that a simple summary measure which cumulates regional changes in coal production and prices is a useful indicator of model response and sensitivity.

<u>Where We Agree</u>: In this section and throughout this Final Report we

have attempted to reflect ICF's comments and qualifications to the substance of the review. While unresolved issues are still significant, it would be misleading to leave the impression that ICF disagrees with all of our results. In particular, ICF

agrees that our analysis of intertemporal rents was a contribution, and indicates that they have implemented a procedure to account for this component of cost in which rents are estimated as a function of real price escalation, adjusted for risk;

agrees that our analysis of mine lifetime was a contribution, suggests that further extensions are appropriate, and indicates they have revised their treatment including allowing differing mine lifetimes by regions and coal types;

agrees with the importance we attach to the coal reserve data base, and indicates they have made improvements;

agrees with our recommendation to adopt the EPRI/NUS mine-costing model;

indicates they have improved their treatment of forced outages, although not necessarily agreeing with our analysis;

indicates they have developed and now use more detailed data on load curves, although not necessarily agreeing with our analysis; and

agrees that our effort at model verification was useful, although emphasizing the coal supply submodel, with less attention to other submodels and data.

FOOTNOTES

1. See Volume VI for a more detailed chronology of events.

2. ICF suggests that the review is only useful to such analysts. We consider this further in Section 1.5 under the heading Single Versus Comparative Model Evaluation.

3. See Section 1.5 for further discussion of ICF's views regarding this recommendation.

4. In reviewing this Final Report, ICF noted that they have reconsidered accepting as errors seven of the eight points we identified. See Section 1.5 for further discussion.

5. This review is of the CEUM only, and--with incidental exceptions--does not provide a comparative review of other models intended for the same or similar applications. For further discussion of ICF's concerns about how this review should be interpreted, see Section 1.5.

6. See Zimmerman and Ellis, "What Happened to Nuclear Power," MIT Energy Laboratory Working Paper No. MIT-EL 80-002WP for one approach to integrating information on costs and regulatory uncertainty into a utility technology choice model.

7. Note that even though a perfectly inelastic demand is given, we cannot say the model determines a price, since the utility industry is regulated, and the model provides no explicit accounting for the procedure by which the price will be determined.

8. The Project Independence Evaluation System (PIES) reports results for 10 demand regions. The National Coal Model--the immediate ancestor of the CEUM--was structured for the PIES demand regions. Thus the CEUM has increased the demand region resolution of the predecessor systems by a factor of 4.

9. ICF has been conducting further research relating to this issue, and is preparing a report for EPRI.

10. This study, mentioned to us during project review meetings with ICF but not cited in the documentation, was conducted by PEDCO for EPA.

11. See Section 1.5 for further discussion of ICF's views regarding data development.

12. In commenting upon this report, ICF indicated that additional work on developing load curve data had been completed.

13. Subsequent to this review, ICF indicated that the CEUM has been employed in studies of slurry pipelines, new technologies, rail rates, federal leasing, reconversions from oil and gas to coal, oil/gas backout, acid rain, coal exports, and numerous private sector applications.

Section 2
DESCRIPTION OF THE COAL AND ELECTRIC UTILITIES MODEL

The ICF, Inc. Coal and Electric Utilities Model (CEUM) is a static, regional, linear programming (LP) model with a highly resolved data base. It has the capability to project coal prices, production, and consumption by region for a given target year with demand levels, transportation costs, and environmental standards all treated explicitly.

The general structure of the CEUM consists of a supply component that provides coal, via a transportation network, to satisfy, at minimum cost, demands from both utility and non-utility users. The CEUM generates a cost-minimizing solution through a conceptually straightforward LP formulation that balances supply and demand requirements for each coal type for each region. The objective function of the linear program minimizes, over all regions, the total costs of electricity delivered by utilities and the costs of coal consumed by the non-utility sectors. Regional levels of electricity generation and non-utility coal use are exogenous. The output of the model includes projections of coal production, consumption, and price by region, by consuming sector, and by coal type for the target year under consideration. The impacts of environmental standards on electricity generation from coal are also considered explicitly.

Table 1 outlines the basic elements of each of the four major components of the CEUM, including coal supply, coal transportation, utility demand, and electricity transmission.

A summary of the spatial, temporal, and informational resolution of the CEUM is given by:

Table 1

COAL AND ELECTRIC UTILITIES MODEL--MAJOR COMPONENTS
(From ICF, Inc. [1977], page II-2, Figure II-1)

SUPPLY	UTILITY DEMAND

- 30 Regions
- 40 Coal types possible
  - 5 Btu categories
  - 8 sulfur levels
- Existing capacity
  - Contract (large mines)
  - Spot } No longer included in model
  - Surge }
- New Capacity
  - Based upon BOM demonstrated reserve base
  - Reserves allocated to model mine types
  - Minimum acceptable selling prices estimated for each model mine type
  - Upper bounds of new mine capacity for each region based upon planned mine openings
- Coal washing
  - Basic washing assumed for all bituminous coals
  - Deep-cleaning option available to lower sulfur content to meet New Source Performance Standard or a one-percent sulfur emission limitation for existing sources
	- 39 Regions
	- 19 Coal piles
	  - 3 Ranks of coal
	  - 6 Sulfur categories
	  - Metallurgical pile includes only the highest grades of coal
	- Utility Sector
	  - Point estimates for KWH sales by region
	  - KWH sales allocated to four load categories (base, intermediate, seasonal peak, and daily peak)
	  - Existing generating capacity utilized by model on basis of variable cost
	  - New generating capacity utilized by model on basis of full costs (including capital costs)
	  - Air pollution standards addressed explicitly
	  - Transmission links between regions
	  - Oil and gas prices fixed
	  - Coal prices determined from supply sector through transportation network

NON-UTILITY DEMAND	TRANSPORTATION
- Five non-utility sectors (metallurgical, export, industrial, residential/commercial, synthetics) - Point estimates of Btu's demanded - Allowable coals specified in terms of Btu and sulfur content - No price sensitivity	- Direct links - Cost based upon unit train or barge shipment rates - Lower bounds used to represent long-term contract commitments - Upper bounds could be used to represent transportation bottlenecks or limited capacity

- Spatial resolution
    - 30 coal supply regions
    - 39 utility demand regions
- Temporal resolution
    - Static

      Individual year solution for selected future years
- Data resolution
    - 40 coal types

      5 Btu levels and 8 sulfur levels
    - 5 non-utility coal consuming sectors
    - 4 load categories
    - 3 compliance alternatives
    - Other informational resolutions specific to model components

Some key characteristics of the CEUM's major components include:

- The LP matrix contains approximately 14000 activity variables and 2000 constraints. In addition, there are on the order of 1000 unbounded (free) rows used either to collect information or to force activity in the 1990 or later case years.

- Coal supply is disaggregated into 30 supply regions.

- The model has the capability for considering up to 40 different coal types representing all possible combinations of 5 Btu content groups and 8 sulfur levels.

- The utility demand for steam coal is disaggregated into 39 demand regions.

- Non-utility coal demand, exogenously specified by region, is disaggregated into 5 consuming sectors: metallurgical, industrial, residential-commercial, synthetics, and exports.

- The electric utility demand for coal is determined endogenously by taking account of the exogenously specified total electricity demand by region and interfuel substitution possibilities.

- Economic dispatch is determined endogenously.

- Transportation costs are based on rail and barge shipment rates.

- Environmental standards for electricity generation from coal are considered explicitly through endogenous options to meet utility demands by use of coal types having appropriate sulfur characteristics and corresponding desulfurization costs.

In the first EPA study (ICF [1978a]) the model was extended to allow for solutions in years subsequent to the 1985 case year. Previously, each case year solution was derived independently of those for other case years. The model was revised so runs for later case years used earlier case year results. Intertemporal constraints were incorporated in the following way: First, lower bounds were set on coal flows to insure that contracts undertaken would continue in force. Since it was assumed that 80 percent of sales were contract sales, transportation links and utility coal flows from coal piles to plant types within demand regions were lower bounded at 80 percent of deliveries in the prior case-year solution. Second, utility capacity additions in the CEUM consist of all plant capacity added since 1975. The modification of the model imposed lower bounds that required capacity additions by plant type in a later case year to at least equal those of the prior case year.

2.1 DISCUSSION OF THE LINEAR PROGRAMMING MATRIX[1]

Each column in the CEUM's LP matrix represents either a physical or an economic activity. Positive entries in a column represent an input into the associated activity; negative entries represent an output of the activity. The last entry in each column represents the annualized cost of operating each activity at unit level and forms the coefficient of that activity in the objective function.

Table 2 gives a listing of the model's important variables. The endogenous variables listed in the table represent the 9 major types of activity variables that appear in the LP matrix. Given coal supply schedules, the various activities in the LP matrix have the following general effects:

- o Coal mining activities transfer coal from available coal reserves to coal stocks in supply regions.
- o Coal cleaning activities transfer coal from a stock of one coal type to a stock of another coal type of lower sulfur level, allowing for cleaning losses. (There are also non-cleaning activities that transfer to a higher sulfur level coals that could be but are not deep-cleaned.)

Table 2

CEUM VARIABLES

Endogenous Variables
o Coal Supply
o Coal Cleaning and Mixing
o Coal Transport
o Oil/Gas Procurement
o Coal Procurement by Non-Utilities
o Electricity Generation from Coal
o Electricity Generation from Non-Coal Sources
o Electricity Transmission, Delivery, and Load Management
o Building Electrical Generating and Scrubber Capacity
Exogenous Variables
o Electricity Demand
o Non-Utility Coal Demand
o Bounds on New Coal-Fired Capacity
o Fixed Nuclear and Hydro Capacity Additions
o Bounds on Scrubber Capacity
o Oil/Gas Prices
o Capital Costs, O&M Costs, Transportation Costs, etc.
o Cost Adjustment Factors Used in Production Costing
o Available Coal Reserves and Resources by Region by Characteristic

- Coal transportation activities transfer coal from coal stocks at supply regions to fuel piles at demand regions.
- Oil/gas procurement activities place oil and gas in fuel piles at demand regions.
- Non-utility coal procurement activities remove coal from fuel piles in order to satisfy exogenous non-utility energy demands.
- Activities for coal-fired electricity generation remove coal from fuel piles, use electrical generating capacity and possibly scrubber capacity, and create electricity supplies.
- Activities for electricity generation from non-coal sources remove non-coal fuels from fuel piles, use electrical generating capacity, and create electricity supplies.
- Electricity transmission activities reduce electricity supplies in one region and increase them in another region, allowing for transmission losses. Electricity delivery activities reduce electricity supplies in order to satisfy exogenous electricity consumption requirements, allowing for distribution losses.
- Activities for building electrical generating or scrubbing capacity create new capacities. Exogenously specified limits may be imposed.

Each row of the LP matrix, except for the objective function row, represents a constraint associated with a physical stock or a consumption requirement. Physical stocks may be of fixed size, exogenously specified, or of variable size, created by activities within the model. Constraints associated with stocks of variable size are called material balances; they force quantities created within the model to equal or exceed quantities used.

Seven major constraint categories appear in the LP matrix. These are:

- available coal reserves by mine type at supply regions;
- coal stocks by coal type at supply regions (material balances);
- fuel "piles" at demand regions (material balances);
- non-utility energy requirements at demand regions;
- electricity constraints, including electricity consumption requirements, and electricity supplies (material balances), at demand regions;

- electrical generating and scrubber capacity constraints, including fixed generating capacity constraints for existing plants, material balances for capacities not yet built (new plants), and material balances for scrubber capacity on both existing and new plants; and
- new capacity building limitations for generating electricity.

2.2 DISCUSSION OF THE OBJECTIVE FUNCTION[2]

The last row of the LP matrix designates the objective function. Its entries are the costs (case year annualized costs in base year dollars) of operating the associated activities at unit level. The objective function includes nine sets of terms. The first set multiplies real annuity coal prices by annual amounts of coal supplied by supply region, cost-of-extraction level, and Btu- and sulfur-content level, to achieve a total coal production cost. The second set represents total deep-cleaning costs for each supply region, at each Btu-content level. The third set of terms multiplies coal transportation prices by the amounts of coal transported annually between each supply and demand region, for each Btu- and sulfur-content level. The fourth set of terms is the product of prices and quantities of oil and gas consumed in each demand region.

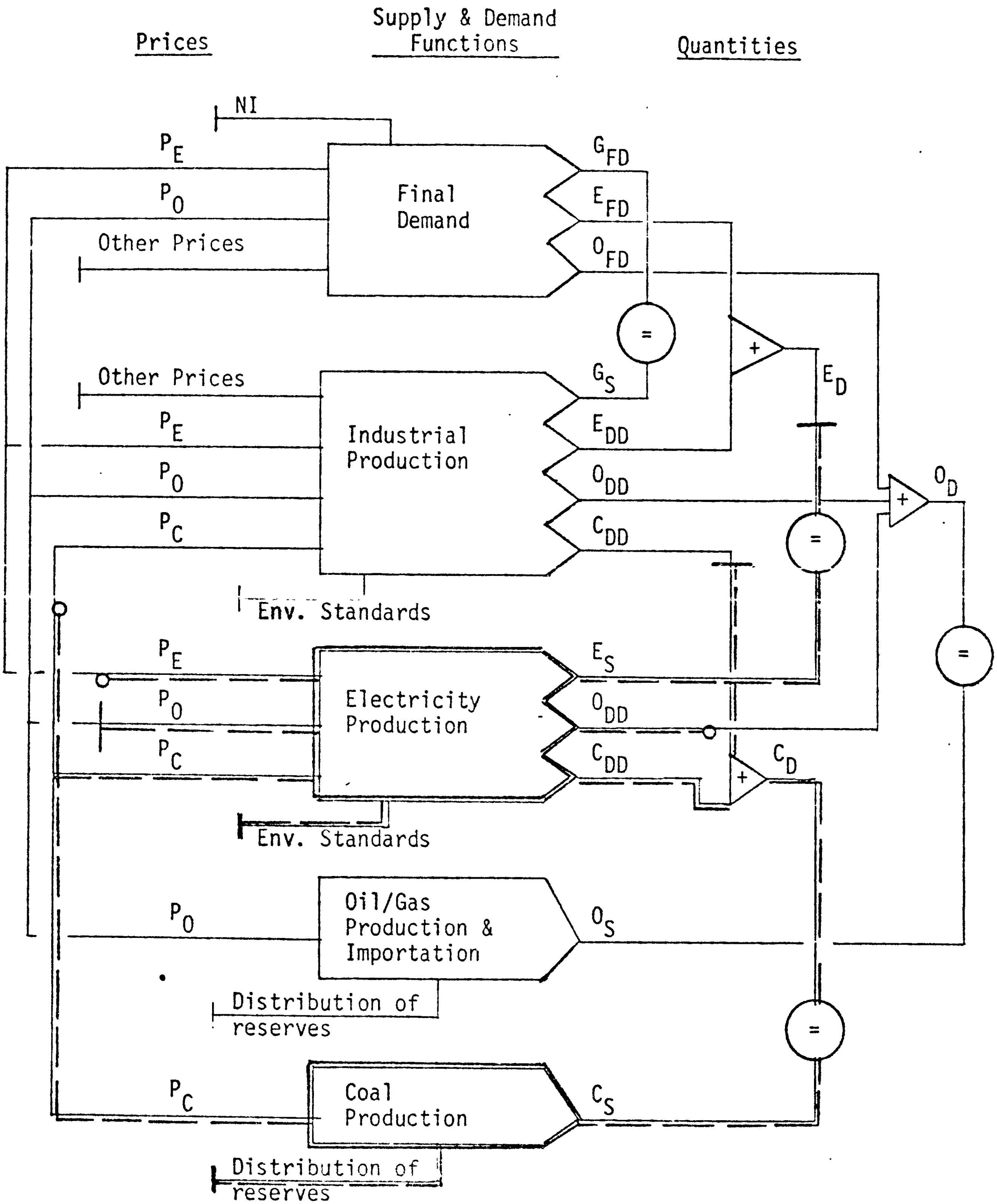
The remaining terms of the objective function collect costs from the electric utility sector. The fifth set of terms multiplies appropriate O&M costs by the annual amounts of electricity generated in each demand region, for each plant type, fuel type, and load mode. The sixth set multiplies transmission costs for new lines by the annual amounts of energy transmitted via new lines between pairs of demand regions. The seventh set is the product of electricity delivery costs and the annual amounts of electricity delivered in each demand region. The eighth set multiplies annualized capital costs for new plants by the amounts of generating capacity built in each demand region, for each plant type. The final terms in the objective function are the product of annualized capital costs for scrubbers and new scrubber capacities in each demand region.

2.3 THE CEUM IN CONTEXT

From a descriptive, as well as from an evaluative viewpoint, it is useful to place the CEUM in the context of a more general model of energy markets. In Figure 1 we characterize a more general energy market model, which includes the CEUM model, to illustrate both the key linkage assumptions and the coverage of the CEUM. Our energy market model includes the major end-use, conversion, and fuel production sectors and highlights the interaction of fuel production, demand, and the determination of equilibrium prices and quantities. In Figure 1, the overlay of the CEUM on the energy market model is designated by the dashed lines.

The CEUM includes only two sectors of our energy market model: electricity production and coal production. Final demand, industrial production, and oil and gas production are omitted. Note that there are six sets of linking variables between the CEUM and the complementary parts of the energy market model, including the prices of electricity, oil and coal, the total demand for electricity, the derived demand for coal and industrial production, and the derived demand for oil and electricity generation. Three of these variables--demand for electricity, industrial derived demand for coal, and price of oil--are exogenously specified in the CEUM. The other three variables--price of electricity, price of coal, and derived demand for oil for electricity generation--are endogenous variables. For the exogenous linking variables to be constant, the CEUM must assume that (i) the supply functions for oil and gas are perfectly elastic, and (ii) the demand for electricity and the industrial derived demand for coal are perfectly inelastic.

Figure 1. Market Equilibrium Analysis of Energy Production



C = coal
D = demand
DD = derived demand

E = electricity
FD = final demand
G = industrial goods

NI = national income
O = oil/gas
P = price

——— general model
— — CEUM

FOOTNOTES

1. An illustrative linear programming matrix that shows how the CEUM's four major components interrelate is discussed and displayed in Volume II, Chapter 3, Section A. A detailed mathematical formulation is presented in Volume II, Chapter 3, Section C.

2. A more detailed mathematical representation of the CEUM's objective function can be found in Volume II, Chapter 3, Section C.

Section 3

EVALUATION OF THE COAL AND ELECTRIC UTILITIES MODEL

This chapter presents the results of our evaluation of the CEUM. The chapter is organized as follows. Section 3.1 presents an evaluation of the CEUM documentation, Section 3.2 discusses model verification issues, and Section 3.3 presents an analysis of issues relating to model validity.

3.1 EVALUATION OF DOCUMENTATION

To be effective, policy model documentation must satisfy the diverse information requirements of several groups, including:

- peer modelers and scientists,
- policy analysts using and/or interpreting model-based results,
- model users and operators,
- nontechnical policy constituencies influenced by model-based analyses, and
- decision makers who must integrate policy analysis with the interests/views of their constituencies.

The information needs of the various policy model clients are quite diverse. The objectives and scope of documentation for a model such as the CEUM will depend upon the modelers' and model sponsors' evaluation of the appropriate response to these needs. Evaluation of documentation must include, therefore, both intent and objectives of the documentation and execution.

For our present purposes we employ the documentation guidelines promulgated by EIA as a classification for types of documentation (Lady

[1978]). The first two columns of Table 2 summarize these guidelines in the form of document types and primary audiences.

Documentation of the CEUM is provided in a series of reports and in the computer implementation of the model. The basic model is described in ICF (1977). This report extends an earlier report prepared for the FEA documenting the National Coal Model. The extensions are in the form of an appendix that updates and extends the model's data structure.

Further documentation is provided in each of three major studies where extensions, revisions, and updates are documented in appendixes to the report in a style and format similar to the July 1977 report. Most of the revisions are to data, not model structure. Thus the basic CEUM documentation consists of:

- ICF, Inc., Coal and Electric Utilities Model Documentation, July 1977.
- ICF, Inc., Appendix B of Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and on Utility Capacity Expansion Plans, Draft, September 1978. (Also see Scenario Specifications in Section II.)
- ICF, Inc., Appendix C of The Demand for Western Coal and its Sensitivity to Key Uncertainties, Draft, June 1978.
- ICF, Inc., Appendix A of Further Analysis of Alternative New Source Performance Standards for New Coal-Fired Power Plants, Draft, September 1978.

In September 1978, ICF transferred the CEUM and the associated extant data base to the Energy Information Administration (EIA). This report is concerned with the documentation and computer code associated with this version of the model. Most importantly, this version of the computer code was the basis for the computational experiments reported in Section 3 and in the associated volumes to this report. The reader should note that ICF has continued its government-sponsored studies with the model, and published in January 1979 Still Further Analyses of Alternative New Source Performance Standards for New Coal-Fired Power

Table 2

DOCUMENT TYPES AND DESCRIPTIONS, PRIMARY AUDIENCE, AND EVALUATION OF THE CEUM DOCUMENTATION

Document Type and Description *	Primary Audience	Evaluation
Model Summary: nontechnical descriptions of the model and model applications	Nontechnical	Uniformly excellent discussions of study objectives and results; good descriptions of scenario data and methods of data development; good summary descriptions of model structure; poor or non-existant discussion of rationale and alternatives for key model concepts, and level of resolution required for intended applications.
Model Methodology: technical description of rationale, precedents, and comparative evaluations with alternative approaches	Modelers, Peers, Model users, other Analysts	Good descriptions of modeling approach, but not usually in the "natural language" for peers/other modelers. Very little technical discussion justifying model concepts, approach; almost no comparative discussion of alternative approaches.
Model Description: presentation of the model sufficient to describe its structure, associated data, and conditions for understanding and interpreting results	Analysts performing policy research	Consistently good description of associated data and results; relatively poor documentation of actual model implementation; almost no discussion of results in terms of limitations and approximations used in developing data at resolution required by the model.
Guide to Model Applications: nontechnical description of model, and model applications to support interpretation and use of model-based analyses	Nontechnical groups, analysts interpreting policy research	Does not exist
Users Guide: detailed description of operating procedures	User/operators	Does not exist

*The document types and descriptions are based upon the documentation guidelines promulgated by the Energy Information Administration. (from Lady [1977])

NOTE: This table duplicates Table 1 in Section 1 for the convenience of the reader.

Plants, a preliminary draft report to EPA. This report includes some further model extensions, most importantly new data on scrubber costs. However, the style and general content of the new report is entirely consistent with the earlier work, and so will not affect our evaluation of the documentation.

3.1.1 Objectives of ICF Documentation

In evaluating ICF's documentation objectives we have relied upon a review of the CEUM documentation contrasted with the EIA guidelines, and upon discussions with ICF.[1] For context the reader should note several aspects of the CEUM development history and intended mode of use. First, the CEUM is intended by ICF as a company-based model to be used in support of client studies. The CEUM was not designed to be transferred to a particular sponsor or client, but to be used by ICF consultants.

Second, the coal supply submodel of the CEUM is based upon earlier work done at FEA with ICF participation. The concepts relating to this part of the model are viewed by ICF as well understood and accepted by the relevant modeler/scientist community. The implication is that extensive technical documentation is not required.

Third, the non-coal supply portion of the model is based upon a methodology analogous to the Project Independence Evaluation System (PIES). The methodology is linear programming, a mature and well-understood method. The distinguishing characteristic of the CEUM is the problem being addressed and the resolution of data details required for that problem.

The ICF documentation objectives may be summarized as follows:

- The most important documentation objective for the CEUM is to describe the model and associated data in a format designed to facilitate general understanding by study clients, as well as interpretation of specific studies and applications.

- o Technical documentaton of the scientific basis for the model, as contrasted with model description, is relatively unimportant since:

  - -- the methodology and basic concepts are relatively simple and widely understood,

  - -- study clients do not need or require such general documentation. Technical points relating to particular applications and studies can be addressed by the modelers/analysts in response to client inquiry, and in documenting and interpreting particular study results.

- o User/operator guides are not required since the model is intended for use by ICF analysts and operators, not for transfer to other groups.

As will be seen, the ICF documentation is consistent with these objectives. However, we believe the objectives are much too narrow and do not do justice to the importance of the applications for which the model is intended, or to the needs of the technical community (including ourselves) being asked to evaluate and comment upon the model and model applications. The most serious problem is that so little information and technical analysis is available to rationalize and support the modeling concepts, approach, and methods of data analysis and extension employed by ICF. Presentation of such technical information and analysis should be the natural consequence of both scientific and problem-oriented policy modeling, and should be presented in the natural language of the discipline(s) involved to make peer review and analysis possible. This is indisputable in scientific research, and the same should be true for problem-oriented analysis models such as the CEUM. In these matters it is as important to be told why things were done and what the alternatives were as to be told what was done.

3.1.2 Evaluation

The objectives of CEUM documentation have been oriented toward users working always in conjunction with the modelers. In general the documentation is consistently good for this objective. Correspondingly the documentation is consistently poor or nonexistent regarding technical description, user guides, and operating instructions. Using the EIA documentation categories (Lady [1978]), we conclude that:

Model Summary: Summary descriptions of the model are complete and well written. Discussion of approach and intended applications provide an excellent introduction for anyone desiring a brief overview of the model. However, the rationale for this particular modeling approach and its limitations are not discussed.

Description of Methodology: The modeling approach and concepts are generally well described. However, technical description and analysis are lacking. For example, while the uses and advantages of the linear programming approach are presented, no formal description of the model in the language natural to this methodology is included. In fact such a formulation was developed as part of the evaluation effort to be certain we understood the model (see Volume II, Chapter 3).

Model Description: In contrast to technical documentation, the discussion of the CEUM structure and its associated data base is well documented. This aspect of documentation employs a language and style natural for presentation and interpretation of model results, given acceptance of the premise that the modeling approach and concepts are appropriate for the issues being addressed. The simple conceptual structure of the model and the significant data requirements for implementation and use dictate that the emphasis on this aspect of the documentation is on describing the model data base in both a base year and the case year(s) being analyzed. Documentation of this extensive scenario data base is essential to ensure that the model users (ICF) have done all the data development and consistency evaluation necessary for the application, so both the client and non-modeler/client analysts have a clear record of what was done as a basis for interpreting results.

Guide to Model Application: As noted, the mode of use for CEUM is for clients to work in collaboration with ICF consultants in designing application scenarios and in integrating model results with other analytical results.

Thus, it is understandable that no extensive documentation of model operations has been developed.[2] Nevertheless, some form of documentation seems necessary to ensure good practice and operator continuity. At the time we were learning how to use the CEUM, the model operating capability had been internalized in one person. We can attest to the difficulty of learning how to operate the model, and would obviously have benefited from some formal documentation. From the perspective of a potential user who is collaborating with the modelers, there would be less direct need for such documentation. However, the lack of such materials should raise some concern about good practice and prospects of continuity.

User's Guide: Again, the intended mode of use has, in ICF's view, eliminated the need for this form of documentation. Here we are more inclined to agree since the style and documentation of model applications provides a useful blueprint for potential users. Even here, though, some evidence of standard procedures--such as data entry forms--would increase user confidence in the orderliness and professionalism of the applications process.

A summary of our evaluation of the CEUM documentation is presented in Table 2 (see page 3-3). The evaluation by document function varies depending upon the perspective of its different potential users. In general what has been done is consistently well done, and should contribute significantly to a potential user's confidence in the professionalism of the modelers. What has not been done, however, is critically important to understanding the strengths and limitations of this particular approach. Reading the CEUM documentation will provide the potential user with little information on how the particular modeling approach and concepts are likely to influence model performance in particular applications. This is a serious deficiency, hopefully in part remedied bv materials presented in this report.

3.2 VERIFICATION OF CEUM IMPLEMENTATION

Model verification consists of three major activities: comparing model documentation to computer implementation to ensure consistency, verifying the logical and operational correctness of the computer implementation, and reprogramming key components of the computer code. The first step in the verification process was to certify that the version of this model transferred to the EIA computer center was in fact the version that EPRI and ICF had agreed was to be evaluated. This was accomplished by having ICF independently replicate the Base Case using the transferred model. This was the first activity in the audit phase of the project.

The actual verification consisted of the three approaches mentioned above: documentation/code comparisons, analysis of the code, and independent reprogramming of key portions of the code. The reprogramming focused upon the production costing portion of the coal supply submodel. The original purpose of this activity was to develop a means of obtaining analytical expressions for elasticities relating average production costs to geologic characteristics of coal deposition. However, it soon became clear that this reprogramming, using a different logical sequence, was also an extremely effective method of code verification since several errors in the original code were discovered in this way. The correspondence of the two codes was assured by parallel runs that matched coal supply prices to five decimal places, both with and without the errors.[3]

3.2.1 The Corrected Base Case

The Base Case version of the CEUM used in our assessment was certified by ICF as the valid September 1, 1978 version of the model. The Base Case employs a particular alternative new source performance standard (ANSPS), one of several analyzed by ICF, defined by a floor and ceiling on SO_2 emissions of 0.5 and 1.2 lb $SO_2/10^6$ Btu, respectively. Recall that with any of the ANSPS coal plants, scrubbers are mandatory and 85 percent sulfur removal (on a daily average basis) down to the specified floor is required. Under the current new source performance standard (NSPS), scrubbers are not mandatory and a maximum emission level of 1.2 lb $SO_2/10^6$ Btu is required. If scrubbers are employed with an NSPS coal plant, a 90 percent efficiency on an annual average basis is used.

Our effort in verifying implmentation of the CEUM was intensive, both because this aspect of model evaluation is important, and because--given the poor state of technical documentation--the verification activity was helpful in learning about the model. It is therefore remarkable that so few errors or problems in implementation were discovered. Further, as will become apparent, those errors that were identified did not result in any dramatic changes in model results. To demonstrate this, we constructed a Corrected Base Case, which reflects our proposed corrections. Both the errors and the proposed corrections were reviewed with ICF and were implemented with their concurrence, with one exception to be noted (deep cleaning costs of metallurgical coal).

The substantive errors found in the verification analysis include:

- o incorrectly modeling the deep-cleaning of all metallurgical coals, resulting in the double counting of deep-cleaning costs for certain coal types, and other related problems,
- o incorrectly escalating base-year (1975) price data for existing mines,
- o skipping one year of cost escalation between the base year and the case year (1985) in the calculation of real annuity coal prices,
- o inappropriate method for approximating treatment of initial capital cost expenditures,
- o incorrectly escalating the property taxes and insurance component of coal mine operating costs,
- o incorrectly calculating base-year Union Welfare Costs for coal mines,
- o changing the smallest seam thickness input value in the midst of cost calculations for deep mines, and
- o improperly allocating more than 100 percent of deferred capital over the lifetime of a mine when the lifetime is not perfectly divisible by four.

Other problems identified include:

- In parts, the CEUM Supply Code relates to old code used for the PIES Coal Supply Analysis. Such code can only lead to confusion and should be deleted;

- Because of an undocumented "patch" that exogenously overrides the coal supply curve output for Utah bituminous low-sulfur coal, this particular supply curve should be considered invalid for CEUM sensitivity runs involving regeneration of supply curves;

- Real escalation of cost factors is not appropriately accounted for in 1990 and 1995 case-year model runs;

- The implementation of a change in the general rate of inflation is not at all straightforward and requires changes in both supply and non-supply oriented components of the CEUM (see Volume VI, Chapter 9 and the CMILL run description in Volume VII, Chapter 2);

- The real rail-rate escalation factor for transportation costs is not implemented as documented;

- All hydroelectric costs except for pumped storage O&M are excluded from the objective function of the linear program (and also from the imputed cost of electricity); and

- Electricity distribution costs are ignored in the LP but are added exogenously at the report-writing stage. This procedure is not documented.

3.2.2 Effects of the Verification Corrections

The remainder of this section discusses and illustrates the effects of the verification corrections on the CEUM output.[4] Before proceeding it is important to mention that after careful review and discussion, the ICF modelers agreed with both the problems identified and the appropriate way to implement the corrections in the Corrected Base Case, with the exception of the appropriate procedure for adjusting the method of deep-cleaning metallurgical coals.[5]

In the tabular results presented below, the model runs with the uncorrected and corrected Base Case are denoted by BC and CBC, respectively. The uncorrected model for the NSPS scenario has only been run for 1985. The corrected version of the NSPS model run is denoted by CNSPS. Another set of uncorrected and corrected model runs, from which the effects of corrections can be examined, have electricity and non-utility coal demands decreased by 10 percent. These runs are denoted by EDMD and CEDMD, respectively.[6]

Important model outputs for the uncorrected and corrected versions of BC, NSPS, and EDMD are displayed in Tables 3 to 10. Percentage changes due to the corrections appear in parentheses in each table. Some of the more interesting and significant effects of the corrections are:

- o In CNSPS-1985 and in CEDMD-1985: There is a general increase in the amount of Western coal (in ton-miles) transported East (see Table 5).
- o In CNSPS-1985: There is a 13 percent increase in ton-miles of Western coal transported East. This change is mostly the result of an increase in subbituminous coal shipments from Western Montana to Western Kentucky and a shift of bituminous coal shipments from Wyoming to Alabama/Mississippi instead of from Wyoming to Western Kentucky (see Table 5).
- o In CBC-1995: There is a 30 percent increase in ton-miles of Western coal transported East. This change is mostly due to large increases in subbituminous coal shipments from Western Montana to Michigan and in bituminous coal shipments from Wyoming to Western Kentucky (see Table 5).
- o In CEDMD-1985: There is an 18 percent increase in ton-miles of Western coal transported East. This change is mostly due to increases in subbituminous coal shipments from Western Montana to Western Kentucky (see Table 5).
- o In CBC-1990: There is a 13 percent increase in ton-miles of Eastern coal transported West. This change is mostly due to increases in bituminous coal shipments from Illinois to Iowa.[8]
- o In CEDMD-1990: There is a 22 percent increase in ton-miles of Eastern coal transported West. This change is mostly due to increases in bituminous coal shipments from Illinois to North Dakota/Minnesota.[8]
- o In CBC-1995: There is an 18 percent increase in kWh of transmission over new lines. This change is the result of large increases in transmission from Georgia/North Florida to South Florida and from Iowa to Illinois (see Table 6).
- o There is a general increase in surface coal production (a high of 5 percent in CBC-1995) and a general decrease in deep coal production (a high of 4 percent in CBC-1995) for all case years. There are small decreases in total coal production in both 1985 and 1990, and small increases in 1995 (see Table

Table 3

LP OBJECTIVE FUNCTION (10^6 \$ - 1978)

	1985	1990	1995
BC	74102.66	103725.18	138847.45
CBC	74062.08 (-.05%)	104366.27 (+.62%)	140080.62 (+.89%)
NSPS	73807.36		
CNSPS	73755.00 (-.07%)	102419.82	136815.48
EDMD	62335.02	88639.84	120099.70
CEDMD	62221.03 (-.18%)	89112.18 (+.53%)	121098.88 (+.83%)

Table 4

COAL TRANSPORTATION (10^9 TON-MILES)

	1985	1990	1995
BC	560.49	889.41	1145.50
CBC	556.88 (-.64%)	885.28 (-.46%)	1208.41 (+5.5%)
NSPS	564.16		
CNSPS	574.44 (+1.8%)	971.17	1289.30
EDMD	495.98	768.16	1004.45
CEDMD	499.16 (+.64%)	769.30 (+.15%)	1031.69 (+2.7%)

Table 5

WESTERN COAL TO EASTERN DESTINATIONS (10^9 TON-MILES)

	1985	1990	1995
BC	102.11	150.23	167.69
CBC	97.71 (-4.3%)	151.60 (+.91%)	218.17 (+30.1%)
NSPS	101.79		
CNSPS	114.66 (+12.6%)	229.00	333.33
EDMD	81.22	130.02	167.48
CEDMD	85.52 (+5.3%)	134.36 (+3.3%)	197.10 (+17.7%)

Table 6

TRANSMISSION OVER NEW LINES (10^9 kWh BEFORE LOSSES)

	1985	1990	1995
BC	196.42	168.92	149.56
CBC	197.29 (+.44%)	167.31 (-.95%)	176.02 (+17.7%)
NSPS	188.90		
CNSPS	186.45 (-1.3%)	156.82	196.06
EDMD	153.54	166.86	145.86
CEDMD	152.32 (-.79%)	173.13 (+3.8%)	150.56 (+3.2%)

Table 7

AVERAGE COAL CONSUMPTION PRICE (1978 $/MM Btu)

	1985	1990	1995
BC	1.40	1.51	1.58
CBC	1.44 (+2.9%)	1.55 (+2.6%)	1.62 (+2.5%)
NSPS	1.41		
CNSPS	1.45 (+2.8%)	1.59	1.70
EDMD	1.40	1.49	1.55
CEDMD	1.40 (0.0%)	1.52 (+2.0%)	1.58 (+1.9%)

Table 8

EFFECTS OF THE VERIFICATION CORRECTIONS ON SELECTED RUNS USING NATIONAL AVERAGE DEVIATION INDEXES (in %) OF EQUILIBRIUM COAL QUANTITIES AND PRICES[7]

	1985		1990		1995	
	Quantity	Price	Quantity	Price	Quantity	Price
BC vs. CBC	4.4	2.8	5.1	3.5	6.1	3.4
NSPS vs. CNSPS	4.9	5.2	*	*	*	*
EDMD vs. CEDMD	4.4	3.2	4.9	3.1	6.2	2.7

*These comparison runs were not made.

Table 9

NATIONAL COAL PRODUCTION (MM TONS)

	1985	1990	1995
Metallurgical			
BC	153.49	154.33	164.01
CBC	163.57 (+6.6%)	169.93 (+.10.1%)	173.23 (+5.6%)
Low Sulfur			
BC	291.71	466.29	577.21
CBC	284.83 (+2.4%)	459.77 (-1.4%)	623.49 (+8.0%)
Medium Sulfur			
BC	412.13	550.35	664.65
CBC	411.75 (-.09%)	544.92 (-1.0%)	641.73 (-3.4%)
High Sulfur			
BC	260.07	342.63	456.07
CBC	254.90 (-2.0%)	330.45 (-3.6%)	437.12 (-4.2%)
Surface			
BC	598.94	776.73	913.39
CBC	599.68 (-.12%)	779.49 (+.35%)	962.60 (+5.4%)
Deep			
BC	518.44	736.87	948.54
CBC	515.37 (-.59%)	725.58 (-1.5%)	912.97 (-3.9%)
Total			
BC	1117.38	1513.60	1861.93
CBC	1115.05 (-.21%)	1505.07 (-.56%)	1875.57 (+.73%)

Table 10

AVERAGE COAL PRODUCTION PRICES (1978 $/MMBtu)

	1985	1990	1995
Metallurgical			
BC	1.64	1.76	1.85
CBC	1.66 (+1.2%)	1.78 (+1.1%)	1.86 (+.54%)
Low Sulfur			
BC	0.83	0.79	0.83
CBC	0.85 (+2.4%)	0.80 (+1.3%)	0.83 (0.0%)
Medium Sulfur			
BC	0.99	1.03	1.09
CBC	1.02 (+3.0%)	1.07 (+3.9%)	1.11 (+1.8%)
High Sulfur			
BC	1.00	1.18	1.27
CBC	1.04 (+4.0%)	1.23 (+4.2%)	1.33 (+4.7%)
Total			
BC	1.07	1.10	1.15
CBC	1.10 (+2.8%)	1.14 (+3.6%)	1.18 (+2.6%)

- There is a consistent average coal production price increase of between 2 and 4 percent (see Table 10).[8]

- There is a consistent average coal consumption price increase of between 2 and 3 percent, except for CEDMD-1985 where there is no change (see Table 7).

- There is a general increase in electric utility oil/gas consumption, except for CEDMD-1995.[8]

- Total electric utility capacity (existing plus new) stays approximately constant. Generally, there is a transfer of new coal capacity to existing oil/gas turbine or steam capacity.[8]

- There are small changes of less than 1 percent in the LP objective function value: decreases in 1985 and increases in both 1990 and 1995 (see Table 3).

More specifically, note the following three effects, which we have not been able to explain:

- Concerning Western coal transported East in 1985, the CNSPS value is greater than the CBC value, while the value for NSPS is less than that for BC (see Table 5).

- With regard to transmission over new lines in 1990, the CEDMD value is greater than the CBC value, while the value for EDMD is less than that for BC (see Table 6).

- For deep coal production in 1985, the CNSPS value is less than the CBC value, while the value for NSPS is greater than that for BC.[8]

While some effects of the verification corrections mentioned above may seem large, in our opinion they are not really very significant. Note that while we account for the changes in the micro detail in the BC versus CBC results (e.g., increases in coal shipments from Illinois to North Dakota/Minnesota), we have not tried to analyze and/or interpret the new results as to their plausibility. As noted many times in Section 1, review and analysis of the most detailed results of the CEUM are the keys to building understanding and confidence in model applications and results. If the corrected reference case is implausible to the analyst/user, then he/she must develop new information to be introduced in the form of changes in input data, or as constraints on model activities. We cannot overemphasize this characteristic of CEUM applications.

3.3 ANALYSIS OF ISSUES

We now turn to a presentation and analysis of issues in model concepts, structure, and associated data identified in this evaluation study. Issues considered may be grouped into three categories:

Conceptual: model constructs and concepts involving simplifications that may significantly influence the validity of certain applications or the interpretation of model results;

Structural: model resolution and organization of model concepts and constructs; and

Data: relation of model resolution to available data, accuracy of source data, sensitivity of model results to key intput data and parameters.

The remainder of this section presents some information as to our approach, and a summary of the computational experiments conducted as part of the evaluation. The remaining subsections consider each of the major components of the model in turn: Model Design and Structure (3.3.1); Coal Supply Submodel (3.3.2); Coal Transportation (3.3.3); Electric Utilities Submodel (3.3.4); and Demand for Electricity and Non-Utility Coal (3.3.5).

Our objective in identifying and analyzing issues relating to model performance and appropriate applications is intended to be constructive in three ways. First, the analysis should inform potential users as to the basis for our recommendations concerning appropriate model applications. Second, the analysis will provide independent information concerning interpretation of model-based results in appropriate applications. While much of this information takes the form of warnings, the constructive intent should not be overlooked. Finally, the analysis provides the basis for some recommendations concerning further developments of the CEUM, including research and data development required to resolve some of the analytical issues we identify but are unable to completely resolve to our and ICF's satisfaction.

Where appropriate, every effort has been made to develop and illustrate each issue with computational experiments. Twenty-six computer runs were made with the full CEUM, and numerous others were made separately with the coal supply model. Results are presented throughout the remainder of this section and in associated volumes, especially Volume VII, Chapter 12.

These results represent only a small part of the full model output.[9] While most of the issues can be developed and/or illustrated with aggregate summary variables, an important exception is the effect of various conceptual, structural, and data changes on the distribution of coal production and prices. To deal with the need to present such distributional information, we employ an index of the average absolute percentage difference in equilibrium coal production quantities and prices by coal type, and for a specified regional level (usually national in this report.)[10] Except when noted, the differences are between the Corrected Base Case and the particular scenario being analyzed.

Tables 11-13 present summary results for 14 of the most referenced output variables for each of the 26 computational experiments for 1985, 1990, and 1995. Each experiment is "coded" with an identifier and a brief description indicating the nature of the change to Base Case data. The first two lines compare the original Base Case using the version of the model transferred from ICF with the Corrected Base Case, which implements corrections (Section 3.2 and Volume II, Chapter 5, Section C). The remainder of the tables summarize results presented and discussed in this section and in Volume II, Chapter 2.

3.3.1 Model Design and Structural Issues

A distinguishing characteristic of the CEUM is its level of detail and the extensive associated data base required to use the model. This modeling approach involves choices and trade-offs between the complexity of detail and structure, in order to achieve a model which is computationally tractable and usable. In the following sections we consider each of the major components of the CEUM in turn, evaluating both the detail and the structure of the model. Here we want to consider factors contributing to modeling decisions trading off detail and

Table 11

SUMMARY OF SELECTED RESULTS OF CEUM SENSITIVITY RUNS

1985

Name of Run	Basis for Run	Coal Production--Aggregate (MM Tons)	Coal Production--Detailed (Deviation Index in %)	Low-Sulfur Coal Production (MM Tons)	Coal Prices--Aggregate (1978 $/MM Btu)	Coal Prices--Detailed (Deviation Index in %)	Coal Washing (MM Tons Input)
BC	Base case as transmitted to MIT by ICF	1117.4	Not applicable	291.7	1.07	Not applicable	16.2
CBC	Implementation of verification corrections on base case	1115.0	Not applicable	284.8	1.10	Not applicable	17.1
NSPS*	Application of NSPS parameters to uncorrected base case (which uses ANSPS)	1120.9 (0.3%)	2.2	299.3 (2.6%)	1.07 (0.0%)	1.0	17.7 (8.9%)
CNSPS	Application of NSPS parameters to corrected base case (which uses ANSPS)	1120.5 (0.5%)	3.6	302.9 (6.3%)	1.10 (0.0%)	1.1	20.1 (17.6%)
EDMD*	10% decrease in electricity and non-utility coal demands from uncorrected base case	1011.3 (-9.5%)	14.2	254.6 (-12.7%)	1.04 (-2.8%)	8.6	11.0 (-32.4%)
CEDMD	10% decrease in electricity and non-utility coal demands	1009.0 (-9.5%)	9.2	253.5 (-11.0%)	1.08 (-1.8%)	2.4	9.9 (-42.2%)
EDMI	5% increase in electricity and non-utility coal demands	1163.9 (4.4%)	4.7	303.9 (6.7%)	1.12 (1.8%)	1.4	18.7 (9.4%)
CEDMU	10% increase in electricity and non-utility coal demands	INFEASIBLE	- - -	- - -	- - -	- - -	- - -
CML20	Mine life decreased from 30 years to 20 years	1109.1 (-0.5%)	19.2	270.1 (-5.2%)	1.07 (-2.7%)	5.3	5.5 (-67.7%)
ROYI	Royalties for privately owned coal increased from 0% to 10%; federal coal royalties were left unchanged	1123.2 (0.7%)	8.8	318.5 (11.8%)	1.16 (5.5%)	7.3	12.4 (-27.2%)
CDRB	Coal reserve data changed randomly between 75% and 150% of BOM figures	1113.5 (-0.1%)	9.1	290.1 (1.9%)	1.09 (-0.9%)	1.6	15.3 (-10.4%)
LOGN	Seam thickness distribution changed from uniform to truncated log-normal, skewed toward the minimum	1112.6 (-0.2%)	9.8	294.3 (3.3%)	1.15 (4.6%)	4.5	15.5 (-9.4%)
LAB3	Real escalation rate of unit labor costs increased from 1% to 3% per year	1141.2 (2.4%)	14.8	360.0 (26.4%)	1.28 (16.4%)	24.8	2.4 (-85.9%)
LAB0	Real escalation rate of unit labor costs decreased from 1% to -1% per year	1103.5 (-1.0%)	8.7	266.9 (-6.3%)	0.96 (-12.7%)	15.6	19.1 (11.9%)
TCML	[illegible] rate escalation factor decreased from $(1.01)^{10}$ to $([illegible].01)^{10}$	[illegible] (0.5%)	3.7	305.6 (7.4%)	1.09 (-0.9%)	0.9	15.6 (-8.8%)
COILG	Joint oil/gas prices increased 25% in 1985; price increments increased 25% thereafter and were added to original CBC 1985 prices	1141.1 (2.3%)	1.8	301.0 (5.7%)	1.11 (0.9%)	0.8	19.1 (12.0%)
NOIL	Total joint oil/gas prices increased 25% over 1985 CBC prices	1141.1 (2.3%)	Comparison run not made	301.0 (5.7%)	1.11 (0.9%)	Comparison run not made	19.1 (12.0%)
CNINC	New nuclear build activity levels increased by 25%	1093.7 (-1.9%)	2.2	281.2 (-1.3%)	1.09 (-0.9%)	0.7	16.4 (-4.0%)
NCAP	Average nuclear capacity factor value decreased from .675 to .55	1141.3 (2.4%)	3.0	295.4 (3.7%)	1.11 (0.9%)	1.0	18.3 (7.5%)
LDC1	Changes to load duration curve parameters: baseload decreased by 1% point; daily peaking increased by 1% point	1113.3 (-0.2%)	0.2	283.9 (-0.3%)	1.11 (0.9%)	0.2	17.1 (0.4%)
LDAD	Changes to load duration curve parameters: baseload decreased by 5% points; daily peaking increased by 5% points	1092.6 (-2.0%)	2.8	277.6 (-2.5%)	1.10 (0.0%)	0.6	16.6 (-2.9%)
BOTX*	Zero upper and lower bound constraints set on transmission activity variables in the uncorrected base case LP	1054.3 (-5.6%)	6.3	263.9 (-9.5%)	1.05 (-1.9%)	2.2	13.6 (-16.1%)
UCD4	Annual real escalation in utility capital costs increased from 2% to 4% from 1975 to 1985; inflation rate remained at 5.5% per year	1104.9 (-0.9%)	3.3	288.0 (1.1%)	1.11 (0.9%)	0.8	19.8 (16.3%)
CMILL	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs remained at 2% per year from 1975 to 1985	1108.3 (-0.6%)	1.0	285.2 (0.1%)	1.15 (4.6%)	4.4	16.8 (-1.3%)
UCIN	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs decreased from 2% per year to zero from 1975 to 1985	1118.7 (0.3%)	1.4	282.1 (-1.0%)	1.15 (4.6%)	4.9	14.9 (-12.9%)
UUIN	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs decreased from +2% to -.5% per year from 1975 to 1985	1120.7 (0.5%)	1.8	282.9 (-0.7%)	1.15 (4.6%)	4.9	13.0 (-24.0%)

*Note: The sensitivity runs marked with an asterisk were carried out using the uncorrected Base Case (BC) as the starting point; percentages shown in those rows indicate the difference between the results of that run and BC results. All runs not marked with an asterisk were made using the Corrected Base Case (CBC), and percentages are measured from the CBC results.

Table 11 (continued)

SUMMARY OF SELECTED RESULTS OF CEUM SENSITIVITY RUNS

1985

Coal Transportation Aggregate (10^9 Ton-Miles)	Coal Transportation West to East (10^9 Ton-Miles)	Electric Utility Oil/Gas Consumption (Quads)	New Total Coal Power Plant Capacity (GW)	New Oil/Gas Turbine Power Plant Capacity (GW)	New Coal Power Plants w/Scrubbers (GW)	Average U.S. Imputed Cost of Electricity (Mill/kWh)	New Transmission Before Losses (10^9 kWh)	Name of Run
560.5	102.1	5.83	111.1	38.0	64.8	27.7	196.4	BC
556.9	97.7	5.85	110.7	38.0	63.4	27.9	197.3	CBC
564.2 (0.7%)	101.8 (-0.3%)	5.70 (-2.3%)	114.4 (3.0%)	36.8 (-3.2%)	50.3 (-22.4%)	27.6 (-0.4%)	188.9 (-3.8%)	NSPS*
574.4 (3.2%)	114.7 (17.4%)	5.72 (-2.2%)	114.1 (3.1%)	36.7 (-3.4%)	44.6 (-29.7%)	27.8 (-0.4%)	186.4 (-5.5%)	CNSPS
496.0 (-11.5%)	81.2 (-20.5%)	4.23 (-27.4%)	87.4 (-21.3%)	18.9 (-50.3%)	48.0 (-25.9%)	25.0 (-9.8%)	153.5 (-21.8%)	EDMG*
499.2 (-10.4%)	85.5 (-12.5%)	4.26 (-27.2)	86.8 (-21.6%)	19.1 (-49.7%)	47.4 (-25.2%)	25.1 (-10.0%)	152.3 (-22.8%)	CEDMD
588.1 (5.6%)	105.1 (7.6%)	6.75 (15.4%)	119.0 (2.5%)	59.8 (57.4%)	70.0 (10.4%)	29.2 (4.7%)	211.0 (6.9%)	EDMI
-	-	-	-	-	-	-	-	CEDMJ
539.8 (-3.1%)	104.6 (7.1%)	5.79 (-1.0%)	111.5 (0.[illegible]%)	38.1 (0.3%)	63.5 (0.2%)	27.6 (-1.1%)	198.5 (0.[illegible])	CHL2J
607.8 (9.2%)	148.3 (51.8%)	5.92 (1.2%)	109.8 (-0.8%)	39.5 (4.0%)	59.4 (-6.3%)	28.3 (1.4%)	195.0 (-1.2%)	ROYI
568.0 (2.0%)	109.5 (12.1%)	5.85 (0.0%)	110.6 (-0.1%)	38.0 (0.0%)	59.4 (-6.3%)	27.8 (-0.4%)	197.[illegible] (-0.2%)	CDRB
562.6 (1.0%)	107.5 (10.0%)	5.89 (0.6%)	109.7 (-0.9%)	39.1 (2.9%)	61.5 (-3.0%)	28.1 (0.7%)	195.9 (-0.7%)	LOGN
699.1 (25.5%)	243.8 (149.5%)	6.11 (4.4%)	108.0 (-2.4%)	42.2 (11.1%)	60.3 (-4.9%)	29.2 (4.7%)	170.[illegible] (-13.7%)	LAB3
514.6 (-7.6%)	76.4 (-21.8%)	5.75 (-1.7%)	112.1 (1.3%)	37.7 (-0.8%)	61.3 (-3.3%)	26.9 (-3.6%)	201.4 (2.[illegible]%)	LAB5
585.9 (5.2%)	120.7 (23.5%)	5.84 (-0.1%)	110.9 (0.[illegible]%)	38.0 (0.0%)	62.1 (-2.1%)	27.7 (-0.[illegible]%)	199.3 ([illegible])	TCHL
579.7 (4.1%)	101.2 (3.5%)	5.29 (-9.6%)	121.7 (9.9%)	35.8 (-5.8%)	72.4 (14.2%)	29.5 (5.7%)	260.2 (31.9%)	COILG
579.7 (4.1%)	101.2 (3.5%)	5.29 (-9.6%)	121.[illegible] (9.9%)	35.3 (-5.8%)	72.4 (14.2%)	29.5 (5.[illegible]%)	260.[illegible] ([illegible])	NOIL
549.8 (-1.3%)	93.2 (-4.6%)	5.47 (-6.4%)	102.9 (-7.[illegible]%)	34.9 (-8.2%)	58.0 (-8.5%)	27.6 ([illegible])	163.[illegible] (-17.[illegible]%)	CH.NC
573.4 (3.0%)	102.5 (4.9%)	6.37 (8.9%)	117.2 (5.9%)	46.6 (22.6%)	68.7 (8.4%)	28.9 (3.6%)	203.[illegible] (3.[illegible])	NCAP
555.9 (-0.2%)	96.0 (-1.7%)	5.96 (2.0%)	111.6 (0.8%)	73.6 (93.7%)	64.0 (1.0%)	29.2 (4.7%)	187.7 (-4.8%)	LDC1
545.9 (-2.0%)	89.2 (-8.7%)	6.75 (15.3%)	106.8 (-3.5%)	262.2 (590.0%)	60.7 (-4.3%)	34.9 (25.1%)	158.5 (-19.7%)	LDAJ
528.2 (-5.8%)	90.8 (-11.0%)	7.97 (36.6%)	91.1 (18.0%)	65.8 (73.2%)	51.6 (-20.4%)	28.7 (3.6%)	0.0 (-100.0%)	NOTX*
559.0 (0.4%)	100.1 (2.5%)	6.10 (4.3%)	103.9 (-6.1%)	42.7 (12.4%)	56.6 (-10.7%)	29.0 (3.9%)	173.6 (-12.0%)	UCD4
554.7 (-0.4%)	97.7 (0.0%)	6.02 (3.0%)	106.9 (-3.4%)	40.1 (5.5%)	60.3 (-4.9%)	29.0 (3.9%)	181.4 (-8.1%)	CMILL
555.3 (-0.3%)	93.7 (-4.2%)	5.77 (-1.4%)	113.0 (2.1%)	37.1 (-2.4%)	67.0 (5.7%)	28.0 (0.4%)	201.4 (2.1%)	UCIR
556.6 (-0.1%)	92.8 (-5.0%)	5.74 (-1.9%)	113.7 (2.7%)	37.0 (-2.6%)	67.7 (6.8%)	27.7 (-0.7%)	205.6 (4.2%)	UDTR

Table 12

SUMMARY OF SELECTED RESULTS OF CEUM SENSITIVITY RUNS

1990

Name of Run	Basis for Run	Coal Production--Aggregate (MM Tons)	Coal Production--Detailed (Deviation Index in %)	Low-Sulfur Coal Production (MM Tons)	Coal Prices--Aggregate (1975 $/MM Btu)	Coal Prices--Detailed (Deviation Index in %)	Coal Washing (MM Tons Input)
BC	Base case as transmitted to MIT by ICF	1513.6	Not applicable	466.3	1.10	Not applicable	21.4
CBC	Implementation of verification corrections on base case	1505.1	Not applicable	459.8	1.14	Not applicable	17.9
NSPS*	Application of NSPS parameters to uncorrected base case (which uses ANSPS)	RUN NOT MADE	- - - - - - - -	- - - - -	- - - - -	- - - - - - - -	- - - - -
CNSPS	Application of NSPS parameters to corrected base case (which uses ANSPS)	1524.6 (1.3%)	16.1	564.7 (22.8%)	1.14 (0.0%)	4.1	33.4 (86.8%)
EDMD*	10% decrease in electricity and non-utility coal demands from uncorrected base case	1312.7 (-13.3%)	11.8	409.1 (-12.3%)	1.08 (-1.8%)	3.1	13.8 (-35.7%)
CEDMD	10% decrease in electricity and non-utility coal demands	1311.2 (-12.9%)	12.2	403.2 (-12.3%)	1.11 (-2.6%)	3.7	18.3 (2.5%)
EDMI	5% increase in electricity and non-utility coal demands	1606.9 (6.8%)	6.2	513.2 (11.6%)	1.14 (0.0%)	1.0	18.5 (3.2%)
CEDMU	10% increase in electricity and non-utility coal demands	INFEASIBLE	- - - - - - - -	- - - - -	- - - - -	- - - - - - - -	- - - - -
CML20	Mine life decreased from 30 years to 20 years	1521.1 (1.1%)	21.6	450.3 (-2.1%)	1.09 (-4.4%)	6.6	14.0 (-21.5%)
ROYI	Royalties for privately owned coal increased from 0% to 10%; federal coal royalties were left unchanged	1526.7 (1.4%)	12.6	544.9 (18.5%)	1.16 (1.8%)	6.4	14.5 (-19.1%)
CORB	Coal reserve data changed randomly between 75% and 150% of BOM figures	1507.0 (0.1%)	14.8	481.9 (4.8%)	1.11 (-2.6%)	3.0	19.5 (8.7%)
LOGN	Seam thickness distribution changed from uniform to truncated log-normal, skewed toward the minimum	1504.8 (-0.0%)	15.4	504.9 (9.8%)	1.15 (0.9%)	2.5	18.4 (2.8%)
LAB3	Real escalation rate of unit labor costs increased from 1% to 3% per year	1551.5 (3.1%)	20.2	546.8 (18.9%)	1.28 (12.3%)	24.2	11.9 (-33.5%)
LABD	Real escalation rate of unit labor costs decreased from 1% to -1% per year	1493.7 (-0.8%)	10.7	453.3 (-1.4%)	1.01 (-11.4%)	15.1	21.6 (20.6%)
TCML	Real rail rate escalation factor decreased from (1.01)[illegible] to (1.01)[illegible]	1533.7 (1.9%)	6.6	537.1 (16.8%)	1.10 ([illegible])	1.1	18.3 (2.2%)
COIL6	Joint oil/gas prices increased 25% in 1985; price increments increased 25% thereafter and were added to original CBC 1985 prices	1529.1 (1.6%)	1.7	477.6 (3.9%)	1.14 (0.0%)	0.1	19.6 (9.3%)
NOIL	Total joint oil/gas prices increased 25% over 1985 CBC prices	1570.2 (4.3%)	4.3	487.3 (6.0%)	1.15 (0.9%)	0.8	16.5 (-6.4%)
CNINC	New nuclear build activity levels increased by 25%	1428.6 (-5.1%)	Comparison run not made	426.7 (-7.2%)	1.14 (0.0%)	Comparison run not made	19.5 (9.1%)
NCAP	Average nuclear capacity factor value decreased from .675 to .55	1584.5 (5.3%)	4.6	502.7 (9.3%)	1.14 (0.0%)	0.7	20.4 (13.3%)
LDC1	Changes to load duration curve parameters: baseload decreased by 1% point; daily peaking increased by 1% point	1495.5 (-0.6%)	1.1	452.8 (-1.5%)	1.14 (0.0%)	0.2	18.3 (2.2%)
LDAD	Changes to load duration curve parameters: baseload decreased by 5% points; daily peaking increased by 5% points	1455.3 (-3.3%)	2.8	428.7 (-6.8%)	1.14 (0.0%)	0.6	20.4 (14.2%)
BOTX*	Zero upper and lower bound constraints set on transmission activity variables in the uncorrected base case LP	1533.5 (1.3%)	3.3	481.2 (3.2%)	1.09 (-0.9%)	0.7	14.9 (-30.5%)
UCD4	Annual real escalation in utility capital costs increased from 2% to 4% from 1975 to 1985; inflation rate remained at 5.5% per year	1463.2 (-2.8%)	3.7	446.4 (-2.9%)	1.14 (0.0%)	0.8	21.8 (22.0%)
CHILL	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs remained at 2% per year from 1975 to 1985	RUN NOT MADE	- - - - - - - -	- - - - -	- - - - -	- - - - - - - -	- - - - -
UCIN	Annual inflation rate increased from 5.5% to 8.0%, real escalation in utility capital costs decreased from 2% per year to zero from 1975 to 1985	1534.1 (1.9%)	3.4	478.7 (4.1%)	1.19 (4.4%)	4.9	15.3 (-14.7%)
UDIN	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs decreased from +2% to -.5% per year from 1975 to 1985	RUN NOT MADE	- - - - - - - -	- - - - -	- - - - -	- - - - - - - -	- - - - -

*Note: The sensitivity runs marked with an asterisk were carried out using the uncorrected Base Case (BC) as the starting point; percentages shown in those rows indicate the difference between the results of that run and BC results. All runs not marked with an asterisk were made using the Corrected Base Case (CBC), and percentages are measured from the CBC results.

Table 12 (continued)

SUMMARY OF SELECTED RESULTS OF CEUM SENSITIVITY RUNS

1990

Coal Transportation Aggregate (10^9 Ton-Miles)	Coal Transportation West to East (10^9 Ton-Miles)	Electric Utility Oil/Gas Consumption (Quads)	New Total Coal Power Plant Capacity (GW)	New Oil/Gas Turbine Power Plant Capacity (GW)	New Coal Power Plants w/Scrubbers (GW)	Average U.S. Imputed Cost of Electricity (Mill/kWh)	New Transmission Before Losses (10^9 kWh)	Name of Run
889.4	150.2	3.15	236.0	32.1	187.6	32.7	168.9	BC
885.3	151.6	3.28	231.7	32.2	182.4	32.9	167.3	CBC
-----	-----	-----	-----	-----	-----	-----	-----	NSPS*
971.2 (9.7%)	229.0 (51.1%)	2.82 (-14.2%)	247.8 (7.0%)	31.4 (-2.5%)	70.7 (-61.2%)	32.3 (-1.8%)	156.8 (-6.3%)	CNSPS
768.2 (-13.6%)	130.0 (-13.4%)	2.57 (-18.6%)	179.9 (-23.8%)	18.2 (-43.3%)	130.5 (-30.4%)	30.2 (-7.7%)	166.9 (-1.2%)	EDMD*
769.3 (-13.1%)	134.4 (-11.4%)	2.63 (-20.0%)	178.2 (-23.1%)	18.4 (-42.9%)	128.8 (-29.6%)	30.4 (-7.6%)	173.1 (3.5%)	CEDMD
956.1 (8.0%)	162.2 (7.0%)	3.52 (7.1%)	261.5 (12.9%)	46.7 (45.0%)	212.3 (16.4%)	34.0 (3.3%)	178.4 (6.7%)	EDMI
-----	-----	-----	-----	-----	-----	-----	-----	CEDMU
863.1 (-2.5%)	138.5 (-8.7%)	3.07 (-6.6%)	240.4 (3.8%)	32.2 (0.0%)	191.1 (4.8%)	32.4 (-1.5%)	178.6 (6.8%)	CML20
1010.7 (14.2%)	268.5 (77.1%)	3.37 (2.6%)	229.9 (-0.8%)	33.8 (5.0%)	177.1 (-2.9%)	33.3 (1.2%)	162.4 (-3.0%)	ROY1
903.1 (2.0%)	167.8 (10.7%)	3.25 (-0.9%)	232.5 (0.4%)	32.0 (-0.6%)	178.5 (-2.1%)	32.7 (-0.6%)	164.9 (-1.5%)	CDRB
936.9 (5.7%)	217.1 (43.2%)	3.44 (4.7%)	226.6 (-2.2%)	33.3 (3.4%)	176.4 (-3.3%)	33.0 (0.3%)	148.7 (-11.1%)	LOGN
1129.4 (27.6%)	410.8 (171.0%)	3.80 (15.8%)	219.5 (-5.3%)	36.9 (14.6%)	171.1 (-6.2%)	34.4 (4.6%)	158.1 (-5.5%)	LAB3
820.5 (-7.3%)	87.8 (-42.1%)	2.86 (-12.8%)	244.2 (5.4%)	32.0 (-0.6%)	191.8 (5.2%)	31.8 (-3.3%)	167.7 (0.2%)	LABD
985.2 (11.3%)	244.5 (61.3%)	3.03 (-7.8%)	240.9 (4.0%)	32.1 (-0.3%)	190.9 (4.7%)	32.6 (-0.9%)	161.3 (-3.6%)	TCML
904.8 (2.2%)	151.9 (0.2%)	2.76 (-15.9%)	248.6 (7.3%)	30.4 (-5.6%)	199.4 (9.3%)	33.2 (0.9%)	184.7 (10.4%)	COIL6
931.2 (5.2%)	152.0 ([illegible])	1.75 (-46.6%)	292.5 (21.9)	30.4 (-5.6%)	233.5 (28.0%)	Report not released to MIT	186.3 ([illegible])	NOIL
828.9 (-6.4%)	133.0 (-13.6%)	3.05 ([illegible])	207.3 (-10.5%)	29.9 (-7.1%)	156.3 (-14.3%)	32.4 ([illegible])	169.2 ([illegible])	CMINC
944.6 (6.7%)	165.8 (7.4%)	3.39 (3.4%)	258.6 (11.6%)	37.4 (16.2%)	208.6 (14.4%)	34.3 ([illegible])	189.7 (13.4%)	NCAP
875.9 (-1.1%)	146.1 (-3.6%)	3.59 (9.5%)	232.2 (0.2%)	71.4 (121.7%)	183.4 (0.6%)	34.3 (4.3%)	174.6 (4.4%)	LOC1
845.1 (-4.5%)	134.5 (-11.3%)	4.85 (47.8%)	229.6 (-0.9%)	284.7 (784.2%)	180.6 (-1.0%)	40.6 (23.4%)	145.9 (-12.8%)	LOAD
942.4 (6.0%)	145.6 (-3.1%)	3.07 (-2.6%)	250.8 (6.3%)	41.6 (29.6%)	206.0 (9.8%)	33.3 (1.8%)	0.0 (-100.0%)	NOTX*
853.4 (-3.6%)	153.3 (1.1%)	4.23 (28.8%)	202.4 (-12.7%)	38.3 (18.9%)	150.7 (-17.4%)	34.7 (5.7%)	150.2 (-10.3%)	UCD4
-----	-----	-----	-----	-----	-----	-----	-----	CHILL
904.7 (2.2%)	151.6 (-0.0%)	2.61 (-20.4%)	253.5 (9.4%)	31.8 (-1.2%)	202.6 (11.1%)	33.0 (0.3%)	176.0 (5.2%)	UCIN
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Table 13

SUMMARY OF SELECTED RESULTS OF CEUM SENSITIVITY RUNS

1995

Name of Run	Basis for Run	Coal Production--Aggregate (MM Tons)	Coal Production--Detailed (Deviation Index in %)	Low-Sulfur Coal Production (MM Tons)	Coal Prices--Aggregate (1978 $/MM Btu)	Coal Prices--Detailed (Deviation Index in %)	Coal Washing (MM Tons Input)
BC	Base case as transmitted to MIT by ICF	1861.9	Not Applicable	577.2	1.15	Not Applicable	21.9
CBC	Implementation of verification corrections on base case	1875.6	Not Applicable	623.5	1.18	Not Applicable	20.6
NSPS*	Application of NSPS parameters to uncorrected base case (which uses ANSPS)	RUN NOT MADE	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -
CNSPS	Application of NSPS parameters to corrected base case (which uses ANSPS)	1877.4 (0.1%)	17.7	735.8 (18.0%)	1.23 (4.2%)	7.4	45.7 (119.7%)
EDMD*	10% decrease in electricity and non-utility coal demands from uncorrected base case	1605.9 (-13.8%)	13.0	546.0 (-5.4%)	1.12 (-2.6%)	3.8	19.2 (-12.3%)
CEDMD	10% decrease in electricity and non-utility coal demands	1612.5 (-14.0%)	12.5	553.1 (-11.3%)	1.14 (-3.4%)	4.7	20.2 (-2.8%)
EDMI	5% increase in electricity and non-utility coal demands	2011.0 (7.2%)	6.2	658.4 (5.6%)	1.17 (-0.9%)	0.7	20.8 (0.1%)
CEDMU	10% increase in electricity and non-utility coal demands	INFEASIBLE	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -
CML20	Mine life decreased from 30 years to 20 years	1855.8 (-1.1%)	20.9	551.9 (-11.5%)	1.13 (-4.2%)	7.6	16.5 (-20.8%)
ROYI	Royalties for privately owned coal increased from 0% to 10%; federal coal royalties were left unchanged	1910.8 (1.9%)	10.2	677.2 (8.6%)	1.20 (1.7%)	6.4	15.0 (-28.0%)
CORB	Coal reserve data changed randomly between 75% and 150% of BOM figures	1877.6 (0.1%)	17.7	676.7 (8.5%)	1.13 (-4.2%)	4.4	18.6 (-10.6%)
LOGN	Seam thickness distribution changed from uniform to truncated log-normal, skewed toward the minimum	1886.8 (0.6%)	12.3	637.8 (2.3%)	1.17 (-0.9%)	1.5	20.5 (-1.6%)
LAB3	Real escalation rate of unit labor costs increased from 1% to 3% per year	1944.8 (3.7%)	18.8	732.3 (17.5%)	1.38 (17.0%)	27.5	14.8 (-28.8%)
LABD	Real escalation rate of unit labor costs decreased from 1% to -1% per year	1834.4 (-2.2%)	12.5	573.8 (-8.0%)	1.05 (-11.0%)	15.2	24.2 (16.3%)
[illegible]	[illegible] decreased from (1.01) to (1.01)	[illegible] (0.9%)	4.4	672.5 (7.9%)	1.15 (-2.5%)	1.7	17.8 (-14.6%)
COILG	Joint oil/gas prices increased 25% in 1985; price increments increased 25% thereafter and were added to original CBC 1985 prices	1882.8 (0.4%)	1.3	621.1 (-0.4%)	1.18 (0.0%)	0.2	20.8 (0.2%)
ROIL	Total joint oil/gas prices increased 25% over 1985 CBC prices	1875.9 (0.0%)	2.5	602.1 (-3.4%)	1.19 (0.9%)	0.4	21.6 (3.8%)
CNINC	New nuclear build activity levels increased by 25%	1750.2 (-6.7%)	Comparison run not made	559.4 (-10.3%)	1.15 (-2.5%)	Comparison run not made	20.6 (-1.1%)
NCAP	Average nuclear capacity factor value decreased from .675 to .55	1994.3 (6.3%)	5.6	658.1 (5.6%)	1.17 (-0.9%)	0.7	21.5 (3.3%)
LDC1	Changes to load duration curve parameters: baseload decreased by 1% point; daily peaking increased by 1% point	1854.6 (-1.1%)	1.1	609.0 (-2.3%)	1.18 (0.0%)	0.3	20.8 (0.3%)
LOAD	Changes to load duration curve parameters: baseload decreased by 5% points; daily peaking increased by 5% points	1774.9 (-5.4%)	4.6	560.8 (-10.1%)	1.16 (-1.7%)	2.3	22.7 (9.3%)
NOTX*	Zero upper and lower bound constraints set on transmission activity variables in the uncorrected base case LP	1885.2 (1.3%)	2.5	590.9 (2.4%)	1.15 (0.0%)	0.9	23.3 (6.3%)
UCD4	Annual real escalation in utility capital costs increased from 2% to 4% from 1975 to 1985; inflation rate remained at 5.5% per year	1853.3 (-1.2%)	2.4	597.6 (-4.2%)	1.19 (0.9%)	0.7	23.3 (11.9%)
CNILL	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs remained at 2% per year from 1975 to 1985	RUN NOT MADE	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -
UCIN	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs decreased from 2% per year to zero from 1975 to 1985	1883.1 (0.4%)	3.9	579.0 (-7.1%)	1.23 (4.2%)	4.8	17.9 (-13.7%)
UDIN	Annual inflation rate increased from 5.5% to 8.0%; real escalation in utility capital costs decreased from +2% to -.5% per year from 1975 to 1985	RUN NOT MADE	- - - - -	- - - - -	- - - - -	- - - - -	- - - - -

*Note: The sensitivity runs marked with an asterisk were carried out using the uncorrected Base Case (BC) as the starting point; percentages shown in those rows indicate the difference between the results of that run and BC results. All runs not marked with an asterisk were made using the Corrected Base Case (CBC), and percentages are measured from the CBC results.

Table 13 (continued)

SUMMARY OF SELECTED RESULTS OF CEUM SENSITIVITY RUNS

1995

Coal Transportation Aggregate (10^9 Ton-Miles)	Coal Transportation West to East (10^9 Ton-Miles)	Electric Utility Oil/Gas Consumption (Quads)	New Total Coal Power Plant Capacity (GW)	New Oil/Gas Turbine Power Plant Capacity (GW)	New Coal Power Plants w/Scrubbers (GW)	Average U.S. Imputed Cost of Electricity (Mill/kWh)	New Transmission Before Losses (10^9 kWh)	Name of Run
1145.5	167.7	1.88	382.3	41.2	336.6	36.9	149.6	BC
1208.4	218.2	1.90	381.8	41.1	334.8	37.2	176.0	CBC
-----	-----	-----	-----	-----	-----	-----	-----	RSPS*
1289.3 (6.7%)	333.3 (52.8%)	1.72 (-9.5%)	389.8 (2.1%)	41.1 (0.0%)	130.7 (-61.0%)	36.5 (-1.9%)	196.1 (11.4%)	CNSPS
1004.4 (-12.3%)	167.5 (-0.1%)	1.68 (-11.0%)	297.6 (-22.2%)	28.7 (-30.3%)	250.9 (-25.5%)	34.8 (-5.7%)	145.9 (-2.5%)	EDMD*
1031.7 (-14.6%)	197.1 (-9.7%)	1.62 (-14.6%)	299.8 (-21.5%)	28.7 (-30.2%)	252.2 (-24.7%)	34.9 (-6.2%)	150.6 (-14.5%)	CEDMD
1300.2 (7.6%)	239.1 (9.6%)	2.0 (5.2%)	424.6 (11.2%)	56.7 (38.0%)	377.9 (12.9%)	[illegible] (2.4%)	190.[illegible] (8.1%)	EDMI
-----	-----	-----	-----	-----	-----	-----	-----	CEDMU
1082.0 (-10.5%)	149.2 (-31.6%)	1.85 (-2.4%)	383.3 (0.4%)	40.7 (-1.0%)	336.1 (0.4%)	36.6 (-1.6%)	157.0 (-10.8%)	CNL20
1353.7 (12.0%)	361.6 (65.7%)	1.93 (1.6%)	382.2 (0.1%)	42.1 (2.4%)	333.4 (-0.4%)	37.6 (1.1%)	173.0 (-1.7%)	ROYI
1230.3 (1.8%)	238.1 (9.1%)	1.86 (-2.2%)	383.3 (0.4%)	41.1 (0.0%)	333.0 (-0.5%)	36.8 (-1.1%)	173.2 (-1.6%)	CORB
1254.6 (3.8%)	268.3 (23.0%)	1.88 (-0.9%)	382.9 (0.3%)	41.5 (-1.0%)	334.7 (-0.0%)	37.3 (0.3%)	157.9 (-10.3%)	LOGN
1509.5 (24.9%)	522.3 (139.4%)	2.15 (13.3%)	375.8 (-1.6%)	44.9 (9.3%)	330.2 (-1.4%)	39.2 (5.4%)	171.6 (-2.5%)	LABS
1059.6 (-12.3%)	94.5 (-56.7%)	1.75 (-7.9%)	387.0 (1.4%)	40.2 (-2.2%)	335.9 (0.3%)	36.0 (-3.2%)	141.9 (-19.4%)	LABD
1282.2 (6.1%)	305.3 (39.9%)	1.86 (-2.2%)	384.0 (0.6%)	41.2 (0.2%)	337.2 (0.7%)	36.9 (-0.8%)	154.1 (-12.5%)	TCML
1207.8 (-0.1%)	219.9 (0.8%)	1.71 (-9.9%)	389.4 (2.0%)	39.0 (-5.1%)	343.1 (2.5%)	37.5 (0.8%)	192.2 (9.2%)	COILG
1184.6 (-2.0%)	205.6 (-5.8%)	1.71 (-9.7%)	389.4 (2.0%)	39.0 (-5.1%)	342.3 (2.2%)	37.8 (1.6%)	180.9 (2.8%)	MOIL
1114.3 (-7.8%)	196.4 (-9.1%)	1.86 (-2.0%)	337.7 (-11.6%)	38.4 (-6.6%)	288.5 (-13.8%)	36.5 (-1.9%)	143.9 (-18.2%)	CRINC
1291.2 (6.9%)	242.6 (11.2%)	1.90 (0.1%)	424.3 (11.1%)	46.5 (13.1%)	376.0 (12.3%)	[illegible] (4.3%)	204.3 (16.1%)	NCAP
1188.2 (-1.7%)	212.9 (-2.4%)	2.48 (30.8%)	375.3 (-1.7%)	88.4 (115.1%)	328.6 (-1.9%)	38.8 (4.3%)	167.2 (-5.0%)	LOC1
1130.7 (-6.4%)	202.5 (-7.2%)	4.73 (149.1%)	349.0 (-8.6%)	351.8 (756.0%)	300.6 (-10.2%)	45.8 (23.1%)	140.4 (-20.2%)	LOAD
1195.1 (4.3%)	175.8 (4.8%)	1.84 (-2.3%)	396.4 (3.7%)	52.2 (26.7%)	353.2 (4.9%)	37.5 (1.6%)	0.0 (-100.0%)	NOTX*
1172.2 (-3.0%)	202.0 (-7.4%)	2.20 (15.7%)	369.2 (-3.3%)	43.5 (5.8%)	320.4 (-4.3%)	39.6 (6.5%)	138.0 (-21.6%)	UCD4
-----	-----	-----	-----	-----	-----	-----	-----	CMILL
1193.2 (-1.3%)	215.9 (-1.0%)	1.72 (-9.4%)	389.4 (2.0%)	41.5 (1.0%)	341.7 (2.1%)	37.0 (-0.5%)	176.2 (1.3%)	UCIN
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structural approach, and to summarize some general advantages and disadvantages of the CEUM approach.

The general design of a policy forecasting model strongly influences the properties that the model will have. Among the most important of those properties are (i) detail, (ii) accuracy, (iii) range of application, and (iv) generality. The property of 'detail' refers to classification (regions, coal types, etc.), and is determined both by the applications for which a policy model is intended, and what is actually supportable by available data and understanding of the processes being modeled. 'Accuracy' refers to expected uncertainty in model projections. In a policy model accuracy must be sufficient to discriminate among the policy alternatives of interest to the analyst. If a 'decision' may depend upon the value of some variable whose range of uncertainty in the model exceeds this discriminating range, then the policy model is not sufficiently accurate to support that application.

Supportable detail and accuracy are closely related. If the modeling approach is based upon methods in which uncertainty can be treated explicitly, either because the process being modeled may be characterized by physical laws or can be treated statistically, then an explicit confidence measure for projections is available to determine if the discriminating power of the model is sufficient for a particular analysis. If not, then the analyst must rely upon sensitivity analysis and "art-of-model" rationalization to justify a particular application.

The 'range of application' property refers to the number of issues which a policy model can address given a particular state of the world. The 'generality' of a model refers to the number of different states of the world for which the model is relevant. For example, a model of fuel demand that can be used to forecast consumption of each different type of fuel has a broader range of application than a model that will forecast the consumption of only one type of fuel. A model that is valid under a broad range of economic conditions is more general than a model whose validity rests on the assumption of a 3 to 5% growth rate of GNP.

In and of themselves, high levels in each of these areas are desirable. However, given a fixed amount of resources for the development and operation of a model, compromises must be made so a reasonable balance of the various properties can be achieved. For example, a high level of accuracy may require a low level of detail, while a high level of detail may preclude a broad range of application. Obviously, there may also be a trade-off between range of application and generality.

The general design of a policy model should depend in large part on the desired mix of the above properties. From the nature of the CEUM it seems clear that ICF placed priority on achieving a high level of detail in its model. The range of application was intended to be broad with less emphasis on accuracy and generality.

Emphasis on detail was a natural and necessary choice. Coal is a very heterogeneous commodity in two different senses. First, there are many varieties of coal, each with different properties and uses. Second, coal is found in different locations and transportation costs are high compared with the cost of mining and utilizing coal. A model that aggregated many types of coal into one classification, or that, through omission, failed to distinguish between different locations of coal deposits, would have a limited range of application indeed. Clearly, to be broadly useful, a coal model must be reasonably detailed.

But where does detail in the output of a policy model originate? In general, detail can originate from any of three sources:

(a) the data used by the model,
(b) the structure of the model, or
(c) ad hoc constraints and parameters imposed on the structure of the model.

The data used in a model provide a description of the state of the world to which that model is being applied. Detailed future forecasts often require a very detailed description, i.e., detailed data. However, this need not always be true. Consider, for example, a model of spaceship flight. The equations of celestial mechanics can provide much of the information for detailed forecasts as to the spaceship's trajectory. Only a modest quantity of data--data describing the initial position of the spaceship and the position and size of large heavenly bodies--would be necessary. In this case, the information for the detailed output is provided mainly by the structure of the model.

Model structure is a second source from which detail in output originates. What is model structure, and how does it differ from the data? Unlike data that describe a particular state of the world, model structure describes general laws about the world which are asserted to be true under a wide range of conditions. To the extent of its generality, model structure is an extremely compact way of storing and producing information when needed.

A third source of detail in the output of a model is information contained in ad hoc constraints and parameters usually coupled with the structure of the model. These ad hoc constraints and parameters are not invariant with different states of the world; rather they must be reformulated whenever the model is applied under new circumstances. Very often such ad hoc material is based on intuitive notions about what the solution of the model should be. The ad hoc constraints and parameters are employed in such a way as to condition the model to produce a solution that the model builder desires. Of course, such forced solutions have no more scientific validity than unadorned intuition. Indeed, the use of ad hoc material in a model presents a serious danger. By expressing intuition in such a formal fashion, it attains an unjustified scientific aura.

What is the breakdown of the CEUM in terms of model data, model structure, and ad hoc constraints and parameters? The most notable feature of the model is that it requires large quantities of detailed data. This is partly necessitated by the fact that the model structure is very simple and in itself contains very little information. Although an LP structure is an excellent organizer of information, it adds only the principle of cost minimization to the information already contained in the data. It should be noted, however, that the LP structure provides an excellent framework for superimposing on the model those ad hoc constraints and parameters that the CEUM requires in great abundance.

A fundamental weakness of the CEUM is that the data requirements cannot adequately be met or even approximated. A large portion of the data required by the structure is nowhere to be found, and as a consequence ICF has synthesized or approximated the data whenever necessary (see, for example, Section 3.3.2). In addition, the structure of the model is simple, and it is not at all clear that the principle of cost minimization is appropriate for simulating the activities of the regulated electric power industry. It is exactly because of the unreliability of the data and, to a lesser extent, the simplicity of the structure, that it has been necessary for the modelers to attach a large quantity of ad hoc material to the model. Some examples of these ad hoc constraints and parameters are the prespecification of:

- currently existing or planned coal and electrical production capacity,
- supply component cost adjustment factors,
- mine lifetime,
- various financial parameters used in the determination of real annuity coal prices,
- oil and gas prices,
- lower bounds on coal transportation activities,
- lower and upper bounds on electricity transmission activities,
- lower and upper bounds on electrical generating capacity and environmental control activities, and
- electric utility load duration curve parameters.

These ad hoc constraints and parameters can be used by the model builders to force the model to yield 'reasonable' results, that is, results consistent with historical patterns of production, transportation, and distribution of coal, as well as consistent with knowledge about future industry plans.

To what extent does the ad hoc material in the CEUM increase the accuracy of its detailed output? This is a difficult question to answer, but some problems of accuracy clearly emerge. First, some of the ad hoc material itself is highly unreliable. For example, both mine lifetime and the unit labor cost escalator play important roles in the model, but neither is accurately specified. Second, the model remains sensitive to some of the least reliable data (e.g., coal reserve data) despite the constraining influence of the ad hoc material. Finally, the ad hoc material by its nature reduces the generality of the model; that is, the model will lose its validity (and accuracy) if conditions change from those described. We must conclude that in ICF's attempt to build a high level of detail into their model they have necessarily sacrificed in maintaining sufficient accuracy and generality to make the model usable at that detailed level.

We now turn to a summary of the advantages and disadvantages of the level of detail chosen by the ICF modelers. The simple LP structure and high level of disaggregation of the CEUM have a number of advantages:

- The structure permits a "natural" representation of the energy sector of the economy. Almost every column of the LP matrix represents a tangible economic activity. Once the notation is mastered and the derivation of the data is understood, it is an easy matter to interpret any part of the model as a description of an economic process or processes.

- With this structure, new data or new economic processes should be able to be easily assimilated into the framework, so the model could be readily modified or updated.

- The ability to operate at a high level of disaggregation allows the representation of considerable regional detail, so solutions of the model may have policy implications for specific regions.

- Being highly disaggregated, the model is more stable and less subject to extreme corner solutions than smaller, more aggregated LP models would be.

The simple LP structure of the CEUM also has some significant disadvantages:

- Any solution of the model must be the solution of a linear optimization problem, in this case the minimization of the total cost of specified electricity production and coal consumed in non-utility sectors. Although cost minimization characterizes a purely competitive equilibrium, it is far from clear that cost minimization is a characteristic of a regulated monopolistic industry such as electricity generation. In fact, it is doubtful that the behavior of this industry can be described by the solution of any optimization problem. None of the economic literature on the behavior of regulated utilities was or could be brought to bear, given the LP model structure.

- The model is completely static. All events must be collapsed into a single time period. Behavior that changes over time cannot be represented or described in the context of the CEUM. In a short-run analysis, for those aspects of coal supply, coal transportation, and electricity generation that can change but slowly, this may not be a serious problem. However, when the horizon of the model is extended, the ability of the model to produce useful results becomes suspect. A time period of 30 years or greater is sufficient for coal mines to open and close, for new technologies to come into play, for patterns of electricity use to vary (witness the past 10 years), and for market conditions for alternative fuels to change, so it becomes impossible to represent the distant future in a timeless model. In addition, it is unreasonable to represent the distant future in a deterministic framework. For such modeling, a more aggregated and dynamic model seems appropriate.

- Available data have been adopted and synthesized to fit the model. A model constructed to take best advantage of available data would have had to be more complicated and less structurally uniform. The CEUM required much data that was not available, so data had to be manufactured. As a result, much of the apparent detail of the model solutions depends on assumptions with little or no empirical basis, but defended on the grounds of "reasonablesness" and with the comment that the user is free to provide his/her data and assumptions.

- The CEUM combines a very high level of detail on coal supply and electricity generation with a very highly aggregated, static description of alternative fuels, including oil, gas, and nuclear fuel. Disaggregation of data is to some extent a functional substitute for complexity of structure. In a large, disaggregated model, the set of feasible solutions can be bounded to include only those with realistic and reasonable properties. In particular, the use of a large number of activities and constraints allows a linear model to approximate the behavior of a nonlinear one. On the other hand, if unrealistic results are to be avoided, it is often essential (and usually inexpensive) to give a highly aggregated model an explicitly nonlinear structure. Because the CEUM is intended to be primarily a model of the coal sector of the U.S. economy, it is not surprising that the coal sector is described in much greater detail than are alternative energy sectors. However, because the coal sector is so strongly dependent on alternative energy forms, systematic errors are undoubtedly introduced into model solutions, errors which can only be eliminated through extensive "out-of-model" checking of results against information on the relation between coal and other components of the energy and economic systems.

Having summarized the advantages and disadvantages of the disaggregated LP framework used in the CEUM, what conclusions can we draw as to its appropriateness for the problems at hand? We believe that in the development phase of the model, the simplicity of the LP framework and the ease of interpreting, modifying, and updating it more than compensate for its limitations. However, now that the model is reasonably complete and is being used for policy-making purposes, consideration should be given to embedding an aggregated variant of the present CEUM into a dynamic system. This dynamic version of the model could be run side-by-side with the more disaggregated static version to serve as a check on serious systematic errors in the latter. We believe that in model runs with long horizons (30 years or more) a dynamic model may be indispensable as a tool for generating constraints to be used by the static CEUM.

We now turn to a more detailed consideration of each of the CEUM components.

3.3.2 Coal Supply Submodel

The coal supply component of the CEUM develops price-sensitive, multi-stepped coal supply curves for each coal type existing within each supply region. The curves are used to simulate potential production levels of coal available at various prices. Each step of a supply curve represents a different type of mine, with the length of the step indicating the potential production level for that mine type and the step height measuring the minimum acceptable real annuity coal price (RACP). The RACPs are based on average variable costs for existing mines and on average total costs for new mines.[11]

The key inputs and concepts of the coal supply submodel include, therefore, the level of coal reserves and their distribution by location and coal type; the concepts by which potential production rates are determined; and the concepts and data used in calculating the costs of potential production. We now turn to an evaluation of these concepts and data used in determining case-year coal supply schedules.

Potential Coal Production Rates.

Given the distribution of coal reserves and the mining recovery factors, the key variable determining the level of potential coal production is the mine lifetime. Mine lifetime affects supply in two ways. First, it is inversely proportional to the rate of extraction from a given parcel of reserves. Therefore, lifetime determines the intensity with which a parcel of reserves is mined. Second, mine lifetime affects the unit cost of coal production from a given parcel of reserves. Longer lifetimes lead to lower extraction costs due to lowering annualized capital requirements. However, long lifetimes delay the realization of revenues, and this imposes a "waiting" cost on the operator.

If a given segment of a coal supply curve represents coal extractable from a given parcel of reserves, a change in mine lifetime will affect the length of that segment through its effect on rate of extraction, and the height of that segment through its effect on costs. Thus, the effect of mine lifetime on the rate of extraction alone can dramatically alter the supply curve for coal. For example, when a mine lifetime of 20 years is changed to 30 years, each supply curve for coal is contracted along the horizontal axis by 33 percent.

In Figures 2 and 3, examples of supply curves for coal illustrate this effect. In each case, the change in lifetime causes the supply curves to shift from S to S'. In these figures, D denotes the demand curves, and E and E' denote the old and new market equilibria, respectively. Note that whether the effect of such a change in lifetime on the market equilibrium prices and quantities is substantial depends on the elasticity of supply. In Figure 2, where the supply curves are highly elastic, the shift from a 20-year to a 30-year lifetime has little effect on the market equilibrium. However, in Figure 3, where the supply curves are inelastic, the effect of the shift is significant.

Because mine lifetime may have a critical influence on coal supply, the determination of lifetime for use in the CEUM is vital to the accuracy of the model results. ICF employs a uniform mine lifetime, the value

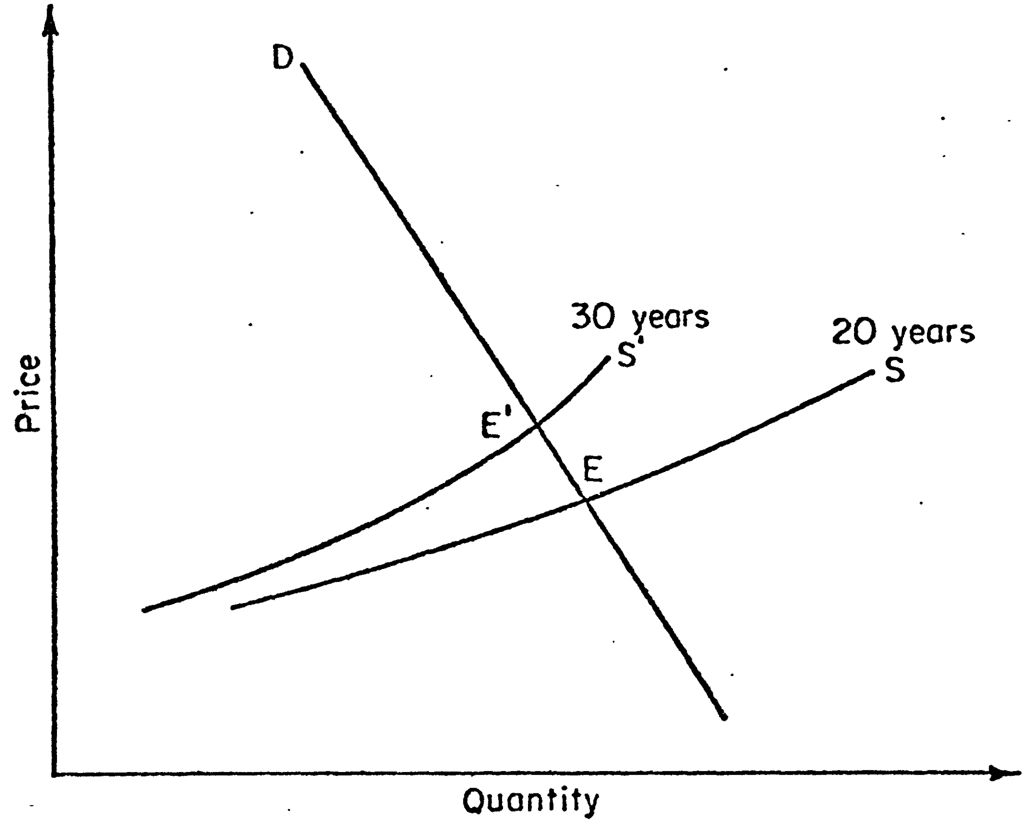

Figure 2

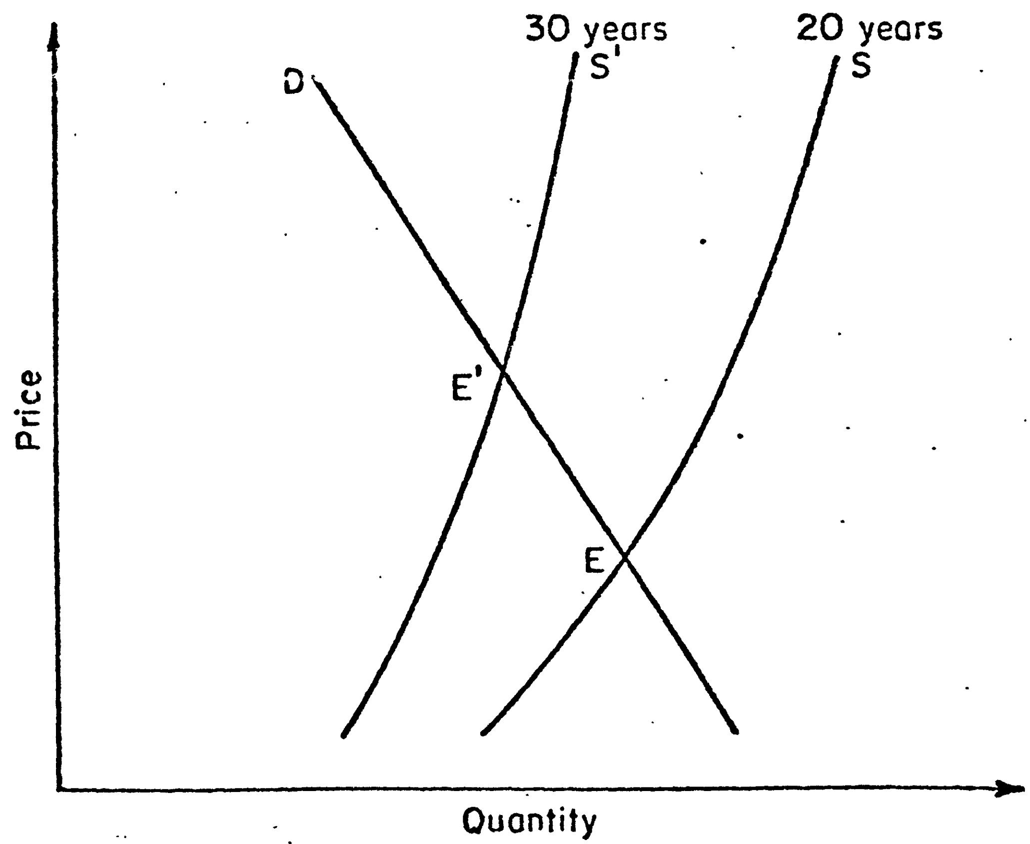

Figure 3

being based on the undocumented opinion of mine engineers and on historical data. This lifetime was set at 20 years in original versions of the CEUM and modified to 30 years in later versions. In the versions of the model considered in this study the lifetime parameter was set at 30 years.

In order to form a concrete estimate of the importance of the mine lifetime parameter in the CEUM, a comparison was made of the output of the Corrected Base Case (CBC) version of the model (30-year lifetime) with that of an oth^rwise identical version with a 20-year mine lifetime (CML20).

This change in the mine lifetime parameter from 30 to 20 years has a significant effect upon the regional distribution of coal production and a smaller impact upon regional coal prices. Deviation Indexes for production and prices are presented in Table 14. The values for the production indexes are the highest of any computational experiment considered in this report.

Table 14

COAL PRODUCTION AND PRICE DEVIATION INDEXES: CML20 vs. CBC

	1985	1990	1995
Coal Production	19.2	21.6	20.9
Coal Price	5.3	6.6	7.6

The change also has an impact upon the distribution of coal production by coal quality, the primary effect being a significant substitutability from low-sulfur to metallurgical coals. This is the result of a high degree of substitutability between these two coal types and the fact that metallurgical coal prices fall relatively more than low-sulfur prices. These results are presented in Table 15, together with information on changes in total coal production (very small) and changes in coal prices. The changes in coal prices are, with one exception (low sulfur in 1985 due to changes in coal type and regional mix), consistent with the expectation that costs of production are negatively correlated with the mine lifetime, since in the CEUM the shorter the mine lifetime, the less capital is required to produce a given quantity of reserves.

An associated effect of this change in regional production patterns was a shift in coal transportation, especially West-to-East transport (see Table 16).

These results demonstrate the importance of the mine lifetime parameters to model results, and the need for a sound method of determining appropriate values. To begin with, mine lifetime should not be assumed to be uniform. That assumption is as unjustifiable as an assumption of uniformity in other mining conditions. Second, the lifetime estimate

Table 15

PERCENTAGE CHANGE IN NATIONAL COAL PRODUCTION AND PRICES
BY COAL TYPE DUE TO REDUCING THE MINE LIFETIME FROM 30 TO 20 YEARS

National Coal Production (MM Tons)	1985	1990	1995
Metallurgical	7.3	9.2	10.2
Low Sulfur	-5.2	-2.1	-11.5
Medium Sulfur	-1.0	2.7	7.3
High Sulfur	.4	-1.5	-3.0
Deep	-1.8	- .6	2.1
Surface	1.0	2.6	-4.0
TOTAL	.6	1.1	-1.1
National Coal Prices ($ MMBtu)	**1985**	**1990**	**1995**
Metallurgical	-6.0	-7.3	-9.1
Low Sulfur	2.4	-2.5	-2.4
Medium Sulfur	-4.9	-3.7	-2.7
High Sulfur	-3.9	-7.3	-6.8
TOTAL	-2.7	-4.4	-4.2

Source: Derived from material in Volume VII, Chapter 2.

Table 16

COAL TRANSPORTATION: CML20 vs. CBC

	Coal Transportation Aggregate (10^9 Ton-Miles)			Coal Transportation West-to-East (10^9 Ton-Miles)		
	1985	1990	1995	1985	1990	1995
CBC	557	885	1208	98	152	218
CML20	540	863	1082	105	138	149
Percent change	-3.1	-2.5	-10.4	+7.1	-9.2	-31.7

should not be based on engineering data alone, but because of its effect on extraction costs, it should be treated as an economic variable. If mine operators set the lifetime with the intent of minimizing the costs involved, the estimates of optimal (cost-minimizing) lifetimes are appropriate for use in forecasting policy models.

In order to get a bearing on which economic variables affect the optimal mine lifetime, and how they affect it, a simple abstract theoretical model of coal extraction has been constructed and analyzed.[12] The results of this analysis suggest a surprising hypothesis: The optimal mine lifetime is determined primarily by only two economic variables, the market rate of interest and the capital recoupment period for the mine in question.[13] Long capital recoupment periods lead to long optimal mine lifetimes. Low and high interest rates also indicate long optimal lifetimes, while intermediate interest rates result in shorter optimal lifetimes.

These results make sense. When a mine functions over a long period of time, a substantial fraction of the present value of the ultimately extracted reserves is "lost" as a result of discounting future revenues at the market interest rate. If the recoupment period of the mine is short (and thus the mine is of high quality), this lost value may be great compared with the cost of the initial capital investment in the mine. Therefore, in such cases, there is strong incentive to construct a mine with a short lifetime and high extraction rate. Conversely, if the recoupment period of a mine is long, the value of revenues lost from discounting will be relatively small compared with the cost of the initial capital investment, so incentives are created to construct a mine with a long lifetime.

The effect of the interest rate on optimal mine lifetime is not monotonic. For very low interest rates, optimal mine lifetime is high because the owner of the reserves is in no hurry to remove them from the ground; he/she extracts the coal slowly to save on initial capital costs. Over some range, mine lifetime decreases and rate of extraction increases as the interest rate increases. However, as interest rates rise still higher, the present value of any income stream from a mine becomes relatively small compared with initial capital expenditures, so it becomes less desirable to incur high capital expenditures in order to extract the coal more quickly. Thus, as with low interest rates, the incentive is created to reduce initial capital costs, thereby increasing the lifetime of the reserves.

To sum up the results of the theoretical analysis, the following factors, by lengthening the recoupment period, would tend to promote mines with long lifetimes and low rates of extraction:

- o low-quality coal,
- o difficult mining conditions (thin seams, bad roofs, water, gas, etc.),
- o low price of coal, and
- o high costs (for labor or other production requirements).

In addition, both very low and very high interest rates would promote long mine lifetimes.

We believe some attention must be devoted to improving this aspect of the CEUM formulation or, at minimum, providing the user with some means to ensure that the assumed mine lifetime for each coal type is consistent with the interest rate, the cost of capital, and the capital recoupment period, the latter being determined by the price of coal.

One possibility is a complete reformulation of this part of the coal supply model, making mine lifetime an endogenous variable. This would make the determination of the coal supply functions simultaneous with the determination of utility coal demand and, therefore, with the price of coal. We have not pursued such a formulation in this report, but anticipate that it would be very difficult and obviously would change significantly the operating characteristics of the model.

A more modest proposal would be to formulate and implement an auxiliary model that included the variables necessary to endogenize the mine lifetime parameter conditional upon the price of coal. Such a model could be used both to estimate the lifetime parameter, conditional upon an estimate of the price of coal, and to check that the parameter actually used in the model was consistent with the coal prices estimated by the model. This latter type of checking would be an example of the post application input-output data consistency checking mentioned throughout Section 1.

We recommend the formulation and implementation of such an auxiliary model. The reader should note, however, that we do not necessarily recommend the implementation of the theoretical model outline mentioned above and presented in Volume III, Chapter 1. The issue of the correct formulation for a satisfactory auxiliary model remains a subject for further research. Our model simply demonstrates why the sensitivity revealed in the computational experiment is of some considerable importance, and why the user should be very concerned about this particular simplification in the CEUM formulation and implementation.

<u>Coal Reserve Data and the Distribution of Unclassified Resources.</u> Two aspects of coal reserve data provide some difficulty for the CEUM. First, there is the question of the accuracy of the Bureau of Mines (BOM) demonstrated reserve base. Second, there is the appropriateness of utilizing the uniform distribution to allocate reserves to overburden ratio, seam thickness and depth, and mine-size categories.

It was beyond the scope of this project to undertake an investigation of the reliability of the U.S. BOM demonstrated reserve base. It should be noted, however, that a recent report (DOE [1977]) undertook a comparison of the demonstrated reserve base estimates between January 1974--the estimates upon which the ICF data base depends (ICF [1977], p. III-6) and January 1976. The revisions are summarized in Table 17 for states having deep or surface reserves exceeding 10 billion tons. While the national totals do not change very much, the state distributions do.

In order to examine the effects of uncertainty in the Bureau of Mines reserve base data, a sensitivity run was conducted (CDRB) in which the specified reserve base for each coal type was randomly selected from a uniform distribution whose minimum was 75 percent of the CEUM figure and whose maximum was 150 percent of that figure. The confidence interval used in CDRB is based upon an inspection of Table 17 and consultation with Professor Richard L. Gordon of Pennsylvania State University.

Table 17

COMPARISON OF U.S. BOM DEMONSTRATED RESERVE BASE FOR DEEP AND SURFACE COAL BY LARGE RESERVE STATES: 1974 VS. 1976[14]

	1/1/74		1/1/76		Percent	Percent
	Deep	Surface	Deep	Surface	Deep	Surface
MT	65,165	42,562	70,959	49,610	+9	+17
IL	53,442	12,223	53,128	14,841	-1	+21
WU	34,378	5,212	33,457	5,149	-3	-1
PA	29,819	1,181	29,303	1,534	-2	+30
WY	27,554	23,674	31,647	23,725	+15	1
OH	17,423	3,652	13,091	6,140	-25	+68
CO	14,000	870	12,465	3,791	-11	+335
ND	0	16,003	0	10,145	0	-37
Others	55,454	31,334	52,926	26,426	-5	-16
Total U.S.:						
	297,235	136,713	296,976	141,361	1	+3

Source: DOE (1977).

The results of the CDRB experiment indicate a significant impact upon regional coal productivity and to a lesser extent on prices (see Table 18). The production Deviation Indexes are the second highest in 1985 of all runs (see summary Tables 11-13). As would be expected, the changes in regional production patterns result in changes in West-to-East coal transportation (12, 11, and 9 percent in 1985, 1990, and 1995, respectively).

Table 18

COAL PRODUCTION AND PRICE DEVIATION INDEXES: CDRB vs. CBC

	1985	1990	1995
Coal Production	9.1	14.8	17.7
Coal Price	1.6	3.0	4.4

The results of the CDRB model runs show substantial increases in the production of high-quality coal and in coal with low extraction costs. This is because, on the average, the specified reserves of all types of coal were increased, while overall demand remained unchanged. Therefore, in the model solution, less expensive coal was substituted for more expensive coal, and higher-quality coal was substituted for lower-quality coal. The pattern of percentage changes in production and prices by coal type presented in Table 19 bears out these conclusions. For a complete summary of CDRB vs. CBC see the CDRB run description in Volume VII, Chapter 2.

The reader should not attach undue significance to the particular outcome of choosing reserve levels at random from the uniform distribution, since other outcomes would have produced different results. Our purpose here is to provide some indication of what effect the uncertainty in basic reserve data might have on model results.

Next we consider a sensitivity experiment to evaluate the potential impact upon model results of a change in the underlying distribution using allocated unclassified reserves to model coal types.

Table 19

PERCENTAGE CHANGE IN NATIONAL COAL PRODUCTION AND PRICES BY COAL TYPE DUE TO CHOOSING RESERVE LEVEL FROM A "PLAUSIBLE" UNIFORM DISTRIBUTION (CDRB vs. CBC)

National Coal Production (MM Tons)	1985	1990	1995
Metallurgical	6.7	4.5	5.9
Low Sulfur	1.9	4.8	8.5
Medium Sulfur	-3.5	-4.3	-5.5
High Sulfur	-1.4	-1.5	-6.0
Deep	-2.1	-1.9	-1.4
Surface	1.6	2.0	1.5
TOTAL	- .1	.1	.1

National Coal Prices ($ MMBtu)	1985	1990	1995
Metallurgical	-4.0	0.0	-3.8
Low Sulfur	0.0	-5.0	-9.6
Medium Sulfur	-2.9	- .9	0.0
High Sulfur	-1.0	-2.4	-2.3
TOTAL	- .9	-2.6	-4.2

The CEUM incorporates no real data on the distribution of reserves by seam thickness. Because CEUM mine-costing algorithms require such data, seam thickness is arbitrarily assumed to be uniformly distributed between the minimum (28 inches) and maximum (72 inches) values for which the Bureau of Mines reports resources. The LOGN sensitivity runs were constructed in order to test the sensitivity of the CEUM to the seam thickness distribution. In the LOGN runs, seam thickness is distributed as a truncated log-normal function between the same minimum and maximum as is specified in the Corrected Base Case. The distribution is highly skewed toward the minimum, with the point of truncation being approximately two standard deviations to the right of the mode. It should be noted that because the seam-thickness minima and maxima were not perturbed in the LOGN runs, the output may understate the effect of seam-thickness uncertainty. The LOGN runs are compared with the Corrected Base Case runs in Tables 20 and 21.

Table 20

COAL PRODUCTION AND PRICE DEVIATION INDEXES: LOGN vs. CBC

	1985	1990	1995
Coal Production	9.8	15.4	12.3
Coal Price	4.5	2.5	1.5

Table 21

PERCENTAGE CHANGE IN NATIONAL COAL PRODUCTION AND PRICES BY COAL TYPE DUE TO ASSUMING A LOGNORMAL DISTRIBUTION FOR SEAM THICKNESS (LOGN vs. CBC)

National Coal Production (MM Tons)	1985	1990	1995
Metallurgical	7.2	6.5	5.8
Low Sulfur	3.5	9.8	2.3
Medium Sulfur	.7	3.3	6.9
High Sulfur	-10.4	-22.5	-13.2
Deep	-5.1	-9.3	-7.3
Surface	3.4	8.6	8.1
TOTAL	- .2	-0.0	.6

National Coal Prices ($ MMBtu)	1985	1990	1995
Metallurgical	2.4	1.1	1.1
Low Sulfur	1.2	-3.8	-2.4
Medium Sulfur	2.9	3.7	-.9
High Sulfur	9.6	5.7	2.3
TOTAL	4.6	.9	-.9

Again, a change in the underlying characterization of the coal reserve data leads to significant impacts on the regional distribution of coal production, with lesser impacts on prices. And as with CDRB, the change shifts coal production from inferior to superior coal types and from deep to surface mining.

There are several additional problems with coal reserve data that were not examined via sensitivity runs. For example, data specifying the distribution of overburden ratios for surface coal reserves were also estimated by ICF employing the uniform distribution to distribute resources within the endpoints provided in the BOM data. No computational experiment was conducted relating to the distribution function for overburden ratio.

Another potentially serious problem is the difficulty of deriving data on recoverable reserves from data specifying the reserve base. A 1975 Bureau of Mines publication that presents reserve base data contains the following warning:

> Extreme caution must be exercised in any attempt to translate the underground reserve base into a recoverable reserve figure.... Because of data gaps and inadequacies, it would be very difficult, if not impossible, to accurately quantify the coal unavailable due to multiple beds, thick beds, subsistence considerations, and other factors. (Thompson and York [1975]).

Such warnings by the principal source data organization, coupled with our computational experiments, suggest that extreme caution must be exercised in interpreting results on coal production and prices from the CEUM, or from any other model using these data. This latter point is worth bearing in mind. Any coal supply model, not just the CEUM, must face up to these problems in the quality of the source data.

Coal Royalties.

In a competitive economy two types of scarcity rents or royalties accrue to the owners of coal reserves: static and dynamic. The static rents occur because of differences in extraction and delivery costs of coal types being mined at a given time. The lower-cost deposits earn a static rent. This type of rent should not be included as a cost in constructing supply curves; rather, the static rent earned by a given parcel of reserves is represented by the vertical distance between the corresponding point on the supply curve and the market price.

The other type of rent on exhaustible resources arising in a competitive economy is a dynamic or intertemporal rent. This rent results from the fact that exploiting a resource at one point in time prevents its owner from exploiting it at a future time. The higher the expected future resources within the endpoints provided in the BOM data. No computational experiment was conducted relating to the distribution function for overburden ratio.

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The other type of rent on exhaustible resources arising in a competitive economy is a dynamic or intertemporal rent. This rent results from the fact that exploiting a resource at one point in time prevents its owner from exploiting it at a future time. The higher the expected future price of coal, the greater is the intertemporal rent that must be reflected in the coal supply curves, for it must be paid to the owners of all currently operating mines, even marginal mines.

When intertemporal rents can be observed in market data, they appear as a portion of the royalty payments made by mine operators to the owners of mineral rights. However, because mine operators often own the mineral rights to their operations, intertemporal rents are frequently implicit and cannot be directly observed. Nevertheless, such implicit rents are as real and as important as explicit rents. The price the mine operator receives for coal must cover implicit as well as explicit intertemporal rents if the operator is to be willing to work the mine. For this reason, in deriving the supply function intertemporal rents should be imputed whenever they cannot be measured.

There is no imputation of rents in the CEUM, and no discussion of this issue in the CEUM Documentation (ICF [1977]). While the computer implementation of the model has provisions for including royalties in the coal supply cost function, royalty payments are always set at zero in supply regions that are not dominated by federal coal lands. Thus, even explicit non-federal royalty payments are omitted, while the possibility of imputed rents is not mentioned. In regions dominated by federal lands, royalty payments at federal rates are included. In Volume III, Chapter 2, a simple model of the generation of intertemporal rents is constructed and analyzed. CEUM data are used to produce crude estimates of the value of these rents. A wide range of estimates is discussed, but the best estimate seems to be 10 percent of the mine-mouth price.

In order to test the potential importance of intertemporal rents in the output of the CEUM, a run was made with intertemporal rents set at our estimated 10 percent of coal extraction costs in non-federal regions. The royalties in federally dominated regions were left unchanged. The results of this run (ROYI) were compared with the Corrected Base Case model runs for the corresponding years (CBC-85, CBC-90, CBC-95). Differences between the results of the ROYI and the CBC runs were substantial in each case year.

Among national aggregate statistics, the most obvious difference between the ROYI and the CBC runs occurs in coal transportation statistics (see Table 22). The ton-mileage figure for West-to-East transportation is an average of 65 percent higher for the three years (1985, 1990, 1995) than it is for the comparable CBC runs. Also, East-to-West ton-mileage decreases by an average of 34 percent. These changes occur because of the imputation of royalties to Eastern coal, while Western coal from federal lands has no additional royalties imputed. Clearly, the issue of intertemporal rents is crucial for predicting the extent to which Western coal will penetrate Eastern markets.

Table 22

COAL TRANSPORTATION: ROYI vs. CBC

	National Aggregate (10^9 Ton-Miles)			West-to-East (10^9 Ton-Miles)			East-to-West (10^9 Ton-Miles)		
	1985	1990	1995	1985	1990	1995	1985	1990	1995
CBC	557	885	1208	98	152	218	3.2	3.1	2.9
ROYI	609	1011	1354	148	268	362	2.5	1.4	2.8
Percent change	+9.3	+14.2	+12.1	+51.0	+76.3	+66.1	-21.8	-54.8	-3.4

Finally, the introduction of an estimate for intertemporal rent into coal production costs influences the pattern of production and prices by coal type. As shown in Table 23, metallurgical production falls in all case years that have sulfur uses. As in the lifetime parameter model run (CML20), this is due to the high substitution between these coal types and the fact that metallurgical prices rose relative to low-sulfur prices.

The ROYI market-equilibrium quantities and prices of coal by coal type and supply region were compared to the corresponding CBC values using the Deviation Index. The national-average coal price increase was 7.3 percent in 1985 and 6.4 percent in both 1990 and 1995. Coal production changed by an average of 8.8 percent in 1985. On the one hand, coal

Table 23

PERCENTAGE CHANGE IN NATIONAL COAL PRODUCTION AND PRICES BY COAL TYPE DUE TO INCLUDING AN ESTIMATE OF INTERTEMPORAL RENT IN THE COST OF COAL PRODUCTION (ROYI vs. CBC)

National Coal Production (MM Tons)	1985	1990	1995
Metallurgical	-7.8	-9.8	-8.1
Low Sulfur	11.8	18.5	8.6
Medium Sulfur	-2.2	-2.2	6.9
High Sulfur	-1.5	-10.6	-11.1
Deep	-4.8	-9.0	-8.7
Surface	5.4	11.2	11.9
TOTAL	.7	1.4	1.9

National Coal Prices ($ MMBtu)	1985	1990	1995
Metallurgical	7.2	6.7	8.1
Low Sulfur	1.2	-2.5	1.2
Medium Sulfur	4.9	4.7	0.0
High Sulfur	9.6	8.9	7.5
TOTAL	5.5	1.8	1.7

regions such as Pennsylvania and Ohio decreased coal production by more than 12 percent in ROYI versus CBC. On the other hand, ROYI increased coal production in Western Montana and Colorado South by about 23 percent. Coal production by supply region changed by an average of 12.6 percent in 1990 and 10.2 percent in 1995. Tables 23-25 summarize these changes.

As expected, equilibrium prices rise with one exception (low sulfur in 1990) due to changes in the regional shares used in obtaining a weighted national average.

To increase the reliability of CEUM output, intertemporal rents should be included in the CEUM analysis. This is more easily said than done. In the general case, intertemporal rents depend on expectations of the very same future prices that the CEUM is designed to predict. As a result, models including such rents cannot be solved by simple static

Table 24

COAL PRODUCTION AND PRICE DEVIATION INDEXES: ROYI vs. CBC

	1985	1990	1995
Coal Production	8.8	12.6	10.2
Coal Price	7.3	6.4	6.4

Table 25

COAL PRODUCTION PRICES: ROYI vs. CBC

Coal Prices Aggregate
(1978 $/MMBtu)

	1985	1990	1995
CBC	1.10	1.14	1.18
ROYI	1.16	1.16	1.20
Percent change	+5.5	+1.8	+1.6

optimization techniques. The imputation of intertemporal rents together with the solution of the entire model is a dynamic optimization problem, which normally requires the use of dynamic programming or an equivalent technique. In the case of the CEUM, the size of the model is so large that true dynamic optimization is impractical. Instead, average intertemporal rents could be calculated using a dynamic model more highly aggregated than the CEUM, but more detailed, for example, than the model presented in Volume III, Chapter 2. The rents so calculated could be introduced into the present static version of the CEUM as exogenous parameters. As a consistency check, the output of the CEUM run with intertemporal rents could then be compared to the output of the more aggregated dynamic model.

The analysis of this study suggests that intertemporal rents on coal have a significant role to play in any model focusing on coal as a source of energy. This omission in the CEUM should be corrected. However, the reader should bear in mind that, to our knowledge, no other supply model of U.S. coal reserves treats the intertemporal rent aspect of production costs.

Coal Production Costing.

The CEUM procedure for calculating costs of potential coal production in any case year is based upon an engineering cost analysis of two "base case" model mines, one surface and one deep.

> A matrix of adjustment factors is used to modify the base-case mine costs as the overburden ratio, seam thickness, seam depth, or mine size changes between model mine types. The base-case cost models were developed from existing mine cost studies by BOM and TRW, and from information obtained through interviews with mining engineers and coal economists. For underground operations the base-case mine was defined as a slope mine producing one million tons per year from a six-foot coal seam 700 feet below the surface using continuous mining and having unit-train loading facilities but no cleaning plant. For surface mining operations the base case was a one million tons per year area mine with a 10:1 overburden ratio and having unit train loading facilities but no preparation plant (ICF [1977] Section III, pp. 47-48).
>
> The actual matrix of cost adjustment factors employed are given in Table 26. These factors were developed from examination and comparison of existing mine cost models and consultations with a mining engineer and the BOM Process Evaluation Group in Morgantown, West Virginia. Changes in values for initial capital, deferred capital, and power and supplies resulting from variations in mine-type parameters were substituted directly into the costing equations specified for the base-case calculations. However, the cost effects of changes in output per man day were computed by dividing the adjusted productivity figure into the annual output level assumed for the mine and multiplying the resulting number of man days per year by the average labor cost per man-day estimated from the base cases (ICF [1977], Section III, p. 50).

The ICF approach is essentially equivalent to specifying the cost function by coal type analytically with cost parameters specified exogenously. However, ICF does not employ an explicit engineering cost function directly relating average cost (i.e., minimum acceptable real annuity coal price) to a mine's physical variables. Beginning with the matrix of cost adjustment factors (see Table 26), real annuity coal prices (RACPs) are determined in the CEUM Supply Code, in a sequential manner, built up in stages, component by component. The underlying cost function is only implicit.

Table 26

MINING COST ADJUSTMENT FACTORS FOR KEY VARIABLES

(From ICF, Inc. [1977], page III-52)

	Initial Capital	Deferred Capital	Output/Manday 1/	Power and Supplies
Underground Mines 2/				
Seam Thickness	+6%/ft. decline in thickness	+6%/ft. decline in thickness	-1.0/TPMD/ft. decline in thickness	+$0.15/ton/ft. decline in thickness
Seam Depth	$500,000/100 ft.	--	--	--
Annual Output	30%/MMTPY	15%/MMTPY	0.5TPMD/0.1MMTPY	100%/MMTPY
Drift Mine	-$6,000,000	-$3,000,000	+10%	--
Conventional Mining	3/	3/		--
Surface Mines 4/				
Overburden Ratio	$1.20/Ton/UOR	$0.25/Ton/UOR	-10%/5UOR	$30,000/UOR
Annual Output:				
Mines ≥1.0MMTPY	5/	5/	3TPMD/0.1MMTPY	100%/MMTPY
Mines <1.0MMTPY	-5%/0.1MMTPY	-5%/0.1MMTPY	3TPMD/0.1MMTPY	100%/MMTPY

1/ The cost effects of changes in output per manday are calculated by dividing the estimated tons per manday figure for a given mine type into the mine's annual output level to get the total number of mandays per year and then multiplying that figure by the average labor cost per manday (i.e., $53.90 for underground mines and $77.12 for surface mines). Note that output per manday is calculated based on the total number of mandays worked by all classes of mine employees in one year.

2/ Variations for underground mines are calculated from a base case operation which is defined as one million ton per year slope mine working a six foot seam seven hundred feet deep using continuous mining and having unit train loading facilities, no cleaning plant, and an average output per manday of 17.3 tons.

3/ Initial capital (less the cost of required shafts) and deferred capital investment costs for mines producing less than one million tons per year are assumed to remain constant on a dollars per ton of annual output basis with the capital costs after all other adjustments are made for one million ton mine with the same characteristics. This assumes that the capital intensity of mines with annual output levels of less than one million tons decreases with size.

4/ Variations in surface mine costs are calculated from a base case mine defined to produce one million tons per year from a six foot seam with a 10:1 overburden ratio using area mining techniques and having unit-train loading facilities but not preparation plant.

5/ The capital costs for surface mines producing over one million tons per year are assumed to experience increasing economies of scale with respect to capital costs. To reflect this the incremental capital required for each million ton increase in annual output is assumed to decline ten percent from the capital costs for a one million ton per year operations. Thus, capital costs for a two million ton per year mine would equal 1.9 times those for a one million ton mine, and capital for a three million ton per year operation would equal 2.7 times those for the one million ton mine.

ABBREVIATIONS: TPMD = tons per manday
MMTPY = million tons per year
UOR = units of overburden ratio.

We have developed and programmed the analytical formulation of ICF's implied engineering cost function for both surface and deep mines, and the analytical formulation of the associated cost elasticities relating real annuity coal prices to each of the physical variables characterizing coal deposition. This computer code was verified by duplicating to five decimal places both the uncorrected and corrected base-case calculations of coal supply prices.[15]

Examination of the analytical cost function and the associated cost adjustment factors suggests that an important parameter within the CEUM's implicit engineering cost function is the real escalation rate of unit labor costs. This rate is exogenous in the CEUM, but in choosing a value the prudent user/analyst will take into account the fact that the escalation rate implies growth rates for either the rate of growth in labor productivity or the nominal wage rate, and (depending upon which of these rates is taken as given) determines the other. Thus, if c denotes unit labor cost, w the average wage rate, and v the average productivity of labor, then $c = w/v$. Therefore, the rate of growth of unit labor costs is the difference between the growth of wage rates and growth of average labor productivity.

In all studies considered in this evaluation the real escalation rate for labor inputs was assumed to be 1 percent per annum. However, given what underlies such a rate, it seems to us that the assumption that wage rates will grow at a rate that is uniformly one percentage point greater than the growth rate of productivity over the next 35 years must be considered highly uncertain. An average unit labor cost escalation of 3 percent/year or -1 percent/year, for example, might be equally plausible. In addition, there is little reason to expect that unit labor cost escalation would be uniform throughout the country. For one thing, both labor market conditions and the technological conditions in the West are quite different from those in the East. One could speculate that productivity will grow more quickly than wages in the West, while the opposite occurs in the East. Such a pattern would imply a considerable difference in the growth of unit labor costs between these two major regions.

To provide the user with some indication of the impact of unit labor costs on model results, two computational experiments were formulated with the real escalation rate for unit labor costs set at 3 percent/year (LAB3) and -1 percent/year (LABD).

The results of the LAB3 model runs indicate that the CEUM is quite sensitive to changes in unit labor cost escalation. The Deviation Index shows that equilibrium coal production prices are roughly 25 percent higher in the LAB3 model runs than in the Corrected Base Case model runs. Solution quantities are about 15 percent smaller. For a complete summary of the important results comparing the LAB3 sensitivity run with the Corrected Base Case, see appropriate tables in Volume VII, Chapter 2. Note that these values differ from the averages taken from the CEUM output reports because of different weighting methods.

Comparing the LAB3 model runs with the Corrected Base Case, the most significant results taken from the CEUM output reports are summarized in Tables 27, 28, and 29.

For the LABD model runs, where it was assumed that labor productivity grows 2 percentage points per year more quickly than wage rates, the Deviation Index shows production prices down about 15 percent from the Corrected Base Case, with quantities increased about 10 percent. Comparing the LABD model runs with the Corrected Base Case, the most signficant results taken from the CEUM output reports are summarized in Tables 30, 31, and 32.

The analytical formulation of the CEUM's coal supply cost function provides a convenient way to calculate the elasticities of the minimum acceptable real annuity coal price with respect to each of the physical variables characterizing coal deposition. Physical variables for deep mines include seam thickness, seam depth, and mine size (annual production rate), while for surface mines they include overburden ratio and mine size. Table 33 summarizes the low and high values for average elasticities across all coal types and supply regions, where elasticities for each coal type are evaluated as averages across all

Table 27

COAL TRANSPORTATION: LAB3 vs. CBC

	Coal Transportation Aggregate (10^9 Ton-Miles)			Coal Transportation West-to-East (10^9 Ton-Miles)		
	1985	1990	1995	1985	1990	1995
CBC	557	885	1208	98	152	218
LAB3	699	1129	1510	244	411	522
Percent change	+ 26	+ 28	+ 25	+149	+171	+139

Table 28

COAL PRODUCTION: LAB3 vs. CBC

	Surface Coal Production (MM Tons)			Deep Coal Production (MM Tons)		
	1985	1990	1995	1985	1990	1995
CBC	600	779	963	515	726	913
LAB3	709	979	1203	433	572	741
Percent change	+ 18	+ 26	+ 25	-16	-21	-19

	Low-Sulfur Coal Production (MM Tons)			Coal Production Detailed (Deviation Index-Percent)		
	1985	1990	1995	1985	1990	1995
CBC	285	460	623	-	-	-
LAB3	360	547	732	-	-	-
Percent change	+ 26	+ 19	+ 18	15	20	19

Table 29

COAL PRODUCTION PRICES: LAB3 vs. CBC

	Coal Prices Aggregate (1978 $/MMBtu)			Coal Prices Detailed (Deviation Index-Percent)		
	1985	1990	1995	1985	1990	1995
CBC	1.10	1.14	1.18	-	-	-
LAB3	1.28	1.28	1.38	-	-	-
Percent change	+ 16	+ 12	+ 17	25	24	28

Table 30

COAL TRANSPORTATION: LABD vs. CBC

	Coal Transportation Aggregate (10^9 Ton-Miles)			Coal Transportation West-to-East (10^9 Ton-Miles)		
	1985	1990	1995	1985	1990	1995
CBC	557	885	1208	98	152	218
LABD	515	820	1060	76	88	95
Percent change	-8	-7	-12	-22	-42	-57

Table 31

COAL PRODUCTION: LABD vs. CBC

	Surface Coal Production (MM Tons)			Deep Coal Production (MM Tons)		
	1985	1990	1995	1985	1990	1995
CBC	600	779	963	515	726	913
LABD	561	704	820	543	790	1014
Percent change	-7	-10	-15	+5	+5	+11

	Low-Sulfur Coal Production (MM Tons)			Coal Production Detailed (Deviation Index-Percent)		
	1985	1990	1995	1985	1990	1995
CBC	285	460	623	-	-	-
LABD	267	453	574	-	-	-
Percent change	-6	-1	-8	9	11	13

Table 32

COAL PRODUCTION PRICES: LABD vs. CBC

	Coal Prices Aggregate (1978 $/MMBtu)			Coal Prices Detailed (Deviation Index-Percent)		
	1985	1990	1995	1985	1990	1995
CBC	1.10	1.14	1.18	-	-	-
LABD	0.96	1.01	1.05	-	-	-
Percent change	-13	-11	-11	16	15	15

possible combinations of physical variables.[16] The elasticities can also be compared with estimates from other modeling efforts. In Table 33 we include comparable values from a study by Zimmerman (1979). In contrast to the CEUM, Zimmerman estimates the parameters of the cost function by combining both engineering and statistical methods. Clearly the CEUM gives elasticity results very different from those of Zimmerman, especially regarding seam thickness. At present we have no opinion as to which results are more likely to be correct since we have not undertaken an evaluation of Zimmerman's coal model.

Another interesting feature, implicit in the CEUM coal supply costing procedure and evident from the analytical formulation of the cost function, is that over the range of mine sizes allowed in the CEUM the average cost curves (i.e., plots of real annuity coal price versus mine size for any coal type in any region, given a set of physical variables) have no minimums. In fact, as mine size increases, the average cost of surface mines becomes <u>negative</u>[17] and the average cost of deep mines asymptotically approaches a low positive value that depends on the physical variables of the given deep-mine type. As a consequence of the shapes of the average cost curves it can be concluded that the CEUM models coal extraction as a decreasing cost activity and that coal production always takes place in the largest deposits available, all other physical characteristics being the same.

Table 33

RANGE OF AVERAGE ELASTICITIES RELATING MINIMUM ACCEPTABLE REAL ANNUITY COAL PRICE TO PHYSICAL VARIABLES CHARACTERIZING COAL DEPOSITION

	CEUM*	Zimmerman
Surface		
Overburden Ratio	.44 to .70	1.0
Mine Size (annual production rate)	-.27 to -.39	N.A.
Deep		
Seam Thickness	-.19 to -.23	-1.1
Seam Depth	.04 to .05	0.0**
Mine Size (annual production rate)	-.24 to -.28	N.A.

*Low and high values were obtained for average elasticities across all coal types and supply regions, where elasticities for each coal type were evaluated as averages across all possible combinations of physical variables.

**Maintained hypothesis.

Volume IV, Chapter 3 provides further discussion of coal supply costing, including the effects of the CEUM Supply Code verification corrections on the coal supply cost function.

3.3.3 Coal Transportation

The transportation component of the ICF Coal and Electric Utilities Model (CEUM) transfers coal from coal stocks in supply regions to coal piles in demand regions at a price per ton. The piles in each demand region are identified by rank (bituminous, subbituminous, or lignite) and sulfur level. The cost of transportation, as a per ton charge, is based upon unit-train or barge shipment rates.

Coal transportation has been modeled with direct links, at a single per ton charge for each link. Each link keeps track of the flow of a single coal type from one supply region to one demand region. The use of lower bounds on the amount of coal that can be shipped via a specific link forces the model to ship coal between regions regardless of cost. The impact of the lower bounds approximates the effect of existing long-term contracts. These constraints are included in the scenario data, which a model user must provide when more than one case year is to be analyzed. In the studies considered in this report, the lower bound was always set at 80 percent of the coal flow estimated in the previous case year. In general, one would expect that the longer the period between case years, the lower would be the percentage value of this constraint. A reader troubled by this "lower bounding" procedure is reminded that there is really no alternative if multiple case years are to be analyzed in a static framework. Further, this type of scenario data is similar to the information required on coal flow relationships between the base and the first case years.

The direct links used to transfer coal from supply regions to demand regions require three inputs. First, the relevant links are identified. Second, the cost of using each link is estimated. Third, relevant bounds are set for each link. The Bureau of Mines Bituminous Coal and Lignite Distribution - Calendar Year 1973 was used to identify existing coal shipment links.

The major transportation assumptions are as follows: (1) all rail shipments of coal are by unit-train; (2) rail transportation costs are modeled by a linear equation; (3) both rail and water modes are subject to the same inflation factor; and (4) no future bottlenecks are recognized and as a result transportation links are never upper bounded.

In reviewing the coal transportation submodel, only one potentially serious issue was identified. The version of the CEUM existing as of September 1, 1978 and as applied in ICF's (1978b) third case study claims to incorporate a real rail-rate escalation factor of 1 percent/yr over each year of the 1975-1995 time horizon of the model. If implemented correctly, transportation costs, after being inflated appropriately from 1975 to 1978 dollars, would be multiplied by:

$(1.01)^{10}$ for a 1985 model run,
$(1.01)^{15}$ for a 1990 model run, and
$(1.01)^{20}$ for a 1995 model run.

Upon examination of the CEUM computer code it was determined that what the model actually does is apply a transportation multiplier (TCMLT) of $(1.01)^{20} = 1.22019$ for all case-year model runs. The implicit effect of such an implementation is that real rail rates escalate at approximately 2 percent/yr from 1975-85 for a 1985 model run, 1.34 percent/yr from 1975-90 for a 1990 model run, and 1 percent/yr from 1975-95 for a 1995 model run.

To investigate the implications of this problem, a sensitivity run (TCML) was implemented by changing the real rail-rate escalation factor in the Corrected Base Case from $(1.01)^{20}$ to $(1.01)^{10}$. The motivation for using an escalation factor of $(1.01)^{10}$ was to bound the magnitudes of the errors that result from the use of a single multiplier for all case years. In particular, the TCML-85 model results should be compared directly with the CBC-85 results, with any differences carefully noted as implementation errors.

The most significant results of comparing the TCML model run with the Corrected Base Case are displayed in Tables 34-36.[18]

3.3.4 Electric Utilities Submodel

The third major component of the CEUM is the electric utilities submodel. Given the demand for electricity, this submodel determines capacity expansion and dispatch, fuel demands--in particular coal demands--investments in control technologies, and interregional transmission.[19] In this section we first describe the electric utilities submodel, then present structural and data issues raised in the review. As noted previously, this review was completed in early 1980, so several modifications to the model and associated data which relate to the issues identified here have taken place. In a final

Table 34

COAL TRANSPORTATION: TCML vs. CBC

	Coal Transportation Aggregate (10^9 Ton-Miles)			Coal Transportation West-to-East (10^9 Ton-Miles)		
	1985	1990	1995	1985	1990	1995
CBC	557	885	1208	98	152	218
TCML	586	985	1282	121	244	305
Percent change	+5.2	+11.3	+6.1	+23.5	+61.3	+39.9

Table 35

COAL PRODUCTION: TCML vs. CBC

	Surface Coal Production (MM Tons)			Deep Coal Production (MM Tons)		
	1985	1990	1995	1985	1990	1995
CBC	600	779	963	515	726	913
TCML	614	850	1018	507	684	875
Percent change	+2.4	+9.0	+5.7	-1.7	-5.7	-4.1

	Low-Sulfur Coal Production (MM Tons)			Coal Production Detailed (Deviation Index-Percent)		
	1985	1990	1995	1985	1990	1995
CBC	285	460	623	-	-	-
TCML	306	537	672	-	-	-
Percent change	+7.4	+16.8	+7.9	3.1	6.6	4.4

Table 36

COAL PRODUCTION: TCML vs. CBC

	1990 Coal Production Price (1878 $/MMBtu)	1990 Utility Oil/Gas Consumption (Quads)	1995 New Transmission (109 KWH)
CBC	1.14	3.28	176.0
TCML	1.10	3.03	154.1
Percent change	-3.5	-7.8	-12.5

section, we summarize for the reader's convenience new developments reported to us by the modelers, but not considered in this review.

Description of Electric Utilities Submodel

The CEUM computes, for each of 39 utility demand regions in the United States, capacity additions for the following plant types:

(1) oil/gas turbine,

(2) oil/gas steam,

(3) bituminous, subbituminous, or lignite coal NSPS (New Source Performance Standards complying),

(4) bituminous, subbituminous, or lignite coal ANSPS (Alternative NSPS complying),

(5) combined cycle,

(6) bituminous to subbituminous coal conversion facilities on existing plants (three types available),

(7) retrofit scrubbers on existing coal plants,

(8) scrubber on new bituminous, subbituminous, or lignite coal NSPS, and

(9) scrubber on new bituminous, subbituminous, or lignite coal ANSPS.

Hydro, geothermal and nuclear capacity additions are treated as exogenous. The CEUM documentation (ICF [1977]) describes an ability to incorporate MHD and synthetic gas turbines; however, they were not included in the version of the model under review.

Capital and operating costs as well as derated capacity factors (net of planned and forced outages) are among the characteristics that describe the new capacity additions. The linear programming structure makes it fairly easy to change any of these data and to constrain various expansion patterns. Dynamic issues are not treated, as capacity additions are measured in total gigawatts of capacity added between the base and case years. The capital costs of the capacity additions are treated as annualized investment costs added directly to the objective function of the LP. The capacity additions are motivated by operating needs for unmet electricity demand in the categories of baseload, intermediate, daily peaking, and seasonal demand. Where there are alternative strategies for capacity additions, those additions that minimize the overall objective function are chosen. Thus, the real annuity coal prices, transportation costs, transmission costs, and all the other coefficients in the objective function influence the capacity expansion strategy.

Understanding the interaction between existing and new capacity, conversions, and investments in control technology is facilitated by considering the system constraints and mass balance relations. There are four types of constraint equations relating to capacity expansion:

(1) Generating capacity constraints for existing plants: These constraint equations ensure that the amount of electricity generated from each plant type, translated into units of capacity using the appropriate capacity factor, plus the amount of capacity removed by conversion, does not exceed the existing capacity.

(2) Material balances for new generation facilities: These equations ensure that for each new plant type the associated operating activities translated into units of capacity, minus the newly built capacity of this type, does not exceed zero.

(3) Material balances for scrubber capacity on both existing and new plants: Scrubber capacity is measured (somewhat artificially) in GW. Whenever only fractional scrubbing of a plant type's exhaust is indicated, then the number of GW of that plant type's capacity, multiplied by the scrubbing fraction, must not exceed the number of "scrubber GW" available. Scrubber categories include retrofitted scrubbers, those that may be put on new NSPS plants, and those on new ANSPS plants that do and do not use coal of sulfur level A.

(4) New capacity building limitations: These constraints limit the expansion of new generating capacity that can occur between the base and case years. In the version of the model being reviewed, they apply only to new coal and oil/gas steam generation. In the studies reviewed, new oil/gas steam generating capacity is constrained to zero (0.0) reflecting current policy.

Electricity generation is scheduled to meet the four types of load demand categories (base, intermediate, seasonal, peak) in each of the CEUM's demand regions. Thus both demand and capacity factors are exogenous. The model combines new and existing capacity to produce and distribute electricity at the least cost subject to the model's constraints, resulting in estimates of, among other variables, annual generating costs and fuel use in the case year.

There are three types of important constraint equations that are relevant to generation:

(1) Total electricity deliveries by utility region: These equations ensure that electricity delivered by all sources--new and existing plants of all types, and interregional transmission--equals the regional demand.

(2) Electricity supply balances: These equations ensure that the amount of electricity leaving a region for delivery and transmission must be less than or equal to the total amount of electricity supplies in that region. Material balances for electricity supplies vary by load category. For activities operating in baseload, the electricity generated from all sources in a region, minus the amount of baseload energy used for pumped storage, plus net transmission into the region, must be greater than or equal to the baseload electricity supply for the region. For the other load modes there is assumed to be no transmission and no pumping for storage.

(3) Fuel pile balances: These equations ensure that fuel use in each utility region equals fuel deliveries to that region.

As is apparent from considering the constraint equations directly related to capacity additions and generation, it is impossible to separate the utility operation from the utility planning in the CEUM. Thus, this section contains discussions of both planning and operating issues in the context of the model sensitivity runs. In particular, reserve margins, capacity factors, heat rates, plant retirements, demands, capacity and load data, reliability, planned and forced outages, and the load duration curve relate to both operating and planning topics.

Review of the CEUM Electric Utilities Submodel

In contrast with the coal supply component of the CEUM, for the most part the issues relating to the electric utilities component concern requirements for data development; the extensive need for sensitivity calculations to ensure that plausible changes in input data do not significantly affect policy-specific model results; and evidence on the general sensitivity of results to plausible changes in structural parameters and input data. These data-related issues are so prominent because in the studies we have reviewed the key behavioral assumption of this component of the model--that utilities choose capacity additions and modifications, and operating patterns which minimize costs--is given relatively little scope to influence model results, except for decisions involving the trade-off between coal types and sulfur control technologies. Thus non-coal capacity additions (excepting turbines), distribution of plant types to load segments, reserve margins, etc. are all "frozen" for any one application of the model. Of course all the variables relating to capacity expansion and operations are explicit in the model, or could be easily introduced. Hence the model is quite general in the explicit scenario data associated with any particular application, but much more focused in terms of what are allowable adjustments in any particular model run, at least in the studies we have reviewed.

For the application we feel is most appropriate--analysis of Clean Air Act Ammendments--the electric utilities component of the CEUM seems properly focused. In our view the effects of coal and control technology investments on nuclear plans, reserve margins, response to forced outages, etc. are best analyzed separately and introduced via scenario modifications, not by endogenizing these variables in any particular model run. Adopting a methodology such as the LP, which maintains a high visibility for scenario variables and facilitates changes to scenario data, seems appropriate here, although a simulation model formulation could also achieve this result. The issue of choosing between LP and simulation methods for applications dominated by exogenous scenario data was much discussed with ICF, and more is said in

Volume V. In the final analysis we believe the choice depends largely on computational efficiency and modeler tastes. For this type of model there is no inherent reason why the LP would be preferred.

We now return to a summary of the major issues identified in our review of the CEUM Electric Utilities Submodel. These include:

- the treatment of oil and gas turbine capacity, as well as the investment costs and lifetimes assumed for this capacity type in the studies we reviewed;
- characterization of utility load, including the relation between the four load segments used to distribute total electricity demand, the number of generating types considered, determination of capacity factors, planned versus forced outages, and reserve margins;
- treatment of interregional transmission, control technologies, and oil-to-coal conversions, and reserve margins; and,
- presentation of some summary results on capacity sensitivity to key data inputs, including utility capital escalation rates, and oil/gas prices.

Role of Oil/Gas Turbines in the CEUM. There is a potentially serious problem for users attempting to interpret expansion of oil/gas turbines in the CEUM. Expansion of oil/gas turbines are unconstrained in the studies we have reviewed. At present there is a serious incompatibility between the model projections and current industry plans. In 1985, for example, the CBC run estimates 38 GW of new turbines. This estimate is some 3 to 4 times current industry plans (see DOE [1978], EMAP [1979]).

Furthermore, the model projection of turbine requirements is quite sensitive to changes in both total demand and load distribution. In Table 37, we present variations in oil/gas turbine additions for each of three case years for the corrected base case, minus 10% and plus 5% in total electricity demand, and a 1% load shift. As can be seen, turbine additions are very sensitive to both peak demand changes and changes in load duration curve parameters, both of which are scenario variables provided by the user. We note for example that a one unit change in the least significant digit of the CEUM parameter for daily peaking energy in the load duration curve will shift 6 GW of turbines, which is about 5-10 years of industry plans according to DOE (1978). Clearly turbine capacity additions must be checked very carefully to insure their credibility and consistency with scenario data such as electricity demand and characterization of the load duration curve.

Table 37

NEW OIL/GAS TURBINE CAPACITY PROJECTIONS IN GW

	1985	1990	1995
CEDMD Energy Demand -10 percent	19.1	18.4	28.7
CBC Corrected Base Case	38.0	32.2	41.1
EDMI Energy Demand +5 percent	59.8	46.7	56.7
LDC1 Load Shift 1 percent*	73.6	71.4	88.4

*This represents about a 4.5% shift in the load factor, a shift which makes a reasonable sensitivity run because it is close to the resolution of the model's inputs, and represents typical interregional and intertemporal variations.

A second point relating to turbine capacity can be observed in Table 37. There it is seen that new turbine capacity between 1975-1990 is less than between 1975-1985. This appears to be contrary to the 100 percent intertemporal capacity carry-over claimed in ICF (1978b), Appendix B, and elsewhere. Upon investigation it turns out that the constraint is imposed as described, but only capacity operated is reported. In particular the CEUM reports do not report new capacity if it is not used. Thus new turbines actually left unused are simply not reported. A cosmetic improvement would be to relabel tables titled CAPACITY BUILT as CAPACITY OPERATED.

In discussing the role of oil/gas turbine additions with the modelers, they made the point that they interpret these additions as a measure of reserve margin and other reliability problems. This may be reasonable,providing that the user of CEUM results bears in mind this special role for turbine capacity.

There is also some question about the particular values for turbine investment costs and service lives used in the studies we reviewed. In particular investment costs per kilowatt in 1975 dollars of $116 to 145 were used, with a service lifetime of 30 years. These investment costs may be too low according to MITRE [1978], which reports estimates approximately $50 higher. Perhaps more importantly service lifetimes of 20 years or less would seem appropriate (see EPRI [1977J). Together these two scenario data changes would increase the new oil/gas turbine annualized investment costs, perhaps significantly. Of course if turbine additions are better interpreted as an indicator of reserve margin problems, then these data corrections are less important, although still relevant in calculating the cost of delivered electricity.

Characterization of Load. Several closely related issues arise concerning the CEUM characterization of the system load, capacity factors for plants serving each load segment, and plant types considered in the model. According to ICF, capacity factors are determined simultaneously with the characterization of the load curve in an "out-of-model" calculation so as to satisfy some 'reasonableness' criteria for the system load factor. The procedure is to employ an independent "screening model" involving essentially a single equation. Thus many possible solutions for capacity factors are possible that still satisfy some 'reasonableness' criteria.

Two implications of the four segment, exogenous capacity factor formulation should be noted. First, while there is no logical reason why new plant capacity types could not be added to the CEUM, in fact with all the analysis that a user must conduct in order to prepare data for the CEUM, the consequences in terms of which plant types will actually be included in the optimal set can be evaluated without the CEUM. Thus adding capacity types without "enriching" the number of load modes being served, while possible, will probably not add very much to the analytic capability of the CEUM. Further, since all capacity types other than coal and oil/gas steam are now exogenous, adding capacity types would just increase the amount of external model data development, without any significant increase in analytic capability. Given the application for which we think the CEUM is best suited--analysis of Clean Air Act amendments--this is not a serious problem. Fixing the non-coal capacity types that compete with coal seems a reasonable simplification. However, uncertainties in actual investments in these alternative capacity types require the user to conduct sensitivity studies of plausible changes in such capacity investment upon model-projected investments in coal capacity and the implications for coal production and prices, all conditional on a "reasonable" projection for oil/gas turbine additions.

A second issue regarding fixed capacity factors is the implicit assumption that all plants of each type operate with constant capacity factors, regardless of size or age. Thus all plants for each type are implicitly assumed to be the same size, apparently the largest size currently being considered for each plant type. The user should be aware of this implicit assumption. Perhaps more serious is the assumption that plants operate with the same capacity factor regardless of age or other operating characteristics. In the studies we reviewed, none of the 197.9 gigawatts of coal plants existing in 1975 are retired in any case year considered. This is the case even though some of these plants have heat rates well below the average rate for old (1950 vintage) U.S. coal plants (approximately 18,000 Btu/kWh). To the extent that the user feels that plant characteristics are important in determining their use, this assumption will be viewed as somewhat simplistic. It should be noted, however, that economic retirement does occur in the CEUM, usually existing oil/gas capacity that cannot compete with new coal capacity. This would be one way to interpret the fact that oil/gas turbines built in early case years are not used in later case years. The only point of concern here would be that the costs of a plant so "economically depreciated" are still impacting the capital cost component of total electricity costs, rather than providing some mechanism for disposing of such capacity.

The importance of assumptions about capacity factors may be illustrated by considering a change in the nuclear capacity employed in the Corrected Base Case. In most of the demand regions a nuclear capacity factor of .70 was assumed. This estimate is somewhat higher than the historical value of approximately .60 (see DOE [1978]). To evaluate model sensitivity results of a reduction in the nuclear capacity factor, an adjustment to the regional factors used in the Corrected Base Case was made. The results are summarized in Table 38. The proportional effects on turbines, coal, and coal with scrubbers in selected years is substantial. Note that this single change in the nuclear capacity factor illustrates the simultaneity of load segment/capacity factor choices for the user. A simple change in one capacity factor implies a change in system load factor, which the user must check for "reasonableness." Thus, for a CEUM user, interpreting a simple change in capacity factor cannot be separated from reevaluation for system implications.

Table 38

MAJOR EFFECTS OF A CHANGE IN NUCLEAR CAPACITY FACTOR

	Regional Nuclear Capacity Factors	New Turbines 1985 (GW)	New Coal W/Scrubbers 1990 (GW)	New Coal W/Scrubbers 1995 (GW)	Total New Baseload Coal 1995 (GW)
CBC Corrected Base Case	.650-.700	38.0	106.7	174.4	215.7
NCAP Nuclear Use Factors Down	.530-.570	46.6	131.2	212.3	255.4

A final point concerning capacity factors that a user should keep in mind is that forced outages are treated as planned outages, reflected in the derating of the capacity factor. An implication of this is that only plants in each load segment can be used to meet the unserved demand because of forced outages. Capacity in other load segments is assumed to be unavailable to meet this demand. This is clearly a considerable simplification of the process characterized by most utility dispatch models. At present the only means of dealing with this problem appears to be ensuring that sufficient construction and use of various capacity types, particularly peaking, takes place with attention to forced outages from other load segments. In an important sense the tuning of model results to achieve a "reasonable" oil/gas turbine additions program can be interpreted as a partial approach to this problem.

Other Structural Issues. There are several other structural issues that a user of the CEUM should keep in mind when employing this model and or interpreting model results. These include:

- o interregional transmission,
- o control technologies,
- o oil-to-coal conversions, and
- o reserve margins.

First consider the treatment of interregional transmission in the CEUM. At present the model determines bulk base load interregional transfers consistent with constraints on transmission linkages and capacities. It is well known that between certain regions, bulk transmission takes place on a regular basis. These include Pacific Northwest to Northern California, Eastern Pennsylvania to Ohio River Valley, the New Mexico four corners to Southern California, Arkansas to Tennessee, and Ontario/Quebec to Michigan and New York (National Electric Reliability Council [1978]). Relative to total generation, however, such interregional transfers tend to be relatively small. While other possibilities exist for future transfers depending upon problems in developing new capacity, etc., it might be argued that such transfers are better treated exogenously rather than allowed to penetrate on a least-cost basis. This will be more relevant, the more importance one attaches to the institutional and regulatory factors that determine these transfers. Alternatively, the model can be used to identify economically attractive transfers, but in any particular application it can be constrained to satisfy the user's assumptions as to a credible interregional transmission scenario. The second point concerns the limited number of control technologies for existing and new plants. Only one control technology--wet limestone scrubbers--is considered, although additional technologies including particulate and nitrogen oxide controls could easily be added subject only to developing the supporting data. The choice of one technology is based on an EPA study providing an economic evaluation of alternatives. The use of one technology is somewhat mitigated by the fact that operating costs depend upon coal characteristics and so influence the choice between various coal types and scrubbing. Although we do not have a particular problem with either the formulation or the data employed, this does seem an area where continuing work on updating scrubber performance and operating cost, as well as on evaluating the economic potential for alternative scrubber technologies, will be very important.

Third, it should be noted that while conversions from bituminous to sub-bituminous coal plants are modeled, oil-to-coal conversions are treated exogenously and assumed to take place in 1975, at least in the studies we reviewed. This means that, to the extent that these conversions take place between 1975 and the case year, as contrasted with 1975, determines the extent to which coal consumption is overestimated. The magnitude of the upward bias depends on the rate of conversion and the utilization of these plants, as well as the depletion effect upon coal production costs. The bias is likely to be small, but would increase the greater the elaspsed time between the base and case years.

A final concern is the CEUM's treatment of reserve margins. Reserve margins are exogenous in the model, but require some adjustments as projections of exogenous capacities change. For example, in the early studies we reviewed a reserve margin of 20 percent was consistent with an estimate of 132 GW of nuclear capacity in 1985 (FPC [1977]). However, in subsequent CEUM applications this nuclear estimate was substantially revised to 99 GW, but with no revision in the reserve margin. Thus the model substituted coal for the decreased availability of nuclear sufficient to meet load plus the 20 percent reserve margin. According to the FPC study mentioned above, this reduction in nuclear capacity was more nearly consistent with a 16 percent reserve margin. The point here is not that the reserve margin should be endogenized in the CEUM (although it could be made more user accessible), but rather that significant changes in nuclear availability require a simultaneous reconsideration of the appropriate reserve margin. This is necessary both for establishing the credibility of the results and as part of the "out-of-model" calculations to set the load segments and capacity factors.

Data Issues in the Electric Utility Submodel. As emphasized elsewhere in this review, a number of computational experiments were designed to evaluate the sensitivity of model results to plausible changes in data. Here we briefly summarize two simulations with respect to the electric utilities submodel. First we note in Table 39 that changes in the real cost escalation rate for utility capital induce a substitution effect between new coal capacity and use of existing capacity. In particular, doubling the real rate from 2 to 4 percent in 1985 results in substitution of approximately 10 GW of operated capacity from existing oil and gas steam for approximately 10 GW of operated capacity from new base-load coal. The substitutions are not exact since we have not accounted for turbines. It is not so much the sensitivity that we want to highlight as the role of the real escalation rate in influencing this substitution possibility. Note also that without considerable effort we are unable to set a non-zero real escalation rate for post-1985 years. This could be accomplished if we reinitialized case-year 1985 as a base year and then set 1995 as the new case year. This would be a substantial effort, and to our knowledge nothing like it has ever been attempted with the CEUM.

Second, we consider the effects on capacity of changes in the oil and gas prices for utilities. In Table 40 Corrected Base Case values for oil and gas prices together with two scenarios for higher prices are presented, along with corresponding values for new coal capacity and operation levels for oil and gas steam and turbine capacity, all in 1990. As can be seen, there is a very substantial substitution between increments to coal capacity, and operated oil and gas capacity. Looked at from the post-Iranian revolution perspective, the higher prices now seem low, suggesting that the pre-1979 studies would have been much influenced by the recent changes in this key input variable.

Table 39

EFFECTS OF CHANGES IN NOMINAL UTILITY CAPITAL COST ESCALATION RATES

	1975 to 1985 Escalation in Utility Capital Costs (%/yr)	1985 to 1995 Escalation in Utility Capital Costs* (%/yr)	Existing Oil/Gas Steam 1995 (GW)	Existing Total Capacity 1995 (GW)	New Baseload Coal 1995 (GW)
CBC Corrected Base Case	7.5	5.5	78.9	417.3	215.7
UCD4 Utility Cost Rate Up	9.5	5.5	90.0	427.2	206.1

*Note that starting in 1985, utility capital costs are escalated at the general rate of inflation, 5.5 percent per year.

Some Post-Review Developments Reported by ICF.

Since this review was completed in early 1980, ICF has informed us of a number of extensions and activities relating to the electric utilities submodel. While these activities have not been considered in this review it is important for the reader to keep them in mind in obtaining current information on the status of the CEUM.

First, an active data maintenance program has been pursued, so all data in the current version of the model have been updated from those in the model reviewed by EMAP. Also, more detailed data on load curves have been developed and analyzed to assist in projecting scenario load curves, and new data on control technologies have been developed.

Second, and of considerable significance, ICF is developing a more sophisticated, dynamic electric utility model with EPRI support. This model, being developed independently of the CEUM, will be useful in supplementing and complementing CEUM applications. Also, ICF is exploring the use of "hybrid methods" for modeling components of the electric utilities industry, thereby partially substituting for the strict LP formulation.

Finally, ICF has noted that additional work has been done regarding the

Table 40

CHANGES IN SOME OUTPUTS DUE TO CHANGES IN OIL/GAS PRICE

	Distillate Oil Price (78$/MMBtu) 1985	1990	1995	Total New Coal Capacity 1990	Capacities in GW: Existing Oil/Gas Steam Capacity 1990	Existing Oil/Gas Turbine Capacity 1990
CBC Corrected Base Case	3.85	4.59	6.21	231.7	121.3	28.7
COILG Oil/Gas Price Increments Up	4.47	4.94	6.97	248.6	105.1	29.7
MOIL Oil/Gas Prices Up	4.47	5.73	7.76	282.5	91.0	10.0

treatment of forced outages, and to develop a time profile of oil-to-coal conversions.

3.3.5 Demand for Electricity and Non-Utility Coal

The CEUM treats electricity and non-utility coal demand as exogenous variables. The treatment is clear and explicit, but may cause the potential user some difficulty both in developing the necessary data at the regional classification used by ICF and in interpreting model results.

Non-Utility Coal Demand.

The ICF approach to modeling non-utility coal demand makes use of an assumption that this portion of coal demand, unlike the utility component, is price-inelastic. Thus:

> The demand for each of the five non-utility sectors is inputted to the model on a regional basis as point estimates. In addition, the coal piles that each sector is allowed to draw from are also specified by sector and region. The use of point estimates is not unreasonable since these sectors typically are not sensitive to the price of coal. Coking and export are closely related to national and worldwide steel production. Since coking coal is critical to

> the steelmaking process, has no competitive substitute, and accounts for only a small portion of the costs of making steel, steel producers do not respond significantly to increases in coal prices (particularly when the companies own their own mines).
>
> Industrial and residential/commercial consumers are typically locked into existing capital facilities which burn coal. The cost of conversion and uncertainties surrounding oil and/or gas prevent large-scale abandonment of coal. On the other hand, potential coal users are confronted with stiff environmental controls and high capital investment costs to use coal. Thus, there is no rush to coal by users in these sectors either. In short, industrial and residential/commercial consumers appear to be limited in their ability and/or willingness to respond to changes in coal prices. Finally, the synthetics sector apparently will be a government-subsidized consuming sector for some time to come. The level of demand from this sector will be related more to government policy than to coal prices. (ICF [1977], pp. II-16,17)

The purpose of the zero price-elasticity assumption is to ensure that the method used by the analyst in projecting non-utility coal demands is not interdependent with the CEUM; that is, the CEUM and the users' non-utility coal demand model (formal or otherwise) do not have to be solved jointly in order to determine market-clearing prices and quantities by coal type.

The difficulties with the ICF approach to non-utility coal demand are threefold. First, empirical evidence does not support the zero price elasticity assumption. Second, the demand region classification, while it may be appropriate for the utility coal demand, does not correspond to a measurement system providing historical data on coal use by CEUM coal type. Third, the approach assumes implicitly that the outcome of non-utility response to environmental regulations can be calculated and reflected in coal demand independently of coal prices.

On the first point we note the estimates of the own-price elasticity for coal in industrial use in two of the most prominent energy demand models. For example, for the EIA regional demand model the most recently published estimate of which we are aware is -.56 (National Academy of Sciences [1978], p. L-10).

Concerning the second issue, the CEUM relies heavily upon FPC data of shipments to utilities of coal, classified by heat and sulfur content, as the basic data base underlying the coal-type classification scheme in the model. This same classification scheme is employed for non-utility coal use. However, no data base corresponding to that provided by FPC exists for non-utility coal demand. Some coal-type use distribution data are available from BOM and, according to a verbal communication from ICF, have been employed in estimating the distribution by coal type for non-utility demand. To the best of our knowledge, however, this has not been documented, certainly not in the customary ICF method of including an appendix with the first applications report in which a new or revised data set is used.

As to the third issue, in contrast to the assumption of zero price elasticity, the assumption of zero cross-price elasticity between coal types and control technologies is not well documented in the ICF reports. The problem arises as follows: For a given set of environmental regulations the analyst must determine in the non-utility coal demand model (NUCDM) how coal quality types trade off with control technology. For the utility component of the CEUM, analysis of this trade-off is a distinctive characteristic, and is the basis for ICF's claim that the model may be used in evaluating the effects of utility decisions regarding coal use upon coal production levels and patterns. Such is not the case, however, for non-utility coal users. The analyst must assume that the coal-type prices have no effect upon the demand for control technology in the NUCDM, which is equivalent to assuming that the cross-price elasticities between coal types and control capital services are zero. The assumption is necessary, since otherwise the NUCDM and CEUM would have to be solved jointly to obtain consistent estimates of coal type quantities and prices, and quantities of control capital services.

Electricity Demand.

We now turn to a consideration of the effects upon model results of treating the demand for electricity as exogenous.[20]

The first point to make regarding electricity demand in the CEUM is that the user must be careful to ensure that the electricity price implied by the model solution is consistent with the assumed level of demand. In developing case-year scenarios a user's projection of electricity demand will depend upon such variables as expected income levels of consumers, production levels in the industrial sector, and prices of the electricity delivered to end-use sectors. Since electricity prices are regulated, the assumed price must reflect the cost of electricity generation, the regulated rate of return, and the rules by which the utility rate base is specified. It will be important to check that the generation costs implicit in this price are consistent with those provided in the case-year solution, and therefore consistent with the exogenously specified level of demand.

Conversely it will be important to check that the demand and implied price in the case years are consistent with a time path that satisfies the user's demand model and/or is plausible.

To assist the user in performing these consistency checks, it would be useful to develop an auxiliary regulatory pricing model. This model might be coupled to the demand model being used, or augmented by elasticities indicated from a separate demand model. There may be other possibilities, but the important point is that the user should be provided with some support for this aspect of consistency checking.

Three computer runs were executed to evaluate model sensitivity to changes in demand levels. Each demand scenario adjusted electricity and non-utility coal demands by a fixed percentage in all demand regions, including -10 percent (EDMD, CEDMD), +5 percent (EDMI), and +10 percent (CEDMU). The most interesting aspect of these runs was the effects upon use of existing plants and construction of new plants. The data for EDMI (+5 percent) and CEDMU (-10 percent) are presented in Tables 41 and 42. When demand is decreased (CEDMD), use of existing capacity changes only to drop oil/gas steam plants from base and intermediate load and turbines from daily and seasonal peak load. Expansion is primarily effected by substantial decreases in coal and oil/gas turbines. Several points should be noted. First, in 1990 there is actually more transmission in the reduced demand case than previously, a counter-intuitive result (173 vs. 167 x 10^9 kWh). However, the reason for increased transmission is that as demand falls, lower-cost capacity in one region is available for use and transmission. For example, in the CEDMU run the West South Central region's coal build activities decreased 2 percent (in response to a 10 percent demand decrease) with an apparent 8 percent increase in capacity available for export.

A demand increase of 10 percent was also executed but, as expected, proved infeasible. Only one constraint equation was not satisfied at the nearest-to-feasible solution, that being the equality between baseload demand and supply of electricity in one region. This was also the source of the infeasibility in the case of no interregional transmission (NOTX) executed as part of audit phase. ICF dealt with the problem there by allowing turbines to satisfy baseload demand. It is most reasonable, of course, that in emergencies any available capacity will be employed, and perhaps turbines should always be allowed to operate in baseload. The infeasibility with a modest increase in demand (approximately one percentage point per year over the 1975-85 period) suggests that a user will often have to "re-tune" the distribution of demand and plant types to load segments in response to plausible changes in demand scenarios. This is the point emphasized in Section 3.3.4; it suggests the need for some kind of formal auxiliary model to support load distribution calculations.

Since the 10 percent increase in demand proved infeasible, a second run was executed that reduced the increase to 5 percent (EDMI). The effects upon use of existing and new capacity include one unusual result. Existing 1985 hydro, 1995 oil/gas steam, and 1990 and 1995 oil/gas turbines and combined cycle actually decreased their contribution to production (see Table 47). The reason for this effect results from the fact that new oil/gas turbines in 1985 were extensively used, because they are the only way the LP can meet new demand and other "initial condition" problems. Once built, these turbines are carried along via the intertemporal constraints, displacing existing peaking capacities.

Table 41

COMPARISON OF ELECTRIC GENERATION CAPACITIES (GW) (CBC VS. CEDMD)

	Coal	Comb. Cycle	Oil/Gas Steam	Oil/Gas Turbine	Nuclear	Hydro
Use of Existing Plants						
CBC 1985	197.9	2.7	145.6	37.4	37.2	65.8
CEDMD 1985	197.9	2.7	128.5	27.2	37.2	65.4
CBC 1990	197.9	2.7	121.3	28.7	37.2	66.4
CEDMD 1990	197.9	2.7	104.8	26.6	37.2	66.1
CBC 1995	197.9	2.7	78.9	33.9	37.2	66.7
CEDMD 1995	197.9	2.7	70.0	34.1	37.2	66.5
Build New Plants						
CBC 1985	110.7	2.1	0	38.0	61.3	18.6
CEDMD 1985	86.8	2.1	0	19.1	61.3	18.5
CBC 1990	231.7	2.1	0	32.2	130.1	21.4
CEDMD 1990	178.2	2.1	0	18.4	130.1	21.2
CBC 1995	381.8	2.0	0	41.1	192.8	22.8
CEDMD 1995	299.8	2.0	0	28.7	191.5	22.6

Table 42

COMPARISON OF ELECTRIC GENERATION CAPACITIES (GW) (CBC VS. EDMI)

	Coal	Comb. Cycle	Oil/Gas Steam	Oil/Gas Turbine	Nuclear	Hydro
Use of Existing Plants						
CBC 1985	197.9	2.7	145.6	37.4	37.2	65.8
EDMI 1985	197.9	2.7	149.0	40.0	37.2	65.0
CBC 1990	197.9	2.7	121.3	28.7	37.2	66.4
EDMI 1990	197.9	2.6	122.2	26.5	37.2	66.5
CBC 1995	197.9	2.7	78.9	33.9	37.2	66.7
EDMI 1995	197.9	2.6	76.3	30.8	37.2	66.7
Build New Plants						
CBC 1985	110.7	2.1	0	38.0	61.3	18.6
EDMI 1985	119.0	2.1	0	59.8	61.3	18.7
CBC 1990	231.7	2.1	0	32.2	130.1	21.4
EDMI 1990	261.5	2.1	0	46.7	130.1	21.5
CBC 1995	381.8	2.0	0	41.1	192.8	22.8
EDMI 1995	424.6	2.0	0	56.7	192.8	22.9

FOOTNOTES

1. See Volume II, Chapter 2 for a more detailed discussion of ICF documentation objectives.

2. While a guide was prepared for the earlier version of the model (NCM) developed for FEA, it has not been updated and is incomplete.

3. For a complete description of the independent reprogramming activity, see Volume IV, Chapters 3 and 4.

4. A Corrected Base Case has been created by implementing corrections to the CEUM Coal Supply Code discussed in Volume II, Chapter 5, Section A, which gives a detailed analysis and verification of the computer implementation of the coal supply component of the CEUM. The specific corrections implemented in creating the Corrected Base Case are those relating to Points 1, 5, 6a, 7, 8, 10, 14, 15, 18, 19, 20, 21, 22, 23, and 24 in Volume II, Chapter 5, Section A. Volume II, Chapter 5, Section A includes a discussion of errors, proposed corrections, programming improvements, questionable assumptions, and aspects of this portion of the code of which the user should be aware. Volume II, Chapter 5, Section B includes a discussion of undocumented aspects of non-supply oriented components of the CEUM of which the user should be aware and documented aspects of these parts of the model that have either not been implemented or have been implemented incorrectly.

5. For a more detailed discussion of this point see Section 3.3.4 and Volume II, Chapter 5, Section A.

6. A separate sensitivity analysis discussion concerning the CEDMD model run is given in Volume VI, Chapter 1.

7. The average Deviation Index is defined as the average change in the absolute value of a quantity (price) between two model runs weighted by the original price (quantity). The measure is unforgiving in that absolute values of differences are accumulated. In this sense it is comparable to similar measures such as the root mean squared difference. For example, consider the value of the index for an aggregation over two regions and a change in quantity between two runs. Assume the original price is 1 in both regions, that the original quantities are 50 and 100 respectively, and that the new quantities are 55 and 95. Then the percentage value of the Deviation Index is 6.67 even though the aggregate quantity is unchanged. The corresponding value for the root mean squared difference measure is 7.07. For our present purposes, there is no inherent basis for prefering one particular measure. A mathematical definition of the Deviation Index is given in Volume VII, Chapter 1.

8. In some cases more detailed information concerning these corrections may be found in Tables 11-13 in Section 3.3, and a complete listing is given in Volume II, Chapter 5, Section 6.

9. Full model runs for each of 26 runs are stored in archival files at the M.I.T. Energy Laboratory. For further information contact Program Manager, Energy Model Analysis Program, M.I.T. Energy Laboratory, Cambridge, MA 02139.

10. See footnote 7 above and Volume VII, Chapter 1 for a further discussion of the Deviation Index. Note that the index is unforgiving in the sense that intraregional differences do not cancel out. Thus, if a region had two coal types and the percentage difference between a particular scenario and the Corrected Base Case was -6.0 percent and +6.0 percent, then the value of the index would be 6 percent.

11. For a complete discussion of minimum acceptable real annuity coal prices, see Volume II, Chapter 2.

12. See Volume III, Chapter 1.

13. The capital recoupment period is the length of time required to earn net revenues equal in amount to the initial capital investment.

14. A state is classified as a "large reserve state" if either Deep or Surface reserves exceed 10 billion tons.

15. Details of our analytical formulation of the CEUM's implied engineering cost function and its applications, together with the associated computer code, are presented in Volume IV, Chapters 3-5.

16. For a detailed discussion see Volume IV, Chapter 3.

17. Note that the coal supply cost function for surface mines is invalid for mine sizes greater than 10.5 million raw tons per year. For details see Appendix F.3.

18. For a complete summary of othe important results comparing the TCML sensitivity run with the Corrected Base Case, see the TCML run description in Volume VII, Chapter 2..

19. See Volume V.

20. Some related issues, most importantly the fixed proportion distribution of total electricity demand to load categories, were discussed above. A more detailed formulation can be found in Volume V, Chapter 1.

Section 4

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APPENDIX A

ABSTRACTS FROM VOLUMES II-VII

VOLUME II: DOCUMENTATION AND VERIFICATION OF MODEL IMPLEMENTATION

This volume presents an evaluation of the ICF, Inc. Coal and Electric Utilities Model (CEUM) documentation, and a verification of the model's implementation. Chapter 1 reviews the development history and previous applications of the CEUM. Chapter 2 presents an evaluation of the CEUM documentation, and Chapter 3 extends the existing documentation by providing a detailed mathematical formulation of the LP portion of the CEUM. Chapter 4 reviews the program structure and operating characteristics. Finally, Chapter 5 presents the results of verifying the correspondence between documentation and computer implementation, the accuracy of implementation, and the effect of implementation errors upon model results.

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VOLUME III: COAL SUPPLY ISSUES: MINE LIFETIME AND COAL ROYALTIES

This volume examines two aspects of the ICF, Inc. Coal and Electric Utilities Model (CEUM), including (1) the assumption of a constant mine lifetime and (2) the assumption of zero intertemporal rents. Chapter 1 provides an analysis of the determinants of mine lifetime, and empirical results of changing this key CEUM parameter. Chapter 2 describes the classical model of intertemporal rents, calibrates this model using data from the CEUM, and presents the effects on CEUM results of incorporating the estimated rate for intertemporal rents.

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VOLUME IV: THE COAL SUPPLY COST FUNCTION

An important objective in evaluating the ICF, Inc. Coal and Electric Utilities Model (CEUM) was to analyze the properties of the coal supply cost portion of the model. In this volume we report the results of this analysis, including development and implementation of an analytical representation of the coal cost function submodel, and comparison of results from the analytic and original submodels.

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VOLUME V: ELECTRIC UTILITY EXPANSION AND OPERATION

This volume contains an overview description and an assessment of the utility generation capacity expansion component of the ICF Coal and Electric Utilities Model (CEUM). The first section includes a discussion and description of those portions of the CEUM relevant to electric generation expansion. We discuss that version of the model extant in September 1978, which was used for producing the model results published by ICF, Inc. Following the descriptive portion of this volume there is an assessment of the capabilities of the CEUM generation expansion technique. Finally, Section 7 discusses application areas for which the CEUM would be appropriate or inappropriate.

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VOLUME VI: OTHER EVALUATION ISSUES

This volume collects together several short papers and notes relating to demand, transmission, transportation, environmental controls, and other topics considered in the Energy Model Analysis Program (EMAP) review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). Chapter 1 considers the CEUM treatment of electricity and non-utility coal demand, and Chapter 2 presents a method for approximating the CEUM demand component for potential use in simplifying calculation of full model results for supply component computational experiments. While suggestive, this procedure was not employed in the EMAP review. Chapters 3 and 4 consider the CEUM treatment of electricity transmission and environmental controls, respectively. Chapters 5 through 9 are short notes on the topics of the role of long-term contracts, use of the uniform distribution in allocating unclassified resources, issues of reserve classification, transport modes, and the role of the general inflation rate.

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VOLUME VII: EVALUATION STRATEGIES AND COMPUTATIONAL RESULTS

Throughout the Final Report (Volume I) and the companion volumes, reference is made to a series of computational experiments performed with the ICF, Inc. Coal and Electric Utilities Model (CEUM). This volume documents these computational experiments and presents the rationale for each experiment, the actual changes implemented, and the summary results.

Two sets of runs were conducted: one set designed by the M.I.T. assessment team and executed by ICF (called "audit runs") and a second set, which was both designed and executed by the M.I.T. team (called "in-depth runs").

Chaptr 1 presents the strategy and description of the audit runs, summary definitions for the important variables that were modified during the course of these computational experiments, and a brief discussion of how deviation indexes were developed for evaluating changes in market equilibrium prices and quantities. Chapter 2 describes each in-depth run; also included are full model runs showing the sensitivity of coal price-quantity equilibria.

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VOLUME II:

DOCUMENTATION AND VERIFICATION OF MODEL IMPLEMENTATION

by

Energy Model Analysis Program

M.I.T. Energy Laboratory Report No. MIT-EL 81-015

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THE ICF, INC. COAL AND ELECTRIC UTILITIES MODEL: AN ANALYSIS AND EVALUATION

VOLUME II:

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M.I.T. Energy Laboratory Report No. MIT-EL 81-015

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INTRODUCTION

This volume presents an evaluation of the ICF, Inc. Coal and Electric Utilities Model (CEUM) documentation, and a verification of the model's implementation. Chapter 1 reviews the development history and previous applications of the CEUM. Chapter 2 presents an evaluation of the CEUM documentation, and Chapter 3 extends the existing documentation by providing a detailed mathematical formulation of the LP portion of the CEUM. Chapter 4 reviews the program structure and operating characteristics. Finally, Chapter 5 presents the results of verifying the correspondence between documentation and computer implementation, the accuracy of implementation, and the effect of implementation errors upon model results.

CHAPTER 1. HISTORY OF THE CEUM DEVELOPMENT*

The history of the ICF Coal and Electric Utilities Model (CEUM) is complex, involving both sponsored development for FEA, and subsequent unsponsored research by ICF to extend the model for application in support of studies sponsored by EPRI and various government agencies including EPA, the Department of Interior, and the Office of Policy Analysis of the DOE. These policy studies each involved further extensions and refinements to the model, including the addition of new activities and the updating and improving of the data base.

The CEUM was developed by ICF as an energy policy planning tool. It was designed to address policy and planning issues related to the coal and electric utility industries and can be used to analyze:

- o regional coal production and consumption
- o regional coal prices
- o coal transportation requirements
- o utility capacity requirements
- o utility fuel use
- o impacts of changes in oil prices, planned generating capacity additions, and the growth rate of electricity consumption
- o impacts of government policies concerning:
  - Clean Air Act Amendments
  - western coal development
  - regulation of strip mining reclamation
  - Energy Supply and Environmental Coordination Act conversion orders
  - taxes on oil and gas use.

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*This chapter was prepared by Neil L. Goldman and David O. Wood

The earliest phase of model development began with the contributions of ICF consultants in the preparation of the Project Independence Report in 1974. In particular, Mr. Hoff Stauffer of ICF was a key consultant in transforming data and information provided by the Project Independence Coal Task Force into a form usable in the Project Independence Evaluation System (PIES), and in interpreting PIES scenario results. Subsequently, a more formal effort to develop a coal supply model based upon the efforts of the Task Force and its contractors (primarily TRW) was initiated by ICF with FEA sponsorship. The product of this effort, the PIES Coal Supply Analysis (PIES/CSA), is documented in ICF, Inc. (May 1976). An effort was then undertaken to extend the PIES/CSA to include a utility coal demand submodel, a transportation network, and to close the extended system by specifying non-utility coal demands exogenously, thus providing a complete model of U.S. coal supply and demand. This model was identified as the National Coal Model (NCM) and is documented in ICF, Inc. (August 1976).

Upon completion of the NCM for FEA in 1976, ICF undertook an unsponsored research effort to extend the model still further to support policy studies relating to development of the domestic coal industry. Perhaps the most convenient way to summarize the relation between the NCM and the CEUM is to quote directly from the CEUM Documentation:

> Although the ICF model is based upon the National Coal Model (NCM) that ICF developed for the Federal Energy Administration, the ICF Coal and Electric Utilities Model is substantially different from the FEA's NCM. For example, the ICF model identifies the marginal deep mine by depth, size, and seam thickness instead of by only seam thickness, handles partial scrubbing and has a different procedure for estimating electrical transmission costs and losses. (ICF, Inc. [July 1977], Preface)

The description of the changes between the NCM and the first version of CEUM are described in Appendix E of ICF, Inc. (July 1977), the remainder of which is the description and documentation of the NCM (ICF, Inc. [August, 1976]). Appendix E of ICF, Inc. (July 1977) includes some 25 memoranda analyzing issues and data considered for revisions in the NCM-to-CEUM transition.

> These memoranda recommend various changes to the data inputs and model structure. Essentially, all the data inputs have already been developed and are contained herein. Similarly, most if not all the changes to model structure (which are neither numerous nor major) have been thought through.
>
> Some of our recommendations are to do nothing, because our in-depth analysis indicated the current data inputs are okay or because we have not yet been able to resolve the issue. Other of our recommendations concern changes that are refinements which will make the model more credible but will not necessarily impact the forecasts substantially. However, other of our recommendations concern changes that are much more than refinements; they are corrections of major mistakes. (ICF, Inc. [July 1977], Appendix E, p. 8)

Thus the revisions to the NCM were primarily improvements to the associated data, not structural improvements. That these revisions were expected to produce significant changes in model results is indicated in Table 1 extracted from ICF, Inc. (July 1977), Appendix E.*

The next phase of the CEUM development effort involved the application of the CEUM in support of a series of policy studies focused on analysis of alternative new source performance standards (ANSPS)--alternative changes in sulfur oxide emission standards--and on western coal development. The first major study is presented in a report prepared for EPA, reviewing the current new source performance standard (NSPS) following the 1977 Amendments to the Clean Air Acts (ICF, Inc. [September 1978a]). These amendments mandate the use, in new large fossil-fuel burning installations, of the best available technologies

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*We are unaware of any subsequent analysis to evaluate the actual effects of the revisions.

TABLE 1

Range of Expected Effects of Extending and Updating Associated Data in the NCM-to-CEUM Transition

Model or Data Revision	Expected Change
- Marginal deep mines	10 to 20% increase from original NCM data base values
- Productivity, wage rates, UMW Welfare and black lung	-10 to +20% in mine-mouth prices
- Income taxes	8% decline in mine-mouth price
- Severance taxes and royalties	12% increase in mine-mouth price on Federal lands
- Coal preparation costs	25% increase in coal mine-mouth prices
- Western coal in eastern boilers	major changes in regional production levels
- Variation in scrubber costs	10% or less decrease in KWH cost from coal-fired plant with scrubber plus major impact on scrubber builds
- Utility capital and O&M costs	30% increase in KWH costs
- Transmission costs	300% increase in new long distance transmission costs per KWH
- Transportation costs	40% increase in transportation costs in the East

Source: ICF, Inc. (July 1977), Appendix E, p. 8

for pollution control. This work involved separate sets of scenario specifications on the meaning and costs of ANSPS. The study employed the model largely in the form reported in ICF, Inc. (July 1977), with the entire data base updated. However, two major changes were made. First, partial scrubbing was allowed. Second, the target-year runs were made in a sequence so information from earlier year runs could be used in later year runs, i.e., intertemporal constraints were incorporated. Previously, each target-year's solution was derived independently of those for other target years. The first phase of this work was completed in late 1977 and the second phase in April 1978, but the documentation of the complete study was not reported until September 1978.

A second study using the CEUM was sponsored by the Departments of Interior and Energy (DOI/DOE), deals with the demand for western coal and demand sensitivity to selected uncertainties, and considers the question of the need for additional leasing of Federal lands in the west (ICF, Inc. [June 1978]). Some structural changes were made in the CEUM but the principal difference between this and the earlier study was development of a new, and significantly different, set of exogenous end-use electricity and non-utility coal demands. ICF's full report on this study was issued in June 1978.

A third study, sponsored jointly by EPA and DOE, again focuses on the impacts of ANSPS (ICF, Inc. [September 1978b]). This study involved still further (although minor) revisions in the basic CEUM, utilized end-use demand assumptions closer to those used in the DOI/DOE study than to those in the earlier EPA study, and considered still another set of scenario specifications on the meaning and costs of ANSPS. It is suggested by ICF that the set of forecasts produced in this study should be given substantially more credibility than forecasts in previous studies because the CEUM is more refined, the scenario specifications are more up-to-date, and better estimates of scrubber costs are utilized.

Each of the three studies has involved extensions and updates to the model, and in each case the revisions are documented in appendixes to the report in a style and format similar to that described above. Most of the revisions are of data, not model structure. Thus the basic CEUM documentation consists of:

- o ICF, Inc., Coal and Electric Utilities Model Documentation, July 1977.
- o ICF, Inc., Appendix B of Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and on Utility Capacity Expansion Plans, Draft, September 1978. (Also see Scenario Specifications in Section II.)
- o ICF, Inc., Appendix C of The Demand for Western Coal and its Sensitivity to Key Uncertainties, Draft, June 1978.
- o ICF, Inc., Appendix A of Further Analysis of Alternative New Source Performance Standards for New Coal-Fired Power Plants, Draft, September 1978.

In September 1978, ICF transferred the CEUM and the associated extant data base at that time to the Energy Information Administration. It is the documentation and computer code associated with this version of the model with which this report is concerned. The reader should note that ICF has continued its government-sponsored studies with the model, and published in January 1979 Still Further Analyses of Alternative New Source Performance Standards for New Coal-Fired Powerplants, a preliminary draft report to EPA (ICF, Inc. [January 1979]). This report includes some further model extensions, most importantly new data on scrubber costs. However, the style and general content of the new report is entirely consistent with the earlier work, and so will not affect our assessment of the documentation.

Finally, the reader should note that various evaluations of the CEUM and its ancestors have been conducted, or are in progress. The original coal supply analysis in the Project Independence Report was reviewed by M.I.T. Energy Laboratory Policy Study Group (May 1975) and by Battelle Memorial Institute (January 1975). The PIES Coal Supply Analysis effort (ICF, Inc. [May 1976]) was reviewed by Resources for the Future (March 1977), and by Gordon (July 1977). The NCM (ICF, Inc. [August 1976]) was also reviewed by Gordon (July 1977). The CEUM was one of the models examined in a 1978 study conducted by the Energy Modeling Forum (September 1978) of Stanford University, entitled Coal in Transition: 1980-2000. The CEUM study reports (ICF, Inc. [September 1978a, June 1978, September 1978b, and January 1979]) have been extensively reviewed by the sponsoring agencies and their scientific consultants although, to our knowledge, none of this peer review has been, or will be, published.

A summary of the development, evaluation history, and major applications of the CEUM is presented in Table 2.

TABLE 2

Development and Evaluation History, and Major Applications of the CEUM

January 1976 - May 1976	PIES Coal Supply Analysis (ICF, Inc. [May 1976])
August 1976	RFF Evaluation of PIES Coal Supply Methodology (Resources for the Future [March 1977])
October 1976	National Coal Model (NCM) Documentation (ICF, Inc. [August 1975])
July 1977	Gordon's Critique of NCM (Gordon [July 1977])
July 1977	CEUM Documentation (NCM Documentation plus extensions in Appendix E) (ICF, Inc. [July 1977])
July 1978	Energy Modeling Forum Study - Coal in Transition: 1980-2000 (Energy Modeling Forum [September 1978])
September 1977 - April 1978	CEUM EPA Study (ICF, Inc. [September 1978a])
April 1978 - June 1978	CEUM DOI/DOE Study (ICF, Inc. [June 1978])
April 1978 - September 1978	CEUM EPA/DOE Study (ICF, Inc. [September 1978b])
September 1978	Transfer of CEUM and associated data base to EIA
January 1979 and to date	Further ICF studies--beyond the scope of this assessment
September 1979	M.I.T. Evaluation of CEUM Documentation (Goldman et al. [September 1979])

CHAPTER 2. AN EVALUATION OF THE CEUM DOCUMENTATION*

This chapter summarizes the results of an M.I.T. evaluation of the documentation prepared by ICF in support of the Coal and Electric Utilities Model (CEUM). While a study of this documentation was a necessary part of our overall model assessment effort, the evaluation may be of particular interest since what constitutes "good" documentation of policy models and applications is at present a contentious issue between modelers and model users. Our study of the CEUM documentation provided us with the opportunity to analyze and contrast the documentation objectives of the modelers with some current guidelines for effective documentation. Toward that end, we consider here the factors influencing documentation objectives, provide a retrospective analysis of the CEUM development and application environment that should be reflected in documentation objectives and products, and then evaluate the CEUM documentation against those objectives.

Our evaluation of the CEUM documentation was conducted in the following manner. First, all relevant model documentation was obtained from ICF, including technical documents, policy study applications, and the computer code. A detailed discussion of the history and applications of the CEUM is presented in Chapter 1 above. The basic documentation that M.I.T. evaluated included:

- <u>Coal and Electric Utilities Model Documentation</u>, (ICF, Inc. [July 1977]);

*This chapter was prepared by David O. Wood, Martha J. Mason, Neil L. Goldman and Michael Manove.

- Appendix B of Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and on Utility Capacity Expansion Plans, Draft (ICF, Inc. [September 1978a]). (Also see Scenario Specifications in Section II.

- Appendix C of The Demand for Western Coal and Its Sensitivity to Key Uncertainties, Draft, (ICF, Inc. [June 1978]);

- Appendix A of Further Analysis of Alternative New Source Performance Standards for New Coal-Fired Power Plants, Draft, (ICF, Inc. [September 1978b]).

The computer code we evaluated represented the version of the model and associated data base as of September 1, 1978, as transferred to EIA by ICF. An important aspect of our effort was to certify that the transfer was complete and correct. This was accomplished by having ICF replicate a base case run using the transferred model.

We next formulated a set of criteria for what constitutes effective documentation, and proposed to employ those criteria in evaluating the CEUM documentation. As a framework, we drew upon recent literature describing documentation standards and issues (especially Gass [February 1979]), and utilized generic categories developed by the Energy Information Administration (EIA). These categories were developed by EIA as "Interim Model Documentation Standards" (Lady [December 4, 1978]) and are described in Table 1. Since EPRI has no such standards to which its contractors must adhere, the EIA list was considered to be an appropriate starting point.

In our attempt to analyze the CEUM materials against these standards, however, it rapidly became evident that many of the document types we expected to find did not exist. In discussions with ICF it became clear that our preliminary criteria included several documentation functions which they, and presumably their sponsors, did

TABLE 1

Interim Model Documentation Standards of the Energy Information Administration, Office of Analysis Oversight and Access (Lady [December 4, 1978])

The EIA standards include five types of documents as follows:

1. Model Summary: A short, one- to two-page, nontechnical description of the model. These summaries describe the model's role and usefulness in DOE analyses, its general structure including inputs needed and answers produced, its relationship to other models, and finally the status of any ongoing enhancements or model development. These summaries would be used to provide general information about the model activities of EIA.

2. Methodology Description: This constitutes a detailed description of a model's rationale, precedent for the model in the literature, and comparison to similar models or approaches. This level of documentation details the capabilities of the model as well as its assumptions and limitations. The basic purpose of this documentation is to explain why the model structure chosen was selected and to communicate how the model compares to, and was chosen over, alternatives.

3. Model Description: A statement of the equations and other procedures that constitute the formal model structure, a description of the data and other information utilized in developing the model structure, statistical characteristics of estimated portions of the model, and any other information necessary to understand what the model is and how results derived from the model are obtained.

4. Guide to Model Applications: A nontechnical description of how to use a model for analysis or forecasting, how to specify alternative input assumptions and data, and how to interpret model output. The purpose of this documentation category is to communicate the range of issues the model is designed to address and the limitations of the model. The intended audience are those who would use model results.

5. User's Guide: This constitutes a detailed description of a model's operating procedures, including names and locations of input files and computer programs, naming conventions, and required job control statements. These documents are intended for the use of EIA staff who actually operate the model and should enable an informed staff member to make model runs and label his/her input files and output files, so subsequent users will be able to properly identify the files. An annotated listing of the computer program should be an appendix to the operating documentation. This documentation category will require frequent revision to be kept current.

not think were relevant to their particular circumstances. In fact, ICF's documentation objectives differed significantly from the EIA categories. While we were not always in agreement with their position, it did seem that in some instances they made a good case. Accordingly, we were led to revise our preliminary criteria and to move from the idea that there can be fixed documentation standards generally applicable to any policy model.

Instead, we became convinced that a documentation process can be developed which would be, in the long run, more productive than the implementation of boilerplate documentation standards. That process will be described in some detail below; it rests on the need for a documentation needs analysis to be undertaken at the onset of every new modeling project. This analysis would be conducted jointly by the modeler, model sponsor, model application client, and/or other affected parties, and would consider the environments in which the model is to be developed and applied. A plan outlining the production and schedule of the documentation process would be drawn up to reflect the needs, interests, expectations, and resource allocations of participants.

In the absence of such a plan for the CEUM, we examined the history and applications of the CEUM (see Chapter 1 above) and considered them from a documentation perspective. Our conclusion was that the CEUM was and is an important policy-making tool, and that sufficient documentation was required both to permit in-depth scientific and peer review and to ensure access and credibility. Such documentation would include not only descriptive materials, but also technical listings of mathematical formulations, structure, and code. Because this kind of documentation represents the fundamental statement of the model, it is critical to an independent assessment of a model; it was from this perspective, appropriate to an important policy model, that the CEUM documentation was evaluated.

The final stage of the documentation evaluation compared the written ICF materials to the model as implemented in the computer code, and identified differences, errors, or omissions. Separate sections describing this work are presented below and concern:

- a detailed analysis and verification of the computer implementation of the coal supply component of the CEUM (see Chapter 5, Section A),
- an analysis of the correspondence between the documentation and the computer implementation for the non-supply components of the model (see Chapter 5, Section B), and
- the effects of verification corrections on the model's base case output (see Chapter 5, Section C).

In the process of this effort, the existing technical documentation was extensively augmented and new documentation was developed (see Chapter 3 above, and Volume IV, Chapter 2).

The following sections consider the documentation planning process, a retrospective analysis of the factors influencing the ICF approach to documentation, and the M.I.T. evaluation of that documentation.

A. GUIDELINES FOR PLANNING POLICY MODEL DOCUMENTATION

This section describes an approach to the production of effective and useful policy model documentation based on the development, by modelers, sponsors, and users, of a documentation plan. The details of a documentation plan for any particular policy model will depend upon a variety of factors dictating the particular document types required, their extent, format, and style, and their costs (both financial and in skills), consistent with the legitimate needs of model clients. The objective of the documentation planning process is to ensure the systematic analysis of these factors prior to the initiation of modeling activities. The effect of the documentation plan will be to communicate the results of the factor analysis in such a way that model clients (including the modeler and model sponsor) share common expectations about the documentation to be produced, and provide sufficient resources to satisfy documentation needs.

Table 2 summarizes the factors to be considered in the documentation planning process. As the table indicates, we distinguish the environment in which a model is developed from that in which it is applied. Analysis of the model development environment will be most influential in determining the extent of technical documentation required. A policy model based upon new scientific results, concepts, or methods will require more comprehensive documentation than a model based upon well-established scientific results. Likewise the more important and conflicted the policy issues under consideration, the greater will be the need for extensive technical documentation to motivate and describe the modeling approach, the scientific results employed, and the associated data used to implement the model. While the fundamental criterion for technical documentation is to ensure the understanding of peers, and possible replication of model implementation and model-based results, importance of issues and/or novelty of scientific basis may dictate efforts beyond this minimum level in order to establish model credibility.

TABLE 2

Factors to be Considered in Preparing a Documentation Needs Analysis

Environment for Model Development

- Importance and scope of policy issues to be modeled
- Diversity of potentially affected policy constituencies
- Potential contribution to state of the art
- Role of model sponsor in the policy process

Environment for Model Use

- Kinds of potential users and their needs
    - o Scientific peers, other policy modelers
    - o Policy analysts/users
    - o Operators
    - o Other groups concerned about the policy issue(s) under analysis
    - o Sponsoring agency
        - model development sponsor
        - application client
    - o Decision makers
- Potential logistics of model use
    - o Hardware and software requirements
    - o Proprietary software or data considerations
    - o Need for portability: potential users
        - modeler only
        - single nonmodeler user at one site
        - many nonmodeler users at many sites
- Probable end uses of model
    - o Specific to one application; specific problem-solving
    - o Foundation for broad policy decisions
    - o Forecasting many interrelated results

The application environment for a policy model also influences the documentation plan. Important factors include the needs of different model clients, the potential uses of the model, and the logistics of model use. Distinguishing the legitimate documentation requirements of different clients for a policy model and for model-based analysis is perhaps the single most important factor in the documentation planning process. Clearly a nontechnically oriented decision maker will have a different set of needs than a policy analyst, a computer operator, or a scientific peer from the modeling community.

Potential model clients often overlooked in discussions of model documentation requirements are groups with a vested interest in the policy issue under analysis. Technical documentation, users' guides, and well-documented studies will partially satisfy the needs of such groups depending upon their analytic abilities. Planning for public access to the model may also help to meet their concerns; the EIA project to transfer important models to the Argonne Software Center is a good example. But many groups will not have the analytical ability and/or resources to take advantage of such documentation or public access. When the importance of the users and the role of the model sponsor warrant it, more must be done to satisfy such groups that the models and model-based analyses are not "black boxes of predetermined results." Model sponsor support of peer review and evaluation policy models and model-based studies with presentation aimed at both technical and nontechnical audiences is one way to deal with the legitimate concerns of this group.

A second major set of model characteristics affecting the need for documentation is that of the logistical requirements of the model design plan for use. As Table 2 indicates, such factors include data, hardware and software requirements, as well as consideration of the need for transferring the model. A model that was intended to be run by the developer at only one site might need different forms of documentation than one which was intended to be portable to a variety of sites.

Finally, consideration must be given in documentation planning to the kind of model results that will be produced. Has the model been designed to problem-solve in only one application with relatively simple and straightforward results, or will it produce a highly complex set of results that are interrelated in nature, complicated to analyze and apply, and perhaps controversial in terms of policy implications? Clearly, the document types, and their style, format, and content will differ between these two extreme applications.

Systematic planning for documentation requirements will go far to redress problems of documentation production. The minimum acceptable level of documentation--that which will permit full analytical review of the model--must fulfill the most basic needs to justify scientific acceptability. Further documentation, as determined through the analysis, will fulfill the needs of analysts/users, operators, and other model clients. Advance planning will contribute to understanding and common expectations among modelers, model sponsors, and other model clients. In short, a documentation planning process will lead to a more orderly, thorough, and competent production of model documentation, and should significantly increase credibility and usability of the model.

B. AN ANALYSIS OF FACTORS INFLUENCING CEUM DOCUMENTATION PRODUCTION

This section considers retrospectively how the unique development of the CEUM may have contributed to the difference in perception between

M.I.T. and ICF as to what constitutes complete and useful documentation. These differences are particularly interesting in light of the controversy over documentation standards in the modeling profession as a whole.

Recall from the discussion above the important factors for developing documentation requirements:

Model Use Environment

- applications, their importance and "conflictedness,"
- model clients, and
- logistics of use.

Model Development Environment

- maturity of scientific results being integrated into the model, and relation to state of the art,
- role of modeler/model sponsor in the policy process, and
- complexity of policy issues.

Each of these factors will be considered below relative to the CEUM.

Intended Applications: The CEUM is intended to be an energy policy model for analysis of issues relating to U.S. coal production, conversion, and use. ICF, Inc. (July 1977), p. I-1,2 includes the following application areas for the model:

- western coal development,
- Clean Air Act Amendments,
- strip mine reclamation requirements,
- Energy Supply and Environmental Coordination Act conversion orders,
- effect of taxes on industry (depletion, investment tax credit),
- effect of changing oil, gas, and nuclear fuel prices,
- effect of changing equipment constraints, both in coal industry and in coal-using industry (e.g., utilities), and

- impact of new technologies that use or compete with coal (e.g., synthetic fuels).

Thus the CEUM is intended for use in a wide variety of applications involving the most difficult and conflicted issues regarding the future production and use of coal resources in the U.S. (In the M.I.T. view, this factor alone argues for very complete documentation, since the model can be expected to be subjected to intense and justified public scrutiny.)

Model Clients: In understanding ICF's view of this element and its relation to documentation requirements, it is important to distinguish the sponsored model development by FEA from ICF's subsequent company-sponsored efforts. While the FEA-sponsored effort to develop the NCM was intended to be internalized and applied within the FEA Policy Analysis Group, the extension of the NCM into the CEUM was an ICF-sponsored activity that was intended to provide an analytical capability to support ICF consultants in coal-related policy studies primarily for government clients. The style of the subsequent policy studies confirms this view. Typically, ICF consultants work with a client in structuring the issue to be analyzed and in developing data and information relevant to that issue. A part of this activity focuses upon structuring scenarios that may be analyzed via application of the model. Specific studies may identify a need to extend the model and/or its associated data base. The end result is an analysis report targeted to the issue of interest to the client using the model, as appropriate, to analyze specific scenarios.

The type and extent of documentation for technical extensions to the model are the result of client perceptions as to what is required to interpret model-based results, as well as what is required to establish the credibility of these results for others considering the study results in a larger policy context. The importance of the CEUM in policy research related to Alternative New Source Performance Standards, as well as in studies of the development of the U.S. coal industry, suggests that the technical documentation has been judged acceptable by the clients of these studies. However, the clients of an important policy model may not be the best qualified to judge technical documentation.

Logistics of Use: Since the principal clients are interested in model-based results, the model is intended for use only by ICF analysts. Thus preparation of user and operator guides, beyond that necessary for ICF personnel, was considered unnecessary by ICF, thereby severely limiting access to the model.

Maturity of Scientific Basis: Recall from Chapter 1 above the evolution of the CEUM. In the first stages ICF consultants were involved in interpreting and transforming data and information from the Project Independence Coal Task Force into a form usable by PIES. The results were not a formal model so much as a structuring of the data for assimilation into the PIES LP framework. The next phase involved formalization of the data structures into a model for FEA. The working relation between ICF and FEA was very close, and FEA's intent was primarily to incorporate the results as a PIES submodel. The important concepts, such as the model mine concept, were considered mature at least by the ICF/FEA community. The subsequent extension to include the utility submodel and to close the model with respect to non-utility coal demands also employed a well-accepted approach, that being the PIES methodology. The effort to extend the NCM into the CEUM involved primarily data revisions and extensions, not structural changes (ICF, Inc. [July 1977], Appendix C, p. 8). Since the methodology (LP) was straightforward and the model concepts were mature, the need for detailed technical documentation was not thought to be significant. Thus, in the basic report only 19 pages (ICF, Inc. [July 1977], Section II) are devoted to technical documentation, and most of this describes the model or its potential applications. Almost none of the material may be interpreted as presenting scientific evidence that justifies and/or supports the choice of the LP formulation or the particular concepts and methods employed in the model.

Role of Modeler/Model Sponsor in Policy Process: The CEUM is clearly intended by ICF for use in support of their contract policy research for both government and private clients. In ICF's view, the relevant professional practice is to determine if the concerns of the potential client can be served by the consultant and, if so, to provide as complete and objective an analysis as possible consistent with the client's requirements and the consultant's perceptions as to what is necessary to understand and interpret the analysis. Given the maturity of the model methodology and concepts, ICF has interpreted good professional practice to mean careful attention to model data, and especially to data associated with client-oriented scenarios.

This analysis of key factors influencing the ICF perspective suggests that ICF's documentation objectives were as follows.

- The most important documentation objective is to describe the model and associated data in a format designed to facilitate general understanding by study clients, as well as interpretation of specific studies and applications.
- Technical documentation of the scientific basis for the model, as contrasted with model description, is relatively unimportant since:

-- the methodology and basic concepts are relatively simple and widely understood, and
-- study clients do not need or require such documentation.

- The model is intended for use by ICF analysts and operators, not for transfer to other groups. Hence operator and user guides need only satisfy the requirements of good internal management and practice.

ICF evidently did not feel a strong need to document the scientific basis of the model since they considered it relatively mature and straightforward, as the following quotes indicate:

> Even though the structural approach taken in the NCM is conceptually simple and straightforward, the NCM may appear complex. The model's apparent complexity is a result of the large number of options and fine level of resolution built into the model's design... (ICF, Inc. [July 1977], p. II-19)

> ...the NCM design is based upon a series of engineering cost relationships and production functions. This attribute allows the components of the model to be easily understood, easily checked, and easily revised. (ICF, Inc. [July 1977], p. III-18)

> The basic NCM structure is conceptually straightforward in that a supply component via a transportation network provides coal to satisfy the demand from both utility and non-utility consumers at least cost. (ICF, Inc. [July, 1977], p. II-1)

As seen below, the M.I.T. Model Assessment Group disagrees with the conclusion that such scientific description is unnecessary.

C. M.I.T. EVALUATION OF THE CEUM DOCUMENTATION

Having described some of the factors influencing the ICF approach to documentation, let us turn to an evaluation of the documentation materials in the context of the categories developed by EIA. These results are presented in Table 3.

The table shows that in many cases the ICF and EIA documentation objectives did not coincide. When the ICF objectives did correspond to an EIA category, the result was quite satisfactory; however, most of the categories were not addressed by ICF. Therefore serious gaps exist in the documentation produced.

In fact, our evaluating team concluded that the CEUM documentation did not meet the criterion we consider to be the minimum acceptable for effective documentation--that which will permit complete analytical review by an assessor.

Specific problems included:

- an unclear description of the model logic
- an uneven presentation of the derivation of data transformation procedures
- the lack of a mathematical formulation of the model
- insufficient instructions for the interpretation of model output

Expanding upon the first point above, the explanation of the model structure given in Chapter 2 of ICF, Inc. (July 1977) is on a level that would ordinarily be sufficient for the user but not for the analyst. At that level of generality, the explanation is misleading in parts and gives little indication as to the true nature of the CEUM's structure. In particular, the "non-technical flowcharts," which are intended to illustrate the model's logic, create the impression that the model structure is in the form of a sequential decision process when in actuality it is a simultaneous process of constrained minimization. While ICF cautions in the documentation that these flowcharts are neither complete nor technically precise, the impression is created that the flowcharts present an accurate general picture of the model structure.

Our belief that formal documentation of model specification issues is important to study clients, regardless of whether or not they intend to execute the model independently, is based on the following factors.

TABLE 3

Evaluation of CEUM Documentation by EIA Category

Category	CEUM Materials	Evaluative Comments
Model Summary	ICF, Inc. (July 1977), Section I Various Sections of ICF, Inc. (September 1978a, June 1978, September 1978b, and January 1979)	Summary descriptions are complete, well-written, and generally excellent.
Description of Methodology	ICF, Inc. (July 1977), Section II and Appendix D	The description of approach, methods, concepts is generally good. The scientific discussion comparing and evaluating alternative approaches, methods, and concepts is, however, very uneven in quality.
Model Description	ICF, Inc. (July 1977), Section III and Appendix E ICF, Inc. (September 1978a), Appendix ICF, Inc. (June 1978), Appendix ICF, Inc. (September 1978b), Appendix	The description of model-associated data is very good, especially in relation to interpreting model results; the material is complete and well-organized. The description of model constraints, including upper and lower bounds, intertemporal constraints, etc. is, however, much less complete. No adequate complete technical description of the model is provided by ICF. Finally, there are many differences between the model description in the documentation and the implemented model.
Guide to Model Application	ICF, Inc. (July 1977), Appendix A	A guide to application is provided for the NCM. However, this was not complete and has not been updated for the CEUM.
Users Guide	ICF, Inc. (July 1977), Appendix A	Same comment as Guide to Model Application above.

First, study users do require the model documentation as a reference for interpreting and analyzing study results. Second, potential model users and analysts require such documentation as the basis for evaluating the model approach, specification, and embodied research results. Finally, such documentation is a necessary condition for good scientific practice.

In summary, the CEUM documentation in our view is most consistent with an environment in which the modeler/analyst works closely with an analyst/client to develop and interpret an application scenario. The documentation of model-based studies is good when viewed from the perspective of the client's ability to understand how his/her scenario was combined with the model data to produce certain results. The documentation is also effective (with some exceptions) in communicating to the analyst/client the sources and characteristics of the model data base. The model documentation is not successful in satisfying the needs of peer modelers in understanding the scientific basis of the concepts embodied in the model structure and of the procedures used in developing model data. The documentation does not provide the information required to use, operate, or modify the model without the assistance of ICF personnel. Finally, a number of inconsistencies between the model documentation and computer code have been identified and several logical errors and questionable assumptions have been noted (see Chapter 5, Sections A and B below).

CHAPTER 3. CONTRIBUTIONS TO THE MODEL DOCUMENTATION

Immediately upon receiving the documentation for the CEUM, the assessment team realized that significant extensions to that documentation would be required before model analysis could begin. In particular, a complete and detailed mathematical formulation of the CEUM was needed. This chapter presents this mathematical formulation, as well as other contributions to the CEUM documentation, because of their potential usefulness to future analysts and users.

A. AN ILLUSTRATIVE LINEAR PROGRAMMING MATRIX*

The general structure of the ICF Coal and Electric Utilities Model (CEUM) consists of a supply component that provides coal, via a transportation network, to satisfy, at minimum cost, demands from both utility and non-utility users. The CEUM generates an equilibrium solution through a conceptually straightforward linear programming formulation that balances supply and demand requirements for each coal type for each region. The objective function of the linear program minimizes, over all regions, the total costs of electricity delivered by utilities and the costs of coal consumed by the non-utility sectors. The output of the model includes projections of coal production, consumption, and price by region, by consuming sector, and by coal type for the target year under consideration. The impacts of air pollution standards on electricity generation from coal are also considered explicitly.

Figure 1 outlines the basic elements of each of the four major components of the CEUM:

(1) Coal Supply
(2) Utility Demand
(3) Non-Utility Demand
(4) Transportation

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* This section was prepared by Neil L. Goldman and Michael Manove.

This section focuses on the linear programming formulation and structure of the CEUM. By the use of an illustrative linear programming matrix it will be shown, in general terms, how the CEUM's four major components interrelate. This matrix is loosely based on an incomplete and unexplained sample matrix that appears in Appendix A of ICF, Inc. (July, 1977). Considerable reconstruction and interpretation were necessary.

The linear programming (LP) matrix (Figure 2) illustrates the basic structure and the naming conventions used in the ICF Coal and Electric Utilities Model (CEUM) for one supply region, Virginia (VA), and one demand region, Western Pennsylvania (WP).

Each column in the LP matrix represents either a physical or a national economic activity. Positive entries in a column represent an input into the associated activity; negative entries represent an output of the activity. The last entry in each column represents the annualized cost of operating each activity at unit level and forms the coefficient of that activity in the objective function. The numerical values appearing in the LP matrix, while representative, are used only for illustrative purposes.

Nine major types of activities appear in the illustrative LP matrix. These are:

- o coal mining
- o coal cleaning
- o coal transportation
- o oil/gas procurement
- o coal procurement by non-utilities
- o electricity generation from coal
- o electricity generation from non-coal sources
- o electricity transmission, delivery, and load management
- o building electrical generating and scrubber capacity.

Each row of the LP matrix, except for the last, represents a constraint associated with a physical stock (coal, heat energy, electricity, etc.) or, in

SUPPLY

- 30 Regions
- 40 Coal types possible
  - 5 Btu categories
  - 8 sulfur levels
- Existing capacity
  - Contract (large mines)
  - Spot } No longer included in model
  - Surge }
- New Capacity
  - Based upon BOM demonstrated reserve base
  - Reserves allocated to model mine types
  - Minimum acceptable selling prices estimated for each model mine type
  - Upper bounds of new mine capacity for each region based upon planned mine openings
- Coal washing
  - Basic washing assumed for all bituminous coals
  - Deep-cleaning option available to lower sulfur content to meet New Source Performance Standard or a one-percent sulfur emission limitation for existing sources

UTILITY DEMAND

- 39 Regions
- 19 Coal piles
  - 3 Ranks of coal
  - 6 Sulfur categories
  - Metallurgical pile includes only the highest grades of coal
- Utility Sector
  - Point estimates for KWH sales by region
  - KWH sales allocated to four load categories (base, intermediate, seasonal peak, and daily peak)
  - Existing generating capacity utilized by model on basis of variable cost
  - New generating capacity utilized by model on basis of full costs (including capital costs)
  - Air pollution standards addressed explicitly
  - Transmission links between regions
  - Oil and gas prices fixed
  - Coal prices determined from supply sector through transportation network

NON-UTILITY DEMAND

- Five non-utility sectors (metallurgical, export, industrial, residential/commercial, synthetics)
- Point estimates of Btu's demanded
- Allowable coals specified in terms of Btu and sulfur content
- No price sensitivity

TRANSPORTATION

- Direct links
- Cost based upon unit train or barge shipment rates
- Lower bounds used to represent long-term contract commitments
- Upper bounds could be used to represent transportation bottlenecks or limited capacity

Figure 1. Coal and Electric Utilities Model--Major Components (from ICF, Inc. (July, 1977).

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THE ICF, INC. COAL AND ELECTRIC UTILITIES MODEL: AN ANALYSIS AND EVALUATION

VOLUME II:

DOCUMENTATION AND VERIFICATION OF MODEL IMPLEMENTATION

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M.I.T. Energy Laboratory Report No. MIT-EL 81-015

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PREFACE

This report is one in a series of seven volumes presenting the results of an indepth review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). The Final Report (Volume I) provides a self-contained summary of the study objectives and results, with supporting papers and materials presented in Volumes II-VII.

The complete series includes:

Energy Model Analysis Program, "The ICF, Inc. Coal and Electric Utilities Model: An Analysis and Evaluation," M.I.T. Energy Laboratory Report No. MIT-EL 81-015, Cambridge, Massachusetts 02139, March 1980.

Volume I: Final Report

Volume II: Documentation and Verification of Model Implementation

Volume III: Coal Supply Issues: Mine Lifetime and Coal Royalties

Volume IV: The Cost Supply Cost Function

Volume V: Electric Utility Expansion and Operation

Volume VI: Other Evaluation Issues

Volume VII: Evaluation Strategies and Computational Results

some cases, with a consumption requirement. Physical stocks may be of fixed size, exogenously specified, or of variable size, created by activities within the model. Constraints associated with stocks of variable sizes are called material balances; they force quantities created within the model to equal or exceed quantities used.

Seven major constraint categories appear in the illustrative LP matrix. These are:

- available coal reserves by mine type at supply regions
- coal stocks by coal type at supply regions (material balances)
- fuel "piles" at demand regions (material balances)
- non-utility energy requirements at demand regions
- electricity constraints, including electricity consumption requirements, and electricity supplies (material balances), at demand regions
- electrical generating and scrubber capacity constraints, including fixed generating capacity constraints for existing plants, material balances for capacities not yet built (new plants), and material balances for scrubber capacity on both existing and new plants
- new capacity building limitations for generating electricity

The following conventions have been adopted with respect to constraint rows in the LP matrix:

- constraints imposed by exogenous size limitations of existing stocks are specified with positive entries on the right-hand sides of the associated rows
- material balance constraints are specified with zero entries on the right-hand sides of the associated rows
- constraints imposed by exogenous consumption requirements are specified with negative entries on the right-hand sides of the associated rows
- negative entries in a constraint row indicate additions to a stock; positive entries indicate subtractions or use

The last row of the LP matrix designates the objective function. Its entries are the costs (1985 annuitized costs in 1978 dollars) of operating the associated activities at unit level. While the interpretation of most of these entries is straightforward, we note that the objective function coefficients for the electricity generation activities represent annualized O&M costs for all plants (existing and new) except for nuclear capacity, which is modeled with its annualized fuel costs as part of its O&M expenses. The objective function coefficients for all building activities represent annualized capital costs, where a real annual fixed charge rate of 10% is used.

Each activity operates on stocks designated in one or more constraint categories. For example, consider Activity 1, SVAC1ZB. This is a coal mining activity in supply region VA, extracting coal type ZB from mine type C1ZB. There is a +1 entry in Row 1, associated with ZB coal reserves in mine type C1ZB in region VA, because these reserves are an input into the mining activity. There is a -1 entry in Row 7, the ZB coal type material balance row in region VA, because this material balance stock at supply region VA receives the output of the mining activity. The objective function entry for Activity 1 appears in Row 34. This quantity, 20.80, represents the cost (minimum acceptable real annuity price), in millions of dollars, of extracting 10^6 tons of ZB coal from mine type C1ZB in supply region VA.

In general, the various activities in the LP matrix have the following effects:

- Coal mining activities transfer coal from available coal reserves to coal stocks at supply regions.

- Coal cleaning activities transfer coal from a stock of one coal type to a stock of another coal type (always of lower sulfur level), allowing for cleaning losses. (There are also non-cleaning activities that transfer to a higher sulfur level coals that could be but are not deep-cleaned.)

- Coal transportation activities transfer coal from coal stocks at supply regions to fuel piles at demand regions.

- Oil/gas procurement activities place oil and gas in fuel piles at demand regions.

- Coal procurement activities by non-utilities remove coal from fuel piles in order to satisfy exogenous non-utility energy demands.

- Activities for electricity generation from coal remove coal from fuel piles, use electrical generating capacity and possibly scrubber capacity, and create electricity supplies.

- Activities for electricity generation from non-coal sources remove non-coal fuels from fuel piles, use electrical generating capacity, and create electricity supplies.

- Electricity transmission activities reduce electricity supplies in one region and increase them in another region, allowing for transmission losses. Electricity delivery activities reduce electricity supplies in order to satisfy exogenous electricity consumption requirements, allowing for distribution losses.

- Activities for building electrical generating or scrubbing capacity create new capacities. Exogenously specified limits may be imposed.

The unit of measurement is given for each activity variable and constraint in the illustrative LP matrix. For purposes of simplicity the time dimension has been omitted. All activity variables and constraints should be considered to be on a per-year basis except for those measured in capacity units of gigawatts (GW).

Figure 2. Illustrative LP Matrix for the ICF Coal and Electric Utilities Model

	Coal Mining (10^6 Tons)						Coal Cleaning (10^6 Tons)	
	1	2	3	4	5	6	7	8
	S VA C1 ZB	S VA N1 ZB	S VA C1 HB	S VA N1 HB	S VA N1 HC	S VA C1 HD	C VA HC HB	C VA HC HD
1	1							
2		1						
3			1					
4				1				
5					1			
6						1		
7	-1	-1						
8			-1	-1			-.92	
9					-1		1	1
10						-1		-1
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34	20.80	34.72	16.28	24.30	36.17	16.28	4.34	0

Figure 2. (continued)

Coal Transport (10^6 Tons)				Oil/Gas (Quads)	Coal Procurement by Non-Utilities (Quads)				
9	10	11	12	13	14	15	16	17	
T VAWP CB	T VAWP ZB	T VAWP HB	T VAWP HD	TPI WP PG	D WP MT 01	D WP MT 02	D WP IN BB	D WP IN 03	
									1
									2
									3
									4
									5
									6
1	1								7
		1							8
									9
			1						10
-.027					.8	.8			11
	-.027	-.025			.2	.1	1	.5	12
			-.025			.1		.5	13
				-1					14
					-1	-1			15
							-1	-1	16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
6.96	6.96	6.96	6.96	2877					34

Figure 2. (continued)

Electricty Generation from Coal (10^9 KWH)						Electricity Generation Non-Coal (10^9 KWH)			
18 OWP O BB I	19 OWP E BB B	20 OWP E BD B	21 OWP P BD I	22 OWP N 01 B	23 OWP M BD I	24 OWP K PG I	25 OWP T PG Z	26 OWP Z NU B	
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
.013	.009			.0046					12
		.009	.010	.0046	.010				13
						.011	.014		14
									15
									16
									17
									18
	-1	-1		-1				-1	19
-1			-1		-1	-1			20
							-1		21
									22
									23
.317									24
	.176	.176	.320						25
				.176	.317				26
						.317			27
							2.28		28
								.176	29
			.163						30
					.072				31
									32
									33
2.70	2.11	2.11	3.01	2.70	4.10	2.35	2.70	8.22	34

Figure 2. (continued)

Electricity (10^9 KWH)				Building Electrical Capacity (GW)				
Transmission		Delivery	Load	Coal	Other	Scrubbing		
27	28	29	30	31	32	33	34	
T WPNU EX	T WPCO NW	D WP EL XX	C WP EL EL	B WP CL 06	B WP NU 16	B WP S1 XX	B WP S2 XX	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
		-1						17
1	1	1.10	-1					18
			.75					19
			.20					20
			.05					21
-.90								22
	-.85							23
								24
								25
				-1				26
								27
								28
					-1			29
						-1		30
							-1	31
				1				32
					1			33
	1.41	0.82		70.84	113.34	17.0	17.0	34

Figure 2. (continued)

CONSTRAINT IDENTIFICATION

Constraint	Row Name	Row Number		VA = Supply Region WP = Demand Region
$\leq$ 1.24	*	1		Available Coal Reserves (10^6 Tons)
$\leq$ .12	*	2		
$\leq$ .56	*	3		
$\leq$ .08	*	4		
$\leq$ .08	*	5		
$\leq$ 1.27	*	6		
$\leq$ 0	LC VA ZB	7		Coal Material Balances at Supply Regions (10^6 Tons)
$\leq$ 0	LC VA HB	8		
$\leq$ 0	LC VA HC	9		
$\leq$ 0	LC VA HD	10		
$\leq$ 0	LU WP MT	11	Coal	Fuel Material Balance "Piles" at Demand Regions (Quads)
$\leq$ 0	LU WP BB	12		
$\leq$ 0	LU WP BD	13		
$\leq$ 0	LU WP PG	14	Oil/Gas	
= -.78	EU WP MT	15		Non-Utility Energy Requirements (Quads)
= -.13	EU WP IN	16		
= -70	EU WP XX	17	Consumption Requirement	Electricity (10^9 KWH)
$\leq$ 0	LU WP EL	18	Material Balance--Total	
$\leq$ 0	LU WP EB	19	Material Balance By Load Category	
$\leq$ 0	LU WP EI	20		
$\leq$ 0	LU WP EZ	21		
$\leq$ 0	LU NU EB	22	Material Balance--Other Demand Regions	
$\leq$ 0	LU CO EB	23		
$\leq$ .50	LU WP 01	24	Existing Coal	Electrical Generating Capacity (GW)
$\leq$ 5	LU WP 02	25		
$\leq$ 0	LU WP 06	26	New Coal	
$\leq$ .35	LU WP 20	27	Existing Non-Coal	
$\leq$ .64	LU WP 17	28		
$\leq$ 0	LU WP 16	29	New Non-Coal	
$\leq$ 0	LU WP S1	30	Existing Plants	Scrubber Capacity (GW)
$\leq$ 0	LU WP S2	31	New Plants	
$\leq$ 10	LU WP CL	32	Coal	New Capacity Building Limits (GW)
= 5	*	33	Nuclear	
= (Min)	NUSCST	34	Objective Function	Total Cost (10^6\$)

*Upper bound constraint on activity variable.

B. NAMING CONVENTIONS FOR THE CEUM LINEAR PROGRAMMING MATRIX*

This section details the naming conventions used in the column (activity variable) and row (constraint structure of the CEUM LP matrix. A complete description of this type is not presented in the CEUM Documentation (ICF, Inc. [July, 1977]). The LP matrix contains approximately 14,000 activity variables and 2000 constraints. In addition, there are on the order of 1000 nonbinding (free) rows used either to collect information or to force activity in the 1990 or later case years. The reader should note that definitions of supply regions, utility demand regions, and all BTU content levels and sulfur content levels can be found in the tables at the end of this appendix.

a. <u>COLUMNS - Activity Variables</u>

Coal Mining (10^6 Tons/year)

S(CR) (IT) (CT)

- coal supply columns, where

  (CR) = coal region

  (IT) = cost of extraction level

  (CT) = coal type

  (IT)(CT) = mine type

e.g., SVAC1ZB -- note that C1 refers to the first existing mine of coal type ZB; N1 would refer to the first new ZB mine; etc.

* This section was prepared by Neil L. Goldman

Coal Cleaning (10^6 Tons/year)

C(CR)(CT_1)(CT_2)

-convert coal type CT_1 to CT_2, where the coal types that can be "deep-cleaned" have sulfur levels C & E; the coal is either cleaned up to sulfur levels B & D, respectively, or not cleaned, in which case it is included in sulfur levels D & F, respectively.

e.g., CVAHCHB

Coal Transportation (10^6 Tons/year)

T(CR)(UR)(CT)

-transport coal type CT (in 10^6 tons/year) from coal region CR to demand region UR; in the demand region, each "coal pile" is in units of Quads (10^{15} BTUs), and BTU levels Z, M, and H are combined into B (bituminous).

e.g., TVAWPZB

T(CR)(UR)C(S)

-transport coal type C(S) into the metallurgical (coking coal) pile, MT, where C = BTU level Z, and S = sulfur levels A, B, or D.

e.g., TVAWPCB

Procurement of Other Fuels (Quads/year)

TPI(UR)OG

-provide old gas to demand region (UR)

TPI(UR)PG

-provide oil/gas to demand region (UR)

e.g., TPIWPPG

Note that in the model's more recent versions the energy form OG is no longer used; OG is replaced by DG and refers to distillate oil or gas for turbines or combined cycles, while PG refers to residual oil or gas for steam plants.

Coal Procurement by Non-Utilities (Quads/year)

D(UR)(OD)(UE)

-activity to satisfy non-utility demand of type (OD) using energy form (UE) in region (UR), where:

(OD) = MT (metallurgical coal)

= RC (residential/commercial)

= IN (industrial)

= EX (export)

= SY (synthetic fuel)

and:

(UE) = MT (metallurgical coal from MT pile)

= BA, BB, BD, BF, BG, BH,
SA, SB, SD, SF, SG, SH, (steam coal from piles)
LA, LB, LD, LF, LG, LH

= OG (old gas)

= PG (oil/gas)

= HG (hydro or geothermal)

= NU (nuclear)

e.g., DWPINBB

D(UR)(OD)(BL)

-activity to satisfy non-utility coal demand of type (OD) using coal blend (BL) = 01, 02, ...in region (UR).

e.g., DWPMT01

<u>Electricity Generation from Coal</u> (10^9 KWH/year)

O(UR)(P)(UE)(L)

-operate in demand region (UR), coal plant type (P) using energy form (UE) in load mode (L), where:

(P) = O (old existing)

= E, F, G (existing w/o scrubber, subject to sulfur standards 1, 2, 3, respectively)

= S (existing w/existing scrubber)

= P, Q, R (existing w/o scrubber, build scrubber, subject to sulfur standards 1, 2, 3, respectively)

= N (new w/o scrubber, New Source Performance Standard -- NSPS)

= M (new w/scrubber, NSPS)

= 8 (new w/scrubber, Alternative New Source Performance Standards -- ANSPS)

= 0 (new MHD)

= 1 (new combined cycle)

= 2 (new coal gas turbine)

Not used in the model's recent versions.

= 5, 6, 7 (existing with new conversion facility, subject to sulfur standards 1, 2, 3, respectively)

etc.

and:

(L) = B (base)

= I (intermediate)

= P (seasonal peak)

= Z (daily peak)

e.g., OWPOBBI

O(UR)(P)(BL)(L)

-operate in demand region (UR), coal plant type (P) using coal blend (BL) in load mode (L), where (BL) = 01, 02, 03, ...etc.; note that these activities are unnecessary if coal mixing activities are employed (see page 2-45).

e.g., OWPN01B

Electricity Generation: Non-Coal (10^9 KWH/year)

O(UR)(P)(UE)(L)

-operate in demand region (UR), non-coal plant type (P) using energy form (UE) = OG, PG, HG, or NU, in load mode, (L), where:

(P) = J (old gas steam)

= K (existing oil/gas steam)

= L (new oil/gas steam)

= T (existing oil/gas turbine)

= U (new oil/gas turbine)

= H (existing hydro)

= I (new hydro)

= Y (existing nuclear)

= Z (new nuclear)

etc.

e.g., OWPKPGI

<u>Electricity Transmission</u> (10^9 KWH/year)

$T(UR_1)(UR_2)EX$

-transmit baseload electricity from region (UR_1) to region (UR_2) using existing transmission links.

e.g., TWPNUEX

$T(UR_1)(UR_2)NW$

-transmit baseload electricity from region (UR_1) to region (UR_2) using new transmission links.

e.g., TWPCONW

<u>Electricity Delivery to Consumers - Demand</u> (10^9 KWH/year)

D(UR)ELXX

-activity to satisfy total electricity requirement by consumers (total sales) in demand region (UR); note that electricity generation will be greater than sales due to line losses.

e.g., DWPELXX

Electricity Load Management (10^9 KWH/year)

C(UR)ELEL

-activity that combines electricity from different load modes into a "total electricity pile" in demand region (UR).

e.g., CWPELEL

Building Electrical Generating Capacity (GW)

B(UR)(PT)(ID)

-build, in demand region (UR), new electrical generating capacity for power plants of type (PT) with identifier (ID), where:

(PT) = CL (coal, NSPS; on line by end of 1982)
= C9 (coal, ANSPS; on line after 1982)
= HG (hydro or geothermal)
= NU (nuclear)
= PT (oil/gas turbine)
= PS (oil/gas steam)
= NT (new technology)
= CV (conversion facility)
etc.

and:

(ID) = 06 (new bituminous coal plant, NSPS)
= 07 (new sub-bituminous coal plant, NSPS)
= 08 (new lignite coal plant, NSPS)
= 14 (new hydro plant)

= 16 (new nuclear plant)

= 18 (new oil/gas turbine plant)

= 21 (new oil/gas steam plant)

= 22 (new bituminous coal plant, ANSPS)

= 23 (new sub-bituminous coal plant, ANSPS)

= 24 (new lignite coal plant, ANSPS)

= 25, 26, 27 (new conversion facilities on existing coal plants, subject to sulfur standards 1, 2, 3, respectively)

= 28 (new MHD plant)

= 29 (new combined cycle plant)

= 30 (new coal gas turbine plant)

Not used in the model's recent versions.

etc.

e.g., BWPCL06

<u>Building Scrubber Capacity</u> (GW)

B(UR)(ST)XX

-build, in demand region (UR), new scrubber capacity, where:

(ST) = S1 (existing plants)

= S2 (new plants, NSPS)

= S3 (new plants, ANSPS, sulfur level ≠ A)

= S4 (new plants, ANSPS, sulfur level = A)

e.g., BWPS1XX

Coal Mixing (Quads/year)

MX(UR)(CT_1)(CT_2)(CT_3)

- activity in demand region UR that mixes fractions of two coal types (coal pile fuels), CT_1 and CT_2, each with the same BTU level but different sulfur levels, to yield a unit of a third coal type, CT_3, with the same BTU level and a sulfur level in between those of CT_1 and CT_2.

e.g., MXWPBADB -- mixes coal types BA and BD to produce coal type BB. Note that this type of activity is not represented in the illustrative LP matrix. If it is employed, there is no longer a need for operate activities using coal blends.

b. ROWS - Constraints

Constraints that represent simple bounds (upper, lower, or fixed) on activity variables are not named below. Nonbinding (free, accounting) rows are also not named below nor do they appear in the illustrative LP matrix of Section A above. A descriptive list of the important constraint-types follows.

LC(CR)(CT) e.g., LCVAZB

- coal stocks (material balances) at supply region (CR) by coal type (CT); one row for each coal type in each supply region; 10^6 tons/year.

LU(UR)(UE) e.g., LUWPMT

- fuel piles (material balances) of energy form (UE) at demand region (UR); both for utility and non-utility fuels; Quads/year.

EU(UR)(OD) e.g., EUWPMT

-exogenous non-utility energy requirements (demands) of type (OD) in demand region (UR); Quads/year.

EU(UR)XX e.g., EUWPXX

-exogenous total electricity consumption requirement (demand) in demand region (UR); 10^9 KWH/year.

LU(UR)EL e.g., LUWPEL

-total electricity supplies (material balance) in demand region (UR); 10^9 KWH/year.

LU(UR)E(L) e.g., LUWPEB

-electricity supplies (material balances) by load category (L) in demand region (UR), where (L) = B, I, P, or Z; 10^9 KWH/year.

LU(UR)(ID) e.g., LUWP01

-electrical generating capacity for plants identified by (ID) in demand region (UR), where (ID) = 01, 02, 03, ...; includes fixed generating capacity constraints for existing plants and material balances for new plant capacity; GW.

For new plants an ID listing is given on pages 2-44 and 2-45. For existing plants:

(ID) = 01 (old existing coal plants)

= 02, 03, 04 (existing coal plants subject to sulfur standards 1, 2, 3, respectively)

= 05 (existing coal plant w/existing scrubber)

= 09 (existing baseload hydro plant)

= 10 (existing intermediate load hydro plant)

= 11 (existing daily peaking hydro plant)

= 15 (existing nuclear plant)

= 17 (existing oil/gas turbine plant)

= 19 (existing old gas steam plant)

= 20 (existing oil/gas steam plant)

etc.

LU(UR)(ST) e.g., LUWPS1

-material balances for new scrubber capacity for existing plants (ST) = S1, or for new plants (ST) = S2, S3, S4, in demand region (UR); GW.

LU(UR)CL e.g., LUWPCL

-constraint row for total new coal plant capacity under NSPS, in demand region (UR); GW.

LU(UR)C9 e.g., LUWPC9

-constraint row for total new coal plant capacity under ANSPS, in demand region (UR); GW.

GA(CR)(UR)

-constraint row to force an aggregate or joint lower bound on coal transported between supply region (CR) and demand region (UR); note that this row-type does not appear in the illustrative LP matrix of Section A above; 10^6 tons/year.

GU(UR)S2

-constraint row to lower bound S2 scrubber capacity in demand region (UR); note that this row-type does not appear in the illustrative LP matrix of Section A above; GW.

G(UR)(P)RET

-constraint row to lower bound retrofit scrubber capacity in demand region (UR) for coal plant types P, Q, and R; note that this row-type does not appear in the illustrative LP matrix of Section A above; GW.

NUSCST

-objective function row; minimization of total cost in millions of dollars per year.

TABLE 1

Btu Content Categories and Codes

Millions of BTU's per Ton	Code	Approximate Rank of Coal
≥26	Z	bituminous
23-25.99	H	bituminous
20-22.99	M	bituminous
15-19.99	S	sub-bituminous
<15	L	lignite

Source: ICF, Inc. (July, 1977), p. III-5)

TABLE 2

Sulfur Level Categories and Codes

Pounds Sulfur per Million BTU's	Code	Justification
0.00-0.40	A	can be blended with higher sulfur coals to meet Federal new source performance standard
0.41-0.60	B	meets Federal new source performance standard
0.61-0.63	C	can be deep cleaned to meet new source performance standard (five percent decline in sulfur content)
0.64-0.83	D	roughly one percent sulfur (.01 x 2,000 pounds per ton ÷ 24 mmbtu/per ton = .833 pounds/mmbtu)
0.84-0.92	E	can be deep cleaned to meet one percent SIP standard (10 percent decline in sulfur content)
0.93-1.67	F	roughly two percent sulfur
1.68-2.50	G	roughly three percent sulfur
>2.50	H	greater than three percent sulfur

Source: ICF, Inc. (July, 1977), p. III-5)

TABLE 3

Supply Region Definitions

PIES Region	CEUM Region	BOM Districts
Northern Appalachia	Pennsylvania (PA)	1, 2
	Ohio (OH)	4
	Maryland (MD)	1
	West Virginia, north (NV)1/	3, 6
Central Appalachia	West Virginia, south (SV)	7, 8
	Virginia (VA)	7, 8
	Kentucky, east (EK)	8
	Tennessee (TN)	8, 13
Southern Appalachia	Alabama (AL)	13
Midwest	Illinois (IL)	10
	Indiana (IN)	11
	Kentucky, west (WK)	9
Central West	Iowa (IA)	12
	Missouri (MO)	15
	Kansas (KN)	15
	Arkansas (AR)	14
	Oklahoma (OK)	14, 15
Gulf	Texas (TX)	15
Eastern Northern Great Plains	North Dakota (ND)	21
	South Dakota (SD)	21
	Montana, east (EM)2/	22
Western Northern Great Plains	Montana, west (WM)	22
	Wyoming (WY)	19
	Colorado, north (CN)	16
Rockies	Colorado, south (CS)	17
	Utah (UT)	20
Southwest	Arizona (AZ)	18
	New Mexico (NM)	17, 18
Northwest	Washington (WA)	23
Alaska	Alaska (AK)	23

1/ Includes all of Nicholas County.

2/ Includes the following counties: Carter, Daniels, Fallon, McCone, Prairie, Richland, Roosevelt, Sheridan, Valley, and Widaux.

Source: ICF, Inc. (July 1977), p. III-3.

TABLE 4

Regional Definitions for CEUM Demand Regions

Census Region	CEUM Region	State	Counties
New England	MV	Maine	All
		Vermont	All
		New Hampshire	All
	MC	Massachusetts	All
		Connecticut	All
		Rhode Island	All
Middle Atlantic	NU	New York, upstate	All counties not in New York, downstate
	PJ	New York, downstate	Suffolk, Orange, Putnam, Bronx, Rockland, Richmond, Nassau, Weschester, New York, Queens, Kings
		New Jersey	All
		Pennsylvania, east	Wayne, Pike, Monroe, Northhampton Bucks, Montgomery, Philadelphia, Delaware, Chester, York, Lancaster, Dauphin, Lebanon, Berks, Schuylkill, Lehigh, Carbon, Susquehanna, Wyoming, Lackawanna, Luzerne, Columbia, Montour, Northumberland, Union, Snyder, Juniata, Perry, Cumberland, Adams, Franklin
	WP	Pennsylvania, west	All counties not in Pennsylvania, east
South Atlantic	VM	Virginia	All
		Maryland	All
		Delaware	All
		District of Columbia	
	WV	West Virginia	All
	CA	North Carolina	All
		South Carolina	All
	GF	Georgia	All
		Florida, north	All counties not in Florida, south
	SF	Florida, south	Nassau, Duval, Baker, Union, Bradford, Clay, St. Johns, Putnam, Flagler, Volusia, Indian River, Okeechobee, Martin, St. Lucie, Manatee, Sarasota, DeSota, Charlotte, Glades, Palm Beach, Lee, Hendry, Collier, Broward, Monroe, Dade
East North Central	ON	Ohio, north	Lucas, Ottawa, Sandusky, Erie, Lorain, Cuyahoga, Lake, Ashtabula

TABLE 4 (Continued)

Census Region	CEUM Region	State	Counties
	OM	Ohio, central	All counties not in Ohio, north or Ohio, south
	OS	Ohio, south	Hamilton, Clermont, Brown, Highland, Adams, Pike, Scioto, Lawrence, Gallia, Jackson, Meigs, Athens, Washington, Morgan, Noble, Monroe, Belmont, Harrison, Jefferson, Columbiana
	MI	Michigan	All
	IL	Illinois	All
	IN	Indiana	All
	WI	Wisconsin	All
East South Central	EK	Kentucky, east	Mason, Lewis, Fleming, Bath, Montgomery, Menifee, Clark, Powell, Madison Estill, Jackson, Rockcastle, Pulaski, Laurel, Clinton, Wayne, McCreary, Greenup, Rowan, Carter, Boyd, Elliott Lawrence, Morgan, Johnson, Martin, Wolfe, Magoffin, Floyd, Pike, Lee, Breathitt, Knott, Owsley, Perry, Letcher, Clay, Leslie, Knox, Bell, Harlan, Whitley
	WK	Kentucky, west	All counties not in Kentucky, east
	ET	Tennessee, east	Pickett, Fentress, Scott Morgan, Cumberland, Bledsoe, Sequatchie, Marion, Hamilton, Rhea, Meigs, Roan, Campbell, Claiborne, Union, Anderson, Knox Loudon, Blount McMinn, Monroe, Bradley, Polk, Hancock, Hawkins, Grainger, Hamblen, Jefferson, Sevier, Cocke, Greene, Sullivan, Washington, Unicoi, Carter, Johnson
	WT	Tennessee, west	All counties not in Tennessee, east
	AM	Alabama	All
		Mississippi	All
West North Central	DM	North Dakota	All
		South Dakota	All
		Minnesota	All
	KN	Kansas	All
		Nebraska	All
	IA	Iowa	All
	MO	Missouri	All
West South Central	AO	Arkansas	All
		Oklahoma	All
		Louisiana	All

TABLE 4 (Continued)

Census Region	CEUM Region	State	Counties
	TX	Texas	All
Mountain	MW	Montana	All
		Wyoming	All
		Idaho	All
	CO	Colorado	All
	UN	Utah	All
		Nevada	All
	AN	Arizona	All
		New Mexico	All
Pacific	WO	Washington	All
		Oregon	All
	CN	California, north	All counties not in California, south
	CS	California, south	San Diego, Imperial, Orange, Santa Barbara, Ventura, Los Angeles, San Bernadino, Kern, Inyo, Mono

Source: ICF, Inc. (July, 1977), pp. III-57 to III-59.

C. MATHEMATICAL FORMULATION OF THE CEUM*

This section presents a detailed mathematical formulation of the basic set of equations employed in the ICF Coal and Electric Utilities Model. An explicit formulation of this type is not presented in ICF, Inc. (July 1977). This formulation does not necessarily adhere to the CEUM naming conventions documented in Section B above.

a. Definition of Subscript Categories

Note that an underscore on a subscript implies that a particular value of the subscript category is being used.

CR = coal supply region

IT = Cost-of-extraction level associated with step-highlights on the appropriate coal supply curve.

HL = BTU content level, in supply regions; the levels are $\underline{Z}$, $\underline{H}$, $\underline{M}$, $\underline{S}$, $\underline{L}$; (see Section B, page 2-50 above).

SL = sulfur content level; the levels are $\underline{A}$, $\underline{B}$, $\underline{C}$, $\underline{D}$, $\underline{E}$, $\underline{F}$, $\underline{G}$, $\underline{H}$, with levels $\underline{C}$ and $\underline{E}$ omitted in demand regions; see Section B, page 2-50 above.

UR = utility demand region.

UE = utility fuel type; a listing of fuel types is given in Section B, p. 2-41 above. (Note that the coal fuel types in each demand region are identified by rank and sulfur level. The ranks are $\underline{B}$, $\underline{S}$, and $\underline{L}$, corresponding to bituminous, sub-bituminous, and lignite, respectively, where $\underline{B}$ coal comes from the three highest BTU categories, $\underline{Z}$, $\underline{H}$, and $\underline{M}$, in the supply regions).

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* This section was prepared by Neil L. Goldman

OD = non-utility demand type; a listing of demand types is given Section B above on page 2-40.

BLM = coal blend type for metallurgical demand; e.g., BLM = 11, 12, ...

BLE = coal blend type for export demand; e.g., BLE = 10, 13, ...

P = plant type for electricity generation activities; a listing of both existing, P_e, and new plant types, P_n, is given in Section B above on pages 2-40, 2-41, and 2-42.

L = load mode; a listing of load modes is given in Section B above on page 2-42.

ID = plant type identifier; a listing is given in Section B above on pages 2-44 and 2-45 for new plant type identifiers, ID_n, and on page 2-48 for existing plant type identifiers, ID_e.

PT = plant type for build activities; a listing is given in Section B on page 2-44.

B. Definition of Parameters

ℓ_C = fractional coal loss in deep cleaning.

$\ell_D(UR)$ = fractional electricity distribution loss in delivery to consumers in demand region UR, measured in terms of the additional fraction of pre-delivered electricity required to produce a unit of delivered electricity.

$\ell_{TE}(UR_i, UR_j)$, $\ell_{TN}(UR_i, UR_j)$ = fractional electricity transmission losses over existing and new lines, respectively, from source region UR_i to sink region UR_j.

ℓ_{PS} = fractional electricity loss in the pumped storage process, measured in terms of the additional fraction of baseload electricity required to produce a unit of daily peaking electricity from pumped storage.

$hc(CR,HL)$ = heat content of coal of BTU level HL, in Quads/10^6 Tons, in supply region CR.

$hr(UR,P,L)$ = heat rate in Quads/10^9 KWH, in demand region UR, for plant type P, operating in load mode L.

$f_{UE}(BLM)$ = fraction of fuel type UE in metallurgical blend type BLM.

$f_{UE}(BLE)$ = fraction of fuel type UE in export blend type BLE.

$f_L(UR)$ = fraction, in load mode L, of total electricity supplies in demand region UR.

$f_{SC}(P,SL,L)$ = partial scrubbing fraction; the fraction of a plant type's exhaust required to be scrubbed, associated with a scrubber on plant type P, operating in load mode L, using coal of sulfur level SL.

$CF(UR,L)$ = capacity factor (in decimal form) for plants operating in load mode L, in demand region UR.

c. Definition of Activity Variables

Coal Mining--Supply (10^6 Tons/year):	$S_{CR,IT,HL,SL}$
Coal Cleaning (10^6 Tons/year):	C_{CR,HL,SL_1,SL_2}
Coal Transportation (10^6 Tons/year):	$T_{CR,UR,HL,SL}$
Oil/Gas Procurement (Quads/year):	$TP_{UR,UE}$, UE = $\underline{OG}$, $\underline{PG}$
Non-Utility Coal Procurement (Quads/year):	$D_{UR,OD,UE}$, OD $\neq$ $\underline{MT}$, $\underline{EX}$
	$D_{UR,\underline{MT},BLM}$, OD = $\underline{MT}$
	$D_{UR,\underline{EX},BLE}$, OD = $\underline{EX}$
Electricity Generation (10^9 KWH/year):	$O_{UR,P,UE,L}$
Electricity Transmission (10^9 KWH/year)	
Existing Lines:	TRE_{UR_i,UR_j}
New Lines:	TRN_{UR_i,UR_j}
Electricity Delivery--Distribution to Users (10^9 KWH/year):	DEL_{UR}
Electricity Load Management (10^9 KWH/year):	CEL_{UR}
Building Electrical Generating Capacity (GW):	BP_{UR,PT,ID_n}
Building Scrubber Capacity (GW):	$BS1_{UR}$, $BS2_{UR}$, $BS3_{UR}$, $BS4_{UR}$

d. Constraint Equations

1. Available Coal Reserves (10^6 Tons/year)

$$S_{CR,IT,HL,SL} \leq S^*_{CR,IT,HL,SL} \qquad (1)$$

where $S^*_{CR,IT,HL,SL}$ represents exogenous supply limitations on coal types, by mine type in each supply region.

2. Coal Stocks by Coal Type at Supply Regions--Material Balances (10^6Tons/year)

(a) For HL $\neq \underline{Z}$ and SL = $\underline{A}$, or for any HL with SL = $\underline{G}$ or $\underline{H}$:

$$-\sum_{IT} S_{CR,IT,HL,SL} + \sum_{UR} T_{CR,UR,HL,SL} \leq 0 \qquad (2)$$

(b) For HL $\neq \underline{Z}$ and SL = $\underline{B}$:

$$-\sum_{IT} S_{CR,IT,HL,\underline{B}} - (1 - \ell_C) C_{CR,HL,\underline{C},\underline{B}} + \sum_{UR} T_{CR,UR,HL,\underline{B}} \leq 0 \qquad (3)$$

(c) For any HL and SL = $\underline{C}$:

$$-\sum_{IT} S_{CR,IT,HL,\underline{C}} + C_{CR,HL,\underline{C},\underline{B}} + C_{CR,HL,\underline{C},\underline{D}} \leq 0 \qquad (4)$$

(d) For HL $\neq \underline{Z}$ and SL = $\underline{D}$:

$$-\sum_{IT} S_{CR,IT,HL,\underline{D}} - C_{CR,HL,\underline{C},\underline{D}} - (1 - \ell_C) C_{CR,HL,\underline{E},\underline{D}} + \sum_{UR} T_{CR,UR,HL,\underline{D}} \leq 0 \qquad (5)$$

(e) For any HL and SL = $\underline{E}$:

$$-\sum_{IT} S_{CR,IT,HL,\underline{E}} + C_{CR,HL,\underline{E},\underline{D}} + C_{CR,HL,\underline{E},\underline{F}} \leq 0 \tag{6}$$

(f) For any HL and SL = $\underline{F}$:

$$-\sum_{IT} S_{CR,IT,HL,\underline{F}} - C_{CR,HL,\underline{E},\underline{F}} + \sum_{UR} T_{CR,UR,HL,\underline{F}} \leq 0 \tag{7}$$

(g) For HL = $\underline{Z}$ and SL = $\underline{A}$, $\underline{B}$, or $\underline{D}$, in Equations (2), (3), and (5), respectively: replace $T_{CR,UR,\underline{Z},SL}$ by $T_{CR,UR,\underline{C},SL} + T_{CR,UR,\underline{Z},SL}$. (A definition of activity $T_{CR,UR,\underline{C},SL}$ is given in Section B above on page 2-39.)

3. Fuel Piles at Demand Regions--Material Balances (Quads/year)

For simplicity we ignore coal blending for industrial coal demand, and electricity generation activities that use coal blends. Coal mixing activities are also excluded.

(a) For UE = $\underline{BA}$, $\underline{BB}$, $\underline{BD}$, $\underline{BF}$, $\underline{BG}$, $\underline{BH}$ and HL = $\underline{Z}$, $\underline{H}$, $\underline{M}$:

$$-\sum_{CR} \sum_{HL=\underline{Z},\underline{H},\underline{M}} hc(CR,HL)\ T_{CR,UR,HL,SL} + \sum_{BLM} f_{UE}(BLM)\ D_{UR,\underline{MT},BLM}$$

$$+ \sum_{BLE} f_{UE}(BLE)\ D_{UR,\underline{EX},BLE} + \sum_{OD\neq\underline{MT},\underline{EX}} D_{UR,OD,UE}$$

$$+\sum_{P} \sum_{L} hr(UR,P,L)\ O_{UR,P,UE,L} \leq 0 \tag{8}$$

(b) For UE = $\underline{SA}$, $\underline{SB}$, $\underline{SD}$, $\underline{SF}$, $\underline{SG}$, $\underline{SH}$, $\underline{LA}$, $\underline{LB}$, $\underline{LD}$, $\underline{LF}$, $\underline{LG}$, $\underline{LH}$:

$$-\sum_{CR} hc(CR,HL)\ T_{CR,UR,HL,SL} + \sum_{OD\neq\underline{MT},\underline{EX}} D_{UR,OD,UE}$$

$$+\sum_{P} \sum_{L} hr(UR,P,L)\ O_{UR,P,UE,L} \leq 0 \tag{9}$$

(c) For UE = $\underline{MT}$, HL = $\underline{Z}$, and SL = $\underline{A}$, $\underline{B}$, or $\underline{D}$:

$$-\sum_{CR} hc(CR,\underline{Z})\ T_{CR,UR,\underline{C},SL} + \sum_{BLM} f_{\underline{MT}}(BLM)\ D_{UR,\underline{MT},BLM}$$

$$+ \sum_{BLE} f_{\underline{MT}}(BLE)\ D_{UR,\underline{EX},BLE} \leq 0 \tag{10}$$

(d) For UE = $\underline{OG}$,$\underline{PG}$:

$$-TP_{UR,UE} + \sum_{P} \sum_{L} hr(UR,P,L)\ O_{UR,P,UE,L} \leq 0 \tag{11}$$

4. Lower Bounds on Transportation Activities (if required)
(10^6 Tons/year)

$$T_{CR,UR,HL,SL} \geq T^{*}_{CR,UR,HL,SL} \tag{12}$$

where $T^{*}_{CR,UR,HL,SL}$ represents exogenous lower bounds on transport between regions CR and UR.

5. Upper Bounds on Old Gas Procurement (Quads/year)

$$TP_{UR,\underline{OG}} \leq TPOG^{*}_{UR} \tag{13}$$

where $TPOG^{*}_{UR}$ represents exogenous upper bounds on procurement of old gas in demand regions UR.

6. Non-Utility Energy Requirements at Demand Regions (Quads/year)

(a) For OD ≠ $\underline{MT}$ or $\underline{EX}$:

$$-\sum_{UE} D_{UR,OD,UE} = -D^{*}_{UR,OD} \tag{14}$$

where $D^{*}_{UR,OD}$ represents exogenous consumption requirements of demand type OD in demand regions UR.

(b) For OD = MT:

$$-\sum_{BLM} D_{UR,\underline{MT},BLM} = -DMT^{*}_{UR} \tag{15}$$

where DMT^{*}_{UR} represents exogenous metallurgical coal demand in regions UR.

(c) For OD = EX:

$$-\sum_{BLE} D_{UR,\underline{EX},BLE} = -DEX^{*}_{UR} \tag{16}$$

where DEX^{*}_{UR} represents exogenous export coal demand in regions UR.

7. Electricity Consumption Requirements (10^9 KWH/year)

$$-DEL_{UR} = -DEL^{*}_{UR} \tag{17}$$

where DEL^{*}_{UR} represents exogenous electricity consumption requirements in demand regions UR.

8. Total Electricity Supplies--Material Balances (10^9 KWH/year)

$$\sum_{UR_j}\left(TRE_{UR_i,UR_j} + TRN_{UR_i,UR_j}\right) + \left(1 + \ell_D(UR_i)\right) DEL_{UR_i} - CEL_{UR_i} \leq 0 \tag{18}$$

where UR_i represents source regions and UR_j represents sink regions.

9. Electricity Supplies by Load Category--Material Balances (10^9 KWH/year)

(a) For L = B:

$$-\sum_{P}\sum_{UE} O_{UR_j,P,UE,\underline{B}} + (1 + \ell_{PS}) \sum_{P\neq\underline{H},\underline{I}} O_{UR_j,P,\underline{HG},\underline{Z}}$$

$$+ f_{\underline{B}}(UR_j)\, CEL_{UR_j} - \sum_{UR_i}\left[\left(1 - \ell_{TE}(UR_i,UR_j)\right) TRE_{UR_i,UR_j}\right.$$

$$\left. + \left(1 - \ell_{TN}(UR_i,UR_j)\right) TRN_{UR_i,UR_j}\right] \leq 0 \tag{19}$$

(b) For $L \neq \underline{B}$:

$$- \sum_{P} \sum_{UE} O_{UR,P,UE,L} + f_L(UR)\ CEL_{UR} \leq 0 \qquad (20)$$

10. Electrical Generating Capacity for Existing Plants (GW)

Let:

P_e = existing plant types, and

ID_e = plant type identifiers for existing plant types.

Recall from the lists given in Section B above.

P_e = ($\underline{O}$, $\underline{E}$, $\underline{F}$, $\underline{G}$, $\underline{S}$, $\underline{P}$, $\underline{Q}$, $\underline{R}$, $\underline{H}$, $\underline{Y}$, $\underline{T}$, $\underline{J}$, $\underline{K}$), and

ID_e = ($\underline{01}$, $\underline{02}$, $\underline{03}$, $\underline{04}$, $\underline{05}$, $\underline{02}$, $\underline{03}$, $\underline{04}$, ($\underline{09}$, $\underline{10}$, $\underline{11}$), $\underline{15}$, $\underline{17}$, $\underline{19}$, $\underline{20}$).

Note that there are three identifiers, one for each of load modes $L = \underline{B}$, $\underline{I}$ and $\underline{Z}$, associated with existing plant type $\underline{H}$.

(a) For P_e = $\underline{O}$, $\underline{S}$, $\underline{Y}$, $\underline{T}$, $\underline{J}$, $\underline{K}$:

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_e,UE,L} \leq EGW^{*}_{UR,ID_e} \qquad (21)$$

where EGW^{*}_{UR,ID_e} represents exogenous electrical generating capacity limits on existing plant types identified by ID_e in demand regions UR.

(b) For P_e = $\underline{E}$ and $\underline{P}$:

$$\sum_{P_e=\underline{E},\underline{P}} \sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_e,UE,L}$$

$$+ BP_{UR,\underline{CV},\underline{25}} \leq EGW^{*}_{UR,\underline{02}} \qquad (22)$$

(c) For $P_e = \underline{F}$ and $\underline{Q}$:

$$\sum_{P_e=\underline{F},\underline{Q}} \sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} \ O_{UR,P_e,UE,L}$$

$$+ BP_{UR,\underline{CV},\underline{26}} \leq EGW^{*}_{UR,\underline{03}} \qquad (23)$$

(d) For $P_e = \underline{G}$ and $\underline{R}$:

$$\sum_{P_e=\underline{G},\underline{R}} \sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} \ O_{UR,P_e,UE,L}$$

$$+ BP_{UR,\underline{CV},\underline{27}} \leq EGW^{*}_{UR,\underline{04}} \qquad (24)$$

(e) For $P_e = \underline{H}$ and $L = \underline{B}, \underline{I}, \underline{Z}$:

$$\left[(8.76)\ CF(UR,L)\right]^{-1} \ O_{UR,\underline{H},\underline{HG},L} \leq EGW^{*}_{UR,ID_e} \qquad (25)$$

11. Electrical Generating Capacity for New Plants--Material Balances (GW)

Let:

P_n = new plant types, and

ID_n = plant type identifiers for new plant types.

Recall from the lists given in Section B above that:

P_n = ($\underline{N}$, $\underline{M}$, $\underline{8}$, $\underline{0}$, $\underline{1}$, $\underline{2}$, $\underline{5}$, $\underline{6}$, $\underline{7}$, $\underline{I}$, $\underline{Z}$, $\underline{U}$, $\underline{L}$),

ID_n = (($\underline{06}$, $\underline{07}$, $\underline{08}$), ($\underline{06}$, $\underline{07}$, $\underline{08}$), ($\underline{22}$, $\underline{23}$, $\underline{24}$), $\underline{28}$, $\underline{29}$, $\underline{30}$, $\underline{25}$, $\underline{26}$, $\underline{27}$, $\underline{14}$, $\underline{16}$, $\underline{18}$, $\underline{21}$), and

PT = ($\underline{CL}$, $\underline{CL}$, $\underline{C9}$, $\underline{NT}$, $\underline{NT}$, $\underline{NT}$, $\underline{CV}$, $\underline{CV}$, $\underline{CV}$, $\underline{HG}$, $\underline{NU}$, $\underline{PT}$, $\underline{PS}$).

Note that there are three identifiers, one for each coal rank, associated with new plant types $P_n = \underline{N}$, $\underline{M}$ and $\underline{8}$.

(a) For $P_n \neq \underline{N}, \underline{M}$, or $\underline{8}$:

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_n,UE,L} - BP_{UR,PT,ID_n} \leq 0 \qquad (26)$$

(b) For $P_n = \underline{N}$ and $\underline{M}$ and UE = $\underline{BA}$, $\underline{BB}$, $\underline{BD}$, $\underline{BF}$, $\underline{BG}$, $\underline{BH}$:

$$\sum_{P_n=\underline{N},\underline{M}} \sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_n,UE,L} - BP_{UR,\underline{CL},\underline{06}} \leq 0 \qquad (27)$$

(c) For $P_n = \underline{N}$ and $\underline{M}$ and UE = $\underline{SA}$, $\underline{SB}$, $\underline{SD}$, $\underline{SF}$, $\underline{SG}$, $\underline{SH}$ use Equation (27) with $BP_{UR,\underline{CL},\underline{06}}$ replaced by $BP_{UR,\underline{CL},\underline{07}}$.

(d) For $P_n = \underline{N}$ and $\underline{M}$ and UE = $\underline{LA}$, $\underline{LB}$, $\underline{LD}$, $\underline{LF}$, $\underline{LG}$, $\underline{LH}$ use Equation (27) with $BP_{UR,\underline{CL},\underline{06}}$ replaced by $BP_{UR,\underline{CL},\underline{08}}$.

(e) For $P_n = \underline{8}$ and UE = $\underline{BA}$, $\underline{BB}$, $\underline{BD}$, $\underline{BF}$, $\underline{BG}$, $\underline{BH}$:

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{8},UE,L} - BP_{UR,\underline{C9},\underline{22}} \leq 0 \qquad (28)$$

(f) For $P_n = \underline{8}$ and UE = $\underline{SA}$, $\underline{SB}$, $\underline{SD}$, $\underline{SF}$, $\underline{SG}$, $\underline{SH}$ use Equation (28) with $BP_{UR,\underline{C9},\underline{22}}$ replaced by $BP_{UR,\underline{C9},\underline{23}}$.

(g) For $P_n = \underline{8}$ and UE = $\underline{LA}$, $\underline{LB}$, $\underline{LD}$, $\underline{LF}$, $\underline{LG}$, $\underline{LH}$ use Equation (28) with $BP_{UR,\underline{C9},\underline{22}}$ replaced by $BP_{UR,\underline{C9},\underline{24}}$.

12. Scrubber Capacity on Existing Coal Plants--Material Balances (GW)

$$\sum_{P_e=\underline{P},\underline{Q},\underline{R}} \sum_{UE} \sum_{L} f_{SC}(P_e,SL,L) \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_e,UE,L}$$

$$- BSl_{UR} \leq 0 \qquad (29)$$

13. Scrubber Capacity on New Coal Plants--Material Balances (GW)

(a) NSPS (New Source Performance Standard) Coal Plants, $P_n = \underline{M}$:

$$\sum_{UE} \sum_{L} f_{SC}(\underline{M},SL,L) \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{M},UE,L} - BS2_{UR} \leq 0 \quad (30)$$

(b) ANSPS (Alternative NSPS) Coal Plants, $P_n = \underline{8}$, $SL \neq \underline{A}$:

$$\sum_{UE} \sum_{L} f_{SC}(\underline{8},SL,L) \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{8},UE,L} - BS3_{UR} \leq 0 \quad (31)$$

(c) ANSPS Coal Plants, $P_n = \underline{8}$, $SL = \underline{A}$:

$$\sum_{UE=\underline{BA},\underline{SA},\underline{LA}} \sum_{L} f_{SC}(\underline{8},\underline{A},L) \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{8},UE,L}$$

$$- BS4_{UR} \leq 0 \quad (32)$$

14. New Capacity Building Limits (GW)

(a) NSPS Coal Plants, $PT = \underline{CL}$:

$$\sum_{ID_n=\underline{06},\underline{07},\underline{08}} BP_{UR,\underline{CL},ID_n} \leq BCL^*_{UR} \quad (33)$$

where BCL^*_{UR} represents exogenous new capacity limits on NSPS coal plants in demand regions UR.

(b) ANSPS Coal Plants, $PT = \underline{C9}$:

$$\sum_{ID_n=\underline{22},\underline{23},\underline{24}} BP_{UR,\underline{C9},ID_n} \leq BC9^*_{UR} \quad (34)$$

where $BC9^*_{UR}$ represents exogenous new capacity limits on ANSPS coal plants in demand regions UR.

(c) Nuclear Plants, PT = NU, ID_n = 16 :

$$BP_{UR,\underline{NU},\underline{16}} = BNU^*_{UR} \tag{35}$$

where BNU^*_{UR} represents exogenously specified fixed nuclear capacity in demand regions UR.

(d) Hydro Plants, PT = HG, ID_n = 14 :

$$BP_{UR,\underline{HG},\underline{14}} = BHG^*_{UR} \tag{36}$$

where BHG^*_{UR} represents exogenously specified fixed hydro capacity in demand regions UR.

(e) Oil/Gas Steam Plants, PT = PS, ID_n = 21 :

$$BP_{UR,\underline{PS},\underline{21}} = 0.0 \tag{37}$$

(f) There are no capacity building limits for:

Oil/Gas Turbine Plants: PT = PT, ID_n = 18,

New Technology Plants: PT = NT, ID_n = 28, 29, 30,

Conversion Facilities: PT = CV, ID_n = 25, 26, 27.

15. Lower Bounds on Scrubber Capacity for NSPS Coal Plants (GW)

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{M},UE,L} \geq BS2^*_{UR} \tag{38}$$

where $BS2^*_{UR}$ represents exogenous lower bounds on scrubber capacity for NSPS coal plants in demand regions UR.

e. Objective Function (10^6 \$/year)

$$\text{Minimize} \left\{ \sum_{CR} \sum_{IT} \sum_{HL} \sum_{SL} RACP(CR,IT,HL,SL)\ S_{CR,IT,HL,SL} \right.$$

$$+ DCC \sum_{CR} \sum_{HL} \left(C_{CR,HL,\underline{C},\underline{B}} + C_{CR,HL,\underline{E},\underline{D}} \right)$$

$$+ \sum_{CR} \sum_{UR} TC(CR,UR) \left[\sum_{HL} \sum_{SL} T_{CR,UR,HL,SL} + \sum_{SL=\underline{A},\underline{B},\underline{D}} T_{CR,UR,\underline{C},SL} \right]$$

$$+ \sum_{UR} \sum_{UE=\underline{OG},\underline{PG}} FC(UR,UE)\ TP_{UR,UE}$$

$$+ \sum_{UR} \sum_{P} \sum_{UE} \sum_{L} OMC(P,UE,L)\ O_{UR,P,UE,L}$$

$$+ \sum_{UR_i} \sum_{UR_j} TRC(UR_i,UR_j)\ TRN_{UR_i,UR_j}$$

$$+ \sum_{UR} DC(UR)\ DEL_{UR}$$

$$+ \sum_{UR} \sum_{PT} \sum_{ID_n} ACP(UR,PT,ID_n)\ BP_{UR,PT,ID_n}$$

$$+ \sum_{UR} \left[ACS1(UR)\ BS1_{UR} + ACS2(UR)\ BS2_{UR} + ACS3(UR)\ BS3_{UR} \right.$$

$$\left. \left. + ACS4(UR)\ BS4_{UR} \right] \right\} \qquad (39)$$

where:

RACP = real annuity coal price (see Appendix F.2), \$/Ton

DCC = deep cleaning cost, \$/Ton

TC = transportation cost, \$/Ton

FC = non-coal fuel cost, 10^6 \$/Quad

OMC = O&M cost (includes fuel cost for nuclear plants), mills/KWH

TRC = transmission cost for new lines, mills/KWH

DC = electricity delivery cost, mills/KWH

ACP = annualized capital cost for new power plants, \$/KW-yr

ACS1 = annualized capital cost for scrubber-type S1, \$/KW-yr

ACS2 = annualized capital cost for scrubber-type S2, \$/KW-yr

ACS3 = annualized capital cost for scrubber-type S3, \$/KW-yr

ACS4 = annualized capital cost for scrubber-type S4, \$/KW-yr

f. Additional Details

There are additional minimally important factors that would vastly complicate the preceding mathematical formulation and would not substantially add to a further understanding of the model. For those interested in such additional precise details, see Chapter 3, Section D of this volume and several descriptive memoranda appearing in Section E of ICF, Inc. (July 1977). These details, not explicitly accounted for in the preceding mathematical formulation, concern the following:

1. (a) Heat rate penalties and capacity factor penalties due to full or partial scrubbing.

(b) Capital cost and O&M cost savings due to partial rather than full scrubbing.

(c) The fact that the partial scrubbing fraction is a function of the relevant environmental standard and the scrubber efficiency, in addition to the sulfur level of the coal being scrubbed.

2. Coal blending for industrial coal demand and coal mixing activities.

3. Joint (aggregate) lower bounds on total coal transported from supply to demand regions, where required.

4. (a) Both upper and lower bounds on electricity transmission via existing lines between demand regions, where required.

(b) Lower bounds on electricity transmission via new lines between demand regions, where required.

5. Some changes in the CEUM's more recent versions pointed out in parts of Section B above, such as the use of $\underline{DG}$ in place of $\underline{OG}$, the omission of new technologies, etc.

D. THE USE OF PARTIAL SCRUBBING IN THE CEUM*

This section presents a detailed analytical description of the use of partial scrubbing in the CEUM. An explicit presentation of this material does not appear in the CEUM Documentation (ICF, Inc. [July 1977]), nor in the applications reports (ICF, Inc. [September 1978a, June 1978b, January 1979]).

Several alternative new source performance standards (ANSPS) are analyzed by ICF (September 1978b). Each ANSPS is defined by a floor and a ceiling on SO_2 emissions. For any ANSPS coal plant, scrubbers are mandatory and 85% sulfur removal (on a daily average basis) down to the specified floor is required. Note that utilities are not required to reduce emissions below the floor, thus allowing for partial scrubbing (i.e., floors are emissions limitations that can be met in place of a percentage removal requirement). The ceiling is an emission limitation that cannot be exceeded on a daily average basis unless there are exemptions allowed that permit it to be exceeded three days per month. In "without exemptions" cases the scrubber efficiency is assumed to be 75%. Under the current new source performance standard (NSPS), scrubbers are not mandatory and a maximum emission level of 1.2 lbs. $SO_2/10^6$ BTU is required. If scrubbers are employed with an NSPS coal plant, a 90% efficiency on an annual average basis is employed.

a. Definition of Terms

Let: S = average sulfur content in a specified coal type; note that lbs. $S/10^6$ BTU = $(\frac{1}{2})$ lbs. $SO_2/10^6$ BTU.

C = ceiling or cap on SO_2 emissions in lbs. $SO_2/10^6$ BTU.

F = floor on SO_2 emissions in bs. $SO_2/10^6$ BTU.

* This section was prepared by Neil L. Goldman.

E = scrubber efficiency (percentage sulfur removal) on a daily average basis = .85 (with exemptions), .75 (without exemptions).

E_A = scrubber efficiency (percentage sulfur removal) on an annual average basis = .90.

R_A = annual SO_2 emissions rate in lbs. $SO_2/10^6$ Btu.

X = percentage of flue-gas scrubbed (partial scrubbing fraction).

RSD = relative standard deviation above the long-run mean sulfur content of a specified coal; this daily average variability factor accounts for differences in peak sulfur content on a daily basis versus an annual average; 3 RSD's are assumed in the "without exemptions" ANSPS scenarios and 2 RSD's are assumed in the "with exemptions" scenarios; RSD = 0.15.

b. Definitions of Sulfur Levels in Utility Demand Regions

	Level	Range (lbs. $S/10^6$ Btu)	Assumed Average Sulfur Content (lbs. $S/10^6$ Btu)
Low	A	0.00-0.40	0.40
	B	0.41-0.60	0.60
Medium	D	0.61-0.83	0.83 (approximately 1% S)
	F	0.84-1.67	1.67 (approximately 2% S)
High	G	1.68-2.50	2.50 (approximately 3% S)
	H	greater than 2.50	3.33

c. Alternative New Source Performance Standards (ANSPS)

Each of the ANSPS listed below is analyzed in ICF, Inc. (September 1978b) and is denoted by: ceiling/floor, exemption status. The ceilings and floors are given in lbs. $SO_2/10^6$ BTU.

1.2 (current NSPS)

1.2/.2, with exemptions; 1.2/.2, without exemptions;

1.2/.5, with exemptions; 1.2/.5, without exemptions;

1.2/.67, with exemptions;

1.2/.80, with exemptions

d. Determination of Maximum Allowable Sulfur Contents under Alternative Standards

Let: S_{max} = maximum allowable sulfur content, given an emissions ceiling and an enforcement standard.

1. Annual Average Enforcement--NSPS:

$$2S(1 - E_A) = C$$

$$\Rightarrow \quad S_{max} = \frac{1.2}{2(1 - .90)} = 6.0 \qquad (1)$$

2. Daily Average Enforcement--ANSPS:

$$2S(1 - E)(1 + n * RSD) = C, \; n = 2, \text{ with exemptions}$$
$$= 3, \text{ without exemptions}$$

$$\text{with exemptions:} \quad S_{max} = \frac{1.2}{2(1 - .85)(1.3)} = 3.08 \qquad (2)$$

$$\text{without exemptions:} \quad S_{max} = \frac{1.2}{2(1 - .75)(1.45)} = 1.66 \qquad (3)$$

3. Coal Types Disallowed:

From Equations (1), (2), and (3) and the definition of sulfur levels on page 2-72, we have:

ANSPS cases with exemptions: H

ANSPS cases without exemptions: G, H

NSPS: none

e. Calculation of Partial Scrubbing Fractions

1. Annual Average Enforcement--NSPS:

$$F = 2S(1 - E_A)X + 2S(1 - X) \quad (4)$$

$$\Rightarrow \quad X = (1 - F/2S)/E_A \quad (5)$$

Recall that for NSPS: $F = C = 1.2$ and $E_A = .90$.

2. Daily Average Enforcement--ANSPS:

Note here that partial scrubbing fractions are calculated by ICF using the 'with exemptions' parameters.

$$F = 2S(1 + 3*RSD)(1 - E)X + 2S(1 + 3*RSD)(1 - X) \quad (6)$$

$$\Rightarrow \quad X = \frac{1 - F/[2S(1 + 3*RSD)]}{E} = \frac{1 - F/(2.9)S}{.85} \quad (7)$$

f. Calculation of Annual Emissions Rate for ANSPS Standards

$$R_A = 2S(1 - E_A)X + 2S(1 - X) \quad (8)$$

where $E_A = .90$ and X is determined from Equation (7).

g. Determination of Coals That Must Be Fully Scrubbed and Coals That Can Be Partially Scrubbed Under Alternative Standards

Let: S_{min} = minimum sulfur level that requires full scrubbing, i.e., $X = 1$.

1. Annual Average Enforcement--NSPS:

From Equation (4) we have:

$$F = 2S_{min}(1 - E_A)$$

$$\Rightarrow \quad S_{min} = \frac{F}{2(1 - E_A)} = \frac{1.2}{2(.1)} = 6.0 \quad (9)$$

The following table displays the scrubbing status of coals for different floors with annual average enforcement. Equation (9) and the definition of sulfur levels on page 2-72 are used.

	F	S_{min}	Coals Not Scrubbed (X=0)	Coals Partially Scrubbed (0 < X < 1)	Coals Fully Scrubbed (X=1)	Coals Disallowed
	.2	1.0	-	A, B, D	F, G, H	-
	.5	2.5	-	A, B, D, F	G, H	-
	.67	3.35	-	A, B, D, F, G	H	-
	.80	4.0	A	B, D, F, G, H	-	-
NSPS	1.2	6.0	A,B	D, F, G, H	-	-

2. Daily Average Enforcement--ANSPS:

From Equation (6) we have:

$$F = 2S_{min}(1 + 3*RSD)(1 - E)$$

$$\Rightarrow S_{min} = \frac{F}{2(1.45)(.15)} = \frac{F}{.435} \tag{10}$$

The following table displays the scrubbing status of coals for each ANSPS scenario under daily average enforcement. The definition of sulfur levels in Subsection b, the results of Subsection d, and Equation (10) are used. Note that we have added an ANSPS that duplicates the NSPS but under daily average enforcement (E = .85) and with exemptions.

ANSPS	F	S_{min}	Coals Partially Scrubbed (0 < X < 1)	Coals Fully Scrubbed (X=1)	Coals Disallowed
1.2/.2, with	.2	.46	A	B, D, F, G	H
1.2/.2, without	.2	.46	A	B, D, F	G, H
1.2/.5, with	.5	1.15	A, B, D	F, G	H
1.2/.5, without	.5	1.15	A, B, D	F	G, H
1.2/.67, with	.67	1.54	A, B, D	F, G	H
1.2/.80, with	.80	1.84	A, B, D, F	G	H
1.2/1.2, with	1.2	2.76	A(X=0), B, D, F, G	-	H

It is important to point out the manner in which ICF has chosen to implement the information contained in the preceding table. We have learned via communications with ICF personnel that whenever the partial scrubbing fraction is greater than 0.8 but less than 1.0, the model fully scrubs (i.e., sets X = 1) rather than partially scrubs the associated coal.* The apparent undocumented justification for this procedure is that the magnitude of the cost savings associated with partially scrubbing coals when $.8 < X < 1$ is small. ICF has no calculations available to support this claim.

*The affected coals (those fully scrubbed instead of partially scrubbed) in the case of daily average enforcement are: with a .2 floor, A coals; with a .5 floor, B and D coals; with a .67 floor, D coals; with a .80 floor, F coals; and with a 1.2 floor, F and G coals. The effected coals in the case of annual average enforcement are: with a .2 floor, B and C coals; with a .5 floor, F coals; with a .67 floor, F and G coals; with a .80 floor, F, G, and H coals; with a 1.2 floor (NSPS), G and H coals.

CHAPTER 4. AN EVALUATION OF THE OPERATING CHARACTERISTICS OF THE CEUM*

The Coal and Electric Utilities Model (CEUM), developed by ICF, Inc., was maintained on the DOE Energy Information Administration's IBM 370 facility at OSI in Rockville, Maryland. While the general design and key characteristics of the CEUM have been discussed elsewhere (see Section 1.2 of Volume 1 and Chapter 3, Section A above), here we consider the operating characteristics and ease of use of the model. It is important to note that no user or operator guide was provided with the model. While the EIA has prepared a draft User's Manual for its version of the model that was of some interest to us, our ability to run the CEUM is largely based upon a study of the computer code and extensive consultation with the modelers. In particular, Dr. Michael Wagner of ICF was extremely helpful in our learning process.

The CEUM is a large-scale, linear programming (LP) model with a highly resolved data base, and it has been designed to be run for three case years: 1985, 1990, and 1995. For each year, a large LP matrix is generated, consisting of approximately 2,000 constraints and 14,000 variables. The matrix is first generated for 1985, and is subsequently updated through a revision operation for the other two case years. In order to complete its operations, the CEUM relies upon a fairly complex file structure. System files are used to generate data files, a composite data tape (GAMOUTC), a matrix file, revise files, and various output files. Major aspects of this file structure are illustrated in Figure 1. Here we provide a summary discussion of each of the major

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* This chapter was prepared by David O. Wood, Martha J. Mason and Vijaya Chandru.

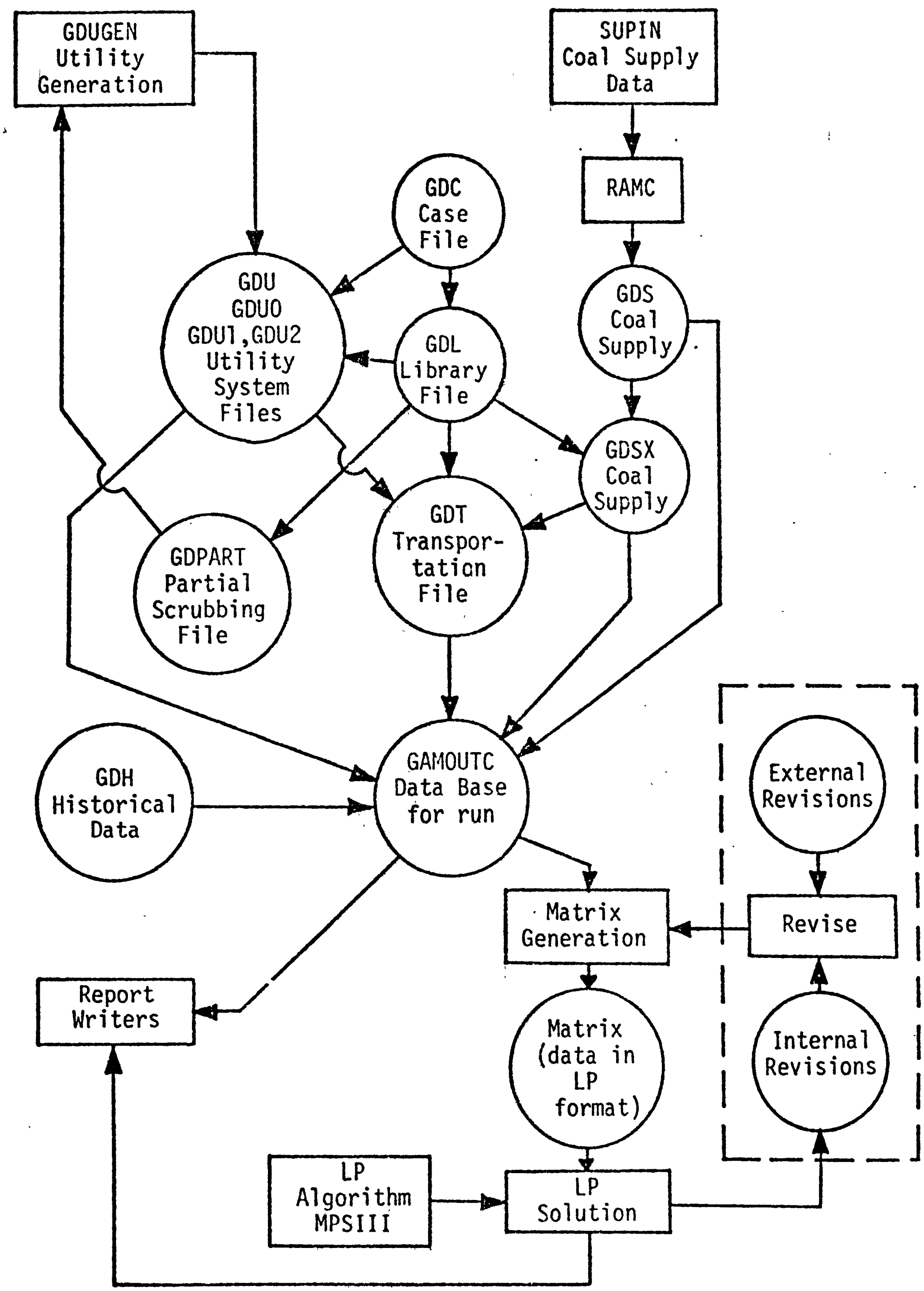

Figure 1. Flow Diagram Indicating the Basic File Structure of the CEUM (Not a Comprehensive Listing of All Files)

steps, together with an indication of the estimated CPU time required for execution of those steps. It should be noted that elapse time for accomplishing each of these steps is a function of the condition of the machine. It might also be noted that in our experience these jobs were run at low priority, and were subject to being lost when the system crashed.

The first major step involves creation of the basic input data files, and the execution of the coal supply module.* The basic data files contain input data for the coal supply model, the utility model, and data characterizing the transportation system. The output of this processing is a single file (GAMOUTC) structured for input to the LP matrix. The time required to process all input data and execute the coal supply model varies depending upon the number of updates, etc. On average the required time is 5 to 6 CPU minutes.

Given the basic input data, the next major phase of the system is to generate the constraint matrix and to solve the LP for the first case year (1985). The matrix generation program, written in GAMMA, takes the variables and puts them in a format usable by the LP algorithm. The LP is then solved, using a software package called MPSIII. The output of this activity consists of files produced for use by the report generators. The estimated CPU time to complete this phase of operations

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*The coal supply data are treated somewhat differently from the other basic data inputs. Coal supply data are entered via a file entitled SUPIN, and are then run through a FORTRAN program called RAMC. RAMC produces supply curves for coal types in step form. Each step represents a different type of mine with the height of the step representing the cost of production, and the width representing the maximum level of operation for that mine type. In short, RAMC supplies the upper limits to the coal production activities in the model.

is 25-30 minutes. It is, however, possible to enter and make a run of the CEUM from an advanced basis. When only minor updates are made to the constraint matrix and the advanced basis from which the solution begins is very close to the new solution, the estimated solution and output report times are somewhat shorter in duration.

Finally, the report writers convert the LP solution into output format. Approximately 15 CPU minutes are required to generate the reports containing model output for the 1985 case year.

Solutions for the case years subsequent to 1985 require some modification of the constraint matrix and solution. Approximately 10 to 15 minutes of CPU time usually are required. However, generation of the output reports for subsequent case years requires the same amount of time as for 1985, approximately 15 CPU minutes.

As noted above, the elapse time for accomplishing these tasks will vary significantly depending upon the status of the equipment.

A. EVALUATION OF OPERATING CHARACTERISTICS

In general, the characteristics of a model that are of importance to the operator are as follows:

1) Ease of updating data,
2) Flexibility through input and parameter changes only,
3) Extensibility of model structure,
4) Efficiency of operation,
5) Interpretability of model output,
6) Clarity of model format, and
7) Transferability--accessibility of documentation, training required, ease of use by persons other than the modeler.

We have considered the CEUM in the context of each of these characteristics, and a summary of each point is presented below.

A.1 Ease of Updating Data

M.I.T. operators found that updating model data is not as easily accomplished and straightforward a process as one might suppose. As illustrated in Figure 1 and discussed above, the CEUM computational structure is complex, involving many input, intermediate, and output files. Attached to this chapter is a listing and brief description of the files associated with the model. In order to update data, the user enters the GAMMA-coded data files and appropriately inserts the new information. However, these new data are not always carried automatically through the necessary series of intermediate steps. It is up to the operators to remember which files the new data may explicitly and implicitly affect, and to change those as well. In short, the many interdependencies among various levels of the structure cause data updating to be a highly operator-dependent operation.

A.2 Flexibility Through Input and Parameter Changes

The above comments on data changes are also applicable to input and parameter changes. The CEUM is not set up to easily accommodate changes to parameters. Again, operator knowledge is required to ensure that correct changes are made in all the necessary places. At this time, given the existing documentation, only the model developer or experienced assessors of this model have a chance of being fully cognizant of all the places in the code where such changes may be necessary. (For further discussion of parameter changes, see Volume VI, Chapter 9 and Point 3 of Chapter 5, Section A below.)

A.3 Extensibility of Structure

Issues concerning the structure of the CEUM are discussed in detail in Volume I, Section 1.2. In brief, the model is structured as a complex set of preliminary programs that feed information into a straightforward linear programming framework that has a very high level of disaggregation. The modelers' emphasis on detail necessitated a simple model design, which resulted in both structural advantages and disadvantages.

From an operational point of view, the LP structure is simple to understand and execute. In general, revised data or new activities can be added to the model without significant difficulty, providing that the operator understands the matrix generation language and is aware of all places where changes must be made. Some structural changes are, however, not that easy to make. For example, one of the proposed audit runs involved substantial regional aggregation of the model. This run was not completed due to the complexity of implementing the change. In such cases, changes or extensions of the structure would be quite complicated, and would require extensive reprogramming.

A.4 Efficiency of Model Operation

The version of the CEUM evaluated by M.I.T. is somewhat inefficient in terms of operating time. As discussed above, several model operations, particularly the solve and report-generation steps, are quite time-consuming in CPU minutes. Table 1 below indicates the approximate amount of time required to execute a specific model run entitled EDMD for 1985 and 1990 (1995 run times would be similar if not identical to 1990 run times).

TABLE 1

Time Required to Run EDMD 1985 and 1990

Step	Approximate CPU Minutes Required
Creation of GAMOUTC	3.5
Generation of 1985 Matrix	2.3
Completion of LP Solution for 1985	10.9
Generation of Report-Writing Files	15.8
Creation of Reports	9.8
Revise, Set-up, and Solve for 1990	15.1
Creation of Reports for 1990	9.0
TOTAL	66.4

While these numbers are approximate due to the large number of steps of extremely short duration, the large amount of time required by certain processes is evident.

It should be observed that there is a trade-off between model extensibility and computational efficiency. In the present system, some model extensibility is preserved at the expense of using a generalized matrix generator program. The computational costs of this interpretive language are substantial, and could be reduced by programming the model in a compiler language such as FORTRAN. The disadvantage of such reprogramming would be that extensions to the model would be more costly to implement.

EPRI is currently supporting ICF in developing a FORTRAN version of the CEUM system. Concurrent with this effort, ICF has been analyzing various decompositions of the model to obtain improvements in computational efficiency. It is our understanding that such improvements could dramatically decrease the amount of CPU execution time required for model runs.

A.5 Interpretability of Output

The output from model runs is presented in four formats: (1) a "small" report, (2) a "large" report, (3) an LP solution report, and (4) a "slim file" which reproduces selected results. In general, the tables are well organized, and finding specific model outputs is not a difficult task. Operationally speaking, interpreting output is a straightforward process. However, as discussed in the documentation evaluation (Chapter 2 above), interpreting the meaning of results and comprehending their implications are very difficult with the CEUM, due to gaps in the descriptions of assumptions, methodology, and mathematical structure. In addition, several hundred pages of output per run are expensive to print and unwieldy to use and store.

A.6 Clarity of Model Format

As discussed above, the CEUM has proven to be somewhat difficult to comprehend from an analytical viewpoint, due to the obscure nature of some of its scientific and methodological bases. However, from an operational viewpoint, the structural relationships, although very cumbersome, are straightforward and provide no difficulty for the competent operator willing to make a substantial time commitment. The aspect of awkwardness is contributed to by the model's size, and the corresponding complexity of its file structure.

A.7 Transferability

Our evaluating team concluded that effective transfer of control of the CEUM is for all practical purposes impossible without significant input from the model developer. (As mentioned earlier, our own grasp of the model was made possible by the cooperation we received from ICF.) Given modeler assistance, it is not extraordinarily difficult to gain enough control over the model to perform straightforward sensitivity analysis. However, personal assistance is essential; the extant documentation and user's materials are not, by themselves, sufficient to enable operation. This fact, coupled with the complexity of the file structures, makes transfer of the CEUM an expensive process. Moreover, since the model has not been transferred from one type of machine environment to another, but has always been run on one specific configuration of IBM equipment, we are unable to comment on further procedures that such a transfer might require.

In order to be able to work with the CEUM, the operator must have, at a minimum, a working knowledge of the following systems:

- FORTRAN
- GAMMA (the matrix- and report-generating system)
- MPSIII (a proprietary software package developed by Ketron; used to solve the linear program)
- SUPERWYLBUR (an editing system necessary for operation at OSI)
- IBM 370 JCL

These language and system requirements present something of an operating problem, since GAMMA and SUPERWYLBUR are not widely known, and MPSIII is proprietary. Any learning time associated with the software must be added to the start-up time.

In addition, as discussed above, the documentation is not presented in a sufficiently complete fashion to permit more than a basic marginal control over the model. If important or complex structural changes were desired, much more personal training of the operator by the modeler would be required.

The evaluation of these seven categories has led us to conclude that, while the model structure is straightforward, several problems exist with model operation, including difficulties in transferability, file complexity, and computation times. Attached below is a listing of the files associated with the CEUM.

A.8 Basic File Structure of the CEUM

'FGAM' is the generic name of the data base from which the run is to be made.

'FRUN' is the generic name of the output files corresponding to various "rim" changes on a given data base.

(These "rim" changes are implemented via the REVISE files.)

'YYYY' represents the system files required by the model (additional sets such as 'XXXX' and 'ZZZZ' may be utilized to make additional parallel runs).

'FGAM' Files

FGAM.GAMOUTC - Data Base

FGAM.MATRIX - Matrix

FGAM.THINDIR }
FGAM.THINRWF } Directory and report-writer-files to publish SLIM and SMALL reports

FGAM.GAMDIR }
FGAM.GAMRWF } Report-writer files to publish LARGE reports

'FRUN' Files

FRUN85/90/95.LPSOLN - Contains solution to LP in MPSIII format

FRUN85/90/95.SMALL - SMALL output report

FRUN85/90/95.LARGE - LARGE (detailed) output report

System files ('XXXX'/'YYYY'/'ZZZZ')

XXXX.SLIM85 XXXX.SLIM90 XXXX.SLIM95	Files used to pass information from 1985 to 1990 run and from 1990 to 1995 run
XXXX.REV90 XXXX.REV95	Revise files for 1990 and 1995
XXXX.PROBFILE XXXX.PROB90 XXXX.PROB95	Probfiles required by MPSIII to solve LP; Special characteristic: //SPACE = (TRK, (80),, CONTIG)
XXXX.BASIS85 XXXX.BASIS90 XXXX.BASIS95	Basis files for LP

Input Data Files ("GD" Files)

GDS GDSX	Coal Supply Files
GDU GDU0 GDU1 GDU2	Utility Sector Files

GDT - Transportation File

GDPART - Partial Scrubbing File

GDH - Historical Data File

GDL - Library File

GDC - Case File--Global Paramters

Revise Files

DATA.REV85 - 1985 revise deck created by GAMMA.REV85

GAMMA.REVISE - Revise program for the 1990 and 1995 case years; generates revise decks in YYYY.REV90 and YYYY.REV95

GAMMA Programs

GMG - Matrix generator program

THIN
THINNER - Programs to create SLIM and SMALL, respectively

GRW - Program to create LARGE report

GAMMA.REVISE - See above

GAMMA.REV85 - Program that generates DATA.REV85

JCL Files

GRACE85 - Contains the entire JCL to prepare data, to generate the LP matrix, to revise, convert, and solve the LP, and to extract and publish the SLIM, SMALL, and LARGE reports for 1985

GRACE90 - Contains JCL to revise the LP matrix for the 1990 case year, to solve the LP, and to extract and publish the SLIM, SMALL, and LARGE reports for 1990

GRACE95 - Same as GRACE90 but for the 1995 case year

RAMCJCL - Contains the JCL to create GDS using the input file SUPIN; GDS is the file containing the coal supply curves

GRACE.REV - Contains the JCL to create DATA.REV85 from the GAMMA program GAMMA.REV85

Miscellaneous Files for Special Purposes

ALLOC	-	Creates space for a file whose name is used in place of "FILE"
CRPROBS	-	Creates space for Probfiles (special characteristics)
PRINTREP	-	Program to print output reports on line printer
UNCAT	-	Program to uncatalog a file
RESTORE	-	Program to restore a file that has been retired
WHIZ85	-	Program used to solve the LP if, due to some problem in the system, the LP solution fails before an optimal solution is found

CHAPTER 5. VERIFICATION OF MODEL DOCUMENTATION AND IMPLEMENTATION

This chapter collects together all the detailed information concerning verification of the CEUM, i.e., the accuracy of the computerized implementation of the model. Sections A and B provide point-by-point discussions of the errors that were discovered, and Section C displays the effects of these errors on the model results. This chapter supports the summary information in Section 3.2 of Volume I.

A. VERIFICATION OF THE CEUM SUPPLY CODE*

A discussion of errors, proposed corrections, programming improvements, questionable assumptions, and aspects for user awareness in the CEUM Supply Code (consisting of the SUPIN and RAMC files) is given below. The points discussed can roughly be broken down into the following categories:

A. Errors: Points 1, 5, 6a, 7, 8, 10, 14, 18, 19, 20, 21, 22.

B. Aspects of the code of which the user should be aware: Points 3, 4, 6b, 11, 15, 16, 17, 25, 26, 27.

C. Questionable assumptions: Points 2, 9, 12, 13.

D. Totally innocuous errors: Points 23, 24.

The most substantive errors are those discussed in points 5, 6a, 7, 8, 10, 14, 18, and 20. The reader should note that the order in which points are presented has significance only in that the material is contextually related. For the aid of the reader, points relating to errors are denoted by an asterisk. Also, the referenced line numbers, from our versions of SUPIN and RAMC, are based on the consecutive numbering of all lines (including comment lines) by tens. These line numbers may not match precisely with the line numbers appearing in other versions of the code.

*This section was prepared by Neil L. Goldman.

1.* On the first page of SUPIN, lines 15-16, global values of 0.1 are given to the parameters ISR (Illegal Surface Reserve Fraction) and IDR (Inaccessible Deep Reserve Fraction). In the RAMC code the values of ISR and IDR in SUPIN are assigned to B(21) and B(1) respectively (see RAMC, line 219). For regional use, the values of vector B are assigned to vector C (RAMC, line 352). Then, whenever there is a regional override for values of ISR and/or IDR, the new values are placed in C(1) and C(21), respectively (RAMC, lines 500-509 and 37-40). -- Note the curious interchange. -- Furthermore, the Equivalence statement on line 54 of RAMC verifies not only that the regional values of ISR and IDR (ISRR and IDRR) are in C(1) and C(2), respectively, but that the global values, ISRG and IDRG, are in B(1) and B(21), respectively. This is in direct opposition to the manner in which the parameters are first read into RAMC, as mentioned above. Note that there are no resulting errors only because the initial global values of ISR and IDR in SUPIN are equal. The simplest correction would be to interchange lines 15 and 16 of SUPIN.

2. The user should note that the total base-year values of deferred capital (not present-valued) for surface and deep mines, given on line 14 of SUPIN, are for a mine lifetime of 20 years. These values are extrapolated for shorter or longer mine lifetimes in the Mine Costing Subroutine of RAMC, lines 1574-1580. No rationale is given for the manner in which the extrapolations are made. Of particular interest is why deferred capital is assumed to be zero for mine lifetimes of 10 years or less. Also, the non-operational comment on line 1577, which assumes a maximum lifetime of 30 years, should be deleted.

3. The user should be aware that the Annuity Price Factor, APFAC, exogenously specified as 16.748 in SUPIN, line 28, is both a function of mine lifetime and the real utility discount rate.

Recall that:

$$APFAC = \sum_{i=1}^{N} 1/(1+K_u)^i = K_u^{-1} [1-(1+K_u)^{-N}] \tag{1}$$

where: $1 + K_u = (1+k_u)/(1+g)$

g = inflation rate = .055

k_u = utility's after-tax nominal cost of capital (defined as RUT in RAMC) = .10

K_u = utility's after-tax real cost of capital = .04265

N = mine lifetime

For N = 30, APFAC = 16.748.

For N = 20, APFAC = 13.276.

For N = 40, APFAC = 19.305. Etc.

After we discussed this point with Phil Childress of DOE, he internalized the calculation of APFAC in the DOE version of the CEUM. The version of the code that Michael Wagner of ICF certified for M.I.T. does not have APFAC internalized.

4. In general, the user should be aware that almost all of the global parameter values given at the beginning of the SUPIN file (see lines 15-26 and 29-32) can be overridden in regional data (e.g., see lines 48-49). It appears that the utility discount rate, RUT, and the annuity price factor, APFAC, cannot be overridden regionally because of their effect on the fixed charge rate used by utilities.

5.* In Memo O, Appendix E of ICF Inc. (July 1977), cleaning costs for bituminous coals, in dollars per clean ton, are defined as follows:

	Fixed Cost	Variable Cost
Basic Cleaning	1.14	0.56
Deep Cleaning	2.03	1.67
Total	3.17	2.23

The cleaning costs given in SUPIN and employed in RAMC should to the basic cleaning of bituminous coals. Deep cleaning costs occur in the LP (only for C and E sulfur level coals) as the objective function coefficients for the deep-cleaning variables. The cleaning costs specified in SUPIN for ZA, ZB, ZC, ZD, and ZE coals are total costs including deep-cleaning and should not include the deep-cleaning component.

We have learned that ICF believes that all metallurgical coals should be deep-cleaned and this was their reason for adding deep-cleaning charges in SUPIN, as described above. In addition to the fact that there has been no documentation of this change, it appears that there have been errors made in implementing it. On page III-108 of ICF Inc. (July 1977) it is stated that 70% of metallurgical coal is drawn from the ZA, ZB, ZC, or ZD coal types while the remaining 30% is drawn from a blend of ZF, HF, and MF coal types. By simply adding deep-cleaning charges in SUPIN for the ZA, ZB, ZC, ZD, and ZE coal types (and thereby claiming that all metallurgical is now deep-cleaned) several problems result:

- double counting of deep-cleaning costs occurs whenever a ZC or ZE coal type is deep-cleaned in the LP,
- deep-cleaning is not charged for the required percentage of ZF

coal (it is charged only for those ZE coals not deep-cleaned in the LP), and

o there is no allowance for deep-cleaning the percentage of HF and MF coals used to meet metallurgical coal demand.

It is also curious that in addition to increasing the cleaning costs for ZA through ZE coals in SUPIN, ICF has lowered the YIELD factors (both surface and deep) for ZA through ZD coals but not for ZE coals.

In our corrected version of the CEUM, we have decided to omit all exogenously imposed deep-cleaning charges for ZA through ZE coals in SUPIN, thereby allowing deep-cleaning to occur only via the LP, as was originally intended. While it may well be true that without ICF's adjustment not enough deep-cleaning of metallurgical coals occurs in the CEUM, the method that ICF chose to remedy the situation is inconsistent and incorrect, and at best represents only a crude approximate approach to modeling the deep-cleaning of all metallurgical coals. For a further discussion of this point see Volume VI, Chapter 4.

6.(a)* The factor used to escalate the average 1975 base-year price data for existing mines to the case year, 1985, is incorrect. The calculation is made on lines 360-367 of RAMC. A derivation of the correct escalator follows.

Let:

P_{1975} = given average 1975 price for an existing mine (includes a capital component)

f_L = fraction of P_{1975} relating to labor costs = .32

f_S = fraction of P_{1975} relating to supplies = .53

f_C = fraction of P_{1975} relating to capital = .15

g_L = total nominal escalation rate for labor costs = .065

g = general inflation rate = total nominal escalation rate for supplies = .055

P^*_{1975} = variable cost component of P_{1975}

$= (1-f_C)\ P_{1975} = (f_L + f_S)\ P_{1975}$

P^*_{1985} = 1985 price for an existing mine due to variable costs only

E = escalator of interest = P^*_{1985}/P_{1975}

Note that only variable costs for existing mines are subject to inflation.

It can easily be shown that:

$$P^*_{1985} = \frac{f_L}{f_L + f_S} P^*_{1975} (1+g_L)^{10} + \frac{f_S}{f_L + f_S} P^*_{1975} (1+g)^{10}$$

$$= \frac{P^*_{1975}}{f_L + f_S} [f_L(1+g_L)^{10} + f_S(1+g)^{10}] \ . \qquad (2)$$

We then have:

$$P^*_{1985}/P_{1975} = E = f_L\ (1 + g_L)^{10} + f_S(1 + g)^{10} \qquad (3)$$

With the values given above, E = 1.506. In RAMC the escalator is called ESCAL1 and is given by (see RAMC, lines 364-365):

$$\text{ESCAL1} = [1 + (f_L g_L + f_S g)]^{10} = 1.628 \qquad (4)$$

ESCAL1 is incorrect and gives a value that is too high by 8.1%.

(b) A further correction of the escalator E may be necessary. As discussed below (Point 7), it appears that base year costs for new mines are in '<u>end</u> of 1975 dollars', and the real annuity coal prices in RAMC output are in '<u>end</u> of 1984 dollars'. If the P_{1975} prices for existing mines are also in '<u>end</u> of 1975 dollars' then the exponent used in the above calculation of E should be 9 instead of 10. If the P_{1975} prices are in '<u>end</u> of 1974 dollars' or in '<u>beginning</u> of 1975 dollars', then the exponent of 10 used in calculating E is correct. We believe that the latter statement is true, so the exponent used in Equation (3) is correct.

7.* Recall the following facts from ICF Inc. (July 1977):

(a) Initial capital is inflated at the nominal capital escalation rate from the base year, 1975, to eight months before the case year, 1985.

(b) Deferred capital, labor, and power and supplies are each escalated, using the appropriate rate, to the end of the year in which the money is considered spent (i.e., all cash expenses occur at the end of the year).

It can be verified from the Mine Costing Subroutine of RAMC (lines 1635 to 1719) that if real annuity coal prices (RACP) are calculated in 'end of 1984 dollars', then base-year mine costs must be in 'end of 1975 dollars'. If the RACPs for the 1985 case-year projection are considered to be in 'early 1985 dollars' (i.e., as of 1/1/85), then the base-year mine costs must be in 'early 1976 dollars' (not in 1975 dollars). If the base-year mine costs are truly meant to be given in 'end of 1974 dollars' or in 'early 1975 dollars', then the following corrections must be made in the Mine Costing Subroutine in order to calculate the RACPs in 'end of 1984 dollars' or in 'early 1985 dollars', respectively:

(a) In lines 1641 and 1664, LL = JJ + NYR instead of LL = JJ + NYR - 1.

(b) The exponent in line 1649 should be (NYR - 2./3.) instead of (NYR - 5./3.).

(c) The exponent in line 1689 should be (NYR + 1) instead of NYR.

Note that this point is currently under active consideration by DOE personnel.

Even if we assume that base-year mine costs are indeed given in 'end of 1975 dollars', there are other errors and questionable assumptions related to the calculation of real annuity coal prices in the Mine Costing Subroutine (lines 1635-1719 of RAMC). -- See Points 8 through 21.

8.* By assuming that all initial capital is sunk (spent) at the end of April 1984, ICF is crudely approximating a stream of initial capital expenditures over time, together with the explicit use of 'interest during construction' at the nominal cost of capital for coal producers, as a means of summing these fractional expenditures. While ICF's approximation clearly simplifies the accounting of initial capital, the approximation is poor and its derivation is not documented. We believe that it is necessary to further escalate the sunk value of initial capital by eight months to the end of 1984 before it can appropriately be added to the present value of deferred capital as of 12/31/84 (for the purpose of calculating cash flow), i.e., initial capital and the present value of deferred capital must be in equivalent dollars before they can be added. For simplicity we implemented the required additional escalation using the general rate of inflation although, as seen from our formal discussion of how initial capital costs should have been treated in the CEUM (given below), the appropriate rate is the nominal cost of capital for coal producers. (Although we resolved this issue too late for the most appropriate correction to be implemented in our corrected version of the CEUM code, our approximation is more accurate than ICF's, as seen below.) Note that while both ICF and DOE personnel disagree with the need for any correction, there is no documentation or other evidence available to support the validity of their argument. A description of our implementation of the correction is as follows:

(a) After initial capital is escalated at the nominal escalation rate for capital, ECAP, to the end of April 1984 (eight months prior to the case year, 1985) and before the result is added to the present value of deferred capital as of the end of 1984 (i.e., 12/31/84), it must be escalated eight months at a rate we chose to be the general inflation rate. (Note that the appropriate rate is ROR, the nominal cost of capital for coal producers--see the formal treatment of initial capital costs given below.) A general GNP deflator is not defined in RAMC, but the cost of power and supplies escalates at the general inflation rate and its escalator, EPAS, can be used as a proxy for this rate. The correction for the escalation of initial capital can thereby be made as follows in line 1649 of RAMC:

```
Y(1,1) = IC*((1 + ECAP)**(NYR - 5./3.))*((1 + EPAS)**(2./3.))      (5)
```

The effect is a 3.6% increase in Y(1,1). Note that Y(1,JJ) has been set equal to Y(1,1), and with NYR = 10 the total number of years of escalation is 9, i.e., from the end of 1975 to the end of 1984. It can also be shown, from lines 1650-1654, that deferred capital in base-year dollars is first escalated 9 years to the end of 1984 and then the spending of deferred capital over the mine lifetime (starting at the end of 1985) is present-valued to the end of 1984, i.e., 12/31/84.

(b) Because of our change in the calculation of escalated initial capital (Equation (5) above), an adjustment is required in the calculation of the annual depreciation charge (total nominal capital costs divided by the mine lifetime). Line 1680 of RAMC should now read:

```
Y(21,JJ) = (Y(6,MYR) + (Y(1,1)/((1+EPAS)**(2./3.))))/MYR      (5a)
```

rather than

```
Y(21,JJ) = (Y(6,MYR) + Y(1,1))/MYR
```

Formal Treatment of Initial Capital Costs

Let:

g = general rate of inflation = .055

g_c = nominal escalation rate in coal mine capital costs (g_c is denoted by ECAP in the CEUM) = .060

k_p = nominal after-tax cost of capital for coal producers (k_p is denoted by ROR in the CEUM) = .150

IC_{75} = initial capital cost in base-year (beginning-1975) dollars

IC_t = initial capital spent at end of year t, in current year dollars

f_t = fraction of initial capital spent at end of year t

PV_{IC} = present value of initial capital costs in case-year dollars (as of the end of 1984)

Following the convention that all expenditures occur at the end of the year, it can easily be shown that:

$$IC_t = IC_{75} (1 + g_c)^t f_t \quad , \text{ and}$$

$$PV_{IC} = \sum_{t=1}^{10} IC_t (1 + k_p)^{10-t} = IC_{75} \sum_{t=1}^{10} (1 + g_c)^t (1 + k_p)^{10-t} f_t \ . \tag{5b}$$

We now illustrate calculations of PV_{IC} in terms of IC_{75}, using three different assumptions for the fractions f_t, and the parameter values of g_c, k_p, and g given above. The third case represents the assumption made by ICF.

(a) Assume equal initial capital expenditures in each year, i.e., f_t = .10 for t = 1, ..., 10. Using Equation (5b) we have:

$$PV_{IC} = IC_{75} (2.656) \ .$$

(b) Assume all initial capital is spent at the end of 1984, i.e., $f_t = 0$ for t = 1, ..., 9 and $f_t = 1$ for t = 10. This case results in the lowest possible value of PV_{IC}, and using Equation (5b) we have:

$$PV_{IC} = IC_{75}\ (1.7908)\ .$$

(c) Assume all initial capital is spent at the end of April 1984. This case represents the assumption made by ICF. Note that there is no documentation available to support the intent or validity of this assumption. Using the logic of Equation (5b) we have:

$$PV_{IC} = IC_{75}\ (1 + g_c)^{9+1/3}\ (1 + k_p)^{2/3} = IC_{75}\ (1.8908)\ .$$

The expression used by ICF is a poor approximation given by:

$$PV_{IC} = IC_{75}\ (1 + g_c)^{9+1/3} = IC_{75}\ (1.7226)\ .$$

The correction implemented by M.I.T. is given by:

$$PV_{IC} = IC_{75}\ (1 + g_c)^{9+1/3}\ (1 + g)^{2/3} = IC_{75}\ (1.7852)\ .$$

While our multiplier understates the true value by 5.6%, ICF's multiplier understates it by 8.9%. To implement the appropriate multiplier in the CEUM code, EPAS should be replaced by ROR in Equations (5) and (5a) given above.

Finally, it should be noted that the overall effect on CEUM output of the correction discussed in this point is small.

9. There is a question concerning the way in which two factors entering into the calculation of operating costs in the base year are escalated over time. The two factors are Royalty fees and Licensing fees, each specified on a dollar-per-clean-ton basis. They are both escalated over the mine lifetime using the nominal escalation rate for capital, ECAP (see lines 1672-1673). Why aren't these factors simply escalated at the general inflation rate (using EPAS as a proxy)? While the intent could well have been to have these factors escalate somewhat faster than inflation (i.e., at a rate equal to ECAP), no justification is given.

It should be noted that a Licensing fee of $.10 per clean ton is charged in all regions and that all Royalty fees in the data base have been set to zero. Federal Royalties, applying to coal mined on Federal Lands, have now been included and are treated, like regional Severance Tax Rates, as a percentage charge on sales. The Royalty charge is 12.5% for surface coal and 8% for deep coal; it occurs only in the following regions: North Dakota, Eastern and Western Montana, Wyoming, Colorado South, Colorado North, and New Mexico.

The full Federal Royalty is applied to all coal from these regions even though, as stated in Memo N, Appendix E of ICF, Inc. (July 1977), less than 100% of the coal-bearing land is Federally owned. ICF's argument is that Federal reserves are such a large percentage of the total that they will set the price. This may be true for all the relevant regions except North Dakota, where only 25% of the reserves are Federally owned. In the other regions more than 50% of the coal lands are Federal.

10.* Property Taxes and Insurance, another factor entering into the calculation of operating costs, has been escalated incorrectly over the mine lifetime. Assuming that this factor, calculated as a percentage of initial capital costs, escalates with the nominal capital escalation rate, line 1676 of RAMC should read:

```
Y(20,JJ) = .02*(Y(1,1)/((1+EPAS)**(2./3.)))*(1+ECAP)**(JJ+2./3.)   (6)
```

rather than

```
Y(20,JJ) = .02*Y(1,JJ)*(1+ECAP)**LL                                (7)
```

Note that the correction for Y(1,JJ) should be made as noted in Equation (5) (see Point 8) and that JJ = 1,2,...,MYR and LL = JJ+9, where

MYR = Mine Lifetime. The effect of the correction is a 38.5% decrease in the taxes and insurance charge for each year of the mine lifetime. Note that if Equation (7) is incorrectly used, there effectively will be a double counting of the number of years between the base year and the case year. (Referring to the discussion at the end of Point 8: we have become convinced that the most appropriate correction to Equation (7), which we ultimately formulated too late to be implemented in our corrected version of the CEUM code, is given by Equation (6) with EPAS replaced by ROR; however, the expression used in Equation (6) above gives results much closer to the appropriate values of Y(20,JJ) than does Equation (7) used by ICF.)

There is also a question concerning the rationale for using the capital escalation rate for property taxes and insurance. One argument, at least concerning insurance, is that the expenses incurred over the mine lifetime should cover the mine's replacement value.

11. The fixed (capital) components of both Reclamation and Cleaning Costs, escalated from the base year to the end of 1985, are added (in addition to the variable components) to operating costs in every year of a mine's lifetime (see lines 1689-1690 of RAMC). Apparently, this implies that the fixed charges must have been pre-annualized over mine lifetime and have been calculated, or are assumed, to be constant in nominal terms (constant in current dollars per clean ton per year) <u>starting</u> at the end of 1985. Such a procedure used to arrive at these data inputs has not been documented.

12. For each region in which Severance Taxes are non-zero, either a Severance Tax Rate (SEVTR) as a percentage of sales or a Severance Tax in base-year dollars per clean ton (SEVT$) is charged. The user should be aware that the RAMC code does not allow for the escalation of SEVT$ in the calculation of sales for each year of a mine's lifetime. It thereby assumes that SEVT$ is constant in nominal terms. If we were to assume that SEVT$ escalates at the general inflation rate (i.e., SEVT$ constant in real terms), then we would again use EPAS as a proxy for this rate, and replace SEVT$ by SEVT$*(1+EPAS)**LL in lines 1696, 1698, 1701, and 1702. Note that if SEVTR is used, the tax escalates with sales over time. Clearly, the allowance for a severance tax charge remaining constant in nominal terms could well have been intentional.

13. It should be noted that insurance charges for Black Lung Disease in base-year dollars per clean ton are assumed <u>constant</u> in nominal terms (i.e., are not escalated over time). See line 1691 of RAMC. It appears that Federal law does not provide for escalation of these charges.

There is also another add-on charge, AMR, given in base-year dollars per clean ton and assumed <u>constant</u> in nominal terms (see line 1691). This charge, defined in ICF, Inc. (June 1978), is an abandoned mine reclamation tax mandated by Federal law.

14.* For both deep mines and surface mines, there is a question concerning the units of the input measure of tons per man-day (TPMD). Are they given in raw tons or in clean tons? If, as we strongly suspect, they are meant to be given in raw tons per man-day, then the calculation of base-year Union Welfare Costs has incorrectly used the YIELD factor. Line 1592 of RAMC should read:

$$B(16,KK) = 1000.*SZ*(WEL*YIELD + WPD/TPMD) \quad (8)$$

rather than

$$B(16,KK) = 1000.*SZ*(WEL + WPD/TPMD)*YIELD \quad (9)$$

If the data inputs for TPMD are given in clean tons per man-day, then:

(a) in the equations for the associated cost adjustment factors (lines 1561 and 1796, for surface and deep mines, respectively) mine size, SZ, must be multiplied by the YIELD factor; and

(b) in the equations calculating base-year labor costs (lines 1562 and 1799, for surface and deep mines, respectively) SZ must be multiplied by the YIELD factor.

Furthermore, although never stated in the code, the data inputs for reclamation costs, cleaning costs, royalty fees, licensing fees, and the union welfare costs per ton, must all be given in base-year dollars per clean ton according to their use in the Mine Costing Subroutine.

15. A Dimension statement in the Mine Costing Subroutine (line 1419 of RAMC) assumes a maximum mine lifetime of 30 years by dimensioning Y(23,30) and DCFRAC(30). The Y matrix contains cost factors for each year of a mine's lifetime and DCFRAC is a vector defining fractions of deferred capital to be spent over the lifetime of each mine. Clearly, if mine lifetimes greater then 30 years are to be considered, the Dimension statement must be changed.

16. A confusing aspect of the Mine Costing Subroutine is that in parts it relates to the code used for the old PIES Coal Supply Analysis, with calculations of minimum acceptable selling prices (MASP) for only the first year of mines. Although never stated, it should be made clear that these prices (case-year MASP in base-year dollars, not annuitized over mine lifetime--see line 1629 of RAMC) are calculated under the assumptions of no inflation and no real escalation, and thereby the code must incorrectly assume that the coal producer's discount rate, ROR, is given in real terms. An example of this confusion is the use of the present value factor PVFAC (calculated in Subroutine PRVAL for use in Subroutine MC) for the present-valuing of deferred capital. The calculation of PVFAC ignores inflation, real capital escalation, and uses the nominal discount rate, ROR. Clearly, in an older version of the code, ROR was real and calculations were in constant dollars with no real escalation.

Now, to be fair, PVFAC and the MASP are never used in the calculation of the real annuity coal prices (RACP) for each mine type. However, their unexplained presence in the code is misleading and can only lead to confusion. Such code should be omitted.

17. There are still other portions of the RAMC code (not only in the Mine Costing Subroutine) that appear to relate either to old PIES calculations or to early versions of the supply component of the CEUM.

A prime example is the calculation and use of two factors, COEF1 and COEF2. These factors are calculated early in the main program of RAMC as follows:

$$COEF1 = (1+ECAP)**(10./2.), \text{ and} \tag{10}$$

$$COEF2 = (10./40.)*((1+ECAP)**(10./4.)) \tag{11}$$

COEF1 and COEF2 next appear at the end of the Mine Costing Subroutine after the calculations of the real annuity coal prices (RACP). They are suddenly used, in the creation of output, as escalators for the base-year values of initial and deferred capital divided by the annual output for each mine type (see RAMC, lines 1870 and 1893). The resulting values of SCAP and DCAP, for surface-mine and deep-mine types, respectively, appear in the RAMC output under column CAPL.

The first escalator, COEF1, appears to relate to an old definition of the point at which initial capital is assumed sunk (an updated definition is now used in the calculation of the RACP--see Point 8 above). There is no reasonable explanation of the second escalator.

At any rate, the output appearing under the column CAPL has an unclear meaning, is misleading, has no direct relationship to the production and price (RACP) output, and should be deleted.

18.* At the beginning of the calculations of real annuity coal prices for deep mines, the smallest seam thickness measure is suddenly changed from 28 to 24 inches (see line 1771 of RAMC) Recalling that coal reserves are allocated to seam thickness categories beginning at 28 inches, there can be no justification for this change. Interestingly, the RAMC output continues to display 28 instead of 24 inches as the smallest seam thickness measure used in pricing coal from deep mines (see line 1782 of RAMC). This is misleading. The simplest resolution of this problem is to delete line 1771 of RAMC.

19.* An error has been made in the Mine Costing Subroutine of RAMC by not declaring the variable LAB (1975 labor cost in thousands of dollars per year) as REAL. The default declaration on variable names beginning with I, J, K, L, M, or N is INTEGER. Thus, the fractional component of the labor cost for each mine is inadvertently dropped.

20.* In Subroutine PRVAL of RAMC, the fractions of deferred capital to be spent over a mine's lifetime are calculated and stored in vector DCFRAC. This vector is an important factor in the calculation of Cash Flow and Depreciation within the Mine Costing Subroutine. If careful attention is given to the allocation scheme used to create DCFRAC in Subroutine PRVAL, it can be shown that due to truncations with integer variables when the mine lifetime, MYR, is not perfectly divisible by four, more than 100% of deferred capital is allocated over the life of the mine. (The error is largest when MYR divided by four has a remainder of three, e.g., when MYR = 35.) An amended version of the allocation scheme that remedies this situation is as follows:

After line 1957 of RAMC, in Subroutine PRVAL, insert:

```
     IF ((MYR-(M75+M99)) .NE. 2) GO TO 120
     M50 = M50+1
     M75 = M75+1
     GO TO 130
120  IF ((MYR-(M75+M99)) .NE. 3) GO TO 130
     M25 = M25+1
     M75 = M75+1
     M99 = M99+1
130 CONTINUE
```

21.* In Memo I, Appendix E of ICF, Inc. (July 1977), the calculation of two separate UMW Welfare Costs, one in 1975 dollars per clean ton and the other in 1975 dollars per man-day, for both surface and deep mines, is discussed. The Welfare Cost in dollars per man-day is determined to be $1.37 per hour or $10.96 per man-day. This data input, for both surface and deep mines, is correctly displayed on line 25 of SUPIN. Unfortunately, the main program of RAMC reads in values of $10.90 per man-day for this Welfare Cost (for both surface and deep mines) because of an error in the associated FORMAT statement, number 8010, on line 1013 of RAMC. A FORMAT of F4.2 is used instead of F5.2. Line 1013 of RAMC should read:

T30,F4.2,2(/,T23,F5.2,T50,F5.2),/,T15,F4.2,/,T27,F6.3,

rather than

T30,F4.2,2(/,T23,F4.2,T50,F4.2),/,T15,F4.2,/,T27,F6.3,

We note that the Welfare cost in dollars per man-day, denoted as WPD in the Mine Costing Subroutine, enters into the calculation of each mine's Operating Cost via lines 1592 and 1671 of RAMC.

It should also be noted that other variables, such as Mine Lifetime, Base Year, and Case Year, are displayed as floating point variables in SUPIN but are read into RAMC as integers. This would only result in errors if fractional values of these variables were specified in SUPIN.

22.* The variable reclamation cost, in base-year dollars per clean ton, for an overburden ratio of 15 in region OK (Oklahoma), is given on line 1308 of SUPIN as 0.30. This value is lower than the values 0.42 and 0.46 given for overburden ratios of 5 and 10, respectively. Since in every other supply region both fixed and variable reclamation costs increase with overburden ratio, this entry is suspicious and could well have been meant to be 0.50, given the value of 0.52 for an overburden ratio of 20 that follows it.

23. The value of YTD (deep-coal yield in clean tons per raw ton) for ZD coal in region OK (Oklahoma) should most likely be 0.60 instead of 0.70, as given in line 1356 of SUPIN. In every other supply region the value of YTD for ZD coal is given as 0.60. This possible data error has no effect since there are no deep ZD reserves in region OK.

24. There is a minor error in initializing the regional overburden ratio distribution vector on line 337 of RAMC. The Do Loop on I should be from 1 to 7 instead of 1 to 4. This error is innocuous.

25. The user should note that the RAMC code on lines 355-359, creating a distribution over deep-mine size given seam thickness and seam depth, is completely overridden by the code on lines 456-469.

26. Since the counter IK must equal 4 at line 947 of RAMC (see lines 750-752), lines 947-963 of the code can be omitted.

27. The user should be aware that the RAMC supply curve output for coal type UTHB (Utah Bituminous Low-Sulfur Coal) is exogenously overridden in the GAMMA REVISE file of the CEUM computer code. The override exogenously resets the production level (supply curve step width) of each new mine type (defined by a particular combination of physical variables) on the UTHB supply curve at twice the value computed

by RAMC. Note that the override refers only to the number of the supply curve step and not to the particular mine type asssociated with the step. The undocumented reason for this 'patch' seems to be that the LP is infeasible without it.

An important consequence is that whenever a sensitivity analysis run of the CEUM is attempted that requires changes in the Supply Code and therefore, regeneration of all supply curves, the full-model (as opposed to RAMC) supply curve output for UTHB coal will most likely be incorrect and should be ignored. The only situation in which no error occurs--an example is our Corrected Base Case (CBC) model run (see Section C below)--would be one in which the number, order, and production levels of the UTHB mine types recomputed by RAMC remain identical to those computed by RAMC in the Base Case or Corrected Base Case. This is unlikely.

Three possible error-producing situations regarding UTHB coal can arise when full-model sensitivity runs involving changes in the Supply Code are attempted.

(a) The number of supply steps generated by RAMC for UTHB coal in the sensitivity run remains the same as in the Base Case (or CBC). If this occurs but the mine-type order and the associated production levels change, then the 'patch' will reset production levels at values equal to twice the Base Case (or CBC) production levels but not equal to twice the new values.

(b) The number of supply steps generated by RAMC for UTHB coal in the sensitivity run is fewer than in the Base Case (or CBC). If this occurs, the model will not run because the 'patch' will try to reset production levels of supply steps that do not exist. Once the relevant supply steps are deleted from the 'patch', the model will run but the basic problem referred to in (a) remains.

(c) The number of supply steps generated by RAMC for UTHB coal in the sensitivity run is greater than in the Base Case (or CBC). If this occurs, the 'patch' will not reset the production levels of the additional mine types generated in the sensitivity run, and as described in (a) it will also incorrectly reset those production levels in the Base Case (or CBC) that have now changed.

In summary, the UTHB supply curve should be considered invalid for CEUM sensitivity runs involving regeneration of supply curves via changes in the Supply Code.

B. VERIFICATION OF NON-SUPPLY COMPONENTS OF THE CEUM*

This section presents a list of undocumented aspects of non-supply oriented components of the CEUM of which the user should be aware and documented aspects of those parts of the model that have either not been implemented or have been implemented incorrectly by ICF.** The reader should note that the order in which the points are presented has no particular significance.

1. We have learned, via communications with ICF personnel, that a most important but undocumented aspect of the CEUM is that real escalation of cost factors is not appropriately accounted for (with one exception) in the 1990 and 1995 case-year model runs. The real annuity coal prices calculated in RAMC in 1985 dollars for 1985 case-year model runs (see Section A above and Volume IV, Chapter 1), and later deflated to 1978 dollars for use in the LP, are used without change in the 1990 and 1995 case-year model runs. This means that the coal-type supply curves generated in RAMC for 1985 model runs are not regenerated for 1990 and 1995 model runs. The only adjustments relate to depletion of resources for existing (as of 1975) mines. It should be noted that in the calculation of the RACPs for 1985 model runs, real escalation in capital and labor costs is employed over the life of mines beginning in 1985. For the 1990 and 1995 case-year model runs, 5 years and 10 years of real escalation are omitted, respectively, prior to mine openings. Therefore, the 1990 and 1995 model runs use cost estimates appropriate only for mines opening in 1985.

*This section was prepared by Neil L. Goldman.

**Note that points 1 and 2 in this section concern the entire CEUM and not just the non-supply oriented components of the model.

On the utility side, utility capital costs escalate in real terms only until 1985 (see Point 3 below). The one exception referred to above concerns real rail-rate escalation. A real escalation factor is employed over the entire model horizon but not as a constant percentage per year independent of the case year and not in a manner implied in the documentation (see Point 4 below).

2. In Memo J, Appendix E of ICF, Inc. (July 1977), it is implied that in future applications the model will use a general inflation rate of 6%/yr, replacing the original rate of 5.5%/yr. Upon examination of the CEUM computer code it can be shown that this change has never been implemented and for all applications to date the CEUM has continued to use 5.5%/yr as the general rate of inflation.

3. On page 51 of ICF, Inc. (September 1978a), it is stated that utility capital costs escalate at 7.5%/yr through 1985 and at 6.0%/yr thereafter. This statement is not entirely correct. In the CEUM case study applications (see ICF, Inc. [June 1978, September 1978a, September 1978b, January 1979], utility capital costs escalate at 7.5%/yr until 1985 and at the general rate of inflation, 5.5%/yr, thereafter.

4. The version of the CEUM existing as of September 1, 1978 and as applied in ICF's third case study, prepared for EPA and DOE (see ICF, Inc. [September 1978b]), claims to incorporate a real rail-rate escalation factor of 1%/yr over each year of the 1975-95 time horizon of the model. If implemented correctly, transportation costs, after being inflated appropriately from 1975 to 1978 dollars, would be multiplied by:

$(1.01)^{10}$ for a 1985 model run,

$(1.01)^{15}$ for a 1990 model run, and

$(1.01)^{20}$ for a 1995 model run.

Upon examination of the CEUM computer code it can be shown that what the model actually does is apply a transportation multiplier (TCMLT) of $(1.01)^{20} = 1.22019$ for all case-year model runs. The implicit effect of such an implementation is that real rail rates escalate at approximately 2%/yr from 1975-85 for a 1985 model run, 1.34%/yr from 1975-90 for a 1990 model run, and 1%/yr from 1975-95 for a 1995 model run.

5. (a) All costs appearing in the LP objective function are in 1978 dollars. In particular, the objective function coefficients of the build activity variables are case-year annualized utility capital costs in 1978 dollars per KW-year (or 10^6\$/GW-yr), taking into account real capital escalation. The CEUM calculates these costs by first converting exogenously specified 1975 (base-year) utility capital costs in 1975 dollars to case-year costs in 1978 dollars, as follows:

Let:

Case Year = 1985

$CAP_{78\$}(85)$ = 1985 utility capital cost in 1978 dollars per KW

$CAP_{75\$}(75)$ = 1975 utility capital cost in 1975 dollars per KW (exogenously specified)

g_{uc} = total (nominal) capital escalation rate for utilities (including inflation)

g = general rate of inflation.

We then have:

$$CAP_{78\$}(85) = \frac{(1 + g_{uc})^{10}}{(1 + g)^{7}} \; CAP_{75\$}(75)$$

Note that both the 1990 and 1995 case-year utility capital costs in 1978 dollars per KW are also given by $CAP_{78\$}(85)$ since utility capital costs escalate at the general rate of inflation after 1985 (see Point 3 above).

The case-year costs in 1978 dollars are annualized by multiplying by a real fixed charge rate (FCR). The model uses a real FCR of 10%, except in Eastern and Western Tennessee where a value of 5% is used.

Applying the CEUM values of g_{uc} = .075 and g = .055, the annualized utility capital costs are given by:

$$\overline{CAP_{78\$}(85)} = (1.4168)(FCR)\ CAP_{75\$}(75)$$

$$= (0.14168) CAP_{75\$}(75) \text{ , outside Tennessee}$$

$$= (0.07084) CAP_{75\$}(75) \text{ , in Tennessee .}$$

(b) It has been learned via personal communications with ICF personnel that before plant capital costs are annualized there is a $50/KW add-on charge for hooking up the new plant to the existing local utility grid, i.e., for intermediate or intraregional transmission. Long-distance capital charges for new interregional transmission lines are treated separately.

6. The user should be aware that nuclear plant capacities are exogenously set, by utility region, in both 1985 and 1990. In 1995 the exogenous specification is derived differently. A national nuclear capacity is exogenously set and regional capacities are determined by multiplying each 1990 regional capacity by the ratio of the national 1995 capacity to the national 1990 capacity (the latter value being the sum of the 1990 regional capacities).

One of ICF's apparent reasons for fixing, rather than upper bounding, nuclear capacity is that nuclear plants have lower unit costs than coal plants in almost all utility regions. If nuclear capacity were treated as upper bounded rather than fixed, then examples of extreme "knife-edge" optimization could result if the unit costs of nuclear plants were increased. Other reasons for fixing nuclear capacity include very long construction lead times and political considerations.

7. All hydroelectric costs, both capital and O&M, are excluded in the CEUM except for new pumped storage O&M. The associated activity variables for building hydroelectric plants and operating existing hydroelectric plants thereby have zero cost. It has been learned via personal communications that ICF's justification for excluding these hydroelectric costs is that the costs are relatively small (they would just appear as add-on costs in the objective function) and that all the available capacity will be locked into the model solution. However, upon examination of the model output it can be observed that new hydroelectric capacity is upper bounded, not fixed as with nuclear, and that several utility regions have unused free hydroelectric capacity. Furthermore, in the Montana utility region, new oil/gas turbine capacity is built at a non-zero cost to meet daily peaking demands while free hydroelectric capacity is unused. This is quite strange. Either the LP has not reached a true optimal solution as is claimed or there are undocumented constraints that prevent utilization of Montana's hydroelectric capacity.

8. Distribution costs for the electricity distribution activity variables by utility region are also ignored by the CEUM. The apparent undocumented justification for this omission is that demands for electricity are fixed and distribution costs would be just an add-on to the objective function. Strangely, distribution costs suddenly appear in the CEUM's model output (Table 4 of the CEUM's Small Report) with no explanation of how they are calculated. We have learned via personal communications with ICF personnel that an add-on distribution charge of $500/KW is used and annualized appropriately by region. From our examination of many model runs, it can be observed that nationally these distribution costs can be between 10 and 15% of total annual utility costs and can vary as much as 30% between runs. Thus it appears that such costs should be included in the objective function coefficients of the electricity distribution activity variables of the LP, rather than being added in an exogenous ex-post fashion at the report-writing stage.

9. The CEUM can set exogenous building limits on coal plant capacity by utility region individually for new NSPS bituminous, subbituminous, and lignite plants and for new ANSPS bituminous, subbituminous, and lignite plants. These build limits are treated as upper-bound constraints on the associated build activity variables in the LP. At the same time there can be joint upper-bound constraints on total (bituminous + subbituminous + lignite) new NSPS and total new ANSPS coal plant capacity by utility region. It should be noted that the joint upper bounds are not always consistent with the sum of the individual limits (when they all exist) on bituminous, subbituminous, and lignite plant capacity. For regions in

which all individual coal plant type build limits are set (for either NSPS or ANSPS plants), there are instances in which the associated joint upper bound is greater than the sum of the individual bounds. This causes no problems so long as it is understood that the sum of the individual limits is the binding constraint. Unfortunately, in Table 8 of the CEUM's Large Report, the total new coal build limits displayed, for the cases of interest, are the sums of the NSPS and the ANSPS joint upper bounds rather than the sums of the individual limits. This can be quite misleading in that the table will show extra unused capacity that could never exist under the given constraints. Furthermore, the user should be aware that in Table 8 of the CEUM's Large Report for case years 1990 and 1995 the build limits displayed are those for case year 1985 and have not been updated appropriately. This is the reason for the frequent appearance of negative unused capacity figures in this table for 1990 and 1995 model runs.

10. Recall from Point 5 that the case year utility capital costs (in base year dollars) take account of the <u>full</u> modeling period's real capital escalation above and beyond inflation. These <u>case year</u> costs are used for making <u>all</u> the base year to case year build decisions. This has the effect of strongly exaggerating impacts of the real escalation rate. A more appropriate approach might be to simulate an averaged effect of accumulated escalation over the modeling period, which could be approximated by reducing by about one-half the real escalation rate imposed.

11. We have learned via communications with ICF personnel that whenever the appropriate partial scrubbing fraction (percentage of the flue-gas scrubbed) is greater than 0.8 but less than 1.0, the model fully scrubs rather than partially scrubs the associated coal. The apparent undocumented justification for this procedure is that the magnitude of the cost savings associated with partially scrubbing such coals is small. ICF has no calculations available to support this claim. For a full discussion of this point, see Chapter 3, Section D above.

C. BASE CASE vs. CORRECTED BASE CASE*

The Base Case version of the CEUM that we have used in our assessment has been certified by ICF as the valid September 1, 1978 version of the model. The Base Case employs a particular alternative new source performance standard (ANSPS), one of several analyzed by ICF, defined by a floor and a ceiling on SO_2 emissions of 0.5 and 1.2 lbs $SO_2/10^6$ BTU, respectively. Recall that with any of the ANSPS coal plants, scrubbers are mandatory and 85% sulfur removal (on a daily average basis) down to the specified floor is required. Under the current new source performance standard (NSPS), scrubbers are not mandatory and a minimum emission level of 1.2 lbs $SO_2/10^6$ BTU is required. If scrubbers are employed with a NSPS coal plant, a 90% efficiency on an average annual basis is used.

A Corrected Base Case has been created by implementing many of the corrections to the CEUM Supply Code discussed in Section A above. (The specific corrections implemented are those relating to Points 1, 5, 6a, 7, 8, 10, 14, 15, 18, 19, 20, 21, 22, 23, and 24 in Section A above). The effects of these corrections on the coal supply cost function are discussed in Volume IV, Chapter 1. This volume discusses and illustrates the effects of the corrections on the complete CEUM, and on the Supply Code alone.

In the tabular results presented below, the case-year model runs with the uncorrected and corrected Base Case are denoted by BC and CBC, respectively. The uncorrected model under the NSPS has only been run for 1985, and this run is denoted by NSPS. The corrected version of the NSPS model run is denoted by CNSPS. Another set of uncorrected and corrected model runs, from which the effects of corrections can be examined, have

* This section was prepared by Neil L. Goldman, with computer support provided by Vijaya Chandru, Michael Manove, and James Gruhl.

electricity and non-utility coal demands decreased by 10%. These runs are denoted by EDMD and CEDMD, respectively. A sensitivity analysis discussion concerning CEDMD is given in Volumes VI and VII..

Important model outputs for the uncorrected and corrected versions of BC, NSPS, and EDMD are displayed in Tables 1 to 13 at the end of this section. Percentage changes due to the corrections appear in parenthesis in each table.

Some of the more interesting and significant effects of the corrections are:

- Except for CBC-1985 there is a general increase in the amount of Western coal (in ton-miles) transported East (see Table 3).
- In CNSPS-1985: There is a 13% increase in ton-miles of Western coal transported East. This change is mostly the result of an increase in sub-bituminous coal shipments from Western Montana to Western Kentucky and a shift of bituminous coal shipments from Wyoming to Alabama/Mississippi instead of from Wyoming to Western Kentucky (see Table 3).
- In CBC-1995: There is a 30% increase in ton-miles of Western coal transported East. This change is mostly due to large increases in sub-bituminous coal shipments from Western Montana to Michigan and in bituminous coal shipments from Wyoming to Western Kentucky (see Table 3).
- In CEDMD-1985: There is an 18% increase in ton-miles of Western coal transported East. This change is mostly due to increases in sub-bituminous coal shipments from Western Montana to Western Kentucky (see Table 3).

- o In CBC-1990: There is a 13% increase in ton-miles of Eastern coal transported West. This change is mostly due to increases in bituminous coal shipments from Illinois to Iowa (see Table 4).
- o In CEDMD-1990: There is a 22% increase in ton-miles of Eastern coal transported West. This change is mostly due to increases in bituminous coal shipments from Illinois to North Dakota/ Minnesota (see Table 4).
- o In CBC-1995: There is a 18% increase in KWH of transmission over new lines. This change is the result of large increases in transmission from Georgia/North Florida to South Florida and from Iowa to Illinois (see Table 5).
- o There is a general increase in surface coal production (a high of 5% in CBC-1995) and a general decrease in deep coal production (a high of 4% in CBC-1995) for all case years. There are small decreases in total coal production in both 1985 and 1990, and small increases in 1995 (see Tables 6 to 8).
- o There is a consistent average coal production price increase of between 2 and 4% (see Table 9).
- o There is a consistent average coal consumption price increase of between 2 and 3%, except for CEDMD-1985 where there is no change (see Table 10).
- o There is a general increase in electric utility oil/gas consumption, except for CEDMD-1995 (see Table 12).
- o Total electric utility capacity (existing plus new) stays approximately constant. Generally, there is a transfer of new coal capacity to existing oil/gas turbine or steam capacity (see Table 13).

- o There are small changes of less than 1% in the LP objective function value (decreases in 1985 and increases in both 1990 and 1995) (see Table 1).

Even more specifically, note the following three effects:

- o Concerning Western coal transported East in 1985, the CNSPS value is greater than the CBC value, while the value for NSPS is less than that for BC (see Table 3). Note the reversal in the effects of the policy variable change.
- o Concerning transmission over new lines in 1990, the CEDMD value is greater than the CBC value, while the value for EDMD is less than for the BC (see Table 5). Note the reversal in the effects of the EDMD pertubation.
- o Concerning deep-coal production in 1985, the CNSPS value is less than the CBC value, while the value for NSPS is greater than that for BC (see Table 6). Note the reversal in the effects of the policy variable change.

Tables 14 to 16 display the aggregate regional and national results of applying a Deviation Index (see Volume VII, Chapter 1) to comparisons of coal Supply Equilibria in BC and CBC for 1985, 1990, and 1995. The absolute percentage deviations in quantities and prices are quite significant. In 1985 the average absolute change in the quantity of coal produced over all coal types and supply regions is 4.4% (5.1% in 1990, 6.1% in 1995), and the corresponding average absolute price change is 2.8% (3.5% in 1990, 3.4% in 1995). In 9 of the 30 coal supply regions, the average absolute change in the quantity of coal produced in 1985 exceeded 5%, and in 7 regions the average absolute change in price in 1985 exceeded 4%. The regional deviations were even more dramatic in the 1990 and 1995 case-year model runs.

The Deviation Index was also used to illustrate the effect of corrections solely on the 1985 RAMC supply curve output. Here, a demand elasticity assumption was required in order to calculate market equilibrium quantities and prices. Tables 17 and 18 display results for a very inelastic and a very elastic demand elasticity, respectively.

Tables 19 to 21 are Summary Build tables that cover a few of the interesting aspects of the in-depth investigation of the CEUM Utility Sector. Table 19 shows some relatively substantial changes in the build activities, across all plant types, from the Base Case to the Corrected Base Case version of the CEUM. Note that there is a consistent net effect of decreases in build activities and that this effect is magnified as the horizon year moves from 1985 to 1995, as seen in Table 20. There is also a persistent shift from Bituminous to Sub-bituminous Coal plants, which shows the regional activity to be rather volatile at the margin. The extent of this regional activity can more easily be seen by examining the percentage changes given in Table 21. Many plant types experience changes in capacity of more than 100% by region due to the verification corrections, while the net effect over the nation of these capacity changes is only on the order of 10% for any plant type. For the total national capacity, the composite build change for all plant types is close to 1%, showing the masking effects of aggregated numbers.

The effect of the corrections on the amount of scrubbers is a quite persistent decrease. As measured in equivalent gigawatts served, the scrubber build activities can also change by more than 100% in some regions. The large decrease in scrubbers by 1995, shown in Table 21, is offset by a 30% increase in the use of low-sulfur western coal in eastern markets.

Table 1. LP Objective Function (10^6 \$ - 1978)

	1985	1990	1995
BC	74102.66	103725.18	138847.45
CBC	74062.08 (-.05%)	104366.27 (+.62%)	140080.62 (+.89%)
NSPS	73807.36		
CNSPS	73755.00 (-.07%)	102419.82	136815.48
EDMD	62335.02	88639.84	120099.70
CEDMD	62221.03 (-.18%)	89112.18 (+.53%)	121098.88 (+.83%)

Table 2. Coal Transportation (10^9 Ton-Miles)

	1985	1990	1995
BC	560.49	889.41	1145.50
CBC	556.88 (-.64%)	885.28 (-.46%)	1208.41 (+5.5%)
NSPS	564.16		
CNSPS	574.44 (+1.8%)	971.17	1289.30
EDMD	495.98	768.16	1004.45
CEDMD	499.16 (+.64%)	769.30 (+.15%)	1031.69 (+2.7%)

Table 3. Western Coal to Eastern Destinations (10^9 Ton-Miles)

	1985	1990	1995
BC	102.11	150.23	167.69
CBC	97.71 (-4.3%)	151.60 (+.91%)	218.17 (+30.1%)
NSPS	101.79		
CNSPS	114.66 (+12.6%)	229.00	333.33
EDMD	81.22	130.02	167.48
CEDMD	85.52 (+5.3%)	134.36 (+3.3%)	197.10 (+17.7%)

Table 4. Eastern Coal to Western Destinations (10^9 Ton -Miles)

	1985	1990	1995
BC	3.34	2.72	3.05
CBC	3.23 (-3.3%)	3.08 (+13.2%)	2.86 (-6.2%)
NSPS	2.91		
CNSPS	2.67 (-8.2%)	3.50	2.65
EDMD	4.02	3.29	2.55
CEDMD	4.26 (+6.0%)	4.00 (+21.6%)	2.47 (-3.1%)

Table 5. Transmission Over New Lines (10^9 KWH, before losses)

	1985	1990	1995
BC	196.42	168.92	149.56
CBC	197.29 (+.44%)	167.31 (-.95%)	176.02 (+17.7%)
NSPS	188.90		
CNSPS	186.45 (-1.3%)	156.82	196.06
EDMD	153.54	166.86	145.86
CEDMD	152.32 (-.79%)	173.13 (+3.8%)	150.56 (+3.2%)

Table 6. National Coal Production in 1985 (MM Tons)

	Surface	Deep	Total
BC	598.94	518.44	1117.38
CBC	599.68 (+.12%)	515.37 (-.59%)	1115.05 (-.21%)
NSPS	600.59	520.30	1120.89
CNSPS	612.28 (+1.9%)	508.21 (-2.3%)	1120.49 (-.04%)
EDMD	558.39	452.86	1011.25
CEDMD	561.25 (+.51%)	447.75 (-1.1%)	1009.00 (-.22%)

Table 7. National Coal Production in 1990 (MM Tons)

	Surface	Deep	Total
BC	776.73	736.87	1513.60
CBC	779.49 (+.35%)	725.58 (-1.5%)	1505.07 (-.56%)
NSPS			
CNSPS	829.98	694.61	1524.59
EDMD	685.21	627.45	1312.66
CEDMD	690.92 (+.83%)	620.23 (-1.2%)	1311.15 (-.12%)

Table 8. National Coal Production in 1995 (MM Tons)

	Surface	Deep	Total
BC	913.39	948.54	1861.93
CBC	962.60 (+5.4%)	912.97 (-3.9%)	1875.57 (+.73%)
NSPS			
CNSPS	1005.44	871.93	1877.37
EDMD	801.83	804.10	1605.93
CEDMD	825.52 (+3.0%)	787.01 (-2.1%)	1612.53 (+.41%)

Table 9. Average Coal Production Price (1978 $/MM BTU)

	1985	1990	1995
BC	1.07	1.10	1.15
CBC	1.10 (+2.8%)	1.14 (+3.6%)	1.18 (+2.6%)
NSPS	1.07		
CNSPS	1.10 (+2.8%)	1.14	1.23
EDMD	1.04	1.08	1.12
CEDMD	1.08 (+3.8%)	1.11 (+2.8%)	1.14 (+1.8%)

Table 10. Average Coal Consumption Price (1978 $/MM BTU)

	1985	1990	1995
BC	1.40	1.51	1.58
CBC	1.44 (+2.9%)	1.55 (+2.6%)	1.62 (+2.5%)
NSPS	1.41		
CNSPS	1.45 (+2.8%)	1.59	1.70
EDMD	1.36	1.49	1.55
CEDMD	1.40 (2.9%)	1.52 (+2.0%)	1.58 (+1.9%)

Table 11. Electric Utility Coal Consumption (MM Tons)

	1985	1990	1995
BC	755.3	1002.7	1266.0
CBC	753.4 (-.25%)	995.4 (-.73%)	1280.8 (+1.2%)
NSPS	757.5		
CNSPS	757.8 (+.04%)	1013.2	1268.6
EDMD	684.7	856.0	1072.0
CEDMD	684.8 (+.01%)	855.4 (-.07%)	1078.7 (+.63%)

Table 12. Electric Utility Oil/Gas Consumption (Quads)

	1985	1990	1995
BC	5.831	3.153	1.882
CBC	5.848 (+.29%)	3.283 (+4.1%)	1.898 (+.85%)
NSPS	5.696		
CNSPS	5.717 (+.37%)	2.816	1.718
EDMD	4.232	2.566	1.675
CEDMD	4.255 (+.54%)	2.626 (+2.3%)	1.621 (-3.2%)

Table 13. Electric Utility Capacity Utilization (GW)

	1985		1990		1995	
	Existing	New	Existing	New	Existing	New
BC	486.2	231.1	449.8	421.7	416.6	641.1
CBC	486.6	230.7	454.1	417.4	417.3	640.6
ΔGW	+.4	-.4	+4.3	-4.3	+.7	-.5
NSPS	484.1	233.2				
CNSPS	484.5	232.8	439.0	432.7	410.1	648.6
ΔGW	+.4	-.4				
EDMD	458.5	188.2	433.8	351.4	410.5	542.4
CEDMD	458.8	187.8	435.3	349.9	408.4	544.6
ΔGW	+.3	-.4	+1.5	-1.5	-2.1	+2.2

TABLE 14

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA TO CEUM CORRECTIONS

BC-85 vs. CBC-85

COMPARISON RUN
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1985.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	DEVIATIONS P
26271	0.044	0.028

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	DEVIATIONS P
PA	2603	0.058	0.033
OH	895	0.000	0.040
MD	52	0.266	0.033
NV	1605	0.119	0.032
SV	5335	0.033	0.011
VA	876	0.025	0.014
EK	2228	0.091	0.014
TN	154	0.000	0.018
AL	751	0.065	0.025
IL	3841	0.023	0.037
IN	798	0.052	0.036
WK	1020	0.000	0.039
IA	10	0.000	0.038
MO	75	0.000	0.050
KS	12	0.000	0.040
OK	73	0.087	0.062
AR	52	0.508	0.261
ND	123	0.000	0.035
SD	12	0.000	0.035
EM	2	0.000	0.048
WM	1153	0.059	0.032
WY	2201	0.043	0.032
CS	696	0.036	0.028
UT	752	0.000	0.046
AZ	96	0.000	0.036
NM	372	0.019	0.035
WA	52	0.000	0.018
TX	393	0.000	0.034
CN	39	0.000	0.021
AK	0	0.000	0.000

TABLE 15

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA TO CEUM CORRECTIONS

BC-90 vs. CBC-90

COMPARISON RUN
BASE ID: BASE CASE, 1990, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1990.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
35568	0.051	0.035

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4004	0.054	0.042
OH	1194	0.074	0.050
MD	87	0.271	0.031
NV	3236	0.061	0.041
SV	5523	0.056	0.019
VA	665	0.218	0.019
EK	1755	0.069	0.021
TN	59	0.000	0.026
AL	636	0.099	0.014
IL	5975	0.043	0.039
IN	1439	0.057	0.037
WK	1489	0.019	0.039
IA	44	0.428	0.050
MO	100	0.105	0.043
KS	5	0.000	0.039
OK	81	0.083	0.031
AR	65	0.268	0.008
ND	166	0.048	0.030
SD	12	0.000	0.035
EM	4	0.000	0.038
WM	2473	0.009	0.046
WY	2976	0.018	0.045
CS	1115	0.068	0.020
UT	560	0.018	0.049
AZ	158	0.000	0.100
NM	796	0.086	0.039
WA	54	0.000	0.027
TX	840	0.000	0.032
CN	40	0.000	0.031
AK	0	0.000	0.000

TABLE 16

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA
TO CEUM CORRECTIONS

BC-95 vs. CBC-95

COMPARISON RUN
BASE ID: BASE CASE, 1995, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1995.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
45624	0.061	0.034

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	6081	0.141	0.041
OH	2234	0.071	0.043
MD	151	0.032	0.020
NV	4295	0.009	0.037
SV	5578	0.046	0.007
VA	681	0.276	0.007
EK	1805	0.073	0.008
TN	0	0.000	0.000
AL	624	0.052	0.006
IL	8027	0.044	0.039
IN	1785	0.006	0.036
WK	1993	0.052	0.039
IA	100	0.111	0.042
MO	146	0.026	-0.042
KS	0	0.000	0.000
OK	106	0.177	0.026
AR	153	0.143	0.007
ND	217	0.000	0.040
SD	12	0.000	0.035
EM	1	0.000	0.038
WM	3852	0.130	0.052
WY	3926	0.000	0.049
CS	1178	0.038	0.034
UT	538	0.043	0.036
AZ	78	0.000	0.036
NM	1032	0.005	0.039
WA	17	0.000	0.029
TX	986	0.000	0.004
CN	28	0.000	0.036
AK	0	0.000	0.000

TABLE 17

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA
TO CEUM CORRECTIONS

<u>Supply Submodule Only</u> -- <u>Inelastic Demand Elasticity</u>

SENSITIVITY ANALYSIS
ASYMPTOTIC DEMAND ELASTICITY = 0.200 DISPLACEMENT = 1.0
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1985. (9/30/79)

NUMBER OF SUPPLY CURVES = 191
EXISTING OUTPUT/TOTAL OUTPUT = 0.409

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26271	0.004	0.020

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2693	0.004	0.020
OH	895	0.001	0.005
MD	52	0.002	0.002
NV	1605	0.006	0.026
SV	5335	0.002	0.010
VA	876	0.002	0.007
EK	2228	0.004	0.016
TN	154	0.000	0.000
AL	751	0.004	0.015
IL	3841	0.008	0.038
IN	798	0.003	0.011
WK	1020	0.000	0.000
IA	10	0.000	0.000
MO	75	0.013	0.050
KS	12	0.000	0.000
OK	73	0.010	0.012
AR	52	0.014	0.027
ND	123	0.008	0.035
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1153	0.007	0.033
WY	2201	0.006	0.028
CS	696	0.002	0.007
UT	752	0.009	0.044
AZ	96	0.002	0.007
NM	372	0.004	0.019
WA	52	0.000	0.000
TX	393	0.007	0.035
CN	39	0.000	0.000
AK	0	0.000	0.000

TABLE 18

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA TO CEUM CORRECTIONS

Supply Submodule Only -- Elastic Demand Elasticity

SENSITIVITY ANALYSIS
ASYMPTOTIC DEMAND ELASTICITY = 5.000 DISPLACEMENT = 1.
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1985. (9/30/79)

NUMBER OF SUPPLY CURVES = 191
EXISTING OUTPUT/TOTAL OUTPUT = 0.409

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26271	0.060	0.012

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2603	0.031	0.016
OH	895	0.028	0.005
MD	52	0.050	0.002
NV	1605	0.115	0.021
SV	5335	0.018	0.003
VA	876	0.019	0.003
EK	2228	0.033	0.006
TN	154	0.000	0.000
AL	751	0.049	0.008
IL	3841	0.092	0.019
IN	798	0.049	0.009
WK	1020	0.000	0.000
IA	10	0.000	0.000
MO	75	0.031	0.005
KS	12	0.000	0.000
OK	73	0.044	0.003
AR	52	0.257	0.019
ND	123	0.181	0.035
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1153	0.154	0.033
WY	2201	0.084	0.018
CS	696	0.048	0.007
UT	752	0.029	0.006
AZ	96	0.039	0.007
NM	372	0.048	0.009
WA	52	0.000	0.000
TX	393	0.119	0.025
CN	39	0.000	0.000
AK	0	0.000	0.000

TABLE 19

Summary of Build Activity Changes from Base Case to Corrected Version of the Full CEUM, in 1985

PLANT TYPE	GW Capacity Largest Decrease Any Region	Largest Increase Any Region	Total Change All Regions /	Number of Regions with Changes
Retrofit Scrubber	-1.053	+0.421	-2.122 /	10
New Scrubber	-0.379	+0.128	-0.580 /	6
Bituminous Coal	-0.394	+0.046	-0.415 /	4
Subbituminous Coal	-0.046	+0.025	-0.021 /	2
Lignite	0.	0.	0. /	0
Turbine	-0.066	+0.013	-0.003 /	5
Oil/Gas Combined Cycle	0.	0.	0. /	0
Conversions	0.	0.	0. /	0
		Total Change in Scrubber GW	-2.702 /	16
		Total Change in Plant GW	-0.439	Regional Totals Changed

Note that Nuclear and Hydro Capacity is fixed

TABLE 20

Summary of Build Activity Changes from Base Case to Corrected Version of the Full CEUM, in 1995

PLANT TYPE	GW Capacity Largest Decrease Any Region	Largest Increase Any Region	Total Change All Regions	/	Number of Regions with Changes
Retrofit Scrubber	-1.925	+0.419	-2.143	/	10
New Scrubber	-2.638	+2.285	-6.808	/	30
Bituminous Coal	-6.038	+2.462	-14.436	/	16
Subbituminous Coal	-0.104	+6.038	+13.959	/	16
Lignite	0.0	0.0	0.0	/	0
Turbine	-0.035	+0.013	-0.067	/	4
Oil/Gas Combined Cycle	0.0	0.0	0.0	/	0
Conversions	0.0	+0.751	+0.968	/	4
		Total Change in Scrubber GW	-8.951	/	32
		Total Change in Plant GW	+0.424		Regional Totals Changed

Note that Nuclear and Hydro Capacity is fixed.

TABLE 21

Percentage Changes in Build Activities from Base Case to Corrected Version of Full CEUM, in 1995

PLANT TYPE	Maximum Absolute % GW Change, Any Region	Absolute % Change of National GW Total, By Plant Type
Retrofit Scrubber	>100%	13%
New Scrubber	89%	3%
Bituminous Coal	>100%	6%
Subbituminous Coal	>100%	11%
Lignite	0%	0%
Turbine	9%	0%
Oil/Gas Combined Cycle	0%	0%
Conversions	>100%	13%

Total % Change in Scrubber GW	3.19%
Total % Change in Plant GW*	0.10%

*Not including Nuclear or Hydro Capacity

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THE ICF, INC. COAL AND ELECTRIC UTILITIES MODEL: AN ANALYSIS AND EVALUATION

VOLUME III:

COAL SUPPLY ISSUES: MINE LIFETIME AND COAL ROYALTIES

by

Energy Model Analysis Program

M.I.T. Energy Laboratory Report No. MIT-EL 81-015

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MASSACHUSETTS INSTITUTE OF TECHNOLOGY

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Cambridge, Massachusetts 02139

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PREFACE

This report is one in a series of seven volumes presenting the results of an indepth review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). The Final Report (Volume I) provides a self-contained summary of the study objectives and results, with supporting papers and materials presented in Volumes II-VII.

The complete series includes:

Energy Model Analysis Program, "The ICF, Inc. Coal and Electric Utilities Model: An Analysis and Evaluation," M.I.T. Energy Laboratory Report No. MIT-EL 81-015, Cambridge, Massachusetts 02139, March 1980.

Volume I: Final Report

Volume II: Documentation and Verification of Model Implementation

Volume III: Coal Supply Issues: Mine Lifetime and Coal Royalties

Volume IV: The Coal Supply Cost Function

Volume V: Electric Utility Expansion and Operation

Volume VI: Other Evaluation Issues

Volume VII: Evaluation Strategies and Computational Results

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INTRODUCTION

This volume examines two aspects of the ICF, Inc. Coal and Electric Utilities Model, including (1) the assumption of a constant mine lifetime and (2) the assumption of zero intertemporal rents. Chapter 1 provides an analysis of the determinants of mine lifetime, and empirical results of changing this key CEUM parameter. Chapter 2 describes the classical model of intertemporal rents, calibrates this model using data from the CEUM, and presents the effects on CEUM results of incorporating the estimated rate for intertemporal rents.

CHAPTER 1. MINE LIFETIME AND POTENTIAL RATE OF COAL PRODUCTION

The lifetime of coal mines is an important factor in the determination of the supply of coal. Mine lifetime affects supply in two ways. First, mine lifetime is inversely proportional to the rate of extraction from a given parcel of reserves. Therefore, mine lifetime determines the intensity with which a parcel of reserves is mined. Second, mine lifetime affects the unit cost of coal production from a given parcel of reserves. Longer lifetimes lead to lower extraction costs by lowering capital requirements. However, long lifetimes delay the realization of revenues, and this imposes a "waiting" cost on the operator.

If a given segment of a coal supply curve represents coal extractable from a given parcel of reserves, a change in mine lifetime will affect the horizonal length of that segment through its effect on rate of extraction, and the height of that segment through its effect on costs.

The effect of mine lifetime on the rate of extraction alone can dramatically alter the supply curve for coal. To see this, ignore for the moment the effect of mine lifetime on extraction costs. Let the function R=R(c) yield the quantity of recoverable coal reserves that can be mined at a cost, per unit of coal, of less than c, and let the function L=L(c) yield the lifetime of mines with unit costs c. Then, assuming that coal is extracted at a uniform rate throughout the life of a mine, and that rates of recovery are constant, the supply function for coal from new mines is given by:

$$S(p) = \int_0^p \frac{1}{L(c)} \frac{dR(c)}{dc} \, dc$$

where p represents the given price of coal. If L is a constant, then the supply function of coal reduces to S(p)=R(p)/L. Thus, the calculated supply of coal from new mines, at any given price, is inversely proportional to an assumed lifetime. When a mine lifetime of 20 years is changed to 30 years, each supply curve for coal is contracted along the horizontal axis by 33 1/3%.

In Figures 1a and 1b, examples of supply curves for coal illustrate this effect. In each case, the change in lifetime causes the supply curves to shift from S to S'. In these figures, D denotes the demand curve, and E and E' denote the old and new market equilibria, respectively. Note that whether the effect of such a change in lifetime on the market equilibrium prices and quantities is substantial, depends on the elasticity of supply. In Figure 1a, where the supply curves are highly elastic, the shift from a 20-year to a 30-year lifetime has little effect on the market equilibrium. In Figure 1b, where the supply curves are inelastic, the effect of the shift is significant.

In Figures 1a and 1b, we have ignored the fact that mine lifetime influences extraction costs as well as extraction rates. The direction of the effect of the cost factor can vary, and depends on considerations explained below.

It is clear that mine lifetime may have a critical influence on coal supply. Therefore, the determination of lifetimes for use in the CEUM is vital to the accuracy of that model. ICF uses a uniform mine lifetime. This lifetime was set at 20 years in original versions of the CEUM and modified to 30 years in later versions. The ICF estimates of lifetime are

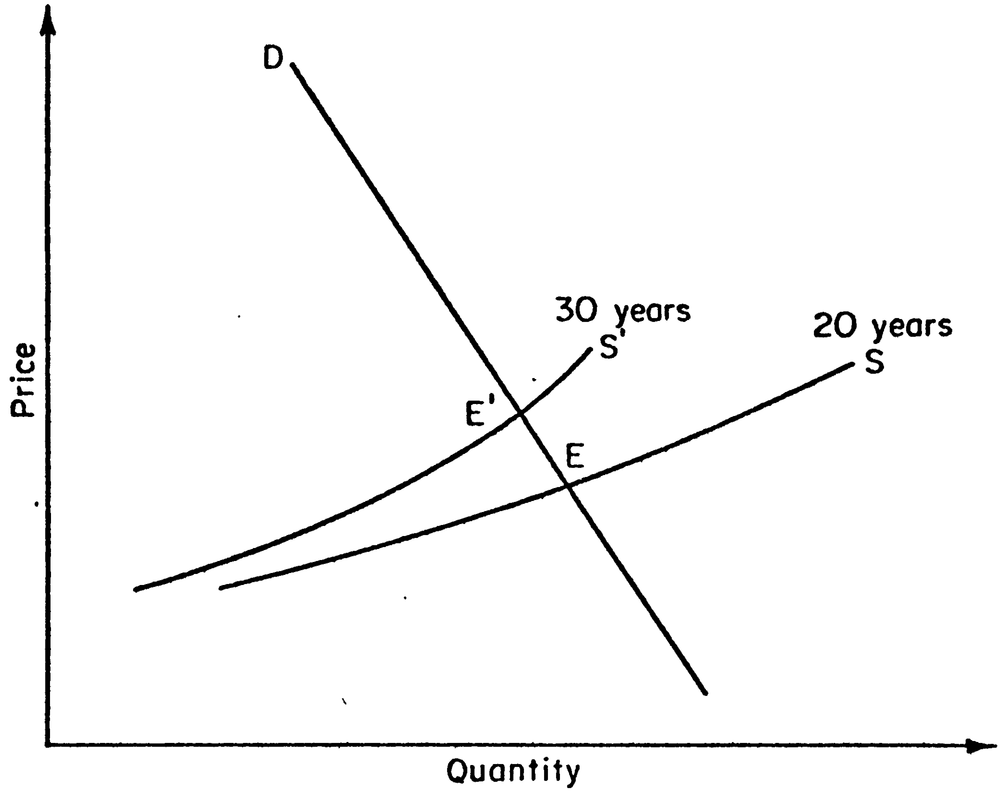


Figure la.

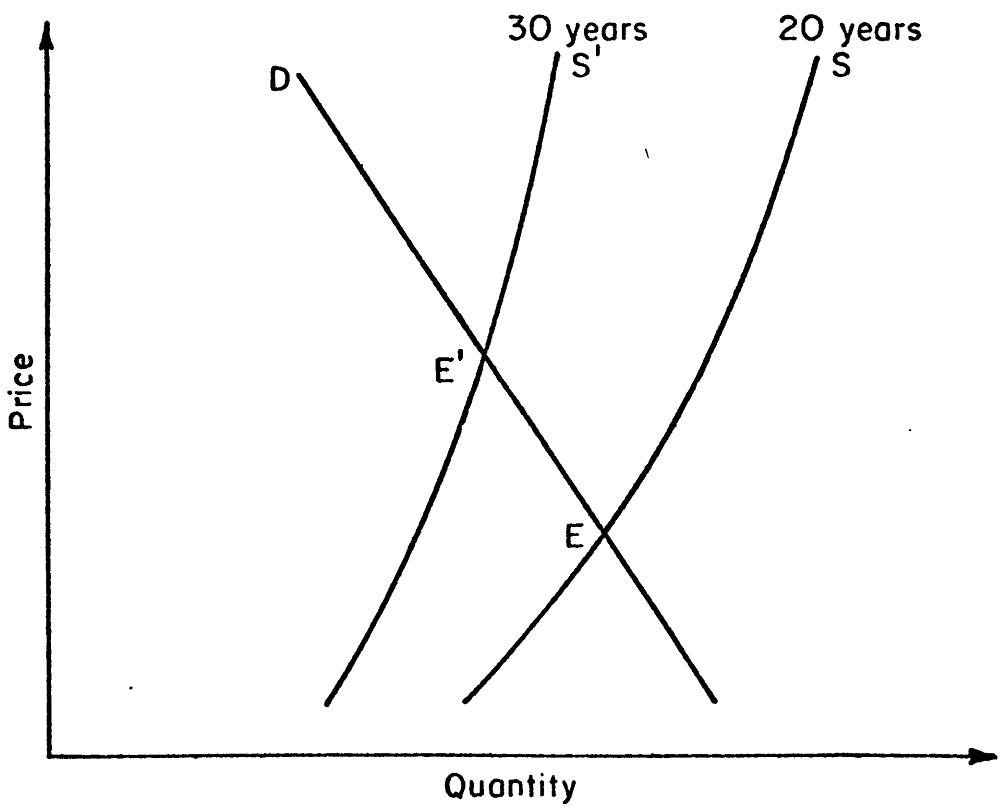


Figure lb.

loosely based on the opinion of mine engineers and on historical data. In order to confirm the importance of the mine-lifetime parameter, we ran the CEUM using a 20-year mine lifetime and compared the results with those of an otherwise identical 30-year mine lifetime run. This comparison is described in Section A below. The changes are dramatic. The M.I.T. Energy Model Assessment Group believes that mine lifetime, because of its effect on extraction costs, is and should be treated as an economic variable. If mine operators set the lifetime with the intent of minimizing the costs involved, then estimates of optimal (cost-minimizing) lifetimes are appropriate for use in forecasting policy models.

In order to get a bearing on which economic variables affect the optimal mine lifetime, and how they affect it, we have constructed and analyzed a simple abstract theoretical model of coal extraction. This analysis is presented in Section B below. The results of this model are intended to be an illustration of what can be done, but more detailed analysis would be desirable before such results can be applied. Nevertheless, our results suggest a surprising hypothesis: The optimal mine lifetime is primarily determined by only two economic variables, the market rate of interest and the capital recoupment period for the mine in question. The nature of our solution allows mine lifetime to be a variable whose value for different mines can be determined endogenously within a model such as the CEUM.

Section D contains general conclusions and recommendations.

A. COMPARISONS OF CEUM OUTPUT WITH 30-YEAR AND 20-YEAR MINE LIFETIMES

In order to form a concrete estimate of the importance of the mine-lifetime parameter in the CEUM, we compared the output of the Corrected Base Case version of the model (30-year lifetime) with that of an otherwise identical version with a 20-year mine lifetime. Using the Deviation Index (described in Volume VII, Chapter 1), we found that the value of the mine-lifetime parameter has an enormous impact on the market equilibrium quantities and prices (see Tables 1 to 5). In the 1985 model runs, the average change in quantity of coal traded over all coal-types and supply regions was 19.2%, and the corresponding average price change was 5.3%. In 8 of the 30 coal-supply regions, the average change in quantity of coal produced exceeded 25%. The deviations were even more dramatic in the 1990 and 1995 model runs.

There were several important differences between the 30-year and the 20-year mine lifetime results aside from market equilibrium coal prices and quantities. In particular, there were major differences in both transportation and transmission results (see Volume VII, Chapter 2).

The mine-lifetime parameter affects the market equilibrium in the CEUM because of its effect on coal supply curves. The M.I.T. Energy Model Assessment Group studied the direct impact of mine lifetime on coal supply. To do this, we ran the supply component of the model (RAMC) both for the 30-year and the 20-year mine lifetimes. The shift in the supply curves was indexed by tabulating the variation of market equilibria along simple hypothetical demand curves of (almost) constant elasticity. The procedure eliminates the effects of the highly complex LP-generated demand side of the CEUM. We found the following effects as a result of changing mine lifetime from 30 to 20 years: Along demand curves of unit elasticity, quantities and prices changed by averages of about 6 and 5%, respectively (see Table 4); along very elastic demand curves (represented by a demand elasticity of 5), quantities and prices changed by averages of about 17 and 3%, respectively (see Table 5). Because such demand curves approach the horizontal, the 17% quantity shift is a rough measure of the horizontal shift in the supply curve described in Figures 1a and 1b.

TABLE 1

Coal and Electric Utilities Model:
Sensitivity of Price-Quantity Equilibria
to the Minelife Parameter

Full Model

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: 20-YEAR MINELIFE, 1985, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.192	0.053

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.158	0.038
OH	931	0.217	0.052
MD	67	0.000	0.044
NV	1626	0.204	0.045
SV	5481	0.174	0.058
VA	867	0.064	0.059
EK	2419	0.130	0.057
TN	157	0.000	0.042
AL	748	0.092	0.059
IL	3892	0.196	0.069
IN	783	0.392	0.069
WK	1060	0.210	0.055
IA	11	0.000	0.050
MO	79	0.000	0.020
KS	13	0.000	0.032
OK	68	0.089	0.026
AR	51	0.768	0.065
ND	127	0.000	0.047
SD	12	0.000	0.047
EM	2	0.000	0.064
WM	1198	0.344	0.045
WY	2191	0.320	0.056
CS	696	0.256	0.057
UI	787	0.075	0.019
AZ	99	0.293	0.027
NM	377	0.203	0.030
WA	53	0.387	0.025
TX	406	0.000	0.095
CN	39	0.324	0.008
AK	0	0.000	0.000

TABLE 2

Coal and Electric Utilities Model:
Sensitivity of Price-Quantity Equilibria
to the Minelife Parameter

Full Model

CCMPARISCN RUN
BASE ID: CORRECTED BASE CASE, 199C.
RUN ID: 20-YEAR MINELIFE, 1990, CCRRECTED.

NUMBER OF SUPPLY CURVES = 191

NATICNAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.216	0.066

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.156	0.053
OH	1161	0.195	0.058
MD	113	0.342	0.064
NV	3567	0.193	0.058
SV	5863	0.196	0.074
VA	769	0.239	0.116
EK	1861	0.175	0.073
TN	60	0.000	0.065
AL	652	0.046	0.064
IL	5940	0.248	0.084
IN	1407	0.276	0.080
WK	1518	0.335	0.063
IA	26	0.839	0.079
MO	93	0.707	0.057
KS	5	0.000	0.024
OK	84	0.319	0.043
AR	108	0.144	0.063
ND	169	0.086	0.047
SD	12	0.000	0.047
EM	5	0.217	0.001
WM	2611	0.108	0.036
WY	3068	0.357	0.048
CS	1052	0.188	0.054
UT	577	0.046	0.004
AZ	174	0.178	0.253
NM	761	0.116	0.103
WA	55	0.385	C.010
TX	867	0.437	0.084
CN	41	0.324	0.026
AK	0	0.000	0.000

TABLE 3

Coal and Electric Utilities Model:
Sensitivity of Price-Quantity Equilibria
to the Minelife Parameter

Full Model

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: 20-YEAR MINELIFE, 1995, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.209	0.076

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.133	0.078
OH	2166	0.381	0.058
MD	167	0.304	0.081
NV	4488	0.157	0.074
SV	5774	0.296	0.088
VA	811	0.512	0.087
EK	1910	0.188	0.091
TN	0	0.000	0.000
AL	595	0.208	0.085
IL	7973	0.131	0.067
IN	1839	0.206	0.067
WK	1963	0.017	0.061
IA	93	0.500	0.085
MO	148	0.466	0.080
KS	0	0.000	0.000
OK	128	0.636	0.071
AR	175	0.132	0.084
ND	226	0.067	0.069
SD	12	0.000	0.047
EM	1	0.392	0.044
WM	4580	0.238	0.074
WY	4120	0.208	0.105
CS	1172	0.258	0.073
UT	533	0.102	0.047
AZ	81	0.526	0.021
NM	1067	0.218	0.102
WA	17	1.495	0.073
TX	990	0.508	0.066
CN	29	0.500	0.052
AK	0	0.000	0.000

TABLE 4

Coal and Electric Utilities Model:
Sensitivity of Price-Quantity Equilibria
to the Minelife Parameter

Supply Submodule

SENSITIVITY ANALYSIS
ASYMPTOTIC DEMAND ELASTICITY = 1.000 DISPLACEMENT = 1.0
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: 20-YEAR MINELIFE, 1985, CORRECTED.

NUMBER OF SUPPLY CURVES = 191
EXISTING OUTPUT/TOTAL OUTPUT = 0.378

NATIONAL AVERAGES

VALUE	DEVIATIONS	
($MM)	Q	P
27062	0.061	0.050

REGIONAL AVERAGES

REG	VALUE	DEVIATIONS	
	($MM)	Q	P
PA	2819	0.016	0.012
OH	931	0.013	0.012
MD	67	0.024	0.009
NV	1626	0.027	0.022
SV	5481	0.071	0.062
VA	867	0.024	0.018
EK	2419	0.033	0.026
TN	157	0.000	0.000
AL	748	0.050	0.036
IL	3892	0.060	0.051
IN	783	0.126	0.097
WK	1066	0.040	0.034
IA	11	0.000	0.000
MO	79	0.026	0.020
KS	13	0.000	0.000
OK	68	0.028	0.007
AR	51	0.303	0.128
ND	127	0.051	0.047
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1198	0.047	0.046
WY	2191	0.156	0.124
CS	696	0.095	0.067
UT	787	0.105	0.102
AZ	99	0.067	0.006
NM	377	0.046	0.036
WA	53	0.136	0.096
TX	406	0.046	0.043
CN	39	0.324	0.195
AK	0	0.000	0.000

TABLE 5

Coal and Electric Utilities Model:
Sensitivity of Price-Quantity Equilibria
to the Minelife Parameter

Supply Submodule

SENSITIVITY ANALYSIS
ASYMPTOTIC DEMAND ELASTICITY = 5.000 DISPLACEMENT = 1.0
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: 20-YEAR MINELIFE, 1985, CORRECTED.

NUMBER OF SUPPLY CURVES = 191
EXISTING OUTPUT/TOTAL OUTPUT = 0.378

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.170	0.027

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.055	0.008
OH	931	0.052	0.009
MD	67	0.126	0.009
NV	1626	0.090	0.015
SV	5481	0.235	0.039
VA	867	0.088	0.013
EK	2419	0.085	0.013
TN	157	0.000	0.000
AL	748	0.113	0.016
IL	3892	0.143	0.024
IN	783	0.392	0.051
WK	1060	0.199	0.030
IA	11	0.000	0.000
MO	79	0.031	0.005
KS	13	0.000	0.000
OK	68	0.093	0.005
AR	51	0.768	0.064
ND	127	0.237	0.047
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1198	0.221	0.046
WY	2191	0.351	0.055
CS	696	0.174	0.024
UT	787	0.186	0.036
AZ	99	0.139	0.006
NM	377	0.117	0.019
WA	53	0.259	0.036
TX	406	0.107	0.020
CN	39	0.324	0.042
AK	0	0.000	0.000

B. A SIMPLE MODEL OF OPTIMAL MINE LIFETIME DETERMINATION

The Model

Notation:

- k = initial investment per mine section
- L = lifetime of coal seam (mine)
- N = number of mine sections opened
- p = net revenue per unit output
- p_0 = initial net revenue per unit output
- Q = quantity of coal in seam
- q = rate of extraction of coal per mine section
- r = market discount rate
- s = period of recoupment
- t = time
- v = rate of increase of net revenue per unit output
- π = present discounted value of coal seam

Picture a coal seam containing a quantity Q of coal. The seam may be thought of as a large underground plane, possibly extending many miles in all directions. The seam is perfectly uniform, both with respect to the quality of the coal and the difficulty of extracting it.

The owner of the mineral rights at the coal seam may open a number of "mine sections," which are grouped into a mine. The number of mine sections in a mine determines its size. A mine section consists of a shaft and a haulage system. Each mine section requires an initial capital investment of amount k and is capable of producing coal at the fixed annual rate of q tons per year. The rate of recovery is assumed to be constant. Net revenue per unit output (i.e., the price of coal net of current operating expenses) is given as p. For the time being, we assume that mine operators expect p to be constant over time t. Thus each mine section creates a net revenue stream of pq per year until the reserves are exhausted.

Suppose N mine sections are opened. We can calculate the present value of reserves as follows:

$$\pi = N\left\{\int_0^L pq\, e^{-rt}\, dt - k\right\} \tag{1}$$

where L is the lifetime of the coal seam and r is the market discount rate. Note that the total rate of extraction from the coal seam is given by N_q, so the lifetime of the seam must be:

$$L = Q/Nq\ . \tag{2}$$

Conversely we have:

$$N = Q/Lq\ . \tag{3}$$

Thus, we may rewrite (1), and express the present discounted value of the reserves, π, as a function of L:

$$\pi = \frac{Q}{Lq}\left\{\int_0^L pq\, e^{-rt}\, dt - k\right\} = \frac{pQ}{rL}(1 - e^{-rL}) - \frac{Qk}{Lq} \tag{4}$$

We assume that the owners of reserves open the number of sections (and implicitly choose a mine lifetime) that maximizes the present discounted value of those reserves. Therefore, if $L > 0$ is optimal, it is necessary that:

$$0 = \frac{d\pi}{dL} = \frac{pQ}{L}\, e^{-rL} - \frac{pQ}{rL^2}(1 - e^{-rL}) + \frac{Qk}{L^2 q}\ . \tag{5}$$

Because $d^2\pi/dL^2$ is strictly negative for all values of L, Equation (5) is sufficient for optimality as well. Multiplying through by rL^2/pQ and rearranging terms yields the equation:

$$(1 + rL)e^{-rL} = 1 - \frac{rk}{pq} \, . \tag{6}$$

Let s denote the recoupment period of a mine: the number of years of production required to recover the initial investment. Then $s = k/pq$, the initial capital costs divided by the annual net revenue flow. Equation (6) may be rewritten as:

$$(1 + rL)e^{-rL} = 1 - rs \, . \tag{7}$$

Equation (7) may be derived more directly. Suppose owners of the seam are trying to decide whether or not to open up an Nth section. The benefits of this section will be the present discounted value of the income stream generated:

$$\int_0^L pq\, e^{-rt}\, dt = \frac{pq}{r}(1 - e^{-rL}) \, .$$

The cost will be in two parts: the initial capital costs, k, and the value lost at the end of the lifetime of the seam as a result of the fact that the quantity of coal qL has already been removed by the additional section. The present discounted value lost is $pqLe^{-rL}$, so the total cost of an Nth mine section is $k + pqLe^{-rL}$. New sections will be opened until benefits equal costs, i.e., until:

$$\frac{pq}{r}(1 - e^{-rL}) = k + pqLe^{-rL} .$$

This equation reduces to Equation (7).

In order to solve Equation (7) for L, we introduce the function:

$$y \equiv f(x) \equiv \frac{e^x}{1 + x}$$

and calculate the inverse function $x = g(y)$. It turns out that the value of g is the limit of the sequence implied by

$$g(y) = \log y + \log(1 + \log(y) + \log(1 + \log y + \log(...))).$$

The function g is similar to a logarithmic function but it increases at a faster rate than the log.

Taking the reciprocal of each side of Equation (7), then applying g, we solve (7) for L^*, the optimal value of L, as follows:

$$L^* = \frac{1}{r}\, g\left(\frac{1}{1 - rs}\right) . \tag{8}$$

This value of L^* is the lifetime of the coal seam (and of each mine section on the seam) that maximizes the present discounted value of the seam. Since g is defined only for positive numbers, an optimal value of L exists only when $rs > 1$. The optimal annual rate of extraction as a fraction of the reserves is $1/L^*$.

One remarkable feature of this solution is that the optimal lifetime of a coal seam is independent of the quantity of reserves in that seam, while the number of mine sections opened will be directly proportional to the quantity of reserves. The optimal lifetime of a mine depends, in this model, on only two factors, the market discount rate r and the recoupment period s. In Figure 2, the optimal lifetime of a mine is plotted as a function of discount rate, for mines with various selected recoupment periods. In Figure 3, the optimal annual rate of extraction as a percentage of initial reserves is plotted as a function of discount rates for various recoupment periods. In Figure 4, optimal lifetime is plotted as a function of recoupment periods for various discount rates.

The Effect of the Recoupment Period on Optimal Mine Lifetime

Recall that the recoupment period s is the number of years of production from a mine needed to recover the initial investment. The definition of recoupment period is free of discounting: Net revenue is simply added together until the amount of the initial investment is reached. In general, the recoupment period may be thought of as an index of the economic quality of a mine, with a good mine having a short recoupment period and a poor mine having a long one.

We now determine the sign of the derivative $\partial L^*/\partial s$ from Equation (8):

$$\frac{\partial L^*}{\partial s} = \frac{1}{r}\, g'\left(\frac{1}{1 - rs}\right) \frac{r}{(1 - rs)^2} = \frac{g'\left(\frac{1}{1 - rs}\right)}{(1 - rs)^2} .$$

To find g', recall that g is the inverse function of $y = e^x/(1+x)$. We have:

Figure 2. Optimal Lifetime of Coal Mines (for various recoupment periods

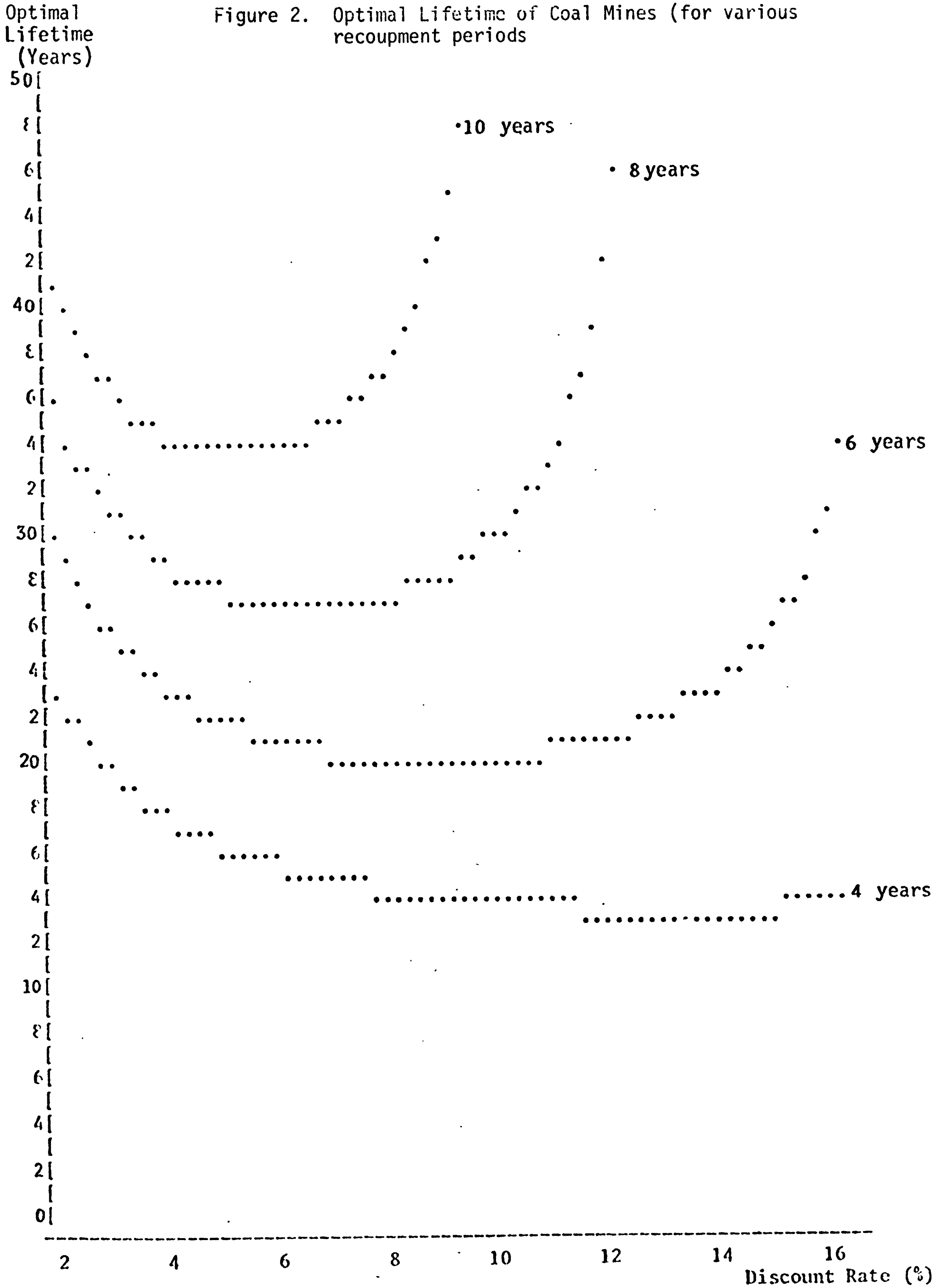


Figure 3. Optimal Rates of Extraction from Coal Mines (for various recoupment periods)

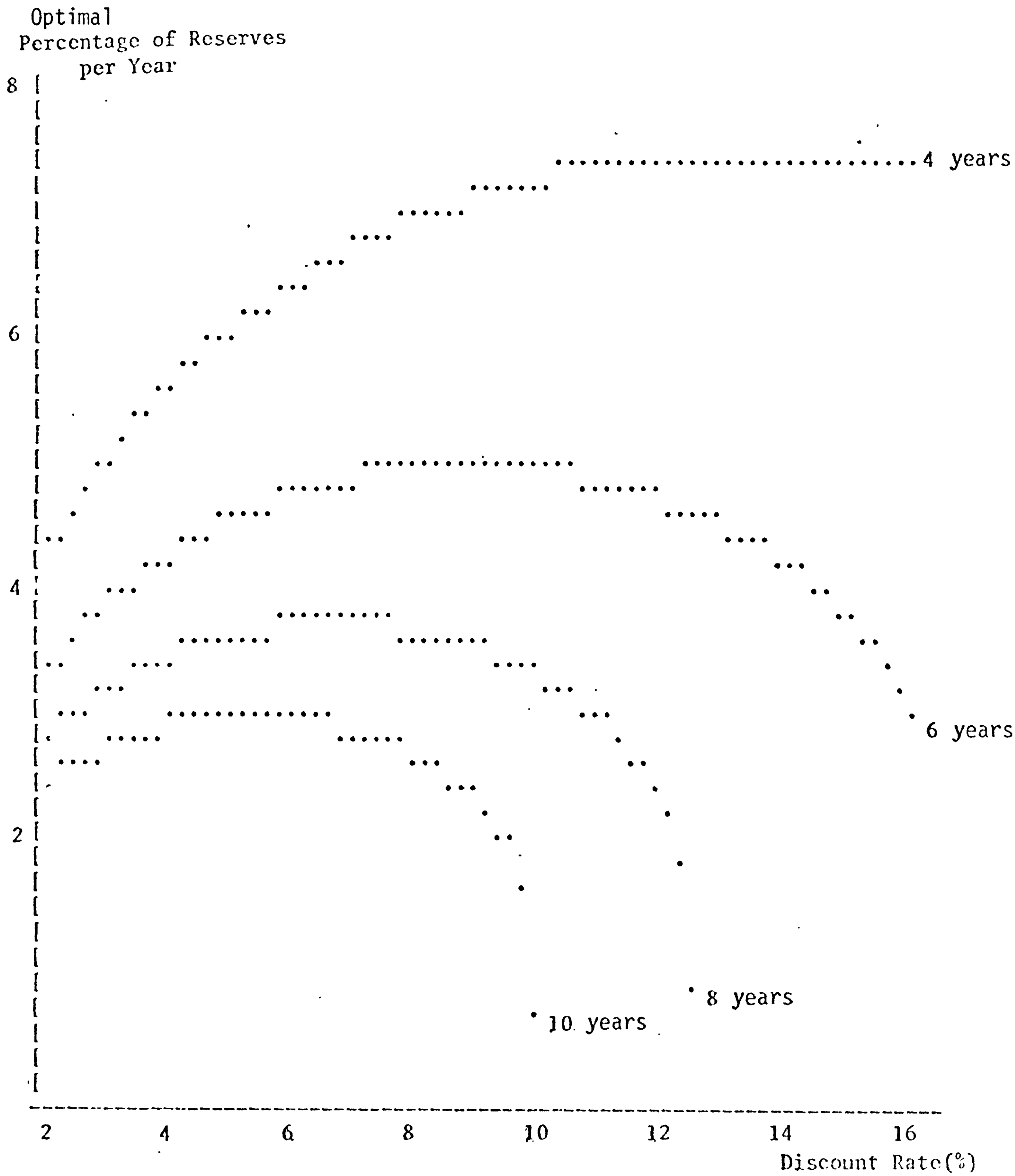
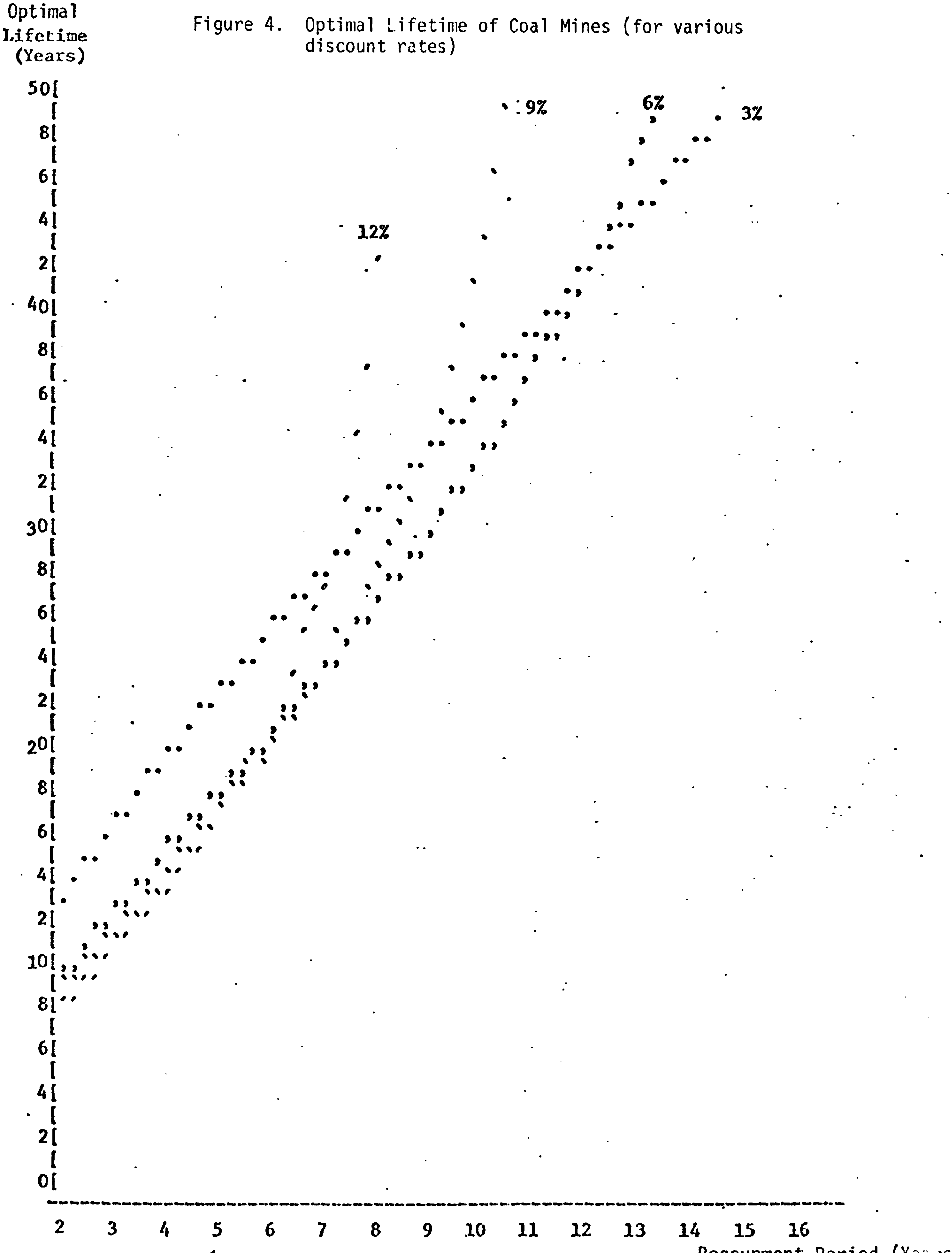


Figure 4. Optimal Lifetime of Coal Mines (for various discount rates)



$$\frac{dy}{dx} = \frac{e^x}{1 + x} \left(\frac{x}{1 + x}\right) = y\left(\frac{x}{1 + x}\right) .$$

Therefore:

$$g'(y) = \frac{dx}{dy} = 1/\frac{dy}{dx} = \frac{1}{y} \left(\frac{1 + x}{x}\right) > 0 .$$

It follows then that $\partial L^*/\partial s > 0$, a fact that is evident from Figures 2 and 4 as well. We conclude that long recoupment periods lead to long optimal mine lifetimes. From Equation (3), we know that the size of the mine (number of sections opened) is inversely proportional to mine lifetime. Thus long recoupment periods lead to small mines.

This result makes sense. When a mine functions over a long period of time, a substantial fraction of the present value of the reserves ultimately extracted is lost as a result of the discount rate. If the recoupment period of the mine is short and thus the mine is of high quality, this value lost may be great compared with the cost of the initial capital investment in the mine. Therefore, in such cases there is strong incentive to construct a large mine with a short lifetime. Conversely, if the recoupment period of a mine is long, the value lost from discounting will be relatively small compared with the cost of the initial capital investment, so incentives are created to construct a small mine with a long lifetime.

What specific factors will affect the recoupment period $s = k/pq$? The capital output ratio k/q will be increased by poor-quality coal deposits and by poor mining conditions. The net revenue per unit coal p will be decreased by low coal prices or high labor costs (or other variable costs). Therefore, in this model, the following factors, through their effect on the recoupment period, would tend to promote small mines with long lifetimes and concomitant low rates of extraction:

a. low-quality coal

b. difficult mining conditions (thin seams, bad roofs, water, gas, etc.)

c. low price of coal

d. high labor costs (or other variable costs)

The Effect of the Discount Rate on Optimal Mine Lifetime

It is evident from Figure 2 that mine lifetime is not a monotonic function of discount rate. For very low discount rates mine lifetime is high and mines are small. This is because at low discount rates the owner of the reserves is in no hurry to remove them from the ground; he extracts the coal slowly to save on initial capital costs. Over some range, mine lifetime decreases and mine size increases as the discount rate increases. Finally, as the discount rate increases toward 1/s, optimal mine lifetime becomes longer and approaches infinity asymptotically, while mine size contracts. For high discount rates, the present value of any income stream from a mine is relatively small as compared with initial capital expenditures, and it does not pay to incur further expenditures in order to extract the coal more quickly.

Reserves will be mined if and only if $r < 1/s$. Recalling that $s = k/pq$, we have from Equation (4):

$$\pi = \frac{pQ}{rL}(1 - e^{-rL} - rs) \quad .$$

If $r \geq 1/s$, then $rs \geq 1$, so from Equation (9) we see that $\pi \leq 0$ for all lifetimes L. On the other hand, if $r < 1/s$, $\pi > 0$ for a sufficiently large L.

Price Expectations

Until now we have assumed that all prices are expected to remain constant. Suppose instead that the owners of reserves expect net revenues to increase at the exponential rate v, so $p = p_0 e^{vt}$, where p_0 is the initial net revenue. Equation (4) for the expected present value of the reserves now must be modified to:

$$\pi = \frac{Q}{Lq}\left\{\int_0^L p_0\, e^{vt} q e^{-rt}\, dt - k\right\}$$

or

$$\pi = \frac{Q}{Lq}\left\{\int_0^L p_0\, q e^{-(r-v)t}\, dt - k\right\}. \qquad (10)$$

However, it is not necessary to rework all of our calculations. Instead, we may simply reinterpret the symbols in Equation (4). Whereas p formerly denoted the assumed constant value of net revenue, we shall now define p to be the initial value of net revenue (p_0 in Equation (10)), so s becomes the recoupment period assuming initial prices. Whereas r formerly denoted the market discount rate, we shall now define r to be the difference between the market discount rate and the expected rate of increase of net revenue. Given this new definition, it is appropriate to rename r and call it the expected "effective" discount rate. When the expected rate of net revenue increase equals the market discount rate, the owner has nothing to lose by postponing the extraction of coal, and r, the effective discount rate, is zero.

Conclusion

We have shown that in a simple model, the optimal lifetime of a coal mine and the optimal rate of extraction from the mine depend only on two variables: the effective discount rate and the recoupment period. These relationships are summarized in Equation (8) and in Figures 2, 3, and 4. The lifetime of mines is an important parameter in the determination of coal supply.

C. CONCLUSIONS AND RECOMMENDATIONS

In the introduction to this chapter, we argued that from a theoretical view, mine lifetime is likely to have a major impact on the supply curves for coal. In Section A, we demonstrated that within the CEUM, the mine-lifetime parameter has enormous effects, both on the position of the supply curves and, as a result, on market equilibrium prices and quantities.

Therefore, the derivation of the mine-lifetime parameter for use in the CEUM is a matter of utmost importance. Currently, the choice of the mine-lifetime parameter is based on what mining engineers regard as the general average for all mines throughout the country. In Section B we argued that mine lifetime should be regarded as an economic variable, determined by mine operators with the objective of maximizing profits. We showed that in a simple model, this profit-maximizing mine lifetime was a function of two other independent variables: the market rate of interest and the capital recoupment period for a given mine.

We believe that the CEUM is unreliable, partly as a result of the lack of attention paid to mine lifetime. A uniform mine-lifetime parameter is inappropriate in a model as disaggregated as the CEUM. We would urge that a mine-lifetime value for each coal type be determined endogenously within the model and that this determination be based on economic criteria.

CHAPTER 2. A DISCUSSION OF COAL ROYALTIES

In a competitive economy there are two types of scarcity rents or royalties that accrue to the owners of coal reserves: static and dynamic. The static rents occur because of differences in extraction and delivery costs of coal being mined at a given time. The lower-cost deposits earn a static rent. This type of rent should not be included as a cost in constructing supply curves, but rather as the static rent earned by a given parcel of reserves, represented by the vertical distance between the corresponding point in the supply curve and the market price.

The other type of rent on exhaustible resources arising in a competitive economy is an intertemporal rent. This rent results from the fact that exploiting a resource at one point in time prevents its owner from exploiting it at a future time. The higher the expected future price of coal, the greater the dynamic rent that must be imputed back to the present. This intertemporal rent or royalty must be included as a cost in the construction of supply curves, for it must be paid to the owners of all currently operating mines, even the marginal mines.

In Section A, we construct a simple analytical model of the origin of intertemporal rent. In Section B, we use this model and CEUM data to estimate the size of these rents. In Section C, we examine the present CEUM treatment of rates, and compare CEUM output with that produced when the estimated rents are imposed.

A. AN ANALYTICAL MODEL OF INTERTEMPORAL RENTS

The following section attempts to estimate the size of the intertemporal rents. First, we construct a very simple model. We assume that the final demand for coal is completely inelastic, and that coal deposits are continuously exploited at a pre-determined rate, with extraction and delivery costs constantly increasing. In some future year, perhaps 50 or 100 years away, a very cheap energy source will become available (nuclear fission?) and coal will cease to be used.

We now analyze this scenario mathematically. The functions manipulated here are represented in Figure 1.

Let:

$p(t) \equiv$ price of coal at time t

$c(t) \equiv$ extraction and delivery costs of the particular deposit of coal mined at time t

$y(t) \equiv$ intertemporal scarcity rent (royalties) accruing to the owner of the coal reserves mined at time t

We have:

$$p(t) = c(t) + y(t) \tag{1}$$

Let:

$v(\tau|t,c) \equiv$ present discounted value at time t, of coal with costs c, mined at time τ.

Letting r denote the real discount rate, we see from Figure 1 that:

$$v(\tau|t,c(t)) = (p(\tau) - c(t))e^{-r(\tau-t)} \tag{2}$$

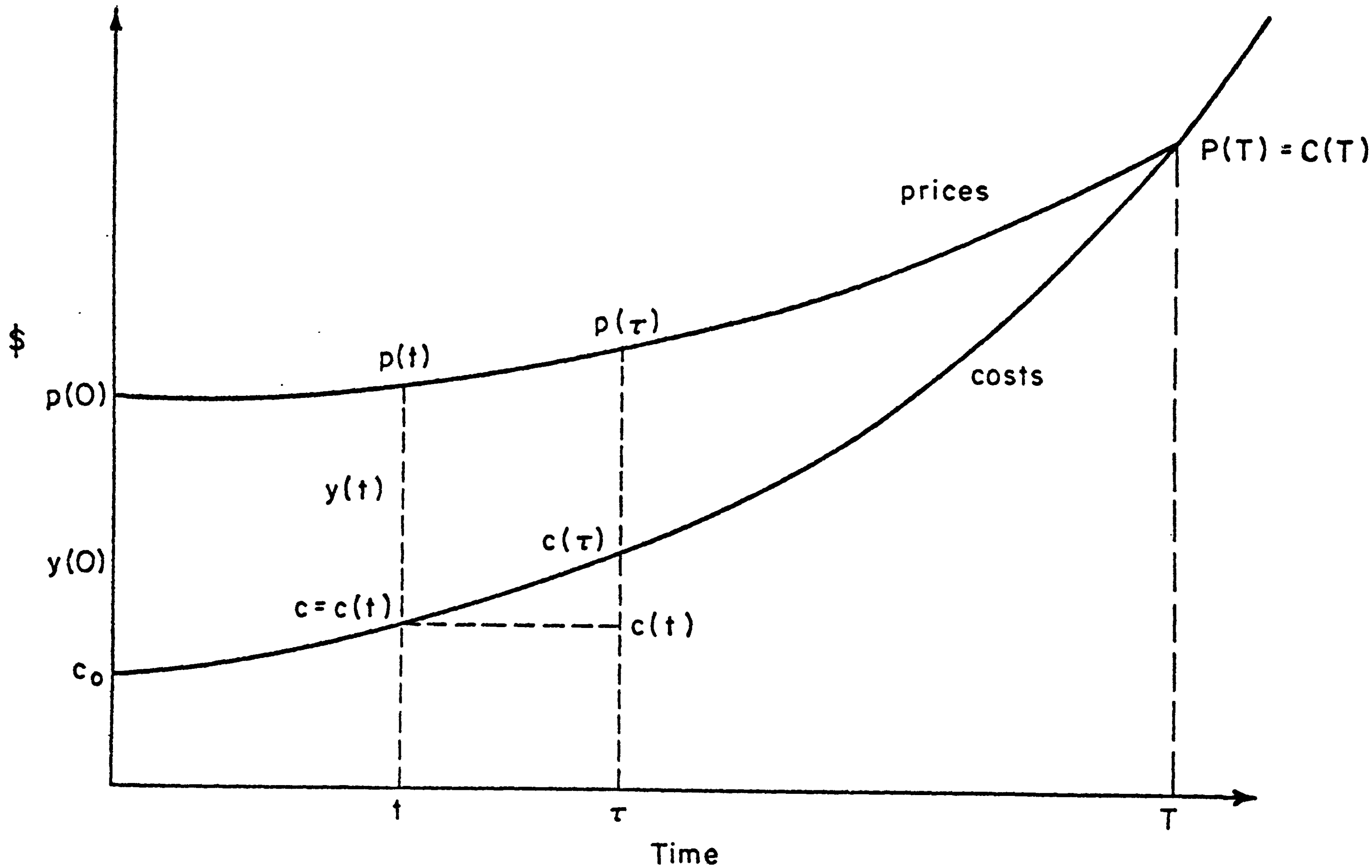


Figure 1.

In competitive equilibrium, new mines with extraction costs c(t) will in fact be opened at time t only if such timing maximizes the present value of the deposit. Therefore, in competitive equilibrium we must have:

$$v(t|t,c(t)) = \max_{\tau} v(\tau|t,c(t)), \tag{3}$$

so that:

$$\left[\frac{d}{d\tau} v(\tau|t,c(t))\right]_{\tau=t} = 0 \tag{4}$$

We determine the value of $\frac{d}{d\tau} v(\tau|t,c(t))$ by substituting the value of p(t) from (1) into (2), and differentiating with respect to τ:

$$\left[\dot{y}(\tau) + \dot{c}(\tau)\right] e^{-r(\tau-t)} - r\left[y(\tau) + c(\tau) - c(t)\right] e^{-r(\tau-t)}$$

Letting $\tau=t$ we have from Equation (4) that:

$$\dot{y}(t) + \dot{c}(t) - ry(t) = 0 \tag{5}$$

The differential Equation (5) governs the time path of royalties on newly opened mines.

From our assumption that a cheap energy source will become available at some future time T, we know that royalties at that time must vanish (coal is no longer scarce), i.e.:

$$y(T) = 0 \tag{6}$$

In addition we assume that:

$$c(t) \equiv c_0 e^{\alpha t} \tag{7}$$

where α is the rate of growth of the cost of extracting and delivering coal resulting from a decline in the quality of the deposit and location of the coal being mined.

The solution of Equation (5) with boundary condition given in Equation (6) and c(t) defined as in Equation (7) is given by:

$$y(t) = \frac{c_0 \alpha}{r-\alpha} e^{\alpha T} \left[e^{-\alpha(T-t)} - e^{-r(T-t)} \right] \tag{8}$$

Therefore the current value of royalties is given by

$$y(0) = \frac{c_0 \alpha}{r-\alpha} (1 - e^{-(r-\alpha)T}). \tag{9}$$

Let $\overline{Y}$ denote the limiting value of current royalties as the date of availability of the new technology recedes into the distant future. Taking the limit of Equation (9) as $T \to \infty$ yields:

$$\overline{Y} = \frac{c_0 \alpha}{r-\alpha} . \tag{10}$$

B. SOME ROUGH ESTIMATES OF INTERTEMPORAL RENTS BASED ON CEUM DATA

In order to use Equations (9) and (10), we need to estimate the values of r, α, and T. If we are content to express our results as a percentage of extraction costs, we may leave c_0 unspecified. For the <u>real</u> rate of return to investment in mining, r, the CEUM uses the value 9%, but we shall try three different values: 5, 10, and 15%. In addition we assume that the availability of a cheap and plentiful alternative energy source is at least 50 years off, so that $T \geq 50$.

It remains to estimate α. To do this, 1985 and 1995 Base Case CEUM model runs have been used. Both of these runs utilize the same supply curves for coal, so an estimate of the growth rate of extraction costs can be based on a direct comparison of 1985 and 1995 equilibrium minemouth prices. Moreover, because intertemporal rents (royalties) in the CEUM are a constant percentage (usually zero) of extraction costs, the growth rate of costs and the growth rate of prices must be the same.

On the average, CEUM minemouth prices increased at a real annual rate of about 1.8%. However, in some large regions, prices increased at the annual rate of 1.5 to 1.6%. Since production will shift over time to regions with a low rate of price increase, the lower end of the range of price and cost growth rates is probably the most appropriate to use as a value of α in estimating rents.

Another estimate of α was formed by comparing 1985 prices with the prices on the 1985 supply curves corresponding to the 1995 equilibrium quantities. The prices corresponding to the 1995 quantities averaged 15% more than the 1985 prices, indicating an annual growth rate of 1.40%. This growth rate may understate the parameter α because the 1995 equilibrium quantities allow certain mines to be shut down as compared to 1985. Therefore this estimate is consistent with the previous estimates. To cover the entire range of possibilities, we use three values of α: 1, 1.5, and 2%.

Assuming that T=50, we use Equation (9) to compute estimates of intertemporal rents (royalties) on marginal mines as a percentage of extraction costs, i.e., $y(o)/c(o)$, given alternative values of α and r.

Royalties as a Percentage of Cost

		r 5%	10%	15%
	1.0%	22	11	7
α	1.5%	35	17	11
	2.0%	52	25	15

As explained above, 1.5% appears to be the most appropriate value of α. Furthermore, a high value of r, say 15%, should be used because not exploiting mineral deposits involves considerable risk. These values of α and r imply that royalty payments should be 11% of current extraction costs, or about 10% of current minemouth prices. (One source indicated to us that royalty payments on new strip-mineable coal in Pennsylvania average about 10% of its price, but that royalties for deep mines are considerably less.) The need for further and more thorough study is clear.

C. THE CEUM TREATMENT OF RENTS

The question of intertemporal rents is ignored in the CEUM. Intertemporal rents are not discussed in ICF, Inc. (July 1977). There is no evidence of any analytical or empirical work directed toward the determination of these rents.

When intertemporal rents can be observed in market data, they appear as a portion of the royalty payments made by mine operators to the owners of mineral rights. However, because mine operators often own the mineral rights to their operations, intertemporal rents are frequently implicit and cannot be directly observed. Nevertheless, such implicit rents are as real and as important as explicit rents. The price the mine operator receives for coal must cover implicit as well as explicit intertemporal rents if the operator is to be willing to work the mine. For this reason, in deriving the supply function, intertemporal rents should be imputed whenever they cannot be measured.

There is no imputation of rents in the CEUM. While the computer implementation of the model has provisions for including royalties in the coal supply cost function, royalty payments are always set at zero in supply regions that are not dominated by Federal coal lands. Thus, even explicit non-Federal royalty payments are omitted, while the possibility of imputed rents is unmentioned. In regions dominated by Federal lands, royalty payments at Federal rates are included.

In order to test the potential importance of intertemporal rents in the output of the CEUM, the M.I.T. Energy Model Assessment Group generated runs of the CEUM with intertemporal rents set at 10% of coal extraction costs in non-Federal regions. The royalties in Federally dominated regions were left unchanged. The results of these runs (ROYI-85, ROYI-90, ROYI-95) were compared with the Corrected Base Case model runs for the corresponding years (CBC-85, CBC-90, CBC-95). Differences between the output of the ROYI and CBC runs were substantial in each case year (see Tables 1 to 3 and Volume VII).

Among national aggregate statistics, the most obvious difference between the ROYI and the CBC runs occurs in West-to-East coal transportation: the ton-mileage figure is an average of 65% higher for the three ROYI runs than for the three CBC runs. Also, East-to-West ton-mileage decreases by an average of 34%. These changes occur because of the imputation of royalties to Eastern coal, while Western coal from

Federal lands has no additional royalties imputed. Clearly, the issue of intertemporal rents is crucial for predicting the extent to which Western coal will penetrate Eastern markets.

The ROYI market-equilibrium quantities and prices of coal at supply regions were compared to the corresponding CBC values using the Deviation Index (see Tables 1 to 3 below and Volume VII). The national-average coal price increase was 7.3% in 1985 and 6.4% in both 1990 and 1995. Coal production by supply region changed by an average of 8.8% in 1985. On the one hand, a number of coal regions, like Pennsylvania and Ohio, showed more than 12% less coal production in ROYI-85 than in CBC-85. On the other hand, ROYI increased coal production in Western Montana and Colorado South by about 23%. Coal production by supply region changed by an average of 12.6% in 1990 and 10.2% in 1995.

D. RECOMMENDATIONS

To increase the reliability of CEUM output, intertemporal rents should be included in the CEUM analysis. This is more easily said than done. In the general case, intertemporal rents depend on expectations of the very same future prices that the CEUM is designed to predict. As a result, models including such rents cannot be solved by simple static optimization techniques. The imputation of intertemporal rents together with the solution of the entire model is a dynamic optimization problem, which normally requires the use of dynamic programming or an equivalent technique. In the case of the CEUM, the size of the model is so large that true dynamic optimization is probably impractical. Instead, average intertemporal rents could be calculated using a dynamic model more highly aggregated than the CEUM (but more detailed than the model presented in

Section A above). The rents so calculated could be introduced into the present static version of the CEUM as exogenous parameters. As a consistency check, the output of the CEUM run with intertemporal rents could then be compared to the output of the more aggregated dynamic model.

E. Conclusion

Preliminary analysis suggests that intertemporal rents on coal have a significant role to play in any model focusing on coal as a source of energy. The omission of these rents from the CEUM renders the output of that model unreliable. This omission should be corrected.

TABLE 1

Sensitivity to Imposing a 10%
Federal Royalty Charge in Non-Federal Regions

CBC-85 vs. ROYI-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: 10% ROYALTY IN NON-FEDERAL REGIONS, 1985, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.088	0.073

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.121	0.092
OH	931	0.130	0.091
MD	67	0.412	0.070
NV	1626	0.148	0.077
SV	5481	0.057	0.075
VA	867	0.011	0.075
EK	2419	0.099	0.082
TN	157	0.000	0.083
AL	748	0.075	0.070
IL	3892	0.072	0.082
IN	783	0.097	0.079
WK	1060	0.000	0.088
IA	11	0.000	0.086
MO	79	0.000	0.111
KS	13	0.000	0.056
OK	68	0.089	0.059
AR	51	0.167	0.081
ND	127	0.119	0.000
SD	12	1.000	0.000
EM	2	0.000	0.000
WM	1198	0.235	0.000
WY	2191	0.073	0.041
CS	696	0.229	0.052
UT	787	0.000	0.113
AZ	99	0.114	0.000
NM	377	0.058	0.001
WA	53	0.000	0.000
TX	406	0.000	0.111
CN	39	0.000	0.000
AK	0	0.000	0.000

TABLE 2

Sensitivity to Imposing a 10%
Federal Royalty Charge in Non-Federal Regions

CBC-90 vs. ROYI-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: 10% ROYALTY IN NON-FEDERAL REGIONS, 1990, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.126	0.064

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.151	0.088
OH	1161	0.157	0.094
MD	113	0.211	0.073
NV	3567	0.103	0.087
SV	5863	0.066	0.068
VA	769	0.271	0.070
EK	1861	0.097	0.072
TN	60	0.000	0.079
AL	652	0.087	0.083
IL	5940	0.127	0.079
IN	1407	0.117	0.072
WK	1518	0.188	0.079
IA	26	0.839	0.058
MO	93	0.564	0.033
KS	5	0.000	0.065
OK	84	0.431	0.054
AR	108	0.117	0.095
ND	169	0.392	0.000
SD	12	1.000	0.000
EM	5	0.000	0.000
WM	2611	0.292	0.002
WY	3068	0.102	0.034
CS	1052	0.059	0.015
UT	577	0.006	0.111
AZ	174	0.103	0.030
NM	761	0.029	0.000
WA	55	0.000	0.013
TX	867	0.000	0.000
CN	41	0.000	0.004
AK	0	0.000	0.000

TABLE 3

Sensitivity to Imposing a 10%
Federal Royalty Charge in Non-Federal Regions

CBC-95 vs. ROYI-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: 10% ROYALTY IN NON-FEDERAL REGIONS, 1995, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.102	0.064

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.081	0.088
OH	2165	0.140	0.096
MD	167	0.094	0.081
NV	4488	0.029	0.090
SV	5774	0.046	0.083
VA	811	0.251	0.069
EK	1910	0.171	0.082
TN	0	0.000	0.000
AL	595	0.077	0.070
IL	7973	0.112	0.067
IN	1839	0.158	0.061
WK	1963	0.137	0.069
IA	93	0.309	0.085
MO	148	0.489	0.055
KS	0	0.000	0.000
OK	123	0.449	0.054
AR	175	0.056	0.078
ND	226	0.298	0.004
SD	12	1.000	0.000
EM	1	0.000	0.000
WM	4580	0.126	0.020
WY	4120	0.133	0.032
CS	1172	0.072	0.022
UT	533	0.039	0.035
AZ	81	0.105	0.073
NM	1067	0.033	0.025
WA	17	1.000	0.051
TX	990	0.000	0.007
CN	29	0.000	0.015
AK	0	0.000	0.000

REFERENCE

ICF, Inc. [July 1977], Coal and Electric Utilities Model Documentation, 1850 K Street, NW, Suite 950, Washington, D.C.

THE ICF, INC. COAL AND ELECTRIC UTILITIES MODEL: AN ANALYSIS AND EVALUATION

VOLUME IV:

THE COAL SUPPLY COST FUNCTION

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PREFACE

This report is one in a series of seven volumes presenting the results of an indepth review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). The Final Report (Volume I) provides a self-contained summary of the study objectives and results, with supporting papers and materials presented in Volumes II-VII.

The complete series includes:

Energy Model Analysis Program, "The ICF, Inc. Coal and Electric Utilities Model: An Analysis and Evaluation," M.I.T. Energy Laboratory Report No. MIT-EL 81-015, Cambridge, Massachusetts 02139, March 1980.

Volume I: Final Report

Volume II: Documentation and Verfication of Model Implementation

Volume III: Coal Supply Issues: Mine Lifetime and Coal Royalties

Volume IV: The Coal Supply Cost Function

Volume V: Electric Utility Expansion and Operation

Volume VI: Other Evaluation Issues

Volume VII: Evaluation Strategies and Computational Results

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INTRODUCTION

An important objective in evaluating the ICF, Inc. Coal and Electric Utilities Model (CEUM) was to analyze the properties of the coal supply cost portion of the model. In this volume we report the results of this analysis, including development and implementation of an analytical representation of the coal cost function submodel, and comparison of results from the analytic and original submodels.

CHAPTER 1. INTRODUCTION TO COAL SUPPLY COSTING IN THE CEUM*

The supply curves employed in the Coal and Electric Utilities Model are based on the coal supply methodology that ICF (May 1976) developed in its Coal Supply Analysis [1] for FEA's Project Independence Evaluation System (PIES). A description of the CEUM supply methodology follows.

The coal supply sector of the CEUM consists of price sensitive, multi-stepped coal supply curves for each coal type that exists within each supply region. The curves are used to simulate potential production levels available at various prices. Each step of a supply curve represents a different type of mine. The length of each step gives the potential production level for each mine type. The height of each step is called the "minimum acceptable selling price" in CEUM terminology (the "reservation price" in economic terminology) and is based on average variable costs for existing mines and average total costs for new mines.

The supply curves are developed in six major steps. The first step defines appropriate coal supply regions and coal types. Here, the CEUM expands the 12 supply regions used for PIES to 30 supply regions. The model recognizes five heat (BTU) content and eight sulfur content categories, including two special sulfur levels designed specifically to allow for deep-cleaning to meet either the New Source Performance Standard (less than .60 pounds of sulfur per million BTUs) or State Implementation Plans (a one-percent sulfur emission limitation for existing sources). All bituminous coals receive a standard level of washing. The supply regions and the coal types form the basis for allocating the Bureau of Mines (BOM) Demonstrated Reserve Base into regional coal type categories.

* This chapter was prepared by Neil L. Goldman

The second step estimates future output from existing mines (using existing production data and expected mine closings) by region and coal type. The third step determines the minimum acceptable selling price for the future output of these existing mines. For such mines capital has been sunk so the minimum acceptable selling price covers only variable costs, i.e., revenues must cover variable operating expenses. The first steps on each supply curve represent coal production from existing mines.

The fourth step analyzes demonstrated reserves that have not yet been developed. The model allocates these uncommitted reserves by region and coal type to hypothetical model mine type categories, defined in terms of overburden ratio and mine size for surface mines and in terms of seam thickness, seam depth, and mine size for deep mines. For a given mine type, region, and coal type the assigned stock of reserves is then translated into a potential production flow (annual production level) using mine lifetime and recovery factor parameters.

The fifth step estimates the minimum acceptable selling price (MASP) for each mine type in each region. This is the price that provides for the recovery and return on invested capital in addition to covering operating costs. At a given mine, it is the minimum price a coal producer would accept for his product and still operate profitably in the long run. The MASP is estimated using engineering mine-costing algorithms as a function of key reserve characteristics (i.e., overburden ratio, mine size, seam thickness, and seam depth).

The last step arrays the mine types in each region for each coal type in order of ascending minimum acceptable selling price, thus generating a step-function supply curve. The height of each step is determined by the MASP (on a per-annual-ton basis) of the associated mine type. The length of each step is determined by the annual potential production level of the mine type.

Estimates of the minimum acceptable selling price per ton of coal for each of approximately 190 hypothetical mine types are developed. This was accomplished by the construction of two "base case" model mines (one surface and one deep) and a matrix of cost adjustment factors for costing changes in key variables. The base case cost models were developed from existing mine cost studies by BOM and TRW and from information obtained by ICF through interviews with mining engineers and coal economists. The cost adjustment factors employed were based on extrapolations of relationships observed in the existing mine cost models and judgments based on consultations with mining engineers. It should be understood that the costing methodology used in the CEUM does not take into account all possible cost-influencing variables such as roof, floor, water and gas conditions. ICF believes that the major influences on mining costs have been captured.

CHAPTER 2. THE CONCEPT OF MINIMUM ACCEPTABLE REAL ANNUITY COAL PRICES: A FORMULATION*

The ultimate objective of the coal supply component of the ICF Coal and Electric Utilities Model is to produce supply schedules for coal as viewed by purchasers. Supply schedules reflecting the producer's point of view are derived, and these schedules are then adjusted to reflect the purchaser's point of view. A central concept of this procedure is the notion of minimum acceptable real annuity coal prices. The CEUM Documentation (ICF, Inc. [July 1977]) does not adequately describe this concept; our own construction of it is included below.

ICF's objectives in employing the minimum acceptable real annuity coal pricing concept were twofold. First, the coal prices ought to reflect the stream of required prices for the entire life of the mine, and second, the prices must be internally consistent with other inflating price series such as oil/gas prices, coal transportation costs, and electric utility O&M costs. The objectives were achieved by the use of real annuity prices that implicitly inflate at the general rate of inflation, thereby remaining constant in real terms. All other inflating series employed in the CEUM are expressed in similar terms.

In this chapter the coal pricing logic employed in the CEUM and in its more recent versions is explained in a step-by-step manner, starting with the calculation of the coal producer's minimum acceptable selling price. The analysis employs two relevant Verification Corrections (Points 7 and 8) from Volume II, Chapter 5, Section A.

*This chapter was prepared by Neil L. Goldman. Note that is also represents a formal addition to the CEUM Documentation (see Volume II, Chapter 3).

1. For each model mine type in each supply region the present value of capital investment (as of the case year, 1985) is calculated using a given initial capital cost and a given distribution of deterred capital costs over the mine lifetime.*

The present value of the total capital investment of coal producers, PV_{CAP} (in case year dollars, as of the beginning of the case year, 1985) is given by:

$$PV_{CAP} = PV_{IC} + PV_{DC}$$

$$PV_{IC} = IC_{75}(1 + g_c)^{10-2/3}(1 + k_p)^{2/3}$$

$$PV_{DC} = DC_{75}(1 + g_c)^{10} \sum_{i=1}^{N} DCF_i \frac{(1 + g_c)^i}{(1 + k_p)^i} \qquad (1)$$

where:

PV_{IC} = present value of initial capital cost, in case year dollars, as of beginning of case year (1985)

PV_{DC} = present value of deferred capital cost, in case year dollars, as of beginning of case year (1985)

IC_{75} = initial capital cost in base year, beginning-1975, dollars

DC_{75} = deferred capital cost in base year, beginning-1975, dollars

*Note that the table of costs for the base case model mines given on page III-51 of ICF, Inc. (July 1977) uses ICF's PIES costing (constant dollars for cash flow) rather than the CEUM methodology (current dollars, constant in nominal terms). The table also implies a real discount rate of 8% for coal producers. This is inconsistent with the statement on page III-55 of ICF, Inc. (July 1977) that a nominal rate of 15% is used together with a 5% capital inflation rate. In more recent versions of the model, a 6% capital escalation rate is used, including approximately (1/2)% real escalation.

DCF_i = fraction of deferred capital spent at end of year i

k_p = coal producer's nominal discount rate (after-tax nominal cost of capital)

g_c = total capital escalation rate (including general inflation and real escalation)

g = general rate of inflation

N = mine lifetime in years

Note that initial capital is inflated at the nominal escalation rate from the base year to eight months before the case year. Deferred capital is escalated to the end of the year in which is money is considered spent.

Let: K_p = coal producer's real discount rate (after-tax real cost of capital)

Recalling that $1 + K_p = \frac{1+k_p}{1+g}$, we point out that

$$PV_{CAP} \neq PV_{IC} + DC_{75}(1 + g_c)^{10} \sum_{i=1}^{N} \frac{DCF_i}{(1 + K_p)^i} \qquad (2)$$

Equation (2) only holds if $g=g_c$.

Using the distribution for deferred capital costs given on page III-49 of ICF, Inc. (July 1977), we have for N = 20:

$$\begin{aligned} DCF_i &= .01 \quad , \quad i = 1\text{-}5 \\ &= .09 \quad , \quad i = 6\text{-}15 \\ &= .0125 \ , \quad i = 16\text{-}19 \end{aligned}$$

Except for mine lifetime, the following parameter values represent recent figures used by ICF to calculate PV_{CAP}. Although ICF is currently using a mine lifetime of 30 years, we use a value of 20 years in Equations (3) and (4) since for this lifetime, the distribution used by ICF for deferred capital costs is documented.

$k_p = .15 \quad , \; g_c = .06 \quad , \; g = .055$

$$1 + K_p = 1.15/1.055 \quad \Rightarrow \quad K_p \cong .09$$

Utilizing Equations (1) and (3), we now have:

$$PV_{CAP} = PV_{IC} + DC_{75}(1 + g_c)^{10} \left[.01 \sum_{i=1}^{5} \left(\frac{1.06}{1.15}\right)^i \right. \tag{4}$$

$$\left. + .09 \sum_{i=6}^{15} \left(\frac{1.06}{1.15}\right)^i + .0125 \sum_{i=16}^{19} \left(\frac{1.06}{1.15}\right)^i \right].$$

2. A minimum acceptable or required annual cash flow (equivalent to annualized capital cost) in nominal terms, CF, can be calculated by annualizing PV_{CAP} using the coal producer's nominal discount rate, k_p, and the mine lifetime, N. This cash flow is constant in <u>nominal</u> terms (i.e., constant in current year dollars). It is given by:

$$CF = \frac{PV_{CAP}}{\sum_{i=1}^{N} \frac{1}{(1+k_p)^i}} = PV_{CAP} \bullet CRF_{k_p, N} \tag{5}$$

where:

$$CRF_{k_p, N} = \text{capital recovery factor} = k_p \left[1 - (1+k_p)^{-N}\right]^{-1}.$$

(based on <u>nominal</u> discount rate)

A minimum acceptable annual cash flow with the same present value but constant in real terms is obtained simply by substituting K_p for k_p in Equation 4.

Note that for ICF's PIES analysis, a cash flow constant in real terms was used. Such a cash flow is implicit in the costing table on page III-51 of ICF, Inc. (July 1977). Also, the PIES analysis assumes no real escalation and employs constant base year dollars.

3. Utilizing given total operating costs for the base year, depreciation, and the above calculated minimum acceptable annual cash flow, total required revenues (referred to as sales by ICF) for the case year can be estimated from the appropriate equation on page III-50 of ICF, Inc. (July 1977C). (Since ICF assumes that the depletion allowance equals 10 percent of required revenues up to 50 percent of gross profit, there are two possible required-revenue equations. Both are derived in the addendum to this chapter. Adjustments to these equations, including severance tax rates as a percentage of sales, severance tax charges in dollars per ton, and Federal royalties, are not included.)

The coal producer's minimum acceptable selling price, MASP, for the case year is determined by dividing required revenue by the annual output of the mine. Note that the case year MASP in case year dollars, calculated in the CEUM via a required cash flow in nominal terms, is higher than the MASP would be for the same model mine type in ICF's PIES analysis, which uses a cash flow in real terms and works in constant base year dollars.

4. Starting from the MASP in the case year, 1985, a minimum acceptable coal price series in nominal terms is generated over the assumed 20-year mine lifetime as follows: The minimum acceptable cash flow or annualized capital cost is constant in nominal terms over the mine

lifetime. Variable costs are escalated from year to year over the life of the mine using a 6.5% rate for labor costs, including approximately 1% real escalation, and the 5.5% general inflation rate for the cost of power and supplies and for other operating expenses. Required revenues are recalculated (as described in step 3 above) for each year, creating a stream of minimum acceptable prices in nominal terms (i.e., in current year dollars). By construction, via this required price stream, the coal company will recover all of its costs and earn the required return on its investment.

5. The coal producer's minimum acceptable coal price series in nominal terms, calculated in the previous step, is present-valued or discounted to the case year using the after-tax nominal cost of capital to electric utilities, k_u. The utility industry's discount rate is used at this stage because the utilities decide which stream of prices is preferable (i.e., which mines are opened) and make the trade-off decisions between various fuels and between capital-intensive and high-variable cost plants. Currently, ICF is using a 10% after-tax nominal cost of capital to utilities. The present-value (as of the case year) of the coal price series, PV_{ps}, is calculated as follows (note that the values p_i are neither constant in real terms nor in nominal terms):

$$PV_{ps} = \sum_{i=1}^{N} \frac{p_i}{(1+k_u)^i} = \sum_{i=1}^{20} \frac{p_i}{(1.10)^i} \tag{6}$$

where:

p_i = coal producer's minimum acceptable coal price in ith year in nominal terms (for model mine type and supply region under consideration).

6. Finally, a minimum acceptable "real annuity coal price," RACP, is calculated from PV_{ps} using k_u and the general inflation rate, g. This calculation implicitly defines an after-tax real cost of capital to electric utilities, k_u.

$$\text{RACP (constant in real terms)} = \frac{PV_{ps}}{\sum_{i=1}^{N} \left(\frac{1+g}{1+k_u}\right)^i} = \frac{PV_{ps}}{\sum_{i=1}^{N} \frac{1}{(1+K_u)^i}} \qquad (7)$$

$$= PV_{ps}/APFAC$$

where:

APFAC = annuity price factor, and

$$1 + K_u = 1.10/1.055 \Rightarrow K_u \cong .0427.$$

The real annuity coal price is a case year value in case year dollars that inflates at the general rate of inflation (i.e., RACP is constant in real terms). Note that while the methodology described above is projecting coal prices p_i in actual nominal terms, it is only the present value of the coal price series that is important. The associated real annuity, given by Equation (7), has the same present value to the utility as does the nominal price series.

Other prices in the CEUM are all assumed to inflate at the general rate of inflation (i.e., to remain constant in constant case year dollars). Therefore, the 1985 price for, say, oil/gas is both its actual price in 1985 and the value of the real annuity for oil/gas stated in 1985 dollars. So the real annuity coal price has the advantage of being consistent with other data inputs, such as oil prices. Its other advantage is that it makes the CEUM's static linear programming framework possible.

It is the minimum acceptable real annuity coal price (deflated to 1978 dollars), for each model mine type in each supply region, that appears in the linear programming matrix as the cost coefficients of the coal mining activity variables in the objective function (see Volume II, Chapter 3, Section A).

Addendum: Derivation of Required-Revenue (Sales) Equations
(For further discussion see page III-50 of ICF, Inc. [July 1977]).

Case 1: Depletion = .50 • Gross Profit (GP) (1)

By definition:

Annual Cash Flow (CF) = Net Profit (NP) + Depreciation (DEP) + Depletion. (2)

Assuming a 50% Federal income tax rate,

$$NP = .50\ (GP - \text{Depletion}) \tag{3}$$

Substituting Equation (1) into Equation (3) yields:

$$NP = .50\ (GP - .5\ GP) = .25\ GP \tag{4}$$

Substituting Equations (1) and (4) into Equation (2) we have:

$$GP = 4\ (CF\text{-}DEP)/3. \tag{5}$$

By definition:

$$GP = \text{Required Revenue} - \text{Operating Costs (OC)} \tag{6}$$

From Equations (5) and (6) we have:

$$\left[\text{Required Revenue} = OC + \frac{4}{3}\ (CF\text{-}DEP)\right]. \tag{7}$$

Case 2: Depletion = .10 • Required Revenue (8)

From Equations (3) and (8):

$$NP = .50\ (GP - .10\ \text{Required Revenue}) \tag{9}$$

Substituting Equations (6), (8), and (9) into Equation (2) yields:

$$CF - DEP = (.55)\ \text{Required Revenue} - (.50)OC \tag{10}$$

Rearranging Equation (10) we have:

$$\left[\text{Required Revenue} = \frac{(.50)OC + CF - DEP}{.55}\right]. \tag{11}$$

CHPATER 3. THE COAL SUPPLY COST FUNCTION IN THE CEUM*

ICF develops estimates of real annuity coal prices for each allowable mine type by establishing two "base case" model mines, one surface and one deep, and a matrix of adjustment factors for costing changes in key variables. The base case model mines are defined as follows: The deep mine is a slope mine producing one million tons per year from a 72 inch coal seam with a seam depth of 700 feet; the surface mine produces one million tons per year with a 10:1 overburden ratio.

The deep-mine types costed consist of combinations of five mine sizes (annual output levels), five seam thicknesses, and four seam depth categories. The surface mine types costed consist of combinations of six mine sizes and seven overburden ratio categories. It is assumed that changes in any one of the mine type parameters (physical variables) affect one or more of four major cost-related variables. These variables include initial capital investment, deferred capital investment, output per man-day in terms of coal tonnage, and requirements for power and supplies. The matrix of cost adjustment factors employed by ICF is given in Table 1.

As implied by the formulation of real annuity coal prices in Chapter 2 above, ICF does not employ an explicit engineering cost function directly relating average cost (i.e., minimum acceptable real annuity coal price) to a mine's physical variables. Beginning with the matrix of cost adjustment factors, real annuity coal prices (RACPs) are determined in the CEUM Supply-Cose -- RAMC, in a sequential manner, built up in stages, component by component. The underlying cost function is only implicit.

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* This chapter was prepared by Neil L. Goldman, with computer support provided by James Gruhl.

TABLE 1

Mining Cost Adjustment Factors for Key Variables
(from ICF, Inc. [July 1977], page III-52)

	Initial Capital	Deferred Capital	Output/Manday 1/	Power and Supplies
Underground Mines 2/				
Seam Thickness	+6%/ft. decline in thickness	+6%/ft. decline in thickness	-1.0/TPMD/ft. decline in thickness	+$0.15/ton/ft. decline in thickness
Seam Depth	$500,000/100 ft.	--	--	--
Annual Output	30%/MMTPY	15%/MMTPY	0.5TPMD/0.1MMTPY	100%/MMTPY
Drift Mine	-$6,000,000	-$3,000,000	+10%	--
Conventional Mining	3/	3/		--
Surface Mines 4/				
Overburden Ratio	$1.20/Ton/UOR	$0.25/Ton/UOR	—10%/5UOR	$30,000/UOR
Annual Output:				
Mines ≥1.0MMTPY	5/	5/	3TPMD/0.1MMTPY	100%/MMTPY
Mines <1.0MMTPY	-5%/0.1MMTPY	-5%/0.1MMTPY	3TPMD/0.1MMTPY	100%/MMTPY

1/ The cost effects of changes in output per manday are calculated by dividing the estimated tons per manday figure for a gives mine type into the mine's annual output level to get the total number of mandays per year and then multiplying that figure by the average labor cost per manday (i.e., $53.98 for underground mines and $77.12 for surface mines). Note that output per manday is calculated based on the total number of mandays worked by all classes of mine employees in one year.

2/ Variations for underground mines are calculated from a base case operation which is defined as one million ton per year slope mine working a six foot seam seven hundred feet deep using continuous mining and having unit train loading facilities, no cleaning plant, and an average output per manday of 17.3 tons.

3/ Initial capital (less the cost of required shafts) and deferred capital investment costs for mines producing less than one million tons per year are assumed to remain constant on a dollars per ton of annual output basis with the capital costs after all other adjustments are made for one million ton mine with the same characteristics. This assumes that the capital intensity of mines with annual output levels of less than one million tons decreases with size.

4/ Variations in surface mine costs are calculated from a base case mine defined to produce one million tons per year from a six foot seam with a 10:1 overburden ratio using area mining techniques and having unit-train loading facilities but not preparation plant.

5/ The capital costs for surface mines producing over one million tons per year are assumed to experience increasing economies of scale with respect to capital costs. To reflect this the incremental capital required for each million ton increase in annual output is assumed to decline ten percent from the capital costs for a one million ton per year operations. Thus, capital costs for a two million ton per year mine would equal 1.9 times those for a one million ton mine, and capital for a three million ton per year operation would equal 2.7 times those for the one million ton mine.

ABBREVIATIONS:
- TPMD = tons per manday
- MMTPY = million tons per year
- UOR = units of overburden ratio.

For several reasons that will become clear below, we developed and programmed both an explicit analytical formulation of ICF's implied engineering cost function for both surface and deep mines, and explicit analytical formulations of the associated cost elasticities with respect to each physical variable. An explicit representation of elasticities is necessary in order to determine the relative influence of each physical variable on the RACP.

The reprogramming effort included the development of two versions of the cost function and its associated elasticities: an uncorrected version and a corrected version. The corrected version has been created by implementing in our own code many of the corrections to the CEUM Supply Code discussed in Volume II, Chapter 5, Section A. The specific corrections implemented are those relating to Points 5, 7, 8, 10, 14, 15, 18, 19, 20, 21, 22, and 23 in Volume II, Chapter 5, Section A. It should be pointed out that in the process of debugging our code and attempting to duplicate ICF's coal supply prices using the uncorrected cost function, we uncovered several of the errors in RAMC (Points 18-21) discussed in Volume II, Chapter 5, Section A. (The other errors were uncovered via a line-by-line verification of the RAMC code.) After duplicating all of ICF's errors in our uncorrected cost function code, we were able to match coal supply prices to five decimal places.

Chapter 4 below presents a detailed and explicit analytical formulation of the corrected version of the CEUM's implied engineering cost function and its associated cost elasticities, for both surface and deep mines. The remainder of this chapter discusses and illustrates the effects of the CEUM Supply Code corrections on the coal supply cost function.

Figure 1 illustrates the returns to scale that are implicit in the choice of cost adjustment factors for initial capital (IC) and deferred capital (DC) for both surface and deep mines. Note that because of the parabolic relationship between IC (or DC) and mine size (SZ) for surface mines with output greater than or equal to one million raw tons per year, the cost function for such mines is invalid for SZ > 10.5. (The largest mine size currently used in the CEUM is four million raw tons per year.)

It can easily be shown analytically from the equations in Chapter 4 below that the average cost curves (i.e., plots of RACP vs. SZ for any coal type in any region, given a set of physical variables) have no minimums. In other words, the CEUM models coal extraction as a decreasing cost activity (see Figure 2).

For each coal type existing in each region, we have calculated the RACP for all possible combinations of physical variables, using both the corrected and uncorrected versions of our cost function code. (There are 42 possible combinations of physical variables for surface mines and 100 possible combinations for deep mines.) ICF's RAMC supply curves do not include mine types for each possible combination of physical variables, either due to constraints disallowing certain values of a physical variable for a particular coal type in a region or due to a limit of 35 steps for each coal type's supply curve. It is quite unlikely that in the development of RAMC's mine costing algorithm any rigorous logic was imposed concerning allowable combinations of physical variables. Therefore, in analyzing the implied cost function in the CEUM (and especially the effects of corrections) we have purposely considered the entire set of possible combinations of physical variables for each coal type. It is fortunate that the largest percentage errors in RACPs as a result of corrections

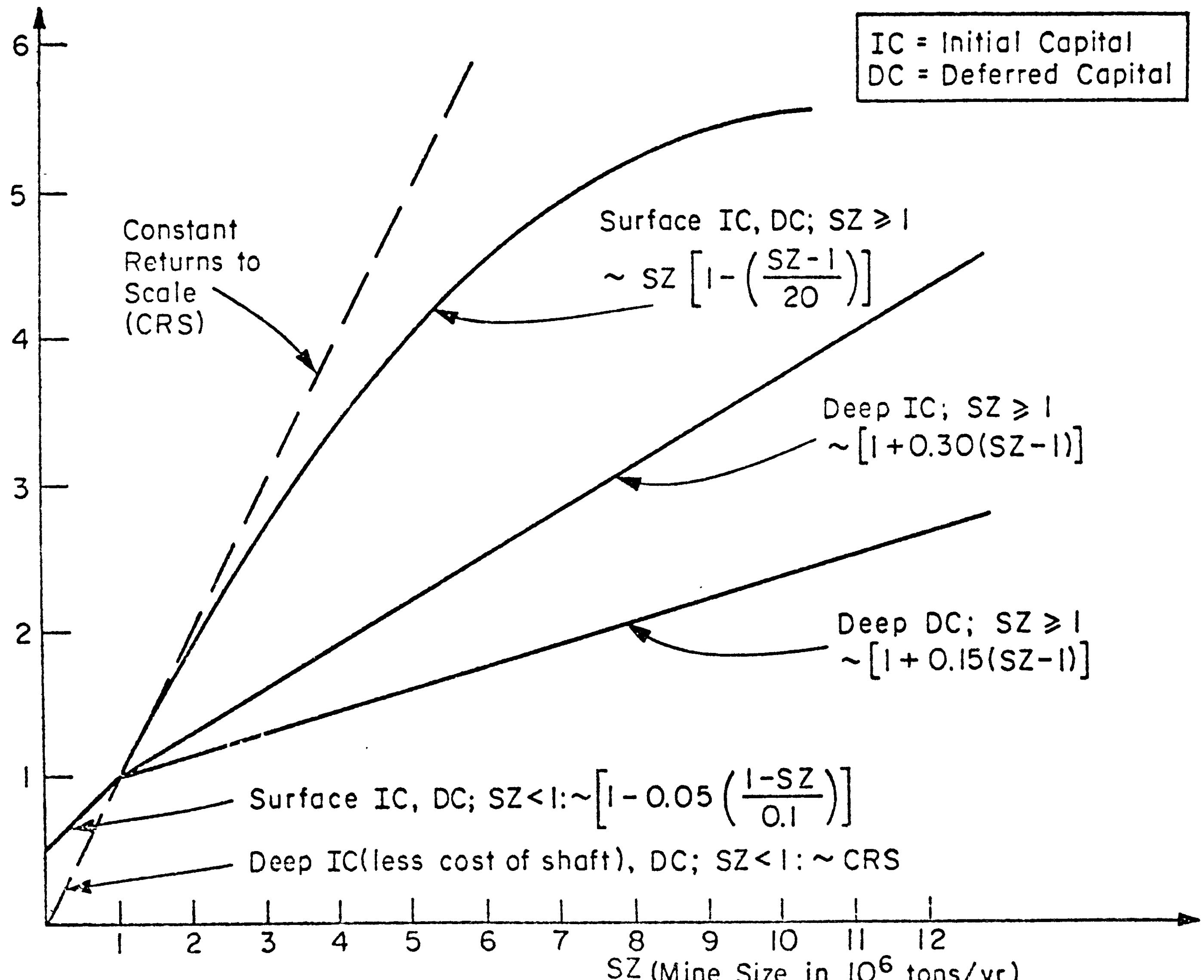


Figure 1. Returns to Scale for Initial Capital and Deferred Capital in the CEUM Cost Function.

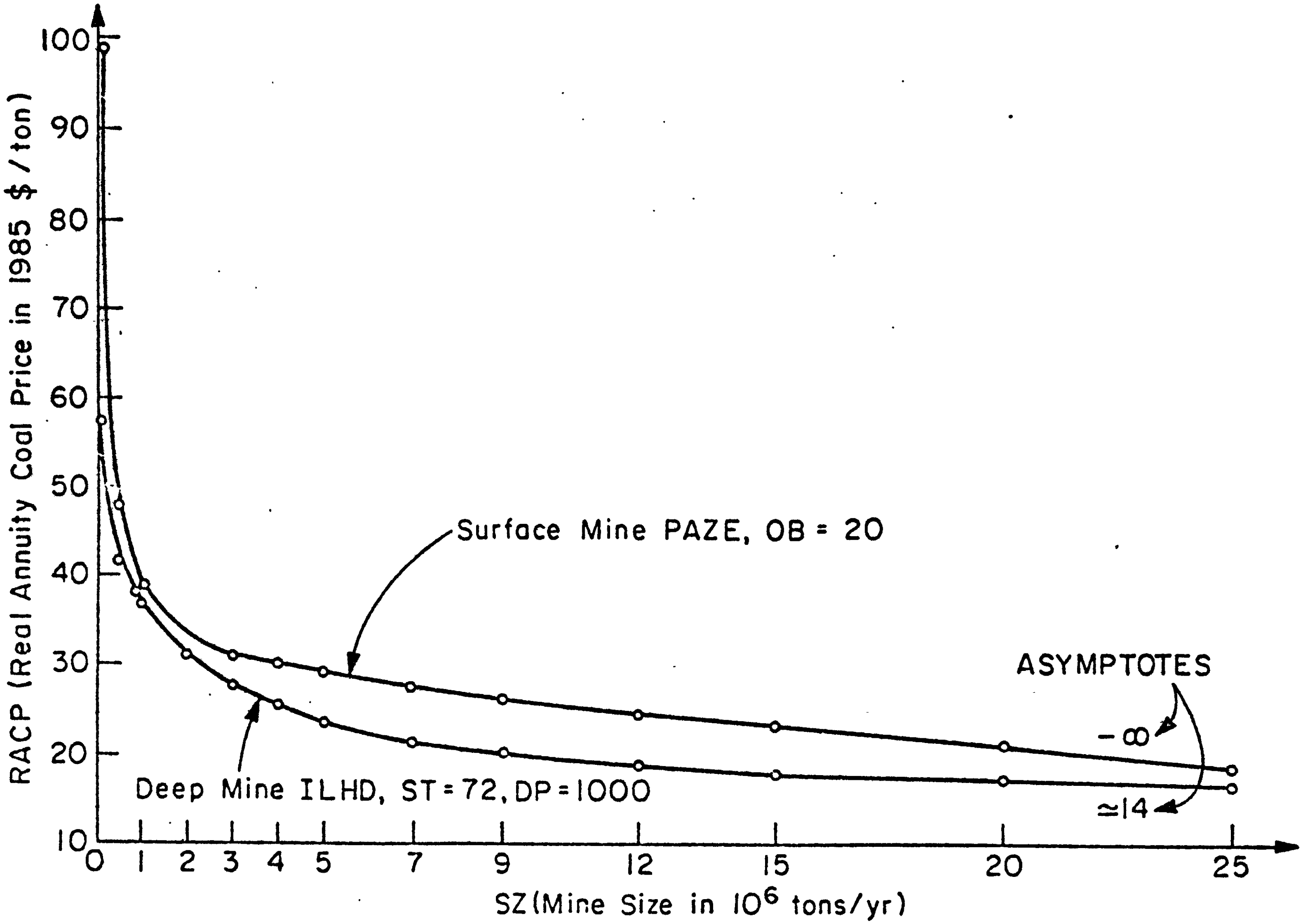


Figure 2. Average Cost Curves for Selected Surface and Deep Mine Types.
Note: The surface mine average cost curve is invalid for SZ > 10.5.

seem to occur for mine types not appearing on the RAMC supply curves (see Figures 3 and 4 below).

In Figures 3 through 6 we illustrate the effects of the CEUM Supply Code corrections on the coal supply cost function, both for particular coal types and for groups of coal types. On each figure the percentage change due to corrections is plotted vs. the uncorrected RACP. Each lettered point on a plot represents a mine type with a particular set of physical variables. Points either circled or squared appear on the corresponding RAMC supply curve for that coal type. Squared points are mine types with RACPs below the uncorrected equilibrium price and so represent mines that are opened.

Figure 3 displays the effects of corrections for an Illinois deep bituminous coal type (ILHD). The points denoted by the letters A and B refer to mine types with the smallest seam thickness. Note that the seam thickness error correction (Point 18 of Volume II, Chapter 5, Section A) by itself lowers the RACP, while the general effect of all the error corrections is to increase the RACP.

Figure 4 displays the effects of corrections for an Arkansas surface bituminous coal type (ARZE). The cleaning cost error correction (Point 5 of Volume II, Chapter 5, Section A) results in a large absolute decrease in costs for the ZA through ZE metallurgical coal types. The largest percentage effects will occur for the lowest priced mine types. It appears that this particular error correction dominates in Figure 4.

In Figures 5 and 6 we display the effects of corrections for five deep coal types and five surface coal types, respectively. In general, it appears that for coal types not affected by the cleaning cost correction the RACP for all mine types, both surface and deep, increases.

Figure 3. Effect of Cost Function Corrections--
Illinois Deep Bituminous Coal Type (ILHD)

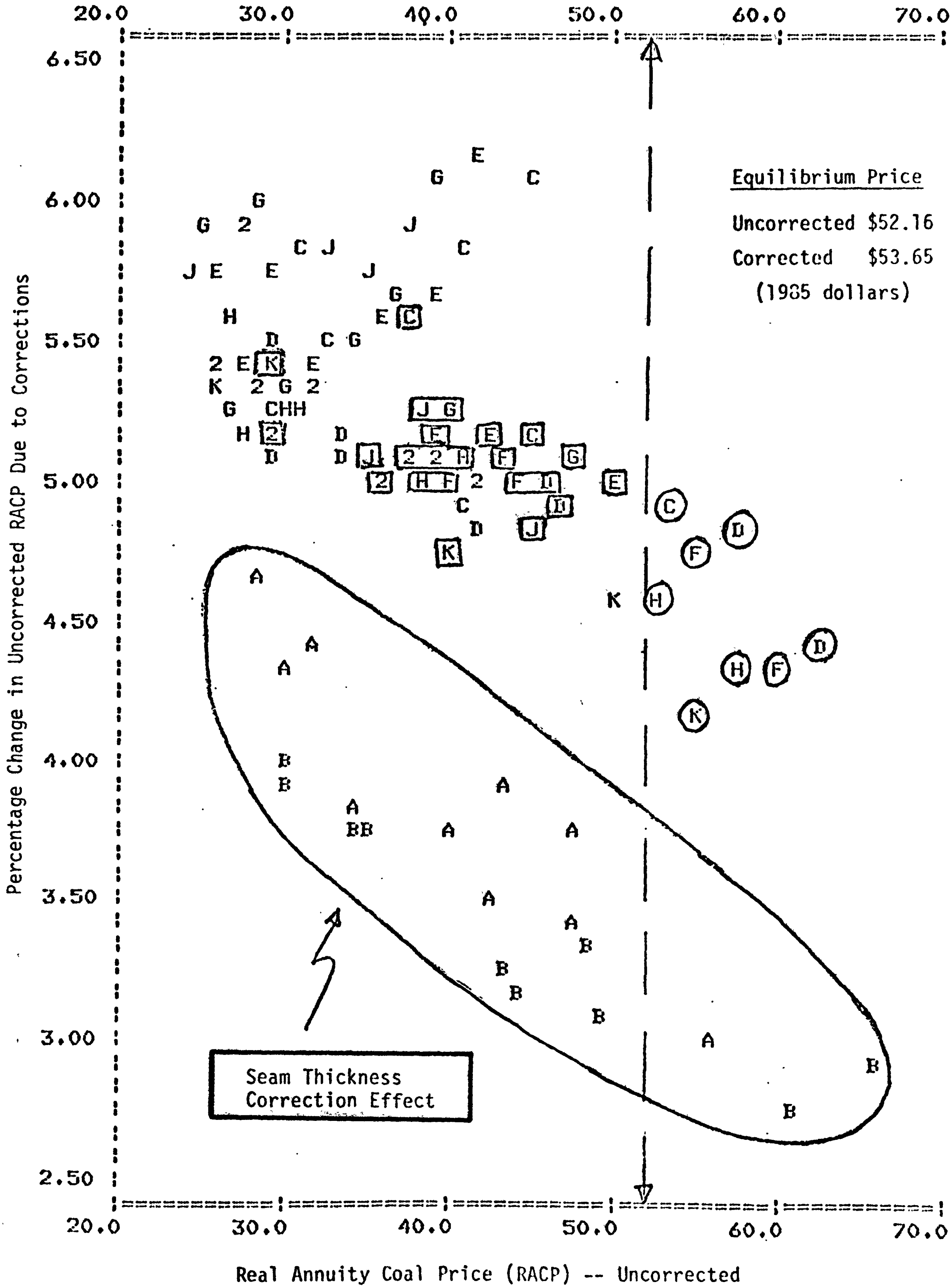


Figure 4. Effect of Cost Function Corrections--
Arkansas Surface Bituminous Coal Type (ARZE)

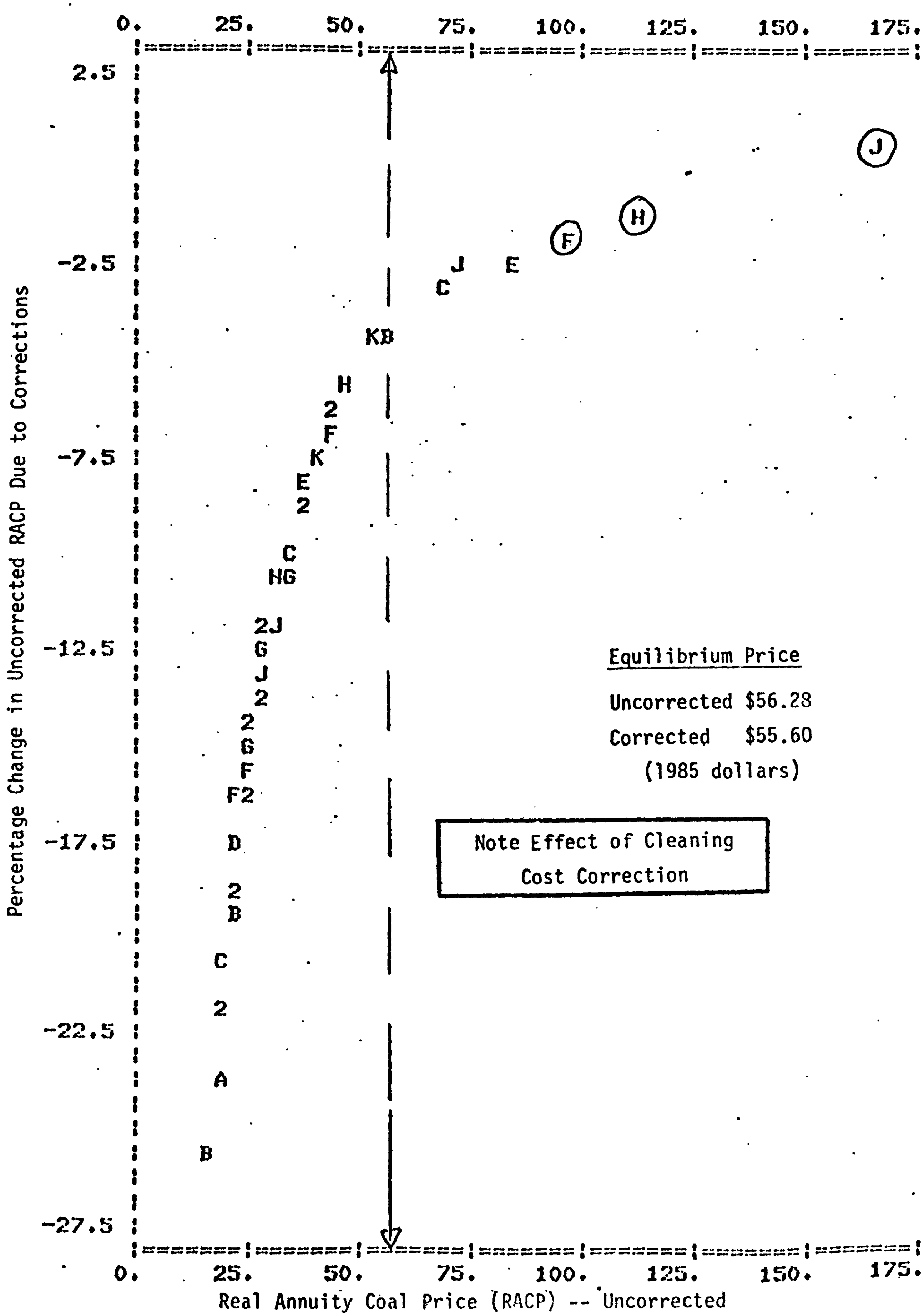


Figure 5. Effect of Cost Function Corrections--
Five Deep Coal Types

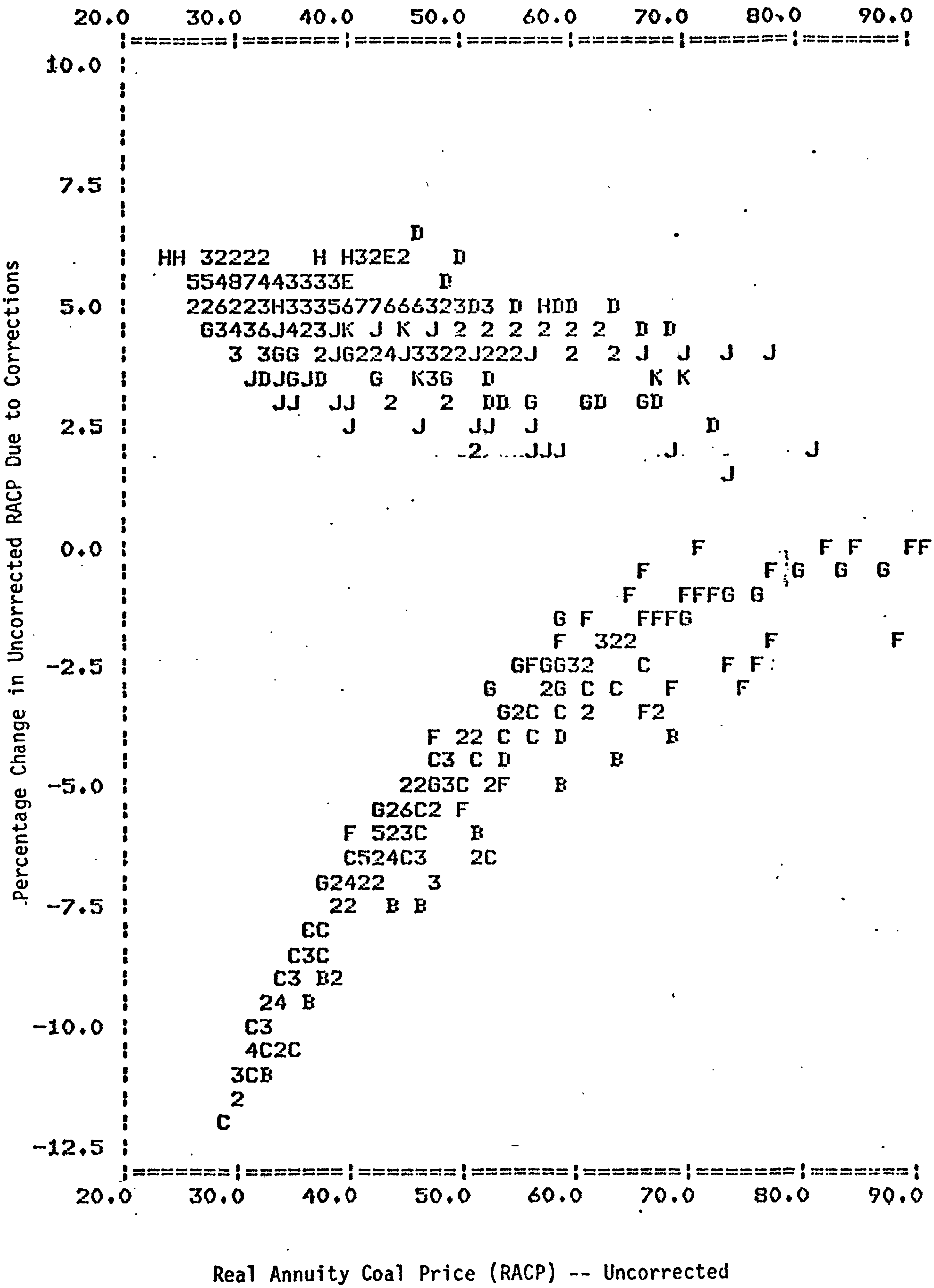
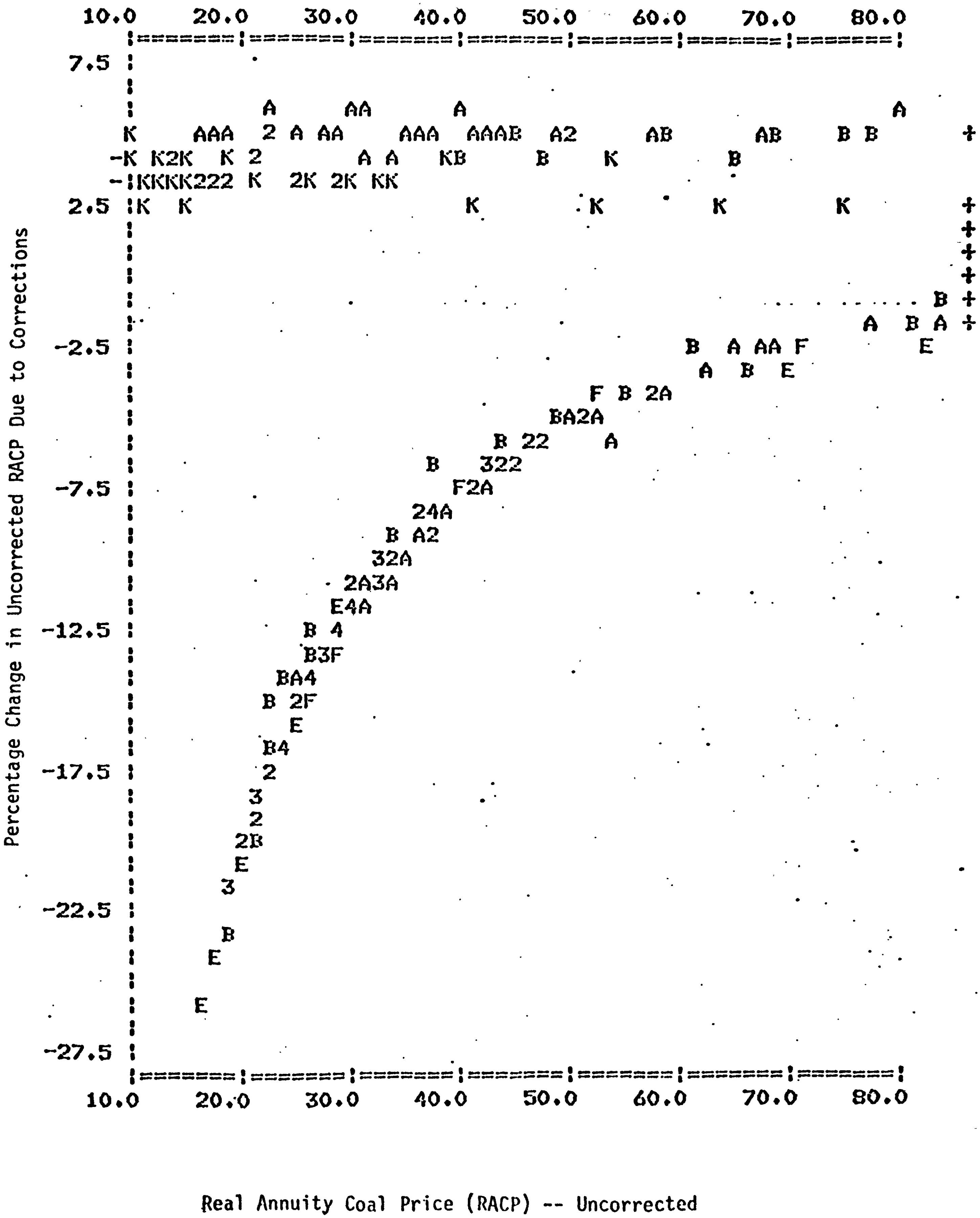


Figure 6. Effect of Cost Function Corrections--
Five Surface Coal Types



These increases are somewhat more uniform for surface mine types. For the metallurgical coal types ZA through ZE, the RACP decreases for all mine types except high-priced surface mines, with the largest percentage decreases corresponding to the lowest-priced mine types.

In Table 2, the sensitivity of the YIELD factor (see definition and use of the YIELD factor in Chapter 4 below), as an important data input to the cost function is illustrated for four particular coal types. Results are displayed for minimum, average, and maximum RACP over combinations of physical variables for each coal type.

Finally, Table 3 displays the average extremes for elasticities of RACP with respect to each physical variable for both surface and deep mines. Average elasticities across all combinations of physical variables are calculated for each coal type. The average extremes represent the minimum and maximum of these averages across all appropriate coal types. Note that the cost elasticities with respect to overburden ratio (OB) and seam thickness (ST) in Table 3 are significantly lower than those found by Zimmerman (1979). Zimmerman calculates approximate cost elasticities with respect to OB and ST of 1.0 and -1.1, respectively. As one would expect, the seam depth variable has the smallest relative influence on the RACP for deep mines. Also, the surface mine cost elasticities appear to have both a greater magnitude and range than the deep mine cost elasticities.

TABLE 2

Data Sensitivity Testing on Cost Function

Change of YIELD factor from variable in Base Case (varies from .60 to .95) to a global value of .875.

COAL TYPE		REAL ANNUITIZED COAL PRICE PER TON (RACP)		
		Minimum	Average	Maximum
		Over All Physical Variable Combinations		
PAZE Surface (Pennsylvania--Bituminous)				
Base Case:	YIELD = .85	16.34	50.71	210.42
	YIELD = .875	16.13	49.79	205.17
SVHB Surface (West Virginia, South--Bituminous)				
Base Case:	YIELD = .85	17.34	67.08	338.47
	YIELD = .875	17.11	65.78	329.85
EKZB Deep (Eastern Kentucky--Bituminous)				
Base Case:	YIELD = .60	34.97	57.58	101.08
	YIELD = .875	25.38	40.88	70.64
ILHD Deep (Illinois--Bituminous)				
Base Case:	YIELD = .80	25.73	40.22	67.86
	YIELD = .875	23.89	37.13	62.39

TABLE 3

Average Extremes for RACP Elasticities

Define:

PELOB = Elasticity of RACP with respect to overburden ratio.

PELST = Elasticity of RACP with respect to seam thickness.

PELDP = Elasticity of RACP with respect to seam depth.

PELSZ = Elasticity of RACP with respect to mine size.

	Elasticity	Low Average	--(coal type)	High Average	--(coal type)
Surface:	PELOB	.4378	(SVZE)	.7042	(EMLD)
	PELSZ	-.2679	(NVZF)	-.3928	(NDLA)
Deep:	PELST	-.1868	(INHE)	-.2315	(WAMA)
	PELSZ	-.2383	(INHE)	-.2789	(WAMA)
	PELDP	.0416	(WAMA)	.0523	(WMSA)

Note in the table above that when elasticities are negative, absolute values are used to distinguish between low and high.

CHAPTER 4. ANALYTICAL FORMULATION OF THE COAL SUPPLY COST FUNCTION AND ASSOCIATED ELASTICITIES*

This chapter presents a detailed and explicit analytical formulation of the corrected version of the CEUM's implied engineering cost function and its associated cost elasticities for both surface and deep mines. Note throughout that the minimum acceptable real annuity coal price (described in Section B above) is equivalent to average cost.

A. DEFINITIONS OF PARAMETERS AND VARIABLES

RACP = real annuity coal price in case year (1985) dollars per clean ton.

MYR = mine lifetime in years.

ECAP = nominal escalation rate in coal mine capital costs.

EMP = nominal escalation rate for coal mine labor costs.

EPAS = nominal escalation rate for coal mine costs of power and supplies; used in places as a proxy for the general inflation rate.

ROR = nominal after-tax cost of capital (nominal discount rate) for coal producers.

RUT = nominal after-tax cost of capital (nominal discount rate) for electric utilities.

APFAC = annuity price factor; analytically defined both in Volume 5, Section A and Section B above; a function of MYR, RUT, and the

SZ = mine size in millions of raw tons per year; the allowable sizes are 0.1, 0.5, 1.0, 2.0, 3.0, and 4.0, for surface mines and 0.1, 0.5, 1.0, 2.0, and 3.0, for deep mines.

OB = overburden ratio for surface mines; the allowable ratios are 5, 10, 15, 20, 25, 30, and 45.

ST = seam thickness in inches for deep mines; the allowable seam thicknesses are 28, 36, 48, 60, and 72.

DP = seam depth in feet for deep mines; the allowable seam depths are 0, 400, 700, and 1000.

*This chapter was prepared by Neil L. Goldman.

DR = drift mine switch; equals one when DP=0, and equals zero otherwise.

ICBS75 = initial capital cost for surface model-mine in thousands of base year (1975) dollars.

ICBD75 = initial capital cost for deep model-mine in thousands of base year (1975) dollars.

DCBS75 = total deferred capital cost for a 20-year surface model-mine in thousands of base year (1975) dollars.

DCBD75 = total deferred capital cost for a 20-year deep model-mine in thousands of base year (1975) dollars.

SLAB75 = labor cost in base year (1975) dollars per man-day for surface model-mine.

DLAB75 = labor cost in base year (1975) dollars per man-day for deep model-mine.

TPMDBS = raw tons per man-day for surface model-mine; varies by supply region.

TPMDBD = raw tons per man-day for deep model-mine; varies by supply region.

PSBS75 = power and supplies cost for surface model-mine in thousands of base year (1975) dollars per million raw tons of output.

PSBD75 = power and supplies cost for deep model-mine in thousands of base year (1975) dollars per million raw tons of output.

POW = power cost in thousands of base year (1975) dollars per million raw tons of output; varies by surface or deep mine.

WEL = union welfare cost in base year (1975) dollars per clean ton; varies by supply region.

WPD = union welfare cost in base year (1975) dollars per man-day.

ROY = royalty fee in base year (1975) dollars per clean ton; has a zero value in all supply regions.

LIC = licensing fee in base year (1975) dollars per clean ton.

SEVTR = severance tax rate as a percentage of required revenue (sales); varies by supply region.

SEVT = severance tax charge in base year (1975) dollars per clean ton; varies by supply region.

SEVT$ = severance tax charge in thousands of current dollars per mine year (constant in nominal terms); determined from SEVT; varies by supply region.

FED = Federal royalty tax rate (applies to coal mined on Federal lands) as a percentage of required revenue (sales); varies by surface or deep mine and by supply region.

EINS = exposure insurance charge as a percentage of labor costs; varies by surface or deep mine and by supply region.

AMR = abandoned mine reclamation charge in base year (1975) dollars per clean ton; varies by surface or deep mine and by Btu content level of coal.

BLUNG = insurance charge for Black Lung Disease in base year (1975) dollars per clean ton; varies by surface or deep mine and by BTU content level of coal.

FREC75, VREC75 = fixed and variable reclamation cost, respectively, in base year (1975) dollars per clean ton; varies by overburden ratio and by supply region.

FCL75, VCL75 = fixed and variable basic bituminous cleaning cost, respectively, in base year (1975) dollars per clean ton; varies by surface or deep mine, by sulfur content level of coal, and by Btu content level of coal.

YIELD = clean coal yield fraction in clean tons per raw ton; varies by surface or deep mine, by sulfur content level of coal, by Btu content level of coal, and by supply region.

IC75 = adjusted initial capital cost for any mine in thousands of base year (1975) dollars.

DC75 = adjusted total deferred capital cost for any 20-year mine in thousands of base year (1975) dollars.

TPMD = adjusted raw tons per man-day for any mine.

LAB75 = labor cost in thousands of base year (1975) dollars per year.

PAS75 = adjusted power and supplies cost in thousands of base year (1975) dollars per year.

CF_{JJ} = required annual cash flow, constant in thousands of current dollars per mine year (constant in nominal terms).

$CRF_{ROR,MYR}$ = capital recovery factor for coal producers; a function of ROR and MYR.

PV_{IC} = present value of initial capital cost, in case year dollars, as of beginning of case year (1985).

PV_{DC} = present value of deferred capital costs, in case year dollars, as of beginning case year dollar (1985).

PV_{CAP} = present value of total capital investment of coal producers, in case year dollars, as of beginning of case year (1985).

DCF_{JJ} = fraction of deferred capital spent at the end of each year of a mine's lifetime.

OC_{JJ} = total operating costs in thousands of current dollars per mine year.

LAB_{JJ} = labor cost in thousands of current dollars per mine year.

PAS_{JJ} = power and supplies cost in thousands of current dollars per mine year.

DEP_{JJ} = annual depreciation charge--total nominal capital costs divided by the mine lifetime.

PO_{JJ} = payroll overhead cost in thousands of current dollars per mine year.

WC_{JJ} = total union welfare cost in thousands of current dollars per mine year.

RF_{JJ}, LF_{JJ} = royalty and licensing cost, respectively, in thousands of current dollars per mine year.

IDC_{JJ} = indirect cost in thousands of current dollars per mine year.

TAI_{JJ} = property taxes and insurance cost in thousands of current dollars per mine year.

RR_{JJ} = total required revenue (sales) in thousands of current dollars per mine year.

$DEPL_{JJ}$ = annual depletion allowance either as a percentage of required revenue or as a percentage of gross profit.

GP_{JJ} = gross profit in thousands of current dollars per mine year.

JJ = counter on mine years.

B. COST ADJUSTMENT FACTORS

1. Surface Mines

(a) For SZ ≥ 1: (Note that Equations (1) & (2) are only valid for SZ ≤ 10.5)

$$IC75 = [ICBS75 + 1.20*10^3(OB-10)]\ SZ\ [1-(SZ-1)/20] \quad (1)$$

$$DC75 = [DCBS75 + 0.25*10^3(OB-10)]\ SZ\ [1-(SZ-1)/20] \quad (2)$$

(b) For SZ < 1:

$$IC75 = [ICBS75 + 1.20*10^3(OB-10)]\ [1-0.05(1-SZ)/0.1] \quad (3)$$

$$DC75 = [DCBS75 + 0.25*10^3(OB-10)]\ [1-0.05(1-SZ)/0.1] \quad (4)$$

(c) For any SZ:

$$TPMD = [TPMDBS + 3(SZ-1)/0.1][1 - 0.1(OB-10)/5] \quad (5)$$

$$LAB75 = (SZ*10^3/TPMD)\ SLAB75 \quad (6)$$

$$PAS75 = [PSBS75 + 30(OB-10)]\ SZ \quad (7)$$

2. Deep Mines

Note that if DP =0, DR = 1, and if DP ≠ 0, DR =0.

(a) For SZ ≥ 1:

$$IC75 = [ICBD75 + 500(DP-700)/100 - 6000(DR)][1 + 0.06(72-ST)/12] * [1 + 0.30(SZ-1)] \quad (8)$$

$$DC75 = [DCBD75 - 3000(DR)][1 + 0.06(72-ST)/12][1 + 0.15(SZ-1)] \quad (9)$$

(b) For SZ < 1:

$$IC75^* = [ICBD75 + 500(DP-700)/100 - 6000(DR)][1 + 0.06(72-ST)/12]$$

$$IC75 = [IC75^* - 500(DP/100)]\ SZ + 500(DP/100) \quad (10)$$

$$DC75 = [DCBD75 - 3000(DR)][1 + 0.06(72-ST)/12]\ SZ \quad (11)$$

(c) For any SZ:

$$TPMD = TPMDBD - 1.0(72-ST)/12 + 0.5(SZ-1)/0.1 \quad (12)$$

$$LAB75 = (SZ*10^3/TPMD)\ DLAB75 \quad (13)$$

$$PAS75 = [PSBD75 + 0.15 * 10^3(72-ST)/12]\ SZ. \quad (14)$$

C. CASH FLOW

$$CF_{JJ} = CRF_{ROR,MYR} * PV_{CAP} \qquad (15)$$

where:

$$CRF_{ROR,MYR} = ROR/[1 - (1 + ROR)^{-MYR}]$$

$$PV_{CAP} = PV_{IC} + PV_{DC}$$

$$PV_{IC} = IC75(1 + ECAP)^{10-2/3} (1 + EPAS)^{2/3}$$

$$PV_{DC} = DC75^{*}(1 + ECAP)^{10} \sum_{JJ=1}^{MYR} DCF_{JJ} \left(\frac{1 + ECAP}{1 + ROR}\right)^{JJ}$$

$$DC75^{*} = DC75(MYR - 10)/10.$$

Let: M25 = MYR/4, M50 = MYR/2, M75 = M25 + M50, M99 = MYR - 1.

When MYR is perfectly divisible by four:

$$\begin{aligned} DCF_{JJ} &= .05/M25 , \quad JJ = 1, \ldots, M25 \\ &= .90/M50 , \quad JJ = M25 +1, \ldots, M75 \\ &= .05/M99 , \quad JJ = M75 +1, \ldots, M99 \end{aligned}$$

When MYR is not perfectly divisible by four, see Point 20 in Volume II, Chapter 5, Section A for an amended version of the allocation of deferred capital.

D. OPERATING COSTS

$$\begin{aligned} OC_{JJ} = {} & LAB_{JJ} + PAS_{JJ} + PO_{JJ} + WC_{JJ} + RF_{JJ} + LF_{JJ} + IDC_{JJ} + TAI_{JJ} + DEP_{JJ} \\ & + [(FREC75 + FCL75)(1 + ECAP)^{11} + VREC75(1 + EMP)^{10+JJ} \\ & + VCL75(1 + EPAS)^{10+JJ} + AMR + BLUNG] \; SZ*10^{3}*YIELD \end{aligned} \qquad (16)$$

where:

$$LAB_{JJ} = LAB75(1 + EMP)^{10+JJ}$$

$$PAS_{JJ} = PAS75(1 + EPAS)^{10+JJ}$$

$$PO_{JJ} = [0.20 + 0.01(EINS)]\ LAB_{JJ}$$

$$WC_{JJ} = [SZ*10^3(WEL*YIELD + WPD/TPMD)]\ (1 + EMP)^{10+JJ}$$

$$RF_{JJ} = [ROY*(SZ*10^3*YIELD)]\ (1 + ECAP)^{10+JJ}$$

$$LF_{JJ} = [LIC*(SZ*10^3*YIELD)]\ (1 + ECAP)^{10+JJ}$$

$$IDC_{JJ} = 0.15[LAB_{JJ} + (PAS_{JJ} - POW*SZ*(1+EPAS)^{10+JJ})]$$

$$TAI_{JJ} = 0.02[PV_{IC}/(1+EPAS)^{2/3}]\ (1 + ECAP)^{2/3+JJ}$$

$$DEP_{JJ} = \left[PV_{IC}/(1+EPAS)^{2/3} + DC75((MYR-10)/10)(1+ECAP)^{10} * \sum_{JJ=1}^{MYR} DCF_{JJ}\ (1 + ECAP)^{JJ}\right] \Big/ MYR \qquad (17)$$

Note that for deep mines FREC75 = VREC75 = 0.0, and that ROY = 0.0 in every coal supply region.

E. REQUIRED REVENUE AND DEPLETION ALLOWANCE

It is assumed that the Federal Income Tax equals half of taxable income and that the depletion allowance equals 10% of required revenue up to 50% of gross profit.

From Section B above it can easily be shown that if $DEPL_{JJ} = 0.1*RR_{JJ}$, then:

$$RR_{JJ} = \frac{0.5\ OC_{JJ} + CF_{JJ} - DEP_{JJ}}{0.55[1 - (SEVTR + FED)]} + \frac{0.5\ SEVT\$}{0.55} \qquad (18)$$

If $DEPL_{JJ} = 0.5 * GP_{JJ}$ then:

$$RR_{JJ} = \frac{4/3\ (CF_{JJ} - DEP_{JJ}) + OC_{JJ}}{[1 - (SEVTR + FED)]} + SEVT\$ \qquad (19)$$

where:

$$GP_{JJ} = [1 - (SEVTR + FED)]\ RR_{JJ} - OC_{JJ} - SEVT\$, \text{ and} \tag{20}$$

$$SEVT\$ = SEVT * 10^3 * SZ * YIELD.$$

Note that in Equations (18) to (20), one or both of SEVTR and SEVT$ will be zero in each coal supply region. Also, FED = 0 in all but seven Western regions.

F. REAL ANNUITY COAL PRICE (RACP)

Again referring to Chapter 2 above, it can easily be shown that if

$DEPL_{JJ} = 0.1 * RR_{JJ}$, then:

$$RACP = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} \frac{1}{SZ}$$

$$* \left[\frac{0.5\ OC_{JJ} + CF_{JJ} - DEP_{JJ}}{0.55[1 - (SEVTR + FED)]} + \frac{0.5\ SEVT\$}{0.55} \right] \tag{21}$$

If $DEPL_{JJ} = 0.5 * GP_{JJ}$:

$$RACP = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} \frac{1}{SZ}$$

$$* \left[\frac{4/3\ (CF_{JJ} - DEP_{JJ}) + OC_{JJ}}{[1 - (SEVTR + FED)]} + SEVT\$ \right] \tag{22}$$

Substituting Equations (15), (16), and (17) into Equations (21) and (22) yields the following set of equations.

If $DEPL_{JJ} = 0.1 * RR_{JJ}$:

$$RACP = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} \frac{1}{SZ}$$

$$* [C1 + C2(B1_{JJ}*IC75 + B2_{JJ}*DC75 + B3_{JJ}*LAB75 + B4_{JJ}*PAS75$$

$$+ B5_{JJ}*(SZ/TPMD) + B6_{JJ}*SZ)] \qquad (23)$$

where:

$C1 = (0.5/0.55)\ SEVT\$$

$C2 = 1/(0.55[1 - (SEVTR + FED)])$

$$B1_{JJ} = (1 + ECAP)^{10-2/3} [CRF_{ROR,MYR}(1 + EPAS)^{2/3} + 0.01(1 + ECAP)^{2/3+JJ} - 1/(2*MYR)]$$

$$B2_{JJ} = (1+ECAP)^{10}\left[CRF_{ROR,MYR} \sum_{JJ=1}^{MYR} DCF_{JJ}\left(\frac{1+ECAP}{1+ROR}\right)^{JJ} - \frac{1}{2*MYR} \sum_{JJ=1}^{MYR} DCF_{JJ}(1+ECAP)^{JJ}\right]$$

$$* \ (MYR - 10)/10$$

$$B3_{JJ} = \frac{1}{2}(1 + EMP)^{10+JJ} [1.35 + 0.01*EINS]$$

$$B4_{JJ} = \frac{1}{2}(1 + EPAS)^{10+JJ} (1.15)$$

$$B5_{JJ} = \frac{1}{2}(1 + EMP)^{10+JJ} (10^3*WPD)$$

$$B6_{JJ} = \frac{1}{2} * 10^3 * YIELD [(1 + EMP)^{10+JJ} (WEL + VREC75) + (1 + ECAP)^{10+JJ}(ROY+LIC)$$

$$+ (1 + EPAS)^{10+JJ} VCL75 + (1 + ECAP)^{11} (FREC75 + FCL75) + AMR + BLUNG]$$

$$- \frac{1}{2}(1 + EPAS)^{10+JJ} (0.15*POW).$$

Recall again that for deep mines FREC75 = VREC75 = 0.0.

If $DEPL_{JJ} = 0.5 * GP_{JJ}$:

$$RACP = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1+RUT)^{-JJ} \frac{1}{SZ} [C1^* + C2^*(B1^*_{JJ} * IC75$$

$$+ B2^*_{JJ} * DC75 + B3^*_{JJ} * LAB75 + B4^*_{JJ} * PAS75 + B5^*_{JJ} * (SZ/TPMD)$$

$$+ B6^*_{JJ} * SZ)] \qquad (24)$$

where:

$C1^* = SEVT\$$

$C2^* = 1/[1 - (SEVTR + FED)]$

$$B1^*_{JJ} = (1+ECAP)^{10-2/3} [\tfrac{4}{3} CRF_{ROR,MYR}(1+EPAS)^{2/3} + 0.02(1+ECAP)^{2/3+JJ} - 1/(3*MYR)]$$

$$B2^*_{JJ} = (1+ECAP)^{10} \left[\frac{4}{3} CRF_{ROR,MYR} \sum_{JJ=1}^{MYR} DCF_{JJ} \left(\frac{1+ECAP}{1+ROR}\right)^{JJ} - \frac{1}{3*MYR} \sum_{JJ=1}^{MYR} DCF_{JJ} (1+ECAP)^{JJ} \right] * (MYR - 10)/10$$

$B3^*_{JJ} = 2 * B3_{JJ}$

$B4^*_{JJ} = 2 * B4_{JJ}$

$B5^*_{JJ} = 2 * B5_{JJ}$

$B6^*_{JJ} = 2 * B6_{JJ}$

Substitution of Equations (1) to (7) into Equations (23) and (24) yields a closed-form expression for RACP as a function of the surface mine physical variables, SZ and OB.

Substitution of Equations (8) to (14) into Equations (23) and (24) yields a closed-form expression for RACP as a function of the deep mine physical variables, SZ, ST, and DP.

G. RACP DERIVATIVES

Note that all derivatives below are calculated assuming that in each year of the mine's lifetime $DEPL_{JJ} = 0.1*RR_{JJ}$. If in any year $DEPL_{JJ} = 0.5*GP_{JJ}$ then $C1^*$, $C2^*$, $B1^*_{JJ}$, $B2^*_{JJ}$, $B3^*_{JJ}$, $B4^*_{JJ}$, $B5^*_{JJ}$, and $B6^*_{JJ}$ must be substituted appropriately.

1. Surface Mines

(a) For SZ ≥ 1.

Price derivative with respect to overburden ratio:

$$\frac{\partial(RACP)}{\partial(OB)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ}$$

$$* \; C2 \Big[[B1_{JJ}(1.20*10^3) + B2_{JJ}(0.25*10^3)][1 - (SZ-1)/20]$$

$$+ \; (0.02) \; [B3_{JJ}(10^3*SLAB75) + B5_{JJ}][TPMDBS + 3(SZ-1)/0.1]^{-1}$$

$$* \; [1 - 0.1(OB-10)/5]^{-2} \; + \; 30*B4_{JJ} \Big] \qquad (25)$$

Price derivative with respect to mine size:

$$\frac{\partial(RACP)}{\partial(SZ)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} \Big\{ - C1/(SZ)^2$$

$$+ \; C2 \Big[- \frac{1}{20} B1_{JJ} \; [ICBS75 + 1.20*10^3(OB - 10)]$$

$$- \frac{1}{20} B2_{JJ} \; [DCBS75 + 0.25*10^3(OB - 10)]$$

$$- \; 30 \; [B3_{JJ}(10^3*SLAB75) + B5_{JJ}] \; [TPMDBS + 3(SZ - 1)/0.1]^{-2}$$

$$* \; [1 - 0.1(OB - 10)/5]^{-1} \Big] \Big\} \qquad (26)$$

(b) For SZ < 1.

Price derivative with respect to overburden ratio:

$$\frac{\partial(RACP)}{\partial(OB)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ}$$

$$* \; C2 \Big[[B1_{JJ}(1.20*10^3) + B2_{JJ}(0.25*10^3)] \; [1 - 0.05(1-SZ)/0.1] \; \frac{1}{SZ}$$

$$+ (0.02) \; [B3_{JJ}(10^3*SLAB75) + B5_{JJ}] \; [TPMDBS + 3(SZ-1)/0.1]^{-1}$$

$$* \; [1 - 0.1(OB-10)/5]^{-2} + 30*B4_{JJ} \Big] \qquad (27)$$

Price derivative with respect to mine size:

$$\frac{\partial(RACP)}{\partial(SZ)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1+RUT)^{-JJ} \Big\{ - C1/(SZ)^2$$

$$+ \; C2 \Big[-B1_{JJ}[ICBS75 + 1.20*10^3(OB-10)] \; \frac{1}{2*(SZ)^2}$$

$$- \; B2_{JJ}[DCBS75 + 0.25*10^3(OB-10)] \; \frac{1}{2*(SZ)^2}$$

$$- \; 30[B3_{JJ}(10^3*SLAB75) + B5_{JJ}] \; [TPMDBS + 3(SZ-1)/0.1]^{-2}$$

$$* \; [1 - 0.1(OB-10)/5]^{-1} \Big] \Big\} \qquad (28)$$

2. Deep Mines

(a) For SZ ≥ 1.

Price derivative with respect to seam thickness:

$$\frac{\partial(RACP)}{\partial(ST)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} * C2 \Big[-(0.005)\ B1_{JJ}$$

$$* [ICBD75 + 5(DP - 700) - 6000*DR]\ [1 + 0.30(SZ-1)]\ \frac{1}{SZ}$$

$$- (0.005)\ B2_{JJ}[DCBD75 - 3000*DR]\ [1 + 0.15(SZ-1)]\ \frac{1}{SZ}$$

$$- \frac{1}{12} [B3_{JJ}(10^3*DLAB75) + B5_{JJ}]\ [TPMDBD - (72-ST)/12 + 0.5(SZ-1)/0.1]^{-2}$$

$$- \frac{1}{12} (0.15*10^3)\ B4_{JJ} \Big] \qquad (29)$$

Price derivative with respect to seam depth:

$$\frac{\partial(RACP)}{\partial(DP)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} * C2 \Big[5*B1_{JJ}$$

$$* [1 + 0.06(72-ST)/12]\ [1 + 0.30(SZ-1)]\ \frac{1}{SZ} \Big] \qquad (30)$$

Price derivative with respect to mine size:

$$\frac{\partial(RACP)}{\partial(SZ)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} \Big\{ - C1/(SZ)^2$$

$$+ C2 \Big[-(0.7)\ B1_{JJ}[ICBD75 + 5(DP-700) - 6000*DR]$$

$$* [1 + 0.06(72-ST)/12] \frac{1}{(SZ)^2} - (0.85)\ B2_{JJ}[DCBD75 - 3000*DR]$$

$$* [1 + 0.06(72-ST)/12] \frac{1}{(SZ)^2} - 5[B3_{JJ}(10^3*DLAB75) + B5_{JJ}]$$

$$* [TPMDBD - (72-ST)/12 + 0.5(SZ-1)/0.1]^{-2} \Big] \Big\} \qquad (31)$$

(b) For SZ < 1.

Price derivative with respect to seam thickness:

$$\frac{\partial(RACP)}{\partial(ST)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} * C2 \Big[-(0.005)\ B1_{JJ}$$

$$* \ [ICBD75 + 5(DP-700) - 6000*DR] - (0.005)\ B2_{JJ}$$

$$* \ [DCBD75 - 3000*DR] - \frac{1}{12} [B3_{JJ}(10^3*DLAB75) + B5_{JJ}]$$

$$* \ [TPMDBD - (72-ST)/12 + 0.5(SZ-1)/0.1]^{-2} - \frac{1}{12} (0.15*10^3)\ B4_{JJ} \Big] \qquad (32)$$

Price derivative with respect to seam depth:

$$\frac{\partial(RACP)}{\partial(DP)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} * C2 \Big[5*B1_{JJ}$$

$$* \ [\ (1 + 0.06(72-ST)/12) + (\ \frac{1}{SZ} - 1\ )\ ] \Big] \qquad (33)$$

Price derivative with respect to mine size:

$$\frac{\partial(RACP)}{\partial(SZ)} = (APFAC*10^3*YIELD)^{-1} \sum_{JJ=1}^{MYR} (1 + RUT)^{-JJ} \Big\{ - C1/(SZ)^2$$

$$+ \ C2 \Big[-5*B1_{JJ}*DP \frac{1}{(SZ)^2} - 5\ [B3_{JJ}(10^3*DLAB75) + B5_{JJ}]$$

$$* \ [TPMDBD - (72-ST)/12 + 0.5(SZ-1)/0.1]^{-2} \Big] \Big\} \qquad (34)$$

H. RACP ELASTICITIES

The elasticities of the real annuity coal price with respect to each physical variable, for both surface and deep mines, are calculated in the usual way. Let X denote any physical variable. Then the elasticity of RACP with respect to X is given by:

$$\frac{X}{RACP} \frac{\partial(RACP)}{\partial(X)} \quad . \tag{35}$$

I. FINAL NOTES

(a) Note that for surface mines the derivatives of RACP with respect to OB and SZ are not continuous at SZ = 1.

(b) Note that for deep mines RACP is not continuous at DP = 0 (i.e., for deep drift mines) and that the derivatives of RACP with respect to ST, DP, and SZ are not continuous at both SZ = 1 and DP = 0.

(c) Each elasticity has its expected sign.

CHAPTER 5. LISTING OF THE COMPUTER CODE FOR THE COAL SUPPLY COST FUNCTION

This chapter contains a listing of the Cost Function program that we developed (1) to verify the engineering cost function implicit in the Supply Code of the CEUM, and (2) to determine ranges, sensitivities, derivatives, and elasticities of general cost function variables.

Figure 1 shows a listing of the Conversational Monitor System (CMS) control language execute routine that initiates the operation of the object deck of our Cost Function program. This execute routine incorporates an interactive query to the user about the choice of output device, either the high-speed printer or the user's terminal.

Figure 2 contains the FORTRAN listing of our Cost Function code. The program is held entirely within a single main routine, that is, subroutines and data blocks are not separated. The first section of the code contains the dimension and equivalence statements. Next is an interactive namelist feature that allows the user a choice of several program options without the necessity of recompilation. These user options include:

(1) optional yearly nominal coal price outputs,

(2) display of real annuity coal prices and associated derivatives and cost elasticities for all physical variable (mine type) combinations,

(3) error messages at different program points,

(4) use of either an uncorrected version (to match ICF's results) of the Cost Function program, or a version that incorporates the

* This chapter was prepared by Neil L. Goldman and James Gruhl.

Verification Corrections discussed in Volume II, Chapter 5, Section A,

(5) specific combinations of mine sizes, overburden ratios, seam thicknesses, and seam depths that can be investigated, instead of a consideration of all physical variable combinations, and

(6) a choice of considering all 236 coal types, or up to 40 user-specified coal types.

Following this interactive section, the listing displays the input data for the model run. Some of these data are in block listings; other data arrays are filled in with conditional loop sequences. Actual computations are then begun, one coal type at a time, with a major branchpoint separating the two main sections of the program: surface- and deep-coal types.

Outputs from the program are formatted and labelled so as to be easily read. The output information includes minimums, averages, and maximums of:

(1) real annuity coal prices (RACPs),

(2) derivatives of RACP with respect to mine sizes, overburden ratios, seam thicknesses, and seam depths, and

(3) elasticities of RACP with respect to those same physical variables.

Outputs can be printed for each coal type, physical variable combination, or year, depending on which option the user has selected.

Again, depending upon the user options selected, the run time for the program can range from small fractions of a minute to three or four minutes CPU time. This Cost Function program is in the public domain and can be made available on cards or tape for a nominal charge.

Figure 1. Listing of the Control Sequence for Operation of the Cost Function Program.

```
        &CONTROL ERROR TIME
        &ERROR &EXIT &RETCODE
        &TYPE COAL SUPPLY COST FUNCTION PROGRAM
        CP TERMINAL LINESIZE 132
        CP SPOOL PRT CLOSE
        &TYPE .      IF NEED HELP CONTACT J. GRUHL OR N. GOLDMAN
        &TYPE .
        &TYPE .  OUTPUT SHOULD BE SENT TO
  -QUES &TYPE .  TERMINAL OR PRINTER, TYPE WHICH ONE
        &READ VARS &TORP
        &IF &TORP NE TERMINAL &IF &TORP NE PRINTER &GOTO -QUES
        FILEDEF 9 CLEAR
        &IF &TORP EQ TERMINAL FILEDEF 9 TERMINAL
        &IF &TORP EQ PRINTER FILEDEF 9 PRINTER
        &TYPE .  ... MODULE LOADING BEGINS
        GLOBAL TXTLIB FORTMOD2 CMSLIB
        LOAD COST
        START
        CP SPOOL PRT CLOSE
        &END
        END
```

Figure 2. Listing of the Code of the Cost Function Program

```
C
C******************************************************************************
C******COAL COST FUNCTION PROGRAM DEVELOPED BY*********************************
C******NEIL GOLDMAN WITH IMPLEMENTATION AND PROGRAMMING************************
C******HELP FROM JAMES GRUHL, JUNE 14-JULY,10 1979*****************************
C******THE PROGRAM EXPLICITLY CALCULATES THE***********************************
C******COST FUNCTION IMPLICIT IN THE ICF CEUM**********************************
C******RAMC COMPUTER CODE.  THE COST FUNCTION**********************************
C******AND ASSOCIATED ELASTICITIES ARE DEVELOPED*******************************
C******AS FUNCTIONS OF THE PHYSICAL VARIABLES**********************************
C******FOR BOTH SURFACE AND DEEP MINES.****************************************
C******************************************************************************
C
C*****************************************************
C****** DIMENSIONING AND DESIGNATIONS ***************
C*****************************************************
C
      REAL MYR, ICBS75, ICBD75, LIC,MDPY,IC75,LB75
      INTEGER SSIZE,SOVER,DSIZE,DDEPTH,DTHICK,Z1,Z2,Z3,Z4,Z5
      INTEGER Z6,Z7,Z8,Z9,Z10,Z11,Z12,Z13,Z14,Z15,Z16,Z17,Z18
      INTEGER Z19,Z20,Z21,Z22,Z23,Z24,Z25,Z26,Z27,Z28,Z29,Z30
      INTEGER Z31,Z32,Z33,Z34,Z35,Z36,Z37,Z38,Z39,Z40
      NAMELIST/PRINT/NYR,NPH,NER,NVER/LIMIT/SSIZE,SOVER,DSIZE,
     &DDEPTH,DTHICK,Z1,Z2,Z3,Z4,Z5,Z6,Z7,Z8,Z9,Z10,Z11,Z12,Z13,Z14,Z15,Z
     &16,Z17,Z18,Z19,Z20,Z21,Z22,Z23,Z24,Z25,Z26,Z27,Z28,Z29,
     &Z30,Z31,Z32,Z33,Z34,Z35,Z36,Z37,Z38,Z39,Z40
      DATA NYR,NPH,NER,NVER,SSIZE,SOVER,DSIZE,DDEPTH,DTHICK,Z1,Z2,Z3,Z4,
     &Z5,Z6,Z7,Z8,Z9,Z10,Z11,Z12,Z13,Z14,Z15,Z16,Z17,Z18,Z19,Z20,Z21,Z22
     &,Z23,Z24,Z25,Z26,Z27,Z28,Z29,Z30,Z31,Z32,Z33,Z34,Z35,Z36,Z37,Z38,
     &Z39,Z40/4*2,45*0/
      DIMENSION AMRM(5,2),BLUNGM(5,2),WEL75(30),SEVTRM(30),
     &SEVT$M(30),FEDM(2,30),YIELDM(8,5,30,2),TPMDB(2,30)
     &,EINS(2,30),CL75(8,2,5),DCFRAC(40),IZ(40)
     &,RECL(7,2,30),IDCOD(236),IDSUL(236),IDBTU(236),
     &IDREG(236),OBM(7),SZSM(14),STM(5),DPM(4),SZDM(14),
     &RACPS(3,236),DPDOB(3,236),DPDSZ(3,236),PELOB(3,236),
     &PELSZ(3,236),RACPD(3,236),DPDST(3,236),DPDDP(3,236),
     &PELST(3,236),PELDP(3,236)
      DIMENSION XSZ(2,5),XOB(2,5),XSZD(2,7),XDP(2,7),XST(2,7)
      DIMENSION B1(40),B1S(40),B2(40),B2S(40),B3(40),B3S(40),
     &B4(40),B4S(40),B5(40),B5S(40),B6(40),B6S(40)
      DIMENSION RECL1(210),RECL2(210)
      EQUIVALENCE (RECL1(1),RECL(1)),(RECL2(1),RECL(211))
C
C**********************
C******INPUT DATA BASE
C**********************
C
      DATA MYR,APFAC/30.0,16.748/
      DATA ISWITA,ISWITB,ISWITC,NEIL/2,2,2,2/
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C*****************************************************
C******IF ISWITB=1 THEN DETAILED PRINTOUT OF YEARLY
C******   OC,RR,PRICE,DCFR,PVDC
C******IF SWITA=1 PRINTOUT PRICES,DERIV, &ELAST
C******   FOR ALL PHYSICAL VARIABLE COMBINATIONS
C******IF ISWITC=1 PRINTOUT ERROR LOCATION DIAGNOSTICS
C******IF NEIL=1 ORIGINAL NEIL ICF PROGRAM
C******          =2 UPDATED AND CORRECTED NEIL VERSION
C*****************************************************
C
      WRITE(6,70)
   70 FORMAT(1X,/,3X,'**************',/,3X,'* PROMPTING *',/,3X,'********
     &******',/,5X,'THE DEFAULTS ARE ALL 2:',/,
     &8X,'IF NYR=1 YEARLY PRICE OUTPUTS, =2 NONE,',/,
     &8X,'IF NPH=1 PHYSICAL VAR OUTPUTS, =2 NONE,',/,
     &8X,'IF NER=1 ERROR CHECKPTS GIVEN, =2 NONE,',/,
     &8X,'IF NVER=1 ORIGINAL ICF VERSION,',/,
     &8X,'   NVER=2 CORRECTED ICF VERSION,',/,/,
     &'   &PRINT NYR,NPH,NER,NVER &END <AS INTEGERS>')
      READ(5,PRINT)
       ISWITA=NPH
       ISWITB=NYR
       ISWITC=NER
       NEIL=NVER
      IF(NEIL.EQ.1)N9=9
      IF(NEIL.NE.1)N9=10
      DATA ROR,RUT/0.150,0.100/
      DATA IER/0/
      DATA ECAP,EMP,EPAS/0.060,0.065,0.055/
      DATA ICBS75,ICBD75/17700.0,29300.0/
      DATA DCBS75,DCBD75/3200.0,11700.0/
      DATA SLAB75,DLAB75/78.04,69.24/
      DATA PSBS75,PSBD75/1226.0,2835.0/
      DATA POWS75,POWD75/400.0,500.0/
      DATA WPD75,ROY,LIC/10.96,0.0,0.10/
      DATA OBM/5.0,10.00,15.0,20.0,25.0,30.,45./
      DATA SZSM/.1,.5,1.,2.,3.,4./
      DATA STM/28.,36.,48.,60.,72./
      DATA DPM/0.,400.,700.,1000./
      DATA SZDM/.1,.5,1.,2.,3./
      DATA AMRM/.35,.35,.35,.35,.25,5*.15/
      DATA BLUNCM/4*.25,0.,5*.5/
      DATA WEL75/17*.72,5*0.,5*.72,3*0./
      DATA SEVTRM/3*0.,2*.0385,0.,.045,4*0.,.045,6*0.,.006,.2,.3,
     &.105,7*0.,.02/
      DATA SEVTIM/0.,.04,5*0.,.18,.31,7*.0,.02,.58,4*0.,.26,2*.0,.34,
     &2*0.,.26,0./
      DATA FEDM/31*00.,.125,.08,2*0.,.125,.08,.125,.08,.125,.08,.125,
     &.08,4*0.,.125,.08,4*0.,.125,.08,2*0./
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
       DATA TPMDB/41.4,18.2,41.4,18.2,41.4,18.2,41.4,18.2,
     &32.4,17.3,32.4,17.3,32.4,17.3,32.4,17.3,41.4,18.2,
     &46.8,19.7,46.8,19.7,46.8,19.7,46.8,19.7,46.8,19.7,
     &46.8,19.7,46.8,19.7,46.8,19.7,
     &45.,17.3,45.,17.3,45.,17.3,50.4,18.8,50.4,18.8,
     &50.4,18.8,50.4,18.8,50.4,18.8,50.4,18.8,
     &46.8,15.7,54.,17.3,50.4,18.8,50.4,18.8/
      DATA EINS/18.,34.,18.,34.,10.,31.,6.,18.,6.,18.,16.,31.,
     &9.,23.,6.,25.,5.,23.,20.,32.,14.,21.,9.,23.,7.,26.,10.,33.,
     &8.,33.,6.,23.,9.,22.,9.,0.,9.,0.,7.,0.,0.,0.,14.,24.,8.,22.,
     &8.,31.,14.,39.,7.,23.,13.,23.,16.,0.,8.,22.,13.,36./
      DATA CL75/8*1.14,8*.56,8*1.14,8*.56,8*1.14,8*.56,32*0./
C
C*************************************************************
C****** CORRECTIONS TO ORIGINAL VERSION ***********
C*************************************************************
C
      IF(NEIL.NE.1)GO TO 96
      DO 95 I=1,5
        CL75(I,1,1)=3.17
        CL75(I,2,1)=2.23
   95 CONTINUE
   96 CONTINUE
C
C**************************************
C****** FILLING IN BLOCKED DATA *******
C**************************************
C
      DATA YIELDM/1200*.85,1200*.80/
      DO 101 K=1,30
       DO 100 I=1,4
        YIELDM(I,1,K,1)=.70
        YIELDM(I,1,K,2)=.60
       YIELDM(I,1,23,1)=.80
       YIELDM(I,1,26,1)=.80
       YIELDM(I,1,23,2)=.70
       YIELDM(I,1,26,2)=.70
  100 CONTINUE
  101 CONTINUE
      DO 104 K=1,30
       DO 103 J=4,5,1
        DO 102 I=1,8
         YIELDM(I,J,K,1)=.95
         YIELDM(I,J,K,2)=.95
  102   CONTINUE
  103  CONTINUE
  104 CONTINUE
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
      DO 106 J=2,3,1
       DO 105 I=1,8
        YIELDM(I,J,27,1)=.80
        YIELDM(I,J,27,2)=.70
105    CONTINUE
106   CONTINUE
      DATA RECL1/1.74,2.77,3.63,4.61,5.44,6.38,9.25,1.32,2.08,
     &2.70,3.40,3.99,4.68,6.74,1.59,2.63,3.49,4.47,5.29,6.24,
     &9.100,1.31,2.06,2.67,3.38,3.97,4.65,6.71,1.74,2.77,3.63,
     &4.61,5.43,6.39,9.25,1.32,2.07,2.69,3.39,3.98,4.67,6.73,
     &1.74,2.78,3.63,4.61,5.44,6.39,9.25,1.26,2.01,2.63,3.33,
     &3.92,4.61,6.67,1.56,2.90,4.28,5.65,7.10,8.48,12.65,1.57,
     &2.53,3.53,4.51,5.55,6.55,9.55,1.56,2.91,4.28,5.65,7.10,
     &8.48,12.65,1.61,2.58,3.58,4.56,5.60,6.59,9.59,1.56,2.90,
     &4.28,5.65,7.06,8.48,12.65,1.54,2.51,3.50,4.48,5.52,6.52,
     &9.52,1.24,2.28,3.14,4.12,4.94,5.89,8.75,1.31,2.06,2.67,
     &3.38,3.97,4.66,6.71,1.15,2.18,3.04,4.02,4.84,5.80,8.66,
     &1.34,2.09,2.70,3.41,4.,4.68,6.74,.13,.19,.25,.29,
     &.34,.37,.4,.22,.27,.31,.33,.36,.38,.4,.14,
     &.2,.26,.3,.35,.37,.41,.25,.29,.33,.35,.39,
     &.4,.43,.13,.2,.26,.3,.34,.37,.4,.22,.27,
     &.31,.33,.36,.38,.4,.19,.25,.31,.35,.4,.43,
     &.46,.24,.28,.32,.35,.38,.4,.42,.15,.21,.27,
     &.31,.36,.38,.42,.27,.31,.35,.38,.41,.43,.45,
     &.19,.25,.31,.35,.4,.42,.46,.4,.44,.48,.51,
     &.54,.56,.58/
      DATA RECL2/.15,.21,.27,.31,.36,.38,.41,.42,
     &.46,.5,.52,.56,.57,.6,.18,.25,.31,.35,.36,
     &.38,.41,.4,.44,.48,.51,.54,.56,.58,
     &.14,.21,.26,.3,.35,.38,.41,.14,.19,.22,.25,.29,.3,.32,
     &.14,.21,.26,.3,.35,.38,.41,.14,.19,.22,.25,.29,.3,.32,
     &.11,.17,.23,.27,.32,.34,.38,.07,.14,.18,.20,.24,.25,.28,
     &.11,.17,.23,.27,.32,.34,.38,.09,.14,.18,.20,.24,.25,.28,
     &.11,.17,.23,.27,.32,.35,.38,.09,.13,.17,.20,.23,.25,.28,
     &.15,.22,.28,.31,.36,.39,.42,.17,.22,.26,.28,.32,.33,.36,
     &14*0.,.11,.17,.23,.27,.32,.35,.38,.11,.16,.2,.22,.25,.27,.29,
     &.13,.19,.25,.29,.34,.36,.39,.13,.17,.21,.24,.27,.29,.31,
     &.12,.18,.24,.28,.33,.35,.39,.1,.15,.19,.21,.25,.26,.29,
     &.11,.17,.23,.27,.31,.34,.37,.17,.22,.25,.28,.31,.33,.35,
     &.15,.21,.27,.31,.36,.39,.42,.17,.21,.25,.28,.31,.33,.35,
     &.16,.22,.28,.32,.37,.39,.42,.1,.14,.18,.21,.24,.26,.28/
      DATA IDSOD/2,1,2,1,2,1,2,1,2,2,1,2,1,2,1,2,
     &2,1,2,1,2,1,2,1,2,1,2,1,2,1,2,1,2,1,2,2,
     &1,2,1,2,1,2,1,2,1,2,1,2,2,1,2,1,2,1,2,1,1,2,1,2,1,2,1,2,1,2,
     &1,2,1,2,1,1,2,1,2,2,1,1,2,1,2,1,2,1,2,1,1,2,1,2,1,2,2,1,1,
     &1,2,1,2,1,2,1,2,1,2,2,1,2,2,2,2,1,2,2,2,
     &2,2,1,2,1,2,1,1,2,1,2,1,2,1,2,1,2,2,1,2,1,2,1,2,2,
     &1,1,2,1,2,1,2,2,2,1,2,1,2,1,2,1,2,1,1,1,1,1,2,1,2,1,2,2,2,
     &1,1,2,1,2,1,2,1,1,1,1,1,1,1,2,2,2,1,2,1,2,2,
     &1,2,1,2,1,2,2,2,1,2,2,1,2,1,2,2,2,2,1,2,1,2,2,1,2,2,
     &2,1,1,1,1,2,1,2,1,2,2,2,1,1,1,1,2,2,2/
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
      DATA IDSUL/2,4,4,5,5,6,6,7,7,4,5,5,6,6,7,7,
     &7,6,6,7,7,8,8,6,6,7,7,8,8,4,4,6,6,7,7,7,
     &1,1,2,2,3,3,6,6,7,7,2,2,4,5,5,6,6,7,7,1,2,2,4,4,5,5,6,6,2,2,
     &1,1,2,2,3,4,4,6,2,3,4,2,2,3,3,4,4,5,5,6,7,7,2,2,3,3,4,5,7,
     &2,2,3,3,4,4,6,6,7,7,6,7,7,2,4,6,2,2,4,6,4,5,6,6,7,7,8,6,6,7,7,8,8,
     &5,5,7,7,2,4,4,5,5,6,6,7,6,7,7,6,6,7,7,8,8,7,7,8,8,7,7,8,8,
     &7,6,7,8,2,2,4,6,1,2,7,7,2,4,4,5,5,6,6,1,2,4,6,7,4,4,2,6,7,1,1,2,2,
     &6,2,2,2,2,4,4,6,8,1,1,2,4,4,6,6,1,6,1,2,2,4,4,6,1,1,2,
     &2,4,6,4,6,1,2,2,3,3,6,1,4,7,6,1,1,4,1/
      DATA IDBTU/9*1,7*2,1,6*2,6*3,6*1,2,10*1,9*2,9*1,2,2,
     &8*1,2,2,2,11*1,7*2,10*1,2,2,2,1,1,1,11*2,6*3,4*2,8*3,2,2,2,
     &5*3,4,2,2,2,2,3,3,3,3,1,2,2,3,1,1,1,1,2,2,2,3,7*1,7*5,3*3,
     &5*4,2,2,6*3,7*4,1,1,6*2,3*3,2,4,4,3,4,2,6*3,4,4,5,4*4/
      DATA IDREG/16*1,13*2,7*3,19*4,11*5,11*6,18*7,13*8,7*9,13*10,
     &12*11,6*12,3*13,8*14,4*15,8*16,7*17,5*18,19,20,8*21,15*22,
     &11*23,3*24,2*25,6*26,3*27,28,3*29,30/
C
C*****************************************************************
C****** CORRECTIONS TO DATA PROBLEMS IN ORIGINAL *********
C******     VERSION OF THE PROGRAM                   *********
C*****************************************************************
C
      IF(NEIL.EQ.1)RECL2(10)=.3
      IF(NEIL.EQ.1)WPD75=10.9
      WRITE(6,71)
   71 FORMAT(1X,/,/,5X,'THE DEFAULTS WILL EXAMINE ALL CASES',/,
     &8X,'PHYSICAL VARIABLES ARE GIVEN BY THEIR INTEGER INDEXES ONLY,',/
     &,8X,     'SURFACE VARIABLES SSIZE, SOVER,   USE 0 IF ALL CASES WANT
     &ED,',/,8X,'DEEP VARIABLES DSIZE,DDEPTH,DTHICK  USE 0 IF WANT ALL,'
     &,/,/,8X,'Z1 TO Z40 ARE SPECIFIC COAL TYPES TO BE INVESTIGATED
     &,',/,8X,'  USE Z1=0 IF ALL 236 COAL TYPES ARE TO BE USED,',/,/,
     &'    &LIMIT SSIZE,SOVER,DSIZE,DDEPTH,DTHICK,Z1 TO Z40 &END <AS INTE
     &GERS>')
      READ(5,LIMIT)
      WRITE(6,72)
   72 FORMAT(1X,/,/,/)
       ISSIZE=0
       ISOVER=0
       IDSIZE=0
       IDDEPT=0
       IDTHIC=0
      DO 85 III=1,40
      IZ(III)=0
 85   CONTINUE
       ISSIZE=SSIZE
       ISOVER=SOVER
       IDSIZE=DSIZE
       IDDEPT=DDEPTH
       IDTHIC=DTHICK
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
       IZ(1)=Z1
       IZ(2)=Z2
       IZ(3)=Z3
       IZ(4)=Z4
       IZ(5)=Z5
      IZ(6)=Z6
      IZ(7)=Z7
      IZ(8)=Z8
      IZ(9)=Z9
      IZ(10)=Z10
      IZ(11)=Z11
      IZ(12)=Z12
      IZ(13)=Z13
      IZ(14)=Z14
      IZ(15)=Z15
      IZ(16)=Z16
      IZ(17)=Z17
      IZ(18)=Z18
      IZ(19)=Z19
      IZ(20)=Z20
      IZ(21)=Z21
      IZ(22)=Z22
      IZ(23)=Z23
      IZ(24)=Z24
      IZ(25)=Z25
      IZ(26)=Z26
      IZ(27)=Z27
      IZ(28)=Z28
      IZ(29)=Z29
      IZ(30)=Z30
      IZ(31)=Z31
      IZ(32)=Z32
      IZ(33)=Z33
      IZ(34)=Z34
      IZ(35)=Z35
      IZ(36)=Z36
      IZ(37)=Z37
      IZ(38)=Z38
      IZ(39)=Z39
      IZ(40)=Z40
C
C******************************************************************
C*****BEGIN LOOP ON ALLOWABLE COAL TYPES(SOD,SUL,BTU,REG)
C******************************************************************
C
      DO 900 ITYPE=1,236
      IF(IZ(1).EQ.0)GO TO 109
      DO 108 MMM=1,40
      IF(ITYPE.EQ.IZ(MMM))GO TO 109
  108 CONTINUE
      GO TO 900
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
  109 CONTINUE
      IDSODX=IDSOD(ITYPE)
      I=IDSUL(ITYPE)
      J=IDDTU(ITYPE)
      K=IDREG(ITYPE)
C
C*******************************
C*****PRINT COAL TYPE INFORMATION
C*******************************
C
      WRITE(6,110)ITYPE,IDSODX,I,J,K
  110 FORMAT(1X,'   *******',/,'    * ',I3,' *  (',
     &I1,',',I1,',',I1,',',I2,')',/,'    *******')
      WEL=WEL75(K)
      SEVTR=SEVTRM(K)
      XPINS=EINS(IDSODX,K)
      IXX=1
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
  111 FORMAT('     ERROR CHECKPOINT ',I2)
      FED=FEDM(IDSODX,K)
      YIELD=YIELDM(I,J,K,IDSODX)
      AMR=AMRM(J,IDSODX)
      BLUNG=BLUNGM(J,IDSODX)
      FCL=CL75(I,1,J)
      VCL=CL75(I,2,J)
      CRF=ROR/(1.0-(1.0+ROR)**(-MYR))
      IF(ISWITB.EQ.1)WRITE(6,121)WEL,SEVTR,XPINS,FED,YIELD,
     &AMR,BLUNG,FCL,VCL,CRF
  121 FORMAT(1X,'INIT VAL ',5E15.5,/,2X,5E15.5)
C
C*****************************************************
C****CALCULATE DCFRAC(*)--FRACTIONS OF DEFERRED CAPITAL
C*****    SPENT OVER THE LIFE OF MINES
C*****************************************************
C
      IXX=2
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      M25=MYR/4
      M50=MYR/2
      M75=M25+M50
      M99=M25-1
C
C*****************************************
C****** CORRECTION OF DCFRAC COMPUTATION *****
C*****************************************
C
      IF(NEIL.EQ.1)GO TO 126
      MMYR=IFIX(MYR)
      IF((MMYR-(M75+M99)).NE.2)GO TO 125
      M50=M50+1
      M75=M75+1
      GO TO 126
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
  125 IF((MMYR-(M75+M99)).NE.3)GO TO 126
      M25=M25+1
      M75=M75+1
      M99=M99+1
  126 CONTINUE
      DO 200 I=1,M25
      DCFRAC(I)=0.05/M25
  200 CONTINUE
      NEXT = M25+1
      DO 201 I=NEXT,M75,1
      DCFRAC(I)=0.90/M50
  201 CONTINUE
      NEXT=M75+1
      MMYR=IFIX(MYR)
       LAST=MMYR-1
      DO 202 I=NEXT,LAST,1
      DCFRAC(I)=0.05/M99
  202 CONTINUE
      DCFRAC(MMYR)=0.0
C
C****************************
C****CALCULATE PVDC & SNOMDC
C****************************
C
      PVDC=0.0
      IXX=3
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      SNOMDC=0.0
      DO 203 JJ=1,MMYR
      SNOMDC=SNOMDC+DCFRAC(JJ)*(1.+ECAP)**JJ
      PVDC=PVDC+(DCFRAC(JJ)*(1.+ECAP)**JJ)*(1.+ROR)**(-JJ)
  203 CONTINUE
C
C**************************************************
C****** SETTING OF CORRECTION TERMS FOR **********
C******     EXPONENTS PROBLEMS IN       **********
C******     ORIGINAL VERSION            **********
C**************************************************
C
      ECAPN=N9-2./3.
      IF(NEIL.NE.1)ECAPN=0.
       EPASN=1.
      IF(NEIL.NE.1)EPASN=(1.+EPAS)**(2./3.)
      EWPDN=YIELD
      IF(NEIL.NE.1)EWPDN=1.
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C*************************
C******BRANCH FOR DEEP MINES
C*************************
C
      IXX=4
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      IF(IDSODX.EQ.2)GO TO 500
C
C***************************************
C******BEGIN CALCULATIONS FOR SURFACE MINES
C***************************************
C
      TPMDBS=TPMDB(1,K)
C
C******************************
C******LOOP ON OVERBURDEN RATIOS
C******************************
C
      IXX=5
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      DO 490 IOB=1,7
      OB=OBM(IOB)
      FRECL=RECL(IOB,1,K)
      VRECL=RECL(IOB,2,K)
C
C**********************
C******LOOP ON MINE SIZES
C**********************
C
      IXX=6
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      DO 480 ISZS=1,6
      IF(ISSIZE.EQ.0)GO TO 190
      IF(ISZS.NE.ISSIZE)GO TO 480
      IF(IOB.NE.ISOVER)GO TO 480
  190 CONTINUE
      SZ=SZSM(ISZS)
      SEVT$=SEVT$M(K)*1000.*SZ*YIELD
C
C*********************************************
C****CALCULATION OF COST ADJUSTMENT FACTORS*******
C*********************************************
C
      IF(SZ.LT.1.)GO TO 204
      IC75=(ICBS75+1.20*(OB-10.)*1000.)*(1.-(SZ-1.)/20.)*SZ
      DC75=(DCBS75+.25*1000.*(OB-10.))*(1.-(SZ-1.)/20.)*SZ
      GO TO 205
  204 IC75=(ICBS75+1.20*1000.*(OB-10.))*(1.-0.05*(1.-SZ)/.1)
      DC75=(DCBS75+.25*1000.*(OB-10.))*(1.-0.05*(1.-SZ)/.1)
  205 CONTINUE
      LB75=(1000.*SLAB75)*((TPMDBS+3.*(SZ-1.)/.1)**(-1))
     $*((1.-.1*(OB-10.)/5.)**(-1))*SZ
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C**************************************************
C****** FIX FOR INTEGER LABOR DECLARATION  *********
C******     IN ORIGINAL VERSION            *********
C**************************************************
C
      IF(NEIL.EQ.1)LB75=IFIX(LB75)
      PAS75=(PSBS75+30.*(OB-10.))*SZ
      MDPY=((TPMDBS+3.*(SZ-1.)/.1)**(-1))*
     &((1.-.1*(OB-10.)/5.)**(-1))*SZ
      XMDPY=SZ/MDPY
      IF(ISWITB.NE.1)GO TO 521
      WRITE(6,522)IC75,DC75,LB75,PAS75,XMDPY
  522 FORMAT(2X,' 75 DATA ',5E15.5)
  521 CONTINUE
C
C*********************
C*****INITIALIZATIONS
C*********************
C
      IXX=7
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      PVTOT=0.0
      DOB=0.0
      DSZ=0.0
      C1=(.5/.55)*SEVT$
      C2=1.0/(.55*(1.0-(SEVTR+FED)))
      C1S=SEVT$
      C2S=1.0/(1.0-(SEVTR+FED))
      MMYR=IFIX(MYR)
      DO 470 JJ=1,MMYR
C
C**********************************************************
C****THIS IS THE LOOP ON SURFACE MINE LIFETIME YEARS*******
C**********************************************************
C
      B1(JJ)=((1.+ECAP)**(N9-2./3.))*(CRF*EPASN
     &+.01*(1.+ECAP)**(JJ+ECAPN+2./3.)-1./(2.*MYR))
      B2(JJ)=((1.+ECAP)**N9)*(CRF*PVDC-(1./(2.*MYR))
     &*SNOMDC)*(MYR-10.)/10.
      B3(JJ)=0.5*((1.+EMP)**(N9+JJ))*(1.35+.01*XPINS)
      B4(JJ)=(1.15/2.)*(1.+EPAS)**(N9+JJ)
      B5(JJ)=(1000.*WPD75*EWPDN)/2.*(1.+EMP)**(N9+JJ)
      B6(JJ)=0.5*1000.*YIELD*(((1.+EMP)**(N9+JJ))
     &*(WEL+WRECL)+(ROY+LIC)*(1.+ECAP)**(N9+JJ)
     &+VCL*(1.+EPAS)**(N9+JJ)+AMR+BLUNG
     &+(FRECL+FCL)*(1.+ECAP)**(N9+1))-(.15/2.)*POWS75*(1.+EPAS)**(N9+JJ)
      B1S(JJ)=((1.+ECAP)**(N9-2./3.))*(4./3.*CRF*
     &EPASN+.02*(1.+ECAP)**(JJ+ECAPN+2./3.)
     &-1./(3.*MYR))
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
      B2S(JJ)=((1.+ECAP)**N9)*(4./3.*CRF*PVDC-
     &(1./(3.*MYR))*SNOMDC)*(MYR-10.)/10.
      B3S(JJ)=2.0*B3(JJ)
      B4S(JJ)=2.0*B4(JJ)
      B5S(JJ)=2.0*B5(JJ)
      B6S(JJ)=2.0*B6(JJ)
C
C*****************************************
C******FIX FOR EXPONENT IN OPERATING ******
C******     COST CALCULATION         ******
C*****************************************
C
      IF(NEIL.EQ.1)ECOC=N9-2./3.
      IF(NEIL.NE.1)ECOC=0.
C
C*****************************************************
C****** CALCULATION OF OPERATING COSTS **************
C*****************************************************
C
      OC=(.02*(1.+ECAP)**(ECOC+N9+JJ)+(1./MYR)
     &*(1.+ECAP)**(N9-2./3.))*IC75
     &+((1./MYR)*((1.+ECAP)**N9)*SNOMDC)
     &*((MYR-10.)/10.)*DC75
     &+B3S(JJ)*LB75+B4S(JJ)*PAS75
     &+B5S(JJ)*MDPY+B6S(JJ)*SZ
C
C**************************************************
C******CALCULATE REQUIRED REVENUE=SALES IN YEAR JJ
C*************************************************
C
      RR=C1+C2*
     &(B1(JJ)*IC75+B2(JJ)*DC75+B3(JJ)
     &*LB75+B4(JJ)*PAS75+B5(JJ)*MDPY+B6(JJ)*SZ)
      DEPL=0.1*RR
      GROPR=(1.0-(SEVTR+FED))*RR-OC-SEVT$
      IF(SZ.LT.1.)GO TO 210
      XDOB=(C2*((1200.*B1(JJ)+250.*B2(JJ))*
     &(1.-(SZ-1.)/20.)+(1000.*SLAB75*B3(JJ)+B5(JJ))*
     &((TPMDBS+3.*(SZ-1.)/0.1)**(-1))*((1.-0.1*
     &(OB-10.)/5.)**(-2))*.02+30.*B4(JJ)))
     &*(1.+RUT)**(-JJ)
      XDSZ=((1.+RUT)**(-JJ))
     &*(-(C1/(SZ**2))+C2*
     &(-B1(JJ)*(ICBS75+1200.*(OB-10.))/20.-B2(JJ)*
     &(DCBS75+250.*(OB-10.))/20.-30.*(1000.*SLAB75*
     &B3(JJ)+B5(JJ))*((TPMDBS+3.*(SZ-1.)/0.1)**(-2))
     &*(1.-0.1*(OB-10.)/5.)**(-1)))
      GO TO 211
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
  210 XDOB=((1.+RUT)**(-JJ))
     &*C2*((1200.*B1(JJ)+250.*B2(JJ))*(1.-0.05*
     &(1.-SZ)/.1)/SZ+(1000.*SLAB75*B3(JJ)
     &+B5(JJ))*((TPMDBS+3.*(SZ-1.)/0.1)**(-1))
     &*((1.-0.1*(OB-10.)/5.)**(-2))*.02+30.*B4(JJ))
      XDSZ=((1.+RUT)**(-JJ))*(-((C1)/
     &(SZ**2))+C2*(-B1(JJ)*(ICBS75+1200.*
     &(OB-10.))/(2.*SZ**2)-B2(JJ)*(DCBS75+
     &250.*(OB-10.))/(2.*SZ**2)-30.*(1000.*
     &SLAB75*B3(JJ)+B5(JJ))*((TPMDBS+3.*(SZ-1.)/
     &0.1)**(-2))*(1.-0.1*(OB-10.)/5.)**(-1)))
  211 CONTINUE
      XYX-GROPR/2.
      IF(DEPL.LE.XYX)GO TO 460
C
C*************************************************
C*****CALCULATE FOR ALTERNATIVE DEPLETION ALLOWANCE
C*************************************************
C
      RR=C1S
     &+C2S*(B1S(JJ)*IC75+B2S(JJ)*DC75
     &+B3S(JJ)*LB75+B4S(JJ)*PAS75
     &+B5S(JJ)*MDPY+B6S(JJ)*SZ)
      GROPR=(1.0-(SEVTR+FED))*RR-OC-SEVT$
      DEPL=0.5*GROPR
      IF (SZ.LT.1.)GO TO 220
      XDOB=(C2S*((1200.*B1S(JJ)+250.*B2S(JJ))*
     &(1.-(SZ-1.)/20.)+(1000.*SLAB75*B3S(JJ)+B5S(JJ))*
     &((TPMDBS+3.*(SZ-1.)/0.1)**(-1))*((1.-0.1*
     &(OB-10.)/5.)**(-2))*.02+30.*B4S(JJ)))
     &*(1.+RUT)**(-JJ)
      XDSZ=((1.+RUT)**(-JJ))
     &*(-((C1S)/(SZ**2))+C2S*
     &(-B1S(JJ)*(ICBS75+1200.*(OB-10.))/20.-B2S(JJ)*
     &(DCBS75+250.*(OB-10.))/20.-30.*(1000.*SLAB75*
     &B3S(JJ)+B5S(JJ))*((TPMDBS+3.*(SZ-1.)/0.1)**(-2))
     &*(1.-0.1*(OB-10.)/5.)**(-1)))
      GO TO 221
  220 XDOB=((1.+RUT)**(-JJ))*
     &C2S*((1200.*B1S(JJ)+250.*B2S(JJ))*(1.-0.05*
     &(1.-SZ)/.1)/SZ+(1000.*SLAB75*B3S(JJ)
     &+B5S(JJ))*((TPMDBS+3.*(SZ-1.)/0.1)**(-1))
     &*((1.-0.1*(OB-10.)/5.)**(-2))*.02+30.*B4S(JJ))
      XDSZ=((1.+RUT)**(-JJ))*(-((C1S)/
     &(SZ**2))+C2S*(-B1S(JJ)*(ICBS75+1200.*
     &(OB-10.))/(2.*SZ**2)-B2S(JJ)*(DCBS75+
     &250.*(OB-10.))/(2.*SZ**2)-30.*(1000.*
     &SLAB75*B3S(JJ)+B5S(JJ))*((TPMDBS+3.*(SZ-1.)/
     &0.1)**(-2))*(1.-0.1*(OB-10.)/5.)**(-1)))
  221 CONTINUE
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
  460 CONTINUE
      PRICE=RR/(SZ*1000.*YIELD)
      PVTOT=PVTOT+PRICE*(1.+RUT)**(-JJ)
      DOB=DOB+XDOB
      DSZ=DSZ+XDSZ
      IF(ISWITB.NE.1)GO TO 471
      WRITE(6,472)JJ,OC,RR,PRICE,XDOB,XDSZ,B1(JJ),B2(JJ),B3(JJ),B4(JJ),B
     &5(JJ),B6(JJ),B1S(JJ),B2S(JJ),B3S(JJ),B4S(JJ),B5S(JJ),B6S(JJ)
  472 FORMAT(2X,'JJ=',I2,5E15.5,/,20X,6E15.5,/,20X,6E15.5)
  471 CONTINUE
  470 CONTINUE
C
C*****************************************************************
C******CALCULATE REAL ANNUITY COAL PRICE,
C******DERIVATIVES W.R.T. OB AND SZ, AND ELASTICITIES
C*****************************************************************
C
      XRACPS=PVTOT/APFAC
      XDPDOB=DOB/(APFAC*1000.*YIELD)
      XDPDSZ=DSZ/(APFAC*1000.*YIELD)
      XPELOB=XDPDOB/(XRACPS/OB)
      XPELSZ=XDPDSZ/(XRACPS/SZ)
      IF(ISWITA.EQ.1)WRITE(6,112)XRACPS,XDPDOB,XDPDSZ,XPELOB,XPELSZ
  112 FORMAT(2X,5E15.5)
      IF(ISZS.NE.1)GO TO 475
      IF(IOB.NE.1)GO TO 475
C
C*************************
C******INITIALIZE AVERAGES
C*************************
C
      RACPS(2,ITYPE)=00.
      DPDOB(2,ITYPE)=0.
      DPDSZ(2,ITYPE)=0.
      PELOB(2,ITYPE)=0.
      PELSZ(2,ITYPE)=0.
C
C***************************************
C******INITIALIZE MINIMUMS AND MAXIMUMS
C***************************************
C
      RACPS(1,ITYPE)=XRACPS
      RACPS(3,ITYPE)=XRACPS
      DPDOB(1,ITYPE)=XDPDOB
      DPDOB(3,ITYPE)=XDPDOB
      DPDSZ(1,ITYPE)=XDPDSZ
      DPDSZ(3,ITYPE)=XDPDSZ
      PELOB(1,ITYPE)=XPELOB
      PELOB(3,ITYPE)=XPELOB
      PELSZ(1,ITYPE)=XPELSZ
      PELSZ(3,ITYPE)=XPELSZ
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C*************************************
C******UPDATE MINIMUMS AND MAXIMUMS
C*************************************
C
  475 IF(XRACPS.LT.RACPS(1,ITYPE))RACPS(1,ITYPE)=XRACPS
      IF(XRACPS.GT.RACPS(3,ITYPE))RACPS(3,ITYPE)=XRACPS
      RACPS(2,ITYPE)=RACPS(2,ITYPE)+XRACPS/42.
      IF(XDPDOB.LT.DPDOB(1,ITYPE))DPDOB(1,ITYPE)=XDPDOB
      IF(XDPDOB.GT.DPDOB(3,ITYPE))DPDOB(3,ITYPE)=XDPDOB
      DPDOB(2,ITYPE)=DPDOB(2,ITYPE)+XDPDOB/42.
      IF(XDPDSZ.LT.DPDSZ(1,ITYPE))DPDSZ(1,ITYPE)=XDPDSZ
      IF(XDPDSZ.GT.DPDSZ(3,ITYPE))DPDSZ(3,ITYPE)=XDPDSZ
      DPDSZ(2,ITYPE)=DPDSZ(2,ITYPE)+XDPDSZ/42.
      IF(XPELOB.LT.PELOB(1,ITYPE))PELOB(1,ITYPE)=XPELOB
      IF(XPELOB.GT.PELOB(3,ITYPE))PELOB(3,ITYPE)=XPELOB
      PELOB(2,ITYPE)=PELOB(2,ITYPE)+XPELOB/42.
      IF(XPELSZ.LT.PELSZ(1,ITYPE))PELSZ(1,ITYPE)=XPELSZ
      IF(XPELSZ.GT.PELSZ(3,ITYPE))PELSZ(3,ITYPE)=XPELSZ
      PELSZ(2,ITYPE)=PELSZ(2,ITYPE)+XPELSZ/42.
C
C**************************************************
C******STORE OB AND SZ ASSOCIATED WITH MINS AND MAXS
C**************************************************
C
      IF(XRACPS.EQ.RACPS(1,ITYPE))XSZ(1,1)=SZ
      IF(XRACPS.EQ.RACPS(1,ITYPE))XOB(1,1)=OB
      IF(XRACPS.EQ.RACPS(3,ITYPE))XSZ(2,1)=SZ
      IF(XRACPS.EQ.RACPS(3,ITYPE))XOB(2,1)=OB
      IF(XDPDOB.EQ.DPDOB(1,ITYPE))XSZ(1,2)=SZ
      IF(XDPDOB.EQ.DPDOB(3,ITYPE))XSZ(2,2)=SZ
      IF(XDPDOB.EQ.DPDOB(1,ITYPE))XOB(1,2)=OB
      IF(XDPDOB.EQ.DPDOB(3,ITYPE))XOB(2,2)=OB
      IF(XDPDSZ.EQ.DPDSZ(1,ITYPE))XSZ(1,3)=SZ
      IF(XDPDSZ.EQ.DPDSZ(1,ITYPE))XOB(1,3)=OB
      IF(XDPDSZ.EQ.DPDSZ(3,ITYPE))XSZ(2,3)=SZ
      IF(XDPDSZ.EQ.DPDSZ(3,ITYPE))XOB(2,3)=OB
      IF(XPELOB.EQ.PELOB(1,ITYPE))XSZ(1,4)=SZ
      IF(XPELOB.EQ.PELOB(1,ITYPE))XOB(1,4)=OB
      IF(XPELOB.EQ.PELOB(3,ITYPE))XSZ(2,4)=SZ
      IF(XPELOB.EQ.PELOB(3,ITYPE))XOB(2,4)=OB
      IF(XPELSZ.EQ.PELSZ(1,ITYPE))XSZ(1,5)=SZ
      IF(XPELSZ.EQ.PELSZ(1,ITYPE))XOB(1,5)=OB
      IF(XPELSZ.EQ.PELSZ(3,ITYPE))XSZ(2,5)=SZ
      IF(XPELSZ.EQ.PELSZ(3,ITYPE))XOB(2,5)=OB
  480 CONTINUE
  490 CONTINUE
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C*************************************************************
C****WRITE STATEMENTS HERE FOR SURFACE MINES*******
C*************************************************************
C
      WRITE(6,496)
      WRITE(6,491)XOB(1,1),XSZ(1,1),(RACPS(L,ITYPE),
     &L=1,3),XOB(2,1),XSZ(2,1)
      WRITE(6,492)XOB(1,2),XSZ(1,2),(DPDOB(L,ITYPE),
     &L=1,3),XOB(2,2),XSZ(2,2)
      WRITE(6,493)XOB(1,3),XSZ(1,3),(DPDSZ(L,ITYPE),
     &L=1,3),XOB(2,3),XSZ(2,3)
      WRITE(6,494)XOB(1,4),XSZ(1,4),(PELOB(L,ITYPE),
     &L=1,3),XOB(2,4),XSZ(2,4)
      WRITE(6,495)XOB(1,5),XSZ(1,5),(PELSZ(L,ITYPE),
     &L=1,3),XOB(2,5),XSZ(2,5)
  491 FORMAT('    RACPS (',F3.0,',',F3.1,') ',
     &3E20.5,'        (',F3.0,',',F3.1,')')
  492 FORMAT('    DPDOB (',F3.0,',',F3.1,') ',
     &3E20.5,'        (',F3.0,',',F3.1,')')
  493 FORMAT('    DPDSZ (',F3.0,',',F3.1,') ',
     &3E20.5,'        (',F3.0,',',F3.1,')')
  494 FORMAT('    PELOB (',F3.0,',',F3.1,') ',
     &3E20.5,'        (',F3.0,',',F3.1,')')
  495 FORMAT('    PELSZ (',F3.0,',',F3.1,') ',
     &3E20.5,'       (',F3.0,',',F3.1,')',/,/)
  496 FORMAT('          ( OB,SZ )              MIN',
     &'             AVE',17X,'MAX',12X,'( OB,SZ )')
C
C**************************
C******GO TO NEXT COAL TYPE
C**************************
C
      GO TO 900
C
C*******************************************
C******BRANCH IN FROM NOT SURFACE COAL TYPE
C*******************************************
C
  500 CONTINUE
C
C*****************************************************************
C*****************************************************************
C******  BEGIN CALCULATIONS FOR DEEP MINES  ***********
C*****************************************************************
C*****************************************************************
C
      TPMDBD=TPMDP(2,K)
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C***************************
C*****LOOP ON SEAM THICKNESS
C***************************
C
      DO 890 IST=1,5
      ST=STM(IST)
C
C*************************************************
C******  PATCH FOR SEAM THICKNESS MISSPECIFICATION
C*************************************************
C
      IF(NEIL.NE.1)GO TO 505
      IF(ST.GT.28.5)GO TO 505
      IF(ST.LT.27.5)GO TO 505
      ST=24.
  505 CONTINUE
C
C************************
C*****LOOP ON SEAM DEPTHS
C************************
C
      DO 880 IDP=1,4
      DP=DPM(IDP)
C
C***********************
C*****LOOP ON MINE SIZES
C***********************
C
      DO 870 ISZD=1,5
      IF(IDSIZE.EQ.0)GO TO 509
      IF(IST.NE.IDTHIC)GO TO 870
      IF(IDP.NE.IDDEPT)GO TO 870
      IF(ISZD.NE.IDSIZE)GO TO 870
  509 CONTINUE
      SZ=SZDM(ISZD)
      SEVT$=SEVT$M(K)*1000.*SZ*YIELD
C
C*************************************************
C***CALCULATE THE COST ADJUSTMENT FACTORS********
C*************************************************
C
      IXX=7
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      DR=0.0
      IF(DP.LE.0.1)DR=1.0
      IF(SZ.LT.1.0)GO TO 510
      IC75=(ICB975+500.*(DP-700.)/100.-
     %6000.*DR)*(1.+.06*(72.-ST)/12.)*(1.+.30*
     %(SZ-1.))
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
      DC75=(DCBD75-3000.*DR)*(1.+.06*(72.-ST)/12.)
     &*(1.+.15*(SZ-1.))
      IXX=8
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      GO TO 520
  510 IC75=((ICBD75+500.*(DP-700.)/100.-6000.*DR)*
     &(1.+.06*(72.-ST)/12.))*SZ+(500.*DP/100.)*(1.-SZ)
      DC75=(DCBD75-3000.*DR)*(1.+.06*(72.-ST)/12.)*SZ
  520 CONTINUE
      LB75=(1000.*DLAB75)*((TPMDBD-1.0*(72.-ST)/12.
     &+0.5*(SZ-1.)/0.1)**(-1))*SZ
      IF(NEIL.EQ.1)LB75=IFIX(LB75)
      PAS75=(PSBD75+0.15*1000.*(72.-ST)/12.)*SZ
      MDPY=((TPMDBD-1.0*(72.-ST)/12.+0.5*
     &(SZ-1.)/0.1)**(-1))*SZ
      XMDPY=SZ/MDPY
      IF(ISWITB.NE.1)GO TO 528
      WRITE(6,527)IC75,DC75,LB75,XMDPY
  527 FORMAT(2X,' 75 DATA ', 5E15.5)
  528 CONTINUE
      IXX=10
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
C
C*********************
C*****INITIALIZATIONS
C*********************
C
      PVTOT=0.0
      DST=0.0
      DDP=0.0
      DSZ=0.0
      C1=(.5/.55)*SEVT$
      C2=1.0/(.55*(1.-(SEVTR+FED)))
      C1S=SEVT$
      C2S=1.0/(1.0-(SEVTR+FED))
      MMYR=IFIX(MYR)
      DO 750 JJ=1,MMYR
C
C*******************************************************
C*****THIS IS THE LOOP ON DEEP MINE LIFETIME YEARS******
C*******************************************************
C
      IXX=11
      IF(ISWITC.EQ.1)WRITE(6,111)IXX
      B1(JJ)=((1.+ECAP)**(N9-2./3.))*(CRF*CPASN
     &+.01*(1.+ECAP)**(JJ+ECAPN+2./3.)-1./(2.*MYR))
      B2(JJ)=((1.+ECAP)**N9)*(CRF*PVDC-(1./(2.*MYR))
     &*SNOMDC)*(MYR-10.)/10.
      B3(JJ)=0.5*((1.+EMP)**(N9+JJ))*(1.35+.01*XPINS)
      B4(JJ)=(1.15/2.)*(1.+EPAS)**(N9+JJ)
      B5(JJ)=(1000.*WPD75*EWPDN)/2.*(1.+EMP)**(N9+JJ)
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C***********************************
C*****SET RECLAMATION COSTS TO ZERO
C***********************************
C
       B6(JJ)=0.5*1000.*YIELD*(((1.+EMP)**(N9+JJ))
      &*(WEL+0.0)+(ROY+LIC)*(1.+ECAP)**(N9+JJ)
      &+VCL*(1.+EPAS)**(N9+JJ)+AMR+BLUNG
      &+(0.0+FCL)*(1.+ECAP)**(N9+1))-(.15/2.)*POWD75*(1.+EPAS)**(N9+JJ)
       B1S(JJ)=((1.+ECAP)**(N9-2./3.))*(4./3.*CRF*
      &EPASN+.02*(1.+ECAP)**(JJ+ECAPN+2./3.)
      &-1./(3.*MYR))
       B2S(JJ)=((1.+ECAP)**N9)*(4./3.*CRF*PVDC
      &-(1./(3.*MYR))*SNOMDC)*(MYR-10.)/10.
       B3S(JJ)=2.0*B3(JJ)
       B4S(JJ)=2.0*B4(JJ)
       B5S(JJ)=2.0*B5(JJ)
       B6S(JJ)=2.0*B6(JJ)
C
C*****************************************
C*****CALCULATE OPERATING COST ON YEAR JJ
C*****************************************
C
       IF(NEIL.EQ.1)ECOC=N9-2./3.
       IF(NEIL.NE.1)ECOC=0.
       OC=(.02*(1.+ECAP)**(N9+ECOC+JJ)+(1./MYR)
      &*(1.+ECAP)**(N9-2./3.))*IC75
      &+((1./MYR)*((1.+ECAP)**N9)*SNOMDC)
      &*((MYR-10.)/10.)*DC75
      &+B3S(JJ)*LB75+B4S(JJ)*PAS75
      &+B5S(JJ)*MDPY+B6S(JJ)*SZ
C
C**************************************
C*****CALCULATE REQUIRED REVENUE=SALES
C*****IN YEAR JJ
C**************************************
C
       RR=C1+C2*
      &(B1(JJ)*IC75+B2(JJ)*DC75+B3(JJ)
      &*LB75+B4(JJ)*PAS75+B5(JJ)*MDPY+B6(JJ)*SZ)
       DEPL=00.1*RR
       GROPR=(1.0-(SEVTR+FED))*RR-OC-SEVT$
       IF(SZ.LT.1.0)GO TO 530
       XDST=((1.0+RUT)**(-JJ))*C2*(-.005*B1(JJ)*
      &(ICBD75+5.*(DP-700.)-6000.*DR)*(1.+.30*
      &(SZ-1.))*(1.0/SZ)-.005*B2(JJ)*(DCBD75-
      &3000.*DR)*(1.+.15*(SZ-1.))*(1./SZ)-(1./12.)*
      &(1000.*DLAB75*B3(JJ)+B5(JJ))*((TPMDBD
      &-(72.-ST)/12.+.5*(SZ-1.)/.1)**(-2))
      &-(150./12.)*B4(JJ))
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
      XDDP=((1.+RUT)**(-JJ))*C2*(5.*B1(JJ)*
     &(1.+.06*(72.-ST)/12.)*(1.+.30*(SZ-1.))*(1./SZ))
      XDSZ=((1.+RUT)**(-JJ))*(-((C1)/
     &(SZ**2))+C2*(-.7*B1(JJ)*(ICBD75+
     &5.*(DP-700.)-6000.*DR)*(1.+.06*(72.-ST)/12.)
     &*(1.0/(SZ**2))-.85*B2(JJ)*(DCBD75-3000.*DR)
     &*(1.+.06*(72.-ST)/12.)*(1./(SZ**2))
     &-5.0*(1000.*DLAB75*B3(JJ)+B5(JJ))*
     &((TPMDBD-(72.-ST)/12.+.5*(SZ-1.)/.1)**(-2))))
      GO TO 540
  530 XDST=((1.+RUT)**(-JJ))*C2*(-.005*
     &B1(JJ)*(ICBD75+5.*(DP-700.)-6000.*DR)-
     &.005*B2(JJ)*(DCBD75-3000.*DR)-(1./12.)*
     &(1000.*DLAB75*B3(JJ)+B5(JJ))*((TPMDBD-
     &(72.-ST)/12.+.5*(SZ-1.)/.1)**(-2))-(150./12.)
     &*B4(JJ))
      XDDP=((1.+RUT)**(-JJ))*C2*(5.*B1(JJ)*
     &((1.+.06*(72.-ST)/12.)+(1./SZ-1.)))
      XDSZ=((1.+RUT)**(-JJ))*(-((C1)
     &/(SZ**2))+C2*(-5.*B1(JJ)*DP/
     &(SZ**2)-5.*(1000.*DLAB75*B3(JJ)+
     &B5(JJ))*((TPMDBD-(72.-ST)/12.+.5*(SZ-1.)/
     &.1)**(-2))))
  540 CONTINUE
      XYX=GROPR/2.
      IF(DEPL.LE.XYX)GO TO 570
C
C**************************************************************
C******CALCULATIONS FOR ALTERNATIVE DEPLETION ALLOWANCE
C**************************************************************
C
      RR=C1S+C2S*
     &(B1S(JJ)*IC75+B2S(JJ)*DC75+B3S(JJ)
     &*LB75+B4S(JJ)*PAS75+B5S(JJ)*MDPY+B6S(JJ)*SZ)
      GROPR=(1.0-(SEVTR+FED))*RR-OC-SEVT$
      DEPL=.5*GROPR
      IF(SZ.LT.1.)GO TO 550
      XDST=((1.+RUT)**(-JJ))*C2S*(-.005*B1S(JJ)*
     &(ICBD75+5.*(DP-700.)-6000.*DR)*(1.+.30*
     &(SZ-1.))*(1./SZ)-.005*B2S(JJ)*(DCBD75-
     &3000.*DR)*(1.+.15*(SZ-1.))*(1./SZ)-(1./12.)*
     &(1000.*DLAB75*B3S(JJ)+B5S(JJ))*((TPMDBD
     &-(72.-ST)/12.+.5*(SZ-1.)/.1)**(-2))
     &-(150./12.)*B4S(JJ))
      XDDP=((1.+RUT)**(-JJ))*C2S*(5.*B1S(JJ)*
     &(1.+.06*(72.-ST)/12.)*(1.+.30*(SZ-1.))*(1./SZ))
      XDSZ=((1.+RUT)**(-JJ))*(-((C1S)/
     &(SZ**2))+C2S*(-.7*B1S(JJ)*(ICBD75+
     &5.*(DP-700.)-6000.*DR)*(1.+.06*(72.-ST)/12.)
     &*(1.0/(SZ**2))-.85*B2S(JJ)*(DCBD75-3000.*DR)
     &*(1.+.06*(72.-ST)/12.)*(1./(SZ**2))
     &-5.0*(1000.*DLAB75*B3S(JJ)+B5S(JJ))*
     &((TPMDBD-(72.-ST)/12.+.5*(SZ-1.)/.1)**(-2))))
      GO TO 560
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
  550 XDST=((1.+RUT)**(-JJ))*C2S*(-.005*
     &B1S(JJ)*(ICBD75+5.*(DP-700.)-6000.*DR)-
     &.005*B2S(JJ)*(DCBD75-3000.*DR)-(1./12.)*
     &(1000.*DLAB75*B3S(JJ)+B5S(JJ))*((TPMDBD-
     &(72.-ST)/12.+.5*(SZ-1.)/.1)**(-2))-(150./12.)
     &*B4S(JJ))
      XDDP=((1.+RUT)**(-JJ))*C2S*(5.*B1S(JJ)*
     &((1.+.06*(72.-ST)/12.)+(1./SZ-1.)))
      XDSZ=((1.+RUT)**(-JJ))*(-((C1S)
     &/(SZ**2))+C2S*(-5.*B1S(JJ)*DP/
     &(SZ**2)-5.*(1000.*DLAB75*B3S(JJ)+
     &B5S(JJ))*((TPMDBD-(72.-ST)/12.+.5*(SZ-1.)/
     &.1)**(-2))))
  560 CONTINUE
  570 CONTINUE
      PRICE=RR/(SZ*1000.*YIELD)
      PVTOT=PVTOT+PRICE*(1.+RUT)**(-JJ)
      DST=DST+XDST
      DDP=DDP+XDDP
      DSZ=DSZ+XDSZ
      IF(ISWITB.NE.1)GO TO 600
      WRITE(6,599)JJ,OC,RR,PRICE,DCFRAC(JJ),PVDC
  599 FORMAT(2X,'JJ=',I2,5E15.5)
  600 CONTINUE
  750 CONTINUE
C
C**********************************************************
C******CALCULATE REAL ANNUITY COAL PRICE, DERIVATIVES
C******W.R.T. ST, DP, AND SZ, AND ELASTICITIES
C**********************************************************
C
      XRACPD=PVTOT/APFAC
      XDPDST=DST/(APFAC*1000.*YIELD)
      XDPDDP=DDP/(APFAC*1000.*YIELD)
      XDPDSZ=DSZ/(APFAC*1000.*YIELD)
      XPELST=XDPDST/(XRACPD/ST)
      XPELDP=XDPDDP*(DP/XRACPD)
      XPELSZ=XDPDSZ/(XRACPD/SZ)
       IF(ISWITA.EQ.1)WRITE(6,113)XRACPD,XDPDST,XDPDDP,XDPDSZ
     &,XPELST,XPELDP,XPELSZ
  113 FORMAT(2X,7E15.5)
      IF(ISZD.NE.1)GO TO 760
      IF(IDP.NE.1)GO TO 760
      IF(IST.NE.1)GO TO 760
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C**************************************
C*****INITIALIZE MINS, AVERAGES, AND MAXS
C**************************************
C
      DO 755 III=1,3
      RACPD(III,ITYPE)=XRACPD
      DPDDP(III,ITYPE)=XDPDDP
      DPDST(III,ITYPE)=XDPDST
      DPDSZ(III,ITYPE)=XDPDSZ
      PELDP(III,ITYPE)=XPELDP
      PELST(III,ITYPE)=XPELST
      PELSZ(III,ITYPE)=XPELSZ
  755 CONTINUE
      RACPD(2,ITYPE)=0.
      DPDDP(2,ITYPE)=0.
      DPDST(2,ITYPE)=0.
      DPDSZ(2,ITYPE)=0.
      PELDP(2,ITYPE)=0.
      PELST(2,ITYPE)=0.
      PELSZ(2,ITYPE)=0.
  760 IF(XRACPD.GT.RACPD(1,ITYPE))GO TO 761
      RACPD(1,ITYPE)=XRACPD
      XSZD(1,1)=SZ
      XST(1,1)=ST
      XDP(1,1)=DP
  761 IF(XRACPD.LT.RACPD(3,ITYPE))GO TO 762
      RACPD(3,ITYPE)=XRACPD
      XSZD(2,1)=SZ
      XST(2,1)=ST
      XDP(2,1)=DP
  762 RACPD(2,ITYPE)=RACPD(2,ITYPE)+XRACPD/100.
      IF(XDPDST.GT.DPDST(1,ITYPE))GO TO 763
      DPDST(1,ITYPE)=XDPDST
      XSZD(1,2)=SZ
      XST(1,2)=ST
      XDP(1,2)=DP
  763 IF(XDPDST.LT.DPDST(3,ITYPE))GO TO 764
      DPDST(3,ITYPE)=XDPDST
      XSZD(2,2)=SZ
      XST(2,2)=ST
      XDP(2,2)=DP
  764 DPDST(2,ITYPE)=DPDST(2,ITYPE)+XDPDST/100.
      IF(XDPDDP.GT.DPDDP(1,ITYPE))GO TO 765
      DPDDP(1,ITYPE)=XDPDDP
      XSZD(1,3)=SZ
      XST(1,3)=ST
      XDP(1,3)=DP
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
765 IF(XDPDDP.LT.DPDDP(3,ITYPE))GO TO 766
    DPDDP(3,ITYPE)=XDPDDP
    XSZD(2,3)=SZ
    XST(2,3)=ST
    XDP(2,3)=DP
766 DPDDP(2,ITYPE)=DPDDP(2,ITYPE)+XDPDDP/100.
    IF(XDPDSZ.GT.DPDSZ(1,ITYPE))GO TO 767
    DPDSZ(1,ITYPE)=XDPDSZ
    XSZD(1,4)=SZ
    XST(1,4)=ST
    XDP(1,4)=DP
767 IF(XDPDSZ.LT.DPDSZ(3,ITYPE))GO TO 768
    DPDSZ(3,ITYPE)=XDPDSZ
    XSZD(2,4)=SZ
    XST(2,4)=ST
    XDP(2,4)=DP
768 DPDSZ(2,ITYPE)=DPDSZ(2,ITYPE)+XDPDSZ/100.
    IF(XPELST.GT.PELST(1,ITYPE))GO TO 769
    PELST(1,ITYPE)=XPELST
    XSZD(1,5)=SZ
    XST(1,5)=ST
    XDP(1,5)=DP
769 IF(XPELST.LT.PELST(3,ITYPE))GO TO 770
    PELST(3,ITYPE)=XPELST
    XSZD(2,5)=SZ
    XST(2,5)=ST
    XDP(2,5)=DP
770 PELST(2,ITYPE)=PELST(2,ITYPE)+XPELST/100.
    IF(XPELDP.GT.PELDP(1,ITYPE))GO TO 771
    PELDP(1,ITYPE)=XPELDP
    XSZD(1,6)=SZ
    XST(1,6)=ST
    XDP(1,6)=DP
771 IF(XPELDP.LT.PELDP(3,ITYPE))GO TO 772
    PELDP(3,ITYPE)=XPELDP
    XSZD(2,6)=SZ
    XST(2,6)=ST
    XDP(2,6)=DP
772 PELDP(2,ITYPE)=PELDP(2,ITYPE)+XPELDP/100.
    IF(XPELSZ.GT.PELSZ(1,ITYPE))GO TO 773
    PELSZ(1,ITYPE)=XPELSZ
    XSZD(1,7)=SZ
    XST(1,7)=ST
    XDP(1,7)=DP
773 IF(XPELSZ.LT.PELSZ(3,ITYPE))GO TO 774
    PELSZ(3,ITYPE)=XPELSZ
    XSZD(2,7)=SZ
    XST(2,7)=ST
    XDP(2,7)=DP
774 PELSZ(2,ITYPE)=PELSZ(2,ITYPE)+XPELSZ/100.
870 CONTINUE
800 CONTINUE
890 CONTINUE
```

Figure 2. Listing of the Code of the Cost Function Program (continued)

```
C
C***********************************************************************
C******WRITE STATEMENTS HERE FOR DEEP MINES*****************************
C***********************************************************************
C
      WRITE(6,798)
      WRITE(6,791)XST(1,1),XDP(1,1),XSZD(1,1),(RACPD(L,ITYPE),
     &L=1,3),XST(2,1),XDP(2,1),XSZD(2,1)
      WRITE(6,792)XST(1,2),XDP(1,2),XSZD(1,2),(DPDST(L,ITYPE),
     &L=1,3),XST(2,2),XDP(2,2),XSZD(2,2)
      WRITE(6,793)XST(1,3),XDP(1,3),XSZD(1,3),(DPDDP(L,ITYPE),
     &L=1,3),XST(2,3),XDP(2,3),XSZD(2,3)
      WRITE(6,794)XST(1,4),XDP(1,4),XSZD(1,4),(DPDSZ(L,ITYPE),
     &L=1,3),XST(2,4),XDP(2,4),XSZD(2,4)
      WRITE(6,795)XST(1,5),XDP(1,5),XSZD(1,5),(PELST(L,ITYPE),
     &L=1,3),XST(2,5),XDP(2,5),XSZD(2,5)
      WRITE(6,796)XST(1,6),XDP(1,6),XSZD(1,6),(PELDP(L,ITYPE),
     &L=1,3),XST(2,6),XDP(2,6),XSZD(2,6)
      WRITE(6,797)XST(1,7),XDP(1,7),XSZD(1,7),(PELSZ(L,ITYPE),
     &L=1,3),XST(2,7),XDP(2,7),XSZD(2,7)
  791 FORMAT(' RACPD(',F3.0,',',F5.0,',',F3.1,')',
     &3E20.5,'      (',F3.0,',',F5.0,',',F3.1,')')
  792 FORMAT(' DPDST(',F3.0,',',F5.0,',',F3.1,')',
     &3E20.5,'      (',F3.0,',',F5.0,',',F3.1,')')
  793 FORMAT(' DPDDP(',F3.0,',',F5.0,',',F3.1,')',
     &3E20.5,'      (',F3.0,',',F5.0,',',F3.1,')')
  794 FORMAT(' DPDSZ(',F3.0,',',F5.0,',',F3.1,')',
     &3E20.5,'      (',F3.0,',',F5.0,',',F3.1,')')
  795 FORMAT(' PELST(',F3.0,',',F5.0,',',F3.1,')',
     &3E20.5,'      (',F3.0,',',F5.0,',',F3.1,')')
  796 FORMAT(' PELDP(',F3.0,',',F5.0,',',F3.1,')',
     &3E20.5,'      (',F3.0,',',F5.0,',',F3.1,')')
  797 FORMAT(' PELSZ(',F3.0,',',F5.0,',',F3.1,')',
     &3E20.5,'      (',F3.0,',',F5.0,',',F3.1,')',/,/)
  798 FORMAT('       ( ST, DP  ,  SZ )',13X,'MIN',17X,
     &'AVE',17X,'MAX',9X,'( ST, DP  ,  SZ )')
  900 CONTINUE
      GO TO 999
C
C*************************************************************
C******ERROR MESSAGES IN HERE*********************************
C*************************************************************
C
  990 WRITE(6,991)IER
  991 FORMAT('   ERROR MESSAGE NUMBER ',I3,/,/)
  999 CONTINUE
      END
EOF:
```

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THE ICF, INC. COAL AND ELECTRIC UTILITIES MODEL:
AN ANALYSIS AND EVALUATION

VOLUME V:

ELECTRIC UTILITY EXPANSION AND OPERATION

by

Energy Model Analysis Program

M.I.T. Energy Laboratory Report No. MIT-EL 81-015

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PREFACE

This report is one in a series of seven volumes presenting the results of an indepth review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). The Final Report (Volume I) provides a self-contained summary of the study objectives and results, with supporting papers and materials presented in Volumes II-VII.

The complete series includes:

Energy Model Analysis Program, "The ICF, Inc. Coal and Electric Utilities Model: An Analysis and Evaluation," M.I.T. Energy Laboratory Report No. MIT-EL 81-015, Cambridge, Massachusetts 02139, March 1980.

Volume I: Final Report

Volume II: Documentation and Verification of Model Implementation

Volume III: Coal Supply Issues: Mine Lifetime and Coal Royalties

Volume IV: The Coal Supply Cost Function

Volume V: Electric Utility Expansion and Operation

Volume VI: Other Evaluation Issues

Volume VII: Evaluation Strategies and Computational Results

TABLE OF CONTENTS

CHAPTER 1. ELECTRIC UTILITY CAPACITY EXPANSION

1. INTRODUCTION*

This volume contains an overview description and an assessment of the utility generation capacity expansion component of the ICF Coal and Electric Utilities Model (CEUM). The first section includes a discussion and description of those portions of the CEUM relevant to electric generation expansion. We discuss that version of the model extant in September 1978, which was used for producing the model results published in ICF, Inc. (September 1978b). Note that some of the changes in the CEUM's more recent versions have not been incorporated in this volume, although Section 3.3.4 of Volume I discusses some of these revisions.

Following the descriptive portion of this volume there is an assessment of the capabilities of the CEUM generation expansion technique. Finally, Section 7 discusses application areas for which the CEUM would be appropriate or inappropriate.

2. DESCRIPTION OF ELECTRICAL GENERATING CAPACITY EXPANSION

The CEUM computes, for each of 39 utility demand regions in the U.S., amounts of capacity additions for the following types of new facilities:

(1) hydro and geothermal,

(2) nuclear,

(3) oil/gas turbine,

(4) oil/gas steam,

(5) bituminous, subbituminous, or lignite coal
NSPS (New Source Performance Standards, NSPS),

*For a summary of this section and for additional perspective information the reader should refer to Section 3.3.4 of Volume I.

(6) bituminous, subbituminous, or lignite coal ANSPS (Alternative NSPS),

(7) combined cycle,

(8) bituminous to subbituminous coal conversion facilities on existing plants (three types available),

(9) retrofit scrubbers on existing coal plants,

(10) scrubber on new bituminous, subbituminous, or lignite coal NSPS, and

(11) scrubber on new bituminous, subbituminous, or lignite coal ANSPS.

The CEUM Documentation (see ICF, Inc. [July 1977]) describes an ability to incorporate MHD and synthetic gas turbines. A "2 region x 2 region" example provided by ICF did include these plant types; however, they were not included in the version of the model we assessed.

Table 1 shows the range of characteristics that describe the new capacity additions. The linear programming (LP) structure makes it fairly easy to change any of these data, or even to exogenously constrain various expansion patterns. Dynamic issues are not treated, as these additions are measured in total gigawatts of capacity added between the present year and the model horizon year for any model run (as opposed to a series of model runs used to simulate a scenario).

Electricity demand and substitutions between electricity and competing energies are provided exogenously. The capital costs of the capacity additions are structurally included as annualized investment costs added directly to the objective function of the LP. The types of constraint equations relating to capacity expansion are:

(a) electrical generating capacity constraints for existing plants,

(b) material balances for new generation facilities,

TABLE 1

Range of Regional Data Describing New Capacity Additions

Plant Type		Capital Cost, (1975 $/KW) High	Low	Derated Capacity Factor, % Base	Intermediate	Seasonal Peak	Daily Peak
Hydro or Geothermal		0	0	70	28-53	--	5-8
Nuclear		800	650	65-70	--	--	--
Oil/Gas Turbine		195	166	--	35-40	20-25	5-9
Oil/Gas Steam		no new		--	--	--	--
Coal NSPS	B	483	396	65-70	33-41	--	--
	S	529	504	65-70	33-41	--	--
	L	513	513	65-70	33-41	--	--
Coal ANSPS	B	512	464	65-70	33-41	--	--
	S	568	464	65-70	33-41	--	--
	L	558	532	65-70	33-41	--	--
MHD		none		--	--	--	--
Combined Cycle		325	270	65-70	34-35	25	--
Coal Gas Turbine			none	--	--	--	--
Conversion Facilities		50	50	59-63	--	--	--
Retrofit Scrubber		113	102	63-70	36	24	--
Scrubber	B	113	102	--	--	--	--
Coal NSPS	S	113	102	--	--	--	--
	L	113	102	--	--	--	--

(c) material balances for scrubber capacity on both existing and new plants, and

(d) new capacity building limitations.

Using the equations and notation from the mathematical formulation of the CEUM given in Volume II, Chapter 3, Section C, these four sets of constraint equations are described below. All subscript categories, parameters, and activity variables are defined in Volume II, Chapter 3, Section C.

2.1 Electrical Generating Capacity Constraints for Existing Plants

Referring to the listing of plant types given in Volume II, Chapter 3, Section C and using the methodology developed there, we have:

P_e = existing plant types, and

P_n = new plant types.

Similarly the plant type identifiers listed in Volume II, Chapter 3, Section C,, used to differentiate various pollution standards, coal types, or load-following capabilities, are separated as:

ID_e = plant type identifiers for existing plant types, and

ID_n = plant type identifiers for new plant types.

Thus for existing plants:

$P_e = (\underline{O}, \underline{E}, \underline{F}, \underline{G}, \underline{S}, \underline{P}, \underline{Q}, \underline{R}, \underline{H}, \underline{Y}, \underline{T}, \underline{J}, \underline{K})$, and

$ID_e = (\underline{01}, \underline{02}, \underline{03}, \underline{04}, \underline{05}, \underline{02}, \underline{03}, \underline{04}, (\underline{09}, \underline{10}, \underline{11}), \underline{15}, \underline{17}, \underline{19}, \underline{20})$.

(a) If $P_e = \underline{E}$ and $\underline{P}$, then the amount of electricity generated from these plants, translated into units of capacity using the appropriate capacity factor, plus the amount of capacity removed for conversion facilities, must not exceed the existing capacity:

$$\sum_{P_e=\underline{E},\underline{P}} \sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} \quad O_{UR,P_e,UE,L}$$

$$+ BP_{UR,\underline{CV},\underline{25}} \leq EGW^{*}_{UR,\underline{02}}$$

where:

UE	=	utility fuel type (a listing of fuel types is given in Volume II, Chapter 3, Section C),
L	=	load mode,
CF	=	capacity factor in decimal,
UR	=	utility demand region,
$O_{UR,P_e,UE,L}$	=	operate activity in 10^9 kWh/year,
$BP_{UR,\underline{CV},\underline{25}}$	=	newly converted electricial generating capacity (GW),
$\underline{CV}$	=	coal conversion facility, and
$EGW^{*}_{UR,\underline{02}}$	=	existing electrical generating capacity limit (GW), for plant type identified by $\underline{02}$, in demand region UR.

The same type of constraint also holds for plants subjected to the other sulfur standards, that is:

P_e = $\underline{F}$ and $\underline{Q}$, with $BP_{UR,\underline{CV},\underline{26}}$ and $EGW^{*}_{UR,\underline{03}}$, and

P_e = $\underline{G}$ and $\underline{Q}$, with $BP_{UR,\underline{CV},\underline{27}}$ and $EGW^{*}_{UR,\underline{04}}$.

(See Equations (23) and (24) in Volume II, Chapter 3, Section C)

(b) If $P_e = \underline{H}$, that is, an existing hydro or geothermal plant, then:

$$\left[(8.76)\ CF(UR,L)\right]^{-1} \quad O_{UR,\underline{H},\underline{HG},\underline{L}} \leq EGW^{*}_{UR,ID_e}$$

where:

$\underline{HG}$ = hydro or geothermal fuel.

(c) For all other existing plant types, P_e = $\underline{0}$, $\underline{S}$, $\underline{Y}$, $\underline{T}$, $\underline{J}$, $\underline{K}$, where no conversion facilities can deplete capacity, the operate activity level, converted to capacity units, must not exceed the available capacity capabilities:

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_e,UE,L} \leq EGW^{*}_{UR,ID_e}$$

2.2 Material Balances for New Generation Facilities

The new plant types, associated plant type identifiers, and plant types for build activities are given by:

P_n = ($\underline{N}$, $\underline{M}$, $\underline{8}$, $\underline{0}$, $\underline{1}$, $\underline{2}$, $\underline{5}$, $\underline{6}$, $\underline{7}$, $\underline{I}$, $\underline{Z}$, $\underline{U}$, $\underline{L}$)

ID_n = (($\underline{06}$, $\underline{07}$, $\underline{08}$), ($\underline{06}$, $\underline{07}$, $\underline{08}$), ($\underline{22}$, $\underline{23}$, $\underline{24}$), $\underline{28}$, $\underline{29}$, $\underline{30}$, $\underline{25}$, $\underline{26}$, $\underline{27}$, $\underline{14}$, $\underline{16}$, $\underline{18}$, $\underline{21}$), and

PT = ($\underline{CL}$, $\underline{CL}$, $\underline{C9}$, $\underline{NT}$, $\underline{NT}$, $\underline{NT}$, $\underline{CV}$, $\underline{CV}$, $\underline{CV}$, $\underline{HG}$, $\underline{NU}$, $\underline{PT}$, $\underline{PS}$).

Note that there are three identifiers, one for each coal rank, associated with new plant types P_n = $\underline{N}$, $\underline{M}$ and $\underline{8}$.

In general, for each new plant type, the associated operate activities translated into units of capacity, minus the newly built capacity of this type, must not exceed zero. From Volume II, Chapter 3, Section C we have:

(a) For $P_n \neq \underline{N}$, $\underline{M}$, or $\underline{8}$:

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_n,UE,L} - BP_{UR,PT,ID_n} \leq 0$$

(b) For P_n = $\underline{N}$ and $\underline{M}$ and UE = $\underline{BA}$, $\underline{BB}$, $\underline{BD}$, $\underline{BF}$, $\underline{BG}$, $\underline{BH}$:

$$\sum_{P_n=\underline{N},\underline{M}} \sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_n,UE,L} - BP_{UR,\underline{CL},\underline{06}} \leq 0 \quad (1)$$

(c) For P_n = $\underline{N}$ and $\underline{M}$ and UE = $\underline{SA}$, $\underline{SB}$, $\underline{SD}$, $\underline{SF}$, $\underline{SG}$, $\underline{SH}$ use Equation (1) with $BP_{UR,\underline{CL},\underline{06}}$ replaced by $BP_{UR,\underline{CL},\underline{07}}$.

(d) For P_n = $\underline{N}$ and $\underline{M}$ and UE = $\underline{LA}$, $\underline{LB}$, $\underline{LD}$, $\underline{LF}$, $\underline{LG}$, $\underline{LH}$ use Equation (1) with $BP_{UR,\underline{CL},\underline{06}}$ replaced by $BP_{UR,\underline{CL},\underline{08}}$.

(e) For P_n = $\underline{8}$ and UE = $\underline{BA}$, $\underline{BB}$, $\underline{BD}$, $\underline{BF}$, $\underline{BG}$, $\underline{BH}$:

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{8},UE,L} - BP_{UR,\underline{C9},\underline{22}} \leq 0 \quad (2)$$

(f) For P_n = $\underline{8}$ and UE = $\underline{SA}$, $\underline{SB}$, $\underline{SD}$, $\underline{SF}$, $\underline{SG}$, $\underline{SH}$ use Equation (2) with $BP_{UR,\underline{C9},\underline{22}}$ replaced by $BP_{UR,\underline{C9},\underline{23}}$.

(g) For P_n = $\underline{8}$ and UE = $\underline{LA}$, $\underline{LB}$, $\underline{LD}$, $\underline{LF}$, $\underline{LG}$, $\underline{LH}$ use Equation (2) with $BP_{UR,\underline{C9},\underline{22}}$ replaced by $BP_{UR,\underline{C9},\underline{24}}$.

2.3 Material Balances for Scrubber Capacity

Scrubber capacity is measured (somewhat artificially) in GW. Whenever only fractional scrubbing of a plant type's exhaust is required, then the number of GW of that plant type's capacity, multiplied by the scrubbing fraction, must not exceed the number of "scrubber GW" available.

(a) Scrubber category S1 is retrofitted scrubbers, and the associated constraint on S1 capacity is treated very much like material balances for new plant additions.

$$\sum_{P_e=\underline{P},\underline{Q},\underline{R}} \sum_{UE} \sum_{L} f_{SC}(P_e,SL,L) \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,P_e,UE,L}$$

$$- BS1_{UR} \leq 0$$

where:

f_{SC} = the fraction of the capacity to be scrubbed,

$BS1_{UR}$ = building of retrofit scrubber capacity (GW), in demand region UR, and

S1 = retrofit scrubbers.

(b) The S2 scrubbers are those that may be put on new NSPS plants. The S2 scrubber capacity is constrained similar to the way in which S1 scrubber capacity is constrained.

For P_n = $\underline{M}$, that is, new NSPS plants with scrubbers:

$$\sum_{UE} \sum_{L} f_{SC}(\underline{M},SL,L) \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{M},UE,L} - BS2_{UR} \leq 0$$

where:

$BS2_{UR}$ = building S2 scrubber capacity (GW), in demand region UR,

S2 = scrubbers on new NSPS coal plants, and

$$\sum_{UE} \sum_{L} \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{M},UE,L} \geq BS2^{*}_{UR}$$

where:

$BS2^{*}_{UR}$ = lower bound on S2 scrubber capacity in demand region UR.

(c) The S3 scrubbers are on new ANSPS plants that do not use coal of sulfur level A.

For P_n = $\underline{8}$ and UE = $\underline{BB}$, $\underline{BD}$, $\underline{BF}$, $\underline{BG}$, $\underline{BH}$, $\underline{SB}$, $\underline{SD}$, $\underline{SF}$, $\underline{SG}$, $\underline{SH}$, $\underline{LB}$, $\underline{LD}$, $\underline{LF}$, $\underline{LG}$, $\underline{LH}$:

$$\sum_{UE} \sum_{L} f_{SC}(\underline{8},SL,L)\ (8.76)\ CF(UR,L)^{-1}\ O_{UR,\underline{8},UE,L} - BS3_{UR} \le 0$$

where:

$BS3_{UR}$ = building S3 scrubber capacity (GW), in demand region UR, and

S3 = scrubbers on new ANSPS coal plants, sulfur level of coal not equal to A.

(d) Finally, S4 scrubbers are those on new ANSPS plants with coal of sulfur level A.

For $P_n = \underline{8}$ and UE = $\underline{BA}$, $\underline{SA}$, $\underline{LA}$:

$$\sum_{UE=\underline{BA},\underline{SA},\underline{LA}} \sum_{L} f_{SC}(\underline{8},\underline{A},L) \left[(8.76)\ CF(UR,L)\right]^{-1} O_{UR,\underline{8},UE,L}$$

$$- BS4_{UR} \le 0$$

where:

$BS4_{UR}$ = building S4 scrubber capacity (GW), in demand region UR, and

S4 = scrubbers on new ANSPS coal plants, SL = $\underline{A}$.

2.4 New Capacity Building Limitations

(a) Building limitations, for coal plants, in GW, have straightforward constraints.

For NSPS Coal Plants, PT = $\underline{CL}$:

$$\sum_{ID_n=\underline{06},\underline{07},\underline{08}} BP_{UR,\underline{CL},ID_n} \le BCL^*_{UR}$$

where:

BCL^*_{UR} = upper limit on NSPS plant capacity (GW), in demand region UR.

For ANSPS Coal Plants, PT = C9:

$$\sum_{ID_n=\underline{22},\underline{23},\underline{24}} BP_{UR,\underline{C9},ID_n} \leq BC9^*_{UR}$$

where:

$BC9^*_{UR}$ = upper limit on ANSPS plant capacity (GW), in demand region UR.

(b) For Nuclear and Hydro Plants the constraints are:

$BP_{UR,\underline{NU},\underline{16}} = BNU^*_{UR}$, and

$BP_{UR,\underline{HG},\underline{14}} = BHG^*_{UR}$

where:

BNU^*_{UR} = fixed nuclear capacity (GW), in demand region UR, and

BHG^*_{UR} = fixed hydro capacity (GW), in demand region UR.

(c) In the examples we have seen, new oil/gas steam plant capacity is fixed at 0.0, i.e., is not allowed, and new oil/gas turbines, new technologies, and conversion facilities are unconstrained.

2.5 Objective Function Terms Associated with Electricity Generation and Build Activities

The capacity additions are motivated by operating needs for unmet electricity demand in the categories of baseload, intermediate, peaking, and seasonal peaking demand. Where there are alternative strategies for capacity additions, those additions that minimize the overall objective function (see Volume II, Chapter 3, Section C) are chosen. It should be noted that the real annuity coal prices, transportation costs, transmission costs, and all the other coefficients in the objective function may well play roles in the resulting capacity expansion strategy. The objective function terms directly related to the activity variables used in the constraint equations of this section are:

$$\sum_{UR}\sum_{P}\sum_{UE}\sum_{L} OMC(P,UE,L)\ O_{UR,P,UE,L}$$

$$+\sum_{UR}\sum_{PT}\sum_{ID_n} ACP(UR,PT,ID_n)\ BP_{UR,PT,ID_n}$$

$$+\sum_{UR}\Big[ACS1(UR)\ BS1_{UR} + ACS2(UR)\ BS2_{UR} + ACS3(UR)\ BS3_{UR}$$

$$+ ACS4(UR)\ BS4_{UR}\Big]$$

where:

OMC = O&M cost (includes fuel cost for nuclear plants), mills/kWh

ACP = annualized capital cost for new power plants, \$/KW-yr,

ACS1 = annualized capital cost for scrubber type S1, \$/KW-yr,

ACS2 = annualized capital cost for scrubber type S2, \$/KW-yr,

ACS3 = annualized capital cost for scrubber type S3, \$/KW-yr, and

ACS4 = annualized capital cost for scrubber type S4, \$/KW-yr.

3. GENERAL ASSESSMENT COMMENTS

There is an obvious advantage to describing the utility expansion portion of the CEUM by itself, since it is simple enough to be discussed in a relatively self-contained manner. There are also important disadvantages. In particular, due to the static (time is not indexed in the LP variables) linear programming format of the CEUM, there is an enormous amount of simultaneous interactivity that makes it difficult to assess the model in decomposed units. For example, utility generation expansion and operation are performed simultaneously, as are utility expansion and transmission. These particular interactions are important and thus some discussion of utility expansion will have to include discussions of, or be qualified due to divorcing from, utility operation and transmission activities.

3.1 General Impressions

We have formed several impressions as a result of running the CEUM and studying the outputs. These impressions cannot really be categorized, or, for that matter, substantiated, and thus they are grouped together here as abstracted comments.

First, there are impressions about how "analytically complex" the model appears to be. In other words, is it "clever" about choosing future paths or is it "blindly" scaling up the past? A first check of complexity is illustrated in Figure 1. Detailed descriptions of the model runs associated with the abbreviated names can be found in Volume VII, Chapter 1. The Corrected Base Case (CBC), the corrected demand increase (EDMI), and the corrected demand decrease (CEDMD) runs arecompared using their performance measure, total dollar costs. In a linear program for which there are many different constraints and types of activities moving in and out of the basis, with major parameter changes, one would normally expect to see curves in Figure 1 with substantially rounded shapes. The curves shown in Figure 1, however, display very little nonlinear activity around the Corrected Base Case. There are two possible explanations:

(1) Activities around the Corrected Base Case are very nearly perfect substitutes for one another, (which the model builders say is the correct explanation), or

(2) There is very little activity around the Corrected Base Case except simple scaling (up or down) of the marginal activities.

To differentiate between these two possibilities some of the generation expansion results are displayed in Table 2. The coal, oil/gas steam, and oil/gas turbine capacities are the only areas in which there is appreciable activity. The results in Table 2 show several important types of model responses. Note that there is no retirement of any coal capacity between 1975 and 1995. This point will be discussed later. Since the total existing coal capacity is thus constant, the only important question is whether or not there is significant load mode redistribution. There is not; there are changes of only a couple of GW on the average, and generally in the direction reflecting the fact that baseload capacity is most easily replaced in the model. The use of existing oil/gas steam increases somewhat with demand increases, and it shifts significantly to cover the baseload demands in 1985 when new coal utilization is severely constrained. In 1990 the baseload oil/gas steam capacity always disappears, and in 1995 the intermediate oil/gas steam capacity always disappears. Whether or not this has been exogenously constrained was not determined from a moderately intensive examination of the code, but from conversations with the model builders they indicated that these are endogenous variables and that decreased oil prices would change these results.

In summary, the effects of demand changes are:

(1) Existing capacity of oil/gas facilities (both steam plants and turbines) generally cover seasonal peaking demands,

(2) The volatile new turbine capacity covers most of the changes in peaking demands, and

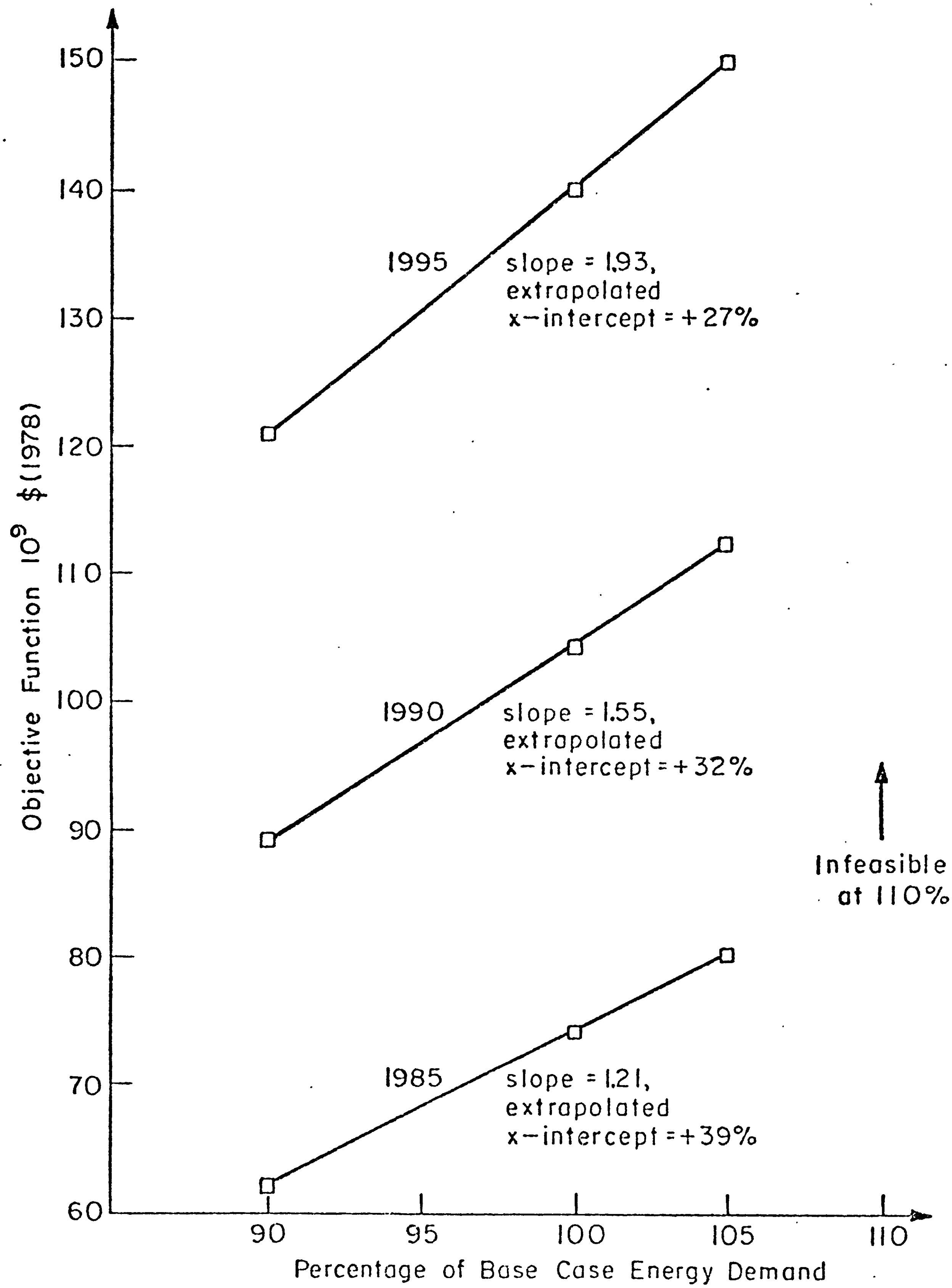


Figure 1. Effect of Energy Demand Changes on the Objective Function for the Corrected Version of the Full Model.

TABLE 2

CEUM Generation Expansion Activities Under Demand Change Scenarios

	CEDMD	CBC	EDMI	CEDMD	CBC	EDMI
	Existing Capacity (GW)			New Capacity (GW)		
Total Coal 1985	197.8	197.9	197.9	86.8	110.7	119.0
Baseload	148.2	154.1	158.9	61.6	81.7	91.7
Intermediate	36.9	36.9	35.7	25.3	29.0	27.2
Seasonal Peak	12.8	7.0	3.4	-	-	-
Total Coal 1990	197.9	197.9	197.9	178.2	231.7	261.5
Baseload	128.6	134.6	134.3	103.8	146.2	170.8
Intermediate	41.0	37.1	37.9	74.4	85.4	90.7
Seasonal Peak	28.3	26.2	25.7	-	-	-
Total Coal 1995	197.9	197.9	197.9	299.8	381.8	424.6
Baseload	109.3	108.0	108.7	156.5	215.7	244.7
Intermediate	31.9	30.6	27.6	143.2	166.1	179.8
Seasonal Peak	56.7	59.4	61.6	-	-	-
Oil/Gas Turbines 1985	27.2	37.4	40.0	19.1	38.0	59.8
1990	26.6	28.7	26.5	18.4	32.2	46.7
1995	34.1	33.9	30.8	28.7	41.1	56.7
Oil/Gas Steam 1985	128.5	145.6	149.0	-	-	-
1990	104.8	121.3	122.2	-	-	-
1995	70.0	78.9	76.3	-	-	-

(3) Once left unconstrained (after 1985), new coal capacity covers baseload and intermediate changes.

Although these activities do have some place in utility planning, they seem to be unsophisticated. The reason for this is that the generation expansion component of the CEUM is a significantly simplified representation of reality. For example, derated existing coal capacity and oil/gas steam and turbine plants should take the pressure off the need for new turbine capacity. As another example, the most easily perturbed component of baseload capacity should be nuclear, not coal. That is, when demand drops, it is the construction of nuclear plants that is generally stalled. The model builders responded to this concern by claiming that no demand changes should be implemented in the CEUM without a series of other exogenous input changes, such as changes in fixed nuclear capacities. This shows one of the many cases in which we have found that there must be considerable intelligence imposed by the model user directly on the model and indirectly on the results. Although the model has tremendous bookkeeping capabilities, outside of sorting out the few coal use alternatives, it does not demonstrate a great deal of analytic complexity.

3.2 The Energy Marketplace

Another general comment about the CEUM from the generation expansion perspective concerns the level of detail and aggregation in the model. There is a very high level of detail in the coal supply component, less detail in the electric utility demand component, and no detail at all in the modeling of alternative energy markets. In these alternative energy markets for electric utilities, for example, nuclear capacity is fixed, so nuclear fuel price changes will not result in changes in utility usage, and both oil and gas prices are fixed at equal (although there are ways around this) prices per million Btu (and at constant prices over each modeling interval). To examine the possible effects of more detail in energy pricing, Table 3 shows a comparison of the electric utility capacity changes that result from the COILG sensitivity run: a 25% increase in the 1985 oil/gas prices and a 25% increase only in the price change increments from 1985 to the other case years; and from the MOIL sensitivity run: straight 25% increases in oil/gas prices over the Corrected Base Case. There is clearly a strong substitution of coal-fired units for oil/gas facilities, as one would expect. In COILG-85 and MOIL-85 new coal-fired capacity increases to its upper limit in almost every region, nationally increasing 11 GW in each case. The use of existing oil/gas steam plants and oil/gas turbines in total GW drops almost this exact amount. In COILG-90 there is about a 17 GW increase in new coal-fired capacity, and an almost identical decrease in oil/gas steam capacity. The 1990 total oil/gas turbine capacity is about the same in both COILG and the Corrected Base Case,while in 1995 the total turbine capacity is greater in the increased oil/gas price scenario (COILG). This is a particularly unusual result considering that demand for electricity has not been increased with the increase in oil/gas price, since the CEUM has no substitution between electricity and other fuels.. The reason for this result is that the turbines are compensating for an even more significant drop in existing oil/gas steam utilization. In MOIL these shifts are even more pronounced, with existing 1990 turbines at 10.0 GW, down from 28.7 GW in the CBC. To compensate, the daily peaking oil/gas steam capacity

TABLE 3

Total U.S. Capacity Changes in GW
Due to Changes in the Oil/Gas Price

	CBC	COILG	MOIL
New Coal Capacity 1985	110.7	121.7	121.7
New Coal Capacity 1990	231.7	248.6	282.5
New Coal Capacity 1995	381.8	389.4	389.4
Existing Oil/Gas Steam Capacity 1985	145.6	140.3	140.3
Existing Oil/Gas Steam Capacity 1990	121.3	105.1	91.0
Existing Oil/Gas Steam Capacity 1995	78.9	68.4	72.0
Existing Turbine Capacity 1985	37.4	34.8	34.8
New Turbine Capacity 1985	38.0	35.8	35.8
Existing Turbine Capacity 1990	28.7	29.7	10.0
New Turbine Capacity 1990	32.2	30.4	30.4
Existing Turbine Capacity 1995	33.9	39.1	35.5
New Turbine Capacity 1995	41.1	39.0	39.0

increases almost 20 GW. This 20 GW and the total drop in oil/gas steam capacity is compensated for by adding more than 50 GW of new coal capacity, compared with the Corrected Base Case.

The user should be cautioned that these changes of as much as 60% in capacity utilizations as a result of 25% changes in oil/gas prices imply a strong connection in the CEUM between energy market prices and electric capacity utilization. If such a strong connection actually exists in reality, which we believe is the case, then more attention to the detail of modeling the price of energy is required. If there is not in reality such a strong connection, then the economics in the CEUM are inappropriate.

On the other side of the energy market modeling issue, the CEUM does not have competition between electricity and other energy sources in the demand sector. Table 4 displays national average imputed (i.e., other than fixed) costs of electricity for several model runs, and it can be seen that there are differences of 15 percent and more between some of these costs in the same year. Of course, it is unreasonable to expect that demands for electricity would remain unchanged in the face of such changes in costs of electricity. The obvious solution to such a problem for the model operator is to adjust the demand mixes to intelligently reflect interfuel substitutions. Such adjustments would require complex out-of-model exercises. For instance, before an oil/gas price increase scenario could be run, the user must guess at and incorporate the required increases in demand for electricity due to its substitution for those fuels. As difficult as this procedure might be to implement, it is still easier than the anticipation of some other types of feedbacks. For example, looking at Table 4, consider the changes in load duration curve

TABLE 4

Imputed National Total Mills per KWH*
for Several Scenarios**

	1985	1990	1995
CBC-Corrected Base Case	27.9	32.9	37.2
CEDMD-Demand Down 10%	25.1	30.4	34.9
LDC1-Load Mode Change 1%	29.2	34.3	38.8
LOAD-Load Mode Change 5%	34.9	40.6	45.8

*These numbers are very likely too low due to omissions of coal profits, coal royalties, hydro capital costs, and other factors; however, these omissions would very likely accentuate the differences. For perspective, the January 1, 1978 charges to consumers were 44.4 mills/kWh for 500 kWh/month residential customers, 67.5 mills/kWh for 1,500 kWh/month commercial customers, and 47.0 mills/kWh for 60,000 kWh/month industrial customers (National Electric Reliability Council [August 1978]).

**For additional scenarios, see Table 36 on page 5-90.

parameters that would result from such changes in costs of electricity; these could not be accurately anticipated before the model run. In this case an iterative procedure is obviously necessary. It would be helpful, even for an experienced user of the model, to have a checklist of feedback effects that are not included in the model, so model runs could be checked and somehow adjusted to account for the lack of these mechanisms. Such checks are sometimes called ex poste facto commonality impositions. Some of the more important feedbacks affecting the commonality of input assumptions in the capacity expansion portion of CEUM are:

(1) adjustments that should be made to demands due to changes in regional costs of electricity that may result from any of a large number of indirect causes,

(2) changes in demand for electricity due to changes in prices for coal and oil/gas and the resultant interfuel substitution,

(3) changes in exogenously specified nuclear, hydro, combined cycle, and coal capacity limits as a result of changes in demand for electricity,

(4) effects of changes in the inflation rate on costs of capital for utilities and on utility fixed charge rates, and

(5) effects of competition for low-sulfur coal from industries that must meet the same types of environmental restrictions as utilities.

Expecting the operator to find an overall consistent set of inputs and outputs might be a difficult or practically impossible task, although the model developers say it is not difficult for them. The iterative procedure of running the model, checking outputs, adjusting the inputs, again running the model, and so on, would be somewhat like trying to solve a large number of simultaneous equations by trial and error. The user should be aware that with a model such as the CEUM, at more than

$1000 per run (and now possibly down to $500), the imposition of commonality on inputs and outputs may not be possible for runs that are substantially changed from the Base Case.

3.3 Geographic Resolution

A final comment about the level of aggegation concerns the geographic resolution used in computations and in output reports. Table 5 shows an example of the effect of aggregation in the reporting of CEUM results. As shown in this table, effects that are very significant at regional levels, such as a greater than 100% change in the construction of bituminous coal capacity, become relatively insignificant nationally with only a 6% change. Such dilutions of impact with aggregation are appropriate and expected. The fact that the CEUM operates at one level of resolution (demand regions) greater than the reporting level (aggregate PIES region districts) is also appropriate. There are only two problems with the level of aggregation in the CEUM. First, there may be substantial and unrealistic dislocations at the state level that would not be spotted in the regional reports. Second, the level of detail in the data must be comparable to the level of detail in the structure; otherwise, the appearance of model resolution is specious. This second point will be addressed further in this volume.*

4. PLANT CHARACTERISTICS

The presentation of the assessment of plant characteristics is broken into ten separate generic discussion areas, given below.

*It is also the topic of a major discussion in Section 3.3.1 of Volume I.

TABLE 5

Percentage Changes in Build Activities from Base Case
to Corrected Version of Full CEUM, in 1995

PLANT TYPE	Maximum Absolute % GW Change, Any Region	Absolute % Change of National GW Total, By Plant Type
Retrofit Scrubber	>100%	13%
New Scrubber	89%	3%
Bituminous Coal	>100%	6%
Subbituminous Coal	>100%	11%
Lignite	0%	0%
Turbine	9%	0%
Oil/Gas Combined Cycle	0%	0%
Conversions	>100%	13%

Total % Change in Scrubber GW	3.19%
Total % Change in Plant GW	0.10%

*Not including Nuclear or Hydro Capacity

4.1 Investment Costs

This discussion of plant characteristics begins with the plant investment costs, in terms of their base values and real escalation factors. Table 1 showed the overall range of plant capital costs for the year 1975. Basic capital costs for plants and scrubbers are taken fromthe GDUGEN file of the CEUM code and are scaled as follows:

(1) 1.00 for New England and North Atlantic regions,

(2) 0.80 for South Atlantic,

(3) 0.90 for Central regions,

(4) 0.95 for Mountain regions, and

(5) 0.90 for Western and Southwestern regions.

This is an example of important data inputs at the level of detail of just five U.S. regions. The base year, 1975, costs are given as follows:

(1)	\$750/kW	Nuclear
(2)	\$433/kW	NSPS, Bituminous, No Scrubber
(3)	\$504/kW	NSPS, Subbituminous, No Scrubber
(4)	\$515/kW	NSPS, Lignite, No Scrubber
(5)	\$145/kW	Oil/Gas Turbines
(6)	\$275/kW	Combined Cycle
(7)	\$450/kW	ANSPS, Bituminous, No Scrubber
(8)	\$518/kW	ANSPS, Subbituminous, No Scrubber
(9)	\$535/kW	ANSPS, Lignite, No Scrubber
(10)	\$100/kW	Existing Coal, Build Retrofit Scrubber, Any Standard
(11)	\$75/kW	Build Scrubber on New Plant, Any Standard

These costs, however, do not conform with those found in the GDU file of the CEUM code, which are the costs actually used (see Table 6). The discrepancy between the product of regional multipliers and base costs, and the figures given in Table 6 appears to be the $50/kW add-on charge for intraregional transmission (from line 1042 of the GDUGEN file).

How good are these dozen or so inputs that are used to generate the approximately 350 regional capital cost figures? Table 7 compares the regional escalation factors with those of the EPRI Technical Assessment Group (August 1977) and Shurr, et al. (1979), and as can be seen, in only 12 of the 17 regions is the CEUM data within the .025 roundoff error from either number in the other two documents. Differences between the RFF and EPRI and the CEUM data range from -17% to +15%. We make no claim that one set of data is better than the other, but it is our intent to point out that there can be substantial regional differences in data developed from different sources, such as a 5-region level of detail (CEUM) versus a 6- or 9-region level of detail. For a model such as the CEUM with the potential for interregional power interchanges, an attempt should be made to estimate 39-region detail, even if it only involves some smoothing (to avoid 25% increases that take place in crossing state lines in the CEUM).

The base year costs of the coal plants are not very different from those generally published,* which range from about $430 to $570/kW in 1975 dollars. Nuclear plant costs are generally reported* between $520

*See Van Horn (June 1979), EPRI Technical Assessment Group (August 1977), U.S. Atomic Energy Commission (Octoer 1974), U.S. Federal Power Commission (December 1, 1976), and MITRE Corporation (October 1978), which do not include the $50/kW hookup charge.

TABLE 6

Plant Capital Costs (1975 $/KW) from the GDU File of the CEUM Code
(Includes $50/KW Intraregional Transmission Charges)

	New England North Atlantic	South Atlantic	Central	Mountain	Western & So.Western
Nuclear	800	650	725	762.5	725
NSPS Bituminous	483	396.4	439.7	461.35	439.7
NSPS Subbituminous	none	none	503.6	527.6	503.6
NSPS Lignite	none	none	513.5	none	none
Hydro	0	0	0	0	0
Oil/Gas Turbine	195	166	180.5	187.75	180.5
Combined Cycle	325	270	297.5	311.25	297.5
ANSPS Bituminous	500	410	455	477.5	455/512.481*
ANSPS Subbituminous	568	464.4	516.2	542.1	516.2/576.033
ANSPS Lignite	none	none	531.5	558.25	none
MHD	none	none	none	none	none
Conversion Subbituminous	50	none	50	none	none

* Different numbers in Southern California.

TABLE 7

Comparison of Regional Capital Cost Variations

	CEUM	EPRI**	RFF*
MN/VT/NH/MA/CN/RI/NYupstate	1.00	1.00	.99
PN-West/VA-West/WV	1.00	1.00	.92
PN-East/NJ/NY/MD/DEL	1.00	1.00	.90
VA-East	1.00	1.00	.83
KT-South	.80	.95	.83
NC/SC/GA/FL/TN/AL/MS-East	.80	.86	.83
OH/MI/IN	.90	.95	.92
IL/WS-East	.90	.95	.90
WS-West	.90	.95	.88
KT-North	.80	.95	.92
MS-West	.80	.86	.88
MO-East	.90	.91	.90
KA/NB/MO-West/MI/IA/ND/SD	.90	.91	.88
TX	.90	.88	.82
MN/WY/CO/UT/NV	.95	.91	.92
AZ/NM/WA/OR/CA	.90	.94	.92
AK/OK/LA	.90	.88	.88

* Numbers normalized so Illinois is the same in both the CEUM and RFF figures (Shurr, et al. [1979]).

** From EPRI Technical Assessment Group (August 1977).

and $750/kW in 1975 dollars. Although nuclear plants have been built at costs ranging from $300/kW to $1200/kW in 1975 dollars, the lower figures come from the 1960s and the higher figures from plants with unusual problems.

Problems with the base year cost figures seem to exist with the non-coal and non-nuclear units. For example, oil-fired gas turbines can range in price from $160 to $200/kW in 1975 dollars (see Mitre Corporation [October 1978]). In addition, the model annualizes capital costs over the presumed 30-year lifetime of each plant. Turbines, however, are generally considered (see EPRI Technical Assessment Group [August 1977], p. III-2) to last only about 20 years; this would increase the annualized cost of turbines considerably. Also, the book life of plants tends to be only 60 to 70% of their actual life (see Commerce Clearing House [1979] and EPRI Technical Assessment Group [August 1977]). Perhaps the CEUM's understatement of the capital cost of turbines might account for some of the unusual popularity of turbines in the CEUM. Combined cycle and scrubber costs also may be as much as $50/kW low (see EPRI Technical Assessment Group [August 1977], U.S. Federal Power Commission [December 1, 1976], and Mitre Corporation [October 1978]). Perhaps these CEUM numbers were based upon the costs for the largest sizes of facilities. However, since the CEUM does not have different size categories of power plants, it must utilize average cost values for 50 MW to 1300 MW coal plants and 5 MW to 100 MW oil/gas turbines. Whenever such generic figures are required, costs somewhat higher than the 'optimum' capital costs should be used.

4.2 Real Escalation of Utility Capital Costs

The next topic of discussion is the real escalation factor used for utility capital costs. Almost everyone concedes that utility capital costs are very likely to increase at a rate faster than inflation, and generally it is estimated that this real escalation will be about 2% per year. Such an escalator is in fact included in the Base Case of the CEUM, but only until 1985. It should be noted that the model documentation does not make it clear that there is no real escalation in utility capital costs between 1985 and 1995. Thus, utility capital costs increase at the general rate of inflation from 1985 onward, and we could find no moderately easy way to correct this situation. To approximately simulate a 2%/year real escalation from 1975 all the way to 1995 we chose to increase the escalation rate over 1975 to 1985 to 4%/year (see sensitivity run UCD4 in Figure 2). This had a significant effect on the model outputs for 1995, which is the only year for which a comparison of UCD4 and CBC should be made. Utilities shift away from coal capacity to cheaper oil/gas turbines, with utility oil/gas consumption increasing by 16% in 1995. Also, 10 GW of additional existing capacity is used in 1995, to avoid the higher building costs. Table 8 shows the 1995 capacity comparisons, and it can easily be seen that existing oil/gas steam plants and a few new oil/gas turbines are displacing new coal plants. With nuclear capacity exogenously set and without the ability to retire coal plants (both of which, if treated exogenously, would have been substantially affected by this capital escalator change), the model is responding in accord with our understanding of the situation. The point of concern here is, however, that there are some rather substantial changes, and that the documentation should be amended to make the user

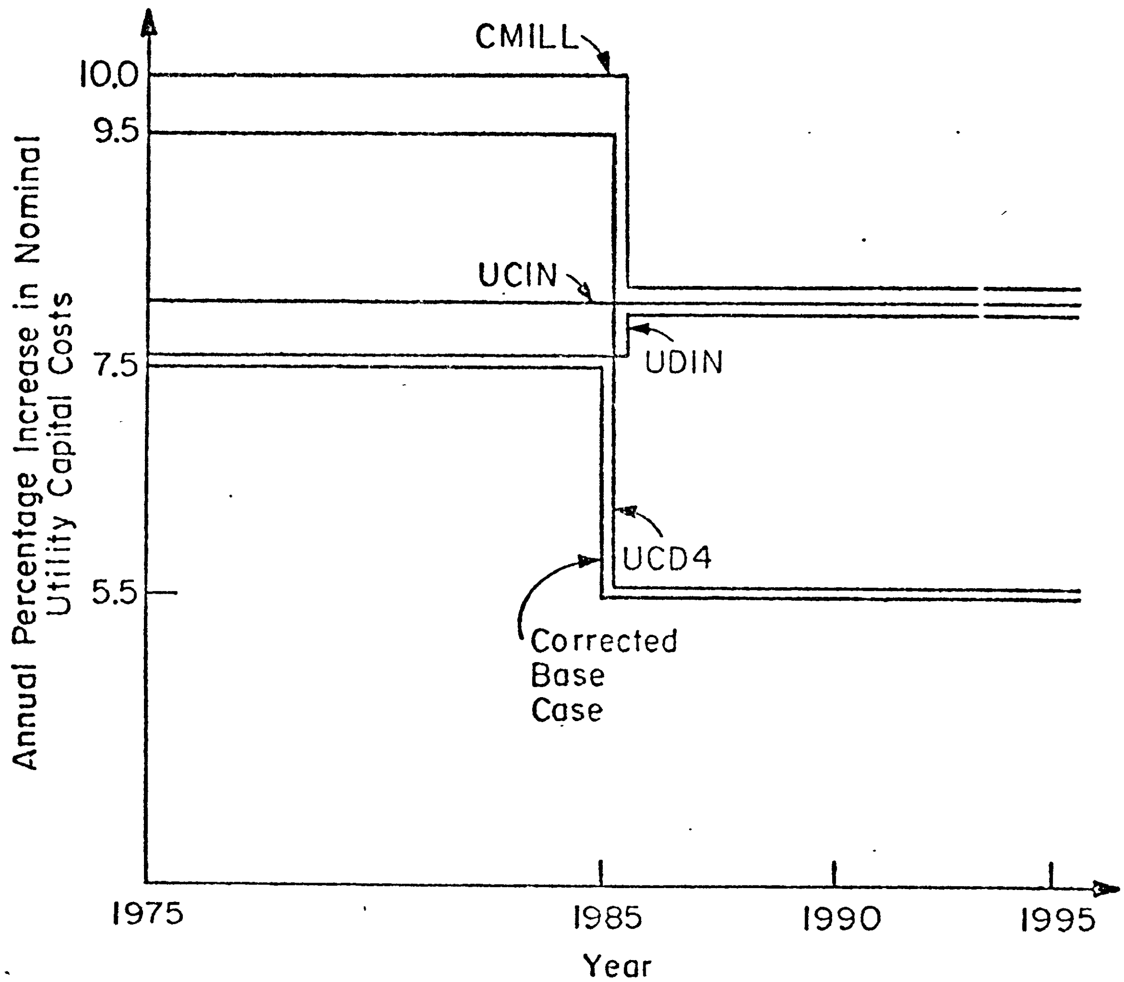


Figure 2. Nominal Utility Capital Cost Escalation Rates in Several CEUM Sensitivity Runs.

TABLE 8

1995 Comparison of CBC (using an Average Utility Capital Cost Escalator of 1%/yr) with UCD4 (using a 4%/yr Average Utility Capital Cost Escalator)

	CBC (GW)	UCD4 (GW)
Existing Oil/Gas Steam	78.9	90.0
Existing Oil/Gas Turbine	33.9	32.7
Existing Total Capacity	417.3	427.2
New Baseload Coal	215.7	206.1
New Intermediate Coal	166.1	163.1
New Coal Total	381.8	369.2
New Oil/Gas Turbines	41.1	43.5
New Total Capacity	640.6	630.4
Total Capacity	1057.9	1057.6

aware that there is no real escalation in utility capital costs after 1985. Obviously, it would be preferable to have a model that would allow real escalations in costs past the year 1985. When asked about this problem the model builders claimed that they had no basis for expecting real escalation far into the future.

Another problem concerning real escalation in capital costs is that, because of the static nature of the model, all new plants are assumed to be built at the end of the model time period. It can be shown that with a 2%/year real escalation rate, having all plants built in 1985 would be about 10% more expensive than if 1/10 of the required 1985 capacity was built in each year between 1975 and 1985. This is clearly a significant problem, and if real escalation were allowed from 1975 to 1995, then the error would be even more serious. In a way it is, then, fortunate that real escalation in utility capital costs was stopped after 1985 if one is examining 1990 and 1995 model results, which are quite sensitive to capital costs.

4.3 Inflation Rate

A final utility capital cost issue concerns the need for expediting changes in the general rate of inflation used in the CEUM. After a year of 13+% inflation in 1979, the inflation rate of 5.5%/year in the CEUM seems much too low. So far as we could determine no model run had been made with other than a 5.5%/year inflation, and in trying to implement a change in the inflation rate we obtained some understanding of why this change had not been made--it is difficult to implement. The inflation rate is an implicit part of many model parameters. It should obviously be extricated and made a user-accessible simple input to the model.

After some false steps in the form of model runs UCIN and UDIN (see Figure 2), a change in the inflation rate to 8.0%/year was attempted in the CMILL sensivity run. The name CMILL is our acronym for Corrected Money Illusion, and if, in fact, the general rate of inflation and all nominal escalation rates had been properly scaled, then only the value of currency would change. Thus, one would not expect actual decisions to change, i.e., what difference should it make if the model uses half-dollars or dollars? Table 9 shows that the CMILL run did produce some decision changes. The model shows a typical response to slightly more expensive utility capital costs: a shift from the use of new to existing base load and intermediate capacity, and the construction of new oil/gas turbines as in the UCD4 run.

The CMILL run was apparently not made correctly; changing inflation rates in the CEUM is extremely difficult. The CEUM employs a real fixed charge rate (FCR) to annualize utility capital costs. Since this rate is real as opposed to nominal, we did not feel that it was necessary to change this particular input when implementing a change in the general rate of inflation. We have learned from ICF that, along with other changes that we have implemented correctly, the real FCR does have to be slightly adjusted when the inflation rate changes. ICF apparently has a separate undocumented computer program that calculates the real FCR as a function of several financial parameters. We were unable to properly adjust the fixed charge rate in the CMILL sensitivity run (and also in the UCIN and UDIN model runs) since we did not receive documentation from ICF detailing the manner in which the real FCR is calculated out-of-model. The effect of not adjusting the real fixed charge rate should not significantly impact CEUM output. Since the CMILL sensitivity run was not implemented correctly, we have no grounds for declaring that the general rate of inflation is treated correctly or incorrectly in the CEUM.

It should also be noted from Table 9 that the UCIN and UDIN sensitivity runs show the appropriate apparent advantage for new baseload coal investments, as well as the characteristically slight decrease in new oil/gas turbine capacity.

4.4 Operating and Maintenance Costs

There does not appear to be any real advantage to an extensive discussion of other plant characteristics data, so only several examples are given. The operating and maintenance costs used for different plant types again show that the data is not very regionally specific (see Table 10), which may in fact be appropriate. Hopefully, these costs also include fuel inventory costs, which can be about 0.7 mills/kWh for nuclear facilities. These costs vary by load mode because a large fraction (see EPRI Technical Assessment Group [August 1977], p. VII-15) of O&M costs is fixed rather than variable. There appears to be a 1.0 mill/kWh error in peaking turbines, as described in the footnote to Table 10.

4.5 Heat Rates

The heat rates used in the CEUM deserve closer consideration. For example, the heat rates for new NSPS bituminous (9200) Btu/kWh,* subbituminous (9632) Btu/kWh, and lignite (9927) Btu/kWh coal plants,

*Could be as low as 8600 Btu/kWh (see Thompson, et al. [1977]), but EPRI Technical Assessment Group (August 1977) reports 9500 Btu/kWh.

TABLE 9

1985 Comparison of Corrected Base Case (CBC), Money Illusion (CMILL), and Other Scenario Capacities (GW)

	CBC	UDIN	UCIN	CMILL
Existing Baseload Coal	154.1	150.5	151.1	154.2
Existing Intermediate Coal	36.9	39.2	38.8	38.2
Existing Seasonal Coal	7.0	8.3	8.1	5.5
Existing Oil/Gas Steam Baseload	25.5	24.7	25.1	27.6
Existing Oil/Gas Steam Intermediate	56.9	56.4	56.5	57.1
Existing Oil/Gas Steam Seasonal	38.3	37.7	37.8	37.9
Total Existing Baseload	247.9	243.5	244.5	250.1
Total Existing Intermediate	117.3	118.9	118.6	118.8
Total Existing Seasonal	49.3	49.5	49.5	47.4
New Baseload Coal	81.7	86.2	85.2	79.5
New Intermediate Coal	29.0	27.5	27.8	27.4
New Seasonal Oil/Gas Turbines	13.3	12.9	12.9	15.2

TABLE 10

O&M Costs for Baseload Plants in All Regions
(with 0.5 mill/KWH Increases For Each Shorter Usage Mode)††

	CEUM
All Existing Coal Plants	1.80
NSPS Bituminous Coal	2.30
NSPS Subbituminous Coal	2.50
NSPS Lignite Coal	2.70
Existing Nuclear	6.50*
New Nuclear	7.00*
Existing Turbine	0.80†
New Turbine	0.50†
Existing Combined Cycle	1.00†
New Combined Cycle	1.00†
Existing Oil/Gas Steam	1.50

* Includes fuel costs.
† In [7], these are 1.80, 2.30, 1.70, and 2.20, respectively, with these changes not documented.
†† Oil/gas turbines are claimed [7, Appendix C, page C-43] to have 0.50 mill/KWH cheaper O&M costs in the daily peaking mode compared with the seasonal peaking mode. This is probably a data error of 1.0 mill/KWH, i.e., O&M costs for daily peaking should be 0.50 mill/KWH more expensive than for seasonal peaking.

although representing good average numbers, do not vary by region as they should due to significant changes in cooling water temperatures and theireffects on efficiencies. Strangely, existing oil/gas turbines and steam plants have dramatically poorer efficiencies in daily peaking modes, for example, in Central regions:

Base	7,900 Btu/kWh
Intermediate	8,580
Seasonal	8,799
Daily	12,500

The old existing coal plants have unrealistically* high heat rates, such as in the Northeast:

Base	17,818 Btu/kWh
Intermediate	18,458
Seasonal	18,718

and inexplicably are not allowed to operate in the daily peaking mode. What is even stranger (although this could just be an artifact of a purely economic decision) is that with such poor heat rates such plants are never retired in the CEUM. Coal plants built before 1950 are considered in other models to have heat rates of about 12,500 Btu/kWh (see Van Horn, et al. [June 1979]).

New coal plants with scrubbers are given slightly increased O&M costs and heat rates compared to plants without scrubbers. The use of scrubbers <u>should</u> introduce significant additional operating cost (see

*Considerably greater than the 14,030 Btu/kWh 1950 average (see Edison Electric Institute [1975]) for <u>all</u> plant types, among which coal plants would have the <u>lowest</u> heat rates.

EPRI Technical Assessment Group [August 1977], p. VII-5) penalties, otherwise the model will bias results in favor of additional scrubber capacity (the modelers say the numbers came from EPA).

The accuracy of data used to generate the LP coefficients for electricity generation activity variables should undergo extensive updating. In many cases these data appear to be crude placeholders and first approximations that have not been updated.

4.6 Fuel Costs

The next area of discussion is the cost of fuel. Since the model employs a national optimization, the cost of fuel is not explicitly considered in utility planning nor dispatching but is indirectly accounted for in fuel production and transportation activities. Fuel inventory costs of from 0.1 to 0.7 mill/kWh are hopefully charged as part of each plant's O&M costs. We now comment on the manner in which generation expansion "responds" to fuel cost variations, and the appropriations of the fuel costs.

With regard to the appropriateness of fuel costs, there are a number of issues discussed in Volume III, Chapter 2 that deal with Coal Royalties. One of these important points is that the market will not have coal prices determined solely by production costs, but by the marginal production cost plus a profit and royalty. By missing the royalties and the intertemporal rents the CEUM effectively and significantly undercharges for coal. (It is not immediately obvious that there may not be some problem with the way the CEUM treats static rents, particularly with regard to the possibility that some utility decisions might change for utilities that own their own coal mines.) The point is that if the average prices of coal are lower than they should be, then coal will definitely be used by the utility component more than it should be. It is hard to think of a way to estimate the impact of higher coal prices. The structure of the LP does not facilitate the implementation of marginal cost decisions. One would have to estimate that a 25 or 30% increase in coal prices would decrease utility coal consumption by at least 15%. However, none of our CEUM sensitivity runs had nearly this effect on coal use. This is due to the fact that no existing coal capacity is ever retired, and new coal plants are used to cover baseload and intermediate demands, load modes for which there is no other new plant-type that can act as a substitute in the CEUM. The apparent conclusion is that although coal prices seem to be too low, both the CEUM generation expansion and the CEUM generation utilization are too inflexible to allow for much change in total coal use.

There are, nevertheless, substitution effects that take place among the different coal types, and these can be investigated in the Base Case versus Corrected Base Case comparisons (see Table 11). Although coal prices have split fairly evenly between being corrected up and down, there is a consistent net effect of decreases in build activities. This effect is magnified as the horizon year moves from 1985 to 1995, as seen in Table 12. There is also a persistent shift from bituminous to subbituminous coal plants. Many plant types experience changes in capacity by substantial percentages by region due to the verification corrections. The final two Build Summary Tables (Tables 13 and 14) confirm the impressions of easily perturbed build activities for small price changes, the majority showing up as substitutions among types of scrubbers or types of coal plants.

TABLE 11

Summary of Build Activity Changes from Base Case to Corrected Version of the Full CEUM, in 1985

PLANT TYPE	GW Capacity Largest Decrease Any Region	Largest Increase Any Region	Total Change All Regions	/	Number of Regions with Changes
Retrofit Scrubber	-1.053	+0.421	-2.122	/	10
New Scrubber	-0.379	+0.128	-0.580	/	6
Bituminous Coal	-0.394	+0.046	-0.415	/	4
Subbituminous Coal	-0.046	+0.025	-0.021	/	2
Lignite	0.0	0.0	0.0	/	0
Turbine	-0.066	+0.013	-0.003	/	5
Oil/Gas Combined Cycle	0.0	0.0	0.0	/	0
Conversions	0.0	0.0	0.0	/	0
		Total Change in Scrubber GW	-2.702	/	16
		Total Change in Plant GW	-0.439		Regional Totals Changed

Note that Nuclear and Hydro Capacity is fixed.

TABLE 12

Summary of Build Activity Changes from Base Case to Corrected Version of the Full CEUM, in 1995

PLANT TYPE	GW Capacity Largest Decrease Any Region	Largest Increase Any Region	Total Change All Regions	/	Number of Regions with Changes
Retrofit Scrubber	-1.925	+0.419	-2.143	/	10
New Scrubber	-2.638	+2.285	-6.808	/	30
Bituminous Coal	-6.038	+2.462	-14.436	/	16
Subbituminous Coal	-0.104	+6.038	+13.959	/	16
Lignite	0.0	0.0	0.0	/	0
Turbine	-0.035	+0.013	-0.067	/	4
Oil/Gas Combined Cycle	0.0	0.0	0.0	/	0
Conversions	0.0	+0.751	+0.968	/	4
		Total Change in Scrubber GW	-8.951	/	32
		Total Change in Plant GW	+0.424		Regional Totals Changed

Note that Nuclear and Hydro Capacity is fixed.

TABLE 13

Summary of Build Activity Changes from Corrected Version to Corrected NSPS Version of the Full CEUM, in 1985

PLANT TYPE	Minimum Change Any Region	Maximum Change Any Region	Total Change All Regions /	Number of Regions with Changes
Retrofit Scrubber	-0.627	+1.867	+4.138 /	11
New Scrubber NSPS	-0.012	+1.696	+2.791 /	4
New Scrubber ANSPS(S≠A)	-4.332	+0.095	-16.505 /	16
New Scrubber ANSPS(S=A)	-1.126	0.0	-3.197 /	8
Bituminous Coal NSPS	-1.300	+1.256	-0.228 /	3
Subbituminous Coal NSPS	-1.256	0.0	-1.706 /	2
Lignite NSPS	0.0	0.0	0.0 /	0
Bituminous Coal ANSPS	-1.279	+0.916	+3.065 /	10
Subbituminous Coal ANSPS	-0.763	+1.279	+1.965 /	8
Lignite ANSPS	0.0	+0.259	+0.259 /	1
Oil/Gas Turbine	-0.549	+0.058	-1.277 /	9
Oil/Gas Steam	0.0	0.0	0.0 /	0
Conversions	-0.077	0.0	-0.077 /	1
		Total	-10.772 /	33

TABLE 14

Summary of Build Activity Changes from Corrected Version to Corrected/20 Year Minelife Version of the Full CEUM, in 1985

PLANT TYPE	Minimum Change Any Region	Maximum Change Any Region	Total Change All Regions	/	Number of Regions with Changes
Retrofit Scrubber	-1.260	+0.622	-3.695	/	9
New Scrubber NSPS	-0.601	0.0	-1.408	/	5
New Scrubber ANSPS(S≠A)	-0.129	+2.239	+2.607	/	8
New Scrubber ANSPS(S=A)	-1.126	+0.066	-1.068	/	4
Bituminous Coal NSPS	0.0	0.0	0.0	/	0
Subbituminous Coal NSPS	0.0	0.0	0.0	/	0
Lignite NSPS	0.0	0.0	0.0	/	0
Bituminous Coal ANSPS	-0.089	+2.347	+3.322	/	7
Subbituminous Coal ANSPS	-2.347	+0.089	-2.601	/	6
Lignite ANSPS	0.0	0.0	0.0	/	0
Oil/Gas Turbine	-0.176	+0.174	+0.166	/	8
Oil/Gas Steam	0.0	0.0	0.0	/	0
Conversions	-0.379	0.0	-0.379	/	1
		Total	-3.056	/	24

Tables 15, 16, and 17 show the use of bituminous, subbituminous, and lignite coal for new generating capacity. It is fairly clear from these tables that when the cost of coal goes down on the average, such as in the CML20 and LABD sensitivity runs (mine lifetime and labor cost decreases), there is again substitution of bituminous for subbituminious coal plants due to less use of western coals. Figure 3 shows the relatively sensitive response of new subbituminous coal plant capacity to coal price variations. The dashed line in this figure is drawn approximately through the four sensitivity runs that represent relatively pure across-the-board coal price changes: CBC, CML20, ROYI, and LABD. If the inference of this line is correct, then a 30% increase in coal prices (from the CBC) would cause an 80% increase in subbituminous coal plants. With such sensitivity, it is obviously important to resolve the issues of rents, royalties, severance taxes, rail rates, and other components in the price of coal!

Since hydro and nuclear capacities are essentially fixed in the CEUM, the only other fuel costs that can be investigated are for oil and natural gas. Although there is regional variation allowed in oil and gas prices, these two prices are required to be equal (note that there are two types of oil--residual and distillate--that have different, but fixed ratio, prices). This constrained equality will have relatively little direct effect on generation expansion, because very little natural gas is used by utilities, and no new natural gas-fired plants are planned. The indirect effects of this equality and the highly sensitive response of the CEUM to changes in oil/gas prices have been described in Table 3 and in the accompanying text.

TABLE 15

U.S. New Bituminous Coal Power Plant Capacity (GW)

	1985	1990	1995
CBC	58.9	.13E03	220.1
CNSPS	58.8	.13E03	.21E03
CML20	62.6	.14E03	.24E03
CEDMD	41.3	.10E03	.17E03
CMILL	55.2	*	*
CNINC	51.3	.11E03	.19E03
COILG	66.2	.14E03	.22E03
UCIN	59.5	.15E03	.23E03
UDIN	59.7	*	*
LAB3	52.2	99.8	.17E03
TCML	58.2	.13E03	.22E03
LOAD	56.5	.13E03	.20E03
ROYI	56.8	.12E03	.21E03
EDMI	64.6	.15E03	.24E03
UCD4	53.1	.11E03	.21E03
LABD	64.6	.16E03	.26E03
LOGN	56.7	.11E03	.20E03
CDRB	59.0	.13E03	.21E03
LDC1	59.6	.13E03	.21E03
NCAP	63.8	.15E03	.24E03
MOIL	66.2	†	.23E03
BC	59.3	.13E03	234.6
EDMD	42.0	.10E03	.17E03
NOTX	43.7	.14E03	.24E03

* These runs were not made.
† This report was not released to us.

TABLE 16

U.S. New Subbituminous Coal Power Plant Capacity (GW)

	1985	1990	1995
CBC	40.4	78.7	142.1
CNSPS	43.6	96.3	.15E03
CML20	37.5	72.2	.10E03
CEDMD	34.1	61.7	.10E03
CMILL	40.2	*	*
CNINC	40.2	70.9	.12E03
COILG	44.1	82.1	.14E03
UCIN	42.0	80.6	.13E03
UDIN	42.0	*	*
LAB3	44.4	.10E03	.18E03
TCML	41.4	92.2	.14E03
LOAD	38.9	72.5	.12E03
ROYI	41.6	91.6	.14E03
EDMI	42.6	88.1	.15E03
UCD4	39.4	71.1	.13E03
LABD	36.2	61.0	.10E03
LOGN	41.6	91.1	.15E03
CDRB	40.2	79.1	.14E03
LDC1	40.6	78.5	.13E03
NCAP	42.0	68.2	.15E03
MOIL	44.1	†	.13E03
BC	40.4	78.7	128.2
EDMD	34.0	61.1	.10E03
NOTX	36.0	85.5	.13E03

* These runs were not made.
† This report was not released to us.

TABLE 17

U.S. New Lignite Coal Power Plant Capacity (GW)

	1985	1990	1995
CBC	11.4	17.5	19.5
CNSPS	11.7	16.5	20.6
CML20	11.4	24.0	26.1
CLDMD	11.4	16.1	18.0
CMILL	11.4	*	*
CNINC	11.4	17.5	18.6
COILG	11.4	17.2	19.3
UCIN	11.4	17.5	19.6
UDIN	11.9	*	*
LAB3	11.4	17.6	19.8
TCML	11.4	16.9	19.6
LOAD	11.4	17.6	18.6
ROYI	11.4	17.2	19.5
EDMI	11.7	17.4	19.5
UCD4	11.4	17.2	19.3
LABD	11.4	16.9	18.6
LOGN	11.4	17.0	19.1
CDRB	11.4	18.0	20.0
LDC1	11.4	17.6	19.5
NCAP	11.4	17.4	19.5
MOIL	11.4	†	19.4
BC	11.4	17.6	19.5
EDMD	11.4	16.1	17.9
NOTX	11.4	16.9	19.2

* These runs were not made.

† This report was not released to us.

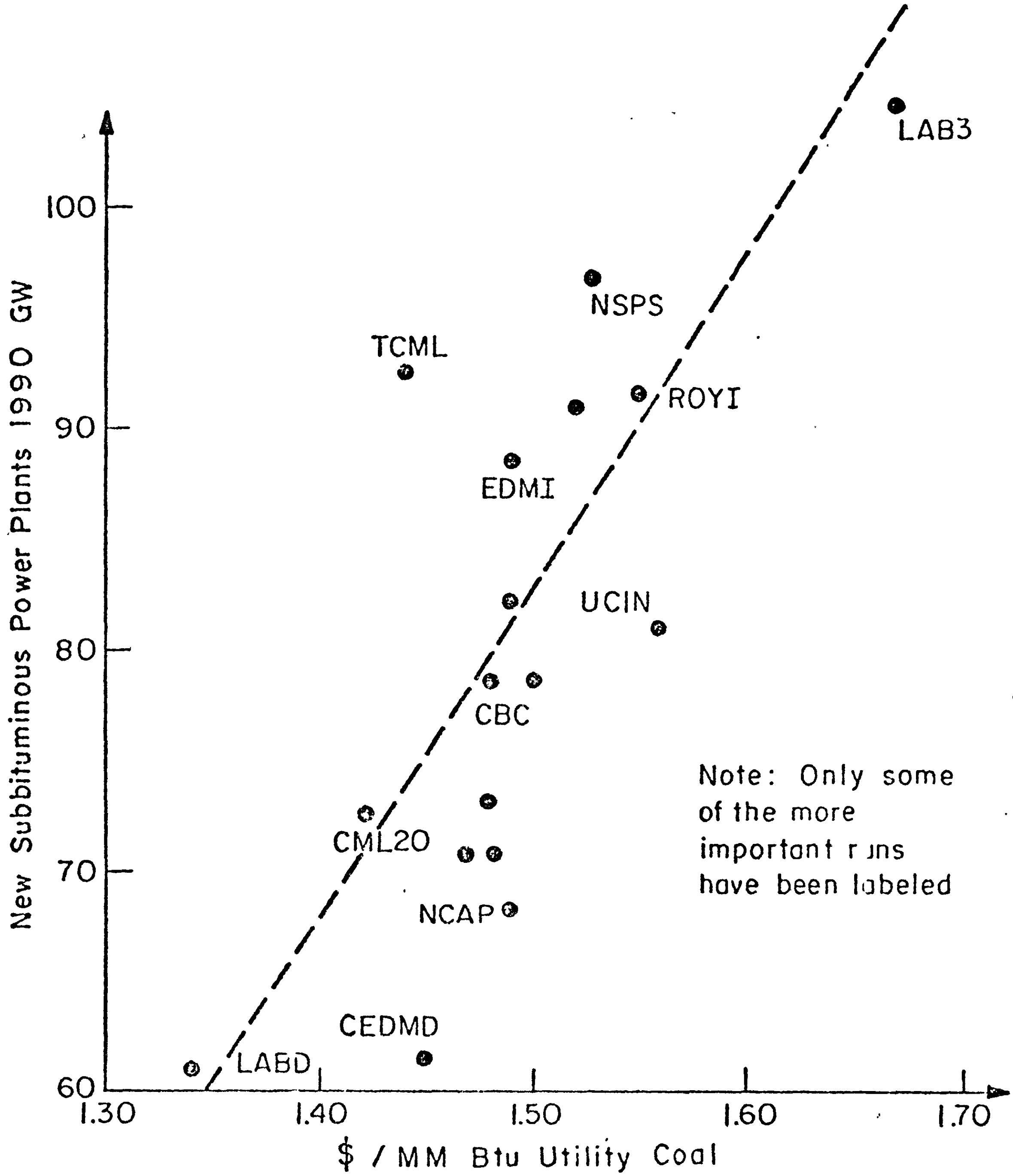


Figure 3. New U.S. Subbituminous Coal Power Plants Compared with Utility Coal Prices in 1990.

4.7 Plant Outages

Other important plant characteristics are planned outage rates, forced outage rates, and capacity factors. The CEUM combines all of these numbers into a single exogenously specified parameter (although combinations of the same plant type in different load modes can offer an approximation to one dimension of variation in this parameter). The problem with this treatment is that those three numbers each require separate treatment. Individual plant capacity factors are generally endogenized in utility planning models, because they are really decision variables and not imposed physical constraints. The forced outage rate is an uncertain physical constraint for each plant. Planned outage is also a physical constraint, but it is known with more certainty than the forced outage rate.

How does the CEUM's approximation in treating outage rates affect the model results? This depends upon issues that are not resolved in the documentation or in the computer code. Specifically, it depends upon whether or not the load mode categories are intended to reflect the generation from the different mode generation types or if the load mode categories are intended to reflect the demand from the different demand mode types. This issue is addressed in Subsection 5 below. For the moment, then, let us examine only the accuracy of the outage input numbers. The CEUM can be described as, in effect, having zero forced outage rates in all its plant types. The planned outage rates are adjusted to make up for those zero forced outage rates. The effect of such a misappropriation in the planning process generally would result in an underestimation of the need for peaking capacity. The reason for this is that peaking capacity is built as much, and sometimes more, to cover uncertainties in generation and transmission availabilities as to cover uncertainties in demand. Do the CEUM projections in fact result in half the combustion turbine capacity additions that they should? As can be seen from Table 18, the CEUM is projecting turbine additions far in excess of industry plans or of projections as calculated using a national model with more sophistication in the utility sector (with capacity targets, load duration curves, and a sophisticated generation expansion logic). What has happened to the guess about the CEUM's response characteristics? As it turns out it is still true that the manner in which the CEUM logic responds to a need for turbine is based solely upon increases in the peaking demands of electric consumers, and not due to the peaking demands of the power system. There are, however, errors concerning: (1) the way in which the peaking demand is defined, and (2) the way this peaking demand is calculated. These two topics are dealt with in detail in Subsection 5.7 below. Concerning the problem of incorporating generation supply uncertainties, there are approximate methods that can be used to incorporate such demands in a linear programming structure. For example, the decision to build new baseload capacity could be tied to additional requirements for peaking and intermediate capacities. In this way, baseload plant types with relatively higher forced outage rates would be effectively penalized by increasing the demands for fast-responding backup capacity. This point is very important for coal plants with scrubbers and no legal scrubber bypass possibilities. Such plants could have forced outage rates 8% (see ERPI Technical Assessment Group [August 1977]) greater than coal plants without scrubbers.

TABLE 18

New Capacity Additions from the CEUM and Industry Plans

Source	Time Period	Total New Generation (GW)	Total New Combustion Turbines (GW)	Turbine Percent of Total (%)
CBC	1975-1985	230.7	38.0	16.47
CBC	1975-1990	417.4	32.2	7.71
CBC	1975-1995	640.6	41.1	6.42
DOE 1978 Plans*	1978-1987	308.7	9.2	2.99
DOE 1978 Plans	1978	28.0	1.3	4.47
DOE 1978 Plans	1979	26.0	0.5	1.97
DOE 1978 Plans	1980	30.1	0.9	2.90
DOE 1978 Plans	1981	25.3	1.1	4.30
DOE 1978 Plans	1982	34.1	0.5	1.58
DOE 1978 Plans	1983	32.5	0.7	2.09
DOE 1978 Plans	1984	33.4	1.3	3.98
DOE 1978 Plans	1985	34.4	1.1	3.06
DOE 1978 Plans	1986	33.5	0.9	2.82
DOE 1978 Plans	1987	31.5	1 0	3 03

* As published in U.S. Department of Energy (October 1978).

TABLE 18 (continued)

New Capacity Additions Minus Retirements

	Total Additional Generations (GW)	Total Additions to Combustion Turbines* (GW)	Turbine Percent of Total %
CBC Existing Total in 1975	500.8**	42.0**	8.39
1975-1985	216.5	33.0	15.24
1975-1990	370.8	18.9	5.10
1975-1995	557.2	33.0	5.92
REM 1977 Results† Existing Total in 1975	512.7	43.4	8.46
REM 1977 Results† 1975-1980	98.9	1.9	1.92
REM 1977 Results† 1975-1985	234.0	14.2	6.07
REM 1977 Results† 1975-1990	408.6	13.6	3.33
REM 1977 Results† 1975-1995	556.6	24.2	4.35
NERC Projections†† 1978-1987	268.	-	-
NERC Projections†† 1975-1985	-	3.7	-

* Additional new capacity minus retired capacity.

**Officially U.S. Department of Energy [January 1979] should be 508.3 GW existing total in 1975 with 36.1 GW of gas turbines and internal combustion capacity in 1976.

†From M.I.T. Energy Model Assessment Program (May 1979), p. 3-90.

††From National Electric Reliability Council (August 1978).

It should be noted that such a scheme of tying baseload plants to peaking requirements would still only be a type of derating or equivalence approximation, although the approximation becomes much better with finer resolution in the load duration curve, say 10 or 20 segments instead of CEUM's 4-segment curve. In addition, although such an equivalence technique would not add to the size (although it would increase the density) of the linear program, it would only be useful if data were utilized that indicated different outage rates for those different types of power plants that supply the same load modes and among which the CEUM can choose. Large differences in outage rates do in fact exist. For example: Forced outage rates for baseload hydro plants are at about 5%, oil at about 10%, coal at about 15%, and nuclear has now exceeded 18% (see U.S. Department of Energy [April 1978] and Ansen [November 1977]). However, it must be recalled that the CEUM has effectively exogenously specified baseload hydro, nuclear, and existing oil/gas steam capacity. Thus the only chance for using a derating scheme would come in choosing between coal plants with and without scrubbers. However, even this limited application would be desirable because the CEUM probably gives an undue advantage to plants with scrubbers by not drawing in the peaking plants needed to support the unreliability of the scrubbers. (Plants with scrubbers do have slight heat rate and capacity factor changes in the CEUM that tend to make them slightly less desirable).

The obvious question at this point concerns the reasonableness of the capacity factors that have been used for the different plant types (see Table 19). It is not difficult to see that there is usually little or no variation of the plant's capacity factors from those the model would like to eventally have as the average in each load mode. The reason the model would like to fix these regional capacity factors is because it is trying to solve all the electric generation planning and operating problems based solely on energy demands. To satisfy the other half of the problem, that is, the peak capacity demands, approximately correct in each region for each load mode, the model has to approximate the regional capacity factors, which are the energy-capacity ratios. There is little doubt that the regional capacity factors will approximately be met given that these regional factors will just be weighted sums of the capacity factors of various plant types in the same columns of Table 19, each of which has capacity factors nearly identical to the regional target. What is lost is the actual variability between individual plant capacity factors (for example, from about .58 for baseload nuclear to about .92 for baseload hydro [see U.S. Department of Energy (April 1978) and Commonwealth Edison Company (1976)]) upon which the generation expansion decisions hinge. The fact that the CEUM can only choose among various coal types, with all else essentially exogenous, somewhat but not totally diminishes the capacity choice problems. More about the implications of these problems follows shortly.

There is some question about whether or not the margin has been handled appropriately in creating CEUM parameters, and this is treated later. Presuming that it is done correctly, then from ICF, Inc. (September 1978a), p. C-25, it is clear that all of the plant and regional capacity factors in the model are created from derated load factors. The average 20% regional margins have been implicitly deducted (-16.7%) from these load factors, so the model will build 20% more capacity to meet the same loads. Escalating these plant capacity factors to yield the implicit underlying load factors, in an even manner across all plant types as shown in Table 20, yields what would seem to be very high implicit load factors (or zero-margin capacity factors) for the baseload units. Obviously, therefore, the reserve margin (as the slack between capacity factors and impicit load factors) has not been implicitly spread equally among the various load categories. In fact the burden of the reserve margin seems to be directed primarily at the intermediate load category. This point is undocumented and unclear in the CEUM, and deserves some explanation. In addition, if the baseload capacity factor is not correct, then the ramifications of this error will fall heavily on certain of the other load categories.

The nuclear capacity factor, at 70% for a majority of the regions, seems to be obviously off target with the more recent units (and the national* average) under 60%. Table 21 shows the substantial effects of a change in this factor, and here again it can be seen that even though the nuclear capacity factor is not a decision variable, it can still have profound indirect implications on the CEUM coal-related results. Coal transportation, utilization, and electricity transmission activities changed between 9 and 27%, showing on the one hand the nice connectiveness within the model, and on the other hand, the criticality of using good data throughout the model, especially in the sensitive areas like the capacity factors.

One more comment should be made about capacity factors relating to the previous comment that such factors are decision variables in ordinary

*In 1974-5 nuclear was 58.6% (see U.S. Department of Energy [April 1978]); in 1971-5 coal factors were 67.5% (see Electric Council of New England [1978]).

TABLE 19

Capacity Factors Used in the CEUM
For Various Plant Types

	Base	Inter-mediate	Seasonal Peaking	Daily Peaking
Spread of Capacity Factors CEUM Tries to Meet in Regions	.650-.700	.320-.410	.200-.250	.050-.090
Old No Scrubber	.650-.700	.330-.400	.250	-
Existing No Scrubber SIP1	.650-.700	.350-.410	.200-.250	-
Existing No Scrubber SIP2	.650-.700	.370-.410	.250	-
Existing No Scrubber SIP3	.695	-	-	-
Existing Retrofit SIP1	.628-.695	.358	.242	-
Existing Retrofit SIP2	.640-.695	-	-	-
Existing Retrofit SIP3	.695	-	-	-
Convert	.585-.630	-	-	-
Existing Scrubber	.628-.677	.329-.358	.242	-
NSPS No Scrubber	.650-.700	.330-.410	-	-
NSPS w/Scrubber	.650-.700	.340-.400	-	-
ANSPS w/Scrubber	.650-.700	.350-.410	-	-
Existing Oil/Gas Turbine	-	-	.250	.050-.090
New Oil/Gas Turbine	-	.350-.400	.200-.250	.050-.090
Existing Oil/Gas Combined Cycle	-	-	.250	.050-.060
New Oil/Gas Combined Cycle	.650-.700	.340-.350	.250	-
Existing Oil/Gas Steam	.650-.700	.320-.400	.200-.250	.050-.090
Existing Nuclear	.650-.700	-	-	-
New Nuclear	.650-.700	-	-	-
Existing Hydro	.650-.882	.276-.446	-	.050-.090
New Hydro	.700	.276-.530	-	.050-.080

TABLE 20

Implicit Load Factors
(Zero-Margin Capacity Factors)

	Base	Inter-mediate	Seasonal Peaking	Daily Peaking
Spread of Implicit Load Factor in Regions	.702-1.058	.331-.636	.240-.300	.060-.108
Old No Scrubber	.780-.840	.396-.480	.300	-
Existing No Scrubber SIP1	.780-.840	.420-.492	.240-.300	-
Existing No Scrubber SIP2	.780-.840	.444-.492	.300	-
Existing No Scrubber SIP3	.780-.840	-	-	-
Existing Retrofit SIP1	.754-.834	.443	.299	-
Existing Retrofit SIP2	.768-.834	-	-	-
Existing Retrofit SIP3	.834	-	-	-
Convert	.702-.756	-	-	-
Existing Scrubber	.754-.812	.395-.430	.290	-
NSPS No Scrubber	.780-.840	.396-.492	-	-
NSPS w/Scrubber	.780-.840	.408-.480	-	-
ANSPS w/Scrubber	.780-.840	.420-.492	-	-
Existing Oil/Gas Turbine	-	-	.300	.050-.108
New Oil/Gas Turbine	-	.420-.480	.240-.300	.060-.108
Ex Oil/Gas Comb Cycle	-	-	.300	.060-.072
New Oil/Gas Comb Cycle	.780-.840	.408-.420	.300	-
Existing Oil/Gas Steam	.780-.840	.384-.480	.240-.300	.060-.108
Existing Nuclear	.780-.840	-	-	-
New Nuclear	.780-.840	-	-	-
Existing Hydro	.780-1.058	.331-.535	-	.060-.108
New Hydro	.840	.331-.636	-	.060-.096

TABLE 21

Comparison of Major Differences Between the CBC and the NCAP Runs
(Lowered Nuclear Capacity Factor)

	CBC	NCAP	% Difference from CBC
Implicit Nuclear Load Factor	.780-.840	.636-.684	12.3
Actual Nuclear Capacity Factor	.650-.700	.530-.570	12.3
New Intermediate Turbines 1985	4.6	8.2	78.3
New Seasonal Turbines 1985	13.3	17.3	30.1
New Total Turbines 1985	38.0	76.6	22.6
New Coal w/Scrubber 1990	106.7	131.2	23.0
New Coal w/Scrubber 1995	174.4	212.3	21.7
Total Base Coal 1995	215.7	255.4	18.6

generation expansion planning programs. It is true that in the CEUM, although capacity factors are exogenous, there is often more than one load mode in which a plant type can serve. For example, turbines can be operated in intermediate, seasonal, or daily peaking, or any combinations of these modes. These combinations cleverly allow for an approximation of what would happen with an endogenously calculated capacity factor. The danger, however, is that since the CEUM has only four load modes, a plant type may look disadvantageous at two modes, but might have been important at some intermediate point, as is the case for plant type C in Figure 4. This may be the problem* with combined cycle in CEUM, which almost always (except in Southern California) gets constructed at its minimum allowable capacity. Actually, in real generation expansion planning schemes, sizes and characteristics of specific individual plants are very important in the decision process.

4.8 Retirement of Capacity

Capacity is generally retired after 20 to 30 years due to a combination of factors, including economic disadvantages of outmoded technologies, frequent expensive repairs, and sometimes the relatively greater advantage of using the plant's site for a newer technology. It is the oil/gas turbines that generally retire within 20 years (see EPRI Technical Assessment Group [August 1977], p. III-2); 25 years is not very uncommon, and 50-year lifetimes have occurred. Coal and oil/gas steam plants are generally retired after 30 years (see EPRI Technical Assessment Group [August 1977]). Figure 5 shows the oil/gas turbine and

*The U..S. Federal Power Commission (December 1, 1976) in fact shows combined cycle to be optimal in a small range near 35% usage.

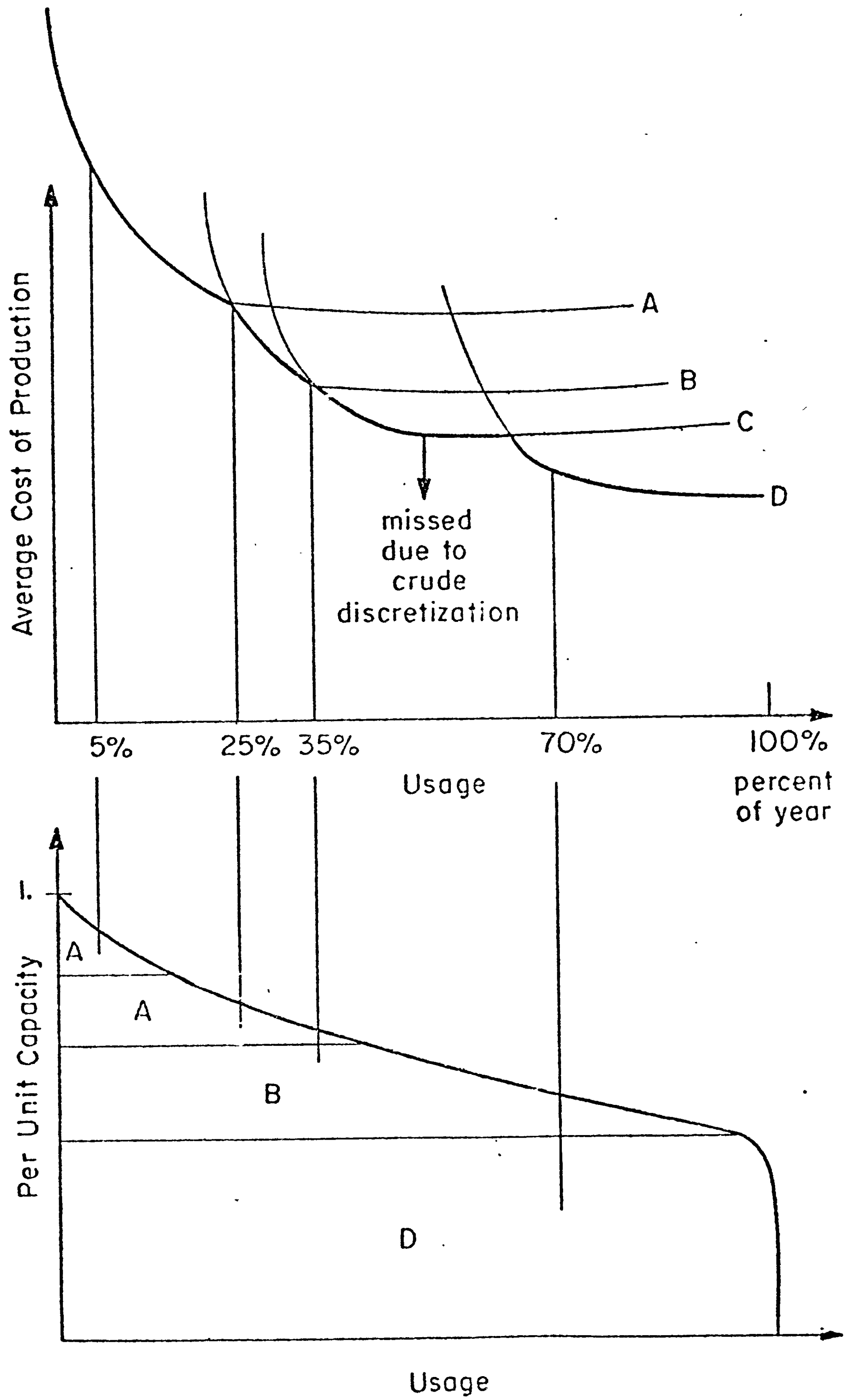
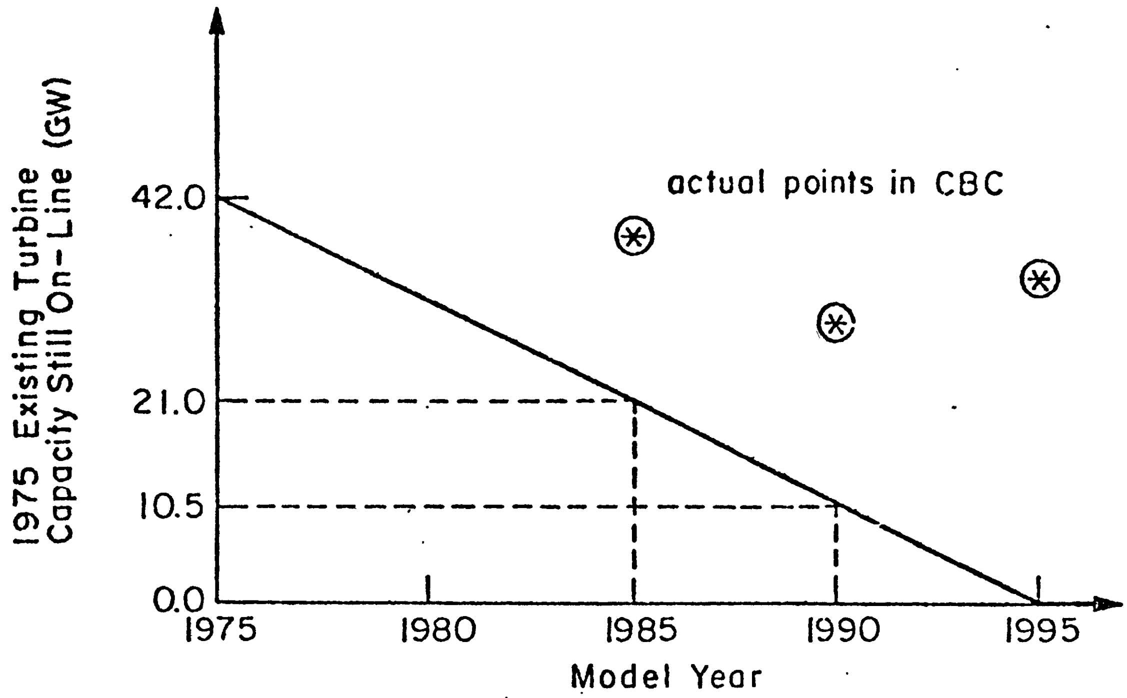


Figure 4. Geometrical Representation of the Standard Calculation of Optimum Capacities, and How the CEUM Might Miss an Optimum Type Due to Its Approximations.



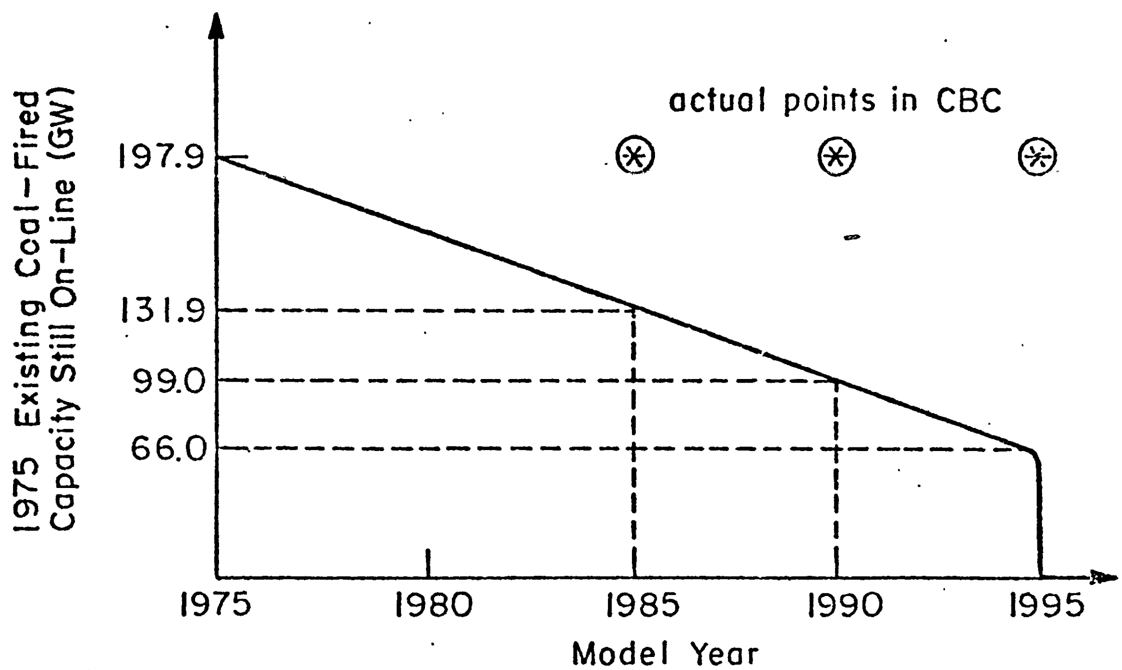


Figure 5. Retirement of Turbines and Coal Plants over the Course of 1975 to 1995 CEUM Horizon, Assuming Linear Retirement; Plans are Reported Underway for Retiring 9.4GW of Fossil Steam and 1.5GW of Turbines by 1987

Source: U.S. Department of Energy (October 1978).

coal capacity that would be retired at the various model horizons (case years) given a linear retirement scheme. Figure 5 also shows the points that indicate the retirements that actually occur in the CEUM. It could be considered unrealistic that the model shows little or no retirement of these existing facilities. The effect of this lack of retirement is most profound on the capital requirements and on the cost of electricity. The impact upon coal production and consumption by coal type would be less important but still significant, recalling the factor-of-two difference in heat rates of old versus new coal plants. Exogenous retirements should be an input of future CEUM uses.

4.9 Derating Capacity

Another issue apparently not addressed by the model is the economic or exogenously specified derating of capacity. There is some economic shifting of existing coal capacities and derating or retirement of the existing oil/gas steam plants (see Table 22). There perhaps could be more derating, either of existing coal plants to daily peaking or of new coal plants to seasonal peaking, by the end of the 1995 planning horizon. It would appear that the extra existing coal plants that really must be retired should be taken mostly from the existing baseload category. If between 30 GW coal and 10 GW of baseload existing coal are retired, then the coal derating situation would appear more reasonable. One way of accomplishing this retirement would be to separate the one "old existing coal" plant category into two categories, setting the heat rate and O&M costs of each category to levels that would reflect some of the major disadvantages of utilizing such plants and shifting plants into the deteriorated "old" category for later horizon years. If this were

TABLE 22

Effective Derating of CEUM Capacities in the CBC (GW)

	1985	1990	1995
Existing Coal Baseload	154.1	114.7	108.0
Existing Coal Intermediate	36.9	25.4	30.6
Existing Coal Seasonal	7.0	17.4	59.4
Existing Coal Daily Peak	0.0	0.0	0.0
Existing Oil/Gas Steam Baseload	25.5	0.0	0 0
Existing Oil/Gas Steam Intermediate	56.9	34.7	0.0
Existing Oil/Gas Steam Seasonal	38.3	46.8	29.0
Existing Oil/Gas Steam Daily Peak	24.9	39.7	49.9

accomplished, it is possible that the model itself might decide in favor of economic retirements, although this is not certain, given that the unrealistically* high heat rates, by themselves, have not brought forth these retirement decisions.

4.10 Lead Times For New Plants

Since for individual runs the CEUM is a static model, it does not have the capability to handle such dynamic expansion issues as:

(1) study, licensing and construction lead times,

(2) fine-tuning of the construction stream to the demand stream with the slack taken up by interregional exchanges,

(3) plants in the construction pipeline at the beginning and at the end of the modeling period, and

(4) different lead times for different plant types,: about 3 years for turbines, 9 years for coal, and 13 years for nuclear (see EPRI Technical Assessment Group [August 1977]).

It is difficult to estimate the magnitudes of discrepancies introduced by not addressing these dynamic issues. They would be smallest for uniform demand growths, relatively small plant sizes, very long horizon times, and no real escalation rates--factors that will to some extent be controlled by the model user's expectation of future events.

For the earliest case year, 1985, there are very tight constraints on model activities due to this lead-time problem. Essentially all coal and other new capacity in 1985 is exogenously specified, except for new oil/gas turbines. These new oil/gas turbines thus take the fullest impact of 1985 scenario changes in the model. The extremely high new

*See footnote two on page 5-37.

oil/gas turbine capacity in 1985 must be viewed the way the model builders view it; they say they do not view turbines as turbines but as indications of reserve margin problems. However, because of the intertemporal constraints within the model, requiring at least a 100% carryover of new capacity to all longer planning horizons, these reserve margin problems are propagated to more distant case years. With 38.0 GW of new turbine capacity built in the CBC for time period 1975-1985, 32.2 GW is built in 1975-1990. The 100% intertemporal constraint <u>is</u> being met in the LP, it is just that some CEUM reports <u>don't count plants not used</u>. This could be misleading; also, it shows that there are major problems in the short term--perhaps reserve margin or initial condition problems--that are being covered up with large amounts of turbine construction. Aside from this "initial condition" problem, which should be tracked down and tuned out, within the linear programming framework and the static, large planning periods, there is not much opportunity nor reason to overcome the methodological problems associated with lead-time issues.

5. SPECIFIC MECHANISTIC PROBLEMS WITH THE CEUM EXPANSION

Having treated the information about plant characteristics it is now appropriate to discuss the concrete issues associated with generation expansion. First it is advantageous to collect some of the remaining capacity summary tables. Thus Tables 23 through 30 are presented; they show the variation in specific generation capacity levels as a result of horizon and scenario variations.

5.1 Capacity Levels of Plant Types

In general the CEUM uses excellent data sources for existing and projected capacity levels. However, these sources, in some cases, could have been checked against independent data, for verification purposes and to provide some indication of uncertainties. Unfortunately most of the CEUM data is developed from a single source. Thus the general comments in this section are:

(1) Data should be cross-checked against different sources with variations noted,

(2) As mentioned previously, there are many exogenously specified capacity levels, because the economically based model otherwise could not handle certain plant types, and this means some of these input data must be checked after the fact to make sure they are consistent with model results. Thus:

(3) The user and operator should be made aware of the sometimes large variations in key numbers, and finally

(4) The user and operator should be made aware of important couplings, as described in Subsection 2 of this volume, that are not contained within the model and which the operator must therefore supply in an iterative fashion.

This brings us to the topic of nuclear capacity levels. The CEUM exogenously specifies 37.2 GW of existing nuclear in 1975, 61.3 GW of new nuclear capacity in 1975-1985, 130.1 GW of new nuclear in 1975-1990, and 192.8 GW in 1975-1995. These figures were based upon a particular published estimate.* They fall considerably short of industry plans (see U.S. Department of Energy [November 1978]) that show 97.8 GW of new and upgraded nuclear capacity in the period 1978-1985 alone, or the estimates of 113.0 GW from 1977 to 1987, and 280.0 GW from 1977 to 1997 (see U.S. Department of Energy [October 1978]). However, given the events

*Estimates of nuclear plus hydro (i.e., non-fossil) shares of capacity have ranged from 34% (see Ford Foundation [1975]) to 83% (see National Petroleum Council [December 1972]).

TABLE 23

U.S. Electric Utility Capacity Utilization (GW)

	1985		1990		1995	
	Existing	New	Existing	New	Existing	New
CBC	486.6	230.7	454.4	417.4	417.3	640.6
CNSPS	484.5	232.8	439.0	432.7	410.1	648.6
CML2C	485.5	231.6	445.0	426.2	415.9	641.6
CEDMD	458.8	187.8	435.3	349.9	408.4	544.6
CMILL	488.3	229.0	*	*	*	*
CNINC	482.4	235.1	448.6	423.2	418.4	639.8
COILG	478.2	239.5	439.0	432.5	411.9	646.1
UCIN	485.3	232.1	433.0	438.8	409.8	648.6
UDIN	484.7	232.7	*	*	*	*
LAB3	488.3	232.2	465.8	410.0	423.7	638.5
TCML	486.5	230.9	445.6	426.5	415.6	642.8
LOAD	500.3	453.0	485.9	671.3	483.0	920.9
ROYI	468.8	231.3	455.6	417.3	417.6	642.0
EDMI	491.8	260.8	452.9	461.9	411.6	699.1
UCD4	488.5	228.6	477.1	394.2	427.2	630.4
LABD	484.9	231.9	441.1	429.7	412.1	645.0
LOGN	486.7	230.8	458.4	413.5	416.3	642.2
CDRB	486.5	230.5	453.3	418.0	415.7	642.1
LDC1	496.4	268.2	470.5	458.4	444.4	682.9
NCAP	482.8	234.4	446.2	425.4	405.5	652.7
MOIL	478.2	239.5	405.2	466.4	411.9	646.1
BC	486.2	231.1	449.8	421.7	416.6	641.1
EDMD	458.5	188.2	433.8	351.4	410.5	542.4
NOTX	477.3	238.7	425.6	444.1	394.7	661.7

* These runs were not made.

TABLE 24

U.S. Existing Oil/Gas Steam Power Plant Capacity (GW)

	1985	1990	1995
CBC	145.6	121.3	78.9
CNSPS	144.7	108.6	71.8
CML20	145.3	112.4	77.3
CEDMD	128.5	104.8	70.0
CMILL	147.0	*	*
CNINC	142.8	116.5	78.6
COILG	140.3	105.1	68.4
UCIN	145.3	104.6	71.8
UDIN	145.3	*	*
LAB3	147.0	132.4	86.3
TCML	145.6	112.7	77.2
LOAD	153.8	144.1	136.5
ROYI	145.8	122.7	79.8
EDMI	149.0	122.2	76.3
UCD4	147.2	140.7	90.0
LABD	145.3	108.5	73.5
LOGN	145.6	125.6	78.0
CDRB	145.6	120.4	77.3
LDC1	150.5	133.6	100.1
NCAP	148.1	120.7	77.4
MOIL	140.3	91.0	72.0
BC	145.6	116.9	78.3
EDMD	128.2	103.8	72.1
NOTX	146.7	108.9	71.6

* These runs were not made.

TABLE 25

U.S. Existing Oil/Gas Turbine Power Plant Capacity (GW)

	1985	1990	1995
CBC	37.4	28.7	33.9
CNSPS	36.3	26.2	33.9
CML20	36.6	28.4	34.1
CEDMD	27.2	26.6	34.1
CMILL	37.8	*	*
CNINC	36.1	27.9	35.3
CCILG	34.8	29.7	39.1
UCIN	36.4	24.2	33.6
UDIN	35.8	*	*
LAB3	37.8	29.3	33.0
TCML	37.4	28.7	33.9
LOAD	42.0	36.9	41.5
ROYI	37.5	28.6	33.3
EDMI	40.0	26.5	30.8
UCD4	37.8	32.1	32.7
LABD	36.1	28.4	34.1
LOGN	37.5	28.6	33.8
CDRB	37.4	37.2	33.9
LDC1	41.3	32.0	39.3
NCAP	38.1	28.1	30.7
MOIL	34.8	10.0	35.5
BC	37.0	28.7	33.9
EDMD	27.2	26.1	34.1
NOTX	38.2	22.5	26.4

* These runs were not made.

TABLE 26

U.S. New Coal Power Plants With Scrubbers (GW)

	1985	1990	1995
CBC	63.4	182.4	334.8
CNSPS	44.6	70.7	130.7
CML20	63.5	191.1	336.1
CEDMD	47.4	128.8	252.2
CMILL	60.3	*	*
CNINC	58.0	156.3	288.5
COILG	72.4	199.4	343.1
UCIN	67.0	202.6	341.7
UDIN	67.7	*	*
LAB3	60.3	171.1	330.2
TCML	62.1	190.9	337.2
LOAD	60.7	180.6	300.6
ROYI	59.4	177.1	333.4
EDMI	70.0	212.3	377.9
UCD4	56.6	150.7	320.4
LABD	61.3	191.8	335.9
LOGN	61.5	176.4	334.7
CDRB	59.4	178.5	333.0
LDC1	64.0	183.4	328.6
NCAP	68.7	208.6	376.0
MOIL	72.4	233.5	342.3
BC	64.8	187.6	336.6
EDMD	48.0	130.5	250.9
NOTX	51.6	206.0	353.2

* These runs were not made.

TABLE 27

U.S. New Coal Power Plants Without Scrubbers (GW)

	1985	1990	1995
CBC	47.2	49.3	47.0
CNSPS	69.5	177.1	259.0
CML20	47.9	49.3	47.2
CEDMD	39.4	49.4	47.6
CMILL	46.6	*	*
CN NC	44.9	51.0	49.2
CO LG	49.3	49.2	46.3
UCIN	46.0	51.0	47.7
UDIN	46.0	*	*
LAB3	47.7	48.4	45.6
TCML	48.8	49.9	46.7
LOAD	46.1	49.0	48.4
ROYI	50.5	52.8	48.8
EDMI	48.9	49.1	46.7
UCD4	47.4	51.6	48.8
LABD	50.8	52.4	51.1
LOGN	48.2	50.2	48.2
CDRB	51.2	54.0	50.3
LDC1	47.5	48.9	46.7
NCAP	48.4	50.0	48.3
MOIL	49.3	49.0	47.1
BC	46.3	48.4	45.6
EDMD	39.5	49.4	46.8
NOTX	39.6	44.8	43.2

* These runs were not made.

TABLE 28

U.S. New Total Coal Power Plant Capacity (GW)

	1985	1990	1995
CBC	110.7	231.7	381.8
CNSPS	114.1	247.8	389.8
CML20	111.5	240.4	383.3
CEDMD	86.8	178.2	299.8
CMILL	106.9	*	*
CNINC	102.9	207.3	337.7
COILG	121.7	248.6	389.4
UCIN	113.0	253.5	389.4
UDIN	113.7	*	*
LAB3	108.0	219.5	375.8
TCML	110.9	240.9	384.0
LOAD	106.8	229.6	349.0
ROYI	109.8	229.9	382.2
EDMI	119.0	261.5	424.6
UCD4	103.9	202.4	369.2
LABD	112.1	244.2	387.0
LOGN	109.7	226.6	382.9
CDRB	110.6	232.5	383.3
LDC1	111.6	232.2	375.3
NCAP	117.2	258.6	424.3
MOIL	121.7	282.5	389.4
BC	111.1	236.0	382.3
EDMD	87.4	179.9	297.6
NOTX	91.1	250.8	396.4

* These runs were not made.

TABLE 29

U.S. New Oil/Gas Turbine Power Plant Capacity (GW)

	1985	1990	1995
CBC	38.0	32.2	41.1
CNSPS	36.7	31.4	41.1
CML20	38.1	32.2	40.7
CEDMD	19.1	18.4	28.7
CMILL	40.1	*	*
CNINC	34.9	29.9	38.4
COILG	35.8	30.4	39.0
UCIN	37.1	31.8	41.5
UDIN	37.0	*	*
LAB3	42.2	36.9	44.9
TCML	38.0	32.1	41.2
LOAD	262.2	284.7	351.8
ROYI	39.5	33.8	42.1
EDMI	59.8	46.7	56.7
UCD4	42.7	38.3	43.5
LABD	37.7	32.0	40.2
LOGN	39.1	33.3	41.5
CDRB	38.0	32.0	41.1
LDC1	73.6	71.4	88.4
NCAP	46.6	37.4	46.5
MOIL	35.8	30.4	39.0
BC	38.0	32.1	41.2
EDMD	18.9	18.2	28.7
NOTX	65.8	41.6	52.2

* These runs were not made.

TABLE 30

U.S. New Pumped Storage Capacity (GW)

	1985	1990	1995
CBC	8.7	10.8	11.8
CNSPS	8.7	10.8	11.8
CML20	8.7	10.8	11.8
CEDMD	8.6	10.6	11.7
CMILL	8.7	*	*
CNINC	8.7	10.8	11.8
COILG	8.7	10.8	11.8
UCIN	8.7	10.8	11.8
UDIN	8.7	*	*
LAB3	8.7	10.8	11.8
TCML	8.7	10.8	11.8
LOAD	10.8	14.2	15.0
ROYI	8.7	10.8	11.8
EDMI	8.8	10.9	11.8
UCD4	8.7	10.8	11.8
LABD	8.7	10.8	11.8
LOGN	8.7	10.8	11.8
CDRB	8.7	10.8	11.8
LDC1	9.8	12.0	13.4
NCAP	8.7	10.8	11.8
MOIL	8.7	10.8	11.8
BC	8.7	10.8	11.8
EDMD	8.6	10.6	11.7
NOTX	7.8	10.8	11.8

* These runs were not made.

subsequent to the CEUM 1978 estimate, particularly with regard to the accident at the Three Mile Island station, the CEUM value may no longer be considered too low, and in fact may be regarded by some as too high. Although the CEUM nuclear capacity estimate shows foresight for an estimate of its vintage, there is a clear warning in this lesson. Where an exogenously specified variable is so uncertain and so vital to a model, there have to be, at a minimum, sensitivity studies with respect to that variable. To test the sensitivity of model results to new nuclear capacity, a 25% increase was made in the NINC sensitivity runs. As can be seen from Table 26, there is the expected drop in new coal capacity with scrubbers, and from Table 15 a significant decrease in new bituminous coal capacity. In general, the 25% increase in new nuclear capacity resulted in about 15% decreases in the capacity of competing types of coal plants.

Perhaps one reason there have only recently been any nuclear capacity sensitivity studies with the CEUM may be due to the difficulty in implementing such runs. In the process of making the NCAP run, for example, we found that the CEUM nuclear capacity lower limit levels were programmed into more than one place in the code. For example, the capital report, and the capital (but not the O&M) components in the objective function receive the exogenously specified nuclear capacity lower limit values regardless of structural or decision changes that decrease the level of nuclear capacity (in NCAP). Also, when the CEUM was last updated* there were not any site-specific plans for the additions of the 1990-1995 nuclear capacities. These capacity levels

*There are now site-specific plans out to 1998 (see Borwell et al. [June 8, 1979]).

were therefore just scaled into the regions based upon previously experienced ratios, not by economics. The user should be cautioned that this may affect regional coal utilization figures, and should be cautioned not to push the model past the limits of the driving data.

Combined cycle plants are also effectively exogenously specified in the CEUM (see Table 31). The existing combined cycle capacity of 2.7 GW is not retired. The lower limit on new capacity of 2.1 GW in 1985, 1990, and 1995 is always met, with one exception: in the no interregional transmission run (NOTX) the new capacity rises to 4.7 GW in 1985, 1990, and 1995. ICF, Inc. (September 1978a), p. C-37 states that it is assumed that there will be a ban on new combined cycle plants. It is also mentioned that such plants will only be allowed in Southern California, which in fact is where they are built in the NOTX run. From our examination of the GAMMA language computer code (which is difficult to read if one is not familiar with GAMMA) and from the CEUM output, it appears that there is an upper bound of 99 GW of combined cycle allowed in each of 39 regions. What is clear is that combined cycle is not a favorable plant type. Oil/gas turbines, with approximately 30% lower investment costs and about the same operating costs and heat rates, meet the new daily peaking demands. In the short run, oil/gas turbines also meet seasonal peaking demands; in the long term, these demands are met mostly by existing coal plants.

The 1978-1987 industry projections (see U.S. Department of Energy [October 1978]) for 4.6 GW* of new combined cycle capacity have not been factored into the CEUM. Again, however, it is likely that the knife-edge

*Or even as much as (9.3 total) minus (2.7 existing) = 6.6 GW in 1985, from National Electric Reliability Council (August 1978).

TABLE 31

Combined Cycle Capacity in Major CEUM Runs (GW)

	BC	NOTX	CBC	EDMI	EDMD	LOAD
Existing Baseload 1985	-	0.4	-	0.4	-	-
Existing Baseload 1990	-	-	-	-	-	-
Existing Baseload 1995	-	-	-	-	-	-
Existing Intermediate 1985	0.3	0.6	0.3	0.4	-	-
Existing Intermediate 1990	0.2	0.2	0.2	0.2	-	-
Existing Intermediate 1995	-	-	-	-	-	-
Existing Seasonal 1985	1.0	0.2	1.0	0.6	0.8	1.1
Existing Seasonal 1990	0.7	0.5	0.7	1.0	0.4	0.4
Existing Seasonal 1995	0.4	0.4	0.4	0.4	0.4	0.4
Existing Daily Peak 1985	1.4	1.4	1.4	1.3	1.9	1.6
Existing Daily Peak 1990	1.8	1.7	1.7	1.3	2.3	2.3
Existing Daily Peak 1995	2.3	2.1	2.3	2.2	2.3	2.3
New Baseload 1985	1.4	4.2	1.5	1.5	1.4	1.4
New Baseload 1990	-	-	-	-	-	-
New Baseload 1995	-	-	-	-	-	-
New Intermediate 1985	0.4	0.3	0.4	0.5	0.3	0.3
New Intermediate 1990	1.7	4.3	1.7	1.7	1.7	1.1
New Intermediate 1995	-	-	-	-	-	-
New Seasonal 1985	0.3	-	0.2	-	0.4	0.4
New Seasonal 1990	0.4	0.2	0.4	0.4	0.4	0.7
New Seasonal 1995	1.3	2.5	1.3	1.3	1.3	1.3
New Daily Peak 1985	-	0.2	-	-	-	-
New Daily Peak 1990	-	0.2	-	-	-	0.2
New Daily Peak 1995	0.8	2.2	0.8	0.8	0.8	0.8

behavior of the linear program will keep the combined cycles capacity exactly at its lower limit until the costs shift. Given any shift, however, there is always the chance that the combined cycle capacity will replace all the oil/gas turbines! This is the danger in the behavior of a linear program operating with just four load categories.

The volatility of oil/gas turbine activity was mentioned previously. As can be seen from Table 29, with changes in the shape of the load duration curve (LOAD and LDC1), with changes in demand (EDMI and EDMD), or with changes in certain other constraints (NOTX), oil/gas turbines are forced to make substantial adjustments. One reason for this is that there is no price/demand coupling. Thus, the demand changes are not dampened by price-motivated compensating responses, as if there were infinite price elasticity for electricity. Another reason for the burden on the oil/gas turbines is that there is very stiff resistance in the model to shifting of load modes for other types of plants. A third reason, of course, is that almost everything but oil/gas turbines is exogenously specified. Also, there is no resistance in the model to unrealistic activities such as the building of 262 GW (in LOAD) of turbines in ten years; these figures have to be noticed by the user so that appropriate constraints can keep the model from operating in unrealistic regions. The user should be warned that the model builders do not view turbine capacity literally; instead it should be interpreted as a surrogate for reserve margin problems.

Pumped hydro is assumed to be all hydro that is set in the daily peaking mode. Industry plans (see U.S. Department of Energy [October 1978]) show about 8.0 GW of pumped storage in the 1978-1987 period, and

Table 30 shows nearly the same* with generally 8.7 GW of new pumped hydro from 1975-1985. The exogenous specification of hydro is apparent from Table 30, although the LOAD and LDC1 changes in the load duration curve shapes show that there is a little extra hydro capacity that can be drawn upon in extreme situations. The constructon of only 3.1 GW of additional storage capacity of all types between 1985 and 1995 is probably quite low, again caused by the activity of the model in areas that are beyond available data. The CEUM pays for pumped storage with 1.35 times the baseload energy. This is equivalent to the reasonable efficiency of 86% in and 86% out (see Gruhl [January 1973]). There probably should also be about a 5% transmission loss, in which case the 1.38 should be raised to 1.45.

Hydro capacity is locked into base and intermediate load levels at fixed values (see Table 32). The fact that building new, and operating old, hydro plants is for some reason set at zero cost is only bothersome in the capital requirements and cost of electricity output reports, where discrepancies are caused. The fact that 1.4 GW of existing hydro is left unused is also an error, caused by the CEUM's inflexibility in shifting energy between load modes. The addition of only 2.1 GW of hydro in the period from 1985 to 1995 is also questionable. Total hydrc and geothermal, including pumped storage in CEUM, is 65.8 GW in 1975, 84.4 GW in 1985, and 89.5 GW in 1995. Industry plans show, for hydro alone, 72.0 GW in 1977, 89.0 GW in 1987, and 108.0 GW in 1997 (see U.S. Department of Energy [October 1978]). This means there are plans to add 19.0 GW of hydro over almost the identical period for which the model allows only

*But from the National Electric Reliability Council (August 1978), (17.2 total) minus (12.4 existing) equals 4.8 GW in 1985.

TABLE 32

U.S. New Hydro Capacity (GW)

	1985	1990	1995
CBC	9.9	10.6	11.0
CNSPS	9.9	10.6	11.0
CML20	9.9	10.6	11.0
CEDMD	9.9	10.6	10.8
CMILL	9.9	*	*
CNINC	9.9	10.6	11.0
COILG	9.9	10.6	11.0
UCIN	9.9	10.6	11.0
UDIN	9.9	*	*
LAB3	9.9	10.6	11.0
TCML	9.9	10.6	11.0
LOAD	9.9	10.6	11.0
ROYI	9.9	10.6	11.0
EDMI	9.9	10.6	11.1
UCD4	9.9	10.6	11.0
LABD	9.9	10.6	11.0
LOGN	9.9	10.6	11.0
CDRB	9.9	10.6	11.0
LDC1	9.9	10.6	11.0
NCAP	9.9	10.6	11.0
MOIL	9.9	10.6	11.0
BC	9.9	10.6	11.0
EDMD	9.9	10.6	10.8
NOTX	9.9	10.6	11.0

* These runs were not made.

2.1 GW. This could reduce new coal capacity by as much 5% or turbine capacity by almost 50%, depending upon the "load modes" used for this 19 GW. It is obviously important to at least incorporate these industry plans or to discredit these industry plans. Ideally, projections should always be made where data are lacking.

Coal plants, as mentioned previously, are essentially exogenously set for 1985. The CEUM can set exogenous building limits on coal plant capacity by utility region individually for new NSPS bituminous, subbituminous, and lignite plants and for new ANSPS bituminous, subbituminous, and lignite plants. These build limits are treated as upper-bound constraints on the associated build activity variables in the LP. Offhand it might be noted that there can also be joint upper-bound constraints on total (bituminous plus subbituminous plus lignite) new NSPS and total new ANSPS coal plant capacity by utility region. It should be noted that the joint upper bounds are not always consistent with the sum of the individual limits (when they all exist) on bituminous, subbituminous, and lignite plant capacity. For regions in which all individual coal plant type build limits are set (for either NSPS or ANSPS plants), there are instances, such as in Arizona, in which the associated joint upper bound is greater than the sum of the individual bounds. This causes no problems, so long as it is understood that the sum of the individual limits is the binding constraint. Unfortunately, in Table 8 of the CEUM's Large Report, the total new coal build limits displayed, for the cases of interest, are the sums of the NSPS and the ANSPS joint upper bounds rather than the sums of the individual limits. This can be quite misleading in that the table will show extra unused capacity that may look like slack for an activity which is actually bound.

Upon closer examination there is other apparent slack in coal activities that has been forced by excess new nuclear capacity (Michigan and Illinois, among others), or that exists in areas where coal capacity is so unfavorable as to be always utilized at its lower bound (Virginia, Maryland, Delaware, and Northern California, for example).

5.2 New Technologies

The CEUM makes decisions about conversion of plants from one coal type to another, but makes no decisions about oil-to-coal conversions. These oil-to-coal conversions have been estimated to be about 23.1 GW, and although these conversions are proceeding very slowly, the CEUM counts them as coal plants as of 1975. This results in a 4 or 5% overestimation of coal consumption between 1975 and 1985, with about an additional 1% error for each further year of delay. If this long conversion process has not been started by 1985, the total error will be about a 10% overestimate of coal use.

There are currently quite a few plant options available in the CEUM. Conceptually, and possibly in practice, adding new types would be easy but there is some question as to the usefulness of their simulation. For instance, if the simulation is from 1975 to 2000 and atmospheric fluidized bed combustors are offered as a cheaper, more efficient generation alternative, then they will always be built at their capacity limit. This then would amount to exogenous specification of any advanced generation technology. Thus, there are considerable limitations on the usefulness of the model for exploring "impacts of commercial development of new technologies, e.g., synthetic fuels, form coke, and

MHD" (see ICF, Inc. [July 1977]). In light of the argument that the capacity expansion is essentially exogenously specified, this quote takes on a more limited meaning. In particular, "impacts" apparently mean pollution control and regional coal supply impacts. This type of statement in ICF, Inc. (July 1977) could be very misleading to a user interested in studying the potential market penetration of MHDs, particularly since MHDs have been taken out of the model (although they could be put in). Synthetic fuels and fluidized bed combustors are also not included in the model. This forces users to accept an ultimately pessimistic view of market penetration of these technologies. These advanced options would have less coal use, higher cost, and generally significantly less pollution than the conventional technologies. Perhaps the most important option not included in the CEUM is low-Btu gasifiers in combination with combined cycle and other types of power plants. It is possible that with more stringent fine particulate control, all coal-fired facilities constructed after 1990 would be of these types.

Cogeneration and renewable energy sources are also missing from the build activities in the CEUM. It is not that these activities will be dominant in 1995, but there will be some capacities of these types. Such activities could either be lumped with hydro and geothermal, or be used to modify demand. In any event, they would require out-of-model exercises that should be documented and which could not be added to the CEUM in any other than an exogenous fashion.

5.3 Control Technologies

It appears that the only possible complex functions of the generation expansion portion of the CEUM is in the choice of coal over existing oil plants and the choice of alternative pollution control configurations. The compliance options here are essentially:

(1) use of naturally low-sulfur coals,

(2) coal cleaning,

(3) use of oil/gas turbines instead of coal facilities, and

(4) use of coal capacity with or without scrubbers.

If alternative coal combustion options, such as fluidized bed, MHD, or low-Btu power plants become options in the model, then these too could be added to this list. (New turbines rarely enter the baseload and intermediate-load modes, so they are not an important control option.) Coal cleaning is viewed in the model as a supply activity, transferring a coal type from one sulfur level to a lower sulfur level at a cost. It is used on only a small fraction of utility coal. Thus the real control technology action is between low-sulfur coal, coal-fired plants without scrubbers, and plants with scrubbers. Tables 33 and 34 show some of the scenarios that most effect the construction of scrubbers. It is, however, the <u>choice between</u> options that is most important. Thus Table 35 shows the <u>percentage</u> of new plants that are built with scrubbers. Notably, for this tremendous gamut of scenarios, the only real scrubber choice changes are in the NSPS run that involves a change in the environmental standard. In fact, for 1985 and 1995 the percentage of new coal plants <u>with</u> scrubbers varies only about ±2%.

What is the reason for so little real activity? The stipulations in the ANSPS regulations are a primary factor. It also appears that there is just not enough <u>detail</u> in the CEUM to cover the effects that are important for anything but major environmental regulation changes. The

TABLE 33

U.S. Retrofit Scrubber Capacity (GW)

	1985	1990	1995
CBC	14.6	14.7	14.9
CNSPS	18.6	20.6	23.5
CML20	10.9	10.9	11.3
CEDMD	12.3	12.8	13.1
CMILL	15.1	*	*
CNINC	13.5	14.2	14.5
COILG	12.4	12.9	13.1
UCIN	17.2	17.4	17.6
UDIN	17.6	*	*
LAB3	14.7	15.4	15.9
TCML	12.0	12.0	17.7
LOAD	14.5	14.8	15.0
ROYI	14.7	14.7	17.6
EDMI	13.6	13.6	13.9
UCD4	11.3	11.3	11.5
LABD	10.2	10.3	10.6
LOGN	11.8	12.0	12.2
CDRB	11.6	11.6	12.0
LDC1	14.2	14.3	14.6
NCAP	14.2	14.2	14.5
MOIL	12.4	†	13.1
BC	16.7	16.9	17.1
EDMD	15.1	15.2	15.5
NOTX	13.2	13.8	14.1

* These runs were not made.

† This report was not released to us.

TABLE 34

U.S. New Scrubber Capacity (GW)

	1985	1990	1995
CBC	40.0	.13E03	256.9
CNSPS	23.1	35.6	82.0
CML20	40.4	.14E03	.26E03
CEDMD	29.0	92.4	.18E03
CMILL	36.7	*	*
CNINC	36.3	.11E03	.22E03
COILG	47.0	.15E03	.26E03
UCIN	42.0	.15E03	.27E03
UDIN	42.6	*	*
LAB3	35.6	.12E03	.24E03
TCML	39.1	.13E03	.25E03
LOAD	37.8	.13E03	.23E03
ROYI	37.6	.12E03	.25E03
EDMI	45.6	.16E03	.29E03
UCD4	35.8	.11E03	.24E03
LABD	40.7	.14E03	.26E03
LOGN	37.6	.12E03	.25E03
CDRB	38.6	.13E03	.25E03
LDC1	40.5	.13E03	.25E03
NCAP	45.0	.15E03	.29E03
MOIL	47.0	†	.26E03
BC	40.6	.13E03	263.7
EDMD	29.7	94.4	.18E03
NOTX	30.7	.15E03	.27E03

* These runs were not made.

† This report was not released to us.

TABLE 35

Percentage of New Coal Plants With Scrubbers

	1985	1990	1995
CBC	57.3	78.7	87.7
CNSPS	39.1	28.5	33.5
CML20	57.0	79.5	87.7
CEDMD	54.6	72.3	84.1
CMILL	56.4	*	*
CNINC	56.4	75.4	85.4
COILG	59.5	80.2	88.1
UCIN	59.3	79.9	87.8
UDIN	59.5	*	*
LAB3	55.8	77.9	87.9
TCML	56.0	79.2	87.8
LOAD	56.8	78.7	86.1
ROYI	54.1	77.0	87.2
EDMI	58.8	81.2	89.0
UCD4	54.5	74.5	86.8
LABD	54.7	78.5	86.8
LOGN	56.1	77.8	87.4
CDRB	53.7	76.8	86.9
LDC1	57.3	79.0	87.6
NCAP	58.6	80.7	88.6
MOIL	59.5	82.7	87.9
BC	58.3	79.3	88.0
EDMD	54.9	72.5	84.3
NOTX	56.6	82.1	89.1

* These runs were not made.

power plants, the coal types, the site options, and the pollution control equipment are without the basic performance and cost details that would cause variations in decision stategies based upon different scenarios. Perhaps most needed are:

(1) a greater variety of pollution abatement options (hot/cold precipitation, baghouse filters, wet/dry scrubbers, and so on),

(2) a variation in the costs and performances of abatement equipments (various particulate and sulfur removal types) based upon different plant sizes and coal characteristics such as Btu content, ash, sulfur, and moisture contents, and

(3) possibly a county-level disaggregation, so pollutant emissions requirements can be more precisely represented (for emission cap and long-range dispersion studies, for example).

How can this be accomplished in the linear programming format within a reasonable problem size? Perhaps it cannot be done, in which case the model is not appropriate for pollution control issues beyond those that essentially require different fixed ways of keeping track or accounting for the use of various control options.

As mentioned previously, scrubber forced outage rates, which can be 10 to 30%, have to be factored into the overall plant operating levels. A product of plant availability and scrubber availability (1-forced outage rate) provides a good first approximation to the forced outage rate of the combination (in EPRI Technical Assessment Group [August 1977], scrubber availability is apparently about 90%).

5.4 Combining Operation With Planning

The process of planning for new generation capacity for utilities is a very distinct and separate activity from the process of scheduling plant operations. Essentially, facilities are built based upon fixed and variable cost considerations, and facilities are operated based solely upon variable cost conditions. In other models, lumping together planning and operation into one decision would yield erroneous results. However, within the assumptions and simplifications of the CEUM (with its static formulation, fixed usage factors, generic plant-types rather than individual plants, and generation and demand certainty) the planning and operating decisions can be combined without introducing additional concerns. The effect of all of the model's assumptions, some of which were mentioned previously, should tend to reduce the construction and use of peaking facilities, reduce the economic retirement of older plants, and probably reduce total costs. The magnitude of these effects would be greatest when the scenarios have the greatest uncertainties. The reason for this is that unexpected events will result in changes between the planned operation and the actual operation of facilities.

5.5 Financial Issues

Some financial issues related to the escalation of utility capital costs were treated in Subsection 4.2 above on plant characteristics. This subsection deals with a few of the remaining issues--regional, as opposed to plant-specific, financial concerns. The first of these issues relates to the imputed (i.e., no fixed cost component) mills/KW for each demand region. Table 36 shows the range of national electricity costs for the several scenarios that were investigated. As mentioned earlier, these costs do not feed back to change the demand for electricity. Thus, the range of values in Table 36 is probably wider than would be the case with negative price/demand feedbacks. Also somewhat misleading is the lack of administrative costs or, for that matter, any costs other than

TABLE 36

Average U.S. Imputed Mills/KWH Cost of Electricity (1978$)

	1985	1990	1995
CBC	27.9	32.9	37.2
CNSPS	27.8	32.3	36.5
CML20	27.6	32.4	36.6
CEDMD	25.1	30.4	34.9
CMILL	29.0	*	*
CNINC	27.6	32.4	36.5
COILG	29.5	33.2	37.5
UCIN	28.0	33.0	37.0
UDIN	27.7	*	*
LAB3	29.2	34.4	39.2
TCML	27.7	32.6	36.9
LOAD	34.9	40.6	45.8
ROYI	28.3	33.3	37.6
EDMI	29.2	34.0	38.1
UCD4	29.0	34.7	39.6
LABD	26.9	31.8	36.0
LOGN	28.1	33.0	37.3
CDRB	27.8	32.7	36.8
LDC1	29.2	34.3	38.8
NCAP	28.9	34.3	38.8
MOIL	29.5	†	37.8
BC	27.7	32.7	36.9
EDMD	25.0	30.2	34.8
NOTX	28.7	33.3	37.5

* These runs were not made.

† This report was not released to us.

the operating and investment costs. The hydro capital costs have also been left out. Thus, the magnitude of these CEUM costs of electricity should be viewed with great caution. Differences between various scenario costs would have more meaning.

Of course, the drop to zero of all the non-supply related real escalation rates (except the rail rates) after 1985 is a financial issue of concern, but it was discussed earlier. This undocumented feature of the model appears to have been motivated by simplicity and expediency, so real dollar costs for 1985 could be used for 1990 and 1995 as well. In addition, the capital costs for all capacity built between 1975 and 1985 are fully escalated to 1985. Thus, all utility capital costs in the CEUM (for any case year) include real escalation to 1985.

The 6% per year inflation implied in Appendix E of ICF, Inc. (July 1977) is actually still at the original 5.5% rate. The 10% real fixed charge rate is changed to 5% for the Tennessee area due to the public utility dominating that area. As implied by some of the sensitivities to changes in the utility capital cost escalation rates (see the UCIN, UDIN, and UCD4 model runs), the regional variations and the overall magnitude of the fixed charge rates should be the subject of an investigation to determine appropriate current and expected values. In addition, the procedure used to calculate fixed charge rates should be documented.

Due to the static nature of the model, the capital outlays and other cash flow problems cannot be investigated.

5.6 Reserve Margins

Reserve margins are satisfied by building capacity in excess of demand expectations. Excess capacity is necessary to ensure reliable electricity supply due to the probabilities of generation outages, transmission outages, and unexpected demand increases. Reserve margins generally range from about 13 to 40% for the NERC electric reliability regions (see Federal Power Commission [May 16, 1977]). The CEUM data, although initially set at 20% across all regions, in the latest versions of the model incorporate regional variations from 15 to 30%, with 5% resolutions. An adjustment to further spread these numbers would be appropriate. The national average of between 20 and 21% is currently quite accurate for 1985 or 1986, and appears to have been appropriately extracted from Federal Power Commission (May 16, 1977). But these numbers are based upon an assumption of 132 GW of nuclear capacity by 1986, not the 99 GW CEUM input for 1985. In fact, if the 90 GW 1986 estimate of the NRC is traced through the industry projections, then the national average margin drops to 14.9% in 1986 (see Federal Power Commission [May 16, 1977]), with regional values ranging from 1.4 to 23.5% reserve in the various NERC regions. With the reserve margin inconsistent with the 1985 exogenously specified coal and nuclear capacity levels, there is pressure within these exogenous CEUM constraints that one might think perhaps accounts for the additional 30 GW of new oil/gas turbines. The NINC sensitivity run, which pushes the nuclear capacities up to levels a little more consistent (114 GW) with the CEUM margins, however, only dropped out 3 GW of the excessive oil/gas turbine capacity. Thus the turbine capacity problems apparently still reside with load curve and structural problems. The FPC (May 16, 1977) low-nuclear calculations, so necessary to show commonality in the 1985 inputs, are in fact contained in another chapter of the same report that was used to extract parts of the CEUM data.

The manner of incorporating these reserve margins into the CEUM is another matter to be examined. The CEUM meets only energy demands, and requires massaging the exogenous capacity factors in order to try to meet peak demands. Since the reserve margin is purely a peak capacity concept, it is clear that the incorporation of margins into the CEUM could not be accomplished in a straightforward way. The CEUM incorporates margins by constraining regional factors by derating regional load factors by 1/1+R where R is the reserve margin. Thus, by meeting the energy demands with a reduced, exogenously specified capacity factor, the excess capacity is induced. The regional capacity factors are ensured to meet the target values because, as previously shown, little or no latitude is possible in the capacity factors of the plant-types that must meet the energy demands in each of the four load-mode categories. Other than being an exogenous specification, the only problem with this scheme is that it requires data on regional capacity factors by load modes that are not measurable nor uniquely determinable. Figure 6 from ICF, Inc. (September 1978a) shows the starting point for the calculation of the capacity factors that will make the peak demand come out as required. The load duration curve in this figure represents a load factor (actual annual energy divided by peak demand times one year) of 0.579. The first point that should be made is that the particular load factor is for Boston Edison, but it is used to model the entire Massachusetts/Rhode Island/Connecticut area (although regionally representative data could be developed and used). From the data listed in Table C-17, p. C-23 of ICF, Inc. (September 1978a), it can be seen that near or neighboring utilities might be expected to have tremendous variations in capacity factors: Louisville Gas and Electric

0.525 versus Ohio River 0.669; or Iowa Power and Light 0.481 versus Montana Power 0.689. From the following discussion it is hoped that it will become evident that these potential variations must be resolved on a regional average basis rather than based upon sample utilities. An example of the magnitude of variation that might occur can be seen from the 1985 60.6% New England load factor (see Federal Power Commission [May 16, 1977]) versus the 56.4 and 57.9% factors in the CEUM that cover the same area, or ERCOT at 57.3% versus CEUM Texas at 50.0% in 1985.

Again for the Boston Edison example, the 0.579 load factor is derated to 0.481 to induce the excess reserve capacity. This type of derating tends to spread the excess capacity among the four load mode groups, as opposed to a peaking dominance in covering these potential needs that is probably used by utilities (because an option with a relatively cheaper investment cost and with a more expensive operating cost is the obvious choice for an uncertain demand).

The CEUM calculation of derated load mode capacity factors then proceeds as follows. Define:

E_i = load factors for energy demanded in load mode i,

i = load mode, 1 to 4, baseload to daily peaking,

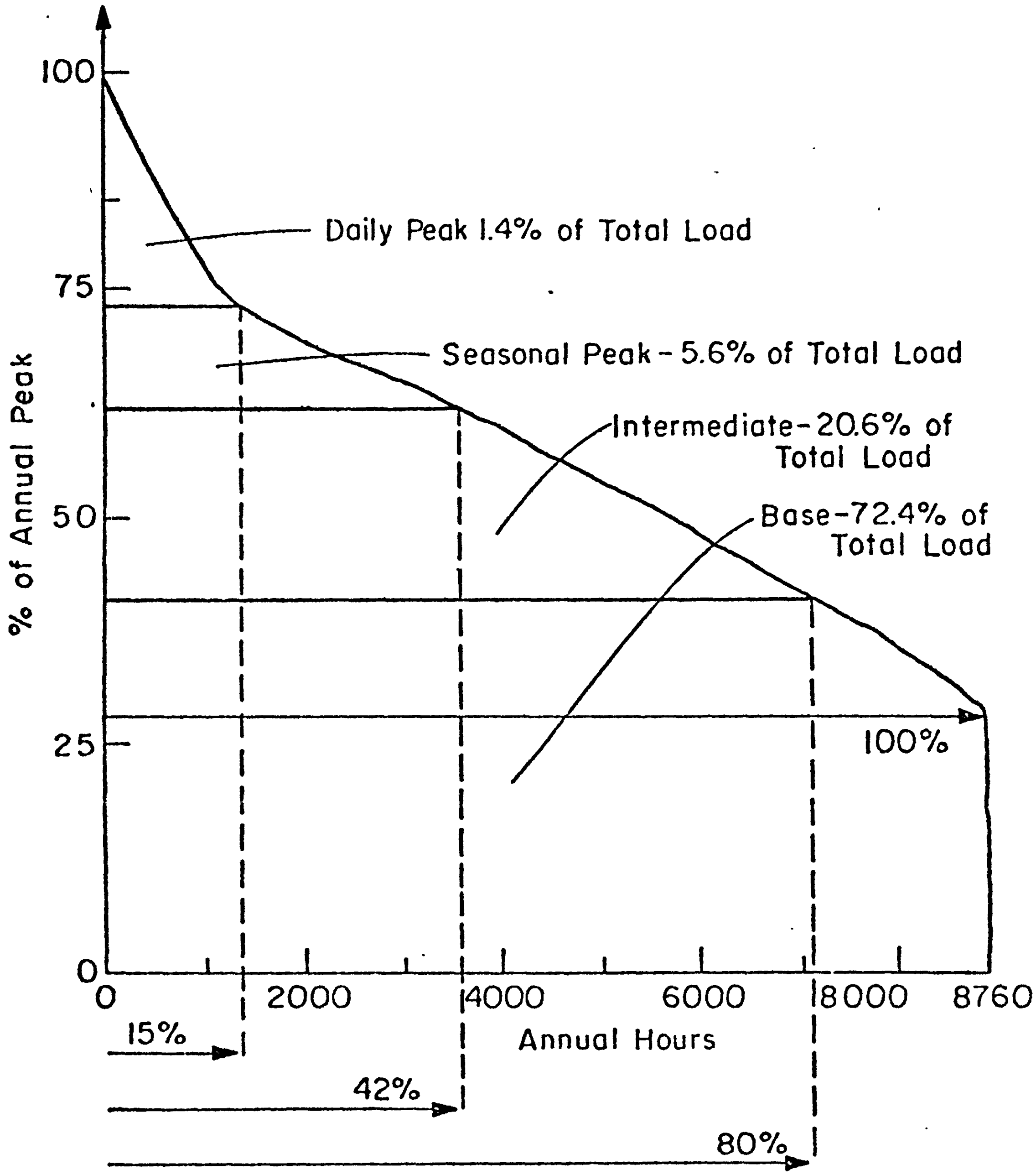
X_i = capacity factor for each load category,

R = reserve margin, and

C = capacity factor measured for a utility (which is supposed to represent the region).

There are exogenous specifications such that:

1. baseload, X_1 is between 0.65 and 0.70,
2. intermediate, X_2 is between 0.30 and 0.42,
3. seasonal peak, X_3 is between 0.20 and 0.25, and



Load that is present 15% of the year or less is Daily Peak.
Load that is present 15% to 40% of the year is Seasonal Peak.
Load that is present 40% of the year is Intermediate.
Load that is present over 80% of the year is Base.

Figure 6. Calculation of Load Categories from Load Duration Curves

Source: ICF, Inc. (September 1978a).

4. daily peak, X_4 is between 0.05 and 0.09.

The problem is now to solve for the X_i such that:

$$\frac{E_1}{X_1} + \frac{E_2}{X_2} + \frac{E_3}{X_3} + \frac{E_4}{X_4} = \frac{1}{\left(\frac{1}{1 + R}\right)C} \tag{3}$$

Of course, one problem is that with one equation and four unknowns, even with the unknowns constrained to ranges, there will not be a unique solution. In fact, any one of the unknowns can probably be anywhere within its range. One logical treatment of this problem would be to penalize (perhaps quadratically) the X_i for being away from their midrange values. At least in this way there would be a unique optimum solution. In ICF, Inc. (July 1977), an unusual hand-computed solution is described that for some reason begins with X_1 at its lowest value, X_3 at its highest value, X_4 at its lowest value, and X_2 to be adjusted to make Equation (3) fit! There is a nonprecise process that then takes place if this setup does not work out. If X_2 cannot be made low enough for there to be an equality, X_3 is moved from its highest value to its lowest value, and then X_1 is tested again. The variable X_1 is always at its highest or lowest value, but sometimes it is moved before X_4; sometimes X_4 is moved and not X_1. The justification for these factors being allowed to switch $\pm 5\%$ or more, somewhat arbitrarily, is from ICF, Inc. (July 1977), p. C-27: "...the impact of alternative capacity factors would be small given the narrow range of possible capacity factors for each load category and the requirement of having a single system average." After making the somewhat related model runs, LOAD and LDC1, which made changes in the E_i and resulted in tremendous (several hundred percent) changes in some outputs like turbine capacity (see Table 25), the assumption that "the impact...would be small" seems questionable and deserves documented testing.

5.7 Load Category Representation

Assessment of the X_i capacity factors are closely related to assessments of the E_i load factors and thus a discussion of both continues. From Figure 6 and the Boston Edison example of E_i = .724, it might seem as though there is some analytic reason for the rules and precisions presented. This is not the case. The first very gross approximation in this technique is that different plant types slice off different, somewhat arbitrarily defined, strata of the load duration curve. Figure 7 shows what the weekly dispatch of a utility would have to look like to make this approximation valid. Actually, dispatching is much less stratified, as shown in Figure 8, with baseload plants and power exchanges dropping in and out of the system due to deratings, maintenance, outages, and so on. Intermediate plants can generally cover demand that is _a priori_ known to be consistent over at least 3 to 6 hours (see Gruhl [January 1973]). Peaking plants pick up the slack all along the edge of the chronological load curve. Thus, even on a weekly basis, the stratified loading is seen actually to be a fiction. Not only is there substantial hourly variation of demand over a week, but as Figure 9 shows (see Finger and Chernick [April 1, 1979]), there is generally substantial weekly variation over the course of a year. Maintenance scheduling is used to move large blocks of baseload power high into the seasonal peaks of the load duration curve. Thus baseload plants actually could, for some systems, cover portions of the load curve that were very

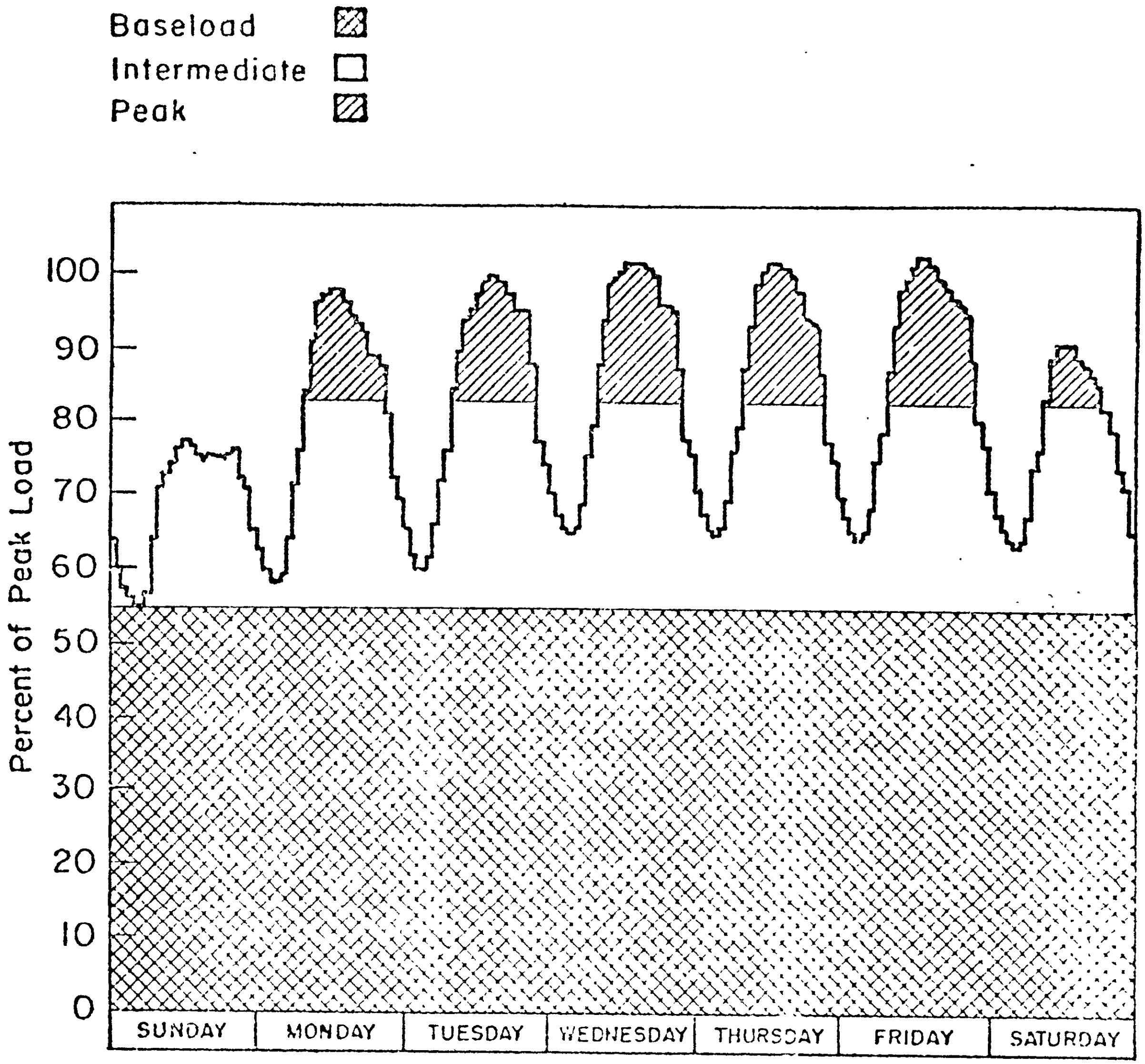


Figure 7. Weekly Load Curve Showing the Approximate Stratified Loading Scheme.

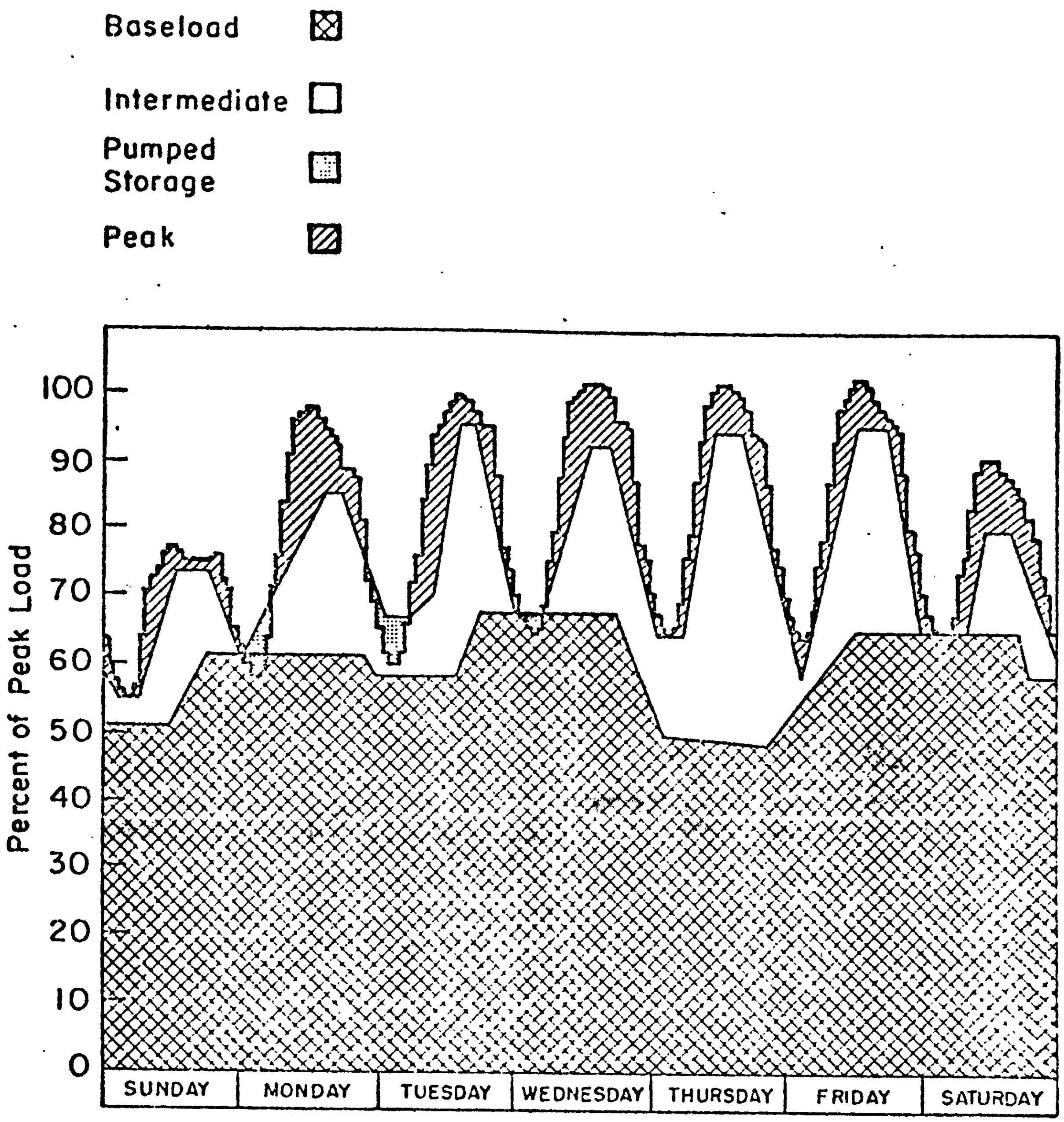


Figure 8. Weekly Load Curves with Hypothetical Dispatching.

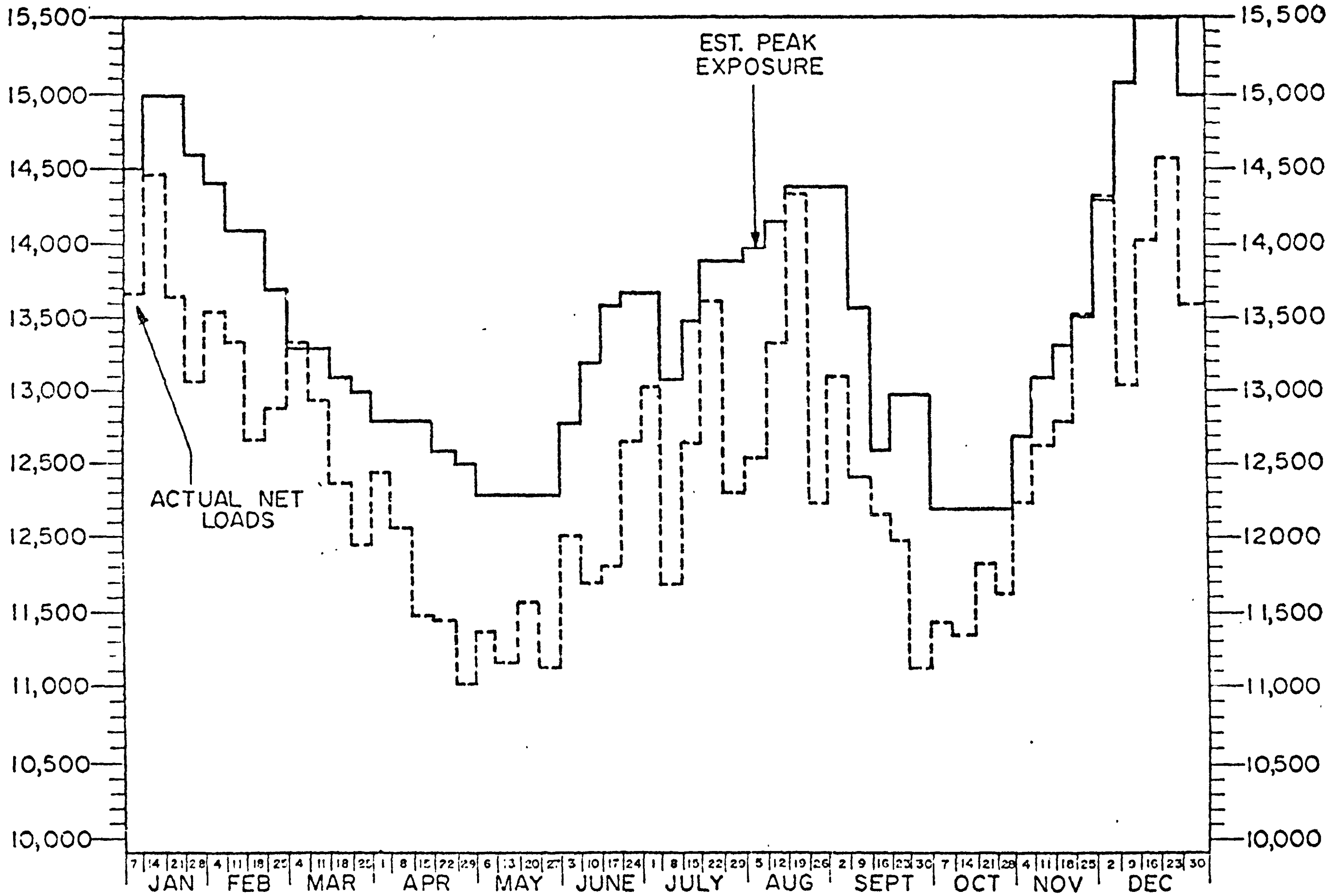


Figure 9. Example Showing the Seasonal Variation in Demand for Electricity

near the annual peak, and peaking units would still have activity even near the annual valley. It can thereby be seen why probabilistic simulators are considered imperative for careful generation scheduling. In addition, it is important to have such simulators to test the sensitivities of results to the imprecise values that come from the load curves.

Two other imprecisions in the CEUM load curve formulation are, of course, its four-level discretization (as opposed to as many as 10 to 50 intervals in some models) and its static nature. Load curves change in somewhat predictable fashion over time. There are components of demand that add proportionally to the old curves and some that are additive. There are some effects (such as peak load pricing or electric cars) that will definitely flatten the shape of the load duration curves. The problems with static curves are exacerbated through the use of past, as opposed to average or estimated end period, curves as the single curves.

Given these uncertainties and the intrinsically fabricated nature of the load factors and capacity factors, it seems altogether appropriate to try some sensitivity testing to see how the outputs of the CEUM would vary in response to these numbers. First, Table 37 shows the performance of the CEUM in meeting the implied prespecified mix. The CBC run indeed very closely matches the capacity mix implied in the factors. Thus, the CEUM is performing as intended.

Table 38 shows the potential variation in the solution of Equation (3). As can be seen, the approximately ± 0.05 changes described earlier are indeed possible. Table 39 shows some of the variation that can take place in the capacity factors when the derating for the margin is done after, instead of before, the solution to Equation (3). Baseload

TABLE 37

Intended and Resultant Capacity Mixes

	Base	Intermediate	Seasonal	Daily
Load Factors	.724	.206	.056	.014
Capacity Factors	.70	.38	.25	.05
Fraction of Total Capacity				
-Intended %	49.7	26.1	10.8	13.5
-CBC %	50.0	25.8	10.4	14.8
-LDC1 %	45.5	23.7	9.6	20.7

Base Case--Boston Edison
.481

	Base	Inter-mediate	Seasonal	Daily
Load Factors	.724	.206	.056	.014
Capacity Factors	.70	.38	.25	.05

Alternative Fit of
Capacity Factors

	Base	Inter-mediate	Seasonal	Daily
Load Factors	.724	.206	.056	.014
Capacity Factors	.65	.39	.20	.09

TABLE 38 Alternative Fit of Capacity Factors to Satisfy Equation (3) and the Constraint Sets.

Base Case--Boston Edison
.481

	Base	Inter-mediate	Seasonal	Daily
Load Factors	.724	.206	.056	.014
Zero-Margin (Not Derated) Capacity Factors	.84	.46	.30	.06
Derated Capacity Factors	.70	.38	.25	.05

Not Derated
.579

	Base	Inter-mediate	Seasonal	Daily
Load Factors	.724	.026	.056	.014
Zero-Margin (Not Derated) Capacity Factors	.75	.43	.30	.15
Derated Capacity Factors	.625	.358	.250	.125

TABLE 39 Recomputed Capacity Factors, Except Derated after Computation; the Not Derated Computations Were Made Using Approximately Equal Additions above Capacity Factor Limits.

Base Case--Boston Edison
.481

	Base	Intermediate	Seasonal	Daily
Load Factors	.724	.206	.056	.014
Fraction of Total Capacity	.41	.21	.11	.27
Capacity Factors	.70	.38	.25	.05

Baseload at 100%
.481

	Base	Intermediate	Seasonal	Daily
Load Factors	.499	.431	.056	.014
Fraction of Total Capacity	.27	.35	.11	.27
Capacity Factors	.70	.42	.25	.12

TABLE 40 Defining Baseload as 100% Usage, as Opposed to the 80% Usage Assumed in the CEUM.

capacity factors here drop to the more normal 60% areas, with peaking increasing substantially. Again this computation was not unique, but was intended to show the magnitude of the variations that could take place in an alternative, equally supportable, computational procedure.

Table 40 explores one other assumption, the defining of baseload capacity at the 80% usage point in Figure 7. In most other uses, baseload is defined as the 100% usage point in Figure 7. It is equally inexact to use 100%, but it does show the variation due to the change in this imprecise value: The computed capacity factors are forced to move up to the top of their ranges. In actual practice, this baseload capacity value might vary from a level even below the annual minimum, to a level perhaps as high as the 57% usage point* for a system with large seasonal changes, with relatively flat weekly load duration curves, and with significant storage capacity.

The principal point in Table 37 is perhaps that, although a .05 change in the baseload load factor may be quite large, it could be viewed as a "worst case." The LOAD run was implemented by a .05 decrease in the baseload, putting this energy into the daily peaking mode. The results, as can be seen in almost every national summary table, usually resulted in the greatest changes of any of the scenarios. In order to verify that the LOAD run was made correctly, the LDC1 run was implemented, this time using .01 changes in load factors. In many cases LDC1 outputs represent exactly what would be expected from a linear interpolation of the CBC and LOAD outputs. The magnitude of the sensitivity may not be unexpected, but is it problematic. For example, from Table 18, showing the forecast

*The usual cutoff for defining baseload capacity is at 57% usage (see Thompson et al. [1977]).

of oil/gas turbine activity, a change of ± 3 GW of new oil/gas turbine capacity might be expected to cover all important estimates of U.S turbine capacity for 1995. Yet a change in the daily peak load factors (which regionally vary from .007 to .040) of just $\pm .0005$ would exceed this band of ± 3 GW of turbines. Even if one wanted to fine-tune the CEUM to come within this range of reasonable turbine building, there are not enough digits of precision in the CEUM parameters to make this change: A change across all regions of just .001 will add or subtract more than 6 GW of new turbines. Again the modelers claim the way to interpret these turbine changes is not to take turbines literally but view them as a surrogate for reserve margin problems.

Hopefully this extended exercise on capacity factors and load factors has alerted future CEUM users to the caution that should be exercised in placing importance on CEUM outputs that change significantly between the CBC and the LOAD runs.

The seasonal peaking load category is either a concept unique to the CEUM, or it is relatively rare. Except for combined cycle, the only use of new capacity to cover seasonal peaking comes from turbines, but existing capacity does shift significantly to cover seasonal demands. It is difficult to determine from the code whether or not new oil/gas turbines and new combined cycle capacity are the only types allowed to cover new seasonal demands. The code does, for example, exclude oil/gas turbines from baseload operation. It would be important to know if and why such intelligence was imposed on the model. Not that imposed intelligence is necessarily undesirable.

In one of the EPRI synthetic utility systems, the use of natural gas in the peaking mode exceeds 25% of the total energy of the system. If the daily and seasonal peaking in the CEUM were tripled to adjust to those peaking energy demands, there would be several hundred GW of turbine capacity built. Here is a case in which the structure of the CEUM shows clearly that the load and capacity factors in the CEUM must be fine-tuned to meet the capacity targets for the different load modes. The documentation might easily mislead the reader into believing that these factors have been derived from independent sources. Hopefully there is an understanding that, first, such independent sources do not exist, and, second, that the CEUM is quite sensitive to certain inputs and so must be closely watched so that it does not yield unreasonable outputs (such as new turbine capacity).

5.8 Transmission

Transmission capabilities and costs have some effects on generation expansion output of the CEUM. First, the intraregional transmission and distribution costs are not included within the linear program (except the $50/KW hookup charge for new capacity), but they are added on before reporting the cost of electricity. There are transmission losses included in the linear programs. One problem with these costs and losses is that they do not change across load categories. If peaking plants were given lower losses compared to baseload, then the realities of the situation would be better represented and there would be a chance to represent some of the advantages of dispersed, versus centralized, expansion schemes.

The bulk, baseload transmission between the CEUM utility demand regions has an important effect on the CEUM outputs, as the summary results of the NOTX run show (see Volume VII, Chapter 1). Generally, the transmission acts to smooth out local anomalies in the model. For example, in the CBC, Central Ohio is constrained to have only 1.9 GW of coal, and thus this region imports huge* amounts (38.8 billion kWh) of power from Indiana. (Because this is the East/West boundary in the model, East/West outputs should be carefully examined to see if these are just Ohio/Indiana effects.) A separate section on interregional electricity transmission discusses the fact that the transmission model is basically invalid for many conditions (see Volume IV, Chapter 3).

6. GENERATION EXPANSION METHODOLOGY, LOGIC, AND DECISION PROCESS

This subsection discusses some of the more abstract concepts associated with the simulation of electric utility planning.

6.1 Optimization

Considerable attention can be aimed at whether or not it is appropriate to simulate the electricity sector with an optimization model. Some of the issues include: fuel adjustment clause biases, decentralization to avoid litigation, differences in allowed returns on operating and capital expenses, and risk aversion.

There are special problems with an overall national optimization. The advantages of an optimization scheme, however, are that it is relatively easy to implement in terms of data and structure, and in certain ways can be claimed to replicate the free market system. Disadvantages of an optimization approach include:

*All U.S. and Canada inter-area transfers for 2 months in 1978 amounted to 14.0 billion kWh (see National Electric Reliability Council [August 1978]).

(1) the potential for large changes in decisions based upon very small changes in model inputs and parameters,

(2) national cost minimization implies that the coal and utility systems will be operated for their mutual benefits, missing the other supply and demand sectors and missing some behavior that is other than mutually beneficial,

(3) as regulated, subregional entities, utilities have a substantial history of operating with behaviors that are more complex than cost minimization,

(4) to the extent they are not modeled, profits, rents, and dislocations in the economy are not included, and

(5) also to the extent they are not modeled, government regulations with respect to unemployment, taxes, environmental regulations, and other controls will push the outputs away from the optimal levels.

The simplistic, logical, accounting-like behavior of the CEUM should be kept in mind by users. The only two general comments that can be made about the effects of such "non-optimum" issues are:

(1) costs should be higher than they are reported in the CEUM, and

(2) unmodeled constraints, feedback effects, and controls will probably tend to diminish the magnitude of perturbations caused by scenario variations in the CEUM.

Linear programming is generally recognized as resulting in very simplistic solutions, due to the required lack of complexity in its framework. Everyone is aware of some of its limitations, such as knife-edge flip-flopping between solutions, impossibility of sequential decisions, and rigidity with regard to constraints and performance measures. The size of a linear program is an easily observed measure of the complexity of a model, but the real test of model-contained "intelligence" versus user-imposed intelligence comes from the size, shape, and activities in the opportunity set. One measure of contained versus imposed "intelligence" comes from the difficulty of forecasting model behavior. If, in fact, the set of all feasible solutions is small and narrowly focused on a predictable result, then the imposed intelligence, in the form of the format and constraints, is the most important contributor to the model. Figure 10 from ICF, Inc. (July 1977) lists a flowchart that attempts to describe model results of coal use for baseload operation. From model results for 1985 we have unravelled a more general heuristic that seems to forecast the CEUM generation expansion and utility operation behavior quite well (see Figure 11). Given this heuristic for 1985 utility behavior, the principally accounting nature of the CEUM should be apparent. We were unable to find new coal capacity constraints for 1990 or 1995 either in the documentation or in the code. Thus, it would appear that for these case years (horizons) the points 3. and 4. in the last block of Figure 11 should read:

3. Remaining Baseload and Intermediate as Coal, and
4. Remaining Seasonal and Daily Peaking as Turbines.

Of course, Figure 11 does not go into the complexity of sorting out the pollution control options in the model. These options are well modeled in their "vertical" competition, that is, competition between:

1. naturally clean coal,
2. cleaned coal, and
3. abatement options.

However, the CEUM is not currently capable of modeling "horizontal" competition, that is, competition between:

1. physical coal cleaning,
2. deep-coal cleaning,

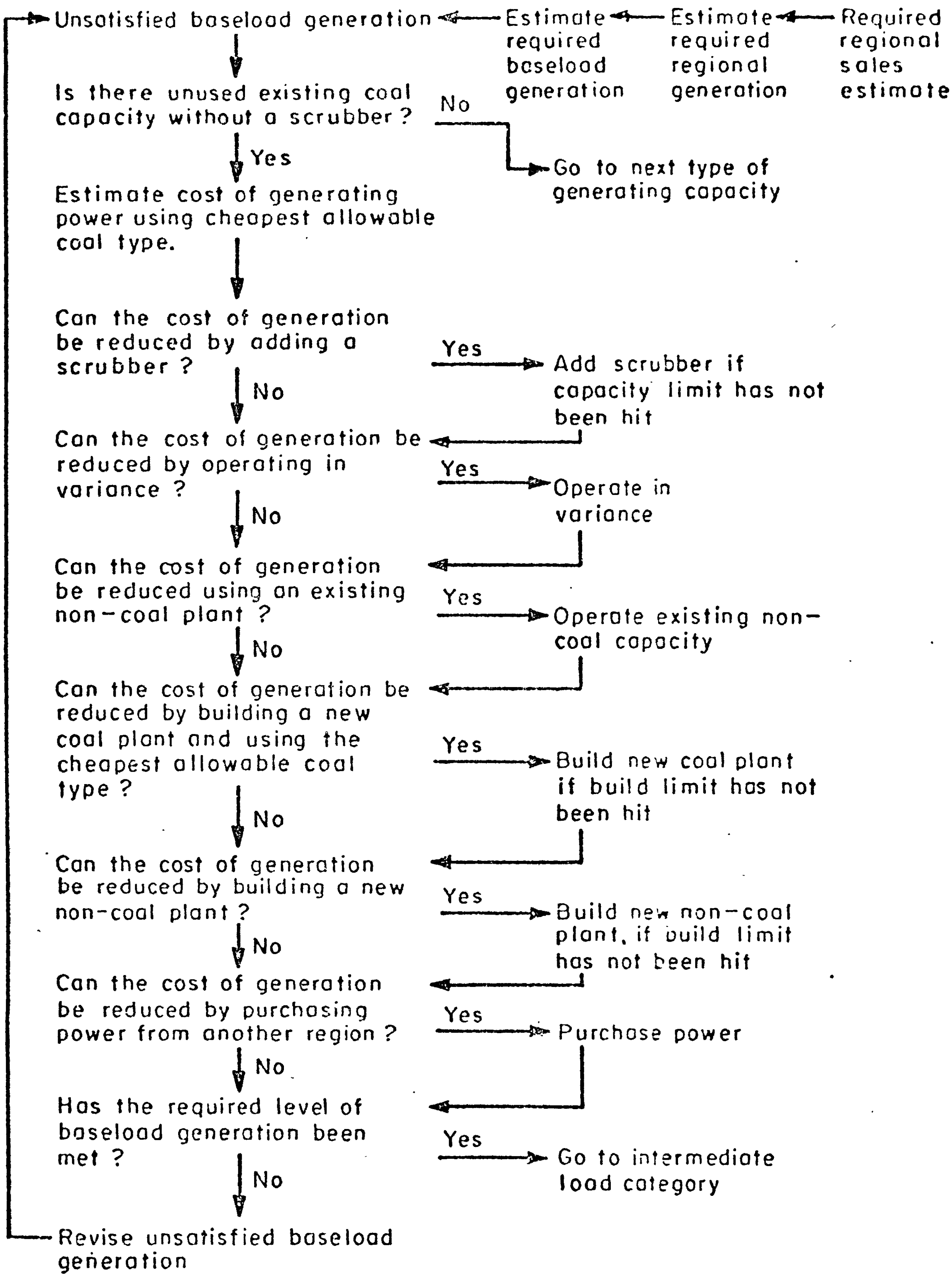


Figure 10. Non-Technical Flowchart of Utility Sector Logic
ICF, Inc. (1977)

Satisfy Lower Bounds on New Nuclear, Combined Cycle, and Coal Plants

↓ unsatisfied electric energy demands (if any) in load modes

Meet Any Remaining Demand with, In Order:

1. Existing Hydro,
2. Existing Coal,
3. Existing Oil/Gas Steam,
4. Existing Oil/Gas Turbines.

↓ unsatisfied electric energy demands (if any) in load modes

Meet Remaining Energy Demands With, in Order:

1. Hydro for Daily Peaking,
2. Hydro for Seasonal Peaking,
3. All Baseload Coal; then All Intermediate Coal (Up to Total Constraint on Coal Capacity),
4. All Remaining Demands Met By Turbines Except Baseload, Which Must Be Met By Combined Cycle

↓

check neighboring demand regions for baseload transmission opportunities

Figure 11. Flowchart of Capacity Choices to Meet Load Demand Categories in 1985.

3. solvent refined coal, and

4. liquid or gaseous synthetic fuels.

or, for another example, competition between:

1. advanced coal combustion,

2. fluidized bed combustion,

3. MHD, and

4. low-Btu combined cycle.

These diagrams do show, however, that in general non-technical terms the CEUM is acting in an appropriately predictable manner for the runs we made.

6.2 Probabilistic Treatments and Risk Aversion

A major deficiency of the CEUM and all other similar models is that they are deterministic. The standard response to this criticism is that sensitivity studies can be made with respect to the uncertainties. However, with uncertainties in:

1. air pollution controls,
2. coal mine reclamation, regulations, and costs,
3. mining regulations,
4. pricing regulations,
5. costs of imported and domestic oil and gas,
6. availabilities of nuclear power,
7. institutional constraints, political and legal uncertainties,
8. market uncertainties,
9. coal transportation costs,

10. inflation rates,

11. costs of capital and fixed change rates,

12. real escalation rates,

13. electricity demand growth rates,

and so on, it becomes immediately apparent that sensitivity studies must be limited, especially for models such as the CEUM that exceed $1000 per run (or possibly $500 in newer versions, according to the modelers). Sensitivity runs for past CEUM applications have been confined to electricity growth, environmental regulations, nuclear growth (in ICF, Inc. [January 1979]), and with/without dry scrubbing (also ICF, Inc. [January 1979]).

We point out that comments about the deterministic nature of the CEUM are not constructive, in that current methodologies and time constraints preclude the possibility of a probabilistic CEUM. Our comments are intended only as cautions to users about the limitations of the CEUM due to limitations in available methodologies and computer machinery.

Risk aversion, which is an important part of utility planning, is also not part of the CEUM linear programming formulation. The non-optimum behaviors of spreading risks were mentioned previously in comments concerning "knife-edge" optimization. The simulation of risk aversion with respect to shortfalls of energy supply is also impossible to implement in the CEUM because of the assumption of perfect demand forecasting.

6.3 Lack of Dynamics

There are a whole set of possible energy scenarios that obviously cannot be treated given the static formulation of the CEUM. The static formulation is generally operated for a series of selected case (horizon) years, and although it can seem to account for some dynamic issues, it still has almost all the disadvantages of purely static formats.

Aside from its static nature, a major problem with the CEUM formulation is that the planning periods are more overlapping than sequential. It seems, perhaps, to have been created this way as a matter of expediency. Consistencies are enforced via intertemporal constraints by setting lower bounds on coal flows to ensure that contracts undertaken in earlier case years would continue in force, and by setting lower bounds on utility capacity additions to force additions by plant type in a later case year to at least be close to those in the prior case year. But in overlapping periods, such as 1975-1985, 1975-1990, and 1975-1995, all of the parameters (such as inflation rate, coal flows, and so on) must remain constant over each of these time intervals. The use of sequential periods should be explored.

One final abstract issue involves the terminal period disposition of the CEUM. Most utility planning models attempt to incorporate an accounting of the quality of the system as it is left at the planning horizon. This is done either through an increase in the model's time horizon or through an accounting of the quality of the state of the system at the model horizon, with the addition of this quality measure to the model's performance measure. Not including this effect will introduce a bias, the magnitude of which will depend upon the expectations of changes beyond the horizon and the non-optimality of the existing system.

7. APPROPRIATE APPLICATIONS

A discussion of the types of applications for which a model is not appropriate is easier than a discussion of applications for which it is appropriate, especially in the context of the capabilities of a single component. The CEUM is not appropriate for investigating the following classes of problems:

1. Dynamic issues are obviously not treatable, that is, there can be no changes, surprise or planned, over the modeling horizon. There is no way to investigate the dynamics of rate constrained activities in construction, manpower production, equipment availability, water availability, distribution, land, environmental dispersive potential, site availability, capital, cash flows, and so on. Plant lead times cannot be treated.

2. Any CEUM runs that result in large changes from the base case should be viewed with considerable skepticism. The reason for this is that there are a great number of untreated feedback effects that must be identified and included in re-runs of the model with a considerable addition of imposed intelligence.

3. The coal and the generation/control machineries are not characterized in enough detail to assure that their use or retrofits can be adequately modeled, particularly in interfacing with existing equipment or with regard to pollutants other than SO_x. Sizes and peculiarities of equipment, and moisture, ash, crushability, slagging, and other characteristics of the different coals, make it difficult to adequately model the capabilities of existing or new equipment. Most models have trouble with this characterization.

4. Changes in the demand rates or the shapes of electricity load duration curves that occur from year to year, as a result of conservation, demographic changes, load management, or cogeneration, cannot be treated.

5. Generation expansion issues with regard to advanced coal technologies, fuel conversions, renewable technologies, nuclear, hydro, turbine, or transmission technologies cannot be addressed without adding new demand and system resolutions to the model.

6. Price and cost issues should be treated with great caution due to the end of period manner of computation, plant size, waste disposal, environmental control cost, and other approximations.

Within the limits of the CEUM formulation, level of detail, and information, and presuming data source and other problems have been satisfactorily resolved, the following appear to be appropriate applications for the model:

1. Approximate resultant effects due to static changes in demand factors, cost factors and other factors directly associated with coal capacity construction and use.

2. Approximate changes in the choice of regional coals, particularly for new capacity, if the coal prices and the slurry, barge, truck, and train coal transportation components are adequately modeled.

3. The CEUM can adequately simulate the choice among the broad "vertical" groups of coal generation SO_x control options, with respect to variations of standards that can be adequately incorporated into the three state implementation plan framework. Although choice can appropriately be investigated, capital or operating costs should be viewed with caution due to the single parameter modeling of the function of these control and generation equipments with respect to plant sizes and coal constitutents.

CHAPTER 2. ELECTRIC UTILITY OPERATION

1. DESCRIPTION OF ELECTRICITY GENERATION SCHEDULING

Electricity generation is scheduled to meet four types of load demand categories in each of the CEUM's demand regions. These demand categories include baseload, intermediate, seasonal peak, and daily peak. Satisfying these exogenously specified demand categories with exogenously specified capacity factors draws in new capacity and produces both costs of generation and amounts of utility fuel use. These generation values represent the annual amounts for the case year (horizon time period).

The equations constraining the generation scheduling activities include the capacity limitations for existing plants and the material balances for new plant capacity (both described in Chapter 1 above), the delivery of electricity to consumers, the material balances at fuel piles, and, indirectly, other constraint equations specified in Volume II, Chapter 3, Section C. Those equations that are directly related to electricity generation, and that are repeated below, include total electricity consumption requirements and material balances both for total electricity supplies and for electricity supplies by load category.

1.1 Total Electricity Consumption Requirements

The straightforward set of constraints that forces the delivery of a specified amount of electricity for each demand region UR is given by:

$$-DEL_{UR} = -DEL^{*}_{UR}$$

where:

UR = utility demand regions,

DEL_{UR} = delivery of electricity to demand region UR, 10^9 KWH/year, and

DEL^*_{UR} = exogenous electricity consumption requirement in demand region UR.

1.2 Material Balances for Total Electricity Supplies

The amount of electricity leaving a region for delivery and transmission must be less than or equal to the total amount of electricity supplies in that region.

$$\sum_{UR_j} \left(TRE_{UR_i,UR_j} + TRN_{UR_i,UR_j} \right) + \left(1 + \ell_D(UR_i) \right) DEL_{UR_i} - CEL_{UR_i} \leq 0$$

where:

UR_i = source regions,

UR_j = sink regions,

TRE_{UR_i,UR_j} = transmission of electricity on existing lines from UR_i to UR_j, 10^9 KWH/year,

TRN_{UR_i,UR_j} = transmission on new lines from UR_i to UR_j,

$\ell_D(UR)$ = fractional electricity distribution loss in delivery to consumers in demand region UR, measured in terms of the additional fraction of pre-delivered electricity required to produce a unit of delivered electricity, and

CEL_{UR_i} = activity that combines electricity from different load modes into a "total electricity pile," in demand region UR_i.

1.3 Material Balances for Electricity Supplies by Load Category

For activities operating in baseload, the electricity generated from all sources in a region, minus the amount of baseload energy used for pumped storage, plus net transmission into the region, must be greater than or equal to the baseload electricity supply for the region. We then have for L = $\underline{B}$:

$$- \sum_{P} \sum_{UE} O_{UR_j, P, UE, \underline{B}} + (1 + \ell_{PS}) \sum_{P=\underline{H},\underline{I}} O_{UR_j, P, \underline{HG}, \underline{Z}}$$

$$+ f_{\underline{B}}(UR_j)\ CEL_{UR_j} - \sum_{UR_i} \left[\left(1 - \ell_{TE}(UR_i, UR_j)\right) TRE_{UR_i, UR_j}\right.$$

$$\left. + \left(1 - \ell_{TN}(UR_i, UR_j)\right) TRN_{UR_i, UR_j} \right] \leq 0$$

where:

$f_L(UR)$ = fraction of total regional electricity supplies in the load mode L,

ℓ_{PS} = fractional loss in the pumped storage process, measured in terms of the additional fraction of baseload electricity required to produce a unit of daily peaking electricity from pumped storage,

$\ell_{TE}(UR_i, UR_j)$, $\ell_{TN}(UR_i, UR_j)$ = fractional electricity transmission losses over existing and new lines respectively, from source region UR_i to sink region UR_j.

For the other load modes there is assumed to be no transmission and no pumping for storage, so for L = $\underline{I}$, $\underline{P}$, or $\underline{Z}$:

$$- \sum_{P} \sum_{UE} O_{UR, P, UE, L} + f_L(UR)\ CEL_{UR} \leq 0$$

1.4 Objective Function Term Associated with Delivery of Electricity

The term in the objective function that is directly related to the delivery of electricity described in this section contains only a simple delivery cost, which is in addition to transmission losses that are accounted for elsewhere:

$$\sum_{UR} DC(UR)\ DEL_{UR}$$

where:

DC = electricity delivery cost, mills/kWh.

As in the other objective function terms, the units are 10^6\$/year (see Volume II, Chapter 3, Section C).

2. DISPATCH SCHEDULING ISSUES

It is impossible to separate the utility operation from the utility planning in the CEUM, because they are conducted simultaneously in the model. In almost all cases the operating issues are imbedded in the planning issues. Thus, Chapter 1 above contains discussions of almost all of the operating issues in the context of planning issues and model sensitivity runs. In particular, Chapter 1 contains discussions of fuels, margins, capacity factors, heat rates, simulation, uncertainties, and methodologies. Particularly important among those issues are those that deal with the lack of plant retirements, uncertainties in covering demands, capacity and load data needs, lack of incentives for reliability, no difference between planned and forced outrages, and the crudeness associated with the static, four-point load duration curve.

2.1 Capacity Factors

Planned maintenance outages and forced outages are both treated in the CEUM as deratings to capacities. As such it must be recognized that the use of oil/gas turbines must be artificially stimulated (and thus essentially exogenously specified) because turbines tend to be used more to cover forced outages than to cover demand peaks. Table 1 shows how the oil/gas turbines (and unfortunately all other oil/gas plants due to aggregated CEUM reporting) are used in the various sensitivity scenarios in each case year. The remarkable runs include the no interregional transmission run (NOTX) where oil/gas turbines are pressed into baseload service in 1985 to cover the tightly constrained regional situations. The LOAD and LDC1 sensitivity runs, which involved increased requirements for peaking plants, caused drops in the average oil/gas capacity factors due primarily to a larger relative number of oil/gas turbines (as opposed to oil/gas steam plants). The demand change runs, EDMI and CEDMD, resulted in similar increases and decreases, respectively, in capacity factors. With increases in coal costs, such as in the LAB3 model run, oil/gas plants are pressed into greater service. All in all, these results were quite understandable.

Coal plant capacity factors, in Tables 2 and 3, were most sensitive to financial parameter and coal cost variations. It is somewhat surprising that ANSPS capacity factors should change inversely with the demand changes (in sensitivity runs EDMI and CEDMD), exacerbating the capacity requirement changes. The reason for this is that baseload ANSPS coal plant capacities are relatively inflexible, thus capacity operating in the intermediate load mode changes most with demand changes. This causes the inverse effect.

TABLE 1

National Average Capacity Factor for all U.S. Oil/Gas Plants

	1985	1990	1995
CBC	.262	.169	.105
CNSPS	.260	.156	.098
CML20	.261	.161	.103
CEDMD	.237	.180	.102
CMILL	.266	*	*
CNINC	.252	.162	.103
COILG	.247	.153	.098
UCIN	.261	.148	.098
UDIN	.260	*	*
LAB3	.267	.181	.114
TCML	.262	.161	.104
LOAD	.141	.093	.077
ROYI	.263	.171	.106
EDMI	.269	.170	.105
UCD4	.266	.190	.115
LABD	.260	.156	.099
LOGN	.262	.172	.104
CDRB	.262	.168	.104
LDC1	.220	.140	.092
NCAP	.272	.171	.105
MOIL	.247	†	.090
BC	.262	.165	.104
EDMD	.236	.158	.104
NOTX	.312	.164	.104

* These runs were not made.

† This report was not released to us.

TABLE 2

National Average Capacity Factor for All U.S. NSPS Coal Plants

	1985	1990	1995
CBC	.582	.608	.627
CNSPS	.599	.591	.573
CML20	.594	.610	.633
CEDMD	.562	.559	.580
CMILL	.586	*	*
CNINC	.581	.589	.596
COILG	.591	.610	.628
UCIN	.596	.609	.633
UDIN	.598	*	*
LAB3	.552	.548	.567
TCML	.588	.593	.628
LOAD	.579	.599	.612
ROYI	.584	.582	.598
EDMI	.601	.617	.631
UCD4	.589	.582	.623
LABD	.594	.618	.628
LOGN	.616	.601	.602
CDRB	.594	.612	.634
LDC1	.583	.610	.627
NCAP	.597	.625	.638
MOIL	.591	†	.626
BC	.582	.578	.616
EDMD	.556	.546	.563
NOTX	.566	.565	.601

* These runs were not made.

† This report was not released to us.

TABLE 3

National Average Capacity Factor for All U.S. ANSPS Coal Plants

	1985	1990	1995
CBC	.611	.531	.511
CNSPS	.566	.528	.531
CML20	.604	.514	.501
CEDMD	.630	.525	.500
CMILL	.609	*	*
CNINC	.603	.517	.495
COILG	.603	.523	.513
UCIN	.597	.515	.508
UDIN	.596	*	*
LAB3	.601	.556	.516
TCML	.610	.524	.506
LOAD	.613	.497	.495
ROYI	.605	.544	.511
EDMI	.604	.542	.518
UCD4	.611	.585	.509
LABD	.607	.511	.504
LOGN	.550	.540	.515
CDRB	.610	.530	.510
LDC1	.604	.525	.508
NCAP	.605	.548	.528
MOIL	.603	†	.510
BC	.609	.541	.511
EDMD	.631	.528	.505
NOTX	.604	.557	.520

* These runs were not made.

† This report was not released to us.

Table 4 shows the movement of the old coal plants away from baseload and intermediate to nearly all seasonal peaking use in 1995. It is still worth mentioning that even with the very high heat rates used for these plants, they still are never retired, even for purely economic reasons. The use of newer existing coal plants (see Table 5) also remains relatively unperturbed through the various sensitivity runs. When these capacity factors are averaged, they range from 61% in 1985 to about 51% in 1995. These figures are quite high.* If the old coal plants were retired, the usage of these newer, existing plants would decrease to cover seasonal demands and their capacity factors would then be more reasonable.

As is obvious from Table 6 and from the way in which they were set up, the national capacity figures come out exactly on the required value, except in the sensitivity runs that changed the load curves, LOAD and LDC1. This demonstrates the rigidity of the levels of capacity factors of the capacity in the various load modes.

2.2 Generation of Electricity

Given the plant-type capacity levels discussed in Chapter 1 above and the capacity factors listed in the previous tables, only a multiplication is required to yield generation of electricity. Tables 7 through 10 show some of the expected results. These numbers are important as intermediate values for use in generating additional reported results. For example, values in Table 10 convert directly to the oil/gas use values in Table 11. The different energy-use tables then just add to produce the total utility energy-use levels given in Table 12. In addition, the generation tables for plant types multiplied by amounts and

*Baseload capacity itself is variously defined as 57% (see Thompson et al. [1977]), to 62% (see U.S. Department of Energy [October 1978]), and total coal plant average capacity factors are about 67% (see Electric Council of New England [1978]).

TABLE 4

National Average Capacity Factors for Old Coal Power Plants

	1985	1990	1995
CBC	.374	.292	.250
CNSPS	.358	.266	.250
CML20	.398	.287	.250
CEDMD	.326	.280	.250
CMILL	.385	*	*
CNINC	.374	.277	.250
COILG	.374	.276	.250
UCIN	.363	.264	.250
UDIN	.363	*	*
LAB3	.360	.283	.268
TCML	.376	.289	.250
LOAD	.329	.267	.250
ROYI	.378	.289	.250
EDMI	.378	.283	.250
UCD4	.385	.306	.262
LABD	.403	.288	.252
LOGN	.376	.291	.250
CDRB	.375	.291	.250
LDC1	.351	.277	.250
NCAP	.382	.296	.250
MOIL	.374	†	.250
BC	.375	.292	.250
EDMD	.336	.281	.250
NOTX	.390	.283	.250

* These runs were not made.

† This report was not released to us.

TABLE 5

National Average Capacity Factors for Existing Coal Power Plants

	1985	1990	1995
CBC	.611	.568	.507
CNSPS	.609	.560	.488
CML20	.607	.573	.519
CEDMD	.599	.559	.511
CMILL	.611	*	*
CN NC	.604	.553	.502
COILG	.606	.557	.493
UCIN	.605	.559	.500
UDIN	.604	*	*
LAB3	.620	.582	.528
TCML	.608	.569	.512
LOAD	.595	.542	.501
ROYI	.610	.570	.519
EDMI	.620	.568	.506
UCD4	.615	.576	.528
LOGN	.606	.569	.512
LAGN	.607	.569	.509
CDRB	.606	.567	.504
LDC1	.608	.560	.505
NCAP	.621	.573	.511
MOIL	.606	†	.498
BC	.611	.568	.511
EDMD	.600	.561	.516
NOTX	.601	.559	.509

* These runs were not made.

† This report was not released to us.

Average Capacity Factor for All U.S. Power Plants
(This checks approximately with the 1978 average plant factor of .557 (see Friedlander [November 15, 1979]) and the 20% reserve margin, which together yield .465)

	1985	1990	1995
CBC	.484	.484	.485
CNSPS	.484	.484	.484
CML20	.484	.484	.485
CEDMD	.484	.484	.485
CMILL	.484	*	*
CNINC	.484	.484	.485
COILG	.484	.484	.485
UCIN	.484	.484	.485
UDIN	.484	*	*
LAB3	.482	.482	.483
TCML	.484	.484	.484
LOAD	.365	.365	.366
ROYI	.484	.483	.484
EDMI	.484	.484	.485
UCD4	.484	.484	.485
LABD	.485	.484	.485
LOGN	.484	.484	.485
CDRB	.484	.484	.485
LDC1	.455	.455	.455
NCAP	.484	.484	.485
MOIL	.484	†	.485
BC	.484	.484	.485
EDMD	.484	.484	.485
NOTX	.483	.484	.484

* These runs were not made.

† This report was not released to us.

TABLE 7

U.S. Generation from Old Coal Power Plants (10^9KWH)

	1985	1990	1995
CBC	24.0	18.8	16.1
CNSPS	23.0	17.1	16.1
CML20	25.6	18.4	16.1
CIDMD	20.7	18.0	16.1
CMILL	24.8	*	*
CNINC	24.0	17.8	16.1
COILG	24.0	17.8	16.1
UCIN	23.3	17.0	16.1
UDIN	23.4	*	*
LAB3	23.2	18.1	17.2
TCML	24.2	18.6	16.1
LOAD	21.2	17.2	16.1
ROYI	24.3	18.6	16.1
EDMI	24.3	18.2	16.1
UCD4	24.8	19.7	16.8
LABD	25.9	18.5	16.2
LOGN	24.2	18.7	16.1
CDRB	24.1	18.7	16.1
LDC1	22.6	17.8	16.1
NCAP	24.6	19.1	16.1
MOIL	24.0	†	16.1
BC	24.1	18.7	16.1
EDMD	21.3	18.1	16.1
NOTX	24.1	17.5	15.4

* These runs were not made.

† This report was not released to us.

TABLE 8

U.S. Generation of Electricity from NSPS Coal Plants (10^9 KWH)

	1985	1990	1995
CBC	413.9	442.5	456.3
CNSPS	415.6	414.1	412.1
CML20	422.0	444.2	460.8
CEDMD	339.6	401.8	421.8
CMILL	415.3	*	*
CNINC	390.1	428.5	434.1
COILG	436.0	450.3	463.1
UCIN	423.8	443.5	460.8
UDIN	425.1	*	*
LAB3	389.3	399.0	412.3
TCML	417.9	431.6	457.0
LOAD	406.5	436.0	445.8
ROYI	415.3	423.8	435.3
EDMI	437.4	449.7	459.9
UCD4	405.7	423.7	433.4
LABD	423.7	450.1	457.4
LOGN	437.2	437.6	438.4
CDRB	422.6	446.0	461.1
LDC1	416.0	444.1	456.0
NCAP	431.7	454.8	464.5
MOIL	436.0	†	462.0
BC	413.5	420.7	448.4
EDMD	336.7	387.2	409.9
NOTX	342.9	374.6	410.3

* These runs were not made.

† This report was not released to us.

TABLE 9

U.S. Generation from New ANSPS Coal Power Plants (10^9 KWH)

	1985	1990	1995
CBC	158.0	691.5	.133E04
CNSPS	172.6	776.4	.143E04
CML20	160.2	707.9	.131E04
CEDMD	98.6	442.0	949.8
CMILL	138.1	*	*
CNINC	138.2	562.9	.110E04
COILG	198.1	752.7	.137E04
UCIN	166.4	769.4	.136E04
UDIN	169.7	*	*
LAB3	144.3	664.3	.132E04
TCML	159.0	724.1	.133E04
LOAD	142.9	637.3	.115E04
ROYI	151.6	699.7	.133E04
EDMI	189.6	846.9	.155E04
UCD4	135.6	611.6	.127E04
LABD	163.6	721.3	.134E04
LOGN	138.0	879.4	.135E04
CDRB	157.2	693.5	.134E04
LDC1	159.3	685.6	.130E04
NCAP	183.6	842.3	.157E04
MOIL	198.1	†	.136E04
BC	159.8	725.1	.134E04
EDMD	101.2	457.5	949.2
NOTX	116.2	854.4	.145E04

* These runs were not made.

† This report was not released to us.

TABLE 10

U.S. Generation from Oil/Gas Fired Power Plants (10^9 KWH)

	1985	1990	1995
CBC	518.4	276.1	145.8
CNSPS	506.4	233.3	130.0
CML20	513.2	250.4	141.8
CEDMD	373.3	217.2	123.0
CMILL	534.7	*	*
CNINC	482.7	254.5	142.1
COILG	466.5	227.8	129.4
UCIN	511.3	214.5	129.9
UDIN	508.5	*	*
LAB3	541.4	323.2	168.1
TCML	517.8	251.9	144.5
LOAD	570.3	382.5	358.8
ROYI	525.0	283.9	147.9
EDMI	598.3	297.6	155.2
UCD4	541.1	360.2	172.6
LABD	509.4	237.0	132.6
LOGN	521.7	290.3	144.3
CDRB	518.2	273.4	142.1
LDC1	521.6	295.3	187.5
NCAP	565.5	286.4	146.6
MOIL	466.5	†	129.4
BC	516.8	263.9	144.4
EDMD	371.0	211.6	127.7
NOTX	705.0	259.3	142.9

* These runs were not made.

† This report was not released to us.

TABLE 11

Total U.S. Oil/Gas Use for Electricity (Quads)

	1985	1990	1995
CBC	5.35	3.28	1.90
CNSPS	5.72	2.82	1.72
CML20	5.79	3.01	1.85
CEDMD	4.26	2.63	1.62
CMILL	6.02	*	*
CNINC	5.47	3.05	1.86
COILG	5.29	2.76	1.71
UCIN	5.77	2.61	1.72
UDIN	5.74	*	*
LAB3	6.11	3.80	2.15
TCML	5.84	3.03	1.86
LOAD	6.75	4.85	4.73
ROYI	5.92	3.37	1.93
EDMI	6.75	3.52	2.00
UCD4	6.10	4.23	2.20
LABD	5.75	2.86	1.75
LOGN	5.89	3.44	1.89
CDRB	5.85	3.25	1.86
LDC1	5.97	3.59	2.48
NCAP	6.37	3.39	1.90
MOIL	5.29	1.75	1.71
BC	5.83	3.15	1.88
EDMD	4.23	2.57	1.68
NOTX	7.97	3.07	1.84

* These runs were not made.

TABLE 12

U.S. Total Utility Energy in Quads

	1985	1990	1995
CBC	31.0	37.4	45.3
CNSPS	30.9	37.1	45.0
CML20	31.0	37.4	45.3
CEDMD	27.9	33.7	40.9
CMILL	31.0	*	*
CNINC	31.0	37.5	45.4
COILG	31.0	37.4	45.3
UCIN	31.0	37.4	45.3
UDIN	31.0	*	*
LAB3	31.0	37.4	45.5
TCML	31.0	37.4	45.3
LOAD	31.4	38.0	46.1
ROYI	31.0	37.4	45.4
EDMI	32.6	39.2	47.6
UCD4	31.0	37.5	45.3
LABD	31.0	37.3	45.2
LOGN	31.0	37.4	45.4
CDRB	31.0	37.4	45.3
LDC1	31.1	37.4	45.5
NCAP	31.1	37.5	45.5
MOIL	31.0	†	45.3
BC	31.0	37.4	45.3
EDMD	27.9	33.7	40.9
NOTX	31.2	37.3	45,2

* These runs were not made.

† This report was not released to us.

efficiencies of scrubbers, and by the appropriate conversion factors, produce similar tables on emissions of SO_2, NO_x, and TSP. There is a general assumption of linearity here, but there are no anomalies in these tables that cannot be traced back to anomalies in previously discussed tables.

2.3 Appropriate Applications

Because the electric power system operation and planning in the CEUM are so closely tied, appropriate application areas are discussed fully in Chapter 1, Section 6 above.

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VOLUME VI:

OTHER EVALUATION ISSUES

by

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PREFACE

This report is one in a series of seven volumes presenting the results of an indepth review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). The Final Report (Volume I) provides a self-contained summary of the study objectives and results, with supporting papers and materials presented in Volumes II-VII.

The complete series includes:

Energy Model Analysis Program, "The ICF, Inc, Coal and Electric Utilities Model: An Analysis and Evaluation," M.I.T. Energy Laboratory Report No. MIT-EL 81-015, Cambridge, Massachusetts 02139, March 1980.

Volume I: Final Report

Volume II: Documentation and Verification of Model Implementation

Volume III: Coal Supply Issues: Mine Lifetime and Coal Royalties

Volume IV: The Coal Supply Cost Function

Volume V: Electric Utility Expansion and Operation

Volume VI: Other Evaluation Issues

Volume VII: Evaluation Strategies and Computational Results

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INTRODUCTION

This volume collects together several short papers and notes relating to demand, transmission, transportation, environmental controls, and other topics considered in the Energy Model Analysis Program (EMAP) review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). Chapter 1 considers the CEUM treatment of electricity and non-utility coal demand, and Chapter 2 presents a method for approximating the CEUM demand component for potential use in simplifying calculation of full model results for supply component computational experiments. While suggestive, this procedure was not employed in the EMAP review. Chapters 3 and 4 consider the CEUM treatment of electricity transmission and environmental controls, respectively. Chapters 5 through 9 are short notes on the topics of the role of long-term contracts, use of the uniform distribution in allocating unclassified resources, issues of reserve classification, transport modes, and the role of the general inflation rate.

CHAPTER 1. UTILITY AND NON-UTILITY DEMAND

A.* DESCRIPTION OF NON-UTILITY DEMAND

Non-utility demands for coal are specified exogenously by the analyst for five consuming sectors in each of the 39 demand regions. The consuming sectors include industrial, residential/commercial, metallurgical, synthetics, and exports. Coal use in these sectors is small relative to utility use, and this fact is a key consideration in the ICF approach. In 1976 non-utility coal consumption accounted for 30% of total U.S. consumption and exports, and EIA projects non-utility coal consumption to be about 27 and 25% of the total in 1985 and 1990, respectively (see Table 1).

TABLE 1

EIA Projections of Coal Consumption by Sector
1976 Actual, 1985, 1990 Scenario F Projections**
(millions of tons)

	1976	1985	1990
Utilities	448.5	771.0	1020.1
Metallurgical	84.7	95.8	100.9
Industrial***	56.5	104.4***	113.0***
Residential/Commercial	3.4	N.A.	N.A.
Synthetics	-	13.7	34.0
Exports	59.4	74.0	81.0
TOTALS	649.1	1058.9	1349.1

N.A.--Not available.

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*This chapter was prepared by David O. Wood and James Gruhl.

**Scenario F refers to "medium" coal supply and demand, and "high" oil prices. In the latter case, imported oil prices are assumed to be $19.61 in 1985 and $24.97 in 1990 (1978$). See U.S. Department of Energy (1977).

***Includes residential and commercial.

The ICF approach to modeling non-utility coal demand makes use of an assumption that this part of coal demand, unlike the utility component, is price-inelastic. Thus:

> The demand for each of the five non-utility sectors is inputted to the model on a regional basis as point estimates. In addition, the coal piles that each sector is allowed to draw from are also specified by sector and region. The use of point estimates is not unreasonable since these sectors typically are not sensitive to the price of coal. Coking and export are closely related to national and worldwide steel production. Since coking coal is critical to the steelmaking process, has no competitive substitute, and accounts for only a small portion of the costs of making steel, steel producers do not respond significantly to increases in coal prices (particularly when the companies own their own mines).
>
> Industrial and residential/commercial consumers are typically locked into existing capital facilities which burn coal. The cost of conversion and uncertainties surrounding oil and/or gas prevent large-scale abandonment of coal. On the other hand, potential coal users are confronted with stiff environmental controls and high capital investment costs to use coal. Thus, there is no rush to coal by users in these sectors either. In short, industrial and residential/commercial consumers appear to be limited in their ability and/or willingness to respond to changes in coal prices. Finally, the synthetics sector apparently will be a government-subsidized consuming sector for some time to come. The level of demand from this sector will be related more to government policy than to coal prices (ICF, Inc. [July 1977], pp. II-16,17).

The purpose of the zero price elasticity assumption is to ensure that the method used by the analyst in projecting non-utility coal demands is not interdependent with the CEUM; that is, the CEUM and the users' non-utility CEUM demand model (NUCDM) do not have to be solved jointly in order to determine coal-type market-clearing prices and quantities.

A.1 Overview Evaluation of Non-Utility Demand

The nonutility demand for coal is exogenously specified in the CEUM as a means of closing the model with respect to coal production and prices. The statement of purpose for this component of the model is made unambiguously clear throughout the model documentation, so the potential user can have no doubts as to the nature of the assumptions underlying this component of the model or the nature and detail of the data that must be specified as part of any application scenario.

The difficulties with the ICF approach to non-utility coal demand are threefold. First, empirical evidence does not support the zero price elasticity assumption. Second, the demand region classification, while it may be appropriate for the utility coal demand, does not correspond to a measurement system providing historical data on coal use by CEUM coal type. Third, the approach assumes implicitly that the outcome of non-utility response to environmental regulations can be calculated and reflected in coal demand independently of coal prices.

On the first point we note the estimates of the own-price elasticity for coal in industrial use in two of the most prominent energy demand models. For the EIA regional demand model, the most recently published estimate of which we are aware is -.56 (see Federal Energy Administration [February 1976], p. C-10). For the DRI Energy Model, the corresponding estimate is -.76 (see National Academy of Sciences [1978], p. 202).

Concerning the second issue, the CEUM relies heavily upon the FPC data on shipments to utilities of coal, classified by heat and sulfur content, as the basic data base underlying the coal-type classification scheme in the model. This same scheme is employed for non-utility coal use. However, no data base corresponding to that provided by FPC exists for non-utility coal demand. ICF and potential users must therefore synthesize such data, a most difficult task, especially in the intermediate to long run.

As to the third issue, in contrast to the assumption of zero price elasticity, the assumption of zero cross-price elasticity between coal types and control technologies is not well documented in the ICF reports. The problem arises as follows: For a given set of environmental regulations the analyst must determine in the non-utility coal demand model (NUCDM) how coal quality types trade off with control technology. For the utility component of the CEUM, analysis of this trade-off is a distinctive characteristic, and is the basis for ICF's claim that the model may be used in evaluating the effects of utility decisions regarding coal use upon coal production levels and patterns. Such is not the case, however, for non-utility coal users. The analyst must assume that the coal-type prices have no effect upon the demand for control technology in the NUCDM, which is equivalent to assuming that the cross-price elasticities between coal types and control capital services are zero. The assumption is necessary since otherwise the NUCDM and CEUM would have to be solved jointly to obtain consistent estimates of coal type quantities and prices, and quantities of control capital services.

A.2 Summary of Non-Utility Demand

The CEUM is oriented toward analysis of coal use in utilities. Non-utility coal demand is required to close the model, in order to calculate market clearing prices by coal type. The extreme assumptions required are clear, and the potential user should have no doubt what must be assumed, and what information must be provided in order to use the model.

The extent to which the assumptions and data requirements limit the applicability of the model is not clear. The model structure is such that model sensitivity changes in non-utility coal demand are easily calculated and evaluated. This point is made directly and indirectly many times in the documentation (see ICF, Inc. [July 1977]. However, not much information and analysis of what the actual sensitivities are under different conditions is provided, primarily because it has not been required by study clients.

B. ELECTRIC UTILITY DEMAND

Utility demands for electricity are exogenous specifications in the CEUM for each of the 39 demand regions. In each region the aggregate demand is then distributed in fixed proportions to base, intermediate, seasonal peaking, and daily peaking load modes, and these demands are met by least-cost combinations of existing and new plants constrained by availability, and by bounds on utilization and expansion. Additional information concerning the mathematical formulation and the resultant sensitivities is discussed in Volume V, Chapter 1.

Discussed here is a short review of some of the more important effects in the Corrected Electricity Demand Down (CEDMD) sensitivity run of the CEUM. All electricity and non-utility coal demands for this run were at 90% of the electricity and non-utility coal demands in the Corrected Base Case (CBC) version of the model.

The principal issue addressed in this 10% demand decrease model run (and also in the 5% demand increase EDMI run) was the appropriateness of the model's general behavior for accommodating different future energy forecasts. This is one test of the extent to which the model's intelligence is applicable only to the Base Case situation, as opposed to being a kind of intelligence generally applicable to different electricity demand scenarios.

The response of the CEUM generation capacity expansion to the change in demand roughly can be divided into two areas: (1) the response regarding the use of existing plants, and (2) the effect on the construction of new plants. First, the use of existing plants is summarized in Table 2. Most of the existing plant capacities are utilized almost exactly the same both before and after the demand decrease. The exceptions are the oil/gas steam plants, which drop principally from baseload usage, and the old turbines, which drop out in favor of new turbines. The new plant build activities are essentially exogenously specified by upper bounds for the attractive alternatives such as nuclear and hydro, and by lower bounds for the unattractive alternatives such as combined cycles. Coal plant capacity, principally constrained in 1985 by upper bounds in the Base Case, in this CEDMD run, decreases to meet lower intermediate and baseload demands. Oil/gas turbine capacity, the only truly flexible fuel-type plant category, drops to accommodate the lower seasonal and daily peak demands. As expected, this run produces extensive generation expansion activity changes compared with other perturbations of the Corrected Base Case that we implemented.

A number of interesting and significant effects result from the implementation of this demand decrease. First, there is a very strange phenomenon taking place in the output levels of electric transmission. In 1990 there is actually more transmission in the reduced demand case (CEDMD) than there was in the corrected base case (CBC), 173

TABLE 2

Comparison of Electric Generation Capacities in 1985, 1990, 1995 for Corrected Base Case (CBC) and Corrected Demand Down by 10% (CEDMD)

	Coal	Comb. Cycle	Oil/Gas Steam	Oil/Gas Turbine	Nuclear	Hydro
Use of Existing Plants						
CBC 1985	197.9	2.7	145.6	37.4	37.2	65.8
CEDMD 1985	197.9	2.7	128.5	27.2	37.2	65.4
CBC 1990	197.9	2.7	121.3	28.7	37.2	66.4
CEDMD 1990	197.9	2.7	104.8	26.6	37.2	66.1
CBC 1995	197.9	2.7	78.9	33.9	37.2	66.7
CEDMD 1995	197.9	2.7	70.0	34.1	37.2	66.5
Build New Plants						
CBC 1985	110.7	2.1	0	38.0	61.3	18.6
CEDMD 1985	86.8	2.1	0	19.1	61.3	18.5
CBC 1990	231.7	2.1	0	32.2	130.1	21.4
CEDMD 1990	178.2	2.1	0	18.4	130.1	21.2
CBC 1995	381.8	2.0	0	41.1	192.8	22.8
CEDMD 1995	299.8	2.0	0	28.7	191.5	22.6

versus 167 x 10^9 kWh. In the uncorrected version of the model, in 1990 the transmission goes down with the demand decrease. Thus the verification corrections have caused a reversal in the effects of the results of this demand perturbation.

Another surprising result is that in 1985 there is a great deal more coal moved from the East to the West in the reduced demand scenario (CEDMD), 4.26 x 10^9 ton-miles, than there is in the Corrected Base Case (CBC), 3.23 x 10^9 ton-miles. The same effect occurs in 1990. This deserves further discussion because one would expect that the reduction of demand would generally leave a more desirable subset of the previous activities. Briefly, the reason this is not taking place is because coal plant build activities in certain regions (where there are relative cost advantages to building coal plants compared to neighboring regions) are significantly constrained by exogenously imposed upper bounds. In the decreased demand scenario, where fewer coal plants are needed to meet electricity demands within these regions, there is additional coal plant capacity available to serve neighboring regions. Thus, the new coal plant capacity activity levels (in these particular regions) will still be at their upper bounds and there will be a net increase in the interregional electricity transmission activity levels. An example of one of these selected regions is the entire West South Central aggregation, which only drops 2% in its coal build activities with the 10% drop in demand, and 8% of additional capacity is used for electricity transmission to neighboring regions.

The energy demand increase of 10%--the EDMU run--resulted in an infeasible solution in 1985, that is to say, the opportunity set in the EDMU-85 activity space was void. Unfortunately, the only CEUM report that results from an infeasible run is the LP report for the nearest-to-feasible solution. This report showed that there was only one constraint equation that could not be met. Upon examining the LP report we could not find any place where this constraint equation was identified. So we can only speculate that the unsatisfied constraint equation was the equation that matches baseload demand and baseload supply for electrical energy in 1985 in one of the utility demand regions. This speculation is based upon the fact that this was also the source of the original infeasibility in the no transmission (NOTX) run, and it is based upon our understanding that the tightest constraints in the CEUM are on baseload supply. In the audit phase of the project, the NOTX infeasibility was eliminated by allowing oil/gas turbines to operate in the baseload mode. The fact that the CEUM in its original form does not allow baseload operation of oil/gas turbines, even in emergency situations, is somewhat bothersome, and perhaps suggests that turbines were coded out of baseload possibilities because they were displacing some other more important baseload energy suppliers. If this is not the case, then the several lines of code that specifically exclude oil/gas turbines from baseload operation should be deleted.

With the failure of the 10% demand increase run, a 5% demand increase run (EDMI) was implemented. The results of some of the EDMI capacity expansion activities are shown in Table 3. There are some interesting results; in particular, 1985 existing hydro, 1995 existing oil/gas steam, and 1990 and 1995 existing oil/gas turbine and existing combined cycle capacities actually decrease with the EDMI increases in demand! The explanation for this effect begins by noting the tremendous new turbine activity in 1985, caused by the short-term dislocations and

TABLE 3

Comparison of Electric Generation Capacities in 1985, 1990, 1995 for Corrected Base Case (CBC) and Corrected Demand Increase by 5% (EDMI)

	Coal	Comb. Cycle	Oil/Gas Steam	Oil/Gas Turbine	Nuclear	Hydro
Use of Existing Plants						
CBC 1985	197.9	2.7	145.6	37.4	37.2	65.8
EDMI 1985	197.9	2.7	149.0	40.0	37.2	65.0
CBC 1990	197.9	2.7	121.3	28.7	37.2	66.4
EDMI 1990	197.9	2.6	122.2	26.5	37.2	66.5
CBC 1995	197.9	2.7	78.9	33.9	37.2	66.7
EDMI 1995	197.9	2.6	76.3	30.8	37.2	66.7
Build New Plants						
CBC 1985	110.7	2.1	0	38.0	61.3	18.6
EDMI 1985	119.0	2.1	0	59.8	61.3	18.7
CBC 1990	231.7	2.1	0	32.2	130.1	21.4
EDMI 1990	261.5	2.1	0	46.7	130.1	21.5
CBC 1995	381.8	2.0	0	41.1	192.8	22.8
EDMI 1995	424.6	2.0	0	56.7	192.8	22.9

the short-term rigidity of other capacity types. In 1990 and 1995 the intertemporal constraints then force the building of all these new turbines, which displace the use of existing peaking capacities.

Aside from that peculiarity, the EDMI results seem to be as one would expect. The brunt of the increased electrical demand is met by new baseload and intermediate coal capacity and new seasonal and daily peaking turbines, as described in the heuristic flowchart given in Figure 12 of Volume V, Chapter 1. East-to-West coal transportation in ton-miles decreased by 25% in 1990; however, the actual numbers are quite small, and the result seems explicable in terms of Eastern coal 'surpluses' that do not exist in the EDMI scenario.

The implication of the demand changes on the objective function (see Figure 1) is a magnification of effects. That is, in 1985 the 10% demand decrease causes about a 16% drop in the objective function, which indicates that the model is closely constrained from above on many of its key activities. The infeasibility of the 10% demand increase run somewhat substantiates the conclusion that many of the model's outputs are inflexible due to direct or imbedded upper-bound constraints. The implication of the nearly linear shape of the curves in Figure 1 is discussed further in Volume V, Chapter 1.

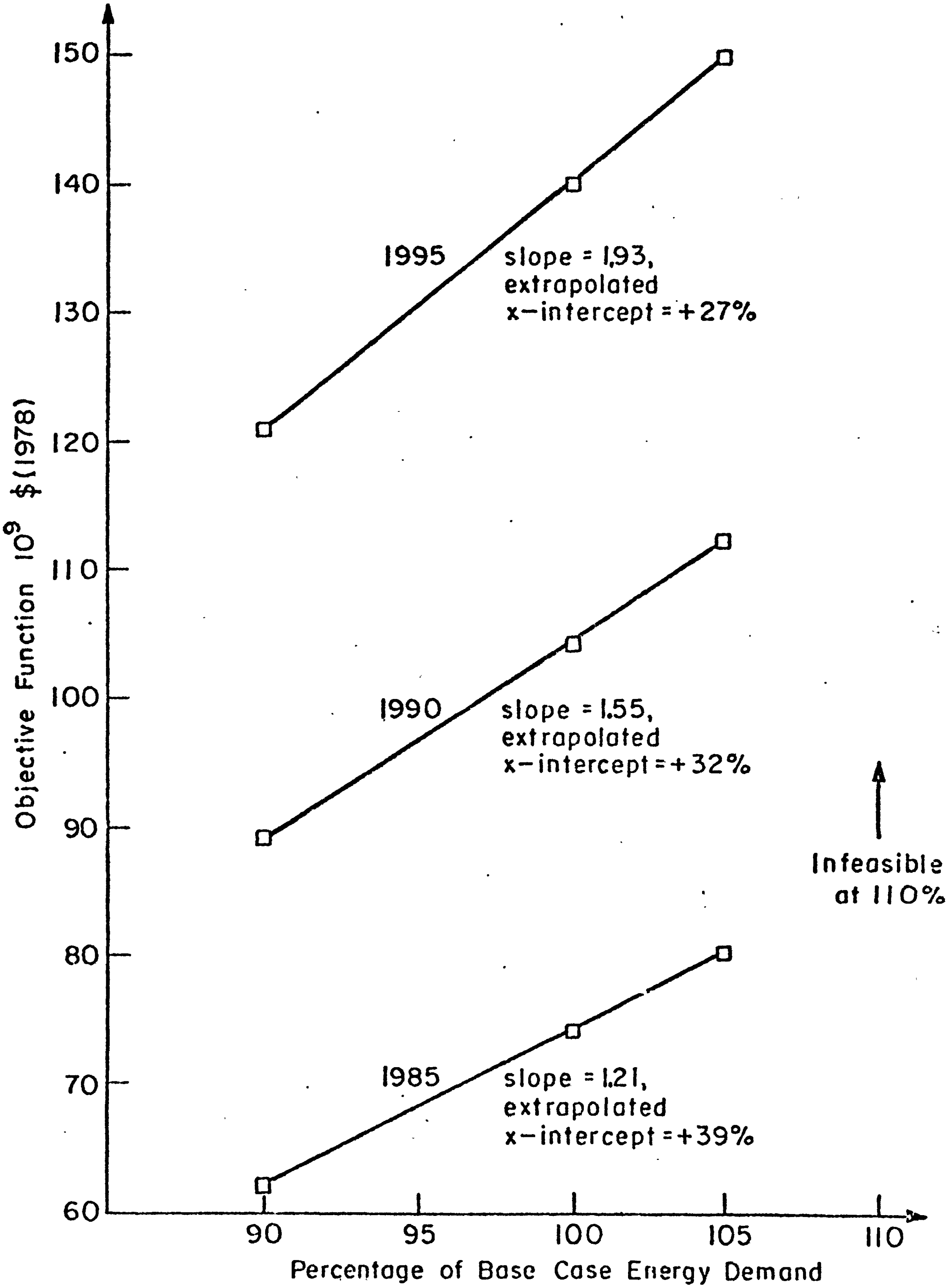

Figure 1. Effect of Energy Demand Changes on the Objective Function for the Corrected Version of the Full Model.

CHAPTER 2. SIMPLIFICATION OF THE MODEL USING A DERIVED DEMAND CURVE*

An attempt has been made to create a simplified representation of the coal demand side of the CEUM. The objective of this activity was to create a simple family of functions that would approximate the implicit demand curves of the CEUM so supply-side experiments could be conducted and easily checked for approximate full-model ramifications.

In the first derived demand curve, the Base Case alone was used for information. As can be seen from Figure 1, there are a considerable number of times in the Base Case where the supply activity levels are on the rises of the steps of the individual coal-type supply curves. Figure 2 shows the relatively fewer times that the activity levels are on the top of the supply curve steps.

It would seem that this information, plus the known lengths of the rises and tops of each supply curve step, could be used to derive a simplified surrogate for the demand side of the CEUM. Suppose, for example, that there is a single uniform-stepped supply curve, and that activities are three times as common on the rises as on the tops (see Figure 3). Intuitively, one would expect that the demand curves that intersect these supply curves are generally of rather shallow slope. In fact, if the slope of the demand curves is uniform, then it probably averages -.33. Where the supply curve steps are not of unit height and width, the frequency of intersection must be divided by the respective lengths of the intercepted segments.

Complications with this technique arise with uneven lengths of rises and tops of the supply curves. There is no obvious advantage to either the

*This chapter was prepared by James Gruhl, with computer support provided by Michael Manove.

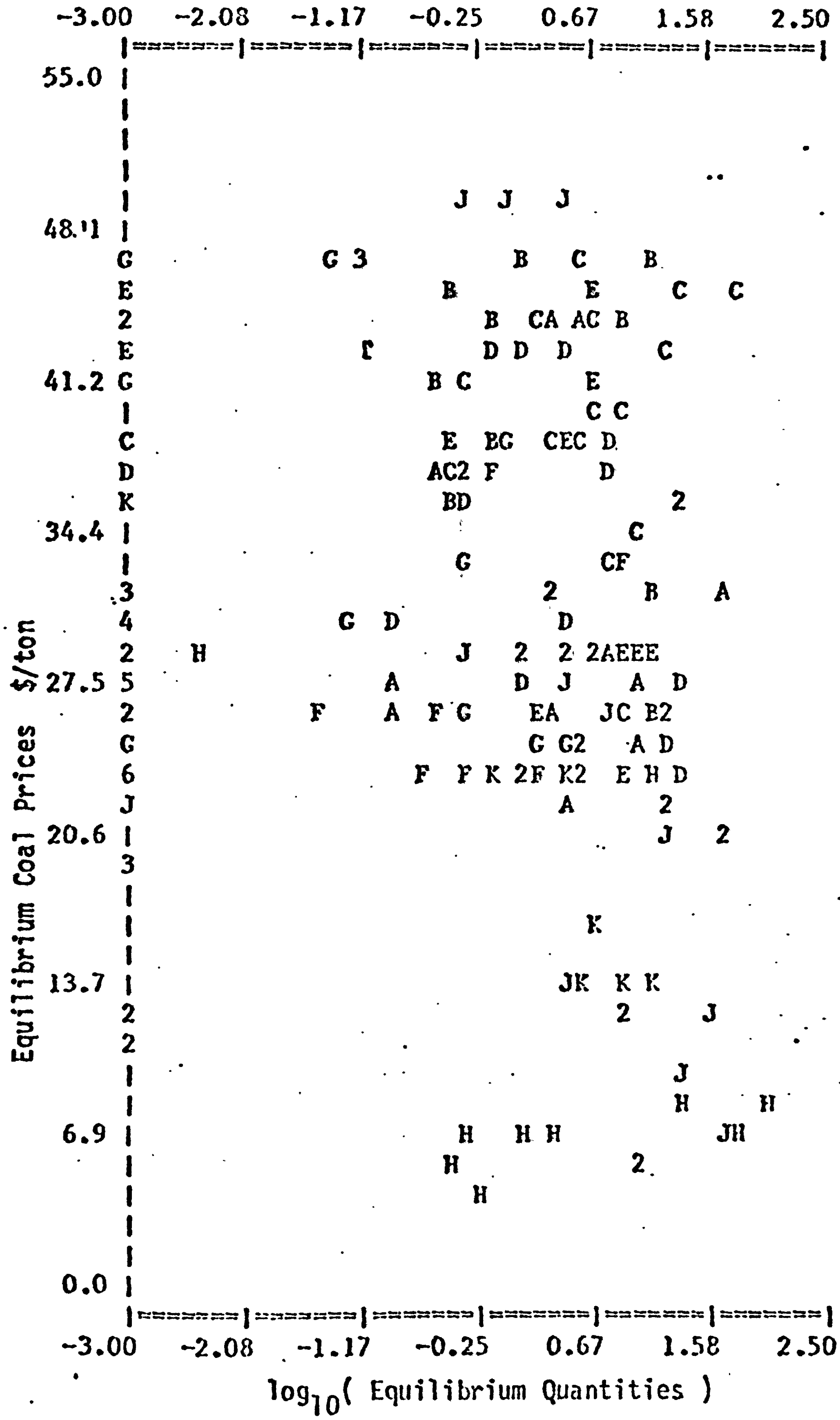

Figure 1. Scatterplot of Points in the Base Case Solution Where Demand Curves Intersect the Rises of the Steps in the Individual Mine Supply Curves.

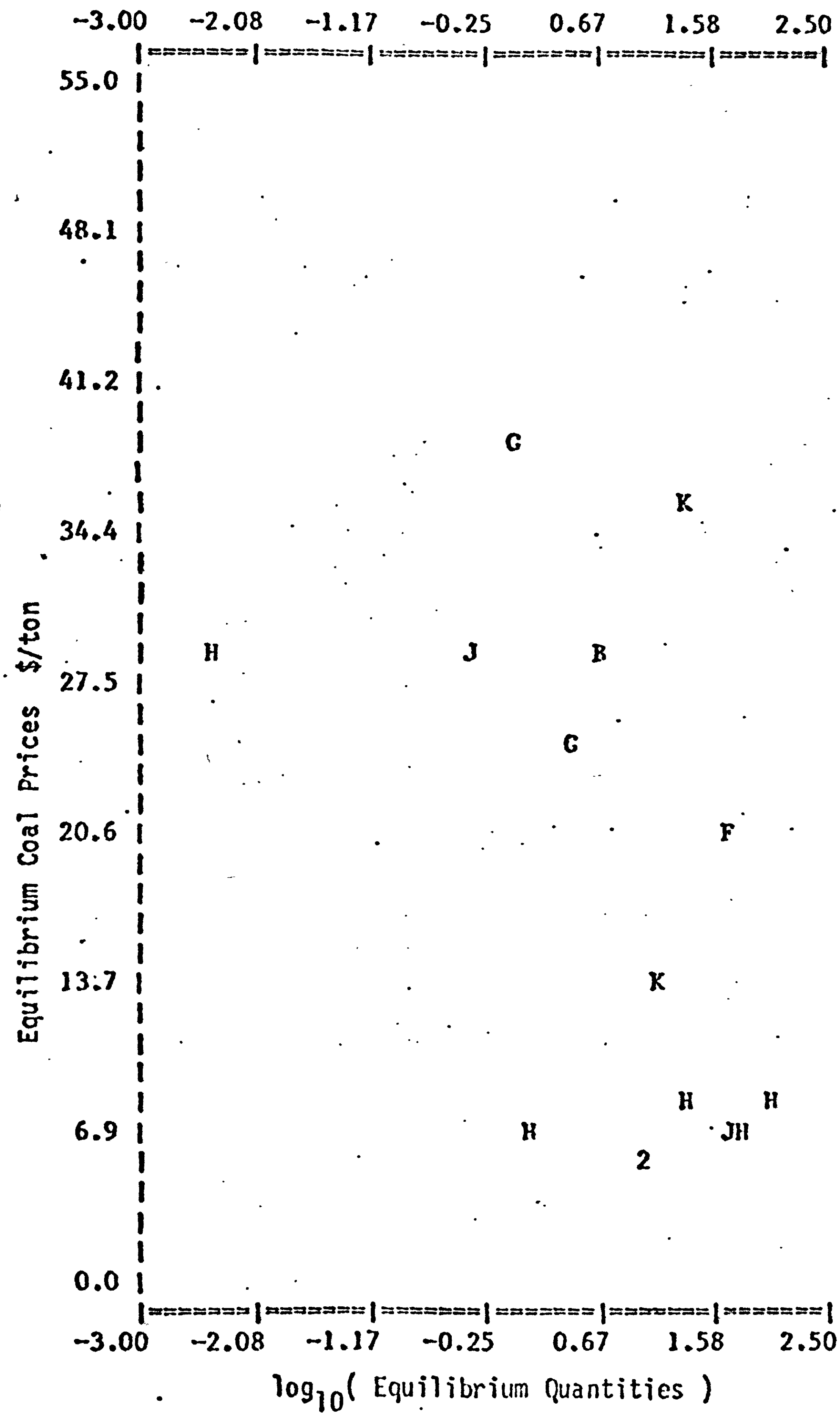

Figure 2. Scatterplot of Points Where Demand Curves Intersect the Top of the Supply Curve Steps.

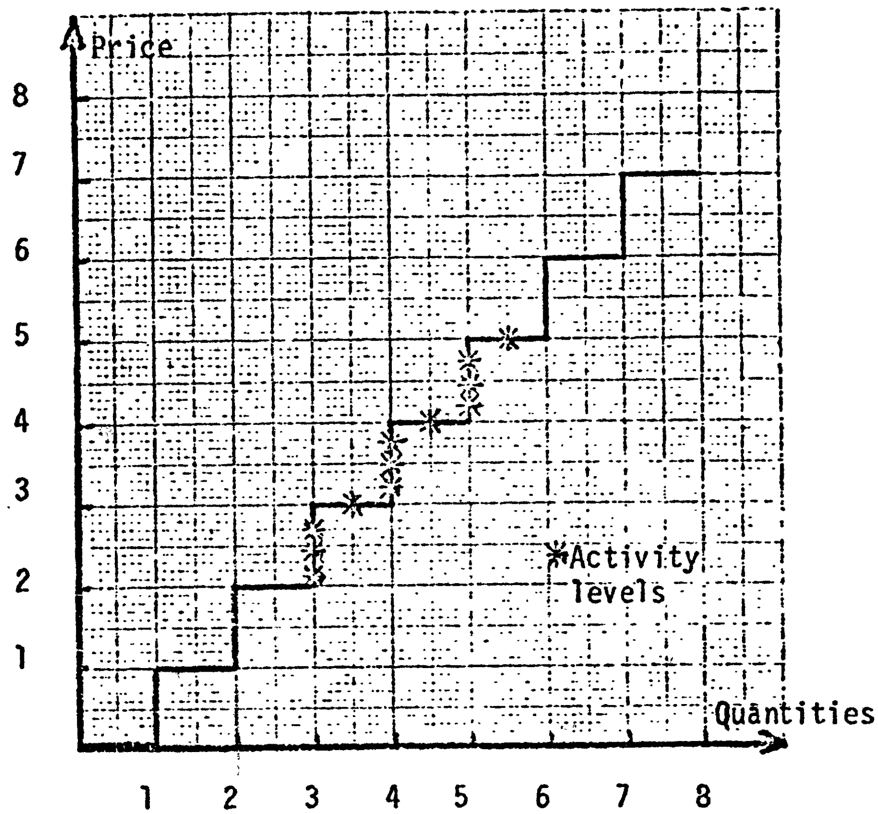

Figure 3. Activity Levels on the Rises and Tops of a Hypothetical Supply Curve.

use of averages or medians of the intersected segments. Average values are used here only because these produced better eventual results. In this case, the formula for computing the slope of the demand curve is:

$$\text{slope} = -\frac{f(t)/s(t)}{f(r)/s(r)} ,$$

where:

- $f(t)$ = the number of times the demand curve intersects a supply curve on the TOP of a supply curve step,
- $f(r)$ = the number of intersections on the RISE of a supply curve step,
- $s(t)$ = the average size of TOPs that are intersected,
- $s(r)$ = the average size of the RISEs that are intersected.

In this exercise, the activities in Figure 1 have been divided into six different regions, and the derived demand slopes at the centerpoints of these regions were computed using the slope formula, with the results as follows:

prices/quantities	0.3	13.0 (10^6 tons/yr)
42	-2.813	-2.578
26	-1.099	-0.749
10	-0.175	-0.102
($/ton)		

Ideally, one would expect that these slopes would fit a family of constant elasticity demand curves:

$$\frac{dp}{dq} = -c \frac{p}{q} ,$$

where:

- p = price,
- q = quantity,
- c = reciprocal of demand elasticity.

There is, however, no constant c that will provide a reasonable fit to the six demand curve slopes. Several possible reasons for this failure to find a single-parameter characterization of demand curves are:

1. There has been no differentiation between different Btu contents of the coals,

2. There has been no differentiation between different sulfur levels of the coal,

3. Cross-elasticities are ignored, and

4. Regional and transportation differences have not been accounted for.

In the absence of a constant elasticity family of demand curves, an additional parameter was added, it being in the form of a quantity displacement, q_o, so:

$$\frac{dp}{dq} = -c \frac{p}{(q-q_o)} \quad ,$$

and an excellent fit (R^2 = .83) to the slopes of the six regions resulted:

$$c = 4.85, \text{ and}$$

$$q_o = 82.7$$

The family of curves represented by this two-parameter derived demand function is shown in Figure 4.

Rounding the slope to 5 and the displacement to 80, this derived demand curve was tested against the full model. The verification corrections were made in the supply sector of the CEUM, and the actual price and quantity levels from the full model run were compared to those from the derived demand curve. The success was limited (see Tables 1 to 3). Efforts were begun to provide derived demand curves for each of the different coal types. The results were very unsatisfactory, in that there were no good constant elasticity fits to date derived from several model runs. Further improvements of the derived demand curve would, therefore, have to come from modeling regional and cross-elasticity effects.

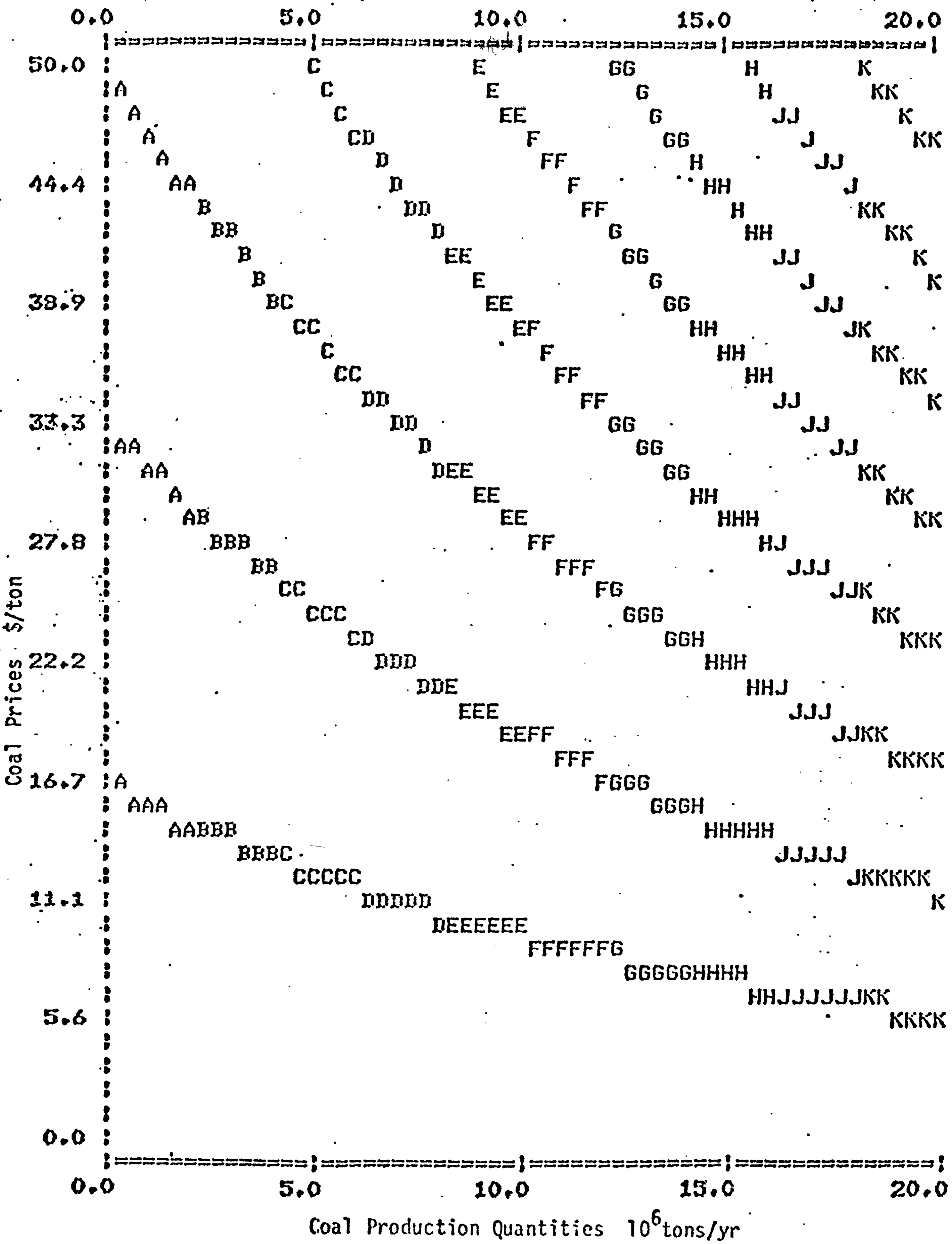

Figure 4. Family of Demand Curves Representing the Simulation of the Demand Situation in the Base Case Full-Model Solution.

TABLE 1

Comparison of the Deviation Indexes for Changes in Coal Supply and Price by State in 1985; Chart on Left is Base Case versus Full Model Corrected Base Case; Chart on Right is Base Case versus Derived Demand Curve Simulation of Corrected Base Case.

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26271	0.044	0.028

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
23938	0.026	0.019

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2603	0.058	0.033
OH	895	0.000	0.040
MD	52	0.266	0.033
NV	1605	0.119	0.032
SV	5335	0.033	0.011
VA	876	0.025	0.014
EK	2228	0.091	0.014
TN	154	0.000	0.018
AL	751	0.065	0.025
IL	3841	0.023	0.037
IN	798	0.052	0.036
WK	1020	0.000	0.039
IA	10	0.000	0.038
MO	75	0.000	0.050
KS	12	0.000	0.040
OK	73	0.087	0.062
AR	52	0.508	0.261
ND	123	0.000	0.035
SD	12	0.000	0.035
EM	2	0.000	0.048
WM	1153	0.059	0.032
WY	2201	0.043	0.032
CS	696	0.036	0.028
UT	752	0.000	0.046
AZ	96	0.000	0.036
NM	372	0.019	0.035
WA	52	0.000	0.018
TX	393	0.000	0.034
CN	39	0.000	0.021
AK	0	0.000	0.000

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2201	0.031	0.021
OH	838	0.017	0.006
MD	24	0.266	0.005
NV	1509	0.068	0.026
SV	4876	0.013	0.013
VA	575	0.022	0.004
EK	1668	0.021	0.011
TN	85	0.000	0.000
AL	682	0.034	0.008
IL	3840	0.023	0.035
IN	792	0.037	0.010
WK	1007	0.000	0.000
IA	7	0.000	0.000
MO	59	0.041	0.006
KS	12	0.000	0.000
OK	69	0.051	0.002
AR	47	0.285	0.013
ND	123	0.090	0.035
SD	12	0.006	0.001
EM	2	0.005	0.000
WM	1153	0.013	0.031
WY	2201	0.027	0.028
CS	696	0.053	0.007
UT	507	0.021	0.015
AZ	96	0.015	0.007
NM	372	0.025	0.018
WA	52	0.000	0.000
TX	393	0.016	0.035
CN	39	0.000	0.000
AK	1	0.000	0.000

TABLE 2

Comparison of Base Case and Corrected Base Case on a Coal-Type by Coal-Type Basis Using the Deviation Index (for comparison with Table 3).

COMPARISON RUN
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1985.

NUMBER OF SUPPLY CURVES = 191

REG	TYPE	BASE EQLBRM		NEW EQLBRM		DEVIATIONS	
		Q	P	Q	P	Q	P
PA	ZB	2.008	44.36	2.308	44.72	0.149	0.008
PA	ZC	0.000	0.00	0.000	0.00	0.000	0.000
PA	ZD	3.782	44.36	4.082	44.72	0.079	0.008
PA	ZE	0.400	36.46	3.520	36.80	7.800	0.009
PA	ZF	46.886	30.96	46.886	32.07	0.000	0.036
PA	ZG	2.536	28.91	2.136	29.93	-0.158	0.035
PA	HD	0.276	37.72	0.276	38.37	0.000	0.017
PA	HE	0.000	30.36	0.000	30.96	0.000	0.020
PA	HF	8.994	27.67	8.994	28.69	0.000	0.037
PA	HG	19.485	25.52	19.485	26.45	0.000	0.036
PA	HH	1.965	25.52	1.965	26.45	0.000	0.036
OH	ZG	0.109	26.91	0.109	27.91	0.001	0.037
OH	HF	5.600	29.32	5.600	30.32	0.000	0.034
OH	HG	11.291	24.16	11.291	25.09	0.000	0.038
OH	HH	3.911	24.04	3.911	25.03	0.000	0.041
OH	MF	0.130	26.46	0.130	27.38	0.001	0.035
OH	MG	2.737	21.44	2.737	22.35	0.000	0.042
OH	MH	13.950	21.44	13.950	22.35	0.000	0.042
MD	ZD	0.300	45.82	0.600	46.18	1.000	0.008
MD	ZF	0.000	32.34	0.000	33.37	0.000	0.032
MD	ZG	0.000	29.65	0.000	31.09	0.000	0.049
MD	HD	0.292	35.64	0.292	36.25	0.000	0.017
MD	HG	1.156	23.80	1.156	25.02	0.000	0.051
NV	ZA	1.241	46.13	1.241	46.63	0.000	0.011
NV	ZB	8.595	44.28	10.445	44.64	0.215	0.008
NV	ZC	0.000	44.28	0.000	44.64	0.000	0.008
NV	ZD	0.733	44.28	0.733	44.64	0.000	0.008
NV	ZF	14.712	31.48	12.712	32.60	-0.136	0.036
NV	ZG	4.645	28.27	4.645	29.69	0.000	0.050
NV	HB	0.282	40.91	0.202	41.26	-0.283	0.009
NV	HD	0.643	38.66	0.643	39.78	0.000	0.029
NV	HE	1.920	31.22	1.691	32.26	-0.119	0.033
NV	HF	4.531	29.07	3.331	30.11	-0.265	0.036
NV	HG	12.119	25.74	12.119	27.07	0.000	0.052
SV	ZA	12.709	47.22	12.709	47.74	0.000	0.011
SV	ZB	61.278	45.29	63.378	45.66	0.034	0.008
SV	ZD	20.336	45.29	20.936	45.66	0.030	0.008
SV	ZE	0.320	37.32	0.560	37.66	0.750	0.009
SV	ZF	9.357	33.69	8.557	34.84	-0.085	0.034

Table 2. (continued)

SV	HB	8.435	40.47	8.005	41.05	-0.051	0.014
SV	HD	4.705	39.41	4.705	40.07	0.000	0.017
SV	HG	7.079	26.09	7.079	26.64	0.000	0.021
VA	ZA	3.436	47.09	3.436	47.61	0.000	0.011
VA	ZB	4.773	44.76	4.773	45.33	0.000	0.013
VA	ZC	0.000	44.67	0.000	45.24	0.000	0.013
VA	ZD	1.423	44.67	1.423	45.24	0.000	0.013
VA	ZE	0.000	0.00	0.000	0.00	0.000	0.000
VA	ZF	5.930	33.11	5.930	33.81	0.000	0.021
VA	HA	0.478	41.19	0.478	41.65	0.000	0.011
VA	HB	3.413	39.11	2.853	39.60	-0.164	0.013
VA	HC	0.000	38.03	0.000	38.55	0.000	0.014
VA	HD	2.312	38.03	2.312	38.55	0.000	0.014
EK	ZB	19.313	43.08	23.513	43.44	0.217	0.008
EK	ZC	0.660	43.08	0.660	43.44	0.000	0.008
EK	ZD	2.950	43.08	2.950	43.44	0.000	0.008
EK	ZE	0.480	35.29	0.480	35.62	0.000	0.009
EK	ZF	2.471	30.76	2.471	31.44	0.000	0.022
EK	ZG	0.000	27.36	0.000	28.01	0.000	0.024
EK	HB	6.351	39.01	6.031	39.35	-0.050	0.009
EK	HC	0.000	37.01	0.000	37.53	0.000	0.014
EK	HD	6.438	37.01	6.198	37.53	-0.037	0.014
EK	HE	0.000	29.71	0.000	30.19	0.000	0.016
EK	HF	20.603	27.63	20.603	28.25	0.000	0.022
EK	HG	3.772	24.41	3.772	24.96	0.000	0.023
TN	ZB	1.178	42.82	1.178	43.37	0.000	0.013
TN	ZC	0.000	44.82	0.000	43.37	0.000	-0.032
TN	ZD	0.095	42.82	0.095	43.37	0.001	0.013
TN	ZF	0.000	31.18	0.000	31.84	0.000	0.021
TN	ZG	0.000	27.80	0.000	28.44	0.000	0.023
TN	HD	0.371	39.01	0.371	39.54	0.000	0.014
TN	HE	0.000	0.00	0.000	0.00	0.000	0.000
TN	HF	1.349	29.49	1.349	30.12	0.000	0.021
TN	HG	1.723	26.22	1.723	26.78	0.000	0.021
AL	ZB	0.000	45.72	0.000	46.29	0.000	0.012
AL	ZD	4.444	45.72	4.744	46.29	0.068	0.012
AL	ZE	0.000	0.00	0.000	0.00	0.000	0.000
AL	ZF	2.120	32.26	2.040	33.39	-0.038	0.035
AL	HB	4.080	40.66	3.280	41.58	-0.196	0.023
AL	HD	2.718	38.26	2.718	39.32	0.000	0.028
AL	HF	7.194	29.17	7.194	30.22	0.000	0.036
IL	HD	24.484	35.86	24.484	36.87	0.000	0.028
IL	HE	11.200	28.65	10.800	29.58	-0.036	0.032
IL	HF	14.676	28.64	14.276	29.58	-0.027	0.033
IL	HG	7.034	23.76	7.034	24.74	0.000	0.041
IL	HH	1.698	23.76	1.698	24.74	0.000	0.041
IL	MF	0.226	25.44	0.226	26.28	0.000	0.033
IL	MG	52.195	20.70	50.595	21.58	-0.031	0.043
IL	MH	44.816	20.70	43.250	21.58	-0.035	0.043
IN	HE	1.200	28.26	1.200	29.17	0.000	0.032

Table 2. (continued)

IN	HG	3.662	24.00	2.062	24.96	-0.437	0.040
IN	HH	0.193	24.00	0.193	24.96	0.001	0.040
IN	MB	0.720	37.10	0.640	38.05	-0.111	0.026
IN	MD	7.360	33.40	7.360	34.34	0.000	0.028
IN	ME	0.000	26.69	0.000	27.56	0.000	0.033
IN	MF	0.032	26.69	0.032	27.56	0.003	0.033
IN	MG	17.581	22.63	17.581	23.54	0.000	0.040
WK	HF	0.116	29.68	0.116	30.68	0.001	0.034
WK	HG	16.118	25.32	16.118	26.30	0.000	0.039
WK	MF	1.401	27.74	1.401	28.68	0.000	0.034
WK	MG	24.123	23.62	24.123	24.55	0.000	0.039
WK	MH	0.000	23.62	0.000	24.55	0.000	0.039
IA	MG	0.000	22.74	0.000	23.61	0.000	0.038
IA	MH	0.461	22.74	0.461	23.61	0.000	0.038
IA	SH	0.000	12.50	0.000	12.85	0.000	0.028
MO	HG	0.000	29.06	0.000	26.76	0.000	-0.079
MO	HH	0.000	30.41	0.000	31.82	0.000	0.046
MO	MG	0.000	25.37	0.000	22.94	0.000	-0.096
MO	MH	3.087	24.36	3.087	25.59	0.000	0.050
KS	ZG	0.000	27.99	0.000	29.11	0.000	0.040
KS	HF	0.000	28.14	0.000	29.18	0.000	0.037
KS	HG	0.485	25.77	0.485	26.81	0.000	0.040
KS	MH	0.000	23.70	0.000	24.90	0.000	0.051
OK	ZA	0.073	46.18	0.000	0.00	-0.999	-1.000
OK	ZB	0.045	46.18	0.045	46.26	0.002	0.002
OK	ZC	0.000	0.00	0.000	0.00	0.000	0.000
OK	ZD	0.065	46.18	0.065	46.26	0.002	0.002
OK	ZE	0.000	0.00	0.000	0.00	0.000	0.000
OK	ZF	0.052	30.33	0.052	31.28	0.002	0.031
OK	ZG	0.000	0.00	0.000	0.00	0.000	0.000
OK	HA	0.000	41.40	0.000	38.69	0.000	-0.065
OK	HB	0.480	37.10	0.400	38.00	-0.166	0.024
OK	HG	1.794	25.30	1.794	25.69	0.000	0.015
OK	MG	0.000	23.24	0.000	23.72	0.000	0.021
AR	ZB	0.000	46.78	0.000	46.26	0.000	-0.011
AR	ZD	0.060	46.78	0.120	46.26	1.002	-0.011
AR	ZE	0.929	38.69	1.200	38.21	0.292	-0.012
AR	ZF	0.395	33.01	0.000	0.00	-1.000	-1.000
ND	LA	1.164	6.30	1.164	6.53	0.000	0.037
ND	LB	0.440	6.30	0.440	6.53	0.000	0.037
ND	LD	9.171	5.80	9.171	6.00	0.000	0.035
ND	LF	9.962	5.80	9.962	6.00	0.000	0.035
ND	LG	0.341	5.80	0.341	6.00	0.000	0.035
SD	LD	1.900	6.32	1.900	6.54	0.000	0.035
SD	LG	0.000	0.00	0.000	0.00	0.000	0.000
EM	LB	0.000	0.00	0.000	0.00	0.000	0.000
EM	LD	0.498	4.60	0.498	4.82	0.000	0.048
WM	MB	0.004	28.39	0.004	29.89	0.025	0.053
WM	MF	0.000	22.96	0.000	23.50	0.000	0.024
WM	MG	0.000	27.42	0.000	29.21	0.000	0.065

Table 2. (continued)

WM	SA	116.268	8.40	120.800	8.67	0.039	0.032
WM	SB	20.969	8.40	17.400	8.67	-0.170	0.032
WM	SF	0.000	19.68	0.000	20.26	0.000	0.029
WY	HB	15.300	26.60	15.300	27.46	0.000	0.032
WY	MB	14.026	23.32	10.826	24.12	-0.228	0.034
WY	MD	17.095	20.80	17.095	21.71	0.000	0.044
WY	MF	0.000	21.48	0.000	22.08	0.000	0.028
WY	MH	0.000	32.01	0.000	34.41	0.000	0.075
WY	SA	38.048	11.90	37.098	12.17	-0.025	0.023
WY	SB	8.220	11.84	8.220	12.10	0.000	0.022
WY	SD	24.272	10.04	24.272	10.32	0.000	0.028
WY	SF	49.630	6.39	50.974	6.61	0.027	0.034
WY	SG	0.000	0.00	0.000	0.00	0.000	0.000
WY	SH	0.000	0.00	0.000	0.00	0.000	0.000
CS	ZA	2.618	48.91	2.689	48.89	0.027	-0.000
CS	ZB	0.980	48.91	0.980	48.89	0.000	-0.000
CS	ZD	0.394	48.91	0.394	48.89	0.000	-0.000
CS	ZF	0.419	29.25	0.419	30.74	0.000	0.051
CS	HA	2.400	28.23	2.400	29.29	0.000	0.038
CS	HB	2.460	26.85	1.660	27.90	-0.325	0.039
CS	HC	0.000	0.00	0.000	0.00	0.000	0.000
CS	HD	6.790	25.70	6.790	26.73	0.000	0.040
CS	HF	0.000	26.57	0.000	27.94	0.000	0.052
CS	MA	3.896	24.29	3.896	25.13	0.000	0.035
CS	MB	2.928	23.02	2.928	23.88	0.000	0.037
CS	MF	0.756	23.51	0.756	24.75	0.000	0.053
UT	HA	0.000	0.00	0.000	0.00	0.000	0.000
UT	HB	20.390	35.25	20.390	36.88	0.000	0.046
UT	HF	0.000	0.00	0.000	0.00	0.000	0.000
UT	SD	0.000	28.55	0.000	30.04	0.000	0.052
UT	SF	1.410	23.79	1.410	25.02	0.000	0.052
AZ	MD	7.437	12.88	7.437	13.34	0.000	0.036
AZ	SF	0.000	18.58	0.000	18.81	0.000	0.012
NM	ZD	0.000	0.00	0.000	0.00	0.000	0.000
NM	HA	0.000	22.72	0.000	23.45	0.000	0.032
NM	HB	0.000	0.00	0.000	0.00	0.000	0.000
NM	HD	0.000	0.00	0.000	0.00	0.000	0.000
NM	MB	4.778	17.20	4.778	17.55	0.000	0.020
NM	MC	13.244	13.27	12.702	13.79	-0.041	0.039
NM	MD	8.579	13.27	8.579	13.79	0.000	0.039
NM	MF	0.000	18.31	0.000	19.94	0.000	0.089
WA	HA	0.000	0.00	0.000	0.00	0.000	0.000
WA	HB	0.000	0.00	0.000	0.00	0.000	0.000
WA	MA	0.000	36.27	0.000	30.07	0.000	-0.171
WA	MB	0.000	0.00	0.000	0.00	0.000	0.000
WA	SA	0.000	0.00	0.000	0.00	0.000	0.000
WA	SD	3.668	14.26	3.668	14.52	0.000	0.018
WA	SG	0.000	12.67	0.000	13.00	0.000	0.026
TX	LF	57.717	6.81	57.717	7.04	0.000	0.034
CN	SA	2.931	13.16	2.931	13.43	0.000	0.021
CN	SD	0.000	11.24	0.000	11.58	0.000	0.030
AK	SA	0.000	10.32	0.000	0.00	0.000	-1.000

TABLE 3

Comparison of the Base Case and the Corrected Base Case that Has Been Simulated Using the Derived Demand Curves; Shown on a Coal-Type by Coal-Type Basis Using the Deviation Index for Comparison

SENSITIVITY ANALYSIS
ASYMPTOTIC DEMAND ELASTICITY = 0.200 DISPLACEMENT = 80.0
BASE ID: RAMC OUTPUT WITH 30-YEAR MINELIFE, 7-79.
RUN ID: MIT-CORRECTED RAMC OUTPUT, 30-YEAR MINELIFE, 7-30-79.

NUMBER OF SUPPLY CURVES = 170

REG	TYPE	BASE EQLBRM		NEW EQLBRM		DEVIATIONS	
		Q	P	Q	P	Q	P
PA	ZB	1.683	44.36	1.810	44.02	0.076	-0.008
PA	ZD	2.937	44.36	3.066	44.02	0.044	-0.008
PA	ZE	0.400	36.46	1.017	35.09	1.542	-0.037
PA	ZF	43.693	30.96	42.937	31.92	-0.017	0.031
PA	ZG	2.027	28.91	1.610	29.66	-0.205	0.026
PA	HD	0.195	37.72	0.195	37.72	0.000	0.000
PA	HE	0.000	30.36	0.000	30.36	0.000	0.000
PA	HF	6.356	27.67	6.356	27.67	0.000	0.000
PA	HG	13.770	25.52	13.770	25.52	0.000	0.000
PA	HH	1.389	25.52	1.389	25.52	0.000	0.000
OH	ZG	0.096	26.91	0.096	26.91	0.000	0.000
OH	HF	5.600	29.32	5.127	30.14	-0.084	0.028
OH	HG	11.184	24.16	11.184	24.16	0.000	0.000
OH	HH	3.443	24.04	3.443	24.04	0.000	0.000
OH	MF	0.114	26.46	0.114	26.46	0.000	0.000
OH	MG	2.409	21.44	2.409	21.44	0.000	0.000
OH	MH	12.280	21.44	12.280	21.44	0.000	0.000
MD	ZD	0.300	45.82	0.442	45.42	0.472	-0.009
MD	ZF	0.000	32.34	0.000	32.34	0.000	0.000
MD	ZG	0.000	29.65	0.000	29.65	0.000	0.000
MD	HD	0.082	35.64	0.082	35.64	0.000	0.000
MD	HG	0.325	23.80	0.325	23.80	0.000	0.000
NV	ZA	1.018	46.13	1.018	46.13	0.000	0.000
NV	ZB	8.450	44.28	8.667	43.74	0.026	-0.012
NV	ZC	0.000	44.28	0.000	44.28	0.000	0.000
NV	ZD	0.601	44.28	0.601	44.28	0.000	0.000
NV	ZF	14.656	31.48	13.820	32.91	-0.057	0.045
NV	ZG	4.440	28.27	3.718	29.51	-0.163	0.044
NV	HB	0.260	40.91	0.180	41.11	-0.308	0.005
NV	HD	0.542	38.66	0.462	38.85	-0.148	0.005
NV	HE	1.920	31.22	1.391	32.25	-0.275	0.033
NV	HF	4.364	29.09	3.569	30.50	-0.182	0.049
NV	HG	9.942	25.74	9.942	25.74	0.000	0.000
SV	ZA	10.680	47.22	10.680	47.22	0.000	0.000
SV	ZB	57.325	44.26	57.801	43.50	0.008	-0.017
SV	ZD	19.559	45.29	19.575	45.25	0.001	-0.001
SV	ZE	0.320	37.32	0.400	37.13	0.250	-0.005
SV	ZF	8.617	33.69	7.817	35.25	-0.093	0.046

Table 3. (continued)

IN	HG	3.661	24.00	2.902	25.12	-0.207	0.047
IN	HH	0.189	24.00	0.189	24.00	0.000	0.000
IN	MB	0.720	37.10	0.640	37.28	-0.111	0.005
IN	MD	7.360	33.40	7.127	33.85	-0.032	0.014
IN	ME	0.000	26.69	0.000	26.69	0.000	0.000
IN	MF	0.031	26.69	0.031	26.69	0.000	0.000
IN	MG	17.330	22.63	17.330	22.63	0.000	0.000
WK	HF	0.114	29.68	0.114	29.68	0.000	0.000
WK	HG	16.057	25.32	16.057	25.32	0.000	0.000
WK	MF	1.374	27.74	1.374	27.74	0.000	0.000
WK	MG	23.650	23.62	23.650	23.62	0.000	0.000
WK	MH	0.000	23.62	0.000	23.62	0.000	0.000
IA	MG	0.000	22.74	0.000	22.74	0.000	0.000
IA	MH	0.306	22.74	0.306	22.74	0.000	0.000
IA	SH	0.000	12.50	0.000	12.50	0.000	0.000
MO	HG	0.000	29.06	0.000	29.06	0.000	0.000
MO	HH	0.000	30.41	0.000	30.41	0.000	0.000
MO	MG	0.000	25.37	0.000	25.37	0.000	0.000
MO	MH	2.431	24.36	2.332	24.51	-0.041	0.006
KS	ZG	0.000	27.99	0.000	27.99	0.000	0.000
KS	HF	0.000	28.14	0.000	28.14	0.000	0.000
KS	HG	0.485	25.77	0.485	25.77	0.000	0.000
KS	MH	0.000	23.70	0.000	23.70	0.000	0.000
OK	ZA	0.068	46.18	0.068	46.18	0.000	0.000
OK	ZB	0.042	46.31	0.042	46.31	0.000	0.000
OK	ZD	0.060	46.18	0.060	46.18	0.000	0.000
OK	ZF	0.048	30.33	0.048	30.33	0.000	0.000
OK	HA	0.000	41.40	0.000	41.40	0.000	0.000
OK	HB	0.480	37.10	0.385	37.32	-0.198	0.006
OK	HG	1.663	25.30	1.663	25.30	0.000	0.000
OK	MG	0.000	23.24	0.000	23.24	0.000	0.000
AR	ZB	0.000	46.78	0.000	46.78	0.000	0.000
AR	ZD	0.060	46.78	0.120	46.61	1.000	-0.004
AR	ZE	0.929	38.69	1.200	38.05	0.292	-0.016
AR	ZF	0.237	33.01	0.237	33.01	0.000	0.000
ND	LA	1.163	6.30	0.565	6.54	-0.514	0.038
ND	LB	0.440	6.30	0.440	6.30	0.000	0.000
ND	LD	9.168	5.80	8.542	6.01	-0.068	0.036
ND	LF	9.958	5.80	9.326	6.01	-0.063	0.036
ND	LG	0.341	5.80	0.341	5.80	0.000	0.000
SD	LD	1.900	6.32	1.889	6.32	-0.006	0.001
EM	LD	0.498	4.60	0.498	4.60	0.000	0.000
WM	MB	0.000	28.39	0.000	28.39	0.000	0.000
WM	MF	0.000	22.96	0.000	22.96	0.000	0.000
WM	MG	0.000	27.42	0.000	27.42	0.000	0.000

Table 3. (continued)

SV	HB	8.286	40.47	7.949	41.25	-0.041	0.019
SV	HD	3.954	39.41	3.954	39.41	0.000	0.000
SV	HG	5.949	26.09	5.949	26.09	0.000	0.000
VA	ZA	1.890	47.09	1.890	47.09	0.000	0.000
VA	ZB	3.755	44.76	3.755	44.76	0.000	0.000
VA	ZC	0.000	44.67	0.000	44.67	0.000	0.000
VA	ZD	0.783	44.67	0.783	44.67	0.000	0.000
VA	ZF	3.262	33.11	3.262	33.11	0.000	0.000
VA	HA	0.263	41.19	0.263	41.19	0.000	0.000
VA	HB	2.957	39.11	2.629	39.89	-0.111	0.020
VA	HC	0.000	38.03	0.000	38.03	0.000	0.000
VA	HD	1.272	38.03	1.272	38.03	0.000	0.000
EK	ZB	16.484	43.08	16.838	42.30	0.022	-0.018
EK	ZC	0.660	43.08	0.660	43.08	0.000	0.000
EK	ZD	2.126	43.08	2.126	43.08	0.000	0.000
EK	ZE	0.480	35.29	0.480	35.29	0.000	0.000
EK	ZF	1.582	30.76	1.582	30.76	0.000	0.000
EK	ZG	0.000	27.36	0.000	27.36	0.000	0.000
EK	HB	4.854	39.01	4.555	39.71	-0.062	0.018
EK	HC	0.000	37.01	0.000	37.01	0.000	0.000
EK	HD	4.323	37.01	4.083	37.54	-0.055	0.014
EK	HE	0.000	29.71	0.000	29.71	0.000	0.000
EK	HF	13.190	27.63	13.190	27.63	0.000	0.000
EK	HG	2.415	24.41	2.415	24.41	0.000	0.000
TN	ZB	0.648	42.82	0.648	42.82	0.000	0.000
TN	ZC	0.000	44.82	0.000	44.82	0.000	0.000
TN	ZD	0.052	42.82	0.052	42.82	0.000	0.000
TN	ZF	0.000	31.18	0.000	31.18	0.000	0.000
TN	ZG	0.000	27.80	0.000	27.80	0.000	0.000
TN	HD	0.204	39.01	0.204	39.01	0.000	0.000
TN	HF	0.742	29.49	0.742	29.49	0.000	0.000
TN	HG	0.948	26.22	0.948	26.22	0.000	0.000
AL	ZB	0.000	45.72	0.000	45.72	0.000	0.000
AL	ZD	3.851	44.59	3.928	44.39	0.020	-0.004
AL	ZF	1.916	32.23	1.836	32.39	-0.042	0.005
AL	HB	4.080	40.66	3.665	41.68	-0.102	0.025
AL	HD	2.462	38.26	2.462	38.26	0.000	0.000
AL	HF	6.475	29.17	6.475	29.17	0.000	0.000
IL	HD	24.478	35.87	24.291	36.19	-0.008	0.009
IL	HE	11.200	28.65	10.800	29.29	-0.036	0.022
IL	HF	14.669	28.65	14.269	29.26	-0.027	0.021
IL	HG	7.024	23.79	6.853	24.03	-0.024	0.010
IL	HH	1.686	23.87	1.686	23.87	0.000	0.000
IL	MF	0.224	25.48	0.224	25.48	0.000	0.000
IL	MG	52.158	20.71	50.795	21.81	-0.026	0.053
IL	MH	44.819	20.70	43.519	21.81	-0.029	0.054
IN	HE	1.200	28.26	1.200	28.26	0.000	0.000

Table 3. (continued)

WM	SA	117.426	8.32	116.219	8.58	-0.010	0.031
WM	SB	21.186	8.32	20.567	8.58	-0.029	0.031
WM	SF	0.000	19.68	0.000	19.68	0.000	0.000
WY	HB	15.300	26.60	14.703	27.45	-0.039	0.032
WY	MB	14.026	23.32	13.076	24.53	-0.068	0.052
WY	MD	17.095	20.80	16.921	20.99	-0.010	0.009
WY	MF	0.000	21.48	0.000	21.48	0.000	0.000
WY	MH	0.000	32.01	0.000	32.01	0.000	0.000
WY	SA	38.048	11.90	37.405	12.23	-0.017	0.028
WY	SB	8.220	11.84	8.220	11.84	0.000	0.000
WY	SD	24.272	10.04	23.898	10.22	-0.015	0.018
WY	SF	49.660	6.39	48.773	6.61	-0.018	0.035
CS	ZA	2.618	48.91	2.627	48.88	0.004	-0.000
CS	ZB	0.980	48.91	0.980	48.91	0.000	0.000
CS	ZD	0.394	48.91	0.394	48.91	0.000	0.000
CS	ZF	0.419	29.25	0.003	30.02	-0.993	0.026
CS	HA	2.400	28.23	2.318	28.37	-0.034	0.005
CS	HB	2.460	26.85	1.744	28.05	-0.291	0.045
CS	HD	6.790	25.70	6.672	25.87	-0.017	0.007
CS	HF	0.000	26.57	0.000	26.57	0.000	0.000
CS	MA	3.896	24.29	3.896	24.29	0.000	0.000
CS	MB	2.928	23.02	2.928	23.02	0.000	0.000
CS	MF	0.756	23.51	0.756	23.51	0.000	0.000
UT	HB	13.445	35.25	13.141	35.83	-0.023	0.017
UT	SD	0.000	28.55	0.000	28.55	0.000	0.000
UT	SF	1.410	23.79	1.410	23.79	0.000	0.000
AZ	MD	7.437	12.88	7.322	12.96	-0.015	0.007
AZ	SF	0.000	18.58	0.000	18.58	0.000	0.000
NM	HA	0.000	22.72	0.000	22.72	0.000	0.000
NM	MB	4.778	17.20	4.778	17.20	0.000	0.000
NM	MC	13.239	13.27	12.534	13.78	-0.053	0.039
NM	MD	8.579	13.27	8.579	13.27	0.000	0.000
NM	MF	0.000	18.31	0.000	18.31	0.000	0.000
WA	MA	0.000	36.27	0.000	36.27	0.000	0.000
WA	SD	3.668	14.26	3.668	14.26	0.000	0.000
WA	SG	0.000	12.67	0.000	12.67	0.000	0.000
TX	LF	57.756	6.81	56.820	7.05	-0.016	0.035
CN	SA	2.931	13.16	2.931	13.16	0.000	0.000
CN	SD	0.000	11.24	0.000	11.24	0.000	0.000
AK	SA	0.000	10.32	0.000	10.32	0.000	0.000

CHAPTER 3. INTERREGIONAL ELECTRICITY TRANSMISSION*

A. DESCRIPTION OF ELECTRICAL TRANSMISSION ACTIVITIES

The CEUM attempts to model the effects, costs, associated losses, and capacity limitations of the interregional electrical transmission network of the United States. The attempt is to model the existing transmission grid in terms of equivalent links between selected regions of the 39 utility demand regions. Each link has a yearly energy transfer limit. Losses depend on the characteristics of the link and the amount of yearly energy transferred. The CEUM also allows prespecified new links to be built if the capital expenditures can be justified in terms of the cost savings associated with the energy transfer and/or reductions in losses.

Essentially, the CEUM attempts to replace the EHV (extra-high voltage) transmission grid of the United States with a "transportation-type" model that considers only yearly energy transfers between regions. This transportation-type model is set up to integrate into the overall linear program optimization where coal supply, electricity supply, and electricity demand vary between regions and where interregional energy transfers are desired.

There are 39 demand regions. However, links do not exist in the model between all adjacent regions even though some links exist between regions that are not adjacent. The linear program is allowed to build new transmission links only between regions where the possibility of such a link has been exogenously prespecified.

*This chapter was prepared by Fred C. Schweppe.

B. BEHAVIOR OF ELECTRICAL TRANSMISSION

The electrical transmission grid component of the CEUM is concluded to be invalid. The reasons for this conclusion are summarized below.

The existing transmission line capabilities were obtained from an heuristic (and undocumented) energy balancing procedure applied to state-by-state, source-sink, yearly energy consumption data for 1974. Unfortunately there is no way to justify placing an upper limit on transmission link exchange from historical yearly energy transfers. An existing transfer capability might not have been utilized historically simply because economics did not dictate it. Even more important, in some parts of the country there are sizable seasonable energy transfers that reverse sign, so the actual transmission grid capability for power transfer bears no relationship at all to the annual energy exchange. Thus, the upper limits on existing transmission are invalid.

Line losses for existing lines are computed using Equation (4) from Appendix E of ICF, Inc. (July 1977), where the capacity, voltage, and mileage are determined from Table III-53 on page III-99. Thus, it appears that only one line of the specified voltage class and length is being assumed to exist between regions. This assumption bears no relationship to the reality of the existing interconnected grid. Combination of an explicit engineering formula such as Equation (4) with the assumption of a single line that does not exist is meaningless. Thus, the loss computations are invalid.

New transmission links' capacity requirements/costs are apparently determined by combining surge impedance loading with the idea that only single transmission lines are to be built between regions. As in the case of losses, this combination of explicit engineering formulas with a single line assumption is meaningless. Thus, the new transmission portion of the transmission component is invalid.

The invalidity of the transmission component invalidates any CEUM runs where transmission activities have a major effect on overall results. Unfortunately, the NOTX (No Interregional Transmission of Electricity) run (see Volume VII, Chapter 2) showed that the removal of transmission activities did cause significant changes in outputs of concern. Hence, no past or future CEUM run with important interregional transmission effects included can be considered valid unless an explicit study is made to determine that the explicit conclusions/policy recommendations made from the study are not influenced by the transmission activities.

One case where the invalidity of the transmission component might night affect overall conclusions is:

- o Costs and demand are such that yearly energy transmission is always less than the upper bounds on existing transmission,
- o Losses are not important, and
- o Costs and demand are such that no new transmission is built.

Private communications with ICF personnel indicates that they are now trying to use the CEUM in such a mode.

Private communications were also held with ICF personnel on the whole transmission network modeling problem. Satisfactory answers to the question of how the model was obtained in the first place could not be provided. The person who developed the model had left the company.

A related question is whether it is only the model parameters that invalidate the model or whether the use of an LP-type transportation model structure is also invalid. This is a more difficult question to address. It is the author's personal opinion that, considering the apparent goals of the overall CEUM, an LP transportation structure for the existing system could be satisfactory _if_ the "correct" transfer limits could be specified and reasonable loss formulas provided. However, the specification of such numbers is extremely difficult. For example, Volume II of the _National Power Grid Study_ (see U.S. Department of Energy [September 1979]) contains several studies on the power (as opposed to energy) transfer capability of the existing network. These national grid considerations covered only part of the CEUM transmission network data requirements, but major efforts were required and some disagreement exists on the validity of the results. Thus, even though the invalidity of the transmission network model might be solved if the correct inputs were provided, it must be emphasized that the chosen structure requires input data that apprently do not exist and that could require a very major effort to develop.

CHAPTER 4. ENVIRONMENTAL CONTROLS*

A. GENERATION OF POLLUTION

Detailed descriptions of the CEUM's environmental aspects and the respective equations and data are presented in Volume II, Chapter 4 and in in the appropriate parts of Volume V, Chapter 1. Generally speaking, the environmental aspects of the model include coal 'piles' differing by rank and sulfur content, corresponding physical cleaning and scrubber costs, capabilities for studying strip-mine regulation, "black lung" taxes, and three different state implementation plan (SIP) SO_2 emission levels that can be met.

B. SULFUR DIOXIDE AIR POLLUTION STANDARDS

Although the environmental aspects of the model are strongest in the sulfur cycle, there are still some important problems in this area. First, there are no diseconomies of scale on stack gas scrubbing; this would make investigations of stricter standards suspect. Second, the deep-cleaning of coal seems to be tied to two standards, NSPS and 1% SIP, and different standards would require new categorization of coal sulfur levels. Many air pollution studies must be disaggregated to the county level, with the 3 SIP's per region being too coarse for those investigations. In some cases even county-level disaggregation can be too coarse. The size limitations of the linear programming format make impossible any investigations of the size of these approximation errors and also currently make it impossible to reformulate the model with considerably greater resolution.

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* This chapter was prepared by James Gruhl and Neil L. Goldman.

In addition, there could be problems caused by the lack of emissions standards for industrial sources. There is thus no background pollution computation possible, no variation in the demands for coals of various sulfur contents by sizes or types of industrial facilities, no scrubber limitations that include scrubbers on industrial boilers, and, for instance, cogeneration would look unusually attractive without the environmental restrictions in the industrial sector.

An O&M penalty for existing plants operating in variance of emissions standards was mentioned briefly in ICF, Inc. (July 1977). The model imposes a very high -- 13.5 mills/kwh -- O&M cost for the plants operating in variance. This scheme carries with it no formal predictive capability. The value is set artifically by the user to allow plants to operate in variance at costs above, or below, other sulfur control options, such as deep-cleaning or use of oil/gas turbines. This feature remains unused in all of the CEUM sensitivity runs that we have made or investigated.

The computation in each scenario of the amount of SO_2 released is uncomplicated. The emissions from the different plant types are simply adjusted by multiplying the fraction of sulfur removed by the capacity of scrubbers operated (see Tables 1 to 4). Table 5 shows an example of one of these multiplications. The summary totals of all SO_2 emissions are then shown in Table 6. Except for the demand change sensitivity runs, these values do not change more than about 5%.

Obviously, the greatest changes in the SO_2 emissions will come as a result of changes in the SO_2 standards. Making CEUM sensitivity runs with changes in these standards has been a major ICF activity in response to their contracts with the Environmental Protection Agency

TABLE 1

Scrubber Use on Existing Coal Power Plants (GW)

	1985	1990	1995
CBC	27.0	27.5	28.7
CNSPS	32.7	37.8	47.0
CML20	22.1	22.0	22.4
CEDMD	22.6	23.7	23.7
CMILL	25.6	*	*
CNINC	25.1	28.1	28.3
COILG	23.2	23.9	24.3
UCIN	29.3	33.5	33.3
UDIN	29.9	*	*
LAB3	26.7	28.1	28.6
TCML	21.6	21.8	32.6
LOAD	25.4	28.2	29.7
ROYI	26.7	26.8	30.8
EDMI	24.3	24.6	25.0
UCD4	21.2	21.1	21.7
LABD	19.6	20.0	20.4
LOGN	22.0	22.2	22.2
CDRB	21.9	22.0	22.5
LDC1	26.3	26.8	27.8
NCAP	23.6	25.8	28.2
MOIL	23.2	†	24.2
BC	30.0	32.6	33.7
EDMD	27.8	28.0	28.0
NOTX	23.0	25.0	25.5

* These runs were not made.

† This report was not released to us.

TABLE 2

U.S. NSPS Scrubber Capacity in GW

	1985	1990	1995
CBC	33.9	33.8	36.1
CNSPS	37.0	41.5	42.8
CML20	33.2	33.8	35.9
CEDMD	29.6	32.6	35.5
CMILL	34.4	*	*
CNINC	31.8	32.1	33.9
COILG	34.9	35.1	37.9
UCIN	35.1	32.1	35.3
UDIN	35.1	*	*
LAB3	32.8	34.7	37.5
TCML	32.4	33.1	35.4
LOAD	34.1	34.1	34.7
ROYI	30.8	30.3	34.7
EDMI	34.1	34.0	36.5
UCD4	31.2	31.5	34.3
LABD	30.6	30.7	32.0
LOGN	32.9	32.9	34.9
CDRB	30.0	29.1	32.8
LDC1	33.9	34.2	36.4
NCAP	34.1	33.1	34.8
MOIL	34.9	†	37.2
BC	34.9	34.6	37.5
EDMD	29.7	31.5	36.3
NOTX	29.6	30.9	34.8

* These runs were not made.

† This report was not released to us.

TABLE 3

Scrubber Use on ANSPS Coal Power Plants (GW)

	1985	1990	1995
CBC	29.5	.14E03	.29E03
CNSPS	7.6	29.2	87.9
CML20	30.3	.15E03	.30E03
CEDMD	17.9	96.1	.21E03
CMILL	25.9	*	*
CNINC	26.2	.12E03	.25E03
COILG	37.5	.16E03	.30E03
UCIN	31.8	.17E03	.30E03
UDIN	32.5	*	*
LAB3	27.4	.13E03	.29E03
TCML	29.7	.15E03	.30E03
LOAD	26.6	.14E03	.26E03
ROYI	28.6	.14E03	.29E03
EDMI	35.9	.17E03	.34E03
UCD4	25.3	.11E03	.28E03
LABD	30.8	.16E03	.30E03
LOGN	28.6	.14E03	.29E03
CDRB	29.4	.14E03	.30E03
LDC1	30.1	.14E03	.29E03
NCAP	34.7	.17E03	.34E03
MOIL	37.5	†	.30E03
BC	30.0	.15E03	.29E03
EDMD	18.3	99.0	.21E03
NOTX	21.9	.17E03	.31E03

* These runs were not made.

† This report was not released to us.

TABLE 4

Total Scrubber Use On All U.S. Power Plants (GW)

	1985	1990	1995
CBC	90.4	.20E03	.36E03
CNSPS	77.3	.10E03	.17E03
CML20	85.6	.21E03	.35E03
CEDMD	70.1	.15E03	.27E03
CMILL	85.8	*	*
CNINC	83.1	.18E03	.31E03
COILG	95.6	.22E03	.36E03
UCIN	96.2	.23E03	.37E03
UDIN	97.6	*	*
LAB3	86.9	.19E03	.35E03
TCML	83.7	.21E03	.36E03
LOAD	86.1	.20E03	.33E03
ROYI	86.0	.20E03	.36E03
EDMI	94.3	.23E03	.40E03
UCD4	77.7	.17E03	.34E03
LABD	81.0	.21E03	.35E03
LOGN	83.5	.19E03	.35E03
CDRB	81.3	.19E03	.35E03
LDC1	90.3	.21E03	.35E03
NCAP	92.4	.23E03	.40E03
MOIL	95.6	†	.36E03
BC	94.8	.22E03	.37E03
EDMD	75.8	.15E03	.27E03
NOTX	74.6	.23E03	.37E03

* These runs were not made.

† This report was not released to us.

TABLE 5

U.S. NSPS Plant SO_2 Production (10^3 Tons/Year)

	1985	1990	1995
CBC	2219	2377	2454
CNSPS	2238	2239	2248
CML20	2263	2382	2477
CEDMD	1820	2172	2286
CMILL	2225	*	*
CNINC	2089	2305	2346
COILG	2306	2408	2481
UCIN	2267	2377	2478
UDIN	2265	*	*
LAB3	2099	2163	2234
TCML	2247	2328	2459
LOAD	2184	2348	2404
ROYI	2229	2285	2351
EDMI	2351	2423	2478
UCD4	2178	2285	2443
LABD	2275	2422	2468
LOGN	2337	2351	2362
CDRB	2260	2389	2476
LDC1	2229	2384	2453
NCAP	2320	2445	2501
MOIL	2306	†	2475
BC	2210	2263	2416
EDMD	1798	2090	2225
NOTX	1872	2061	2258

* These runs were not made.

† This report was not released to us.

TABLE 6

U.S. Total Power Plant Production of SO_2 (10^3 Tons/Year)

	1985	1990	1995
CBC	19586	18886	18360
CNSPS	20246	21392	23234
CML20	19679	18887	18615
CEDMD	18224	17793	17417
CMILL	19753	*	*
CNINC	19178	18297	17684
COILG	19449	18684	18120
UCIN	19726	18793	18252
UDIN	19569	*	*
LAB3	19496	18383	17557
TCML	19560	18634	18350
LOAD	19174	18550	18410
ROYI	19566	18331	18325
EDMI	20152	19238	18619
UCD4	19665	19080	18822
LABD	19770	19023	18691
LOGN	19579	18607	17976
CDRB	19718	18898	16232
LDC1	19643	19023	18564
NCAP	20047	19325	18916
MOIL	19449	†	18249
BC	19584	18838	18510
EDMD	18159	17691	17533
NOTX	19026	18213	18220

* These runs were not made.

† This report was not released to us.

(EPA), the Department of Energy (DOE), and the Department of Interior (DOI). It has not been a fruitful assessment activity to examine those model runs that have been the principal focus of the model builder and model sponsors (ICF, EPA, DOE, AND DOI). (This may be a general comment that can be made with regard to any model assessment.) Some brief discussion of the results of these changing standards is, however, in order.

The New Source Performance Standard (NSPS) requires a maximum emission level of 1.2 lb of SO_2 per 10^6 Btu, with scrubbers being optional. The Alternative NSPS (ANSPS) scenarios consist of combinations of floors and ceilings on SO_2 emissions, but with scrubbers mandatory. The ANSPS generally require 85% sulfur removal on a daily basis down to specified floors. Floors are emissions limitations that could be met in place of a percentage removal requirement. (Utilities would not be required to reduce emissions below these floors.) This provision allows for scrubbing at less than the 85% required level, thus allowing for partial scrubbing of SO_2 emissions from coal-fired electrical generating facilities (for further discussion see Volume II, Chapter 4). Floors are to be enforced on a 24-hour average with no violations allowed.

Ceilings are maximum emission rates that cannot be exceeded (on a 24-hour average) unless there are exemptions that permit violations three days a month. Ceilings just determine which coals cannot be burned.

Figures 1 and 2 display some results of ICF, Inc. (September 1978b) studies that have been conducted with regard to the sensitivity of changing the SO_2 standards. In these figures, "with exemptions" means that violations are allowed for three days per month; "without exemptions" means that no

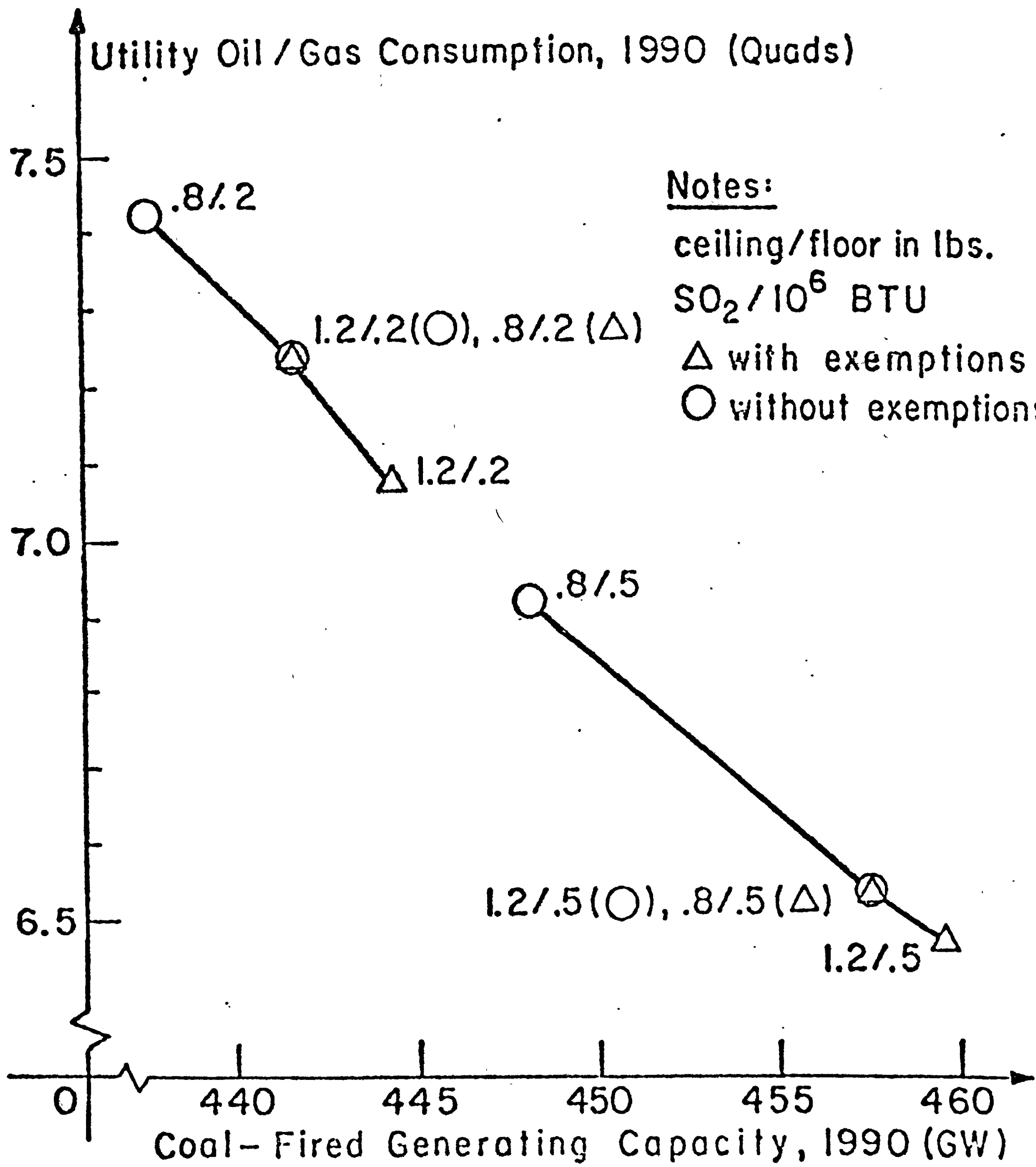
Figure 1

MAPPING OF SENSITIVITY STUDIES

Utility Oil/Gas Consumption

vs

Coal-Fired Generating Capacity



SOURCE: Goldman and Gruhl (January 10, 1979).

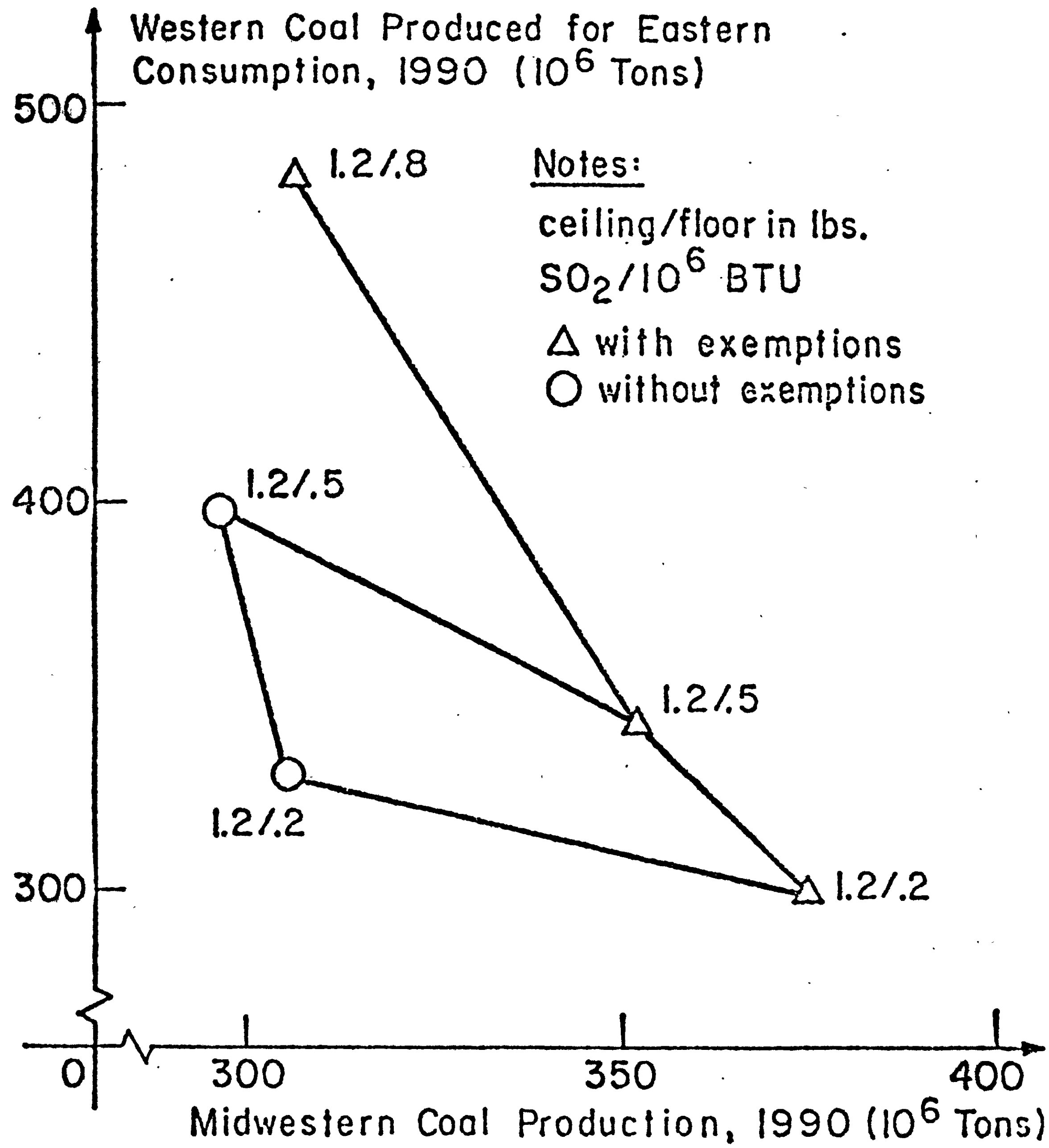
Figure 2

MAPPING OF SENSITIVITY STUDIES

Western Coal Produced for Eastern Consumption

vs

Midwestern Coal Production



SOURCE: Goldman and Gruhl (January 10, 1979).

violations are allowed. As one's intuition would expect, Figure 1 shows a very strong substitution between utility use of oil/gas and utility coal-fired capacity. Oil/gas consumption is greatest for the strictest coal facility emission standard (.8/.2, without) and coal-fired capacity is greatest for the least restrictive standard (1.2/.5, with). Figure 2 shows some interesting effects:

(1) allowing exemptions strongly favors the use of the higher-sulfur Midwestern coals, and

(2) with lower floors even the low-sulfur Western coals require increased scrubbing and lose their relative advantage over Eastern coals.

Some of these results are obvious; some are more interesting. The point is that there has been a great deal of examination of CEUM outputs of sensitivity runs involving changes in SO_2 standards. Fruitful grounds for additional assessment activities in this area might come from reprogramming critical portions of the computer code related to SO_2 standards.

C. OTHER AIR, WATER, AND SOLID EMISSIONS

Particulates and NO_x are potentially binding air pollution standards in much of the country, yet these pollutants do not enter the decision logic of the CEUM. Tables 7 and 8 again show the relatively unperturbability of these emissions.

Water-use limitations can only be imposed as coal supply limitations, and liquid wastes are nowhere constrained. The biggest problems with scrubbers--solid and liquid wastes--are not accounted for in the model. These and any future air standards, such as on trace

U.S. Total Power Plant Production of NO_x (10^3 Tons/Year)

	1985	1990	1995
CBC	7607	8155	9060
CNSPS	7581	7976	8852
CML20	7611	8230	9213
CEDMD	6678	7050	7806
CMILL	7608	*	*
CNINC	7325	7589	8284
COILG	7597	8092	9023
UCIN	7595	8061	8998
UDIN	7593	*	*
LAB3	6954	7284	8209
TCML	7547	7941	8943
LOAD	7295	7850	8764
ROYI	7425	7835	8889
EDMI	7978	8618	9607
UCD4	7597	8192	9137
LABD	7655	8228	9215
LOGN	7535	8004	9215
CDRB	7597	8158	9060
LDC1	7546	8109	9051
NCAP	7898	8633	9701
MOIL	7595	†	9042
BC	7609	8159	9118
EDMD	6681	7068	7850
NOTX	7235	8067	9120

*These runs were not made.

†This report was not released to us.

TABLE 8

U.S. Total Power Plant Production of TSP (10^3 Tons/Year)

	1885	1990	1995
CBC	965	925	921
CNSPS	961	898	888
CML20	964	920	926
CEDMD	860	840	842
CMILL	970	*	*
CNINC	934	879	872
COILG	959	908	909
UCIN	963	903	913
UDIN	962	*	*
LAB3	966	936	928
TCML	964	915	924
LOAD	953	916	949
ROYI	966	921	923
EDMI	1011	958	955
UCD4	969	947	941
LABD	963	915	917
LOGN	969	927	916
CDRB	964	923	919
LDCL	962	923	929
NCAP	999	960	963
MOIL	959	†	912
BC	965	916	920
EDMD	860	835	843
NOTX	940	880	899

* These runs were not made.

† This report was not released to us, or was lost in the mail.

elements, would be difficult to incorporate in the model without a multiplicative (for the most part) size increase, and size is a critical factor in the CEUM.

D. SITING LIMITATIONS

Regional limitations on specific types of sites presently can only be introduced as new capacity building constraints. Modifications might be possible to account for several generic site types. Even with this change, however, attractions of decentralized capacity expansion options would still not be adequately simulated.

E. ALTERNATIVE POLLUTION CONTROLS

New technologies with "built-in" sulfur removal capabilities, such as fluidized bed combustors, could be added to the model format. As discussed in Volume V, Chapter 1, however, their attractiveness would probably necessitate exogenous specifications of capacity levels. Although this would result in no new information on these particular technologies, it would in some way shed light on the control options that would have to take up the slack due to limited availability of these new technologies.

Deep-cleaning of coal (called coal washing in the CEUM output reports) has a somewhat troublesome structural problem in the CEUM formulation. The problem occurs for most of the 'Z' coals (ZA through ZE), the highest Btu category (and five lowest sulfur levels) of bituminous coals. These Z category coals comprise about 70% of the metallurgical coals, and coincidentally about 70% of the Z coals are used for this purpose. If they are to be used metallurgically, these Z coals must be deep-cleaned, but there has not been the structural or constraint formulation within the CEUM to properly force this deep-cleaning. Thus, as a partial fix in the original CEUM, the price of ZA through ZE coals was exogenously increased by the deep-cleaning charges. There are two problems with this: (1) a small fraction of these Z coals are deep-cleaned in the LP and thus deep-cleaning charges are doubly counted for these coals, and (2) the 30% of these coals used by the electric utility sector carry the erroneous exogenous deep-cleaning costs. For additional discussion of this issue, see Point 5 of Volume II, Chapter 5, Section A. If coal washing is to be included in the CEUM, it is important to get the structural changes and the constraints set up so this washing is costed correctly. Properly implementing the deep-cleaning of all metallurgical coals was outside the scope of the assessment project, but two partial corrections were considered. One partial correction would have been to set to zero the deep-cleaning costs imposed in the LP for those Z coals already exogenously charged for deep-cleaning. However, it was decided that a better partial correction would be to omit all exogenously imposed deep-cleaning charges, and thereby allow deep-cleaning to occur only via the linear program. This under-accounts for the total cost of metallurgically used Z coals, but since metallurgical coal demand is specified exogenously, it was decided that the inaccuracies introduced would be relatively unimportant. The utility sector, via our correction, sees the correct total costs for the Z coals, and the appropriate amounts of these coals for utility use are deep-cleaned via the LP. While there was little difference in the BC versus NSPS 1985 coal-washing outputs in the uncorrection version, Table 9 shows that there is a larger difference in the outputs from the corresponding corrected model runs. In fact, it can be seen from Tables 10 and 11 that it is apparently important to get

TABLE 9

U.S. Total Coal Washing (10^6 Tons Input)

	1985	1990	1995
CBC	17.060	17.900	20.784
CNSPS	20.069	33.430	45.667
CML20	5.520	14.047	16.459
CEDMD	9.868	18.338	20.210
CMILL	16.841	*	*
CNINC	16.378	19.527	20.561
COILG	19.111	19.563	20.833
UCIN	14.863	15.277	17.937
UDIN	12.963	*	*
LAB3	2.400	11.899	14.797
TCML	15.556	18.307	17.760
LOAD	16.569	20.438	22.718
ROYI	12.424	14.480	14.968
EDMI	18.665	18.469	20.795
UCD4	19.843	21.836	23.253
LABD	19.086	21.578	24.177
LOGN	15.455	18.400	20.450
CDRB	15.293	19.451	18.580
LDC1	17.129	18.293	20.835
NCAP	18.340	20.377	21.466
MOIL	19.111	16.755	21.569
BC	16.246	21.408	21.903
EDMD	10.976	13.767	19.202
NOTX	13.633	14.876	23.274
NSPS	17.688	*	*

* These runs were not made.

TABLE 10

U.S. Total Coal Washing for ZE→ZD Coals (10^6 Tons Input)

	1985	1990	1995
CBC	5.760	10.880	14.866
CNSPS	6.800	14.400	22.880
CML20	5.520	10.921	11.179
CEDMD	3.289	10.240	11.280
CMILL	5.760	*	*
CNINC	5.409	10.720	12.480
COILG	5.760	10.880	14.805
UCIN	5.466	10.560	11.444
UDIN	4.800	*	*
LAB3	2.400	8.720	10.077
TCML	4.800	10.603	12.480
LOAD	5.600	10.600	13.262
ROYI	4.168	9.680	9.688
EDMI	6.800	11.248	14.877
UCD4	6.000	10.880	15.040
LABD	6.960	11.361	15.796
LOGN	10.000	12.080	14.194
CDRB	7.440	14.842	13.142
LDC1	5.760	10.880	14.863
NCAP	6.571	10.880	12.800
MOIL	5.760	10.880	14.805
BC	2.129	7.408	9.571
EDMD	1.222	5.608	8.750
NOTX	1.539	6.640	11.417
NSPS	3.368	*	*

* These runs were not made.

TABLE 11

U.S. Total Coal Washing for HE→HD Coals (10^6 Tons Input)

	1985	1990	1995
CBC	11.300	7.020	5.918
CNSPS	13.269	19.030	22.787
CML20	0.000	3.126	5.280
CEDMD	6.579	8.098	8.930
CMILL	11.081	*	*
CNINC	10.969	8.807	8.081
COILG	13.351	8.683	6.028
UCIN	9.397	4.717	6.493
UDIN	8.163	*	*
LAB3	0.000	3.179	4.720
TCML	10.756	7.704	5.280
LOAD	10.969	9.838	9.456
ROYI	8.256	4.800	5.280
EDMI	11.865	7.221	5.918
UCD4	13.843	10.956	8.213
LABD	12.126	10.217	8.381
LOGN	5.455	6.320	6.256
CDRB	7.853	4.609	5.438
LDC1	11.369	7.413	5.972
NCAP	11.769	9.497	8.666
MOIL	13.351	5.875	6.764
BC	14.117	14.000	12.332
EDMD	9.754	8.159	10.452
NOTX	12.094	8.236	11.857
NSPS	14.320	*	*

* These runs were not made.

the coal-washing costs corrected, especially when environmental standards are changed, and even for scenarios that result in large changes in the costs of coal.

F. Appropriate Applications

The appropriate applications from the pollution control perspective are discussed in Volume V, Chapter 1, Section G.

CHAPTER 5. THE ROLE OF LONG-TERM CONTRACTS*

The general pattern of enforcement of contracts in common law and more recently under the Uniform Commercial Code seems to respect a rational economic principle: Namely, contracts should act as devices that facilitate the efficient allocation of economic resources but should not be permitted to enforce arrangements that are or have become inefficient. That is why the enforcement of contracts is normally limited to the payment of damages (lost profits) in case of breach, rather than the requirement of specific enforcement of its original provisions.

Consider this example. An electric utility and a coal mining company enter into a contract that requires the mining company to deliver to the utility a million tons of coal per year, for 20 years, at $12 per ton. A number of years later, the mining company discovers that operating costs alone are $18 per ton of coal produced. In addition, it is known that the utility would be able to obtain coal in the requisite amounts from alternative sources at a cost of $14 per ton.

What is the likely outcome of this situation? The mining company could be expected to breach the long-term contract. As a result of the breach, the company would be required to pay damages to the utility equivalent to the additional cost of $2 per ton incurred by the utility. Such damage payments would be a smaller expense to the mining company than

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* This chapter was prepared by Michael Manove.

the alternative of continued production of coal at an operating loss of $6 per ton. Having been fully compensated, the utility would be indifferent to the breach.

That this contract should be breached is desirable from the social as well as from the private point of view. Presumably, the true social cost of the coal used drops from $18 per ton to $14 per ton after the breach. Economic efficiency has increased as a result.

In principle, previously existing contracts do not constrain the allocation of reserves. This line of argument implies that in modeling an economic system such as U.S. coal supply, contracts should not be represented as binding constraints. The ICF model does represent contracts as binding constraints, and we recommend that this be changed. Of course, contracts can affect the distribution of wealth and this may have an indirect effect on the allocation of resources. In addition, the parties to a contract may decide, in marginal cases, to carry out the terms of an inefficient contract rather than to breach and risk costly litigation. Nevertheless, our general conclusion remains unchanged.

CHAPTER 6. ALLOCATION OF RESERVES: THE USE OF A UNIFORM DISTRIBUTION*

Some of the assumptions made in the reserve allocation procedure employed in the CEUM are based on simplifications necessary in a model of this size. However, ICF's use of a uniform distribution to allocate reserves to overburden ratio, seam thickness and depth, and mine size categories appears to be based on convenience. There is some evidence (see Zimmerman [1979]) that for seam thickness at least, a log-normal distribution is more appropriate. With the method currently used by ICF in allocating reserves to mine sizes, there is bound to be a strong correlation between seam thickness and mine size. Hence, any bias in the allocation of seam thickness could have significant effects on the shape of supply curves for coal types in any supply region. The reserve allocation procedure, via uniform distributions, is only applied if data are unknown. Thus, the share of data assigned through the distribution assumption increases over time. The sensitivity of the model to this assumption therefore should rise the further into the future one looks.

What is the model's sensitivity to using different and possibly more empirically justifiable distributions? This issue could be tested by using Zimmerman's (1979) log-normal parameters for seam thickness and letting the mine size distribution follow by applying the procedure currently used by ICF. Credible assumptions on overburden ratios could also be taken from Zimmerman, while those on seam depth for underground mines must await further empirical work.

*This chapter was prepared by Neil L. Goldman.

We constructed a model sensitivity run (LOGN) to test the sensitivity of the CEUM to the seam thickness distribution. The results of allocating coal reserves to seam thickness categories via a log-normal distribution are discussed and displayed in Volume VII, Chapter 2.

CHAPTER 7. BUREAU OF MINES CLASSIFICATION OF RESERVES BY COAL CHARACTERISTICS*

On page III-123 of ICF, Inc. (July 1977), the observation is made that in some cases the FPC Form 423, which identifies contract shipments and coal types shipped, reports coal types being shipped from a region that are not reported in the BOM reserve classification for that supply region. The example mentioned is coal with a heat content of 20-23 MMBtu/ton being shipped from Central Appalachia when BOM's demonstrated reserve base shows no such coal available from that region. ICF provides various explanations for this discrepancy, including: (i) unreported variance of the BOM mean estimates, (ii) upward bias in the characteristics of the samples from which the BOM estimates are made (samples taken from government purchases), and (iii) the influence of coal cleaning, since FPC Form 423 data are obtained on coal actually delivered to utilities. The ICF approach to reconciliation has been to adjust the FPC to the BOM data by moving the unclassified FPC data to the nearest Btu and/or sulfur category.**

The basic issue suggested by the apparent discrepancy between BOM demonstrated reserves and reported production is that costs and actual coal demand required to produce a given level of electricity may be improperly estimated. In particular, if the BOM data overestimate that

*This chapter was prepared by David O. Wood

**As with other data-related issues regarding the CEUM, the ICF, Inc. (July 1977) study provides a lucid, concise statement of the issue, the possible explanations, and the ICF approach to reconciliation.

content and underestimate sulfur content, then coal demand will be underestimated, as will the costs of environmental control. Underestimating environmental control costs for coal-based electric power will tend to overestimate coal's share in power generation, thereby off-setting the downward bias in coal demand.

To determine the potential effect of these biases, it would be necessary to develop new data to reconcile the BOM and FPC data. To our knowledge, no information exists that will permit us to distinguish between the three possible explanations for the discrepancy. As a first step a computational experiment could be constructured, in which reconciliation takes place in the direction opposite from that used by ICF--that is, adjusting the BOM data to the FPC data. Comparing the results of running the model with each data set would provide some indication of the extent of the problem.

CHAPTER 8. COAL TRANSPORTATION*

A. DESCRIPTION

The transportation component of the ICF Coal and Electric Utilities Model (CEUM) transfers coal from coal stocks in supply regions to coal piles in demand regions at a price per ton. The piles in each demand region are identified by rank (bituminous, subbituminous, or lignite) and sulfur level. The cost of transportation, as a per-ton charge, is based upon unit-train or barge shipment rates.

Coal transportation has been modeled with direct links, at a single per-ton charge for each link. Each link keeps track of the flow of a single coal type from one supply region to one demand region. The use of lower bounds on the amount of coal that can be shipped via a specific link forces the model to ship coal between regions regardless of cost. The impact of the lower bounds approximates the effect of existing long-term contracts. The CEUM assumes, via intertemporal constraints, that at least 80% of flows under such contracts will persist over the model's time horizon.

The direct links used to transfer coal from supply to demand regions require three inputs. First, the relevant links are identified. Second, the cost of using each link is estimated. Third, relevant bounds are set for each link. The Bureau of Mines Bituminous Coal and Lignite Distribution - Calendar Year 1973 was used to identify existing coal shipment links.

The logic employed in the CEUM's coal transportation sector seems to be sound as a whole but can be strengthened in a few areas. A discussion

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* This chapter was prepared by Neil L. Goldman.

of several important assumptions made in this sector is given below. The major transportation assumptions are as follows: (1) All rail shipments of coal are by unit-train, (2) rail transportation costs are modeled by a linear equation, (3) both rail and water modes are subject to the same inflation factor, and (4) no future bottlenecks are recognized, and as a result transportation links are never upper bounded.

B. RAIL TRANSPORTATION

Rail haulage costs depend on many factors, including distance, volume, volume of traffic, state of repair of lines, mode of rail transport, and competition from other modes of transportation. Quantifying and modeling these cost-influencing variables would make the model much too complicated. ICF assumes that the most signficant new incremental users of coal will be new coal-burning power plants large enough, in their annual tonnage requirements, to justify the use of unit-trains. However, for the assumption of rail shipments solely by unit-trains to be valid in 1980, existing rail shipping must alter considerably by that time.

The CEUM models rail transportation costs with a linear equation representing a fixed charge per ton of coal shipped and a variable charge per ton-mile. Four sets of values for the fixed charge and variable charge parameters were developed to simulate differences in unit-train costs based on origin and destination of shipment. Such a procedure was followed based on studies by the ICC (December 1974) and Zimmerman (September 1975), which showed that rail costs for a given size coal shipment are significantly influenced by their place of origin and destination. Both of these studies indicated that fixed charges for shipments out of Appalachia tend to be higher than for shipments out of the West or Midwest, and that per-mile variable costs tend to be higher in the West and Midwest than in Appalachia. Regression analyses performed by Zimmerman suggested that shipments originating in the West with destinations east of the Mississippi River tend to have higher fixed charges than shipments from western regions that remain in the West.

The linear equation employed to estimate all freight charges is given by:

$$TC = a + bM$$

where:

TC = total cost in \$/ton over a given route

a = fixed charge in \$/ton

b = variable charge per ton-mile

M = distance in rail miles

ICF mentions that Hutschuler et al. (1973) investigated the use of a parabolic equation to calculate haulage costs by allowing for haul economies as distance increases. This study found that with large volume unit-trains, the parabolic costing model did not produce significant changes from the use of a linear model. ICF decided that the linear costing method would produce adequate results and was sufficient for their purposes.

C. BARGE TRANSPORTATION

The costing of barge links was derived in a straightforward way by use of the <u>Domestic Waterborne Shipping Market Analysis</u> performed by A.T. Kearney, Inc. in 1974. Costs per ton-mile by river and by direction are multiplied by the water mileage between region centroids. In addition, a fixed charge of \$.60 per ton is added for loading and unloading.

The CEUM assumes the same inflation rate for both rail and water transportation. This assumption may not hold true in the future due to differences in fuel efficiency and capital needs. Capital costs for railroads are higher per ton-mile than are those for barges. If the cost of capital increases relative to fuel, the railroads will be more adversely affected than barges. Also, even though water transport tends to be more fuel efficient than rail, fuel costs represent a higher percentage of total cost for barges. Thus, if the inflation rates are not equal, a bias toward the mode with the higher relative inflation rate will have been introduced in the model, i.e., the mode with the higher relative inflation rate will tend to be utilized more in the model than it is in reality.

Another interesting point relates to the addition of the costs of trucking or railing coal from supply centroids to the closest port on the nearest body of water and also from the destinations on water to the demand centroids. A truck rate of \$.06 per ton-mile is used when a centroid is within 77 miles of water in Appalachia, and within 29 miles of water in the Midwest. When ground mileage away from water exceeds these figures, rail rates are used. ICF does not mention how these cut-off figures were determined.

D. SLURRY PIPELINES

In its present version, the CEUM does not allow for slurry pipelines as a mode of transportation. This assumption is certainly reasonable for 1985, and may also be for later target years, since the future of such pipelines is highly uncertain. Only a small fraction of coal is shipped via this mode at present, and little or new capacity is expected to come on-stream in the near term. One of the main obstacles to slurry pipeline construction is the reluctance on the part of railroads to allow pipelines to cross their right-of-way.

E. LONG-TERM CONTRACTS AND BOTTLENECKS

Existing long-term coal contracts are used to establish lower bounds for transportation links in the CEUM. On the other hand, ICF does not identify bottlenecks in any case year and, therefore, does not upper bound any rail links. If future bottlenecks do develop, the CEUM does have the capability of second linking a supply and demand region at a higher transportation charge representing the cost of bypassing the bottleneck.

F. MODEL SPLITS

Finally, the CEUM does not allow for modal splits for coal transportation. The dominant mode between regions is chosen, i.e., the least expensive transportation link is used. This assumption can be justified by noting that allowing for intermodal splits would extremely complicate the model.

G. VERIFICATION AND SENSITIVITY ANALYSIS

The version of the CEUM existing as of September 1, 1978 and as applied in ICF's (September 1978b) third case study prepared for EPA & DOE claims to incorporate a real rail-rate escalation factor of 1%/yr over each year of the 75-95' time horizon of the model. If implemented correctly, transportation costs, after being inflated appropriately from 1975 to 1978 dollars, would be multiplied by:

$(1.01)^{10}$ for a 1985 model run,

$(1.01)^{15}$ for a 1990 model run, and

$(1.01)^{20}$ for a 1995 model run.

Upon examination of the CEUM computer code it can be shown that what the model actually does is apply a transportation multiplier (TCMLT) of $(1.01)^{20} = 1.22019$ for all case year model runs. The implicit effect of such an implementation is that real rail rates escalate at approximately 2%/yr from 1975-85 for a 1985 model run, 1.34%/yr from 1975-90 for a 1990 model run, and 1%/yr from 1975-95 for a 1995 model run.

The TCML sensitivity run was implemented by changing the real rail rate escalation factor in the Corrected Base Case from $(1.01)^{20}$ to $(1.01)^{10}$. The motivation for using an escalation factor of $(1.01)^{10}$ was to bound the upper magnitudes of the errors that result from the use of a single multiplier for all case years. The TCML-85 model results should be compared directly with the CBC-85 results with any differences carefully noted as implementation errors.

For a complete summary of important results comaring the TCML sensitivity run with the Corrected Base Case, see the TCML run description in Volume VII, Chapter 2.

CHAPTER 9. CHANGING THE GENERAL RATE OF INFLATION*

An interesting sensitivity run, derived from our Corrected Base Case of the CEUM, concerned increasing the general inflation rate from 5.5%/year to 8.0%/year. The implementation of this change involved appropriately increasing the following model parameters:

1. the total nominal estimation rates for coal mine capital costs, labor costs, and the costs of power and supplies;
2. the total nominal escalation rate for utility capital costs;
3. the nominal costs of capital for coal producers and for utilities;
4. the GNP escalator, now used to internally calculate the annuity price factor, APFAC (see Volume II, Chapter 5, Section 1 and Volume IV, Chapter 2); and
5. the general GNP deflator.

The model run implementing the change in the general inflation rate was made only for 1985. Some of the more significant results of this sensitivity run are:

- A 5% increase in the LP objective function value.
- A 20% change in ton-miles of Eastern coal transported West. This change is mostly due to new shipments of bituminous coal from Eastern Kentucky to Arkansas/Oklahoma/Louisiana.
- An 8% increase in kWh of transmission over new lines, mostly due to changes in transmission out of both Missouri and Alabama/Mississippi.
- Small decreases in surface-, deep-, and total coal production.
- A 5% increase in both average coal production price and average coal consumption price.

*This chapter was prepared by Neil L. Goldman.

- A 4.4% national-average coal price increase, using the Deviation Index to compare coal supply equilibria in CBC-85 and MILL-85.
- A 3% increase in electric utility oil/gas consumption and a 1% decrease in electric utility coal consumption.
- A transfer of 1.7 GW from new coal capacity to existing oil/gas turbine capacity.

A Final Note:

The CEUM employs a real fixed charge rate (FCR) to annualize utility capital costs. Since this rate is real as opposed to nominal, we did not feel that it was necessary to change this particular input when implementing a change in the general rate of inflation. We have learned from ICF that, along with other changes that we have implemented correctly, the real FCR does have to be slightly adjusted when the inflation rate changes. ICF apparently has a separate undocumented computer program that calculates the real FCR as a function of several financial parameters. We were unable to properly adjust the fixed charge rate in the CMILL sensitivity run (and also in the UCIN and UDIN model runs) since we did not receive documentation from ICF detailing the complicated manner in which the real FCR is calculated out-of-model. The effect of not adjusting the real fixed charge rate should not significantly impact CEUM output.

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THE ICF, INC. COAL AND ELECTRIC UTILITIES MODEL: AN ANALYSIS AND EVALUATION

VOLUME VII:

EVALUATION STRATEGIES AND COMPUTATIONAL RESULTS

by

Energy Model Analysis Program

M.I.T. Energy Laboratory Report No. MIT-EL 81-015

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PREFACE

This report is one in a series of seven volumes presenting the results of an indepth review of the ICF, Inc. Coal and Electric Utilities Model (CEUM). The Final Report (Volume I) provides a self-contained summary of the study objectives and results, with supporting papers and materials presented in Volumes II-VII.

The complete series includes:

Energy Model Analysis Program, "The ICF, Inc. Coal and Electric Utilities Model: An Analysis and Evaluation," M.I.T. Energy Laboratory Report No. MIT-EL 81-015, Cambridge, Massachusetts 02139, March 1980.

Volume I: Final Report

Volume II: Documentation and Verification of Model Implementation

Volume III: Coal Supply Issues: Mine Lifetime and Coal Royalties

Volume IV: The Coal Supply Cost Function

Volume V: Electric Utility Expansion and Operation

Volume VI: Other Evaluation Issues

Volume VII: Evaluation Strategies and Computational Results

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INTRODUCTION

Throughout the Final Report (Volume I) and the companion volumes, reference is made to a series of computational experiments performed with the ICF, Inc. Coal and Electric Utilities Model (CEUM). This volume documents these computational experiments and presents the rationale for each experiment, the actual changes implemented, and the summary results.

Two sets of runs were conducted: one set designed by the M.I.T. assessment team and executed by ICF (called "audit runs") and a second set, which was both designed and executed by the M.I.T. team (called "in-depth runs").

Chapter 1 presents the strategy and descriptions of the audit runs, summary definitions for the important variables that were modified during the course of these computational experiments, and a brief discussion of how deviation indexes were developed for evaluating changes in market equilibrium prices and quantities. Chapter 2 describes each in-depth run; also included are full model runs showing the sensitivity of coal price-quantity equilibria.

CHAPTER 1. STRATEGY FOR AUDIT RUNS*

This chapter presents the description of proposed and implemented audit runs. The first step in the audit process for the CEUM was for ICF to certify that the model transferred to the Energy Information Administration during September 1978 corresponded to the version of the model to be assessed, and to establish a Base Case. The Base Case scenario we proposed is described in Volume II, Chapter 5, Section C. Once the Base Case had been established, we proposed a set of nine independent audit runs divided into three types of runs:

(1) equivalence,

(2) screening, and

(3) issue.

Equivalence runs are designed to show that the version of the model to be used is comparable or identical to the version chosen for the assessment. For this report the assessment version was that version of the CEUM which was used to create the results in the ICF, Inc. (September 1978b) report for EPA and DOE, Further Analysis of Alternative New Source Performance Standards for New Coal-Fired Power Plants. Two cases, shown in Figure 1, were chosen to determine if the version in hand was comparable with the September 1978 version. The so-called Base Case was chosen to be the ANSPS (Alternative New Source Performance Standards) case denoted by '1.2 ceiling/0.5 floor, with exemptions' (see ICF, Inc. [September 1978b]).

As shown in Figure 1, if there was a sufficiently close match on the

*This chapter was prepared by James Gruhl and Neil L. Goldman, with the assistance of Martha J. Mason.

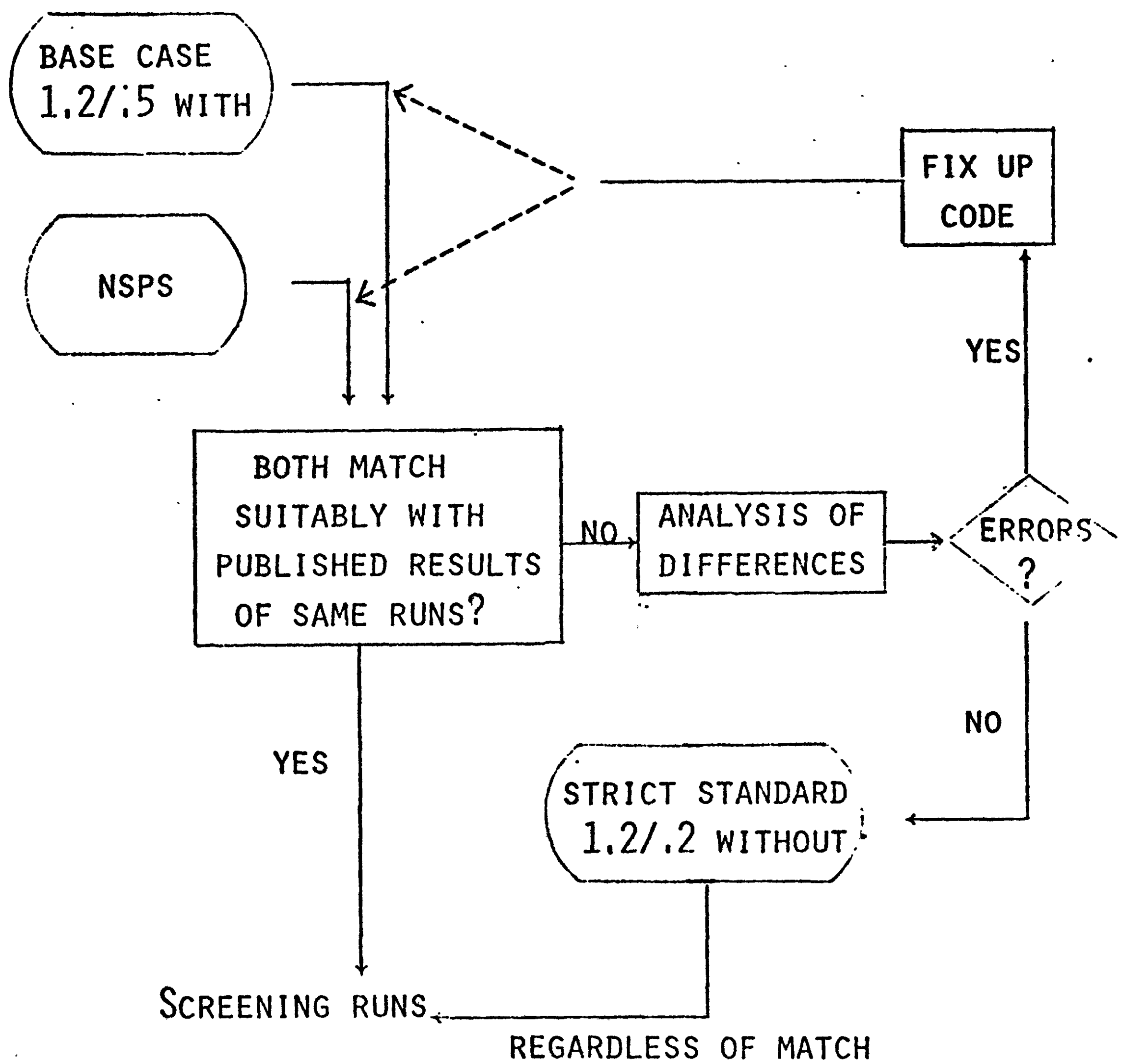


Figure 1. Strategy for the Equivalence Runs in the Audit Process.

Base Case results, as well as on the results of the NSPS (New Source Performance Standard) case, then the in-hand version would be considered equivalent to the version chosen for assessment. If significant differences occurred between the in-hand version's results and the September 1978 published results, then the alternative pathway in Figure 1 would be the strategy followed, i.e., analysis would be undertaken to determine the reason for the differences. If errors were discovered, they would be corrected and the equivalence runs would be started again. If for some reason the discrepancies were left unresolved, then an additional equivalence run was planned, in the direction from the Base Case that is opposite to the changes implicit in the NSPS run. In the case of unresolved discrepancies, this third model run would "complete the story" on the extent of the discrepancies over widely different input assumptions.

Once the issue of equivalence had been satisfactorily resolved, we proposed a series of screening runs. The idea behind the strategy for screening runs was to set up groups of model changes that would yield sets of output perturbations that were in the <u>same direction</u> and of <u>reasonable magnitude</u> (see Figure 2). An analogy would be the classical problem of determining the minimum number of weightings necessary to identify a brass coin from a group of gold coins, all of identical appearance. The condition of same direction avoids cancellation of important effects and the condition of reasonable magnitude avoids masking or swamping more subtle effects that might be discerned in the intermediate results. The importance of confounding effects within the model was thought to be small, and in general it was thought that the availability of intermediate model results as well as multiple outputs (instead of a single measure of weight) would seem to

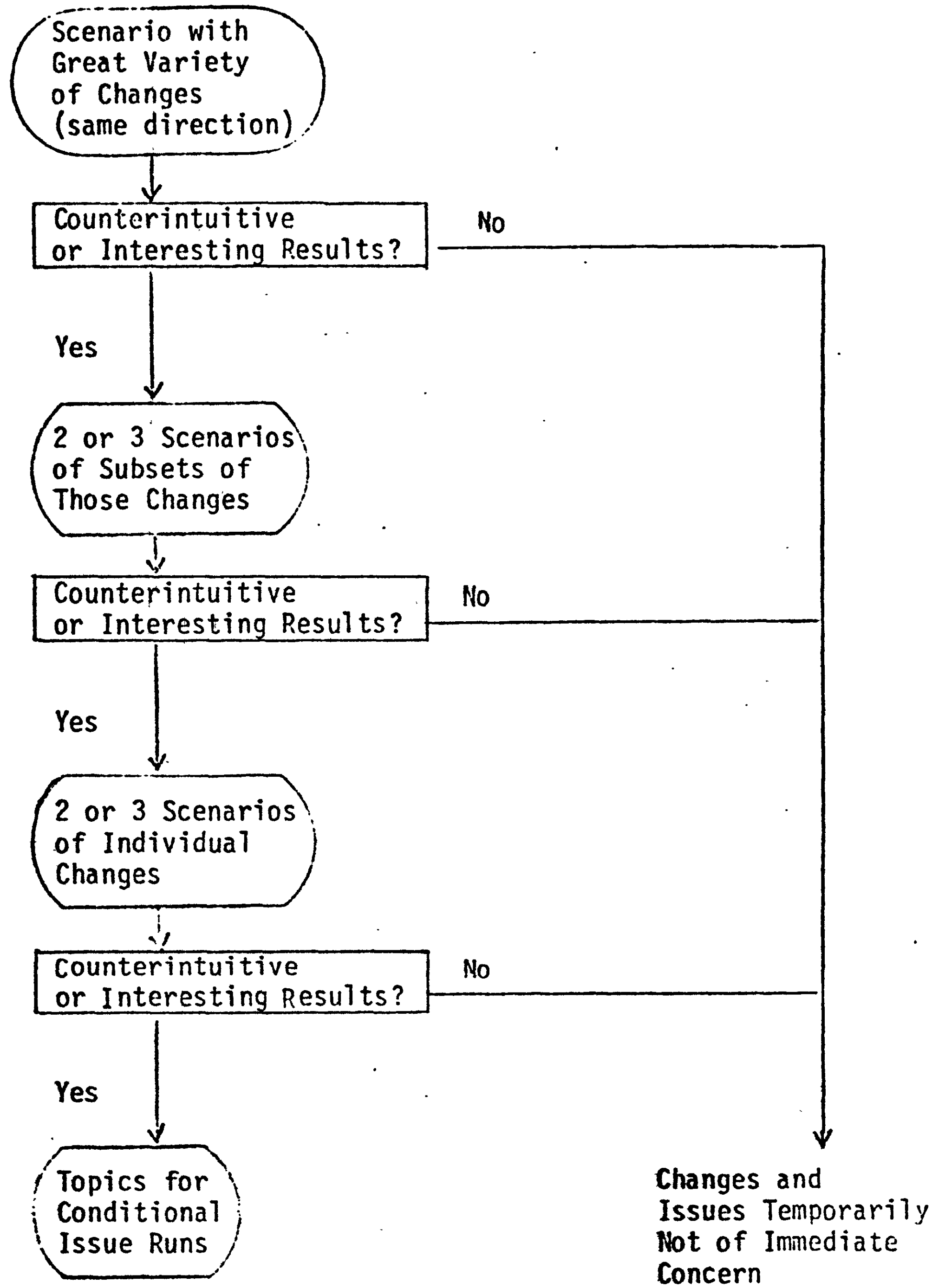


Figure 2. General Procedure for Screening Runs (Finding Issues That are of Most Interest for Further Investigation)

move the optimal strategy more in the direction of larger initial screening groups than would be indicated by classical branch-and-bound strategies.

Table 1 shows the order of runs and the groupings of input changes in the CEUM that were proposed for the initial audit screening runs. Run 5 in this table called for the resolution of the first (if any) of these four screening runs that resulted in an infeasible solution. This run and others that allowed the model operator to resolve infeasibilities were principally intended as tests of the manner in which the operator imposed his/her intelligence on the model in order to obtain results. Only one such resolution run was planned for this early stage of the audit; others were to follow the issue runs if deemed necessary.

Issue runs were intended to test and document the way in which particular changes in the model were made. Table 2 displays the first three of the issue runs that were proposed for the audit. Run 1 was motivated by a need to estimate the coal demand curves implicit in the CEUM Base Case. As part of the in-depth plan, the coal supply modules, SUPIN and RAMC, were brought in-house and were analyzed. Table 3 illustrated various methods that could be useful in analyzing the output from changes within these coal supply modules. One of the most useful of these methods is No. 4, the use of simulated demand curves. Audit Issue Run 1 was to be instrumental in creating information for the analytic development of these curves.

Audit Issue Run 2 called for the aggregation of the CEUM supply and demand regions into the PIES regions. As shown in Figure 3, this run was conditional upon the availability and form of the output. Audit Issue Run 3 was a scenario in which no interregional transmission was allowed. Such a run essentially decomposed the electricity supply sectors and was useful in

TABLE 1

Groupings of Input Changes Proposed for the Audit
First-Level Screening Runs

RUN 1 (Free-Up Coal)

- 0% Intertemporal Coal Flows
- 20-Year Mine Lifetime
- Appalachian Coal Production: Lower Bound of 400 Million Tons in 1990
- Real Escalation Rate in Coal Mine Capital Costs: 0.25%/year

RUN 2 (Tight Electricity Supply)

- 0% Intertemporal Capacity
- Nuclear/Hydro Capacity: -25%
- Scrubber Costs: +50%
- Scrubber Capacity Upper Bounds: 75 GW/1985, 150 GW/1990, 225 GW/1995
- Deep-Cleaning Costs: +25%
- Plant Capital Costs: +25%
- Real Escalation Rates in Utility Capital Costs: +25%

TABLE 1 (continued)

RUN 3 (Inflation and Escalation Spiral)

- Base Case Transmission Flows
- Oil/Gas Prices: 25% Higher
- Real Rail Rate Escalation: 2%/year from 1985 to 1995
- Inflation Rate Increased to 8%/year
- Real Labor Cost Escalation: 3%/year from 1981 to 1995
- Nominal Costs of Capital for Coal and Utility Industries: +25%

RUN 4 (Alternate Data)

- FPC Coal Data
- Changes in Load Duration Curve Parameters
- Changes in Cost Adjustment Factors
- Changes in Severance Taxes on Regional Coal Production
- Upper Bounds on Coal Use

RUN 5 (Resolve Infeasibility)

- Model User Resolves Infeasibility of First of Above Runs that is Infeasible

TABLE 2

List of Initial Audit Issue Runs

RUN 1 (Demand Curve)

Electric Growth: -10%

Non-Utility Demand: -10%

RUN 2 (Level of Aggregation)

Aggregation to PIES Supply and Demand Regions

RUN 3 (Regional Decoupling)

No Interregional Transmission (Zero Upper and Lower Bounds on LP Transmission Activities) the study of electricity supply data, electricity transmission issues as shown in Figure 4, and potentially even in the creation of a simplified version of the CEUM (see bottom of Figure 3).

Figures 5 and 6 present some additional issue runs that were either to be part of the audit, or were to be left to the in-depth assessment. The order and number of audit runs at this stage were conditional upon the timing and results of the previous screening and issue runs.

We have described above the strategy for the audit phase of the assessment. Unfortunately, only four audit runs were completed by ICF: uncorrected Base Case (BC), uncorrected NSPS, uncorrected Energy Demand Down (EDMD), and No Interregional Transmission (NOTX). By the time these were completed, it was so late in the project that we already had the CEUM running in-house. As a result, the remaining audit runs involving multiple changes in the model (the results of which would have been very useful as a learning experience for us before attempting in-depth full model runs on our own) were no longer deemed necessary.

For the reader's convenience, Table 4 provides summary definitions for the important variables that were modified during the course of both the audit and in-depth computational experiments. Section A below provides a brief discussion of deviation indexes, which were used to evaluate changes in market equilibrium prices and quantities.

Run descriptions and model results relating to NOTX and the uncorrected versions of BC, NSPS, and EDMD are presented below. Important model outputs for both the uncorrected and corrected versions of BC, NSPS, and EDMD are discussed and displayed in Volume II, Chapter 5, Section C.

TABLE 3

Methods for Analyzing the Coal Supply SUPIN/RAMC Runs

1. Plotting and Comparison of Aggregated Supply Curves
2. Statistics and Displays of Differences or Ratios Between Supply Curves
3. Use of Base Case Quantities or Prices with New Supply Curves
4. Simulate Base Case Demand Curves by Slopes and Impose on New Supply Curves
5. Use of Aggregated LP as a Surrogate for Remainder of Model and Impose on New Supply Curves
6. New Runs of Full LP Model

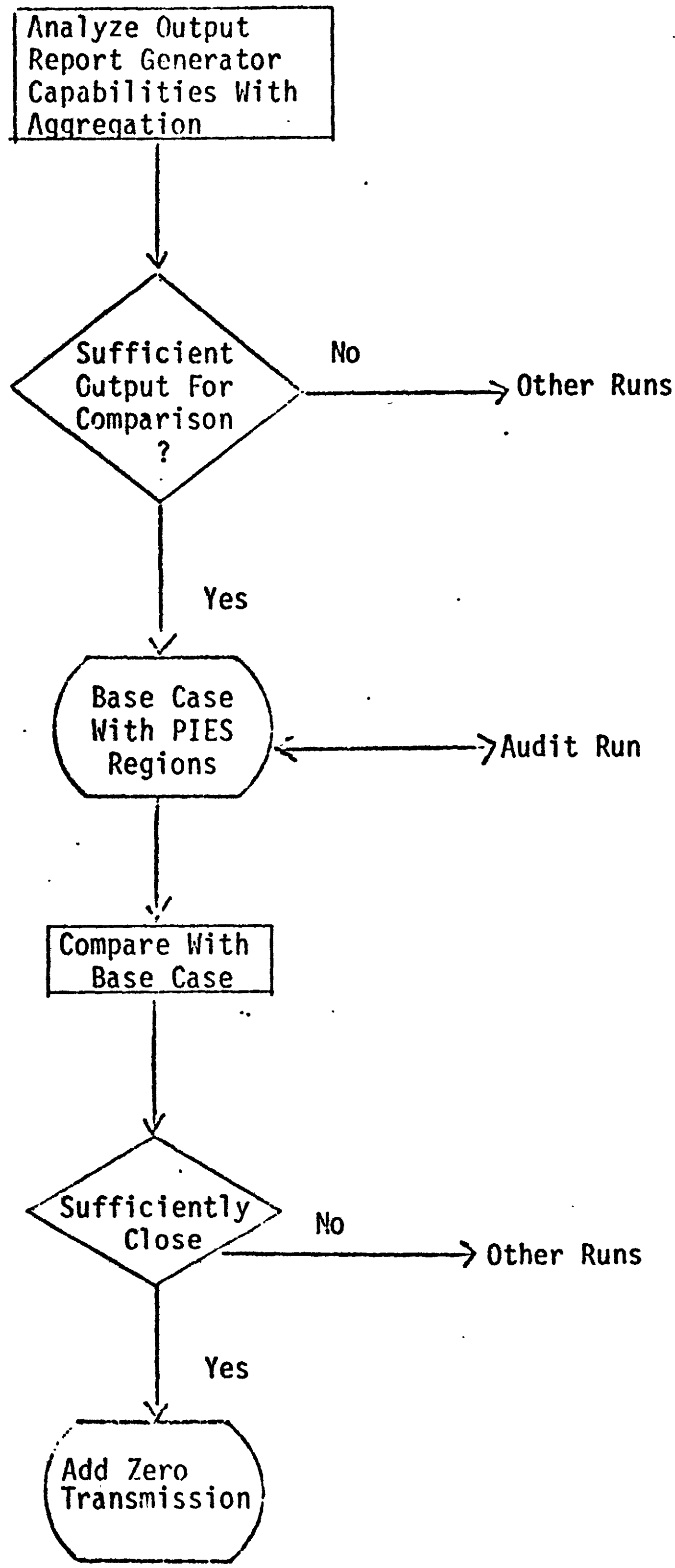


Figure 3. Conditional Strategies for Issue Runs; Level of Aggregation

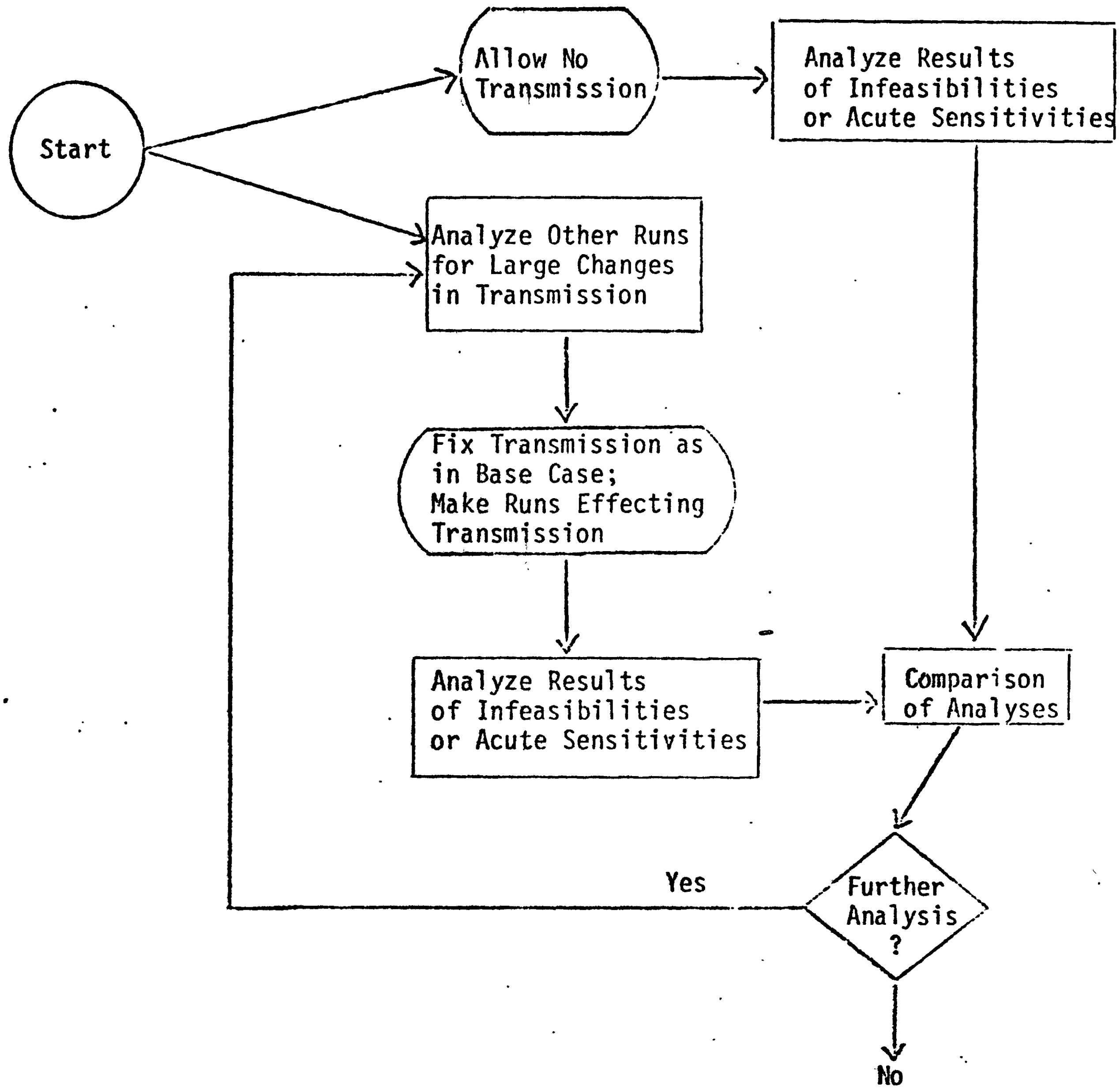


Figure 4. Conditional Strategies for Issue Runs; Electricity Transmission

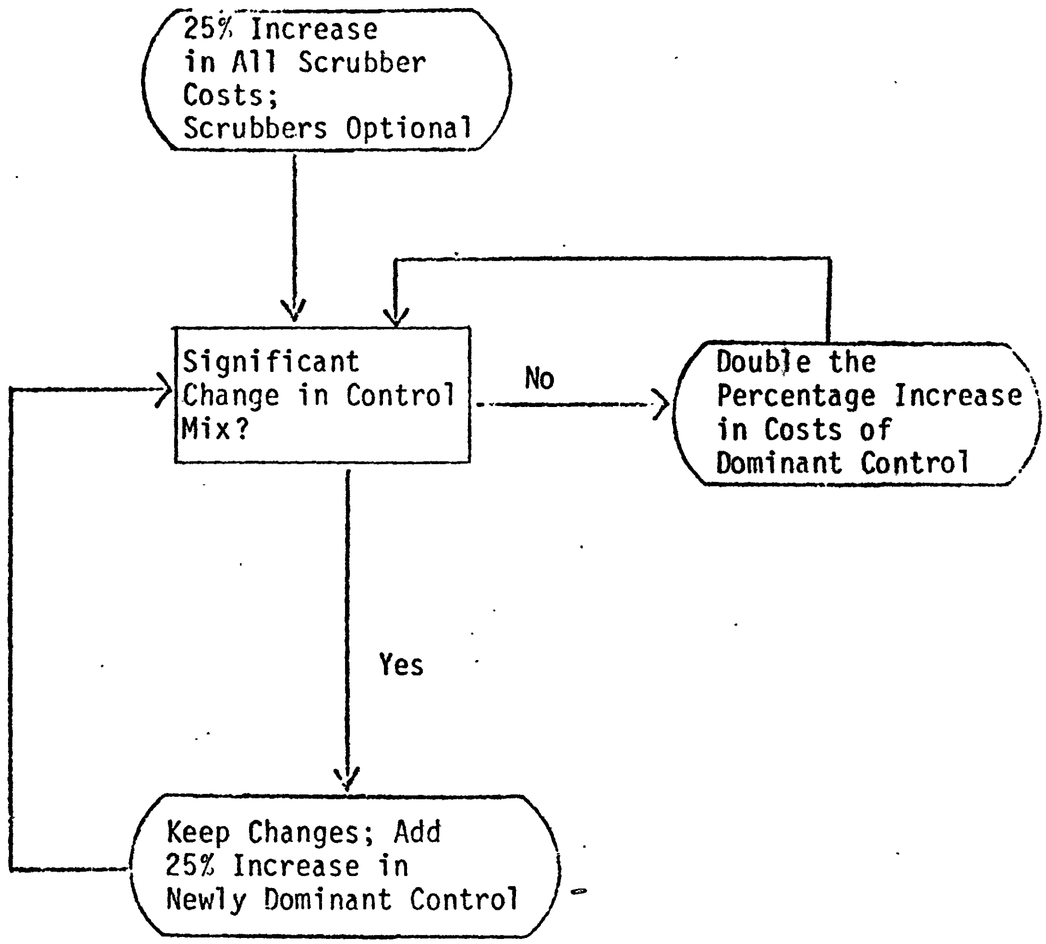


Figure 5. Conditional Strategies for Issue Runs; Control Technology Switch Points

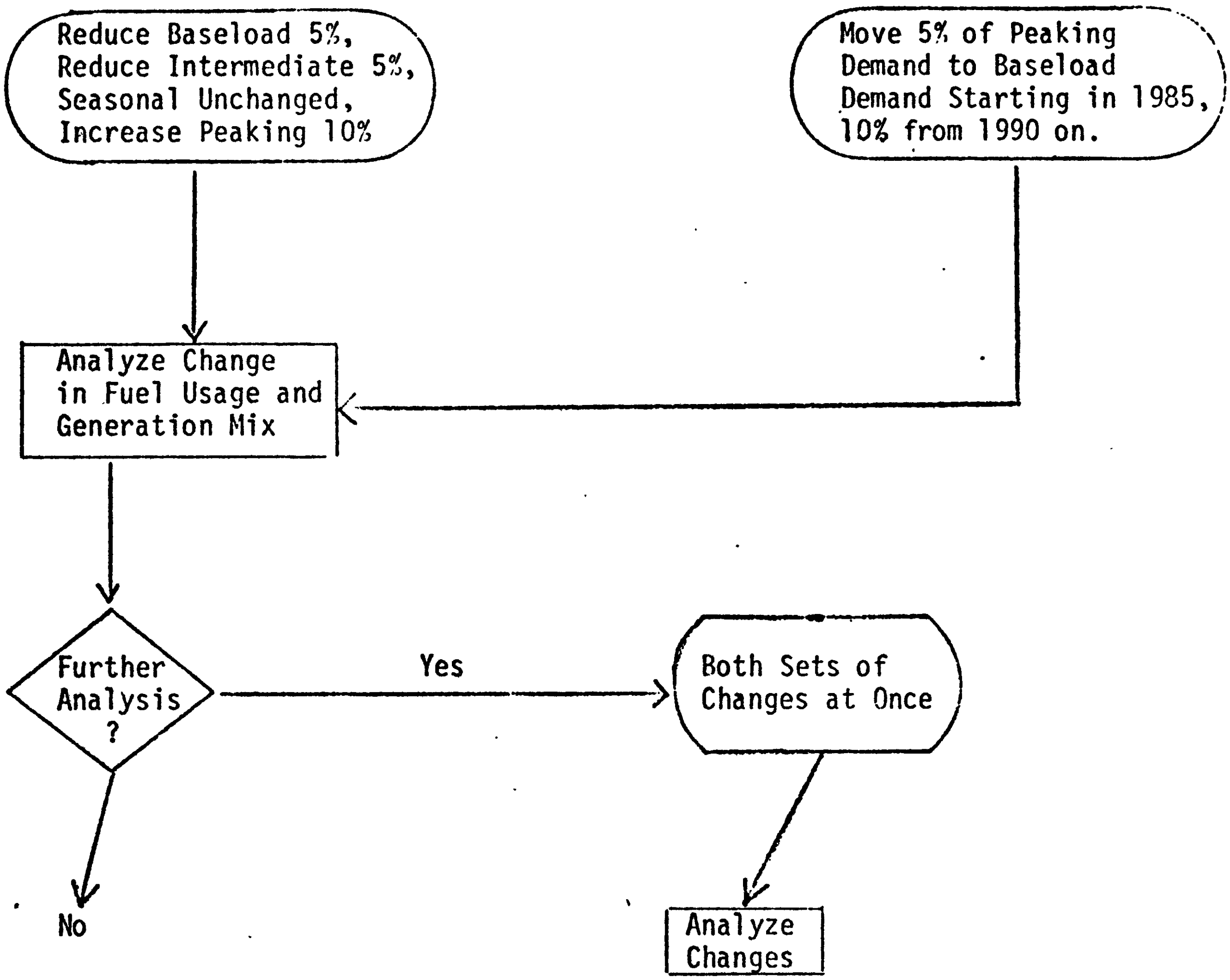


Figure 6. Conditional Strategies for Issue Runs; Electricity Load Characterization

Table 4

Important Base Case Inputs*

AMR	=	abandoned mine reclamation charge in base year (1975) dollars per clean ton; varies by surface or deep mine and by Btu content level of coal; surface mine charges vary from 0.25 to 0.35 and deep mine charges are 0.15.
APFAC	=	annuity price factor; analytically defined both in Volume I, Section 2.4.2 and in Appendix E of Goldman, Mason, and Wood (September 1979); a function of MYR, RUT, and the general inflation rate = 16.748 (using the base case values of MYR, RUT, and GNP).
BASYR	=	base year = 1975.
BLUNG	=	insurance charge for Black Lung disease in base year (1975) dollars per clean ton; varies by surface or deep mine and by Btu content level of coal; surface mine charges vary from 0.0 to 0.25, and deep mine charges are 0.50.
CASYR	=	case year = 1985, 1990, or 1995.
CCR	=	capital charge rate for utilities in real terms (except for Tennessee) = 0.10.
CCRET	=	real capital charge rate for Eastern Tennessee = 0.05.
CCRWT	=	real capital charge rate for Western Tennessee = 0.05.
CTAX	=	corporate income tax rate = 0.50.
DCB75	=	total deferred capital cost for a 20-year deep model-mine in thousands of base year (1975) dollars = 11700.0.
DCBS75	=	total deferred capital cost for a 20-year surface model-mine in thousands of base year (1975) dollars = 3200.0.
DCF_{JJ}	=	fraction of deferred capital spent at the end of each year of a mine's lifetime, where JJ is an index on mine years.
DLAB75	=	labor cost in base year (1975) dollars per man-day for deep model-mine = 69.24.

*This table was prepared by Neil L. Goldman.

DP = seam depth in feet for deep mines; the allowable seam depths are 0, 400, 700, and 1000.

DR = drift mine switch; equals one when DP=0, and equals zero otherwise.

ECAP = nominal escalation rate in coal mine capital costs = 0.060.

EINS = exposure insurance charge as a percentage of labor costs; varies by surface or deep mine and by supply region; surface mine charges vary from 0.0 to 20.0 and deep mine charges vary from 0.0 to 39.0.

EMP = nominal escalation rate for coal mine labor costs = 0.065.

EPAS = nominal escalation rate for coal mine costs of power and supplies; used in places as a proxy for the general inflation rate = 0.055.

FCL75, VREC75 = fixed and variable basic bituminous cleaning cost, respectively, in base year (1975) dollars per clean ton; varies by surface or deep mine, by sulfur content level of coal, and by Btu content level of coal.

FED = federal royalty tax rate (applies to coal mined on federal lands) as a percentage of required revenue (sales); varies by surface or deep mine and by supply region; 0.125 for surface coal and 0.08 for deep coal.

FREC75, VREC75 fixed and variable reclamation cost, respectively, in base year (1975) dollars per clean ton; varies by overburden ratio and by supply region.

GNP = GNP deflator, as a percentage = 5.50.

ICBD75 = initial capital cost for deep model-mine in thousands of base year (1975) dollars = 29300.0.

ICBS75 = initial capital cost for surface model-mine in thousands of base year (1975) dollars = 17700.0.

LIC = licensing fee in base year (1975) dollars per clean ton = 0.10.

MYR = mine lifetime in years = 30.

OB = overburden ratio for surface mines; the allowable ratios are 5, 10, 15, 20, 25, 30, and 45.

POW = power cost in thousands of base year (1975) dollars per million raw tons of output; varies by surface or deep mine = 400 (surface), 500 (deep).

PSBD75 = power and supplies cost for deep mine-mine in thousands of base year (1975) dollars per million raw tons of output = 2835.0.

PSBS75 = power and supplies cost for surface model-mine in thousands of base year (1975) dollars per million raw tons of output = 1226.0.

REPYR = report year dollars = 1978 dollars.

ROR = nominal after-tax cost of capital (nominal discount rate) for coal producers = 0.150.

ROY = royalty fee in base year (1975) dollars per clean ton; has a zero value in all supply regions.

RUT = nominal after-tax cost of capital (nominal discount rate) for electric utilities = 0.100.

SEVT = severance tax rate as a percentage of required revenue (sales); varies by supply region, from 0.0 to 0.105.

SLAB75 = labor cost in base year (1975) dollars per man-day for surface model-mine = 78.04.

ST = seam thickness in inches for deep mines; the allowable seam thicknesses are 28, 36, 48, 60, and 72.

SZ = mine size in millions of raw tons per year; the allowable sizes are 0.1, 0.5, 1.0, 2.0, 3.0, and 4.0 for surface mines and 0.1, 0.5, 1.0, 2.0, and 3.0 for deep mines.

TCMLT = real rail rate escalation factor for transportation costs = $(1.01)^{20}$ = 1.22019.

TPMDBD = raw tons per man-day for deep model-mine; varies by supply region, from 32.4 to 50.4.

TPMDBS = raw tons per man-day for surface model-mine; varies by supply region, from 15.7 to 19.7.

UCD = nominal escalation rate in utility capital costs (utility capital cost deflator), as a percentage = 7.50.

VCL75, FCL75 = variable and fixed basic bituminous cleaning cost, respectively, in base year (1975) dollars per clean ton; varies by surface or deep mine, by sulfur content level of coal, and by Btu content level of coal.

VREC75, FREC75 = variable and fixed reclamation cost, respectively, in base year (1975) dollars per clean ton; varies by overburden ratio and by supply region.

WEL = union welfare cost in base year (1975) dollars per clean ton; varies by supply region, from 0.0 to 0.72.

WPD = union welfare cost in base year (1975) dollars per man-day = 10.96.

YIELD = clean coal yield fraction in clean tons per raw ton; varies by surface or deep mine, by sulfur content level of coal, by Btu content level of coal, and by supply region; surface yields vary from 0.70 to 0.95 and deep yields vary from 0.60 to 0.95.

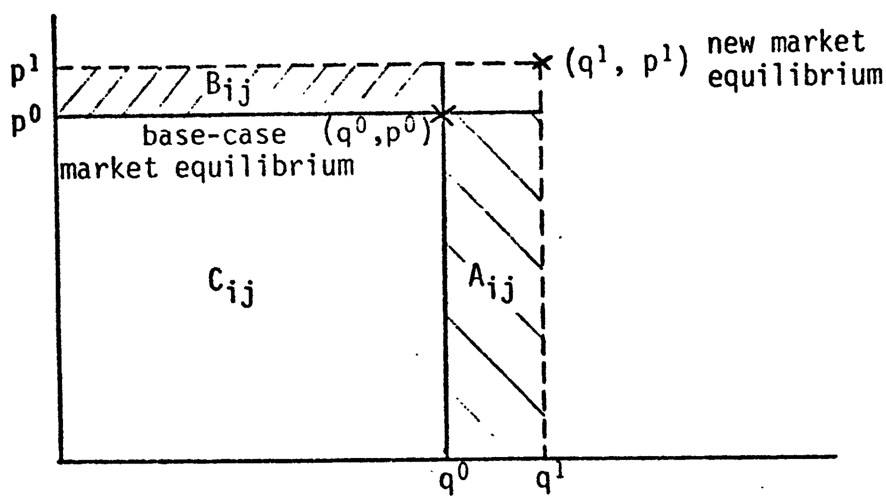
Additional Important Exogenous Input Categories:

- Electricity Demands
- Non-Utility Coal Demands
- Upper and Lower Bounds on New Coal-Fired Capacity
- Fixed Nuclear and Hydro Capacity Additions
- Lower Bounds on Scrubber Capacity
- Load Duration Curve Parameters
- Utility Generation Capacity Factors
- Oil/Gas Prices
- Capital, O&M, Transportation, Transmission, and Other Costs
- Cost Adjustment Factors Used in Production Costing
- Available Coal Reserves and Resources by Region by Coal Characteristic
- Pollutant Emission Rates and Emission Reduction Potentials of Control Technologies

A. DEVIATION INDEXES FOR EVALUATING CHANGES IN MARKET EQUILIBRIUM PRICES AND QUANTITIES*

When parameters of the CEUM are changed, a new set of market equilibrium quantities and prices is generated by the CEUM for each coal type in each supply region. We employ simple quantity and price indexes to measure the deviations of the new market equilibria from the old, both for individual markets and in the aggregate. The aggregate quantity and price indexes are appropriately weighted averages of quantity changes and of price changes, respectively.

Equilibria for the Market for
Coal-Type i in Supply Region j



The following table provides precise definitions of the quantity and price indexes. The symbols A, B, and C refer to the designated areas in the above illustration.

This section was prepared by Michael Manove.

	Quantity Deviation Index	Price Deviation Index
Type, Region (Individual Market)	$I^q_{ij} = \frac{p^0_{ij}(q^1_{ij}-q^0_{ij})}{p^0_{ij}q^0_{ij}} \equiv \frac{A_{ij}}{C_{ij}}$	$I^p_{ij} = \frac{q^0_{ij}(p^1_{ij}-p^0_{ij})}{p^0_{ij}q^0_{ij}} \equiv \frac{B_{ij}}{C_{ij}}$
Regional Aggregate	$I^q_j = \frac{\sum_i p^0_{ij}\lvert q^1_{ij}-q^0_{ij}\rvert}{\sum_i p^0_{ij}q^0_{ij}} \equiv \frac{\sum_i \lvert A_{ij}\rvert}{\sum_i C_{ij}}$	$I^p_j = \frac{\sum_i q^0_{ij}\lvert p^1_{ij}-p^0_{ij}\rvert}{\sum_i p^0_{ij}q^0_{ij}} \equiv \frac{\sum_i \lvert B_{ij}\rvert}{\sum_i C_{ij}}$
National Aggregate	$I^q = \frac{\sum\sum_{ij} p^0_{ij}\lvert q^1_{ij}-q^0_{ij}\rvert}{\sum\sum_{ij} p^0_{ij}q^0_{ij}} \equiv \frac{\sum_{ij} \lvert A_{ij}\rvert}{\sum_{ij} C_{ij}}$	$I^p = \frac{\sum\sum_{ij} q^0_{ij}\lvert p^1_{ij}-p^0_{ij}\rvert}{\sum\sum_{ij} p^0_{ij}q^0_{ij}} \equiv \frac{\sum_{ij} \lvert B_{ij}\rvert}{\sum_{ij} C_{ij}}$

NOTX - No Interregional Transmission of Electricity

The NOTX run involves preventing the interregional transmission of electricity by setting zero upper-and lower-bound constraints on transmission activity variables in the LP. This sensitivity run was conducted on the uncorrected Base Case (BC) version of the CEUM, and was implemented at ICF in the audit phase of the project. There were three major goals of this audit run. First, there were suspicions that interregional transmission was not handled correctly, and a NOTX run would illustrate the extent of the effect of transmission on model results. Second, in the structure of the linear program it appeared that the transmission activities played a regional cross-cut or feedback role that may have significantly increased computation times. Finally, without transmission the utility demand regions were essentially decomposed, so that anomalies in demand activities could more easily be recognized.

The computation time for this run was only about 30% less than that for the Base Case solution. The apparent reason for this small difference is that almost all of the CEUM runs are made from advanced bases, and these bases apparently have already resolved much of the transmission activity.

The decomposition of the demand side of the CEUM pointed out one problem in particular, that being the tightness within which generation capacity levels are constrained from above. This was especially true for baseloaded plants, where nuclear, hydro, and coal capacities are at or near exogenously specified maxima, thus forcing turbines to be built to meet baseload demands in some regions.

Important model results comparing outputs from BC and NOTX are displayed in the following tables.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases by 6% in 1985, but increases by 6% in 1990 and by 4% in 1995.

(2) West-to-East coal transportation in ton-miles decreases by 11% in 1985 and by 3% in 1990, but increases by 5% in 1995.

(3) East-to-West coal transportation in ton-miles increases by 19% in 1985 and by 5% in 1990, but decreases by 1% in 1995.

(4) Surface coal production decreases by 3% in 1985, but decreases by 2% in 1990 and by 1% in 1990; deep coal production decreases by 9% in 1985, but increases by 1% in both 1990 and 1995; total coal production decreases by 6% in 1985, but increases by 1% in both 1990 and 1995.

(5) The average coal production price decreases by 2% in 1985, by 1% in 1990, and remains approximately the same in 1995.

(6) The average coal consumption price changes by less than 1% in each case year.

(7) Electric utility coal consumption in tons decreases significantly in 1985 (by 11%), but increases by 1% in 1990 and by 2% in 1995.

(8) Electric utility oil/gas consumption increases significantly in 1985 (by 37%), but decreases by 3% in 1990 and by 2% in 1995.

(9) There is a shift from the use of existing electric utility capacity to the use of new capacity in each case year.

(10) The LP objective function value increases in each case year: 5% in 1985, 3% in 1990, 2% in 1995.

Table 5

NO INTERREGIONAL TRANSMISSION OF ELECTRICITY (NOTX)

	BC-1985	NOTX-1985	BC-1990	NOTX-1990	BC-1995	NOTX-1995
LP Objective Function (10^6\$, 1978)	74102.66	77584.18	103725.18	106341.09	138847.45	141628.06
National Coal Transportation (10^9 Ton Miles)	560.49	528.20	889.41	942.40	1145.50	1195.11
Western Coal to Eastern Destinations						
(10^6 Tons)	80.55	71.99	121.84	118.74	136.95	144.46
(10^9 Ton-Miles)	102.11	90.84	150.23	145.63	167.69	175.81
Eastern Coal to Western Destinations						
(10^6 Tons)	19.26	20.17	19.62	19.84	19.47	19.40
(10^9 Ton-Miles)	3.34	3.96	2.72	2.85	3.05	3.01
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	160.85	0.0	135.20	0.0	107.49	0.0
New	196.42	0.0	168.92	0.0	149.56	0.0
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	153.49	148.33	154.33	151.48	164.01	158.80
Metallurgical ($/MM Btu)	1.64	1.62	1.76	1.74	1.85	1.84
Low Sulfur (MM Tons)	291.71	263.89	466.29	481.18	577.21	590.94
Low Sulfur ($/MM Btu)	0.83	0.83	0.79	0.78	0.83	0.82
Medium Sulfur (MM Tons)	412.13	400.41	550.35	548.21	664.65	675.79
Medium Sulfur ($/MM Btu)	0.99	0.95	1.03	1.04	1.09	1.08
High Sulfur (MM Tons)	260.07	241.71	342.63	352.64	456.07	459.67
High Sulfur ($/MM Btu)	1.00	0.98	1.18	1.19	1.27	1.30
Surface	598.94	580.73	776.73	790.72	913.99	924.55
Deep	518.44	473.60	736.87	742.79	948.54	960.65
Total: (MM Tons)	1117.38	1054.33	1513.60	1533.51	1861.93	1885.20
Total: ($/MM Btu)	1.07	1.05	1.10	1.09	1.15	1.15
Growth Rate (%/year)	5.6	5.0	5.8	5.9	5.4	5.5
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1108.0	1022.7	1514.3	1526.7	1861.1	1881.0
($/Tons)[b]	30.83	30.61	32.25	32.34	33.52	33.73
($/MM Btu)	1.40	1.39	1.51	1.51	1.58	1.59
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	15.089	14.263	21.059	21.302	26.546	26.935
($/MM Btu)	1.31	1.29	1.44	1.45	1.51	1.53
Electric Utility Coal Consumption[d] (MM Tons)	755.3	670.4	1002.7	1016.0	1266.0	1286.1
Electric Utility Oil/Gas Consumption[e] (Quads)	5.831	7.966	3.153	3.071	1.882	1.839
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.2	477.3	449.8	425.6	416.6	394.7
New	231.1	238.7	421.7	444.1	641.1	661.7

Table 6

SENSITIVITY TO NO INTERREGIONAL TRANSMISSION

BC-85 vs. NOTX-85

COMPARISON RUN
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: NO TRANSMISSION, 1985, UNCORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26271	0.063	0.022

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2603	0.082	0.021
OH	895	0.052	0.027
MD	52	0.000	0.009
NV	1605	0.116	0.015
SV	5335	0.033	0.020
VA	876	0.014	0.027
EK	2228	0.023	0.023
TN	154	0.000	0.024
AL	751	0.065	0.021
IL	3841	0.083	0.025
IN	798	0.117	0.022
WK	1020	0.000	0.027
IA	10	0.000	0.025
MO	75	0.000	0.000
KS	12	0.000	0.016
OK	73	0.041	0.008
AR	52	0.000	0.001
ND	123	0.247	0.000
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1153	0.129	0.010
WY	2201	0.106	0.025
CS	696	0.062	0.019
UT	752	0.000	0.001
AZ	96	0.138	0.290
NM	372	0.048	0.054
WA	52	0.000	0.006
TX	393	0.000	0.000
CN	39	0.000	0.028
AK	0	0.000	0.000

Table 7

SENSITIVITY TO INTERREGIONAL TRANSMISSION

BC-90 vs. NOTX-90

COMPARISON RUN
BASE ID: BASE CASE, 1990, UNCORRECTED.
RUN ID: NO TRANSMISSION, 1990, UNCORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
35568	0.033	0.007

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4004	0.033	0.013
OH	1194	0.036	0.008
MD	87	0.065	0.011
NV	3236	0.071	0.013
SV	5523	0.006	0.008
VA	665	0.042	0.008
EK	1755	0.024	0.008
TN	59	0.000	0.008
AL	636	0.039	0.004
IL	5975	0.014	0.003
IN	1439	0.000	0.002
WK	1489	0.086	0.000
IA	44	0.479	0.000
MO	100	0.000	0.000
KS	5	0.000	0.003
OK	81	0.000	0.005
AR	85	0.093	0.001
ND	166	0.453	0.004
SD	12	0.000	0.000
EM	4	0.121	0.000
WM	2473	0.067	0.000
WY	2976	0.010	0.005
CS	1115	0.011	0.003
UT	560	0.059	0.034
AZ	158	0.000	0.098
NM	796	0.015	0.004
WA	54	0.000	0.000
TX	840	0.000	0.002
CN	40	0.000	0.000
AK	0	0.000	0.000

Table 8

SENSITIVITY TO NO INTERREGIONAL TRANSMISSION

BC-95 vs. NOTX-95

COMPARISON RUN
BASE ID: BASE CASE, 1995, UNCORRECTED.
RUN ID: NO TRANSMISSION, 1995, UNCORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
45624	0.025	0.009

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	6091	0.020	0.010
OH	2234	0.033	0.009
MD	151	0.000	0.006
NV	4295	0.022	0.010
SV	5578	0.005	0.007
VA	681	0.021	0.005
EK	1805	0.076	0.005
TN	0	0.000	0.000
AL	624	0.044	0.008
IL	8027	0.024	0.009
IN	1785	0.014	0.008
WK	1993	0.032	0.014
IA	100	0.000	0.006
MO	146	0.018	0.007
KS	0	0.000	0.000
OK	106	0.170	0.005
AR	153	0.000	0.001
ND	217	0.585	0.278
SD	12	0.000	0.000
EM	1	0.261	0.000
WM	3852	0.037	0.000
WY	3926	0.003	0.009
CS	1178	0.027	0.005
UT	538	0.012	0.025
AZ	78	0.000	0.053
NM	1032	0.025	0.006
WA	17	0.000	0.001
TX	986	0.000	0.008
CN	28	0.000	0.000
AK	0	0.000	0.000

NSPS - New Source Performance Standard

The primary purpose of this audit run was to analyze the effects of assumptions regarding the current new source performance standards (NSPS) on model results. The Base Case of the model employs a particular alternative new source performance standard (NSPS), one of several analyzed by ICF, defined by a floor and a ceiling on SO_2 emissions of 0.5 and 1.2 lb $SO_2/10^6$ Btu, respectively. Scrubbers are mandatory on ANSPS coal plants and 55% sulfur removal (on a daily average basis) is required.

The NSPS case, on the other hand, assumes:

(1) Scrubbers are not mandatory;

(2) Scrubber efficiency is 90% sulfur removal on an annual average basis, with no daily accountabilities; and

(3) The SO_2 emission floor and ceiling both are 1.2 lb $SO_2/10^6$ Btu.

In this run the NSPS assumptions were implemented by applying the NSPS parameters to the uncorrected Base Case. Results are displayed in the tables immediately following.

Table 9

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

	BC-1985	NSPS-1985
LP Objective Function (10^6\$, 1978)	74102.66	73807.31
National Coal Transportation (10^9 Ton Miles)	560.49	564.16
Western Coal to Eastern Destinations		
(10^6 Tons)	80.55	81.37
(10^9 Ton-Miles)	102.11	101.79
Eastern Coal to Western Destinations		
(10^6 Tons)	19.26	18.65
(10^9 Ton-Miles)	3.34	2.91
Transmission Transmitted (Before Losses) (10^9 kWh)		
Existing	160.85	162.966
New	196.42	188.897
National Total Coal Production Quantities and Prices[a]		
Metallurgical (MM Tons)	153.49	156.79
Metallurgical (\$/MM Btu)	1.64	1.66
Low Sulfur (MM Tons)	291.71	299.31
Low Sulfur (\$/MM Btu)	0.83	0.84
Medium Sulfur (MM Tons)	412.13	410.99
Medium Sulfur (\$/MM Btu)	0.99	0.99
High Sulfur (MM Tons)	260.07	253.80
High Sulfur (\$/MM Btu)	1.00	0.98
Surface	598.94	600.592
Deep	518.44	520.295
Total: (MM Tons)	1117.38	1120.888
Total: (\$/MM Btu)	1.07	1.07
Growth Rate (%/year)	5.6	5.6
Total U.S. Coal Consumption - Quantities and Prices		
(MM Tons)	1108.0	1110.5
(\$/Tons)[b]	30.83	30.99
(\$/MM Btu)	1.40	1.41
Electric Utility Coal Consumption - Quantities and Prices		
(Quads)	16.089	16.18
(\$/MM Btu)	1.31	1.31
Electric Utility Coal Consumption[d] (MM Tons)	755.3	757.5
Electric Utility Oil/Gas Consumption[e] (Quads)	5.831	5.696
Electric Utility Capacity Utilization (GW)[f]		
Existing	486.2	484.1
New	231.1	233.2

NOTE: Runs for NSPS-1990 and NSPS-1995 were not made.

Table 10

SENSITIVITY TO CHANGE IN ENVIRONMENTAL STANDARD

BC-85 vs. NSPS-85

COMPARISON RUN
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: NEW SOURCE PERFORMANCE STANDARDS, 1985, UNCORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26271	0.022	0.010

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2603	0.030	0.007
OH	895	0.000	0.017
MD	52	0.266	0.007
NV	1605	0.034	0.004
SV	5335	0.010	0.008
VA	876	0.000	0.010
EK	2228	0.023	0.008
TN	154	0.000	0.017
AL	751	0.040	0.013
IL	3841	0.017	0.012
IN	798	0.063	0.011
WK	1020	0.000	0.015
IA	10	0.000	0.014
MO	75	0.031	0.007
KS	12	0.000	0.043
OK	73	0.091	0.050
AR	52	0.089	0.004
ND	123	0.126	0.000
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1153	0.015	0.010
WY	2201	0.023	0.012
CS	696	0.023	0.006
UT	752	0.053	0.034
AZ	96	0.000	0.000
NM	372	0.042	0.001
WA	52	0.000	0.006
TX	393	0.000	0.000
CN	39	0.000	0.011
AK	0	0.000	0.000

EDMD - Energy Demand Down

The EDMD audit run was implemented at ICF by decreasing by 10% in the uncorrected Base Case both exogenously specified electricity demands and non-utility coal demands. The principle issue addressed in this run was the appropriateness of the model's general behavior for accommodating different future energy forecasts. The primary motivation was to highlight the types of activity that are marginal. The major result of the run was that the supply and generation activities that drop to meet the decreased demands are very restricted. Results are displayed in the tables immediately following.

Table 11

ENERGY DEMAND DOWN (EDMD)

	BC-1985	EDMD-1985	BC-1990	EDMD-1990	BC-1995	EDMD-1995
LP Objective Function (10^6\$. 1978)	74102.66	62335.02	103725.18	88639.81	138847.45	120099.68
National Coal Transportation (10^9 Ton Miles)	560.49	495.98	889.41	768.16	1145.50	1004.45
Western Coal to Eastern Destinations						
(10^6 Tons)	80.55	65.23	121.84	105.93	136.95	134.29
(10^9 Ton-Miles)	102.11	81.22	150.23	130.02	167.69	167.48
Eastern Coal to Western Destinations						
(10^6 Tons)	19.26	19.92	19.62	20.28	19.47	18.24
(10^9 Ton-Miles)	3.34	4.02	2.72	3.29	3.05	2.55
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	160.85	167.720	135.20	145.603	107.49	132.414
New	196.42	153.539	168.92	166.860	149.56	145.862
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	153.49	141.20	154.33	146.82	164.01	149.16
Metallurgical (\$/MM Btu)	1.64	1.59	1.76	1.73	1.85	1.81
Low Sulfur (MM Tons)	291.71	254.55	466.29	409.13	577.21	546.02
Low Sulfur (\$/MM Btu)	0.83	0.83	0.79	0.77	0.83	0.77
Medium Sulfur (MM Tons)	412.13	387.08	550.35	472.05	664.65	533.00
Medium Sulfur (\$/MM Btu)	0.99	0.96	1.03	1.02	1.09	1.10
High Sulfur (MM Tons)	260.07	228.41	342.63	284.66	456.07	377.74
High Sulfur (\$/MM Btu)	1.00	0.98	1.18	1.14	1.27	1.23
Surface	598.94	558.39	776.73	685.21	913.99	801.83
Deep	518.44	452.86	736.87	627.45	948.54	804.10
Total: (MM Tons)	1117.38	1011.245	1513.60	1312.67	1861.93	1605.93
Total: (\$/MM Btu)	1.07	1.04	1.10	1.08	1.15	1.12
Growth Rate (%/year)	5.6	4.6	5.8	4.8	5.4	4.6
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1108.0	1001.4	1514.3	1314.0	1861.1	1607.0
(\$/Tons)[b]	30.83	29.94	32.25	31.85	33.52	32.96
(\$/MM Btu)	1.40	1.36	1.51	1.49	1.58	1.55
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.089	14.59	21.059	17.99	26.546	22.39
(\$/MM Btu)	1.31	1.26	1.44	1.42	1.51	1.50
Electric Utility Coal Consumption[d] (MM Tons)	755.3	684.7	1002.7	856.0	1266.0	1072.0
Electric Utility Oil/Gas Consumption[e] (Quads)	5.831	4.232	3.153	2.566	1.882	1.675
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.2	458.5	449.8	433.8	416.6	410.5
New	231.1	188.2	421.7	351.4	641.1	542.4

Table 12

SENSITIVITY TO DECREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 10%

BC-85 vs. EDMD-85

COMPARISON RUN
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: ELECTRICITY & NON-UTILITY 10% DEMAND DECREASE, 1985. UNCORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26271	0.142	0.086

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2603	0.002	0.603
OH	895	0.052	0.030
MD	52	0.255	0.279
NV	1605	0.169	0.022
SV	5335	0.053	0.036
VA	876	0.014	0.032
EK	2228	0.079	0.037
TN	154	0.000	0.027
AL	751	0.092	0.027
IL	3841	0.149	0.034
IN	798	0.117	0.030
WK	1020	0.000	0.030
IA	10	0.000	0.028
MO	75	0.010	0.000
KS	12	0.000	0.024
OK	73	0.041	0.010
AR	52	0.140	0.007
ND	123	0.036	0.000
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1153	0.134	0.010
WY	2201	0.103	0.028
CS	696	0.193	0.049
UT	752	0.000	0.002
AZ	96	0.000	0.003
NM	372	0.019	0.000
WA	52	0.000	0.006
TX	393	0.000	0.000
CN	39	0.000	0.028
AK	0	0.000	0.000

Table 13

SENSITIVITY TO DECREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 10%

BC-90 vs. EDMD-90

COMPARISON RUN
BASE ID: BASE CASE, 1990, UNCORRECTED.
RUN ID: ELECTRICITY & NON-UTILITY 10% DEMAND DECREASE, 1990. UNCORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
35568	0.118	0.031

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4004	0.223	0.028
OH	1194	0.230	0.028
MD	87	0.000	0.022
NV	3236	0.096	0.029
SV	5523	0.024	0.017
VA	665	0.126	0.016
EK	1755	0.055	0.017
TN	59	0.000	0.025
AL	636	0.037	0.013
IL	5975	0.136	0.032
IN	1439	0.113	0.032
WK	1489	0.195	0.037
IA	44	0.908	0.443
MO	100	0.105	0.036
KS	5	0.000	0.014
OK	81	0.015	0.015
AR	85	0.141	0.006
ND	166	0.232	0.004
SD	12	0.000	0.000
EM	4	0.217	0.018
WM	2473	0.151	0.039
WY	2976	0.103	0.027
CS	1115	0.153	0.058
UT	560	0.049	0.007
AZ	158	0.021	0.014
NM	796	0.096	0.107
WA	54	0.000	0.018
TX	840	0.000	0.094
CN	40	0.000	0.027
AK	0	0.000	0.000

Table 14

SENSITIVITY TO DECREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 10%

BC-95 vs. EDMD-95

COMPARISON RUN
BASE ID: BASE CASE, 1995, UNCORRECTED.
RUN ID: ELECTRICITY & NON-UTILITY 10% DEMAND DECREASE, 1995. UNCORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
45624	0.130	0.038

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	6081	0.262	0.024
OH	2234	0.323	0.029
MD	151	0.020	0.021
NV	4295	0.072	0.025
SV	5578	0.020	0.019
VA	681	0.157	0.031
EK	1805	0.195	0.019
TN	0	0.000	0.000
AL	624	0.037	0.021
IL	8027	0.128	0.029
IN	1785	0.083	0.029
WK	1993	0.104	0.033
IA	100	0.440	0.029
MO	146	0.397	0.259
KS	0	0.000	0.000
OK	106	0.016	0.018
AR	153	0.059	0.022
ND	217	0.163	0.048
SD	12	0.000	0.000
EM	1	0.392	0.000
WM	3852	0.048	0.104
WY	3926	0.171	0.062
CS	1178	0.119	0.034
UT	538	0.091	0.038
AZ	78	0.013	0.038
NM	1032	0.091	0.049
WA	17	0.000	0.053
TX	986	0.000	0.052
CN	28	0.000	0.060
AK	0	0.000	0.000

CHAPTER 2. SELECTION STRATEGY, DESCRIPTION OF IN-DEPTH FULL MODEL RUNS, AND RESULTS*

The in-depth model runs performed at M.I.T. can be divided into several categories:

(1) Equivalence Runs - replication of the Base Case and NSPS results for comparison with the audit runs made by ICF and for comparison with results published by ICF in September 1978.

(2) Effects of Verification Corrections - implementation of the verification corrections in the Corrected Base Case, Corrected NSPS, and Corrected Electricity Demand Decrease scenarios, to provide a set of runs from which the effects of the corrections can be examined.

(3) New Standard Scenario - the Corrected Base Case also serves, perhaps more importantly, as a new starting point from which to observe the effects of perturbations without imbedding the effects of the verification corrections.

(4) Individual Issue Runs:

- Supply Issues - these model runs are aimed principally at important issues within the coal supply component of the model, such as mine lifetime and real labor cost escalations, to determine the effects on model outputs.
- Coal Transportation Issues - an examination of another component of the model, this time with changes in areas such as the real rail rate escalation, intertemporal coal flow constraints and interregional coal flow constraints.

*This section was prepared by Neil L. Goldman and James Gruhl, with computer support provided by Vijaya Chandru and Jai Oum. Michael Manove prepared the sensitivity tables with the assistance of Martha J. Mason.

- o Electric Utility Issues - principally issues related to cost and availability of capacity types, and electricity demand characteristics.
- o Electric Transmission Issues - those model runs aimed at investigating constraints on transmission.
- o Energy Demand Issues - cost and availability of alternative fuels and energy demand requirements.
- o Pervasive Issues - for example, effects of changes in the general inflation rate.

(5) Combined Issue Runs - investigation of nonlinear effects of important issues, and possibly an investigation of directions toward a new standard scenario.

Descriptions of and motives for each of the in-depth full model runs follow. After each description we display tables showing national summary results for each of 20 model sensitivity tests; following them are tables that display an analysis of the raw data expressed as a deviation from the base case, both national and regional. At the end of this chapter, Tables 81 - 93 display the same data, but grouped to show the effect of each of the tests on important output categories. Finally, Table 94 summarizes the national totals.

It should be noted that, starting with the UCIN sensitivity run, we stopped using C as the first letter of run names, to denote "Corrected," even though all of our sensitivity runs were made from the Corrected Base Case.

CBC - Corrected Base Case

A Corrected Base Case has been created by implementing many of the corrections to the CEUM Supply Code discussed in Volume II, Chapter 5, Section A and in Goldman, et al. (September 1979). First recall that the Base Case uses a particular Alternative New Source Performance Standard (ANSPS) defined by a floor and ceiling on power plant SO_2 emissions of 0.5 and 1.2 lb $SO_2/10^6$ Btu, respectively. Scrubbers are mandatory, usually with an 85% sulfur removal rate on a daily basis (with three daily excursions to 75% allowed per month). Exceptions to the 85% removal rate occur in cases where emission levels below the 0.5 floor would be reached with 85% scrubbing. In these cases partial scrubbing is allowed so as to exactly meet the emissions floor. Those cases in which 85% scrubbing would not reduce emissions to the 1.2 ceiling are considered unviable alternatives.

The specific Verification Corrections implemented in CBC are those relating to calculations of: reserve fractions, coal cleaning costs, property taxes and insurance, definition of base year dollars, depreciation charges, welfare costs, smallest seam thickness, labor costs, allocation of deferred capital, Oklahoma reclamation costs, and escalators for initial capital and existing mine prices. This, of course, provides a new base case for use in making comparisons with other runs that represent perturbations from the "corrected" version of the model. In addition, this run also provides the most important measures of the effects of the verification corrections on the model results.

The start-from-scratch solution time for the Corrected Base Case is about 46 minutes CPU time on the machine environment leased by the Department of Energy. By saving advanced bases from which to begin further sensitivity runs the computation time can be reduced to about 20 minutes.

Implementation of the CBC Run

Files: SUPIN and RAMCFORT of the Base Case (BC).

Changes: The corrections implemented related to the verification errors detailed in Points 1, 5, 6a, 7, 8, 10, 14, 15, 18, 19, 20, 21, 22, 23, and 24 of Volume II, Chapter 5, Section A.

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA
TO CEUM CORRECTIONS

BC-85 vs. CBC-85

COMPARISON RUN
BASE ID: BASE CASE, 1985, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1985.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26271	0.044	0.028

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2603	0.058	0.033
OH	895	0.000	0.040
MD	52	0.266	0.033
NV	1605	0.119	0.032
SV	5335	0.033	0.011
VA	876	0.025	0.014
EK	2228	0.091	0.014
TN	154	0.000	0.018
AL	751	0.065	0.025
IL	3841	0.023	0.037
IN	798	0.052	0.036
WK	1020	0.000	0.039
IA	10	0.000	0.038
MO	75	0.000	0.050
KS	12	0.000	0.040
OK	73	0.087	0.062
AR	52	0.508	0.261
ND	123	0.000	0.035
SD	12	0.000	0.035
EM	2	0.000	0.048
WM	1153	0.059	0.032
WY	2201	0.043	0.032
CS	696	0.036	0.028
UT	752	0.000	0.046
AZ	96	0.000	0.036
NM	372	0.019	0.035
WA	52	0.000	0.018
TX	393	0.000	0.034
CN	39	0.000	0.021
AK	0	0.000	0.000

Table 2

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA TO CEUM CORRECTIONS

BC-90 vs. CBC-90

COMPARISON RUN
BASE ID: BASE CASE, 1990, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1990.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
35568	0.051	0.035

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4004	0.054	0.042
OH	1194	0.074	0.050
MD	87	0.271	0.031
NV	3236	0.061	0.041
SV	5523	0.056	0.019
VA	665	0.218	0.019
EK	1755	0.069	0.021
TN	59	0.000	0.025
AL	635	0.099	0.014
IL	5975	0.043	0.039
IN	1439	0.057	0.037
WK	1489	0.019	0.039
IA	44	0.428	0.050
MO	100	0.105	0.043
KS	5	0.000	0.039
OK	81	0.083	0.031
AR	85	0.263	0.008
ND	165	0.048	0.030
SD	12	0.000	0.035
EM	4	0.000	0.038
WM	2473	0.009	0.046
WY	2976	0.018	0.045
CS	1115	0.068	0.020
UT	560	0.018	0.049
AZ	158	0.000	0.100
NM	796	0.086	0.039
WA	54	0.000	0.027
TX	840	0.000	0.032
CN	40	0.000	0.031
AK	0	0.000	0.000

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA TO CEUM CORRECTIONS

BC-95 vs. CBC-95

COMPARISON RUN
BASE ID: BASE CASE, 1995, UNCORRECTED.
RUN ID: CORRECTED BASE CASE, 1995.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
45624	0.061	0.034

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	6081	0.141	0.041
OH	2234	0.071	0.043
MD	151	0.032	0.020
NV	4295	0.009	0.037
SV	5578	0.046	0.007
VA	681	0.276	0.037
EK	1805	0.073	0.008
TN	0	0.000	0.000
AL	624	0.052	0.036
IL	8027	0.044	0.039
IN	1785	0.006	0.036
WK	1953	0.052	0.039
IA	100	0.111	0.042
MO	146	0.026	0.042
KS	0	0.000	0.000
OK	106	0.177	0.026
AR	153	0.143	0.007
ND	217	0.000	0.040
SD	12	0.000	0.035
EM	1	0.000	0.038
WM	3852	0.130	0.052
WY	3926	0.000	0.049
CS	1178	0.038	0.034
UT	538	0.043	0.036
AZ	78	0.000	0.036
NM	1032	0.005	0.039
WA	17	0.000	0.029
TX	986	0.000	0.004
CN	28	0.000	0.036
AK	0	0.000	0.000

CNSPS - Corrected New Source Performance Standard

The Corrected NSPS run was implemented by applying the NSPS parameters to the corrected version of the model. The specific differences between the base case and the NSPS case are:

(1) scrubbers are not mandatory,

(2) scrubber efficiency is 90% sulfur removal on an annual average basis, with no daily accountabilities, and

(3) the SO_2 emission floor and ceiling both are 1.2 lbs. $SO_2/10^6$ Btu.

This model run was principally motivated by the desire to investigate the effects of the verification corrections. The results showed that many of the effects of going from the Base Case to the NSPS were greatly magnified in the corresponding corrected versions. For example, the change in 1985 coal transportation was magnified about five times. There were also some surprising reversals, such as Western coal to the East going down in BC to NSPS but greatly increasing from CBC to CNSPS. There was also a similar reversal in deep coal production for 1985.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases in each case year: 3% in 1985, 10% in 1990, 7% in 1995.

(2) West-to-East coal transportation in ton-miles increases significantly in each case year: 17% in 1985, 51% in 1990, 53% in 1995.

(3) East-to-West coal transportation in ton-miles decreases in 1985 (17%) and 1995 (7%) but increases in 1990 (14%).

(4) KWH of transmission over new lines decreases in 1985 and 1990 by 6% but increases in 1995 by 11%.

(5) Both metallurgical coal production and price increase in each case year;

low-sulfur coal production increases while its average production price stays about the same except for an increase in 1995; medium-sulfur coal production decreases while its average price stays about the same except for an increase in 1985; high-sulfur coal production and price decrease in each case year.

(6) Surface coal production increases: 2% in 1985, 7% in 1990, 5% in 1995; deep coal production decreases: 1% in 1985, 4% in 1990, 5% in 1995; total coal production increases slightly in each case year.

(7) The average coal production price stays approximately constant in each case year; the average coal consumption price increases slightly in each case year; total U.S. coal consumption increases slightly in 1985 and 1990 but decreases in 1995.

(8) There are very slight changes in utility coal consumption: a maximum change of +2% in 1985.

(9) Utility oil/gas consumption decreases in each case year: 2% in 1985, 14% in 1990, 10% in 1995.

(10) There are slight increases in GW of new utility capacity in each case year, and decreases in the use of existing capacity.

(11) There are small decreases in the LP objective function value: a maximum change of 2% in 1995.

Implementation of the CNSPS Run

Files: SUPIN and RAMCFORT of NSPS (same as in BC).

Changes: Same changes as in CBC.

Table 4

Corrected New Source Performance Standard (CNSPS)

	CBC-1985	CNSPS-1985	CBC-1990	CNSPS-1990	CBC-1995	CNSPS-1995
LP Objective Function (10^6\$, 1978)	74062.08	73755.00	104366.27	102419.82	140080.62	136815.48
National Coal Transportation (10^9 Ton Miles)	556.88	574.44	885.28	971.17	1208.41	1289.30
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	89.37	123.38	169.56	175.32	244.00
(10^9 Ton-Miles)	97.71	114.66	151.60	229.00	218.17	333.33
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	18.12	20.41	21.67	18.17	19.89
(10^9 Ton-Miles)	3.23	2.67	3.08	3.50	2.85	2.65
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	161.171	135.309	132.463	107.377	111.837
New	197.289	186.448	167.308	156.822	176.021	196.061
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	166.63	169.93	200.44	173.23	208.44
Metallurgical (\$/MM Btu)	1.66	1.68	1.78	1.87	1.86	2.05
Low Sulfur (MM Tons)	284.83	302.85	459.77	564.67	623.49	735.75
Low Sulfur (\$/MM Btu)	0.85	0.85	0.80	0.80	0.83	0.92
Medium Sulfur (MM Tons)	411.75	411.73	544.92	489.58	641.73	604.23
Medium Sulfur (\$/MM Btu)	1.02	1.02	1.07	1.03	1.11	1.15
High Sulfur (MM Tons)	254.90	239.28	330.45	269.90	437.12	328.95
High Sulfur (\$/MM Btu)	1.04	1.02	1.23	1.18	1.33	1.27
Surface	599.675	612.283	779.491	829.975	962.536	1005.437
Deep	515.373	508.206	725.578	694.614	912.968	871.929
Total: (MM Tons)	1115.048	1120.489	1505.069	1524.589	1875.564	1877.366
Total: (\$/MM Btu)	1.10	1.10	1.14	1.14	1.18	1.23
Growth Rate (%/year)	5.6	5.6	5.8	5.9	5.5	5.5
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1109.8	1506.6[c]	1522.8	1875.5	1861.4
(\$/Tons)[b]	31.58	31.81	33.19	33.82	34.14	35.99
(\$/MM Btu)	1.44	1.45	1.55	1.59	1.62	1.70
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.14	20.92	21.13	26.54	26.35
(\$/MM Btu)	1.35	1.36	1.48	1.53	1.56	1.66
Electric Utility Coal Consumption[d] (MM Tons)	753.4	757.8	995.4	1013.2	1280.8	1268.6
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.717	3.283	2.816	1.898	1.718
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	484.5	454.1	439.0	417.3	410.1
New	230.7	232.8	417.4	432.7	640.6	643.6

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 5

EFFECT OF CEUM CORRECTIONS ON NSPS MODEL RUN FOR 1985

NSPS-85 vs. CNSPS-85

COMPARISON RUN
BASE ID: NEW SOURCE PERFORMANCE STANDARDS, 1985, UNCORRECTED.
RUN ID: NEW SOURCE PERFORMANCE STANDARDS, 1985, CORRECTED

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
26409	0.049	0.029

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2653	0.065	0.041
OH	890	0.053	0.038
MD	65	0.212	0.028
NV	1632	0.116	0.034
SV	5382	0.033	0.016
VA	883	0.014	0.019
EK	2286	0.085	0.021
TN	153	0.000	0.024
AL	791	0.046	0.020
IL	3730	0.067	0.035
IN	739	0.039	0.032
WK	1006	0.000	0.034
IA	10	0.000	0.036
MO	72	0.000	0.040
KS	12	0.000	0.038
OK	77	0.127	0.029
AR	56	0.155	0.016
ND	121	0.000	0.035
SD	12	0.000	0.035
EM	2	0.000	0.048
WM	1159	0.060	0.042
WY	2235	0.030	0.034
CS	708	0.024	0.027
UT	777	0.002	0.032
AZ	96	0.000	0.036
NM	387	0.001	0.036
WA	52	0.000	0.024
TX	393	0.000	0.034
CN	38	0.000	0.031
AK	0	0.000	0.000

Table 6

SENSITIVITY TO CHANGE IN ENVIRONMENTAL STANDARD

CBC-85 vs. CNSPS-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: NEW SOURCE PERFORMANCE STANDARDS, 1985, CORRECTED

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.036	0.011

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.035	0.012
OH	931	0.052	0.018
MD	67	0.206	0.011
NV	1626	0.073	0.011
SV	5481	0.003	0.011
VA	867	0.011	0.011
EK	2419	0.025	0.012
TN	157	0.000	0.015
AL	748	0.066	0.006
IL	3892	0.062	0.014
IN	783	0.051	0.014
WK	1060	0.000	0.019
IA	11	0.000	0.017
MO	79	0.031	0.017
KS	13	0.000	0.050
OK	68	0.000	0.039
AR	51	0.000	0.001
ND	127	0.127	0.000
SD	12	0.000	0.000
EM	2	0.000	0.000
WM	1198	0.068	0.000
WY	2191	0.037	0.007
CS	696	0.036	0.007
UT	787	0.051	0.021
AZ	99	0.000	0.000
NM	377	0.064	0.000
WA	53	0.000	0.000
TX	406	0.000	0.000
CN	39	0.000	0.000
AK	0	0.000	0.000

Table 7

SENSITIVITY TO CHANGE IN ENVIRONMENTAL STANDARD

CBC-90 vs. CNSPS-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: NEW SOURCE PERFORMANCE STANDARDS, 1990, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	F
36807	0.161	0.041

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	F
PA	4187	0.248	0.025
OH	1161	0.204	0.028
MD	113	0.370	0.038
NV	3567	0.110	0.032
SV	5863	0.044	0.059
VA	769	0.331	0.047
EK	1861	0.433	0.046
TN	60	0.000	0.036
AL	652	0.098	0.031
IL	5940	0.123	0.034
IN	1407	0.151	0.039
WK	1518	0.214	0.041
IA	26	0.839	0.041
MO	93	0.000	0.020
KS	5	0.000	0.022
OK	84	0.254	0.026
AR	108	0.150	0.021
ND	169	0.062	0.022
SD	12	0.000	0.000
EM	5	0.000	0.000
WM	2611	0.314	0.002
WY	3068	0.113	0.029
CS	1052	0.056	0.020
UT	577	0.087	0.046
AZ	174	0.000	0.012
NM	761	0.229	0.093
WA	55	0.000	0.013
TX	867	0.040	0.261
CN	41	0.000	0.001
AK	0	0.000	0.000

Table 8

SENSITIVITY TO CHANGE IN ENVIRONMENTAL STANDARD

CBC-95 vs. CNSPS-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: NEW SOURCE PERFORMANCE STANDARDS, 1995, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.177	0.074

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.192	0.035
OH	2166	0.298	0.039
MD	167	0.562	0.079
NV	4488	0.169	0.056
SV	5774	0.027	0.101
VA	811	0.250	0.107
EK	1910	0.552	0.109
TN	0	0.000	0.000
AL	595	0.214	0.061
IL	7973	0.147	0.050
IN	1839	0.148	0.053
WK	1963	0.234	0.057
IA	93	0.314	0.022
MO	148	0.043	0.013
KS	0	0.000	0.000
OK	128	0.249	0.032
AR	175	0.218	0.057
ND	226	0.794	0.001
SD	12	0.000	0.000
EM	1	0.023	0.000
WM	4580	0.215	0.130
WY	4120	0.135	0.082
CS	1172	0.216	0.044
UT	533	0.146	0.066
AZ	81	0.000	0.131
NM	1067	0.065	0.187
WA	17	0.000	0.008
TX	990	0.000	0.117
CN	29	0.000	0.093
AK	0	28.226	0.000

CML20 - Corrected 20-Year Mine Lifetime

The lifetime of coal mines is an important factor in determining the supply of coal. Mine lifetime affects supply in two ways. First, mine lifetime is inversely proportional to the rate of extraction from a given parcel of reserves. Therefore, mine lifetime determines the intensity with which a parcel of reserves is mined. Second, mine lifetime affects the unit cost of coal production from a given parcel of reserves. Longer lifetimes lead to lower extraction costs by lowering capital requirements. However, long lifetimes delay the realization of revenues, and this imposes a "waiting" cost on the operator.

Because mine lifetime may have a critical influence on coal supply, the determination of lifetimes for use in the CEUM is vital to the accuracy of that model. ICF uses a uniform mine lifetime. This lifetime was set at 20 years in original versions of the CEUM and modified to 30 years in later versions. The ICF estimates of lifetime are loosely based on the opinions of mine engineers and on historical data. In order to confirm the importance of the mine-lifetime parameter, we ran the CEUM using a 20-year-mine lifetime and compared the results with the Corrected Base Case, an otherwise identical 30-year mine lifetime run. This run, CML20, results in important changes at the greatest resolutions, and in many significant changes at aggregated levels.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases in each case year: [illegible]% in 1985 and 1990, 11% in 1995.

(2) West-to-East coal transportation in ton-miles increases by 7% in 1985 and decreases by 9% in 1990 and by 32% in 1995.

(3) East-to-West coal transportation in ton-miles increases in each case year: 115% in 1985, 57% in 1990, 5% in 1995.

(4) KWH of transmission over new lines increases in 1985 (1%) and 1990 (7%) but decreases by 11% in 1995.

(5) Metallurgical coal production increases and coal price decreases in each case year; low-sulfur production decreases and price decreases (except in 1985) in each case year; medium-sulfur production increases (except in 1985) and price decreases in each case year; high-sulfur production decreases (except in 1985) and price decreases in each case year.

(6) There are slight increases in surface coal production in 1985 (1%) and in 1990 (3%), and a decrease of 4% in 1995; there are slight decreases in deep coal production in 1985 (2%) and in 1990 (1%), and an increase of 2% in 1995. Overall coal production decreases by 1% in 1985 and in 1995, and increases by 1% in 1990.

(7) The average coal production price decreases by 3 to 4% in each case year.

(8) Coal consumption decreases slightly in 1985 and 1995, and increases in 1990; the average consumption price decreases by 4 to 5% in each case year.

(9) Utility coal consumption decreases slightly in 1985 and 1995, and increases in 1990; utility oil/gas consumption decreases in each case year.

(10) There are slight decreases of between 1 and 2% in the LP objective function value.

Implementation of the CML20 Run

File: SUPIN

Lines: 11, 12, 13, 28

Changes:

(a) Lines 11, 12: The 4 components of the MLIFE matrix were changed from 30 to 20.

(b) Line 13: The contract mine lifetime was changed from 30 to 20.

(c) Line 28: The value of the Annuity Price Factor, APFAC, was changed from 16.748 to 13.276. (Note that for a mine lifetime of 40 years, APFAC=19.035, assuming the real component of RUT is unchanged.)

Table 9

Corrected 20-Year Mine Lifetime (CML20)

	CBC-1985	CML20-1985	CBC-1990	CML20-1990	CBC-1995	CML20-1995
LP Objective Function (10^6\$, 1978)	74062.08	73390.59	104366.27	102897.20	140080.62	137763.32
National Coal Transportation (10^9 Ton Miles)	556.88	539.82	885.28	863.08	1208.41	1082.03
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	82.99	123.38	113.22	175.32	123.83
(10^9 Ton-Miles)	97.71	104.61	151.60	138.49	218.17	149.18
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	24.80	20.41	24.19	18.17	20.02
(10^9 Ton-Miles)	3.23	6.94	3.08	4.84	2.86	2.99
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	161.939	135.308	134.243	107.377	107.268
New	197.289	198.525	167.308	178.620	176.021	156.993
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	175.62	169.93	185.58	173.23	190.94
Metallurgical (\$/MM Btu)	1.66	1.56	1.78	1.65	1.86	1.69
Low Sulfur (MM Tons)	284.83	270.09	459.77	450.30	623.49	551.88
Low Sulfur (\$/MM Btu)	0.85	0.87	0.80	0.78	0.83	0.81
Medium Sulfur (MM Tons)	411.75	407.62	544.92	559.68	641.73	688.79
Medium Sulfur (\$/MM Btu)	1.02	0.97	1.07	1.03	1.11	1.06
High Sulfur (MM Tons)	254.90	255.75	330.45	325.49	437.12	424.18
High Sulfur (\$/MM Btu)	1.04	1.00	1.23	1.14	1.33	1.24
Surface	599.675	603.042	779.491	799.563	962.596	923.865
Deep	515.373	506.026	725.578	721.488	912.968	931.922
Total: (MM Tons)	1115.048	1109.068	1505.069	1521.051	1875.564	1855.787
Total: (\$/MM Btu)	1.10	1.07	1.14	1.09	1.18	1.13
Growth Rate (%/year)	5.6	5.5	5.8	5.9	5.5	5.4
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1101.4	1506.6[c]	1524.5[c]	1875.5	1858.5[c]
(\$/Tons)[b]	31.58	30.80	33.19	31.62	34.14	32.70
(\$/MM Btu)	1.44	1.39	1.55	1.48	1.62	1.54
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.10	20.92	21.18	26.54	26.55
(\$/MM Btu)	1.35	1.31	1.48	1.42	1.56	1.49
Electric Utility Coal Consumption[d] (MM Tons)	753.4	752.1	995.4	1014.8	1280.8	1264.7
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.792	3.283	3.066	1.898	1.853
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	485.5	454.1	445.0	417.3	415.9
New	230.7	231.6	417.4	426.2	640.6	641.6

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 10

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA
TO THE MINELIFE PARAMETER

CBC-85 vs. CML20-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: 20-YEAR MINELIFE, 1985, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.192	0.053

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.158	0.038
OH	931	0.217	0.052
MD	67	0.000	0.044
NV	1626	0.204	0.045
SV	5481	0.174	0.058
VA	867	0.064	0.059
EK	2419	0.130	0.057
TN	157	0.000	0.042
AL	748	0.092	0.059
IL	3892	0.196	0.060
IN	783	0.392	0.069
WK	1060	0.210	0.055
IA	11	0.000	0.050
MO	79	0.000	0.020
KS	13	0.000	0.032
OK	68	0.089	0.026
AR	51	0.768	0.065
ND	127	0.000	0.047
SD	12	0.000	0.047
EM	2	0.000	0.064
WM	1198	0.344	0.045
WY	2191	0.320	0.056
CS	696	0.256	0.057
UT	787	0.075	0.019
AZ	99	0.293	0.027
NM	377	0.203	0.039
WA	53	0.387	0.025
TX	406	0.000	0.095
CN	39	0.324	0.008
AK	0	0.000	0.000

Table 11

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA TO THE MINELIFE PARAMETER

CBC-90 vs. CML20-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: 20-YEAR MINELIFE, 1990, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.216	0.066

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.156	0.053
OH	1161	0.195	0.058
MD	113	0.342	0.064
NV	3567	0.193	0.058
SV	5863	0.196	0.074
VA	769	0.239	0.116
EK	1861	0.175	0.073
TN	60	0.000	0.065
AL	652	0.046	0.064
IL	5940	0.248	0.084
IN	1407	0.276	0.080
WK	1518	0.335	0.063
IA	26	0.839	0.079
MO	93	0.707	0.057
KS	5	0.000	0.024
OK	84	0.319	0.043
AR	108	0.144	0.063
ND	169	0.086	0.047
SD	12	0.000	0.047
EM	5	0.217	0.001
WM	2611	0.108	0.036
WY	3068	0.357	0.048
CS	1052	0.188	0.054
UT	577	0.046	0.004
AZ	174	0.178	0.253
NM	761	0.116	0.10[illegible]
WA	55	0.385	0.010
TX	867	0.437	0.084
CN	41	0.324	0.026
AK	0	0.000	0.000

Table 12

SENSITIVITY OF PRICE-QUANTITY EQUILIBRIA
TO THE MINELIFE PARAMETER

CBC-95 vs. CML20-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: 20-YEAR MINELIFE, 1995, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.209	0.076

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.133	0.079
OH	2166	0.381	0.058
MD	167	0.304	0.081
NV	4488	0.157	0.074
SV	5774	0.296	0.088
VA	811	0.512	0.087
EK	1910	0.188	0.091
TN	0	0.000	0.000
AL	595	0.208	0.085
IL	7973	0.131	0.067
IN	1839	0.206	0.067
WK	1963	0.017	0.061
IA	93	0.500	0.085
MO	148	0.466	0.080
KS	0	0.000	0.000
OK	128	0.636	0.071
AR	175	0.132	0.084
ND	226	0.067	0.069
SD	12	0.000	0.047
EM	1	0.392	0.044
WM	4580	0.238	0.074
WY	4120	0.208	0.105
CS	1172	0.258	0.073
UT	533	0.102	0.047
AZ	81	0.526	0.021
NM	1067	0.218	0.102
WA	17	1.495	0.073
TX	990	0.508	0.066
CN	29	0.500	0.052
AK	0	0.000	0.000

CEDMD - Corrected Energy Demand Down

The corrected EDMD run was implemented by decreasing by 10% both exogenously specified electricity demands and non-utility coal demands. The primary motivation for this run was to highlight the types of activities that are marginal. The result of this run was that the supply and generation activities that drop to meet the decreased demands are very restricted. Peaking demand decreases are met by drops in total oil/gas turbine capacity; baseload demand decreases are met by drops in the building of new coal plant capacity. The previously upper bounded coal-plant builds stay at upper bounds in some regions and drop significantly in others. The net result is a more erratic regional distribution of coal-fired plant building, with associated increases in transportation and transmission activities.

The following is a summary of some important results at national levels:

(1) There are significant decreases in overall coal transportation in ton-miles in each case year: 10% in 1985, 13% in 1990, 15% in 1995.

(2) There are significant decreases in West-to-East coal transportation in ton-miles: 12% in 1985, 11% in 1990, 10% in 1995.

(3) East-to-West coal transportation increases significantly in 1985 (32%) and in 1990 (30%), but decreases in 1995 (14%).

(4) KWH of transmission over new lines decreases significantly in 1985 (23%) and in 1995 (15%), but increases in 1995 (4%).

(5) Metallurgical, low-, medium-, and high-sulfur coal production and price decrease in each case year.

(6) Surface coal production decreases: 6% in 1985, 11% in 1990, 14% in 1995. Deep coal production decreases: 13% in 1985, 15% in 1990, 14% in 1995. Total

coal production decreases: 10% in 1985, 13% in 1990, 14% in 1995.

(7) The average coal production price decreases in each case year about 2 to 3%.

(8) Total U.S. coal consumption decreases significantly in each case year; the average coal consumption price decreases by 2 to 3% in each case year.

(9) Utility coal consumption decreases: 9% in 1985, 14% in 1990, 16% in 1995.

(10) Utility oil/gas consumption decreases significantly: 27% in 1985, 20% in 1990, 15% in 1995.

(11) Both existing and new utility capacity utilization drop significantly in each case year.

(12) There are large decreases in the LP objective function value: 16% in 1985, 15% in 1990, 14% in 1995.

Implementation of the CEDMD Run

1. File: GAMMA.NOH85

Changes:

(a) After Line 44 (PROBLEM NCM,REVISE) the following seven lines of code were added:

```
*****REVISE NON-UTILITY DEMANDS*****
     MODIFY, ROW
       LD(UR)(XX)      ,FOR (XX)=((UR)DMD,*,)*'1234'/'34',
         IF (XX).NM.EL.AND.((UR)DMD,DMD,CD(XX)).GT.0)
       RHS1,RHS=-((UR)DMD,DMD,CD(XX))*0.90
         *(CASE,(XX)MULT,DATA)
*****END NON-UTILITY DEMANDS*****
```

(b) After Line 72 (SUTNOHB,MAX=0.63999999) the following three lines of code were added:

```
MODIFY, COLUMN
  D(UR)ELXX
    BND, FIX=((UR)DMD,DMD,EDEL)*0.90
```

2. File: GAMMA.REVISE 90,95

Lines: 477-478, 483, 487, 523

Changes:

(a) Original Lines 477-478 (in CBC):

```
RHS1, RHS=-((UR)DMD,DMD,CD(XX))*(FACTOR,(XX),(YY))
          *(CASE,(XX)MULT,DATA)
```

New Lines 477-478 (in CEDMD):

```
RHS1, RHS=-((UR)DMD,DMD,CD(XX))*(FACTOR,(XX),(YY))
          *(CASE,(XX)MULT,DATA)*0.90
```

(b) Original Line 483 (in CBC):

```
RHS1, RHS=-(IND(XX),1,(UR))*(INDFAC,1,(YY))/1000
```

New Line 483 (in CEDMD):

```
RHS1, RHS=-(IND(XX),1,(UR))*(INDFAC,1,(YY))/1000*0.90
```

(c) Original Line 487 (in CBC):

```
RHS1, RHS=-(SYN(T),1,(UR))/1000
```

New Line 488 (in CEDMD):

```
RHS1, RHS=-(SYN(T),1,(UR))/1000*0.90
```

(d) Original Line 523 (in CBC):

```
BND, FIX=(DEM(YY),(UR),QTY)
```

New Line 525 (in CEDMD):

```
BND, FIX=(DEM(YY),(UR),QTY)*0.90
```

Table 13

Corrected Energy Demand Down (CEDMD)

	CBC-1985	CEDMD-1985	CBC-1990	CEDMD-1990	CBC-1995	CEDMD-1995
LP Objective Function (10^6\$, 1978)	74062.08	62221.03	104366.27	89112.18	140080.62	121098.68
National Coal Transportation (10^9 Ton Miles)	556.88	499.16	885.28	769.30	1208.41	1031.69
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	67.91	123.38	108.94	175.32	154.46
(10^9 Ton-Miles)	97.71	85.52	151.60	134.36	218.17	197.10
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	19.74	20.41	20.94	18.17	17.65
(10^9 Ton-Miles)	3.23	4.26	3.08	4.00	2.86	2.47
Transmission Transmitted (Before Losses) (10^3 kWh)						
Existing	161.167	168.646	135.308	152.358	107.377	129.061
New	197.289	152.322	167.308	173.133	176.021	150.561
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	152.20	169.93	156.74	173.23	162.66
Metallurgical (\$/MM Btu)	1.66	1.61	1.78	1.74	1.86	1.62
Low Sulfur (MM Tons)	284.83	253.46	459.77	403.15	623.49	553.14
Low Sulfur (\$/MM Btu)	0.85	0.85	0.80	0.78	0.83	0.78
Medium Sulfur (MM Tons)	411.75	374.66	544.92	467.17	641.73	549.64
Medium Sulfur (\$/MM Btu)	1.02	0.99	1.07	1.04	1.11	1.11
High Sulfur (MM Tons)	254.90	228.68	330.45	284.09	437.12	346.69
High Sulfur (\$/MM Btu)	1.04	1.02	1.23	1.18	1.33	1.23
Surface	599.675	561.253	779.491	690.922	962.596	825.515
Deep	515.373	447.747	725.578	620.229	912.968	787.010
Total: (MM Tons)	1115.048	1009.000	1505.069	1311.150	1875.564	1612.526
Total: (\$/MM Btu)	1.10	1.08	1.14	1.11	1.18	1.14
Growth Rate (%/year)	5.6	4.5	5.8	4.8	5.5	4.7
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1000.6	1506.6[c]	1313.2[c]	1875.5	1613.0[c]
(\$/Tons)[b]	31.58	30.73	33.19	32.53	34.14	33.53
(\$/MM Btu)	1.44	1.40	1.55	1.52	1.62	1.53
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	14.56	20.92	17.92	26.54	22.44
(\$/MM Btu)	1.35	1.31	1.48	1.45	1.56	1.53
Electric Utility Coal Consumption[d] (MM Tons)	753.4	684.8	995.4	855.4	1280.8	1078.7
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	4.255	3.283	2.626	1.898	1.621
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	458.8	454.1	435.3	417.3	408.4
New	230.7	187.8	417.4	349.9	640.6	544.6

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 547.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption · Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 14

EFFECT OF CEUM CORRECTIONS ON THE EDMD MODEL RUN FOR 1985

EDMD-85 vs. CEDMD-85

COMPARISON RUN
RUN ID: ELECTRICITY & NON-UTILITY 10% DEMAND DECREASE,1985, UNCORRECTED.
RUN ID: EDMD85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
21902	0.044	0.032

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	1008	0.025	0.040
CH	823	0.055	0.044
MD	37	0.000	0.045
NV	1272	0.136	0.034
SV	4884	0.044	0.018
VA	836	0.015	0.022
EK	1976	0.075	0.023
TN	150	0.000	0.023
AL	664	0.069	0.025
IL	3158	0.061	0.042
IN	683	0.000	0.040
WK	990	0.000	0.042
IA	10	0.000	0.041
MO	74	0.000	0.050
KS	12	0.000	0.036
OK	70	0.083	0.021
AR	44	0.197	0.027
ND	112	0.107	0.036
SD	12	0.000	0.035
EM	2	0.000	0.050
WM	931	0.030	0.043
WY	1925	0.019	0.034
CS	530	0.004	0.038
UT	754	0.000	0.047
AZ	95	0.114	0.000
NM	365	0.002	0.036
WA	52	0.000	0.024
TX	393	0.000	0.035
CN	37	0.000	0.028
AK	0	0.000	0.000

Table 15

EFFECT OF CEUM CORRECTIONS ON THE EDMD MODEL RUN FOR 1990

EDMD-90 vs. CEDMD-90

COMPARISON RUN
BASE ID: ELECTRICITY & NON-UTILITY 10% DEMAND DECREASE,1990, UNCORRECTED
RUN ID: EDMD90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
30444	0.049	0.031

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	3026	0.078	0.035
OH	894	0.065	0.048
MD	85	0.000	0.024
NV	2841	0.100	0.037
SV	5300	0.044	0.012
VA	571	0.152	0.011
EK	1629	0.092	0.012
TN	57	0.000	0.022
AL	585	0.038	0.011
IL	5001	0.027	0.037
IN	1237	0.025	0.036
WK	1155	0.011	0.040
IA	4	0.000	0.039
MO	86	0.000	0.051
KS	5	0.000	0.049
OK	79	0.080	0.036
AR	91	0.211	0.013
ND	119	0.439	0.036
SD	12	0.000	0.035
EM	3	0.000	0.030
WM	2018	0.000	0.029
WY	2583	0.023	0.035
CS	879	0.067	0.035
UT	542	0.047	0.018
AZ	153	0.083	0.216
NM	639	0.003	0.062
WA	53	0.000	0.016
TX	761	0.000	0.048
CN	38	0.000	0.019
AK	0	0.000	0.000

Table 16

EFFECT OF CEUM CORRECTIONS ON THE EDMD MODEL RUN FOR 1995

EDMD-95 vs. CEDMD-95

COMPARISON RUN
BASE ID: ELECTRICITY & NON-UTILITY 10% DEMAND DECREASE,1995,UNCORRECTED.
RUN ID: EDMD95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
38273	0.062	0.027

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4383	0.042	0.031
OH	1468	0.037	0.038
MD	145	0.000	0.014
NV	3857	0.049	0.030
SV	5358	0.043	0.005
VA	563	0.327	0.006
EK	1425	0.210	0.006
TN	0	0.000	0.000
AL	583	0.048	0.005
IL	6805	0.053	0.023
IN	1590	0.036	0.029
WK	1727	0.102	0.024
IA	55	0.008	0.049
MO	107	0.190	0.230
KS	0	0.000	0.000
OK	103	0.157	0.028
AR	141	0.193	0.008
ND	174	0.675	0.336
SD	12	0.000	0.035
EM	1	0.000	0.038
WM	3264	0.037	0.052
WY	3063	0.031	0.034
CS	1003	0.049	0.023
UT	476	0.000	0.028
AZ	74	0.133	0.029
NM	893	0.054	0.022
WA	16	1.000	1.000
TX	935	0.000	0.014
CN	26	0.000	0.021
AK	0	0.000	0.000

Table 17

SENSITIVITY TO DECREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 10%

CBC-85 vs. CEDMD-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: EDMD85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.092	0.024

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.143	0.020
OH	931	0.104	0.027
MD	67	0.266	0.020
NV	1626	0.186	0.021
SV	5481	0.037	0.027
VA	867	0.004	0.025
EK	2419	0.033	0.028
TN	157	0.000	0.022
AL	748	0.035	0.027
IL	3392	0.171	0.029
IN	783	0.069	0.026
WK	1060	0.000	0.027
IA	11	0.000	0.025
MO	79	0.010	0.000
KS	13	0.000	0.028
OK	68	0.039	0.009
AR	51	0.226	0.025
ND	127	0.055	0.002
SD	12	0.000	0.000
EM	2	0.000	0.002
WM	1193	0.188	0.001
WY	2191	0.053	0.025
CS	696	0.180	0.053
UT	787	0.000	0.002
AZ	99	0.114	0.037
NM	377	0.003	0.001
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.021
AK	0	0.000	0.000

Table 18

SENSITIVITY TO DECREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 10%

CBC-90 vs. CEDMD-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: EDMD90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36607	0.122	0.037

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.206	0.034
OH	1161	0.222	0.031
MD	113	0.211	0.027
NV	3567	0.182	0.053
SV	5863	0.037	0.024
VA	769	0.195	0.024
EK	1861	0.045	0.025
TN	63	0.000	0.029
AL	652	0.053	0.019
IL	5940	0.122	0.033
IN	1407	0.083	0.032
WK	1518	0.183	0.036
IA	26	0.839	0.440
MO	93	0.000	0.031
KS	5	0.000	0.004
OK	84	0.095	0.014
AR	108	0.146	0.014
ND	169	0.593	0.002
SD	12	0.000	0.000
EM	5	0.217	0.026
WM	2611	0.159	0.055
WY	3063	0.085	0.037
CS	1052	0.153	0.045
UT	577	0.079	0.037
AZ	174	0.103	0.296
NM	751	0.019	0.093
WA	55	0.000	0.029
TX	867	0.000	0.080
CN	41	0.000	0.038
AK	0	0.000	0.000

Table 19

SENSITIVITY TO DECREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 10%

CBC-95 vs. CEDMD-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: EDMD95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.125	0.047

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.123	0.033
OH	2166	0.299	0.034
MD	167	0.094	0.026
NV	4483	0.103	0.032
SV	5774	0.032	0.022
VA	811	0.102	0.022
EK	1910	0.149	0.025
TN	0	0.000	0.000
AL	595	0.033	0.023
IL	7973	0.136	0.044
IN	1839	0.157	0.047
WK	1963	0.152	0.047
IA	93	0.375	0.022
MO	148	0.223	0.026
KS	0	0.000	0.000
OK	128	0.140	0.015
AR	175	0.018	0.022
ND	226	0.674	0.326
SD	12	0.000	0.000
EM	1	0.392	0.000
WM	4580	0.126	0.104
WY	4120	0.147	0.075
CS	1172	0.126	0.040
UT	533	0.050	0.045
AZ	81	0.144	0.044
NM	1067	0.146	0.063
WA	17	1.000	1.000
TX	990	0.000	0.042
CN	29	0.000	0.074
AK	0	0.000	0.000

CEDMU - Corrected Energy Demand Up

The corrected EDMU run involved reversing the direction of the changes made in the CEDMD run. Here there was a 10% increase in both exogenously specified electricity demands and non-utility coal demands. The motivation for this run was to determine the overall extent to which the model's activities were constrained from above. The result of this run was that indeed the model appears to be tightly constrained by upper bounds on activity variables, because this run was infeasible, i.e., there was no complete set of model activity levels that could simultaneously statisfy all of the constraints imposed in the model. The only output received on the infeasible run was the linear program activities that were nearest to feasible. This nearest-to-feasible set of activity levels showed that there was only one constraint that could not be met. From the LP output it was surmised that the model was too tightly constrained to meet the additional electricity demands, probably the baseload electricity demands. Unfortunately, there are no model output reports produced from an infeasible run, and thus national results from CEDMU are not included in the run summary tables.

CMILL - Corrected Money Illusion

The corrected Money Illusion run was made to investigate changing the general rate of inflation from 5.5%/year to 8.0%/year. This change was implemented by appropriate increases in nominal escalation rates, in nominal costs of capital, and in the GNP escalator and deflator. The motivation for this run (made only for 1985) was to verify that inflation had been correctly accounted for in all sections of the model. One would expect that if there were a uniform change in the value of money, all activity decisions would remain unchanged. The model results showed some persistent changes, principally away from coal-fired power plants and their associated coal transportation requirements and electricity transmission implications. Total oil/gas turbine capacity picks up the drop in coal-fired capacity. At this time it is not clear what was responsible for this move away from coal-fired capacity.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases slightly.

(2) West-to-East transportation in ton-miles stays approximately the same.

(3) East-to-West transportation in ton-miles increases by 20%.

(4) There is an 8% decrease in KWH of transmission over new lines.

(5) There are negligible changes in metallurgical, low-, and high-sulfur coal production; medium-sulfur coal production decreases by 2%.

(6) There is an increase in the average coal production price at all sulfur levels: 5% for metallurgical, 3% for low sulfur, 4% for medium sulfur, and 4% for high sulfur.

(7) There are small decreases of approximately 1% in surface, deep, and total coal production and in coal consumption.

(8) Average coal production and consumption prices increase by 5%.

(9) There is a slight decrease of 1% in utility coal consumption.

(10) Utility oil/gas consumption increases by 3%.

(11) The LP objective function value increases by 5%.

Implementation of the CMILL Run

1. File: SUPIN

   Lines: 17, 27, 28

   Changes:

   (a) Original Line 17 (in CBC):

   ECP=0.060, EMP=0.065, EPS=0.055, ROR=0.150

   New Line 17 (in CMILL):

   ECP=0.085, EMP=0.090, EPS=0.080, ROR=0.177

   (b) Line 27: The value of RUT was changed from 0.100 to 0.126.

   (c) Line 28: The value of GNPESC was changed from 5.50 to 8.00.

2. File: GDC , Table: CASE

   Lines: 8, 9

   Changes:

   (a) Line 8: The value of UCD was changed from 7.50 to 10.0474.

   (b) Line 9: The value of GNP was changed from 5.50 to 8.00.

A Final Note

The CEUM employs a real fixed charge rate (FCR) to annualize utility capital costs. Since this rate is real as opposed to nominal, we did not feel that it was necessary to change this particular input when implementing a change in the general rate of inflation. We have learned from ICF that, along with other changes that we have implemented correctly, the real FCR does have to be slightly adjusted when the inflation rate changes. ICF apparently has a separate undocumented computer program that calculates the real FCR as a function of several financial parameters. We were unable to properly adjust the fixed charge rate in the CMILL sensivitity run (and also in the UCIN and UDIN model runs) since we did not receive documentation from ICF detailing the complicated manner in which the real FCR is calculated out-of-model. The effect of not adjusting the real fixed charge rate should not significantly impact CEUM output.

Table 20

Corrected Money Illusion (CMILL)

	CBC-1985	CMILL-1985	CBC-1990	CMILL-1990	CBC-1995	CMILL-1995
LP Objective Function (10^6\$, 1978)	74062.08	77664.36	104366.27	*	140080.62	*
National Coal Transportation (10^9 Ton Miles)	556.88	554.67	885.28	*	1208.41	*
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	77.51	123.38	*	175.32	*
(10^9 Ton-Miles)	97.71	97.74	151.60	*	218.17	*
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	20.01	20.41	*	18.17	*
(10^9 Ton-Miles)	3.23	3.87	3.08	*	2.86	*
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	161.549	135.308	*	107.377	*
New	197.289	181.401	167.308	*	176.021	*
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	163.79	169.93	*	173.23	*
Metallurgical (\$/MM Btu)	1.66	1.74	1.78	*	1.86	*
Low Sulfur (MM Tons)	284.83	285.24	459.77	*	623.49	*
Low Sulfur (\$/MM Btu)	0.85	0.88	0.80	*	0.83	*
Medium Sulfur (MM Tons)	411.75	405.23	544.92	*	641.73	*
Medium Sulfur (\$/MM Btu)	1.02	1.06	1.07	*	1.11	*
High Sulfur (MM Tons)	254.90	254.08	330.45	*	437.12	*
High Sulfur (\$/MM Btu)	1.04	1.08	1.23	*	1.33	*
Surface	599.675	598.107	779.491	*	962.596	*
Deep	515.373	510.227	725.578	*	912.968	*
Total: (MM Tons)	1115.048	1108.334	1505.069	*	1875.564	*
Total: (\$/MM Btu)	1.10	1.15	1.14	*	1.18	*
Growth Rate (%/year)	5.6	5.5	5.8	*	5.5	*
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1099.3	1506.6[c]	*	1875.5	*
(\$/Tons)[b]	31.58	33.17	33.19	*	34.14	*
(\$/MM Btu)	1.44	1.51	1.55	*	1.62	*
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	15.91	20.92	*	26.54	*
(\$/MM Btu)	1.35	1.41	1.48	*	1.56	*
Electric Utility Coal Consumption[d] (MM Tons)	753.4	747.4	995.4	*	1280.8	*
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	6.022	3.283	*	1.898	*
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	488.3	454.1	*	417.3	*
New	230.7	229.0	417.4	*	640.6	*

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption · Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 21

SENSITIVITY TO INCREASE IN GENERAL RATE OF INFLATION

CBC-85 vs. CMILL-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: MILL85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.010	0.044

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.023	0.045
OH	931	0.000	0.038
MD	67	0.000	0.048
NV	1626	0.057	0.047
SV	5481	0.003	0.049
VA	867	0.000	0.048
EK	2419	0.000	0.046
TN	157	0.000	0.045
AL	748	0.013	0.047
IL	3892	0.000	0.040
IN	783	0.013	0.042
WK	1060	0.000	0.037
IA	11	0.000	0.039
MO	79	0.000	0.046
KS	13	0.000	0.037
OK	68	0.000	0.052
AR	51	0.000	0.047
ND	127	0.098	0.036
SD	12	0.000	0.035
EM	2	0.000	0.022
WM	1198	0.038	0.036
WY	2191	0.003	0.041
CS	696	0.002	0.041
UT	787	0.000	0.047
AZ	99	0.114	0.005
NM	377	0.007	0.034
WA	53	0.000	0.052
TX	406	0.000	0.045
CN	39	0.000	0.049
AK	0	0.000	0.000

CNINC - Corrected Nuclear Increase

The Corrected Nuclear Increase run was created by increasing by 25% the exogenously specified new nuclear build activity levels for 1985, 1990, and 1995. This run was motivated partly by an availability of information that suggested that the 99 GW (existing plus new) of nuclear in 1985 was a low figure, and that 114 GW was closer to a lower bound of available estimates. The 1990 and 1995 CBC numbers for fixed nuclear capacity were deemed similarly low and thus also escalated. In addition, this run was motivated by a desire to investigate the ramifications of the model output resulting from this type of perturbation. The results showed some relatively large changes from the CBC, such as 17 and 18% decreases in KWH of transmission over new lines in 1985 and 1995, respectively. The predictable occurred in the generation expansion section of the model, namely, extra nuclear capacity offset "coal with scrubber" baseload capacity.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases in each case year: 1% in 1985, 6% in 1990, 8% in 1995.

(2) West-to-East coal transportation in ton-miles decreases in each case year: 5% in 1985, 12% in 1990, 9% in 1995.

(3) East-to-West coal transportation in ton-miles decreases by 1% in 1985, by 3% in 1990, and remains unchanged in 1995.

(4) There are significant decreases in KWH of transmission over new lines in 1985 (17%) and in 1995 (18%), and a slight increase of 1% in 1990.

(5) Metallurgical, low-, medium-, and high-sulfur coal production decreases in each case year.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals generally decrease in each case year (except for a slight increase in the low-sulfur price in 1990) with the largest decreases occurring in 1995.

(7) Surface coal production decreases in each case year: 1% in 1985, 5% in 1990, 7% in 1995; deep coal production decreases in each case year: 3% in 1985, 5% in 1990, 7% in 1995; total coal production decreases in each case year: 2% in 1985, 5% in 1990, 7% in 1995.

(8) The overall average coal production price decreases by 1% in 1985, by 3% in 1995, and remains unchanged in 1990.

(9) Total U.S. coal consumption decreases significantly in each case year; the average coal consumption price decreases slightly in each case year.

(10) Electric utility coal consumption in tons decreases in each case year: 3% in 1985, 6% in 1990, 10% in 1995.

(11) Electric utility oil/gas consumption decreases in each case year: 6% in 1985, 7% in 1990, 2% in 1995.

(12) The LP objective function value decreases by approximately 1% in each case year.

Implementation of the CNINC Run

File: GDU, Tables: (UR)PLNTD, Rows: CPM, Columns: PZ16

Changes: Non-zero values for each utility demand region (UR) were increased by 25%.

Table 22

Corrected Nuclear Increase (CNINC)

	CBC-1985	CNINC-1985	CBC-1990	CNINC-1990	CBC-1995	CNINC-1995
LP Objective Function (10^6\$, 1978)	74062.08	73406.23	104366.27	102923.39	140080.62	138060.06
National Coal Transportation (10^9 Ton Miles)	556.88	549.80	885.28	828.91	1208.41	1114.27
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	73.65	123.38	107.84	175.32	158.44
(10^9 Ton-Miles)	97.71	93.23	151.60	133.00	218.17	198.39
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	19.08	20.41	20.32	18.17	18.18
(10^9 Ton-Miles)	3.23	3.20	3.08	3.00	2.86	2.86
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	173.077	135.308	161.369	107.377	143.003
New	197.289	162.998	167.308	169.164	176.021	143.912
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	161.64	169.93	167.11	173.23	171.13
Metallurgical (\$/MM Btu)	1.66	1.65	1.78	1.78	1.86	1.84
Low Sulfur (MM Tons)	284.83	281.18	459.77	426.71	623.49	559.36
Low Sulfur (\$/MM Btu)	0.85	0.84	0.80	0.81	0.83	0.81
Medium Sulfur (MM Tons)	411.75	402.52	544.92	530.78	641.73	629.52
Medium Sulfur (\$/MM Btu)	1.02	1.01	1.07	1.05	1.11	1.08
High Sulfur (MM Tons)	254.90	248.36	330.45	303.99	437.12	390.17
High Sulfur (\$/MM Btu)	1.04	1.03	1.23	1.22	1.33	1.30
Surface	599.675	595.872	779.491	741.746	962.596	900.441
Deep	515.373	497.813	725.578	686.838	912.968	849.736
Total: MM Tons	1115.048	1093.685	1505.069	1428.584	1875.564	1750.177
Total: \$/MM Btu	1.10	1.09	1.14	1.14	1.18	1.15
Growth Rate (%/year)	5.6	5.4	5.8	5.4	5.5	5.1
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1084.4	1506.6[c]	1429.6[c]	1875.5	1750.5[c]
(\$/Tons)[b]	31.58	31.34	33.19	33.06	34.14	33.63
(\$/MM Btu)	1.44	1.43	1.55	1.54	1.62	1.59
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	15.55	20.92	19.30	26.54	23.97
(\$/MM Btu)	1.35	1.33	1.48	1.47	1.56	1.53
Electric Utility Coal Consumption[d] (MM Tons)	753.4	731.9	995.4	920.0	1280.8	1156.5
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.473	3.283	3.051	1.898	1.860
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	482.4	454.1	448.6	417.3	418.4
New	230.7	235.1	417.4	423.2	640.6	639.8

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 23

SENSITIVITY TO NUCLEAR CAPACITY INCREASE

CBC-85 vs. CNINC-85

COMPARISON RUN

BASE ID: CORRECTED BASE CASE, 1985.

RUN ID: NINC85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.022	0.007

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.038	0.005
CH	931	0.052	0.011
MD	67	0.000	0.005
NV	1626	0.084	0.005
SV	5481	0.005	0.006
VA	867	0.000	0.007
BK	2419	0.022	0.008
TN	157	0.000	0.009
AL	748	0.000	0.009
IL	3892	0.022	0.011
IN	783	0.051	0.010
WK	1060	0.000	0.012
IA	11	0.000	0.011
MC	79	0.000	0.000
KS	13	0.000	0.013
OK	68	0.000	0.002
AR	51	0.054	0.007
ND	127	0.000	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.003	0.001
WY	2191	0.021	0.005
CS	696	0.037	0.009
UT	787	0.000	0.000
AZ	99	0.114	0.037
NM	377	0.022	0.000
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.001
AK	0	0.000	0.000

COILG - Corrected Oil/Gas Price Increase

The corrected Oil/Gas Price Increase run was implemented by increasing this joint price by 25% in all demand regions for 1985. In 1990 and 1995 25% increases in the original intertemporal increments were added to the Corrected Base Case (CBC) 1985 prices. These exogenously set oil/gas prices, being figures of great uncertainty and representing two quite differently priced commodities, were an obvious choice for a sensitivity study. Additional motivation for this change was provided by the recent price increases for these fuels. The following chart displays oil/gas prices in $/MMBTU for the Maine/Vermont/New Hampshire utility demand region:

Residual Oil	CBC (75$)	CBC (78$)	COILG (78$)	MOIL (78$)
1985	2.65	3.11	3.88	3.88
1990	3.51	4.12	4.47	5.15
1995	4.89	5.74	6.50	7.17
Distillate Oil/ Natural Gas				
1985	3.05	3.58	4.47	4.47
1990	3.91	4.59	4.94	5.73
1995	5.29	6.21	6.97	7.76

Note that the MOIL sensitivity run is described later in this section.

The results of this run showed an acute sensitivity of the coal supply system to the oil/gas price. There were several coal production, transportation, and consumption categories where this change produced the largest effects of all the sensitivity runs up to this point in the in-depth study.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases in 1985 (4%) and in 1990 (2%), but stays about the same in 1995.

(2) West-to-East transportation in ton-miles increases in each case year: 4% in 1985, 0.2% in 1990, 1% in 1995.

(3) East-to-West transportation in ton-miles increases significantly in 1985 (13%) but decreases in 1990 (9%) and in 1995 (2%).

(4) There are significant increases in KWH of transmission over new lines in each case year: 32% in 1985, 10% in 1990, 9% in 1995.

(5) Metallurgical coal production stays approximately constant in each case year; low-sulfur coal production increases in 1985 and 1990 but decreases slightly in 1995; medium-sulfur coal production increases in 1985 and 1995 but decreases slightly in 1990; high-sulfur coal production increases in each case year.

(6) The average price of metallurgical, low-, medium-, and high-sulfur coal stays approximately constant in each case year.

(7) Surface coal production increases by 2% in 1985 and in 1990, and stays about the same in 1995; deep coal production increases by 2% in 1985 and in 1990, and by 1% in 1995; overall coal production increases by 2% in 1985 and in 1990, and by less than 1% in 1995.

(8) The average coal production price stays approximately constant in each case year.

(9) Total U.S. coal consumption increases in each case year; the average consumption price stays approximately constant in each case year.

(10) Utility coal consumption in Quads increases in each case year: 3% in 1985, 2% in 1990, 1% in 1995.

(11) Utility oil/gas consumption decreases significantly in each case year: 10% in 1985, 16% in 1990, 10% in 1995.

(12) There is a shift from the use of existing to the use of new capacity in each case year (15 GW in 1990).

(13) The LP objective function value increases by 6% in 1985 and by 1% in 1990 and 1995.

Implementation of the COILG Run

1. File: GAMMA.NOH85

   Lines: 98, 100

   Changes:

   (a) Original Line 98 (in CBC):

   NUSCST=(TRPGPRCP,(UR),PRC)+345*(CASE,CSTMULT,DATA)

   New Line 98 (in COILG):

   NUSCST=(TRPGPRCP,(UR),PRC)+345*(CASE,CSTMULT,DATA)*1.25

   (b) Original Line 100 (in CBC):

   NUSCST=(TRDGPRCP,(UR),PRC)+345*(CASE,CSTMULT,DATA)

   New Line 100 (in COILG):

   NUSCST=(TRDGPRCP,(UR),PRC)+345*(CASE,CSTMULT,DATA)*1.25

2. File: GAMMA.REVISE 90,95 , Table: OILPRICE

   Line 85: The values of 1207 (for 1990) and 2586 (for 1995) were replaced by 1508.75 and 3232.50, respectively, representing 25% increases.

Table 24

Corrected Oil/Gas Price Increase (COILG)

	CBC-1985	COILG-1985	CBC-1990	COILG-1990	CBC-1995	COILG-1995
LP Objective Function ($10^6$$, 1978)	74062.08	78496.86	104366.27	105313.45	140080.62	141368.44
National Coal Transportation (10^9 Ton Miles)	556.88	579.71	885.28	904.83	1208.41	1207.81
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	80.63	123.38	123.26	175.32	176.51
(10^9 Ton-Miles)	97.71	101.16	151.60	151.93	218.17	219.90
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	18.98	20.41	18.63	18.17	18.01
(10^9 Ton-Miles)	3.23	3.65	3.08	2.81	2.86	2.79
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	178.901	135.308	138.409	107.377	114.114
New	197.289	260.238	167.308	184.650	176.021	192.194
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	165.89	169.93	169.93	173.23	172.85
Metallurgical ($/MM Btu)	1.66	1.67	1.78	1.79	1.86	1.86
Low Sulfur (MM Tons)	284.83	301.00	459.77	477.55	623.49	621.14
Low Sulfur ($/MM Btu)	0.85	0.84	0.80	0.80	0.83	0.84
Medium Sulfur ($/MM Tons)	411.75	414.42	544.92	543.12	641.73	646.74
Medium Sulfur ($/MM Btu)	1.02	1.03	1.07	1.07	1.11	1.12
High Sulfur (MM Tons)	254.90	259.75	330.45	338.52	437.12	442.06
High Sulfur ($/MM Btu)	1.04	1.05	1.23	1.24	1.33	1.33
Surface	599.675	613.842	779.491	792.909	962.596	961.213
Deep	515.373	527.209	725.578	736.206	912.968	921.577
Total: (MM Tons)	1115.048	1141.051	1505.069	1529.115	1875.564	1882.790
Total: ($/MM Btu)	1.10	1.11	1.14	1.14	1.18	1.18
Growth Rate (%/year)	5.6	5.8	5.8	5.9	5.5	5.5
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1131.9	1506.6[c]	1530.6[c]	1875.5	1882.7
($/Tons)[b]	31.58	31.80	33.19	33.17	34.14	34.20
($/MM Btu)	1.44	1.45	1.55	1.55	1.62	1.62
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.59	20.92	21.41	26.54	26.71
($/MM Btu)	1.35	1.36	1.48	1.49	1.56	1.56
Electric Utility Coal Consumption[d] (MM Tons)	753.4	778.9	995.4	1019.7	1280.8	1288.2
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.289	3.283	2.760	1.898	1.711
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	478.2	454.1	439.0	417.3	411.9
New	230.7	239.5	417.4	432.5	640.6	646.1

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 25

SENSITIVITY TO INCREASE IN OIL/GAS PRICES

CBC-85 vs. COILG-85

COMPARISON RUN

BASE ID: CORRECTED BASE CASE, 1985.

RUN ID: OILG85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS C	P
27062	0.018	0.008

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS C	P
PA	2819	0.014	0.008
CH	931	0.000	0.010
MD	67	0.206	0.005
NV	1626	0.026	0.006
SV	5481	0.003	0.011
VA	867	0.011	0.009
EK	2419	0.020	0.010
TN	157	0.000	0.023
AL	748	0.053	0.004
IL	3892	0.018	0.010
IN	783	0.051	0.010
WK	1060	0.000	0.010
IA	11	0.000	0.009
MO	79	0.000	0.000
KS	13	0.000	0.001
OK	68	0.000	0.002
AR	51	0.000	0.001
ND	127	0.013	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.089	0.001
WY	2191	0.021	0.007
CS	696	0.034	0.003
UT	787	0.000	0.000
AZ	99	0.000	0.001
NM	377	0.004	0.000
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.001
AK	0	0.000	0.000

Table 26

SENSITIVITY TO INCREASE IN OIL/GAS PRICES

CBC-90 vs. COILG-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: OILG90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS C	P
36807	0.017	0.001

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS C	P
PA	4187	0.015	0.001
CH	1161	0.043	0.003
MD	113	0.000	0.000
NV	3567	0.000	0.000
SV	5863	0.000	0.001
VA	769	0.000	0.001
EK	1861	0.000	0.001
TN	60	0.000	0.001
AL	652	0.000	0.000
IL	5940	0.028	0.001
IN	1407	0.000	0.001
WK	1518	0.000	0.001
IA	26	0.029	0.001
MO	93	0.000	0.001
KS	5	0.000	0.001
OK	84	0.000	0.001
AR	108	0.000	0.000
ND	169	0.314	0.001
SD	12	0.000	0.000
EM	5	0.000	0.001
WM	2611	0.037	0.000
WY	3068	0.004	0.001
CS	1052	0.025	0.011
UT	577	0.043	0.019
AZ	174	0.000	0.002
NM	761	0.169	0.000
WA	55	0.000	0.000
TX	867	0.000	0.001
CN	41	0.000	0.000
AK	0	0.000	0.000

Table 27

SENSITIVITY TO INCREASE IN OIL/GAS PRICES

CBC-95 vs. COILG-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: OILG95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.013	0.002

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.012	0.001
CH	2166	0.025	0.001
MD	167	0.000	0.000
NV	4488	0.000	0.001
SV	5774	0.000	0.000
VA	811	0.000	0.000
EK	1910	0.031	0.000
TN	0	0.000	0.000
AL	595	0.000	0.000
IL	7973	0.030	0.001
IN	1839	0.006	0.001
WK	1963	0.000	0.000
IA	93	0.000	0.000
MC	148	0.023	0.001
KS	0	0.000	0.000
OK	128	0.118	0.001
AR	175	0.000	0.000
ND	226	0.098	0.009
SD	12	0.000	0.000
EM	1	0.000	0.001
WM	4580	0.007	0.001
WY	4120	0.003	0.000
CS	1172	0.037	0.006
UT	533	0.033	0.003
AZ	81	0.000	0.000
NM	1067	0.009	0.032
WA	17	0.000	0.001
TX	990	0.000	0.000
CN	29	0.000	0.000
AK	0	0.000	0.000

UCIN - No Real Escalation in Utility Capital Costs with Inflation Increased to 8%/year

This run was implemented in the same manner as the CMILL run except that utility capital costs experienced no real escalation. Thus, the general inflation rate was increased to 8%/year, as opposed to 5.5%/year in the Corrected Base Case (CBC), and utility capital costs escalated at 8%/year from 1975 to 1995 (no real escalation), as opposed to 7.5%/year until 1985 and 5.5%/year thereafter in the CBC. The motive for this run was based upon published reports that utility capital costs are estimated to increase in the near term by 7.5 to 8%/year. The results of this run should be compared with the other two 8%/year inflation runs, UDIN and CMILL, as well as with CBC.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases by less than 1% in 1985 and by 1% in 1995, but increases by 2% in 1990.

(2) West-to-East coal transportation in ton-miles decreases by 4% in 1985 and by 1% in 1995, but remains essentially unchanged in 1990.

(3) East-to-West coal transportation in ton-miles decreases in each case year: 10% in 1985, 21% in 1990, 6% in 1995.

(4) KWH of transmission over new lines increases in each case year: 2% in 1985, 5% in 1990, 1% in 1995.

(5) Metallurgical coal production decreases in each case year; low-sulfur coal production decreases in 1985 and in 1995, but increases in 1990; medium-sulfur coal production increases in each case year; high-sulfur coal production increases in 1985 and in 1990, but decreases in 1995.

(6) The average production prices of metallurgical, low-, medium-,

and high-sulfur coals increase in each case year.

(7) Surface coal production increases by less than 1% in both 1985 and 1995, and by 2% in 1990; deep coal production increases by 1% or less in each case year; total coal production increases by 2% in 1990 and by less than 1% in both 1985 and 1995.

(8) The overall average coal production price increases in each case year: 5% in 1985, 4% in 1990, 4% in 1995.

(9) Total U.S. coal consumption increases in each case year and the average coal consumption price increases by 5% in each case year.

(10) Electric utility coal consumption increases by 3% in 1990 and by less than 1% in both 1985 and 1995.

(11) Electric utility oil/gas consumption decreases in each case year: 1% in 1985, 20% in 1990, 9% in 1995.

(12) There is a shift in GW of capacity utilization from existing to new: 2 GW in 1985, 21 GW in 1990, 8 GW in 1995.

(13) The LP objective function value changes by less than 1% in each case year.

Implementation of the UCIN Run

1. File: SUPIN

   Lines: 17, 27, 28

   Changes: Same changes as in CMILL.

2. File: GDC , Table: CASE

   Lines: 8, 9

   Changes:

   (a) Line 8: The value of UCD was changed from 7.50 to 8.00.

   (b) Line 9: The value of GNP was changed from 5.50 to 8.00.

Table 28

No Real Escalation in Utility Capital Costs (with Inflation Increased to 8%/year) (UCIN)

	CBC-1985	UCIN-1985	CBC-1990	UCIN-1990	CBC-1995	UCIN-1995
LP Objective Function (10^6\$, 1978)	74062.08	74773.57	104366.27	105261.60	140080.62	140040.50
National Coal Transportation (10^9 Ton Miles)	556.88	555.30	885.28	904.74	1208.41	1193.22
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	74.25	123.38	122.36	175.32	173.26
(10^9 Ton-Miles)	97.71	93.66	151.60	151.58	218.17	215.90
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	18.55	20.41	18.39	18.17	17.86
(10^9 Ton-Miles)	3.23	2.92	3.08	2.42	2.86	2.69
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	160.349	135.308	128.491	107.377	107.488
New	197.289	201.376	167.308	175.997	176.021	178.225
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	161.99	169.93	164.55	173.23	171.14
Metallurgical (\$/MM Btu)	1.66	1.73	1.78	1.86	1.86	1.95
Low Sulfur (MM Tons)	284.83	282.13	459.77	478.70	623.49	579.01
Low Sulfur (\$/MM Btu)	0.85	0.88	0.80	0.84	0.83	0.89
Medium Sulfur (MM Tons)	411.75	416.87	544.92	546.51	641.73	706.45
Medium Sulfur (\$/MM Btu)	1.02	1.07	1.07	1.14	1.11	1.13
High Sulfur (MM Tons)	254.90	257.72	330.45	344.40	437.12	426.55
High Sulfur (\$/MM Btu)	1.04	1.11	1.23	1.28	1.33	1.40
Surface	599.675	601.683	779.491	798.179	962.596	956.747
Deep	515.373	517.020	725.578	735.963	912.968	926.398
Total: (MM Tons)	1115.048	1118.703	1505.069	1534.143	1875.564	1883.145
Total: (\$/MM Btu)	1.10	1.15	1.14	1.19	1.18	1.23
Growth Rate (%/year)	5.6	5.6	5.8	5.9	5.5	5.5
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1109.2	1506.6[c]	1535.4[c]	1875.5	1883.3[c]
(\$/Tons)[b]	31.58	33.22	33.19	34.93	34.14	35.85
(\$/MM Btu)	1.44	1.51	1.55	1.63	1.62	1.70
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.14	20.92	21.54	26.54	26.73
(\$/MM Btu)	1.35	1.41	1.48	1.56	1.56	1.64
Electric Utility Coal Consumption[d] (MM Tons)	753.4	757.5	995.4	1024.7	1280.8	1289.3
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.768	3.283	2.613	1.898	1.719
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	485.3	454.1	433.0	417.3	409.8
New	230.7	232.1	417.4	438.8	640.6	648.6

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 29

SENSITIVITY TO INCREASE IN GENERAL INFLATION
RATE TO 8.0% PER YEAR WITH NO REAL
ESCALATION IN UTILITY CAPITAL COSTS

CBC-85 vs. UCIN-85

COMPARISCN RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: UCIN, 1985, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATICNAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.014	0.049

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATICNS Q	P
PA	2819	0.006	0.057
OH	931	0.000	0.058
MD	67	0.000	0.046
NV	1626	0.069	0.049
SV	5481	0.003	0.048
VA	867	0.000	0.050
EK	2419	0.022	0.050
TN	157	0.000	0.068
AL	748	0.017	0.051
IL	3892	0.003	0.052
IN	783	0.051	0.054
WK	1060	0.000	0.060
IA	11	0.000	0.060
MO	79	0.000	0.046
KS	13	0.000	0.040
OK	68	0.000	0.048
AR	51	0.000	0.047
ND	127	0.072	0.036
SD	12	0.000	0.035
EM	2	0.000	0.022
WM	1198	0.009	0.036
WY	2191	0.030	0.034
CS	696	0.032	0.034
UT	787	0.000	0.048
AZ	99	0.000	0.033
NM	377	0.022	0.035
WA	53	0.000	0.052
TX	406	0.000	0.045
CN	39	0.000	0.039
AK	0	0.000	0.000

Table 30

SENSITIVITY TO INCREASE IN GENERAL INFLATION RATE TO 8.0% PER YEAR WITH NO REAL ESCALATION IN UTILITY CAPITAL COSTS

CBC-90 vs. UCIN-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: UCIN, 1990, CORRECTED

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.034	0.049

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.061	0.052
OH	1161	0.131	0.056
MD	113	0.000	0.046
NV	3567	0.025	0.050
SV	5863	0.035	0.043
VA	769	0.019	0.044
EK	1861	0.000	0.044
TN	60	0.000	0.052
AL	652	0.000	0.050
IL	5940	0.012	0.048
IN	1407	0.015	0.048
WK	1518	0.000	0.048
IA	26	0.747	0.047
MO	93	0.000	0.026
KS	5	0.000	0.048
OK	84	0.039	0.044
AR	108	0.022	0.047
ND	169	0.523	0.054
SD	12	0.000	0.035
EM	5	0.000	0.050
WM	2611	0.031	0.039
WY	3068	0.001	0.046
CS	1052	0.046	0.048
UT	577	0.019	0.055
AZ	174	0.000	0.030
NM	761	0.241	0.076
WA	55	0.000	0.060
TX	867	0.000	0.116
CN	41	0.000	0.049
AK	0	0.000	0.000

Table 31

SENSITIVITY TO INCREASE IN GENERAL INFLATION RATE TO 8.0% PER YEAR WITH NO REAL ESCALATION IN UTILITY CAPITAL COSTS

CBC-95 vs. UCIN-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: UCIN, 1995, CORRECTED

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.039	0.048

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.064	0.050
OH	2166	0.035	0.048
MD	167	0.000	0.048
NV	4488	0.004	0.047
SV	5774	0.014	0.047
VA	811	0.023	0.046
EK	1910	0.035	0.046
TN	0	0.000	0.000
AL	595	0.000	0.048
IL	7973	0.008	0.049
IN	1839	0.006	0.050
WK	1963	0.000	0.049
IA	93	0.000	0.037
MO	148	0.131	0.037
KS	0	0.000	0.000
OK	128	0.124	0.042
AR	175	0.000	0.047
ND	226	0.555	0.036
SD	12	0.000	0.035
EM	1	0.000	0.050
WM	4580	0.097	0.040
WY	4120	0.085	0.041
CS	1172	0.058	0.040
UT	533	0.012	0.038
AZ	81	0.000	0.048
NM	1067	0.081	0.137
WA	17	0.000	0.055
TX	990	0.000	0.048
CN	29	0.000	0.050
AK	0	0.000	0.000

UDIN - Real De-Escalation in Utility Capital Costs with Inflation Increased to 8%/year

The UDIN run is identical with the CMILL run except that utility capital costs escalate until 1985 at a rate 0.5%/year less than the general inflation rate, 8%/year. Thus, utility capital costs escalate at 7.5%/year until 1985 and at 8%/year thereafter, with general inflation at 8%/year. This run was mistakenly made in an attempt to implement an increase in the general inflation rate. The utility capital cost escalation rate was left at the 7.5%/year level that exists in the Corrected Base Case. Note that this run was made only for 1985.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles remains essentially unchanged.

(2) West-to-East coal transportation in ton-miles decreases by 5%.

(3) East-to-West coal transportation in ton-miles decreases by 10%.

(4) There is a 5% increase in KWH of transmission over new lines.

(5) Metallurgical and low-sulfur coal production decrease slightly while both medium- and high-sulfur coal production increase by small amounts.

(6) There is an increase in the average production prices of metallurgical, low-, medium-, and high-sulfur coals.

(7) Surface, deep, and total coal production increase by less than 1%.

(8) The overall average coal production price increases by 5%.

(9) Total U.S. coal consumption increases by less than 1% and the average coal consumption price increases by 5%.

(10) Electric utility coal consumption increases by less than 1%.

(11) Electric utility oil/gas consumption decreases by 2%.

(12) The LP objective function value changes by less than .1%.

Implementation of the UDIN Run

1. File: SUPIN

   Lines: 17, 27, 28

   Changes: Same changes as CMILL.

2. File: GDC , Table: CASE

   Line 9: The value of GNP was changed from 5.50 to 8.00.

Table 32

Real De-Escalation in Utility Capital Costs
(with Inflation Increased to 8%/year) (UDIN)

	CBC-1985	UDIN-1985	CBC-1990	UDIN-1990	CBC-1995	UDIN-1995
LP Objective Function (10^6\$, 1978)	74062.08	74127.66	104366.27	103899.82	140080.62	137959.75
National Coal Transportation (10^9 Ton Miles)	556.88	556.58	885.28	*	1208.41	*
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	73.49	123.38	*	175.32	*
(10^9 Ton-Miles)	97.71	92.80	151.60	*	218.17	*
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	18.55	20.41	*	18.17	*
(10^9 Ton-Miles)	3.23	2.92	3.08	*	2.86	*
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	162.334	135.308	*	107.377	*
New	197.289	205.618	167.308	*	176.021	*
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	161.99	169.93	*	173.23	*
Metallurgical (\$/MM Btu)	1.66	1.73	1.78	*	1.86	*
Low Sulfur (MM Tons)	284.83	282.90	459.77	*	623.49	*
Low Sulfur (\$/MM Btu)	0.85	0.87	0.80	*	0.83	*
Medium Sulfur (MM Tons)	411.75	417.60	544.92	*	641.73	*
Medium Sulfur (\$/MM Btu)	1.02	1.07	1.07	*	1.11	*
High Sulfur (MM Tons)	254.90	258.25	330.45	*	437.12	*
High Sulfur (\$/MM Btu)	1.04	1.11	1.23	*	1.33	*
Surface	599.675	603.051	779.491	*	962.596	*
Deep	515.373	517.686	725.578	*	912.968	*
Total: (MM Tons)	1115.048	1120.737	1505.069	*	1875.564	*
Total: (\$/MM Btu)	1.10	1.15	1.14	*	1.18	*
Growth Rate (%/year)	5.6	5.6	5.8	*	5.5	*
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1111.3	1506.6[c]	*	1875.5	*
(\$/Tons)[b]	31.58	33.19	33.19	*	34.14	*
(\$/MM Btu)	1.44	1.51	1.55	*	1.62	*
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.17	20.92	*	26.54	*
(\$/MM Btu)	1.35	1.41	1.48	*	1.56	*
Electric Utility Coal Consumption[d] (MM Tons)	753.4	758.5	995.4	*	1280.8	*
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.737	3.283	*	1.898	*
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	484.7	454.1	*	417.3	*
New	230.7	232.7	417.4	*	640.6	*

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 33

SENSITIVITY TO INCREASE IN GENERAL INFLATION RATE TO 8.0% PER YEAR WITH REAL DE-ESCALATION IN UTILITY CAPITAL COSTS BY 0.5% PER YEAR

CBC-85 vs. UDIN-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: UDIN85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.018	0.049

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.015	0.060
OH	931	0.000	0.058
MD	67	0.000	0.046
NV	1626	0.084	0.051
SV	5481	0.003	0.047
VA	867	0.000	0.050
EK	2419	0.022	0.051
TN	157	0.000	0.069
AL	748	0.017	0.052
IL	3892	0.006	0.052
IN	783	0.051	0.055
WK	1060	0.000	0.060
IA	11	0.000	0.060
MO	79	0.000	0.046
KS	13	0.000	0.043
OK	68	0.000	0.047
AR	51	0.000	0.047
ND	127	0.142	0.036
SD	12	0.000	0.035
EM	2	0.000	0.022
WM	1198	0.027	0.036
WY	2191	0.035	0.032
CS	696	0.032	0.033
UT	787	0.000	0.049
AZ	99	0.000	0.033
NM	377	0.022	0.035
WA	53	0.000	0.052
TX	406	0.000	0.045
CN	39	0.000	0.034
AK	0	0.000	0.000

LAB3 - Increase in Real Escalation of Labor Costs

The CEUM utilizes a real escalation rate of 1% per year in the unit labor cost (per ton of coal output). The LAB3 sensitivity runs change this escalation rate to 3% per year.

Note that if c denotes unit labor cost, w the average wage rate, and v the average productivity of labor, then $c=w/v$. Therefore, the rate of growth of unit labor costs is the difference between the growth of wage rates and growth of average labor productivity. The CEUM projection that wage rates will grow at a rate that is uniformly one-percentage point higher than the growth-rate of productivity over the next 35 years must be considered highly uncertain. We believed that an average unit labor cost escalation of 3%/year, for example, is well within the realm of possibility. In addition, there is little reason to expect that unit labor cost escalation would be uniform throughout the country. For one thing, both labor-market conditions and technological conditions in the West are quite different from those in the East. One could speculate that productivity will grow more quickly than wages in the West, while the opposite occurs in the East. Such a pattern would imply a considerable difference in the growth of unit labor costs between these two major regions.

The LAB3 model runs indicate that the CEUM is quite sensitive to changes in unit labor cost escalation. The Deviation Index (described in Chapter 1 above) shows that equilibrium coal production prices are roughly 25% higher in the LAB3 model runs than in the Corrected Base Case model runs. Equilibrium quantities are about 15% smaller. Note that these values differ from the averages taken from the CEUM output reports (see below) because of different weighting methods.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases significantly in each case year: 26% in 1985, 28% in 1990, 25% in 1995.

(2) West-to-East coal transportation in ton-miles increases enormously in each case year: 149% in 1985, 171% in 1990, 139% in 1995.

(3) East-to-West coal transportation in ton-miles decreases significantly in each case year: 25% in 1985, 46% in 1990, 25% in 1995.

(4) There are decreases in KWH of transmission over new lines in each case year: 14% in 1985, 6% in 1990, 2% in 1995.

(5) There are significant decreases in metallurgical and high-sulfur coal production, and significant increases in low-sulfur coal production in each case year; medium-sulfur coal production decreases in 1985 and increases significantly in both 1990 and 1995.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals increase significantly in each case year.

(7) Surface coal production increases significantly in each case year: 18% in 1985, 26% in 1990, 25% in 1995; deep coal production decreases significantly in each case year: 16% in 1985, 21% in 1990, 19% in 1995; total coal production increases in each case year: 2% in 1985, 3% in 1990, 4% in 1995.

(8) The overall average coal production price increases significantly in each case year: 16% in 1985, 12% in 1990, 17% in 1995.

(9) Total U.S. coal consumption increases significantly in each case year; the average coal consumption price increases by 15 to 18% in each case year.

(10) Electric utility coal consumption in tons increases in each case year: 3% in 1985, 5% in 1990, 5% in 1995; utility coal consumption in quads decreases by 1 to 2% in each case year.

(11) Electric utility oil/gas consumption increases in each case year:

4% in 1985, 16% in 1990, 13% in 1995.

(12) The LP objective function value increases in each case year: 6% in 1985, 7% in 1990, 8% in 1995.

Implementation of the LAB3 Run

File: SUPIN

Line 17: The value of EMP was changed from 0.065 to 0.087.

Table 34

Increase in Real Escalation of Labor Costs (LAB3)

	CBC-1985	LAB3-1985	CBC-1990	LAB3-1990	CBC-1995	LAB3-1995
LP Objective Function (10^6\$, 1978)	74062.08	78368.76	104366.27	111791.06	140080.62	150923.25
National Coal Transportation (10^9 Ton Miles)	556.88	699.07	885.28	1129.41	1208.41	1509.54
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	176.15	123.38	299.20	175.32	378.59
(10^9 Ton-Miles)	97.71	243.76	151.60	410.78	218.17	522.32
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	16.07	20.41	9.73	18.17	7.95
(10^9 Ton-Miles)	3.23	2.43	3.08	1.66	2.86	2.14
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	160.372	135.308	137.668	107.377	109.067
New	197.289	170.341	167.308	158.054	176.021	171.633
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	140.15	169.93	134.24	173.23	135.53
Metallurgical (\$/MM Btu)	1.66	2.07	1.78	2.22	1.86	2.34
Low Sulfur (MM Tons)	284.83	359.97	459.77	546.77	623.49	732.30
Low Sulfur (\$/MM Btu)	0.85	0.90	0.80	0.88	0.83	1.03
Medium Sulfur (MM Tons)	411.75	400.29	544.92	589.09	641.73	715.31
Medium Sulfur (\$/MM Btu)	1.02	1.17	1.07	1.16	1.11	1.28
High Sulfur (MM Tons)	254.90	240.81	330.45	281.42	437.12	361.64
High Sulfur (\$/MM Btu)	1.04	1.35	1.23	1.57	1.33	1.68
Surface	599.675	708.688	779.491	979.434	962.596	1203.311
Deep	515.373	432.534	725.578	572.082	912.958	741.470
Total: (MM Tons)	1115.048	1141.223	1505.069	1551.516	1875.554	1944.781
Total: (\$/MM Btu)	1.10	1.28	1.14	1.28	1.18	1.38
Growth Rate (%/year)	5.6	5.8	5.8	6.0	5.5	5.7
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1132.8	1506.6[c]	1552.5[c]	1875.5	1944.3
(\$/Tons)[b]	31.58	35.55	33.19	36.44	34.14	38.72
(\$/MM Btu)	1.44	1.67	1.55	1.78	1.62	1.91
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	15.85	20.92	20.50	26.54	26.42
(\$/MM Btu)	1.35	1.54	1.48	1.67	1.56	1.82
Electric Utility Coal Consumption[d] (MM Tons)	753.4	778.9	995.4	1041.3	1280.8	1349.4
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	6.106	3.283	3.802	1.898	2.150
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	488.3	454.1	465.8	417.3	423.7
New	230.7	232.2	417.4	410.0	640.6	638.5

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption - Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 35

SENSITIVITY TO INCREASE IN
REAL LABOR COST ESCALATION

CBC-85 vs. LAB3-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: LAB385C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.148	0.248

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.146	0.305
OH	931	0.130	0.327
MD	67	0.412	0.277
NV	1626	0.221	0.286
SV	5481	0.093	0.255
VA	867	0.022	0.232
EK	2419	0.139	0.261
TN	157	0.000	0.268
AL	748	0.159	0.230
IL	3892	0.181	0.243
IN	783	0.233	0.226
WK	1060	0.000	0.257
IA	11	0.000	0.253
MO	79	0.000	0.315
KS	13	0.000	0.228
OK	68	0.179	0.218
AR	51	0.054	0.270
ND	127	0.121	0.177
SD	12	1.000	0.171
EM	2	0.000	0.234
WM	1198	0.620	0.169
WY	2191	0.124	0.182
CS	696	0.144	0.233
UT	787	0.000	0.290
AZ	99	0.114	0.131
NM	377	0.108	0.132
WA	53	0.000	0.096
TX	406	0.000	0.179
CN	39	0.000	0.097
AK	0	0.000	0.000

Table 36

SENSITIVITY TO INCREASE IN
REAL LABOR COST ESCALATION

CBC-90 vs. LAB3-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: LAB390C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.202	0.242

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.307	0.285
OH	1161	0.190	0.303
MD	113	0.343	0.256
NV	3567	0.210	0.282
SV	5863	0.124	0.247
VA	769	0.409	0.235
EK	1861	0.153	0.253
TN	60	0.000	0.257
AL	652	0.195	0.241
IL	5940	0.146	0.241
IN	1407	0.177	0.222
WK	1518	0.188	0.245
IA	26	0.839	0.240
MO	93	0.557	0.223
KS	5	0.000	0.252
OK	84	0.470	0.220
AR	108	0.057	0.277
ND	169	0.372	0.180
SD	12	1.000	0.171
EM	5	0.000	0.173
WM	2611	0.377	0.196
WY	3068	0.260	0.207
CS	1052	0.215	0.208
UT	577	0.116	0.267
AZ	174	0.075	0.174
NM	761	0.016	0.188
WA	55	0.000	0.128
TX	867	0.000	0.149
CN	41	0.000	0.132
AK	0	0.000	0.000

Table 37

SENSITIVITY TO INCREASE IN
REAL LABOR COST ESCALATION

CBC-95 vs. LAB3-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: LAB395C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.188	0.275

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.201	0.281
OH	2166	0.252	0.303
MD	167	0.339	0.256
NV	4488	0.133	0.281
SV	5774	0.085	0.260
VA	811	0.588	0.245
EK	1910	0.317	0.261
TN	0	0.000	0.000
AL	595	0.119	0.236
IL	7973	0.152	0.239
IN	1839	0.196	0.224
WK	1963	0.181	0.255
IA	93	0.375	0.262
MO	148	0.412	0.262
KS	0	0.000	0.000
OK	128	0.400	0.232
AR	175	0.000	0.269
ND	226	0.410	0.186
SD	12	1.000	0.171
EM	1	0.000	0.173
WM	4580	0.284	0.362
WY	4120	0.223	0.354
CS	1172	0.195	0.213
UT	533	0.089	0.216
AZ	81	0.000	0.270
NM	1067	0.116	0.298
WA	17	1.000	0.232
TX	990	0.000	0.133
CN	29	0.000	0.256
AK	0	0.000	0.000

TCML - Change in Transportation Cost Multiplier

The TCML run was implemented by changing the real rail rate escalation factor in the Corrected Base Case from $(1.01)^{20}$ to $(1.01)^{10}$. The CEUM documentation claims that there is a 1% per year real escalation in transportation costs over the 1975-95 time horizon of the model, but in fact, the escalation factor employed for each case year model run is $(1.01)^{20}$. This will significantly overstate the 1985 real rail rates intended by the user and modeler. The motivation for using an escalation factor of $(1.01)^{10}$ was to bound the magnitudes of the errors that result from the use of a single multiplier for all case years. The TCML-85 model results should be compared directly with the CBC-85 results with any differences carefully noted as implementation errors.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases in each case year: 5% in 1985, 11% in 1990, 6% in 1995.

(2) West-to-East coal transportation in ton-miles increases significantly in each case year: 24% in 1985, 61% in 1990, 40% in 1995.

(3) East-to-West coal transportation in ton-miles decreases by 10% in 1985 and by 2% in 1990, but increases by 2% in 1995.

(4) KWH of transmission over new lines decreases by 4% in 1990 and by 13% in 1995, but increases by 1% in 1985.

(5) Metallurgical, medium-, and high-sulfur coal production decreases in each case year; low-sulfur coal production increases significantly in each case year.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals decrease in each case year.

(7) Surface coal production increases in each case year: 2% in 1985, 9% in 1990, 6% in 1995; deep coal production decreases in each case year: 2% in 1985, 6% in 1990, 4% in 1995; total coal production increases in each case year: .5% in 1985, 2% in 1990, 1% in 1995.

(8) The overall average coal production price decreases in each case year: 1% in 1985, 4% in 1990, 3% in 1995.

(9) Total U.S. coal consumption increases in each case year; the average coal consumption price decreases by 3% in each case year.

(10) Electric utility coal consumption in tons increases by less than 1% in 1985, by 3% in 1990, and by 2% in 1995.

(11) Electric utility oil/gas consumption decreases by 8% in 1990 and by 2% in 1995, and remains approximately unchanged in 1985.

(12) The LP objective function value decreases by approximately 1% in each case year.

Implementation of the TCML Run

File: GDC , Table: CASE

Line 40: The value of TCMLT was changed from $(1.01)^{20}=1.22019$ to $(1.01)^{10}=1.10462$.

Table 38

Change in Transportation Cost Multiplier (TCML)

	CBC-1985	TCML-1985	CBC-1990	TCML-1990	CBC-1995	TCML-1995
LP Objective Function (10^6\$, 1978)	74062.08	73196.40	104366.27	103055.00	140080.62	138459.60
National Coal Transportation (10^9 Ton Miles)	556.88	585.93	885.28	985.24	1208.41	1282.24
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	94.36	123.38	188.32	175.32	236.32
(10^9 Ton-Miles)	97.71	120.71	151.60	244.48	218.17	305.30
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	18.62	20.41	19.64	18.17	18.41
(10^9 Ton-Miles)	3.23	2.91	3.08	3.03	2.86	2.91
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	160.866	135.308	133.349	107.377	108.103
New	197.289	199.270	167.308	161.258	176.021	154.107
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	162.84	169.93	165.15	173.23	169.15
Metallurgical ($/MM Btu)	1.66	1.65	1.78	1.77	1.86	1.84
Low Sulfur (MM Tons)	284.83	305.83	459.77	537.06	623.49	672.46
Low Sulfur ($/MM Btu)	0.85	0.83	0.80	0.77	0.83	0.83
Medium Sulfur (MM Tons)	411.75	399.73	544.92	535.64	641.73	638.94
Medium Sulfur ($/MM Btu)	1.02	1.01	1.07	1.05	1.11	1.09
High Sulfur (MM Tons)	254.90	252.45	330.45	295.88	437.12	412.56
High Sulfur ($/MM Btu)	1.04	1.03	1.23	1.22	1.33	1.30
Surface	599.675	614.232	779.491	849.681	962.596	1017.620
Deep	515.373	506.615	725.578	684.040	912.968	875.492
Total: (MM Tons)	1115.048	1120.847	1505.069	1533.720	1875.564	1893.113
Total: ($/MM Btu)	1.10	1.09	1.14	1.10	1.18	1.15
Growth Rate (%/year)	5.6	5.6	5.8	5.9	5.5	5.5
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1111.9	1506.6[c]	1535.6[c]	1875.5	1893.5[c]
($/Tons)[b]	31.58	30.59	33.19	31.79	34.14	32.79
($/MM Btu)	1.44	1.40	1.55	1.50	1.62	1.57
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.06	20.92	21.17	26.54	26.60
($/MM Btu)	1.35	1.31	1.48	1.44	1.56	1.51
Electric Utility Coal Consumption[d] (MM Tons)	753.4	758.1	995.4	1025.7*	1280.8	1300.0
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.843	3.283	3.025	1.898	1.856
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	486.5	454.1	445.6	417.3	415.6
New	230.7	230.9	417.4	426.5	640.6	642.8

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 39

SENSITIVITY TO DECREASE IN
REAL RAIL RATE ESCALATION

CBC-85 vs. TCML-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: TCML85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.031	0.009

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.056	0.005
CH	931	0.052	0.009
MD	67	0.000	0.004
NV	1626	0.083	0.005
SV	5481	0.005	0.005
VA	867	0.000	0.007
EK	2419	0.000	0.004
TN	157	0.000	0.006
AL	748	0.000	0.015
IL	3892	0.003	0.011
IN	783	0.060	0.013
WK	1060	0.000	0.014
IA	11	0.000	0.016
MO	79	0.000	0.000
KS	13	0.000	0.044
OK	68	0.000	0.033
AR	51	0.054	0.009
ND	127	0.000	0.001
SD	12	0.000	0.001
EM	2	0.000	0.034
WM	1198	0.183	0.001
WY	2191	0.046	0.019
CS	696	0.069	0.018
UT	787	0.000	0.001
AZ	99	0.068	0.028
NM	377	0.108	0.025
WA	53	0.000	0.052
TX	406	0.000	0.001
CN	39	0.000	0.033
AK	0	0.000	0.000

Table 40

SENSITIVITY TO DECREASE IN
REAL RAIL RATE ESCALATION

CBC-90 vs. TCML-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: TCML90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.066	0.011

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.043	0.008
OH	1161	0.091	0.005
MD	113	0.000	0.012
NV	3567	0.032	0.009
SV	5863	0.020	0.010
VA	769	0.057	0.010
EK	1861	0.000	0.010
TN	60	0.000	0.012
AL	652	0.005	0.005
IL	5940	0.102	0.012
IN	1407	0.059	0.018
WK	1518	0.139	0.019
IA	26	0.241	0.021
MO	93	0.000	0.019
KS	5	0.000	0.020
OK	84	0.275	0.018
AR	108	0.016	0.003
ND	169	0.311	0.001
SD	12	0.000	0.001
EM	5	0.000	0.001
WM	2611	0.249	0.002
WY	3068	0.008	0.015
CS	1052	0.012	0.008
UT	577	0.001	0.000
AZ	174	0.041	0.065
NM	761	0.231	0.000
WA	55	0.000	0.037
TX	867	0.000	0.052
CN	41	0.000	0.030
AK	0	0.000	0.000

Table 41

SENSITIVITY TO DECREASE IN
REAL RAIL RATE ESCALATION

CBC-95 vs. TCML-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: TCML95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.044	0.017

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.001	0.011
OH	2166	0.031	0.006
MD	167	0.094	0.015
NV	4488	0.048	0.011
SV	5774	0.016	0.014
VA	811	0.065	0.014
EK	1910	0.051	0.013
TN	0	0.000	0.000
AL	595	0.017	0.015
IL	7973	0.047	0.022
IN	1839	0.100	0.026
WK	1963	0.055	0.026
IA	93	0.000	0.010
MO	148	0.141	0.010
KS	0	0.000	0.000
OK	128	0.178	0.018
AR	175	0.000	0.017
ND	226	0.293	0.009
SD	12	0.000	0.001
EM	1	0.000	0.001
WM	4580	0.124	0.026
WY	4120	0.006	0.003
CS	1172	0.070	0.019
UT	533	0.000	0.007
AZ	81	0.000	0.018
NM	1067	0.045	0.060
WA	17	0.000	0.028
TX	990	0.000	0.048
CN	29	0.000	0.009
AK	0	0.000	0.000

LOAD - Load Duration Curve Parameter Changes

This run was implemented by taking the corrected version of the Base Case and making two changes to the load duration curve parameters. These load duration curve parameters define the percentages of the electric energy that can be categorized as baseload, intermediate, seasonal peaking, and daily peaking. Although these percentages vary by region, typical numbers are 75% baseload, 18% intermediate, 5% seasonal peaking, and 2% daily peaking. The changes implemented in this run were to drop the baseload percentages by 5 percentage points and increase the daily peaking by 5 percentage points. The principal motive for making this run was based primarily on the synthetic nature of these data, that is, synthetic in that there does not exist a measurement system nor consensus definitions for the load categories. The 5% perturbations were viewed as a reasonable maximum range for variations in these numbers.

A secondary motive for these changes was to simulate some of the effects of forced outages in the larger facilities. Peaking units are constructed not only to cover short-term increases in the load, as measured in the load duration curve, but also and perhaps most importantly, to cover short-term losses in generation caused by forced outages on generation equipment.

The results of this change, particularly with respect to turbine capacity, were very significant. Our first response to these results was to check the implementation of the changes. The second response was to make the same change again, except with 1% rather than 5% load factor perturbations. This 1% run is denoted by LDC1 and is described separately.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases in each case year: 2% in 1985, 5% in 1990, 6% in 1995.

(2) West-to-East transportation in ton-miles decreases in each case year: 9% in 1985, 11% in 1990, 8% in 1995.

(3) East-to-West transportation in ton-miles increases in 1985 (18%) and in 1995 (1%) but decreases by 5% in 1990.

(4) KWH of transmission over new lines decreases significantly in each case year: 20% in 1985, 13% in 1990, and 20% in 1995.

(5) Coal production and price decrease for metallurgical, low-, medium-, and high-sulfur coal, in each case year.

(6) Surface coal production decreases in each case year: 2% in 1985, 4% in 1990, 6% in 1995; deep coal production decreases by 2% in 1985 and 1990 and by 4% in 1995; overall coal production decreases by 2% in 1985, 3% in 1990, and 5% in 1995.

(7) The average coal production price increases by 6% in 1985, and stays approximately the same in 1990 and 1995.

(8) Total U.S. coal consumption decreases in each case year; the average consumption price decreases slightly in 1985 and 1995, and remains unchanged in 1990.

(9) Utility coal consumption decreases in each case year: 2% in 1985, 5% in 1990, 8% in 1995.

(10) Utility oil/gas consumption increases significantly in each case year: 15% in 1985, 48% in 1990, 149% in 1995.

(11) Existing GW usage increases in each case year: 3% in 1985, 7% in 1990, 16% in 1995; there are enormous increases in new capacity usage in each case year (almost entirely due to new turbine capacity): 96% in 1985, 61% in 1990, 44% in 1995; the percentage increases in new turbine capacity are: 590% in 1985, 784% in 1990, 756% in 1995.

(12) There are significant increases in the LP objective function value: 11% in 1985, 12% in 1990, 14% in 1995.

Implementation of the LOAD Run

File: GDU1, Tables: (UR)LOAD, Rows: B and Z, Columns: LD

Changes: In each (UR)LOAD table the value in row B, column LD was decreased by 0.05 and the value in row Z, column LD was increased by 0.05.

Table 42

Load Duration Curve Parameter Changes (LOAD)

	CBC-1985	LOAD-1985	CBC-1990	LOAD-1990	CBC-1995	LOAD-1995
LP Objective Function (10^6\$, 1978)	74062.08	82449.21	104366.27	116612.62	140080.62	159400.85
National Coal Transportation (10^9 Ton Miles)	556.88	545.85	885.28	845.13	1208.41	1130.65
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	69.26	123.38	108.63	175.32	162.23
(10^9 Ton-Miles)	97.71	89.20	151.60	134.53	218.17	202.46
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	19.24	20.41	19.20	18.17	18.27
(10^9 Ton-Miles)	3.23	3.81	3.08	2.94	2.86	2.89
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	166.843	135.308	144.078	107.377	120.826
New	197.289	158.497	167.308	145.909	176.021	140.444
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	161.64	169.93	165.55	173.23	171.24
Metallurgical (\$/MM Btu)	1.66	1.65	1.78	1.77	1.86	1.85
Low Sulfur (MM Tons)	284.83	277.61	459.77	428.66	623.49	560.77
Low Sulfur (\$/MM Btu)	0.85	0.84	0.80	0.81	0.83	0.81
Medium Sulfur (MM Tons)	411.75	401.00	544.92	538.04	641.73	634.13
Medium Sulfur (\$/MM Btu)	1.02	1.01	1.07	1.06	1.11	1.08
High Sulfur (MM Tons)	254.90	252.40	330.45	323.03	437.12	408.77
High Sulfur (\$/MM Btu)	1.04	1.03	1.23	1.23	1.33	1.30
Surface	599.675	589.563	779.491	746.041	962.596	902.187
Deep	515.373	503.075	725.578	709.241	912.968	872.709
Total: (MM Tons)	1115.048	1092.638	1505.069	1455.281	1875.564	1774.897
Total: (\$/MM Btu)	1.10	1.10	1.14	1.14	1.18	1.16
Growth Rate (%/year)	5.6	5.4	5.8	5.5	5.5	5.2
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1083.3	1506.6[c]	1456.3[c]	1875.5	1775.5[c]
(\$/Tons)[b]	31.58	31.35	33.19	33.22	34.14	33.82
(\$/MM Btu)	1.44	1.43	1.55	1.55	1.62	1.60
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	15.57	20.92	19.93	26.54	24.53
(\$/MM Btu)	1.35	1.33	1.48	1.48	1.56	1.54
Electric Utility Coal Consumption[d] (MM Tons)	753.4	730.3	995.4	947.0	1280.8	1181.2
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	6.745	3.283	4.850	1.898	4.727
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	500.3	454.1	485.9	417.3	483.0
New	230.7	453.0	417.4	671.3	640.6	920.9

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 43

SENSITIVITY TO CHANGE IN
LOAD DURATION CURVE PARAMETERS

CBC-85 vs. LOAD-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: LOAD85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.028	0.006

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.024	0.004
OH	931	0.052	0.010
MD	67	0.000	0.004
NV	1626	0.084	0.004
SV	5481	0.005	0.005
VA	867	0.000	0.007
EK	2419	0.022	0.006
TN	157	0.000	0.008
AL	748	0.000	0.007
IL	3892	0.000	0.010
IN	783	0.051	0.009
WK	1060	0.000	0.011
IA	11	0.000	0.010
MO	79	0.000	0.000
KS	13	0.000	0.009
OK	68	0.000	0.002
AR	51	0.054	0.007
ND	127	0.046	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.247	0.001
WY	2191	0.029	0.006
CS	696	0.037	0.007
UT	787	0.000	0.001
AZ	99	0.000	0.000
NM	377	0.011	0.001
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.004
AK	0	0.000	0.000

Table 44

SENSITIVITY TO CHANGE IN
LOAD DURATION CURVE PARAMETERS

CBC-90 vs. LOAD-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: LOAD90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.028	0.006

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.033	0.006
OH	1161	0.063	0.002
MD	113	0.000	0.007
NV	3567	0.028	0.006
SV	5863	0.020	0.009
VA	769	0.057	0.008
EK	1861	0.000	0.009
TN	60	0.000	0.005
AL	652	0.005	0.004
IL	5940	0.022	0.000
IN	1407	0.002	0.000
WK	1518	0.000	0.000
IA	26	0.000	0.000
MO	93	0.000	0.012
KS	5	0.000	0.000
OK	84	0.039	0.005
AR	108	0.000	0.000
ND	169	0.247	0.012
SD	12	0.000	0.000
EM	5	0.000	0.001
WM	2611	0.112	0.000
WY	3068	0.004	0.008
CS	1052	0.012	0.006
UT	577	0.064	0.034
AZ	174	0.000	0.015
NM	761	0.019	0.041
WA	55	0.000	0.000
TX	867	0.000	0.034
CN	41	0.000	0.000
AK	0	0.000	0.000

Table 45

SENSITIVITY TO CHANGE IN
LOAD DURATION CURVE PARAMETERS

CBC-95 vs. LOAD-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: LOAD95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.046	0.023

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.001	0.014
OH	2166	0.119	0.013
MD	167	0.094	0.009
NV	4488	0.069	0.013
SV	5774	0.002	0.007
VA	811	0.021	0.007
EK	1910	0.046	0.007
TN	0	0.000	0.000
AL	595	0.017	0.007
IL	7973	0.035	0.018
IN	1839	0.078	0.017
WK	1963	0.055	0.020
IA	93	0.000	0.017
MO	148	0.223	0.017
KS	0	0.000	0.000
OK	128	0.124	0.012
AR	175	0.000	0.008
ND	226	0.340	0.021
SD	12	0.000	0.000
EM	1	0.000	0.001
WM	4580	0.126	0.063
WY	4120	0.003	0.053
CS	1172	0.069	0.017
UT	533	0.001	0.000
AZ	81	0.000	0.035
NM	1067	0.087	0.045
WA	17	0.000	0.034
TX	990	0.000	0.031
CN	29	0.000	0.045
AK	0	0.000	0.000

ROYI - Corrected Royalty Increase

The ROYI run was implemented by changing royalties for privately owned coal from 0% in the Corrected Base Case to 10%. A Federal royalty tax rate, as a percentage of sales, is used here as a proxy for royalty payments on non-Federal coal. The royalties for coal on Federal lands were left unchanged at 12.5% for surface coal and 8% for deep coal. The M.I.T. Model Assessment Group believes that the use of zero values for royalties on non-Federal coal results from a conceptual error in the development of the CEUM. Our choice of 10% is motivated by information obtained from coal company and coal association sources, by theoretical computations (see Volume III, Chapter 2), and by the average of surface and deep Federal royalties. This number is not absolutely defensible and should be viewed only as a rough estimate to gain some insight into the effects of royalty charges on non-Federal coal.

As would be expected, this change tends to favor Federal coal use. The magnitude of this effect is substantial. Since most Federally-owned coal is in the West, the transportations of coal between the West and the East are good, although somewhat muted, indicators of Federal and non-Federal coal activities.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases significantly in each case year: 9% in 1985, 14% in 1990, and 12% in 1995.

(2) West-to-East coal transportation in ton-miles increases enormously in each case year: 52% in 1985, 77% in 1990, and 66% in 1995.

(3) East-to-West coal transportation in ton-miles decreases quite significantly in each case year: 21% in 1985, 54% in 1990, and 27% in 1995.

(4) There are slight decreases (1 to 3%) in KWH of transmission over new

lines in each case year.

(5) There are moderate decreases in the production of metallurgical, medium-sulfur (except in 1995), and high-sulfur coal, and significant increases in the production of low-sulfur coal (19% in 1990) in each case year.

(6) There are significant increases in the average production price of metallurgical (7 to 8%) and high-sulfur coal (8 to 10%) in each case year; the average production price of medium-sulfur coal increases in 1985 and 1990 with no change in 1995; the average production price of low-sulfur coal remains relatively constant in each case year.

(7) There are significant increases in surface coal production: 5% in 1985, 11% in 1990, 12% in 1995; there are significant decreases in deep coal production: 5% in 1985, 9% in 1990, 9% in 1995; total coal production increases slightly in each case year.

(8) There are small increases (moderate in 1985) in the overall average coal production price in each case year; there are moderate increases (4 to 5%) in the average coal consumption price in each case year.

(9) Electric utility coal consumption in tons increases slightly (1 to 3%) in each case year; there are small decreases in utility coal consumption in quads.

(10) There are small increases (1 to 3%) in electric utility oil/gas consumption in each case year.

(11) There are small increases in total coal consumption in each case year.

(12) There are negligible shifts in GW of capacity utilization.

(13) The LP objective function value increases approximately 2% in each case year.

Implementation of the ROYI Run

File: SUPIN

Changes: Federal royalty tax rates of 10% for both surface and deep coal were imposed as proxies for royalty payments in non-Federal coal supply regions. The royalties for coal on Federal lands were left unchanged at 12.5% for surface coal and 8.0% for deep coal. The change was implemented by adding the regional overrides F$S=.100 and F$D=.100 in the SUPIN data for each coal supply region except North Dakota, Eastern and Western Montana, Wyoming, Colorado South and North, and New Mexico.

Table 46

Corrected Royalty Increase (ROYI)

	CBC-1985	ROYI-1985	CBC-1990	ROYI-1990	CBC-1995	ROYI-1995
LP Objective Function ($10^6$$, 1978)	74062.08	75232.38	104366.27	106475.16	140080.62	143139.17
National Coal Transportation (10^9 Ton Miles)	556.88	607.81	885.28	1010.68	1208.41	1353.71
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	113.95	123.38	205.38	175.32	274.84
(10^9 Ton-Miles)	97.71	148.27	151.60	268.49	218.17	361.59
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	16.42	20.41	9.70	18.17	8.15
(10^9 Ton-Miles)	3.23	2.54	3.08	1.41	2.86	2.08
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	159.502	135.308	132.914	107.377	104.079
New	197.289	194.971	167.308	162.357	176.021	173.011
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	150.74	169.93	153.34	173.23	159.23
Metallurgical ($/MM Btu)	1.66	1.78	1.78	1.90	1.86	2.01
Low Sulfur (MM Tons)	284.83	318.51	459.77	544.87	623.49	677.20
Low Sulfur ($/MM Btu)	0.85	0.86	0.80	0.78	0.83	0.84
Medium Sulfur (MM Tons)	411.75	402.77	544.92	533.21	641.73	685.80
Medium Sulfur ($/MM Btu)	1.02	1.07	1.07	1.12	1.11	1.11
High Sulfur (MM Tons)	254.90	251.14	330.45	295.31	437.12	388.57
High Sulfur ($/MM Btu)	1.04	1.14	1.23	1.34	1.33	1.43
Surface	599.675	632.254	779.491	866.373	962.596	1077.063
Deep	515.373	490.903	725.578	660.358	912.968	833.729
Total: (MM Tons)	1115.048	1123.157	1505.069	1526.731	1875.564	1910.792
Total: ($/MM Btu)	1.10	1.16	1.14	1.16	1.18	1.20
Growth Rate (%/year)	5.6	5.7	5.8	5.9	5.5	5.6
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1113.7	1506.6[c]	1528.0[c]	1875.5	1910.4
($/Tons)[b]	31.58	32.83	33.19	34.05	34.14	34.82
($/MM Btu)	1.44	1.51	1.55	1.62	1.62	1.68
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.00	20.92	20.85	26.54	26.57
($/MM Btu)	1.35	1.41	1.48	1.55	1.56	1.61
Electric Utility Coal Consumption[d] (MM Tons)	753.4	761.2	995.4	1017.5	1280.8	1315.9
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.919	3.283	3.367	1.898	1.928
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	486.8	454.1	455.6	417.3	417.6
New	230.7	231.3	417.4	417.3	640.6	642.0

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption ≠ Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 47

SENSITIVITY TO IMPOSING A 10%
FEDERAL ROYALTY CHARGE IN NON-FEDERAL REGIONS

CBC-85 vs. ROYI-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: 10% ROYALTY IN NON-FEDERAL REGIONS, 1985, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.088	0.073

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.121	0.092
OH	931	0.130	0.091
MD	67	0.412	0.070
NV	1626	0.148	0.077
SV	5481	0.057	0.075
VA	867	0.011	0.075
EK	2419	0.099	0.082
TN	157	0.000	0.083
AL	748	0.075	0.070
IL	3892	0.072	0.082
IN	783	0.097	0.079
WK	1060	0.000	0.088
IA	11	0.000	0.086
MO	79	0.000	0.111
KS	13	0.000	0.056
OK	68	0.089	0.059
AR	51	0.167	0.081
ND	127	0.119	0.000
SD	12	1.000	0.000
EM	2	0.000	0.000
WM	1198	0.235	0.000
WY	2191	0.073	0.041
CS	696	0.229	0.052
UT	787	0.000	0.113
AZ	99	0.114	0.000
NM	377	0.058	0.001
WA	53	0.000	0.000
TX	406	0.000	0.111
CN	39	0.000	0.000
AK	0	0.000	0.000

Table 48

SENSITIVITY TO IMPOSING A 10%
FEDERAL ROYALTY CHARGE IN NON-FEDERAL REGIONS

CBC-90 vs. ROYI-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: 10% ROYALTY IN NON-FEDERAL REGIONS, 1990, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.126	0.064

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.151	0.088
OH	1161	0.157	0.094
MD	113	0.211	0.073
NV	3567	0.103	0.087
SV	5863	0.066	0.068
VA	769	0.271	0.070
EK	1861	0.097	0.072
TN	60	0.000	0.079
AL	652	0.087	0.083
IL	5940	0.127	0.079
IN	1407	0.117	0.072
WK	1518	0.188	0.079
IA	26	0.839	0.058
MO	93	0.564	0.033
KS	5	0.000	0.065
OK	84	0.431	0.054
AR	108	0.117	0.095
ND	169	0.392	0.000
SD	12	1.000	0.000
EM	5	0.000	0.000
WM	2611	0.292	0.002
WY	3068	0.102	0.034
CS	1052	0.059	0.015
UT	577	0.006	0.111
AZ	174	0.103	0.030
NM	761	0.029	0.000
WA	55	0.000	0.013
TX	867	0.000	0.000
CN	41	0.000	0.004
AK	0	0.000	0.000

Table 49

SENSITIVITY TO IMPOSING A 10%
FEDERAL ROYALTY CHARGE IN NON-FEDERAL REGIONS

CBC-95 vs. ROYI-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: 10% ROYALTY IN NON-FEDERAL REGIONS, 1995, CORRECTED.

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE	DEVIATIONS	
($MM)	Q	P
46605	0.102	0.064

REGIONAL AVERAGES

REG	VALUE	DEVIATIONS	
	($MM)	Q	P
PA	5549	0.081	0.088
OH	2165	0.140	0.096
MD	167	0.094	0.081
NV	4488	0.029	0.090
SV	5774	0.046	0.083
VA	811	0.251	0.069
EK	1910	0.171	0.082
TN	0	0.000	0.000
AL	595	0.077	0.070
IL	7973	0.112	0.067
IN	1839	0.158	0.061
WK	1963	0.137	0.069
IA	93	0.309	0.085
MO	148	0.489	0.055
KS	0	0.000	0.000
OK	123	0.449	0.054
AR	175	0.056	0.078
ND	226	0.298	0.004
SD	12	1.000	0.000
EM	1	0.000	0.000
WM	4580	0.126	0.020
WY	4120	0.133	0.032
CS	1172	0.072	0.022
UT	533	0.039	0.035
AZ	81	0.105	0.073
NM	1067	0.033	0.025
WA	17	1.000	0.051
TX	990	0.000	0.007
CN	29	0.000	0.015
AK	0	0.000	0.000

EDMI - Corrected Energy Demand Increase

Exogenously specified regional electricity and non-utility coal demands were increased by 5% from the levels in the Corrected Base Case version of the model. This run was initiated after learning that the 10% increase (EDMU run) was infeasible. A major motivation for both of these runs was to determine how much of the supply activity within the model was directed by constraints and how much was just linear scaling of Base Case solution activities. The overall objective function dollar costs in the three demand runs (EDMD, CBC, and EDMI) form almost exactly straight lines for 1985, 1990, and 1995, when plotted versus total energy demand. One result of investigating these runs shows that although there are some important constraints and substitutions of activities in the model, there are either relatively few of these or they are so nearly of equal performance that the overall national cost is just a linear scaling of demands. Another result of these investigations showed that this linear scaling was steeper in 1995 than in 1985. There are no significant real escalation factors to steepen this slope and thereby, it can probably be said that the model is not really increasing the opportunity set from 1985 to 1995. In other words there are not significant differences in the strategies for meeting variations in demands.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases in each case year: 6% in 1985, 8% in 1990, 8% in 1995.

(2) West-to-East coal transportation in ton-miles increases in each case year: 8% in 1985, 7% in 1990, 10% in 1995.

(3) East-to-West coal transportation in ton-miles decreases by 2% in 1985 and by 25% in 1990, but increases by 4% in 1995.

(4) KWH of transmission over new lines increase in each case year: 7% in

1985, 6% in 1990, 8% in 1995.

(5) Metallurgical, low-, medium-, and high-sulfur coal production increases in each case year.

(6) The average production prices of metallurgical and high-sulfur coal increase in each case year; the average production price of low-sulfur coal remains unchanged in 1985, decreases slightly in 1990, and increases slightly in 1995; the average production price of medium-sulfur coal increases in both 1985 and 1990, but decreases slightly in 1995.

(7) Surface coal production increases in each case year: 3% in 1985, 6% in 1990, 8% in 1995; deep coal production increases in each case year: 6% in 1985, 7% in 1990, 7% in 1995; total coal production increases in each case year: 4% in 1985, 7% in 1990, 7% in 1995.

(8) The overall average coal production price increases by 2% in 1985 but changes by less than 1% in both 1990 and 1995.

(9) Total U.S. coal consumption increases significantly in each case year; the average coal consumption price increases slightly in both 1985 and 1990, and remains unchanged in 1995.

(10) Electric utility coal consumption in both tons and quads increases in each case year: 4% in 1985, 8% in 1990, 8% in 1995.

(11) Electric utility oil/gas consumption increases in each case year: 15% in 1985, 7% in 1990, 5% in 1995.

12) There is a significant increase in GW of new capacity utilization in each case year: 13% in 1985, 11% in 1990, 9% in 1995.

(13) The LP objective function value increases in each case year: 9% in 1985, 8% in 1990, 7% in 1995.

Implementation of the EDMI Run

1. File: GAMMA.NOH85

   Changes: Same changes as in CEDMD except that each value of 0.90 is replaced by 1.05.

2. File: GAMMA.REVISE 90,95

   Changes: Same changes as in CEDMD except that each value of 0.90 is replaced by 1.05.

Table 50

Corrected Energy Demand Increase (EDMI)

	CBC-1985	EDMI-1985	CBC-1990	EDMI-1990	CBC-1995	EDMI-1995
LP Objective Function (10^6\$, 1978)	74062.08	80420.73	104366.27	112323.32	140080.62	149998.51
National Coal Transportation (10^9 Ton Miles)	556.88	588.06	885.28	956.07	1208.41	1300.19
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	83.76	123.38	131.34	175.32	191.27
(10^9 Ton-Miles)	97.71	105.09	151.60	162.19	218.17	239.05
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	19.40	20.41	19.01	18.17	18.39
(10^9 Ton-Miles)	3.23	3.16	3.08	2.31	2.86	2.97
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	169.425	135.308	129.552	107.377	108.602
New	197.289	210.960	167.308	178.441	176.021	190.214
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	172.59	169.93	176.32	173.23	179.11
Metallurgical (\$/MM Btu)	1.66	1.68	1.78	1.80	1.86	1.87
Low Sulfur (MM Tons)	284.83	303.89	459.77	513.15	623.49	658.38
Low Sulfur (\$/MM Btu)	0.85	0.85	0.80	0.79	0.83	0.84
Medium Sulfur (MM Tons)	411.75	421.89	544.92	558.81	641.73	707.70
Medium Sulfur (\$/MM Btu)	1.02	1.03	1.07	1.09	1.11	1.10
High Sulfur (MM Tons)	254.90	265.53	330.45	358.63	437.12	465.77
High Sulfur (\$/MM Btu)	1.04	1.06	1.23	1.25	1.33	1.34
Surface	599.675	617.220	779.491	829.364	962.596	1037.324
Deep	515.373	546.674	725.578	777.558	912.968	973.632
Total: (MM Tons)	1115.048	1163.894	1505.069	1606.921	1875.564	2010.956
Total: (\$/MM Btu)	1.10	1.12	1.14	1.14	1.18	1.17
Growth Rate (%/year)	5.6	6.0	5.8	6.2	5.5	5.8
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1154.9	1506.6[c]	1608.6[c]	1875.5	2011.0[c]
(\$/Tons)[b]	31.58	32.07	33.19	33.31	34.14	34.09
(\$/MM Btu)	1.44	1.46	1.55	1.56	1.62	1.62
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.73	20.92	22.49	26.54	28.67
(\$/MM Btu)	1.35	1.37	1.48	1.49	1.56	1.56
Electric Utility Coal Consumption[d] (MM Tons)	753.4	784.1	995.4	1071.1	1280.8	1386.0
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	6.747	3.283	3.515	1.898	1.996
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	491.8	454.1	452.9	417.3	411.6
New	230.7	260.8	417.4	461.9	640.6	699.1

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 51

SENSITIVITY TO INCREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 5%

CBC-85 vs. EDMI-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: EDMI85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.047	0.014

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.032	0.018
OH	931	0.000	0.020
MD	67	0.206	0.009
NV	1626	0.107	0.012
SV	5481	0.050	0.016
VA	867	0.017	0.016
EK	2419	0.025	0.018
TN	157	0.000	0.030
AL	748	0.084	0.012
IL	3892	0.033	0.019
IN	783	0.100	0.018
WK	1060	0.000	0.018
IA	11	0.000	0.017
MO	79	0.005	0.000
KS	13	0.000	0.001
OK	68	0.000	0.004
AP	51	0.000	0.003
ND	127	0.104	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.169	0.001
WY	2191	0.045	0.011
CS	696	0.095	0.016
UT	787	0.000	0.000
AZ	99	0.000	0.000
NM	377	0.012	0.000
WA	53	0.000	-0.000
TX	406	0.000	0.001
CN	39	0.000	0.001
AK	0	0.000	0.000

Table 52

SENSITIVITY TO INCREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 5%

CBC-90 vs. EDMI-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: EDMI90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.062	0.010

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.077	0.009
OH	1161	0.122	0.010
MD	113	0.264	0.007
NV	3567	0.034	0.009
SV	5863	0.005	0.006
VA	769	0.114	0.006
EK	1861	0.073	0.006
TN	60	0.000	0.008
AL	652	0.038	0.004
IL	5940	0.090	0.011
IN	1407	0.077	0.010
WK	1518	0.010	0.012
IA	26	0.833	0.001
MO	93	0.079	0.007
KS	5	0.000	0.012
OK	84	0.030	0.008
AR	108	0.224	0.001
ND	169	0.276	0.001
SD	12	0.000	0.000
EM	5	0.091	0.001
WM	2611	0.154	0.001
WY	3068	0.008	0.012
CS	1052	0.033	0.012
UT	577	0.054	0.019
AZ	174	0.000	0.008
NM	761	0.167	0.052
WA	55	0.000	0.004
TX	867	0.000	0.042
CN	41	0.000	0.000
AK	0	0.000	0.000

Table 53

SENSITIVITY TO INCREASE IN ELECTRICITY AND NON-UTILITY DEMAND BY 5%

CBC-95 vs. EDMI-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: EDMI95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.062	0.007

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.184	0.003
OH	2166	0.058	0.005
MD	167	0.000	0.004
NV	4488	0.000	0.003
SV	5774	0.000	0.004
VA	811	0.024	0.004
EK	1910	0.091	0.005
TN	0	3.024	0.000
AL	595	0.037	0.004
IL	7973	0.055	0.006
IN	1839	0.006	0.005
WK	1963	0.109	0.023
IA	93	0.125	0.007
MO	148	0.027	0.005
KS	0	0.000	0.000
OK	128	0.046	0.002
AR	175	0.000	0.004
ND	226	0.258	0.004
SD	12	0.000	0.000
EM	1	0.142	0.001
WM	4580	0.076	0.001
WY	4120	0.080	0.004
CS	1172	0.064	0.014
UT	533	0.045	0.018
AZ	81	0.000	0.045
NM	1067	0.010	0.098
WA	17	0.000	0.002
TX	990	0.000	0.000
CN	29	0.000	0.001
AK	0	0.000	0.000

UCD4 - Real Escalation of Utility Capital Costs Increased

The UCD4 run was implemented by changing, in the Corrected Base Case, the effective real escalation in utility capital costs from 2%/year to 4%/year for the period 1975-85. Thus, with inflation at 5.5%/year, the utility capital cost escalator was increased from 7.5%/year to 9.5%/year. The motivation for this run relates to the manner in which real escalation of utility capital costs is implemented in the CEUM. Real escalation is allowed only between 1975 and 1985, with costs increasing at the general rate of inflation from 1985 to 1995. As a result, the implementation of an effective real escalation of 2%/year will have an approximately averaged effect of only 1%/year over the 1975 to 1995 time horizon of the model. Implementing a 4%/year real escalation from 1975 to 1985, therefore, approximates a persistent 2%/year average real escalation from 1975 to 1995. The results of this run are most meaningfully compared with the 1995 CBC results.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases by less than 1% in 1985, but decreases by 4% in 1990 and by 3% in 1995.

(2) West-to-East coal transportation in ton-miles increases by 3% in 1985 and by 1% in 1990, but decreases by 7% in 1995.

(3) East-to-West coal transportation in ton-miles increases in each case year: 29% in 1985, 10% in 1990, 1% in 1995.

(4) There are significant decreases in KWH of transmission over new lines in each case year: 12% in 1985, 10% in 1990, 22% in 1995.

(5) Metallurgical coal production increases while high-sulfur coal production decreases in each case year; low-sulfur coal production increases in 1985, but decreases in 1990 and in 1995; medium-sulfur coal production

decreases in 1985 and in 1990, but increases in 1995.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals change by less than 1% in each case year, except for a 4% increase in the 1995 low-sulfur price.

(7) Surface coal production decreases in each case year: .3% in 1985, 2% in 1990, 3% in 1995; deep coal production decreases by 2% in 1985 and by 3% in 1990, but increases by 1% in 1995; total coal production decreases in each case year: 1% in 1985, 3% in 1990, 1% in 1995.

(8) The overall average coal production price increases by 1% in both 1985 and 1995 while the 1990 price remains the same.

(9) Total U.S. coal consumption decreases in each case year; the average coal consumption price is unchanged in each case year.

(10) Electric utility coal consumption decreases by 1% in both 1985 and 1995, and by 4% in 1990.

(11) Electric utility oil/gas consumption increases in each case year: 4% in 1985, 29% in 1990, 16% in 1995.

(12) There is a shift in GW of capacity utilization from new to existing in each case year: 2 GW in 1985, 23 GW in 1990, 10 GW in 1995.

(13) The LP objective function value increases by approximately 2% in each case year.

<u>Implementation of the UCD4 Run</u>

File: GDC, Table: CASE

Line 8: The value of UCD was changed from 7.50 to 9.50.

Table 54

Real Escalation of Utility Capital Costs Increased (UCD4)

	CBC-1985	UCD4-1985	CBC-1990	UCD4-1990	CBC-1995	UCD4-1995
LP Objective Function (10^6\$, 1978)	74062.08	77205.22	104366.27	110463.19	140080.62	150012.12
National Coal Transportation (10^9 Ton Miles)	556.88	558.99	885.28	853.44	1208.41	1172.24
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	79.62	123.38	125.41	175.32	162.47
(10^9 Ton-Miles)	97.71	100.14	151.60	153.30	218.17	201.96
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	19.57	20.41	19.66	18.17	17.99
(10^9 Ton-Miles)	3.23	4.18	3.08	3.39	2.86	2.90
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	161.013	135.308	136.409	107.377	110.084
New	197.289	173.581	167.308	150.166	176.021	138.005
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	165.89	169.93	172.92	173.23	179.40
Metallurgical (\$/MM Btu)	1.66	1.67	1.78	1.79	1.86	1.87
Low Sulfur (MM Tons)	284.83	288.02	459.77	446.36	623.49	597.60
Low Sulfur (\$/MM Btu)	0.85	0.86	0.80	0.80	0.83	0.86
Medium Sulfur (MM Tons)	411.75	405.63	544.92	530.31	641.73	643.65
Medium Sulfur (\$/MM Btu)	1.02	1.02	1.07	1.06	1.11	1.11
High Sulfur (MM Tons)	254.90	245.38	330.45	313.57	437.12	432.66
High Sulfur (\$/MM Btu)	1.04	1.03	1.23	1.23	1.33	1.32
Surface	599.675	597.769	779.491	759.747	962.596	931.611
Deep	515.373	507.146	725.578	703.410	912.968	921.691
Total: (MM Tons)	1115.048	1104.915	1505.069	1463.157	1875.564	1853.303
Total: (\$/MM Btu)	1.10	1.11	1.14	1.14	1.18	1.19
Growth Rate (%/year)	5.6	5.5	5.8	5.6	5.5	5.4
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1095.7	1506.6[c]	1465.0[c]	1875.5	1854.3[c]
(\$/Tons)[b]	31.58	31.71	33.19	33.21	34.14	34.38
(\$/MM Btu)	1.44	1.44	1.55	1.55	1.62	1.62
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	15.84	20.92	20.04	26.54	26.25
(\$/MM Btu)	1.35	1.35	1.48	1.48	1.56	1.57
Electric Utility Coal Consumption[d] (MM Tons)	753.4	742.7	995.4	953.8	1280.8	1259.9
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	6.101	3.283	4.227	1.898	2.195
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	488.5	454.1	477.1	417.3	427.2
New	230.7	228.6	417.4	394.2	640.6	630.4

---

*These runs were not made.
[a] For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b] Volume - Weighted Average
[c] Consumption > Production (Due to Negative Net Washing Losses)
[d] The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e] The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f] The base year (1975) existing electric utility capacity is 500.8 GW.

Table 55

SENSITIVITY TO INCREASE IN
REAL ESCALATION OF UTILITY CAPITAL COSTS

CBC-85 vs. UCD4-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: UCD485C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.033	0.008

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.057	0.005
OH	931	0.000	0.011
MD	67	0.206	0.006
NV	1626	0.060	0.005
SV	5481	0.003	0.010
VA	867	0.011	0.009
EK	2419	0.020	0.008
TN	157	0.000	0.008
AL	748	0.053	0.004
IL	3892	0.045	0.009
IN	783	0.051	0.009
WK	1060	0.000	0.012
IA	11	0.000	0.011
MO	79	0.000	0.000
KS	13	0.000	0.006
OK	68	0.000	0.006
AR	51	0.000	0.000
ND	127	0.025	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.179	0.001
WY	2191	0.018	0.006
CS	696	0.034	0.011
UT	787	0.000	0.001
AZ	99	0.114	0.205
NM	377	0.029	0.014
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.001
AK	0	0.000	0.000

Table 56

SENSITIVITY TO INCREASE IN
REAL ESCALATION OF UTILITY CAPITAL COSTS

CBC-90 vs. UCD4-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: UCD490C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.037	0.008

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.074	0.009
OH	1161	0.091	0.006
MD	113	0.000	0.006
NV	3567	0.033	0.009
SV	5863	0.000	0.004
VA	769	0.114	0.003
EK	1861	0.037	0.003
TN	60	0.000	0.003
AL	652	0.000	0.002
IL	5940	0.029	0.005
IN	1407	0.019	0.004
WK	1518	0.065	0.004
IA	26	0.000	0.004
MO	93	0.000	0.004
KS	5	0.000	0.004
OK	84	0.236	0.012
AR	108	0.086	0.005
ND	169	0.260	0.001
SD	12	0.000	0.000
EM	5	0.066	0.001
WM	2611	0.036	0.001
WY	3068	0.021	0.015
CS	1052	0.090	0.013
UT	577	0.013	0.000
AZ	174	0.075	0.065
NM	761	0.022	0.022
WA	55	0.000	0.006
TX	867	0.000	0.061
CN	41	0.000	0.000
AK	0	0.000	0.000

Table 57

SENSITIVITY TO INCREASE IN
REAL ESCALATION OF UTILITY CAPITAL COSTS

CBC-95 vs. UCD4-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: UCD495C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.024	0.007

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.019	0.005
OH	2166	0.034	0.003
MD	167	0.000	0.006
NV	4488	0.003	0.006
SV	5774	0.002	0.006
VA	811	0.024	0.006
EK	1910	0.091	0.006
TN	0	0.000	0.000
AL	595	0.042	0.006
IL	7973	0.008	0.002
IN	1839	0.025	0.003
WK	1963	0.002	0.003
IA	93	0.000	0.005
MO	148	0.052	0.005
KS	0	0.000	0.000
OK	128	0.047	0.005
AR	175	0.000	0.006
ND	226	0.271	0.009
SD	12	0.000	0.000
EM	1	0.035	0.001
WM	4580	0.069	0.001
WY	4120	0.000	0.025
CS	1172	0.076	0.024
UT	533	0.045	0.021
AZ	81	0.000	0.006
NM	1067	0.054	0.017
WA	17	0.000	0.004
TX	990	0.000	0.008
CN	29	0.000	0.000
AK	0	0.000	0.000

LABD - Decrease in Real Escalation of Labor Costs

The LABD sensitivity runs were motivated by the same logic as the LAB3 runs (see the LAB3 run description above). In LABD, however, the real escalation of unit labor costs was assumed to be -1% per year. In other words, in LABD it was assumed that labor productivity grows 2 percentage points per year more quickly than wage rates. For the LABD runs, the Deviation Index (described in Chapter 1 above) shows production prices down about 15% from the Corrected Base Case, with quantities increased by about 10%. Again note that these values differ from the averages taken from the CEUM output reports (see below) because of different weighting methods.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases in each case year: 8% in 1985, 7% in 1990, 12% in 1995.

(2) West-to-East coal transportation in ton-miles decreases significantly in each case year: 22% in 1985, 42% in 1990, 57% in 1995.

(3) East-to-West coal transportation in ton-miles increases enormously in each case year: 188% in 1985, 83% in 1990, 48% in 1995.

(4) KWH of transmission over new lines increases by 2% in 1985 and by less than 1% in 1990, but decreases by 19% in 1995.

(5) There are significant increases in metallurgical coal production and decreases in low- and medium-sulfur coal production in each case year; high-sulfur coal production decreases in 1985 but increases in both 1990 and 1995.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals decrease significantly in each case year.

(7) Surface coal production decreases significantly in each case year: 7% in 1985, 10% in 1990, 15% in 1995; deep coal production increases

significantly in each case year: 5% in 1985, 5% in 1990, 11% in 1995; total coal production decreases in each case year: 1% in 1985, 1% in 1990, 2% in 1995.

(8) The overall average coal production price decreases significantly in each case year: 13% in 1985, 11% in 1990, 11% in 1995.

(9) Total U.S. coal consumption decreases in each case year; the average coal consumption price decreases by 10 to 12% in each case year.

(10) Electric utility coal consumption in tons decreases in each case year: 1% in 1985, 1% in 1990, 3% in 1995; utility coal consumption in quads increases by less than 1% in 1985 and in 1995, and by 2% in 1990.

(11) Electric utility oil/gas consumption decreases in each case year: 2% in 1985, 13% in 1990, 8% in 1995.

(12) There is a shift in GW of capacity utilization from existing to new: 2 GW in 1985, 12 GW in 1990, 5 GW in 1995.

(13) The LP objective function value decreases in each case year: 4% in 1985, 5% in 1990, 5% in 1995.

<u>Implementation of the LABD Run</u>

File: SUPIN

Line 17: The value of EMP was changed from 0.065 to 0.045.

Table 58

Decrease in Real Escalation of Labor Costs (LABD)

	CBC-1985	LABD-1985	CBC-1990	LABD-1990	CBC-1995	LABD-1995
LP Objective Function (10^6\$, 1978)	74062.08	71278.48	104366.27	99634.64	140080.62	133527.96
National Coal Transportation (10^9 Ton Miles)	556.88	514.55	885.28	820.48	1208.41	1059.58
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	61.65	123.38	72.34	175.32	78.66
(10^9 Ton-Miles)	97.71	76.40	151.60	87.79	218.17	94.52
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	30.03	20.41	28.50	18.17	25.67
(10^9 Ton-Miles)	3.23	9.31	3.08	5.63	2.86	4.24
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	163.479	135.308	130.986	107.377	107.306
New	197.289	201.351	167.308	167.651	176.021	141.342
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	188.33	169.93	194.01	173.23	194.00
Metallurgical (\$/MM Btu)	1.66	1.41	1.78	1.52	1.86	1.61
Low Sulfur (MM Tons)	284.83	266.93	459.77	453.25	623.49	573.82
Low Sulfur (\$/MM Btu)	0.85	0.77	0.80	0.73	0.83	0.74
Medium Sulfur (MM Tons)	411.75	398.95	544.92	506.52	641.73	597.24
Medium Sulfur (\$/MM Btu)	1.02	0.87	1.07	0.96	1.11	1.02
High Sulfur (MM Tons)	254.90	249.31	330.45	339.90	437.12	459.39
High Sulfur (\$/MM Btu)	1.04	0.86	1.23	1.03	1.33	1.11
Surface	599.675	560.759	779.491	703.583	962.596	[illegible]
Deep	515.373	542.765	725.578	790.096	912.968	1014.311
Total: (MM Tons)	1115.048	1103.523	1505.069	1493.679	1875.564	1834.442
Total: (\$/MM Btu)	1.10	0.96	1.14	1.01	1.18	1.05
Growth Rate (%/year)	5.6	5.5	5.8	5.7	5.5	5.3
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1094.8	1506.6[c]	1495.8[c]	1875.5	1835.6[c]
(\$/Tons)[b]	31.58	28.38	33.19	30.36	34.14	[illegible]
(\$/MM Btu)	1.44	1.27	1.55	1.39	1.62	1.45
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.13	20.92	21.15	26.54	26.59
(\$/MM Btu)	1.35	1.20	1.48	1.34	1.56	1.41
Electric Utility Coal Consumption[d] (MM Tons)	753.4	746.4	995.4	987.5	1280.8	1241.0
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.750	3.283	2.862	1.898	1.743
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	484.9	454.1	441.1	417.3	412.1
New	230.7	231.9	417.4	429.7	640.6	645.0

---

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 59

SENSITIVITY TO DECREASE IN
REAL LABOR COST ESCALATION

CBC-85 vs. LABD-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: LABD85C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.087	0.156

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.086	0.182
OH	931	0.000	0.202
MD	67	0.206	0.164
NV	1626	0.154	0.172
SV	5481	0.078	0.151
VA	867	0.230	0.154
EK	2419	0.073	0.160
TN	157	0.000	0.152
AL	748	0.103	0.160
IL	3892	0.040	0.170
IN	783	0.011	0.161
WK	1060	0.000	0.166
IA	11	0.000	0.160
MO	79	0.000	0.173
KS	13	0.000	0.165
OK	68	0.118	0.133
AR	51	0.054	0.172
ND	127	0.000	0.094
SD	12	0.000	0.093
EM	2	0.000	0.125
WM	1198	0.334	0.093
WY	2191	0.090	0.138
CS	696	0.228	0.151
UT	787	0.037	0.157
AZ	99	0.000	0.089
NM	377	0.033	0.087
WA	53	0.000	0.053
TX	406	0.000	0.095
CN	39	0.000	0.060
AK	0	0.000	0.000

Table 60

SENSITIVITY TO DECREASE IN
REAL LABOR COST ESCALATION

CBC-90 vs. LABD-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: LABD90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.107	0.151

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.118	0.175
OH	1161	0.104	0.182
MD	113	0.264	0.155
NV	3567	0.046	0.173
SV	5863	0.053	0.147
VA	769	0.310	0.146
EK	1861	0.441	0.152
TN	60	0.000	0.150
AL	652	0.080	0.143
IL	5940	0.042	0.157
IN	1407	0.101	0.153
WK	1518	0.098	0.155
IA	26	0.872	0.174
MO	93	0.042	0.176
KS	5	0.000	0.141
OK	84	0.234	0.138
AR	108	0.194	0.150
ND	169	0.289	0.096
SD	12	0.000	0.093
EM	5	0.126	0.093
WM	2611	0.082	0.106
WY	3068	0.127	0.142
CS	1052	0.148	0.131
UT	577	0.111	0.127
AZ	174	0.080	0.195
NM	761	0.275	0.129
WA	55	0.000	0.061
TX	867	0.000	0.104
CN	41	0.000	0.072
AK	0	0.000	0.000

Table 61

SENSITIVITY TO DECREASE IN
REAL LABOR COST ESCALATION

CBC-95 vs. LABD-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: LABD95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.125	0.152

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.237	0.170
OH	2166	0.133	0.176
MD	167	0.397	0.144
NV	4488	0.026	0.168
SV	5774	0.059	0.138
VA	811	0.112	0.136
EK	1910	0.433	0.139
TN	0	3.024	0.000
AL	595	0.186	0.130
IL	7973	0.069	0.156
IN	1839	0.024	0.149
WK	1963	0.090	0.154
IA	93	0.125	0.152
MO	148	0.281	0.153
KS	0	0.000	0.000
OK	128	0.165	0.126
AR	175	0.057	0.142
ND	226	0.341	0.111
SD	12	0.000	0.093
EM	1	0.205	0.093
WM	4580	0.126	0.159
WY	4120	0.197	0.177
CS	1172	0.168	0.123
UT	533	0.145	0.118
AZ	81	0.000	0.120
NM	1067	0.056	0.119
WA	17	0.000	0.089
TX	990	0.000	0.014
CN	29	0.000	0.112
AK	0	0.000	0.000

LOGN - Log-Normal Allocation of Reserves to Seam Thickness Categories

In the Corrected Base Case, the seam thickness of coal deposits is arbitrarily assumed to be uniformly distributed between a specified minimum and maximum. The LOGN sensitivity runs were constructed to test the sensitivity of the CEUM to the seam thickness distribution. In the LOGN runs, seam thickness is distributed as a truncated log-normal function between the same minimum and maximum as specified in the Corrected Base Case. The distribution is highly skewed toward the minimum, with the point of truncation being approximately two standard deviations to the right of the mode. (More precisely, the distribution was truncated only on the right-hand side in such a way that (maximum - mode)/(mode - minimum) = e^2 .)

The results of these runs indicate substantial changes in coal transportation patterns, and significant changes by coal type in quantity produced.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases in each case year: 1% in 1985, 6% in 1990, 4% in 1995.

(2) West-to-East coal transportation in ton-miles increases significantly in each case year: 10% in 1985, 43% in 1990, 23% in 1995.

(3) East-to-West coal transportation in ton-miles decreases significantly in each case year: 29% in 1985, 47% in 1990, 7% in 1995.

(4) KWH of transmission over new lines decreases in each case year: 1% in 1985, 11% in 1990, 10% in 1995.

(5) There are moderate increases in the production of metallurgical, low- and medium-sulfur coal, and significant decreases (22% in 1990) in the production of high-sulfur coal in each case year.

(6) The average production price of both metallurgical and high-sulfur coal increases in each case year; the average production price of low-sulfur coal

increases slightly in 1985 but decreases in 1990 and 1995; the average production price of medium-sulfur coal increases in 1985 and 1990 but decreases slightly in 1995.

(7) Surface coal production increases in each case year: 4% in 1985, 9% in 1990, 8% in 1995; deep coal production decreases in each case year: 5% in 1985, 9% in 1990, 7% in 1995; total coal production decreases slightly in 1985 and 1990, and increases by 1% in 1995.

(8) The overall average coal production price increases by 5% in 1985 but changes by less than 1% in both 1990 and 1995.

(9) Total U.S. coal consumption changes by less than 1% in each case year; the average coal consumption price increases in each case year.

(10) Electric utility coal consumption in tons changes by less than 1% in 1985 and 1990, and increases by 1% in 1995; utility coal consumption in quads decreases slightly in 1985 and 1990 but increases slightly in 1995.

(11) Electric utility oil/gas consumption changes by less than 1% in 1985 and 1995 but increases by 5% in 1990.

(12) The LP objective function value increases by approximately 1% in each case year.

<u>Implementation of the LOGN Run</u>

File: RAMCFORT

Change: The seam thickness subroutine (SUBROUTINE STHK), Lines 1190-1277, was replaced by the following new subroutine:

```
C THIS SUBROUTINE REPLACES THE BAMC  SUBROUTINE 'STHK'.
C SEAM-THICKNESS IS DISTRIBUTED ACCORDING TO THE
C       PROBABILITY DISTRIBUTION FUNCTION D 'DF' TRUNCATED
C       BY 'DMIN' AND 'DMAX'.
C       IN THE ORIGINAL SUBROUTINE A UNIFORM DISTRIBUTION WAS ASSUMED.
C
      SUBROUTINE STHK(ARY,LMIN,LMAX)
      DIMENSION ARY(1), TDFV(5),DTHK(5),STHK(5)
      DATA STHK/200.,72.,60.,48.,42./
C
C DEFINITION OF THE DISTRIBUTION FUNCTION USED
C   'DMIN' AND 'DMAX' ARE THE LOWER AND UPPER BOUNDS FOR
C            TRUNCATION OF THE FUNCTION.
C
      DATA DMIN/0./, DMAX/7.389/
      DF(X)=.5*(1. + ERF(ALOG(AMAX1(X,.0001))))
C     DF(X)=X
      TDF(X)=AMAX1(0.,AMIN1(1.,DFFAC*(DF(X)-DMIN)))
      DFMIN=DF(DMIN)

      DFMIN=DF(DMIN)
      DFFAC=1./(DF(DMAX)-DFMIN)
C
C SET RETURN ARRAY 'ARY' = 0
C
      DO 20 I=1,6
 20   ARY(I)=0.0
      IF(LMIN .LT. 42) LMIN=42
      IF(LMIN+LMAX .EQ. 0 .OR. LMIN .GE. LMAX) RETURN
C
C SET THE DISTRIBUTION OF THIN SEAMS ACCORDING TO
C     EXOGENOUS PARAMETERS
C
      ARY(5)=42.9
      ARY(6)=57.1
C
C TRANSFORM SEAM-THICKNESS BOUNDARIES TO RANDOM VARIABLE
C
      B=(DMAX-DMIN)/(LMAX-LMIN)
      DO 30 J=1,5
 30   DTHK(J)=DMIN+B*(STHK(J)-LMIN)
C
C CALCULATE PROBABILITY OF FALLING WITHING EACH CATEGORY
C
      DO 40 J=1,5
 40   TDFV(J)=TDF(DTHK(J))
      DO 50 J=1,4
      NRND=1000.*(TDFV(J)-TDFV(J+1))+.5
 50   ARY(J)=NRND/10.
      RETURN
      END
```

Table 62

Lognormal Allocation of Reserves to Seam Thickness Categories (LOGN)

	CBC-1985	LOGN-1985	CBC-1990	LOGN-1990	CBC-1995	LOGN-1995
LP Objective Function ($10^6\$$, 1978)	74062.08	74774.08	104366.27	105529.43	140080.62	141607.66
National Coal Transportation (10^9 Ton Miles)	556.88	562.63	885.28	935.88	1208.41	1254.63
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	85.15	123.38	168.98	175.32	210.27
(10^9 Ton-Miles)	97.71	107.50	151.60	217.13	218.17	268.32
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	15.28	20.41	16.05	18.17	13.71
(10^9 Ton-Miles)	3.23	2.28	3.08	1.62	2.86	2.67
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	159.446	135.308	134.167	107.377	106.224
New	197.289	195.857	167.308	148.729	176.021	157.317
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	175.20	169.93	181.04	173.23	183.23
Metallurgical ($/MM Btu)	1.66	1.70	1.78	1.80	1.86	1.88
Low Sulfur (MM Tons)	284.83	294.28	459.77	504.86	623.49	637.75
Low Sulfur ($/MM Btu)	0.85	0.86	0.80	0.77	0.83	0.81
Medium Sulfur (MM Tons)	411.75	414.68	544.92	562.73	641.73	686.17
Medium Sulfur ($/MM Btu)	1.02	1.05	1.07	1.11	1.11	1.10
High Sulfur (MM Tons)	254.90	228.36	330.45	256.17	437.12	379.82
High Sulfur ($/MM Btu)	1.04	1.14	1.23	1.30	1.33	1.36
Surface	599.675	623.357	779.491	846.586	962.596	1043.339
Deep	515.373	489.218	725.578	658.213	912.968	846.133
Total: (MM Tons)	1115.048	1112.575	1505.069	1504.799	1875.564	1886.321
Total: ($/MM Btu)	1.10	1.15	1.14	1.15	1.18	1.17
Growth Rate (%/year)	5.6	5.6	5.8	5.8	5.5	5.5
* Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1103.7	1506.6[c]	1506.8[c]	1875.5	1885.9[illegible]
($/Tons)[b]	31.58	32.73	33.19	33.74	34.14	34.35
($/MM Btu)	1.44	1.49	1.55	1.58	1.62	1.63
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.01	20.92	20.77	26.54	26.39
($/MM Btu)	1.35	1.40	1.48	1.52	1.56	1.57
Electric Utility Coal Consumption[d] (MM Tons)	753.4	752.3	995.4	999.1	1280.8	1295.7
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.885	3.283	3.437	1.898	1.681
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	486.7	454.1	458.4	417.3	416.3
New	230.7	230.8	417.4	413.5	640.6	642.2

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 63

SENSITIVITY TO USE OF LOG-NORMAL
ALLOCATION OF RESERVES TO SEAM
THICKNESS CATEGORIES

CBC-85 vs. LOGN-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: logn85c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.098	0.045

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.104	0.039
OH	931	0.159	0.072
MD	67	1.023	0.031
NV	1626	0.159	0.032
SV	5481	0.035	0.027
VA	867	0.107	0.029
EK	2419	0.071	0.034
TN	157	0.000	0.053
AL	748	0.126	0.026
IL	3892	0.184	0.082
IN	783	0.171	0.079
WK	1060	0.197	0.104
IA	11	0.000	0.091
MO	79	0.000	0.101
KS	13	0.000	0.061
OK	68	0.045	0.041
AR	51	0.411	0.001
ND	127	0.019	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.075	0.001
WY	2191	0.011	0.022
CS	696	0.178	0.036
UT	787	0.000	0.147
AZ	99	0.000	0.001
NM	377	0.024	0.000
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.001
AK	0	0.000	0.000

Table 64

SENSITIVITY TO USE OF LOG-NORMAL
ALLOCATION OF RESERVES TO SEAM
THICKNESS CATEGORIES

CBC-90 vs. LOGN-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: logn90c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.154	0.025

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.273	0.019
OH	1161	0.139	0.039
MD	113	0.342	0.012
NV	3567	0.106	0.017
SV	5863	0.044	0.010
VA	769	0.173	0.011
EK	1861	0.161	0.012
TN	60	0.000	0.030
AL	652	0.076	0.012
IL	5940	0.285	0.053
IN	1407	0.135	0.045
WK	1518	0.121	0.054
IA	26	0.839	0.058
MO	93	0.608	0.033
KS	5	0.000	0.044
OK	84	0.311	0.031
AR	108	0.176	0.008
ND	169	0.066	0.001
SD	12	0.000	0.000
EM	5	0.000	0.001
WM	2611	0.211	0.001
WY	3068	0.054	0.026
CS	1052	0.243	0.030
UT	577	0.054	0.096
AZ	174	0.007	0.083
NM	761	0.002	0.000
WA	55	0.000	0.007
TX	867	0.000	0.001
CN	41	0.000	0.000
AK	0	0.000	0.000

Table 65

SENSITIVITY TO USE OF LOG-NORMAL
ALLOCATION OF RESERVES TO SEAM
THICKNESS CATEGORIES

CBC-95 vs. LOGN-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: logn95c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.123	0.015

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.153	0.015
OH	2166	0.070	0.022
MD	167	0.113	0.009
NV	4488	0.041	0.016
SV	5774	0.059	0.007
VA	811	0.060	0.007
EK	1910	0.161	0.007
TN	0	0.000	0.000
AL	595	0.117	0.011
IL	7973	0.239	0.024
IN	1839	0.134	0.020
WK	1963	0.034	0.031
IA	93	0.625	0.052
MO	148	0.168	0.014
KS	0	0.000	0.000
OK	128	0.193	0.011
AR	175	0.079	0.007
ND	226	0.040	0.009
SD	12	0.000	0.000
EM	1	0.017	0.001
WM	4580	0.076	0.001
WY	4120	0.156	0.010
CS	1172	0.185	0.033
UT	533	0.134	0.049
AZ	81	0.000	0.121
NM	1067	0.116	0.021
WA	17	0.000	0.002
TX	990	0.000	0.000
CN	29	0.000	0.001
AK	0	0.000	0.000

CDRB - Change in Demonstrated Reserve Base

The CDRB sensitivity runs were made in order to examine the effects of possible errors in the data on demonstrated coal reserves, supplied to ICF by the Bureau of Mines. For the purposes of the CDRB runs, the specified reserves for each coal type were randomly selected from a uniform distribution whose minimum was 75% of the Bureau of Mines figure, and whose maximum was 150% of that figure. The 75 to 150% range was selected because, in the opinion of one coal mining authority (Professor Richard L. Gordon, Pennsylvania State University), this range is a reasonable confidence interval for these Bureau of Mines estimates. Except for these changes in the demonstrated coal reserve data, the CDRB model runs have specifications identical to the Corrected Base Case.

The results of the CDRB model runs show substantial increases in the production of high quality coal and in coal with low extraction costs. This is because on the average, the specified reserves of all types of coal were increased, while overall demand remained unchanged. Therefore, in the model solution, less expensive coal was substituted for more expensive coal, and higher quality coal was substituted for lower quality coal.

This run demonstrates the importance of collecting accurate data on the demonstrated coal reserve base.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases by 2% in each case year.

(2) West-to-East coal transportation in ton-miles increases significantly in each case year: 12% in 1985, 11% in 1990, 9% in 1995.

(3) East-to-West coal transportation in ton-miles increases by 17% in 1985, but decreases by 17% in 1990 and by 5% in 1995.

(4) There are slight decreases (up to 2% in 1995) in KWH of transmission over new lines in each case year.

(5). Metallurgical and low sulfur-coal production increases in each case year; medium- and high-sulfur coal production decreases in each case year.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals decrease or remain the same in each case year.

(7) Surface coal production increases in each case year: 2% in 1985, 2% in 1990, 1% in 1995; deep coal production decreases in each case year: 2% in 1985, 2% in 1990, 1% in 1995; total coal production changes by less than 1% in each case year.

(8) The overall average coal production price decreases in each case year: 1% in 1985, 3% in 1990, 4% in 1995.

(9) Total U.S. coal consumption changes by less than 1% in each case year; the average coal consumption price decreases in each case year.

(10) Electric utility coal consumption changes by less than 1% in each case year.

(11) Electric utility oil/gas consumption decreases by 2% in 1995, and by less than 1% in both 1985 and 1990.

(12) The LP objective function value decreases by approximately 0.5% in each case year.

Implementation of the CDRB Run

File: RAMCFORT

Changes:

(a) Before Line 198 (KSTT=20) the following two lines of code were added:

```
VARYF(COUNTV)=AMOD(1000000.*ALOGIO(COUNTV),75)/100.+.75
COUNTV=1.0
```

(b) After Line 812 (after the calculation of reserves available for new mines and the associated NAMELIST statement) the following six lines of code were added:

```
COUNTV=COUNTV+1.0
T2(3)=VARYF(COUNTV)*T2(3)
COUNTV=COUNTV+1.0
T2(6)=VARYF(COUNTV)*T2(6)
COUNTV=COUNTV+1.0
T2(8)=VARYF(COUNTV)*T2(8)
```

Table 66

Change in Demonstrated Reserve Base (CDRB)

	CBC-1985	CDRB-1985	CBC-1990	CDRB-1990	CBC-1995	CDRB-1995
LP Objective Function (10^6\$, 1978)	74062.08	73826.20	104366.27	103850.20	140080.62	139229.20
National Coal Transportation (10^9 Ton Miles)	556.88	568.00	885.28	903.14	1208.41	1230.29
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	86.78	123.38	136.43	175.32	186.63
(10^9 Ton-Miles)	97.71	109.53	151.60	167.81	218.17	238.08
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	18.86	20.41	17.98	18.17	17.50
(10^9 Ton-Miles)	3.23	3.78	3.08	2.55	2.86	2.73
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	161.538	135.308	135.498	107.377	107.955
New	197.289	196.950	167.308	164.887	176.021	173.177
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	174.55	169.93	178.02	173.23	183.45
Metallurgical (\$/MM Btu)	1.66	1.62	1.78	1.72	1.86	1.79
Low Sulfur (MM Tons)	284.83	290.09	459.77	481.85	623.49	676.73
Low Sulfur (\$/MM Btu)	0.85	0.85	0.80	0.76	0.83	0.75
Medium Sulfur (MM Tons)	411.75	397.50	544.92	521.71	641.73	606.38
Medium Sulfur (\$/MM Btu)	1.02	0.99	1.07	1.06	1.11	1.11
High Sulfur (MM Tons)	254.90	251.34	330.45	325.44	437.12	411.08
High Sulfur (\$/MM Btu)	1.04	1.03	1.23	1.20	1.33	1.30
Surface	599.675	609.081	779.491	795.318	962.596	977.321
Deep	515.373	504.398	725.578	711.705	912.968	900.326
Total: (MM Tons)	1115.048	1113.478	1505.069	1507.023	1875.564	1877.647
Total: (\$/MM Btu)	1.10	1.09	1.14	1.11	1.18	1.13
Growth Rate (%/year)	5.6	5.6	5.8	5.8	5.5	5.5
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1105.1	1506.6[c]	1509.5[c]	1875.5	1879.6[c]
(\$/Tons)[b]	31.58	31.43	33.19	32.57	34.14	32.23
(\$/MM Btu)	1.44	1.43	1.55	1.52	1.62	1.58
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.05	20.92	20.92	26.54	26.55
(\$/MM Btu)	1.35	1.35	1.48	1.47	1.56	1.53
Electric Utility Coal Consumption[d] (MM Tons)	753.4	753.2	995.4	998.9	1280.8	1285.2
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.846	3.283	3.254	1.898	1.856
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	486.5	454.1	453.3	417.3	415.7
New	230.7	230.6	417.4	418.0	640.6	642.1

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 67

SENSITIVITY TO CHANGE IN
DEMONSTRATED RESERVE BASE

CBC-85 vs. CDRB-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: cdrb85c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
27062	0.091	0.016

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	2819	0.094	0.010
OH	931	0.052	0.012
MD	67	0.206	0.013
NV	1626	0.116	0.013
SV	5481	0.081	0.020
VA	867	0.070	0.019
EK	2419	0.068	0.020
TN	157	0.000	0.016
AL	748	0.018	0.021
IL	3892	0.170	0.013
IN	783	0.056	0.012
WK	1060	0.000	0.011
IA	11	0.000	0.011
MO	79	0.000	0.000
KS	13	0.000	0.027
OK	68	0.134	0.006
AR	51	0.530	0.036
ND	127	0.096	0.008
SD	12	1.000	0.000
EM	2	0.000	0.001
WM	1198	0.024	0.001
WY	2191	0.129	0.012
CS	696	0.170	0.027
UT	787	0.046	0.036
AZ	99	0.000	0.001
NM	377	0.048	0.000
WA	53	0.259	0.000
TX	406	0.000	0.001
CN	39	0.160	0.760
AK	0	0.000	0.000

Table 68

SENSITIVITY TO CHANGE IN
DEMONSTRATED RESERVE BASE

CBC-90 vs. CDRB-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: cdrb90c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.148	0.030

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.113	0.014
OH	1161	0.123	0.011
MD	113	0.184	0.024
NV	3567	0.127	0.017
SV	5863	0.087	0.033
VA	769	0.296	0.033
EK	1861	0.175	0.034
TN	60	0.000	0.028
AL	652	0.081	0.032
IL	5940	0.244	0.018
IN	1407	0.115	0.021
WK	1518	0.171	0.021
IA	26	2.516	0.065
MO	93	0.000	0.054
KS	5	0.000	0.021
OK	84	0.436	0.028
AR	108	0.346	0.044
ND	169	0.582	0.001
SD	12	1.000	0.000
EM	5	0.217	0.045
WM	2611	0.121	0.075
WY	3068	0.150	0.050
CS	1052	0.208	0.032
UT	577	0.027	0.012
AZ	174	0.007	0.179
NM	761	0.040	0.043
WA	55	0.259	0.036
TX	867	0.066	0.034
CN	41	0.324	0.039
AK	0	0.000	0.000

Table 69

SENSITIVITY TO CHANGE IN
DEMONSTRATED RESERVE BASE

CBC-95 vs. CDRB-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: cdrb95c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.177	0.044

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.144	0.020
OH	2166	0.195	0.016
MD	167	0.286	0.031
NV	4488	0.161	0.022
SV	5774	0.122	0.036
VA	811	0.306	0.037
EK	1910	0.243	0.038
TN	0	3.024	0.000
AL	595	0.047	0.033
IL	7973	0.213	0.035
IN	1839	0.206	0.035
WK	1963	0.103	0.020
IA	93	0.375	0.036
MO	148	0.665	0.036
KS	0	0.000	0.000
OK	128	0.483	0.033
AR	175	0.215	0.036
ND	226	0.663	0.038
SD	12	1.000	0.213
EM	1	0.392	0.001
WM	4580	0.172	0.110
WY	4120	0.181	0.083
CS	1172	0.331	0.049
UT	533	0.050	0.033
AZ	81	0.000	0.001
NM	1067	0.078	0.067
WA	17	1.000	0.088
TX	990	0.077	0.045
CN	29	0.500	0.078
AK	0	0.000	0.000

LDC1 - Load Duration Curve Changed 1%

Using the Corrected Base Case version of the model the LDC1 run was implemented by changing the baseload demand down 1 percentage point and the daily peaking up 1 percentage point in each demand region. The run was initiated after the somewhat spectacular results of the similar 5 percentage point changes in the LOAD run. The two principal motivations for this run were: (1) a check on the implementation of the LOAD run, and (2) another view of the tremendous rise in turbine building at a point closer to the Corrected Base Case, as a better indication of the gradient of new turbine capacity with respect to changes in the daily peaking of the load duration curve. These gradients run between 3 and 5 GW per 0.1%. This means that the regional daily peaking demand fractions, which vary from 0.7% to 4.1%, must be very finely tuned to yield meaningful generation capacity levels. Some of this peaking demand is due to short-term changes in loads and some is required to cover, in the short-term, unexpected losses of generation facilities. The fine tuning is made quite difficult by the fact that there is no measurement system for obtaining the peaking demand fractions of total energy demand.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles decreases in each case year: .2% in 1985, 1% in 1990, 2% in 1995.

(2) West-to-East coal transportation in ton-miles decreases in each case year: 2% in 1985, 4% in 1990, 2% in 1995.

(3) East-to-West coal transportation in ton-miles increases by 11% in 1985 and by 2% in 1995, but decreases by 2% in 1990.

(4) KWH of transmission over new lines decreases by 5% in both 1985 and 1995, and increases by 5% in 1990.

(5) Metallurgical coal production remains approximately the same in each case year; there are small decreases in low-sulfur coal production in each case year; medium-sulfur coal production decreases slightly in both 1985 and 1990, but increases slightly in 1995; high-sulfur coal production remains the same in 1985, increases slightly in 1990, and decreases moderately in 1995.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals remain approximately the same in each case year.

(7) Surface coal production decreases in each case year: .3% in 1985, 1% in 1990, 2% in 1995; deep coal production changes by less than 1% in each case year; total coal production decreases by 1% or less in each case year.

(8) The overall average coal production price remains approximately the same in each case year.

(9) Total U.S. coal consumption decreases in each case year; the average coal consumption price remains unchanged in each case year.

(10) Electric utility coal consumption in tons decreases by less than 1% in both 1985 and 1990, and by 2% in 1995.

(11) Electric utility oil/gas consumption increases in each case year: 2% in 1985, 10% in 1990, 31% in 1995.

(12) Existing GW usage increases in each case year: 2% in 1985, 4% in 1990, 6% in 1995; there are significant increases in new capacity usage in each case year (almost entirely due to new turbine capacity): 16% in 1985, 10% in 1990, 7% in 1995; the percentage increases in new turbine capacity are: 94% in 1985, 122% in 1990, 115% in 1995.

(13) The LP objective function value increases by approximately 2% in each case year.

Implementation of the LDC1 Run

File: GDU1, Tables: (UR)LOAD, Rows: B and Z, Columns: LD

Changes: In each (UR)LOAD table the value in row B, column LD was decreased by 0.01 and the value in row Z, column LD was increased by 0.01.

Table 70

Load Duration Curve Changed 1% (LDC1)

	CBC-1985	LDC1-1985	CBC-1990	LDC1-1990	CBC-1995	LDC1-1995
LP Objective Function (10^6\$, 1978)	74062.08	75511.10	104366.27	106587.08	140080.62	143622.92
National Coal Transportation (10^9 Ton Miles)	556.88	555.90	885.28	875.90	1208.41	1188.19
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	75.29	123.38	118.17	175.32	170.71
(10^9 Ton-Miles)	97.71	96.03	151.60	146.09	218.17	212.86
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	19.45	20.41	19.88	18.17	18.88
(10^9 Ton-Miles)	3.23	3.57	3.08	3.01	2.86	2.93
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	164.395	135.308	134.699	107.377	113.285
New	197.289	187.732	167.308	174.588	176.021	167.155
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	163.79	169.93	169.93	173.23	172.45
Metallurgical (\$/MM Btu)	1.66	1.66	1.78	1.78	1.85	1.86
Low Sulfur (MM Tons)	284.83	283.94	459.77	452.80	623.49	608.95
Low Sulfur (\$/MM Btu)	0.85	0.85	0.80	0.81	0.83	0.84
Medium Sulfur (MM Tons)	411.75	410.68	544.92	538.00	641.73	650.95
Medium Sulfur (\$/MM Btu)	1.02	1.02	1.07	1.07	1.11	1.10
High Sulfur (MM Tons)	254.90	254.90	330.45	334.79	43[illegible].12	422.2[illegible]
High Sulfur (\$/MM Btu)	1.04	1.05	1.23	1.23	1.33	1.3[illegible]
Surface	599.675	597.648	779.491	771.683	962.595	947.1[illegible]
Deep	515.373	515.658	725.578	723.831	912.963	907.4[illegible]
Total: (MM Tons)	1115.048	1113.306	1505.069	1495.514	1875.564	1854.551
Total: (\$/MM Btu)	1.10	1.11	1.14	1.14	1.18	1.19
Growth Rate (%/year)	5.6	5.6	5.8	5.7	5.5	5.4
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1104.1	1506.6[c]	1497.1[c]	1875.5	1854.5
(\$/Tons)[b]	31.58	31.67	33.19	33.19	34.14	34.14
(\$/MM Btu)	1.44	1.44	1.55	1.55	1.62	1.62
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.04	20.92	20.74	26.54	26.15
(\$/MM Btu)	1.35	1.35	1.48	1.48	1.56	1.56
Electric Utility Coal Consumption[d] (MM Tons)	753.4	751.4	995.4	987.4	1280.8	1260.9
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.962	3.283	3.594	1.898	2.483
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	496.4	454.1	470.5	417.3	444.4
New	230.7	268.2	417.4	458.4	640.6	682.9

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

SENSITIVITY TO CHANGE IN LOAD DURATION CURVE PARAMETERS

CBC-85 vs. LDC1-85

COMPARISON RUN .
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: ldc185c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	DEVIATIONS P
27062	0.002	0.002

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	DEVIATIONS P
PA	2819	0.000	0.002
OH	931	0.000	0.002
MD	67	0.000	0.001
NV	1626	0.001	0.001
SV	5481	0.000	0.003
VA	867	0.000	0.002
EK	2419	0.000	0.004
TN	157	0.000	0.017
AL	748	0.013	0.002
IL	3892	0.000	0.002
IN	783	0.000	0.002
WK	1060	0.000	0.002
IA	11	0.000	0.002
MO	79	0.000	0.000
KS	13	0.000	0.001
OK	68	0.000	0.000
AR	51	0.000	0.000
ND	127	0.107	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.010	0.001
WY	2191	0.003	0.001
CS	696	0.000	0.002
UT	787	0.000	0.000
AZ	99	0.000	0.010
NM	377	0.003	0.000
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.001
AK	0	0.000	0.000

SENSITIVITY TO CHANGE IN
LOAD DURATION CURVE PARAMETERS

CBC-90 vs. LDC1-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: ldc190c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
36807	0.011	0.002

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	4187	0.005	0.000
OH	1161	0.003	0.000
MD	113	0.000	0.000
NV	3567	0.000	0.000
SV	5863	0.000	0.000
VA	769	0.000	0.000
EK	1861	0.000	0.000
TN	60	0.000	0.000
AL	652	0.000	0.000
IL	5940	0.033	0.000
IN	1407	0.000	0.000
WK	1518	0.000	0.000
IA	26	0.000	0.000
MO	93	0.000	0.000
KS	5	0.000	0.000
OK	84	0.000	0.000
AR	108	0.000	0.000
ND	169	0.495	0.008
SD	12	0.000	0.000
EM	5	0.000	0.001
WM	2611	0.026	0.000
WY	3068	0.000	0.002
CS	1052	0.000	0.000
UT	577	0.046	0.019
AZ	174	0.000	0.000
NM	761	0.019	0.029
WA	55	0.000	0.000
TX	867	0.000	0.023
CN	41	0.000	0.000
AK	0	0.000	0.000

SENSITIVITY TO CHANGE IN LOAD DURATION CURVE PARAMETERS

CBC-95 vs. LDC1-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: ldc195c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.011	0.003

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.000	0.007
OH	2166	0.031	0.005
MD	167	0.000	0.003
NV	4488	0.001	0.006
SV	5774	0.000	0.001
VA	811	0.000	0.001
EK	1910	0.023	0.001
TN	0	0.000	0.000
AL	595	0.000	0.001
IL	7973	0.005	0.004
IN	1839	0.024	0.003
WK	1963	0.000	0.004
IA	93	0.000	0.000
MO	148	0.052	0.002
KS	0	0.000	0.000
OK	128	0.124	0.004
AR	175	0.000	0.001
ND	226	0.547	0.001
SD	12	0.000	0.000
EM	1	0.000	0.001
WM	4580	0.035	0.000
WY	4120	0.001	0.000
CS	1172	0.005	0.001
UT	533	0.032	0.003
AZ	81	0.000	0.007
NM	1067	0.000	0.002
WA	17	0.000	0.000
TX	990	0.000	0.000
CN	29	0.000	0.000
AK	0	0.000	0.000

NCAP - Nuclear Capacity Factor Decreased

The NCAP run was implemented by multiplying by .55/.675 all of the nuclear capacity factors in the Corrected Base Case version of the CEUM. Because these capacity factors are different for new and existing nuclear plants, and vary by demand region, the change was made multiplicatively to every nuclear capacity factor. The CBC nuclear capacity factors are all either .70 or .65. Since a reasonable lower limit on this factor is .55, a multiplicative scaling was chosen that changes the average value from .675 to .55. The most important runs with which to compare NCAP are CBC, CNINC, and EDMI.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases in each case year: 3% in 1985, 7% in 1990, 7% in 1995.

(2) West-to-East coal transportation in ton-miles increases in each case year: 5% in 1985, 9% in 1990, 11% in 1995.

(3) East-to-West coal transportation decreases by 27% in 1990 and by 3% in 1995, but increases by 17% in 1985.

(4) KWH of transmission over new lines increases in each case year: 4% in 1985, 14% in 1990, 16% in 1995.

(5) Metallurgical, low-, medium-, and high-sulfur coal production increases in each case year.

(6) The average production prices of metallurgical and medium-sulfur coal increase slightly in 1985 and in 1990, but remain unchanged in 1995; the average production price of low-sulfur coal remains the same in 1985 and in 1995, but decreases slightly in 1990; the average production price of

high-sulfur coal increases slightly in each case year.

(7) Surface coal production increases in each case year: 2% in 1985, 5% in 1990, 7% in 1995; deep coal production increases in each case year: 3% in 1985, 5% in 1990, 6% in 1995; total coal production increases in each case year: 2% in 1985, 5% in 1990, 6% in 1995.

(8) The overall average coal production price changes by less than 1% in each case year.

(9) Total U.S. coal consumption increases significantly in each case year; the average coal consumption price changes by less than 1% in 1985 and remains unchanged in both 1990 and 1995.

(10) Electric utility coal consumption in both tons and quads increases in each case year: 4% in 1985, 8% in 1990, 9% in 1995.

(11) Electric utility oil/gas consumption increases in each case year: 9% in 1985, 3% in 1990, 1% in 1995.

(12) There is a shift in GW of capacity utilization from existing to new in each case year: 4 GW in 1985, 8 GW in 1990, 12 GW in 1995.

(13) The LP objective function value increases in each case year: 4% in 1985, 4% in 1990, 5% in 1995.

Implementation of the NCAP Run

File: GMG

Section: Generate Utility Plant Operate Vectors

Change: After Line 220 (after the expression beginning with GU(UR)S2=) the following line of code was added:

```
LU(UR)(ID/SIDFUEL)=.140100/((UR)LOAD,(L),XX),  IF((S).IM.Y Z)
```

Table 74

Nuclear Capacity Factor Decreased (NCAP)

	CBC-1985	NCAP-1985	CBC-1990	NCAP-1990	CBC-1995	NCAP-1995
LP Objective Function (10^6\$, 1978)	74062.08	76857.16	104366.27	109006.11	140080.62	146587.15
National Coal Transportation (10^9 Ton Miles)	556.88	573.39	885.28	944.62	1208.41	1291.16
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	81.73	123.38	133.80	175.32	193.51
(10^9 Ton-Miles)	97.71	102.52	151.60	165.84	218.17	242.64
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	19.22	20.41	17.62	18.17	17.99
(10^9 Ton-Miles)	3.23	3.78	3.08	2.25	2.86	2.78
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	179.977	135.308	135.082	107.377	113.988
New	197.289	203.634	167.308	189.712	176.021	204.316
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	165.89	169.93	171.43	173.23	174.37
Metallurgical (\$/MM Btu)	1.66	1.67	1.78	1.79	1.86	1.86
Low Sulfur (MM Tons)	284.83	295.35	459.77	502.68	623.49	658.14
Low Sulfur (\$/MM Btu)	0.85	0.85	0.80	0.79	0.83	0.83
Medium Sulfur (MM Tons)	411.75	417.14	544.92	558.21	641.73	697.25
Medium Sulfur (\$/MM Btu)	1.02	1.03	1.07	1.09	1.11	1.11
High Sulfur (MM Tons)	254.90	262.88	330.45	352.34	437.12	464.53
High Sulfur (\$/MM Btu)	1.04	1.06	1.23	1.25	1.33	1.34
Surface	599.675	608.649	779.491	821.339	962.596	1027.258
Deep	515.373	532.615	725.578	763.309	912.968	967.021
Total: (MM Tons)	1115.048	1141.264	1505.069	1584.647	1875.564	1994.280
Total: (\$/MM Btu)	1.10	1.11	1.14	1.14	1.18	1.17
Growth Rate (%/year)	5.6	5.8	5.8	6.1	5.5	5.8
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1132.1	1506.6[c]	1585.1[c]	1875.5	1994.2
(\$/Tons)[b]	31.58	31.85	33.19	33.22	34.14	34.06
(\$/MM Btu)	1.44	1.45	1.55	1.55	1.62	1.62
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.64	20.92	22.58	26.54	28.99
(\$/MM Btu)	1.35	1.36	1.48	1.49	1.56	1.56
Electric Utility Coal Consumption[d] (MM Tons)	753.4	779.0	995.4	1074.6	1280.8	1399.3
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	6.371	3.283	3.394	1.898	1.899
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	482.8	454.1	446.2	417.3	405.5
New	230.7	234.4	417.4	425.4	640.6	652.7

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption > Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 75

SENSITIVITY TO DECREASE IN NUCLEAR CAPACITY FACTOR

CBC-85 vs. NCAP-85

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1985.
RUN ID: ncap85c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS C	F
27062	0.030	0.010

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS C	F
PA	2819	0.029	0.012
OH	931	0.000	0.014
MD	67	0.206	0.006
NV	1626	0.070	0.007
SV	5481	0.003	0.012
VA	867	0.011	0.010
EK	2419	0.020	0.013
TN	157	0.000	0.024
AL	748	0.057	0.008
IL	3892	0.033	0.012
IN	783	0.051	0.012
WK	1060	0.000	0.012
IA	11	0.000	0.012
MO	79	0.000	0.000
KS	13	0.000	0.001
OK	68	0.000	0.003
AR	51	0.000	0.000
ND	127	0.025	0.001
SD	12	0.000	0.000
EM	2	0.000	0.001
WM	1198	0.195	0.001
WY	2191	0.022	0.008
CS	696	0.034	0.010
UT	787	0.000	0.000
AZ	99	0.000	0.000
NM	377	0.004	0.000
WA	53	0.000	0.000
TX	406	0.000	0.001
CN	39	0.000	0.001
AK	0	0.000	0.000

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Table 77

SENSITIVITY TO DECREASE IN
NUCLEAR CAPACITY FACTOR

CBC-95 vs. NCAP-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: ncap95c

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.056	0.007

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.165	0.002
OH	2166	0.099	0.006
MD	167	0.000	0.001
NV	4488	0.000	0.002
SV	5774	0.000	0.000
VA	811	0.000	0.000
EK	1910	0.029	0.000
TN	0	3.024	0.000
AL	595	0.000	0.000
IL	7973	0.051	0.007
IN	1839	0.006	0.007
WK	1963	0.110	0.023
IA	93	0.000	0.010
MO	148	0.145	0.011
KS	0	0.000	0.000
OK	128	0.124	0.009
AR	175	0.000	0.002
ND	226	0.244	0.004
SD	12	0.000	0.000
EM	1	0.000	0.001
WM	4580	0.076	0.001
WY	4120	0.060	0.005
CS	1172	0.043	0.009
UT	533	0.045	0.012
AZ	81	0.000	0.029
NM	1067	0.020	0.098
WA	17	0.000	0.000
TX	990	0.000	0.000
CN	29	0.000	0.001
AK	0	0.000	0.000

MOIL - Modified Oil/Gas Price Increase

As with COILG, this run also involved increases to the oil/gas prices in the corrected version of the CEUM. Here, however, the change was a 25% increase in the total oil/gas price for the years 1985, 1990, and 1995. This differs from the COILG run in that the 1990 and 1995 increases in COILG were on incremental rather than total prices. The motivation for this run was to provide another set of effects based upon a persistent, rather than a primarily one-time, price increase. For a comparison of oil/gas prices among the CBC, COILG, and MOIL sensitivity runs see the chart in the COILG run description given earlier.

The following is a summary of some important results at national levels:

(1) Overall coal transportation in ton-miles increases by 4% in 1985 and by 5% in 1990, but decreases by 2% in 1995.

(2) West-to-East coal transportation in ton-miles increases by 4% in 1985 and by less than 1% in 1990, but decreases by 6% in 1995.

(3) East-to-West coal transportation in ton-miles decreases by 27% in 1990 and by 5% in 1995, but increases by 13% in 1985.

(4) KWH of transmission over new lines increases in each case year: 32% in 1985, 11% in 1990, 3% in 1995.

(5) Metallurgical, medium-, and high-sulfur coal production increase in each case year; low-sulfur coal production increases in both 1985 and 1990, but decreases in 1995.

(6) The average production prices of metallurgical, low-, medium-, and high-sulfur coals change by 1% or less in each case year except for 2% increases in the 1990 high-sulfur price and the 1995 low-sulfur price.

(7) Surface coal production increases by 2% in 1985 and by 3% in 1990,

but decreases by 2% in 1995; deep coal production increases in each case year: 2% in 1985, 6% in 1990, 3% in 1995; total coal production increases by 2% in 1985 and by 4% in 1990, and remains approximately the same in 1995.

(8) The overall average coal production price increases by 1% in each case year.

(9) Total U.S. coal consumption increases in each case year; the average coal consumption price changes by less than 1% in each case year.

(10) Electric utility coal consumption increases in each case year: 3% in 1985, 7% in 1990, 1% in 1995.

(11) Electric utility oil/gas consumption decreases significantly in each case year: 10% in 1985, 47% in 1990, 10% in 1995.

(12) There is a shift in GW of capacity utilization from existing to new: 9 GW in 1985, 49 GW in 1990, 6 GW in 1995.

(13) The LP objective function value increases in each case year: 6% in 1985, 2% in 1990, 2% in 1995.

<u>Implementation of the MOIL Run</u>

1. File: GAMMA.NOH85

   Lines: 98, 100

   Changes: Same changes as in COILG.

2. File: GAMMA.REVISE 90, 95

   Lines: 601-602, 604-605

   Changes:

   (a) Original Lines 601-602 (in CBC):

```
NUSCST=(TRPGPRCP,(UR),PRC)+(OILPRICE,1,(YY))
     *(CASE,CSTMULT,DATA)
```

   New Lines 601-602 (in MOIL):

```
NUSCST=(TRPGPRCP,(UR),PRC)+(OILPRICE,1,(YY))
     *(CASE,CSTMULT,DATA)*1.25
```

(b) Original Lines 604-605 (in CBC):

```
NUSCST=(TRDGPRCP,(UR),PRC)+(OILPRICE,1,(YY))
      *(CASE,CSTMULT,DATA)
```

New Lines 604-605 (in MOIL):

```
NUSCST=(TRDGPRCP,(UR),PRC)+(OILPRICE,1,(YY))
      *(CASE,CSTMULT,DATA)*1.25
```

Table 78

Modified Oil/Gas Price Increase (MOIL)

	CBC-1985	MOIL-1985	CBC-1990	MOIL-1990	CBC-1995	MOIL-1995
LP Objective Function (10^6\$, 1978)	74062.08	78496.86	104356.27	106772.68	140080.62	142617.81
National Coal Transportation (10^9 Ton Miles)	556.88	579.71	885.28	931.22	1208.41	1184.60
Western Coal to Eastern Destinations						
(10^6 Tons)	77.37	80.63	123.38	123.90	175.32	167.02
(10^9 Ton-Miles)	97.71	101.16	151.60	152.02	218.17	205.56
Eastern Coal to Western Destinations						
(10^6 Tons)	19.07	18.98	20.41	17.40	18.17	17.83
(10^9 Ton-Miles)	3.23	3.65	3.08	2.25	2.86	2.72
Transmission Transmitted (Before Losses) (10^9 kWh)						
Existing	161.167	178.901	135.308	136.422	107.377	113.793
New	197.289	260.238	167.308	186.303	176.021	180.942
National Total Coal Production Quantities and Prices[a]						
Metallurgical (MM Tons)	163.57	165.89	169.93	170.23	173.23	177.47
Metallurgical (\$/MM Btu)	1.66	1.67	1.78	1.79	1.86	1.86
Low Sulfur (MM Tons)	284.83	301.00	459.77	487.30	623.49	602.08
Low Sulfur (\$/MM Btu)	0.85	0.84	0.80	0.81	0.83	0.85
Medium Sulfur (MM Tons)	411.75	414.42	544.92	556.31	641.73	646.23
Medium Sulfur (\$/MM Btu)	1.02	1.03	1.07	1.08	1.11	1.12
High Sulfur (MM Tons)	254.90	259.75	330.45	356.40	437.12	450.14
High Sulfur (\$/MM Btu)	1.04	1.05	1.23	1.25	1.33	1.33
Surface	599.675	613.842	779.491	801.620	962.596	939.347
Deep	515.373	527.209	725.578	768.610	912.968	936.569
Total: (MM Tons)	1115.048	1141.051	1505.069	1570.229	1875.564	1875.915
Total: (\$/MM Btu)	1.10	1.11	1.14	1.15	1.18	1.19
Growth Rate (%/year)	5.6	5.8	5.8	6.1	5.5	5.5
Total U.S. Coal Consumption - Quantities and Prices						
(MM Tons)	1105.9	1131.9	1506.6[c]	1571.9[c]	1875.5	1875.9
(\$/Tons)[b]	31.58	31.80	33.19	33.36	34.14	34.40
(\$/MM Btu)	1.44	1.45	1.55	1.56	1.62	1.62
Electric Utility Coal Consumption - Quantities and Prices						
(Quads)	16.07	16.59	20.92	22.36	26.54	26.70
(\$/MM Btu)	1.35	1.36	1.48	1.49	1.56	1.57
Electric Utility Coal Consumption[d] (MM Tons)	753.4	778.9	995.4	1060.6	1280.8	1281.3
Electric Utility Oil/Gas Consumption[e] (Quads)	5.848	5.289	3.283	1.753	1.898	1.714
Electric Utility Capacity Utilization (GW)[f]						
Existing	486.6	478.2	454.1	405.2	417.3	411.9
New	230.7	239.5	417.4	466.4	640.6	646.1

*These runs were not made.
[a]For 1985, the base year (1975) total coal production is 647.45 MM Tons.
[b]Volume - Weighted Average
[c]Consumption - Production (Due to Negative Net Washing Losses)
[d]The base year (1975) electric utility coal consumption is 420.8 MM Tons.
[e]The base year (1975) electric utility oil/gas consumption is 3.073 Quads.
[f]The base year (1975) existing electric utility capacity is 500.8 GW.

Table 79

SENSITIVITY TO INCREASE IN OIL/GAS PRICES BY 25%

CBC-90 vs. MOIL-90

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1990.
RUN ID: MOIL90C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE	DEVIATIONS	
($MM)	Q	P
36807	0.043	0.008

REGIONAL AVERAGES

REG	VALUE	DEVIATIONS	
	($MM)	Q	P
PA	4187	0.064	0.008
OH	1161	0.124	0.009
MD	113	0.000	0.004
NV	3567	0.025	0.007
SV	5863	0.000	0.002
VA	769	0.019	0.001
EK	1861	0.000	0.001
TN	60	0.000	0.004
AL	652	0.000	0.002
IL	5940	0.074	0.008
IN	1407	0.064	0.008
WK	1518	0.000	0.011
IA	26	0.746	0.001
MO	93	0.013	0.007
KS	5	0.000	0.005
OK	84	0.039	0.005
AR	108	0.086	0.001
ND	169	0.303	0.001
SD	12	0.000	0.000
EM	5	0.000	0.001
WM	2611	0.058	0.000
WY	3068	0.008	0.005
CS	1052	0.048	0.031
UT	577	0.098	0.084
AZ	174	0.103	0.233
NM	761	0.213	0.000
WA	55	0.000	0.001
TX	867	0.000	0.001
CN	41	0.000	0.000
AK	0	0.000	0.000

Table 80

SENSITIVITY TO INCREASE IN OIL/GAS PRICES BY 25%

CBC-95 vs. MOIL-95

COMPARISON RUN
BASE ID: CORRECTED BASE CASE, 1995.
RUN ID: MOIL95C

NUMBER OF SUPPLY CURVES = 191

NATIONAL AVERAGES

VALUE ($MM)	DEVIATIONS Q	P
46605	0.025	0.004

REGIONAL AVERAGES

REG	VALUE ($MM)	DEVIATIONS Q	P
PA	5549	0.006	0.002
OH	2166	0.047	0.001
MD	167	0.000	0.002
NV	4488	0.000	0.002
SV	5774	0.000	0.001
VA	811	0.000	0.001
EK	1910	0.091	0.001
TN	0	0.000	0.000
AL	595	0.031	0.001
IL	7973	0.040	0.002
IN	1839	0.006	0.002
WK	1963	0.000	0.002
IA	93	0.000	0.003
MO	148	0.027	0.003
KS	0	0.000	0.000
OK	128	0.103	0.002
AR	175	0.000	0.001
ND	226	0.253	0.009
SD	12	0.000	0.000
EM	1	0.000	0.001
WM	4580	0.058	0.000
WY	4120	0.003	0.003
CS	1172	0.098	0.017
UT	533	0.076	0.038
AZ	81	0.000	0.096
NM	1067	0.009	0.049
WA	17	0.000	0.000
TX	990	0.000	0.000
CN	29	0.000	0.000
AK	0	0.000	0.000

Table 81

LP Objective Function (10^6\$ - 1978)

	1985	1990	1995
CBC	74062.08	104366.27	140080.62
CNSPS	73755.00	102419.82	136815.48
CML20	73390.59	102897.20	137763.32
CEDMD	62221.03	89112.18	121098.88
CMILL	77664.36	*	*
CNINC	73406.23	102923.39	138060.06
COILG	78496.86	105313.45	141368.44
UCIN	74773.57	105261.60	140040.50
UDIN	74127.66	103899.82	137959.75
LAB3	78368.76	111791.06	150923.25
TCML	73196.40	103055.00	138459.60
LOAD	82449.21	116612.62	159400.85
ROYI	75232.38	106475.16	143139.17
EDMI	80420.73	112323.32	149998.51
UCD4	77205.22	110463.19	150012.12
LABD	71278.48	99634.64	133527.96
LOGN	74774.08	105529.43	141607.66
CDRB	73826.20	103850.20	139229.20
LDC1	75511.10	106587.08	143622.92
NCAP	76857.16	109006.11	146587.15
MOIL	78496.86	106772.68	142617.81

*These runs were not made.

Table 82

Coal Transportation in National 10^9 Ton-Miles

	1985	1990	1995
CBC	556.88	885.28	1208.41
CNSPS	574.44	971.17	1289.30
CML20	539.82	863.08	1082.03
CEDMD	499.16	769.30	1031.69
CMILL	554.67	*	*
CNINC	549.80	828.91	1114.27
COILG	579.71	904.83	1207.81
UCIN	555.30	904.74	1193.22
UDIN	556.58	*	*
LAB3	699.07	1129.41	1509.54
TCML	585.93	985.24	1282.24
LOAD	545.85	845.13	1130.65
ROYI	607.81	1010.68	1353.71
EDMI	588.06	956.07	1300.19
UCD4	558.99	853.44	1172.24
LABD	514.55	820.48	1059.58
LOGN	562.63	935.88	1254.63
CDRB	568.00	903.14	1230.29
LDC1	555.90	875.90	1188.19
NCAP	573.39	944.62	1291.16
MOIL	579.71	931.22	1184.60

*These runs were not made.

Table 83

Western Coal to Eastern Destinations

	1985		1990		1995	
	10^6 Tons	10^9 Ton-Miles	10^6 Tons	10^9 Ton-Miles	10^6 Tons	10^9 Ton-Miles
CBC	77.37	97.71	123.38	151.60	175.32	218.17
CNSPS	89.37	114.66	169.56	229.00	244.00	333.33
CML20	82.99	104.61	113.22	138.49	123.83	149.18
CEDMD	67.91	85.52	108.94	134.36	154.46	197.10
CMILL	77.51	97.74	*	*	*	*
CNINC	73.65	93.23	107.84	133.00	158.44	198.39
COILG	80.63	101.16	123.26	151.93	176.51	219.90
UCIN	74.25	93.66	122.36	151.58	173.26	215.90
UDIN	73.49	92.80	*	*	*	*
LAB3	176.15	243.76	299.20	410.78	378.59	522.34
TCML	94.36	120.71	188.32	244.48	236.32	305.30
LOAD	69.26	89.20	108.63	134.53	162.23	202.46
ROYI	113.95	148.27	205.38	268.49	274.84	361.59
EDMI	83.76	105.09	131.34	162.19	191.27	239.05
UCD4	79.62	100.14	125.41	153.30	162.47	201.96
LABD	61.65	76.40	72.34	87.79	78.66	94.52
LOGN	85.15	107.50	168.98	217.13	210.27	268.32
CDRB	86.78	109.53	136.43	167.81	186.63	238.08
LDC1	75.29	96.03	118.17	146.09	170.71	212.86
NCAP	81.73	102.52	133.80	165.84	193.51	242.64
MOIL	80.63	101.16	123.90	152.02	167.02	205.56

*These runs were not made.

Table 84

Eastern Coal to Western Destinations

	1985		1990		1995	
	10^6 Tons	10^9 Ton-Miles	10^6 Tons	10^9 Ton-Miles	10^6 Tons	10^9 Ton-Miles
CBC	19.07	3.23	20.41	3.08	18.17	2.86
CNSPS	18.12	2.67	21.67	3.50	19.89	2.65
CML20	24.80	6.94	24.19	4.84	20.02	2.99
CEDMD	19.74	4.26	20.94	4.00	17.65	2.47
CMILL	20.01	3.87	*	*	*	*
CNINC	19.08	3.20	20.32	3.00	18.18	2.86
COILG	18.98	3.65	18.63	2.81	18.01	2.79
UCIN	18.55	2.92	18.39	2.42	17.86	2.69
UDIN	18.55	2.92	*	*	*	*
LAB3	16.07	2.43	9.73	1.66	7.95	2.14
TCML	18.62	2.91	19.64	3.03	18.41	2.91
LOAD	19.24	3.81	19.20	2.94	18.27	2.89
ROYI	16.42	2.54	9.70	1.41	8.15	2.08
EDMI	19.40	3.16	19.01	2.31	18.39	2.97
UCD4	19.57	4.18	19.66	3.39	17.99	2.90
LABD	30.03	9.31	28.50	5.63	25.67	4.24
LOGN	15.28	2.28	16.05	1.62	13.71	2.67
CDRB	18.86	3.78	17.98	2.55	17.50	2.73
LDC1	19.45	3.57	19.88	3.01	18.88	2.93
NCAP	19.22	3.78	17.62	2.25	17.99	2.78
MOIL	18.98	3.65	17.40	2.25	17.83	2.72

*These runs were not made.

Table 85

Transmission - 10^9 KWH Transmitted (Before Losses)

	1985		1990		1995	
	Existing	New	Existing	New	Existing	New
CBC	161.167	197.289	135.308	167.308	107.377	176.021
CNSPS	161.171	186.448	132.463	156.822	111.837	196.061
CML20	161.939	198.525	134.243	178.620	107.268	156.993
CEDMD	168.646	152.322	152.358	173.133	129.061	150.561
CMILL	161.549	181.401	*	*	*	*
CNINC	173.077	162.998	161.369	169.164	143.003	143.912
COILG	178.901	260.238	138.409	184.650	114.114	192.194
UCIN	160.349	201.376	128.491	175.997	107.488	178.226
UDIN	162.334	205.618	*	*	*	*
LAB3	160.372	170.341	137.668	158.054	109.067	171.633
TCML	160.866	199.270	133.349	161.258	108.103	154.107
LOAD	166.843	158.497	144.078	145.909	120.826	140.444
ROYI	159.502	194.971	132.914	162.357	104.079	173.011
EDMI	169.425	210.960	129.552	178.441	108.602	190.214
UCD4	161.013	173.581	136.409	150.166	110.084	138.006
LABD	163.479	201.351	130.986	167.651	107.306	141.942
LOGN	159.446	195.857	134.167	148.729	106.224	157.917
CDRB	161.538	196.950	135.498	164.887	107.955	173.177
LDC1	164.395	187.732	134.699	174.588	113.286	167.155
NCAP	179.977	203.634	135.082	189.712	113.988	204.316
MOIL	178.901	260.238	136.422	186.303	113.793	180.942

*These runs were not made.

A

Table 86a

1985 Production Quantities and Prices - National 1

	MET		Low Sulfur		Med. Sulfur		High Sulfur	
	MM Tons	$/MM BTU	MM Tons	$/MM BTU	MM Tons	$/MM BTU	MM Tons	$/MM BTU
CBC	163.57	1.66	284.83	0.85	411.75	1.02	254.90	1.04
CNSPS	166.63	1.68	302.85	0.85	411.73	1.02	239.28	1.02
CML20	175.62	1.56	270.09	0.87	407.62	0.97	255.75	1.00
CEDMD	152.20	1.61	253.46	0.85	374.66	0.99	228.68	1.02
CMILL	163.79	1.74	285.24	0.88	405.23	1.06	254.08	1.08
CNINC	161.64	1.65	281.18	0.84	402.52	1.01	248.36	1.03
COILG	165.89	1.67	301.00	0.84	414.42	1.03	259.75	1.05
UCIN	161.99	1.73	282.13	0.88	416.87	1.07	257.72	1.11
UDIN	161.99	1.73	282.90	0.87	417.60	1.07	258.25	1.11
LAB3	140.15	2.07	359.97	0.90	400.29	1.17	240.81	1.35
TCML	162.84	1.65	305.83	0.83	399.73	1.01	252.45	1.03
LOAD	161.64	1.65	277.61	0.84	401.00	1.01	252.40	1.03
ROYI	150.74	1.78	318.51	0.86	402.77	1.07	251.14	1.14
EDMI	172.59	1.68	303.89	0.85	421.89	1.03	265.53	1.06
UCD4	165.89	1.67	288.02	0.86	405.63	1.02	245.38	1.03
LABD	188.33	1.41	266.93	0.77	398.95	0.87	249.31	0.86
LOGN	175.26	1.70	294.28	0.86	414.68	1.05	228.36	1.14
CDRB	174.55	1.62	290.09	0.85	397.50	0.99	251.34	1.03
LDC1	163.79	1.66	283.94	0.85	410.68	1.02	254.90	1.05
NCAP	165.89	1.67	295.35	0.85	417.14	1.03	262.88	1.06
MOIL	165.89	1.67	301.00	0.84	414.42	1.03	259.75	1.05

B

Table 86b

1985 Production Quantities and Prices - National Totals

	Surface	Deep	Total: MM Tons	$/MM BTU	Growth Rate - %/yr.
CBC	599.675	515.373	1115.048	1.10	5.6
CNSPS	612.283	508.206	1120.489	1.10	5.6
CML20	603.042	506.026	1109.068	1.07	5.5
CEDMD	561.253	447.747	1009.000	1.08	4.5
CMILL	598.107	510.227	1108.334	1.15	5.5
CNINC	595.872	497.813	1093.685	1.09	5.4
COILG	613.842	527.209	1141.051	1.11	5.8
UCIN	601.683	517.020	1118.703	1.15	5.6
UDIN	603.051	517.686	1120.737	1.15	5.6
LAB3	708.688	432.534	1141.223	1.28	5.8
TCML	614.232	506.615	1120.847	1.09	5.6
LOAD	589.563	503.075	1092.638	1.10	5.4
ROYI	632.254	490.903	1123.157	1.16	5.7
EDMI	617.220	546.674	1163.894	1.12	6.0
UCD4	597.769	507.146	1104.915	1.11	5.5
LABD	560.759	542.765	1103.523	0.96	5.5
LOGN	623.357	489.218	1112.575	1.15	5.6
CDRB	609.081	504.398	1113.478	1.09	5.6
LDC1	597.648	515.658	1113.306	1.11	5.6
NCAP	608.649	532.615	1141.264	1.11	5.8
MOIL	613.842	527.209	1141.051	1.11	5.8

†The base year (1975) total coal production is 647.45 MM Tons.

Table 87a

1990 Production Quantities and Prices - National T

	MET		Low Sulfur		Med. Sulfur		High Sulfur	
	MM Tons	$/MM BTU	MM Tons	$/MM BTU	MM Tons	$/MM BTU	MM Tons	$/MM BTU
CBC	169.93	1.78	459.77	0.80	544.92	1.07	330.45	1.23
CNSPS	200.44	1.87	564.67	0.80	489.58	1.08	269.90	1.18
CML20	185.58	1.65	450.30	0.78	559.68	1.03	325.49	1.14
CEDMD	156.74	1.74	403.15	0.78	467.17	1.04	284.09	1.18
CMILL	*	*	*	*	*	*	*	*
CNINC	167.11	1.78	426.71	0.81	530.78	1.05	303.99	1.22
COILG	169.93	1.79	477.55	0.80	543.12	1.07	338.52	1.24
UCIN	164.55	1.86	478.70	0.84	546.51	1.14	344.40	1.28
LAB3	134.24	2.22	546.77	0.88	589.09	1.16	281.42	1.57
TCML	165.15	1.77	537.06	0.77	535.64	1.05	295.88	1.22
LOAD	165.55	1.77	428.66	0.81	538.04	1.06	323.03	1.23
ROYI	153.34	1.90	544.87	0.78	533.21	1.12	295.31	1.34
EDMI	176.32	1.80	513.15	0.79	558.81	1.09	358.63	1.25
UCD4	172.92	1.79	446.36	0.80	530.31	1.06	313.57	1.23
LABD	194.01	1.52	453.25	0.73	506.52	0.96	339.90	1.03
LOGN	181.04	1.80	504.86	0.77	562.73	1.11	256.17	1.30
CDRB	178.02	1.72	481.85	0.76	521.71	1.06	325.44	1.20
LDC1	169.93	1.78	452.80	0.81	538.00	1.07	334.79	1.23
NCAP	171.43	1.79	502.68	0.79	558.21	1.09	352.34	1.25
MOIL	170.23	1.79	487.30	0.81	556.31	1.08	356.40	1.25

* This run was not made.

Table 87b

1990 Production Quantities and Prices - National

	Surface	Deep	Total: MM Tons	$/MM BTU	Growth Rate - %/yr.
CBC	779.491	725.578	1505.069	1.14	5.8
CNSPS	829.975	694.614	1524.589	1.14	5.9
CML20	799.563	721.488	1521.051	1.09	5.9
CEDMD	690.922	620.229	1311.150	1.11	4.8
CMILL	*	*	*	*	*
CNINC	741.746	686.838	1428.584	1.14	5.4
COILG	792.909	736.206	1529.115	1.14	5.9
UCIN	798.179	735.963	1534.143	1.19	5.9
LAB3	979.434	572.082	1551.516	1.28	6.0
TCML	849.681	684.040	1533.720	1.10	5.9
LOAD	746.041	709.241	1455.281	1.14	5.5
ROYI	866.373	660.358	1526.731	1.16	5.9
EDMI	829.364	777.558	1606.921	1.14	6.2
UCD4	759.747	703.410	1463.157	1.14	5.6
LABD	703.583	790.096	1493.679	1.01	5.7
LOGN	846.586	658.213	1504.799	1.15	5.8
CDRB	795.318	711.705	1507.023	1.11	5.8
LDC1	771.683	723.831	1495.514	1.14	5.7
NCAP	821.339	763.309	1584.647	1.14	6.1
MOIL	801.620	768.610	1570.229	1.15	6.1

* This run was not made.

A

Table 88a

1995 Production Quantities and Prices - National

	MET		Low Sulfur		Med. Sulfur		High Sulfur	
	MM Tons	$/MM BTU	MM Tons	$/MM BTU	MM Tons	$/MM BTU	MM Tons	$/MM BTU
CBC	173.23	1.86	623.49	0.83	641.73	1.11	437.12	1.33
CNSPS	208.44	2.06	735.75	0.92	604.23	1.15	328.95	1.27
CML20	190.94	1.69	551.88	0.81	688.79	1.08	424.18	1.24
CEDMD	162.86	1.82	553.14	0.78	549.84	1.11	346.69	1.28
CMILL	*	*	*	*	*	*	*	*
CNINC	171.13	1.84	559.36	0.81	629.52	1.08	390.17	1.30
COILG	172.85	1.86	621.14	0.84	646.74	1.12	442.06	1.33
UCIN	171.14	1.95	579.01	0.89	706.45	1.13	426.55	1.40
LAB3	135.53	2.34	732.30	1.03	715.31	1.28	361.64	1.68
TCML	169.15	1.84	672.46	0.83	638.94	1.09	412.56	1.30
LOAD	171.24	1.85	560.77	0.81	634.13	1.08	408.77	1.30
ROYI	159.23	2.01	677.20	0.84	685.80	1.11	388.57	1.43
EDMI	179.11	1.87	658.38	0.84	707.70	1.10	465.77	1.34
UCD4	179.40	1.87	597.60	0.86	643.65	1.11	432.66	1.32
LABD	194.00	1.61	573.82	0.74	597.24	1.02	469.39	1.11
LOGN	183.28	1.88	637.75	0.81	686.17	1.10	379.62	1.36
CDRB	183.45	1.79	676.73	0.75	606.38	1.11	411.08	1.30
LDC1	172.45	1.86	608.96	0.84	650.96	1.10	422.22	1.33
NCAP	174.37	1.86	658.14	0.83	697.25	1.11	464.53	1.34
MOIL	177.47	1.86	602.08	0.85	646.23	1.12	450.14	1.33

* This run was not made.

B

Table 88b

1995 Production Quantities and Prices - National Totals

	Surface	Deep	Total: MM Tons	$/MM BTU	Growth Rate - %/yr.
CBC	962.596	912.968	1875.564	1.18	5.5
CNSPS	1005.437	871.929	1877.366	1.23	5.5
CML20	923.865	931.922	1855.787	1.13	5.4
CEDMD	825.515	787.010	1612.526	1.14	4.7
CMILL	*	*	*	*	*
CNINC	900.441	849.736	1750.177	1.15	5.1
COILG	961.213	921.577	1882.790	1.18	5.5
UCIN	966.747	916.398	1883.145	1.23	5.5
LAB3	1203.311	741.470	1944.781	1.38	5.7
TCML	1017.620	875.492	1893.113	1.15	5.5
LOAD	902.187	872.709	1774.897	1.16	5.2
ROYI	1077.063	833.729	1910.792	1.20	5.6
EDMI	1037.324	973.632	2010.956	1.17	5.8
UCD4	931.611	921.691	1853.303	1.19	5.4
LABD	820.131	1014.311	1834.442	1.05	5.3
LOGN	1040.639	846.183	1886.821	1.17	5.5
CDRB	977.321	900.326	1877.647	1.13	5.5
LDC1	947.187	907.404	1854.591	1.18	5.4
NCAP	1027.258	967.021	1994.280	1.17	5.8
MOIL	939.347	936.569	1875.915	1.19	5.5

* This run was not made.

Table 69

Total U.S. Coal Consumption - Quantities and Prices

	1985			1990			1995		
	MM Tons	\$/Ton▽	\$/MM BTU	MM Tons	\$/Ton▽	\$/MM BTU	MM Tons	\$/Ton▽	\$/MM BTU
CBC	1105.9	31.58	1.44	1506.6†	33.19	1.55	1875.5	34.14	1.6[illegible]
CNSPS	1109.8	31.81	1.45	1522.8	33.82	1.59	1861.4	35.99	1.70
CML20	1101.4	30.80	1.39	1524.5†	31.62	1.48	1858.5†	32.70	1.54
CEDMC	1000.6	30.73	1.40	1313.2†	32.53	1.52	1613.0†	33.53	1.5[illegible]
CMILL	1099.3	33.17	1.51	*	*	*	*	*	*
CNINC	1084.4	31.34	1.43	1429.6†	33.06	1.54	1750.5†	33.63	1.59
COILG	1131.9	31.80	1.45	1530.6†	33.17	1.55	1882.7	34.20	1.6[illegible]
UCIN	1109.2	33.22	1.51	1535.4†	34.93	1.63	1883.3†	35.85	1.70
UDIN	1111.3	33.19	1.51	*	*	*	*	*	*
LAB3	1132.8	35.55	1.67	1552.5†	36.44	1.78	1944.3	38.72	1.9[illegible]
TCML	1111.9	30.59	1.40	1535.6†	31.79	1.50	1893.5†	32.79	1.57
LOAD	1083.3	31.35	1.43	1456.3†	33.22	1.55	1775.5†	33.82	1.60
ROYI	1113.7	32.83	1.51	1528.0†	34.05	1.62	1910.4	34.82	1.69
EDMI	1154.9	32.07	1.46	1608.6†	33.31	1.56	2011.0†	34.09	1.6[illegible]
UCD4	1095.7	31.71	1.44	1465.0†	33.21	1.55	1854.3†	34.38	1.6[illegible]
LABD	1094.8	28.38	1.27	1495.8†	30.36	1.39	1835.6†	31.33	1.4[illegible]
LOGN	1103.7	32.73	1.49	1506.8†	33.74	1.58	1886.9†	34.26	1.63
CDRB	1105.1	31.43	1.43	1509.5†	32.57	1.52	1879.6†	33.23	1.5[illegible]
LDC1	1104.1	31.67	1.44	1497.1†	33.19	1.55	1854.5	34.14	1.6[illegible]
NCAP	1132.1	31.85	1.45	1586.1†	33.22	1.55	1994.2	34.06	1.6[illegible]
MOIL	1131.9	31.80	1.45	1571.9†	33.36	1.56	1875.9	34.40	1.6[illegible]

▽ Volume - Weighted Average

† Consumption > Production (Due to Negative Net Washing Losses)

* These runs were not made.

Table 90

Electric Utility Coal Consumption - Quantities and Prices

	1985		1990		1995	
	Quads	$/MM BTU	Quads	$/MM BTU	Quads	$/MM BTU
CBC	16.07	1.35	20.92	1.48	26.54	1.56
CNSPS	16.14	1.36	21.13	1.53	26.35	1.66
CML20	16.10	1.31	21.18	1.42	26.55	1.49
CEDMD	14.56	1.31	17.92	1.45	22.44	1.53
CMILL	15.91	1.41	*	*	*	*
CNINC	15.55	1.33	19.30	1.47	23.97	1.53
COILG	16.59	1.36	21.41	1.49	26.71	1.56
UCIN	16.14	1.41	21.54	1.56	26.73	1.64
UDIN	16.17	1.41	*	*	*	*
LAB3	15.85	1.54	20.50	1.67	26.42	1.82
TCML	16.06	1.31	21.17	1.44	26.60	1.51
LOAD	15.57	1.33	19.93	1.48	24.53	1.54
ROYI	16.00	1.41	20.85	1.55	26.57	1.61
EDMI	16.73	1.37	22.49	1.49	28.67	1.56
UCD4	15.84	1.35	20.04	1.48	26.25	1.57
LABD	16.13	1.20	21.25	1.34	26.59	1.41
LOGN	16.01	1.40	20.77	1.52	26.59	1.57
CDRB	16.05	1.35	20.92	1.47	26.55	1.53
LDC1	16.04	1.35	20.74	1.48	26.15	1.56
NCAP	16.64	1.36	22.58	1.49	28.99	1.56
MOIL	16.59	1.36	22.36	1.49	26.70	1.57

* These runs were not made.

Table 91

Electric Utility Coal Consumption† (MM Tons)

	1985	1990	1995
CBC	753.4	995.4	1280.8
CNSPS	757.8	1013.2	1268.6
CML20	752.1	1014.8	1264.7
CEDMD	684.8	855.4	1078.7
CMILL	747.4	*	*
CNINC	731.9	920.0	1156.5
COILG	778.9	1019.7	1288.2
UCIN	757.5	1024.7	1289.3
UDIN	758.5	*	*
LAB3	778.9	1041.3	1349.4
TCML	758.1	1025.7	1300.0
LOAD	730.3	947.0	1181.2
ROYI	761.2	1017.5	1315.9
EDMI	784.1	1071.1	1386.0
UCD4	742.7	953.8	1259.9
LABD	746.4	987.5	1241.0
LOGN	752.3	999.1	1295.7
CDRB	753.2	998.9	1285.2
LDC1	751.4	987.4	1260.9
NCAP	779.0	1074.6	1399.3
MOIL	778.9	1060.6	1281.3

† The base year (1975) electric utility coal consumption is 420.8 MM Tons.

* These runs were not made.

Table 92

Electric Utility Oil/Gas Consumption† (Quads)

	1985	1990	1995
CBC	5.848	3.283	1.898
CNSPS	5.717	2.816	1.718
CML20	5.792	3.066	1.853
CEDMD	4.255	2.626	1.621
CMILL	6.022	*	*
CNINC	5.473	3.051	1.860
COILG	5.289	2.760	1.711
UCIN	5.768	2.613	1.719
UDIN	5.737	*	*
LAB3	6.106	3.802	2.150
TCML	5.843	3.025	1.856
LOAD	6.745	4.850	4.727
ROYI	5.919	3.367	1.928
EDMI	6.747	3.515	1.996
UCD4	6.101	4.227	2.195
LABD	5.750	2.862	1.748
LOGN	5.885	3.437	1.881
CDRB	5.846	3.254	1.856
LDC1	5.962	3.594	2.483
NCAP	6.371	3.394	1.899
MOIL	5.289	1.753	1.714

† The base year (1975) electric utility oil/gas consumption is 3.073 Quads.

* These runs were not made.

Table 93

Electric Utility Capacity Utilization† (GW)

	1985		1990		1995	
	Existing	New	Existing	New	Existing	New
CBC	486.6	230.7	454.1	417.4	417.3	640.6
CNSPS	484.5	232.8	439.0	432.7	410.1	648.6
CML20	485.5	231.6	445.0	426.2	415.9	641.6
CEDMD	458.8	187.8	435.3	349.9	408.4	544.6
CMILL	488.3	229.0	*	*	*	*
CNINC	482.4	235.1	448.6	423.2	418.4	639.8
COILG	478.2	239.5	439.0	432.5	411.9	646.1
UCIN	485.3	232.1	433.0	438.8	409.8	648.6
UDIN	484.7	232.7	*	*	*	*
LAB3	488.3	232.2	465.8	410.0	423.7	638.5
TCML	486.5	230.9	445.6	426.5	415.6	642.8
LOAD	500.3	453.0	485.9	671.3	483.0	920.9
ROYI	486.8	231.3	455.6	417.3	417.6	642.0
EDMI	491.8	260.8	452.9	461.9	411.6	699.1
UCD4	488.5	228.6	477.1	394.2	427.2	630.4
LABD	484.9	231.9	441.1	429.7	412.1	645.0
LOGN	486.7	230.8	458.4	413.5	416.3	642.2
CDRB	486.5	230.6	453.3	418.0	415.7	642.1
LDC1	496.4	268.2	470.5	458.4	444.4	682.9
NCAP	482.8	234.4	446.2	425.4	405.5	652.7
MOIL	478.2	239.5	405.2	466.4	411.9	646.1

† The base year (1975) existing electric utility capacity is 500.8 GW.

* These runs were not made.

Table 94

Comparison of Sensitivity Runs with the Corrected Base Case Using National Average Deviation Indexes of Coal Equilibrium Quantities and Prices

	1985		1990		1995	
	Quantity	Price	Quantity	Price	Quantity	Price
CNSPS	.036	.011	.161	.041	.177	.074
CML20	.192	.053	.216	.066	.209	.076
CEDMD	.092	.024	.122	.037	.125	.047
CMILL	.010	.044	*	*	*	*
CNINC	.022	.007	*	*	*	*
COILG	.018	.008	.017	.001	.013	.002
UCIN	.014	.049	.034	.049	.039	.048
UDIN	.018	.049	*	*	*	*
LAB3	.148	.248	.202	.242	.188	.275
TCML	.031	.009	.066	.011	.044	.017
LOAD	.028	.006	.028	.006	.046	.023
ROYI	.088	.073	.126	.064	.102	.064
EDMI	.047	.014	.062	.010	.062	.007
UCD4	.033	.008	.037	.008	.024	.007
LABD	.087	.156	.107	.151	.125	.152
LOGN	.098	.045	.154	.025	.123	.015
CDRB	.091	.016	.148	.030	.177	.044
LDC1	.002	.002	.011	.002	.011	.003
NCAP	.030	.010	.046	.007	.056	.007
MOIL	*	*	.043	.008	.025	.004

*These comparison runs were not made.

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